ATTACHMENT 1

2010 Demand Response Cost Effectiveness Protocols

2010 Demand Response Cost-Effectiveness Protocols

Table of Contents

List of Abbreviations 3
SECTION 1: BASIC INFORMATION 4
Section 1.B: Methods Used to Estimate Costs and Benefits 6
Section 1.C: Confidentiality 10
Section 1.D: Relationship to the Standard Practice Manual 10
Section 1.E: Relationship to the Planning Reserve Margin and Resource Adequacy 11
Section 1.F: Types of analyses expected 12
Section 1.G: Portfolio Analysis 14
SECTION 2: USING THE STANDARD PRACTICE MANUAL TESTS TO DETERMINE DR COST-EFFECTIVENESS 14
Section 2.A: Total Resource Cost (TRC) Test 15
Section 2.B: Program Administrators Cost (PAC) Test 15
Section 2.C: Ratepayer Impact Measure (RIM) Test 16
Section 2.D: Participant Test 16
SECTION 3: COSTS AND BENEFITS OF DEMAND RESPONSE 17
Section 3.A: Administrative Costs 17
Section 3.B: Ancillary Services Market Revenues 18
Section 3.C: Avoided Costs of Supplying Electricity 18
1) Avoided Generation Capacity Costs 21
2) Avoided Energy Costs 25
3) Avoided Transmission and Distribution Costs: 26
4) Avoided Costs and the MRTU 27
Section 3.D: Bill Increases and Reductions 28
Section 3.E: Capital Costs to LSE 28
Section 3.F: Capital Costs to Participant 29
Section 3.G: Environmental Benefits 29
Section 3.H: Incentives Paid 31
Section 3.I: Increased Supply Costs 32
Section 3.J: Market and Reliability Benefits 32
Section 3.K: Non-Energy and Non-Monetary Benefits 33
Section 3.L: Revenue Gain or Loss from Sales Increases or Decreases 34
Section 3.M: Tax Credits 34
Section 3.N: Transaction Costs and Value of Service Lost 34

List of Abbreviations

AMI – Advanced Metering Infrastructure (i.e., Smart Meters)
AS – Ancillary Services
BUG – Back-up Generator
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
E3 – Energy and Environmental Economics (consulting firm)
ED – Energy Division (of the CPUC)
EE – Energy Efficiency
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
LMP – Locational Marginal Price
LOLE/P – Loss of Load Expectation/Loss of Load Probability
LSE – Load-Serving Entity
MRTU – Market Redesign and Technology Upgrade
MW – Megawatt
MWh – Megawatt-hour
NOAA – National Oceanic and Atmospheric Administration
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 2010 Demand Response (DR) Cost-Effectiveness Protocols (2010 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 DR cost-effectiveness protocols that are described in this document are 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),[1] the Demand Response Cost-effectiveness Evaluation Framework submitted by the Consensus Parties (Consensus Parties Framework),[2] and the Staff Draft Demand Response Cost-effectiveness Protocols filed as Attachment A of the April 4, 2008 ruling in this proceeding.[3] The protocols described in this document are designed for these 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 those three IOUs may 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. 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. As a result, the methods we use to measure the costs and benefits of demand response must be flexible enough to capture these emerging benefits.

---

[1] *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)

[2] *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).

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

The purpose of these cost-effectiveness protocols is to:

- Address the broad variety of DR programs, including current and future activities;
- Identify all relevant quantitative and qualitative inputs that are important for determining the cost-effectiveness of DR;
- Establish methods for determining the value of the 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 other Commission proceedings:

- 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 rates and tariffs

Section 1.A: Intended Use of Protocols

These protocols will be used for determining the cost-effectiveness of both individual DR programs and an LSE's overall DR portfolio. They will be used for evaluations associated with approval of all DR programs that provide measurable load reductions. 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 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 will also be a key tool for evaluating third-party aggregation proposals. However, 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 those programs will be considered when measuring the cost-effectiveness of a utility's entire DR portfolio.

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 or Advanced Metering Infrastructure (AMI) application. 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.

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, avoided costs, Smart Grid or other issues, by actual program design and operations, and by the California Independent System Operator's (CAISO's) Market Redesign and Technology Upgrade (MRTU). 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 utilities used in their AMI cases, and the Integrated Resource Planning (IRP) approach. Both of these approaches could be workable for programs that have a large decremental effect on the utility systems, but these approaches are generally not "sensitive" enough to properly measure the costs and benefits of specific demand response programs, which sometimes 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.

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 cost-effectiveness, 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*. However, *ex post* analysis is useful for informing assumptions or forecasts needed for *ex ante* analysis. *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 budgeting cycles to ensure the new forecasts are consistent with actual experience.

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

In prior reporting cycles, 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 gross margin and residual capacity value calculations. 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 is extremely difficult to determine to what degree the variations reflect actual differences in the IOU service territories or are 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 results.

The avoided costs used for DR cost-effectiveness calculations will be 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 draws heavily on the methods established by its predecessor, the E3 Calculator, which provides the avoided costs used to value energy efficiency programs. However, the Avoided Cost Calculator refined and updated the E3 Calculator so as to calculate avoided costs applicable to a wide range of distributed energy resources. The Avoided Cost Calculator has been further refined to make it applicable to Demand Response programs, and this modified version of the Avoided Cost Calculator will be used as part of these protocols. The methods used in the modified Avoided Cost Calculator to calculate avoided costs values are similar to those used by the IOUs to report the cost-effectiveness of their 2009-11 DR programs. More information about the calculation of avoided costs is found below in Section 3.c.

In 2009, Energy Division provided the IOUs with an Excel spreadsheet template to facilitate consistent reporting of DR program cost-effectiveness results. An updated version of that template will be used by LSEs to report DR program cost-effectiveness and will be considered part of these protocols. This DR Reporting Template 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 Template. This will enhance both the transparency and consistency of those calculations. The DR Reporting Template will also include a sensitivity analysis, showing how the benefit-cost ratios vary with changes in several key inputs.

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

1. Avoided 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

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
2. Energy Savings, based on expected call hours of the program
3. Administrative Costs
4. Participant Costs
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
11. Adjustment Factors
    - Availability (A Factor)
    - Notification Time (B Factor)
    - Trigger (C Factor)
    - Distribution (D Factor)
    - Energy Price (E Factor)

The LSE may also add the following optional inputs:

1. Environmental benefits (other than the avoided environmental costs for GHG)
2. Market and reliability benefits
3. Non-energy benefits
4. Participant costs

Estimates of the load impacts of a Demand Response resource will be based on expected load impacts as measured using as a basis the Commission-approved DR Load Impact Protocols previously adopted in this proceeding.[4] 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 Requirement (RAR), as determined by the Resource Adequacy (RA) counting rules and requirements in D.10-06-036,[5] 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

[4] 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

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

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.

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[6] of the peak day for each month, then adjusted, as determined by the Energy Division, 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 Energy Division'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 five possible adjustment factors that will be applied to the avoided costs. Utilities have described various methods for adjusting avoided cost values to reflect program characteristics such as notification time and trigger type. These protocols do not adopt a single method for calculating each of the respective factors. With further study and review, it is possible that a consistent method will be developed for one or more factors in future proceedings. Each of the five factors listed above will be input as a percentage adjustment to the relevant avoided cost values. The utilities will be expected to use non-proprietary models and publicly available data to calculate the adjustment factors, and document the calculation of the factors for each applicable program in separate work papers. Application of these factors in the DR Reporting Template will make the relative impact of such

[6] The measurement hours are currently 2:00 – 6:00 p.m. Effective 2012, the new measurement hours for January – March, November and December are 4:00 – 9:00 p.m.; for all other months the hours 1:00 – 6:00 p.m.

factors on each program's cost-effectiveness more transparent, will allow for a more direct comparison of different programs and will facilitate a sensitivity analysis of those factors.

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.

LSEs must also forecast the expected number of hours each dispatchable DR program will be called and, based on the program's load impacts, input the expected energy (MWh) savings of the program. 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 Reporting Template will calculate the costs and benefits of each DR program. The DR Reporting Template 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 Reporting Template 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 Reporting Template will also calculate the $/kW-yr costs of the kW reductions provided by each program. The DR Reporting Template will also perform a sensitivity analysis of key inputs, as discussed in Section 1.F below.

<u>Section 1.C: Confidentiality</u>

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. 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.[7]

<u>Section 1.D: Relationship to the Standard Practice Manual</u>

These cost-effectiveness protocols use the tests described in the California Standard Practice Manual (SPM),[8] 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

[7] *See* Section 454.5(g) of the California Public Utilities Code and D. 06-06-066.

[8] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

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 Demand Response programs and each LSE's Demand Response 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.

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, particularly 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.

As a result, the extent to which DR programs enable a LSE to avoid procurement of generation capacity costs depends upon the extent to which the Commission's RA "counting rules" allow that LSE to count the capacity of DR programs in complying with its RA requirement. At the present time, dispatchable (i.e., event based) Demand Response is counted towards an LSE's RA requirement. Non-dispatchable (i.e., non-event based) DR reduces the LSE's demand forecast, and so ultimately should reduce the LSE's RA requirement. All DR programs covered by these protocols should be designed, to the greatest extent possible, to provide RA value. Nevertheless, for the purpose of DR cost-effectiveness analysis the value of generation capacity avoided by a DR resource will generally not depend on whether the region's physical resources already provide the planning reserve margin required by the Commission, nor on whether an LSE already has enough resources to meet its RA requirement.

Another factor to consider in this context is that cost-effectiveness analyses of DR programs done for resource planning purposes are designed to examine the value of projected load impacts over the appropriate planning horizon. This is likely to encompass a relatively long time period. Load impacts and other DR assessments needed by the CAISO will likely need to be estimated within a much shorter time frame to allow for the CAISO to quickly determine the availability and magnitude of a DR resource. As a result, these cost-effectiveness protocols are not expected to be completely consistent with the CAISO's perspective at this time. In particular, there are significant differences between the CAISO's identified needs, long term procurement needs, and the Resource Adequacy counting rules, especially in how emergency-triggered DR (i.e., DR which is operationally triggered during a CAISO Emergency) is valued, and the impact of locational constraints. As DR plays more of a role in the emerging MRTU framework, we expect that CAISO-identified needs, long term procurement needs and RA counting rules will become more aligned, which will allow us to not only value these programs appropriately but also determine their optimum MW level.

Section 1.F: Types of analyses expected

Many of the costs and benefits of Demand Response (and other) programs are based on uncertain inputs or 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 reporting template 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 on one or two different values for each key variable in addition to the base case analysis. Energy Division 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 Capacity Costs

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 when the benefits **exceed** the costs. Hence, a more accurate assumption is that Participant Benefits are the maximum value for Participant Costs.[9] Hence,

[9] 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 3K. 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.

the sensitivity analysis will use the quantity Incentive Costs + Bill Reductions – Capital Costs to Participant as the **high** value, rather than as the base case value.

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 than the base case, as determined by Energy Division.

For **T&D Capacity Value**, the values calculated by the Avoided Cost Calculator will be considered the base case values. 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.

Each LSE should input the **Capital Amortization Period** for each long-term investment. The base case value of each long-term investment for each year of the program cycle will be the annual levelized value of that investment, increased by a "dropout factor," to reflect customer dropout rates. A sensitivity analysis will be performed which sets the Capital Amortization Period equal to the length of the program cycle (usually three years) for which the cost-effectiveness analysis is being performed, as a high value, and uses the annual levelized value of the investment before the dropout factor (i.e., assuming no dropouts), as a low value. Energy Division will determine a default dropout factor, but LSEs may substitute an alternate dropout factor for any particular DR program, if there is enough program history to determine a more accurate value. LSEs should provide documentation for any alternate value submitted.

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 10^{th} and 90^{th} percentile values as low and high values.

Sensitivity analysis of the adjustment factors is required only for the **A factor** (discussed in Section 3C, below). LSEs should input the results of their A factor analysis, which will be used as the base case value.

Where it is not possible to approximate an uncertain cost or benefit, qualitative analysis of that cost or benefit 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 actually 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. For example, parties have occasionally questioned the environmental benefits of DR because of the possibility that some DR customers are using diesel backup generators during DR events. If a particular DR program does not allow customers to use those generators during events, that program provides a clear environmental benefit which would not be provided by a program which allows the use of backup generators. Another 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.

For each of the optional inputs listed in Section 1.B, LSEs may make an attempt to estimate a value for each DR program. This should be accompanied by an explanation of how the value was derived. If a value cannot be estimated, the LSE shall provide a qualitative analysis, or an explanation of why it is not possible to describe the possible magnitude and impact of that cost or benefit. Other parties are encouraged to provide relevant information about any of the optional inputs.

Section 1.G: 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 the Technical Assistance[10] program and marketing programs such as the Statewide Marketing Campaign, which promote DR in a general rather than any one specific DR program. It does not have to include 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 should include that program's costs and benefits in its portfolio analysis.

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 other 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 Demand Response 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 Reporting Template 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.

[10] But **not** the Technical Incentives program, which should be included in the cost-effectiveness analysis of specific DR programs.

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

The TRC test calculates the costs and benefits to "society" of a demand response resource. For the purposes of these protocols, "society" is considered to be each LSE and its customers.[11]

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 Demand Response to society, these additional benefits should be considered:

- Environmental benefits
- Market benefits
- Participant non-monetary and non-energy benefits

From the perspective of the TRC, the costs of a Demand Response resource are:

- Administrative and capital costs of the resource
- Net 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 Reporting Template. For those costs and benefits which cannot be quantified, LSEs or other parties may provide a qualitative analysis of particular cost or benefit *if* there is evidence that a particular DR resource provides that benefit or incurs that cost, as discussed in Section 1F. It is expected that these types of analyses would be necessary for certain environmental benefits, market benefits, non-monetary and non-energy benefits, value of service lost and participant transaction costs.

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

The PAC test measures cost-effectiveness from the perspective of the LSE or other entity administering the Demand Response program. The benefits are the LSE's avoided costs of supplying electricity, revenue the program may earn in exchange for CAISO market participation, and market benefits.

From the perspective of the PAC, the costs of a Demand Response resource are:

- Administrative and capital costs of the resource
- 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 Reporting Template.

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

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 (such as ancillary services or proxy demand resource)
- 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 of the resource
- 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 Reporting Template.

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 Paid
- Participant non-monetary and 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 safe 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[12]" programs are, for the purposes of this analysis, 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 costs and benefits. The deployment of Smart Meters will allow 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. We expect that 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.

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
Environmental benefits	BENEFIT			
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy/monetary benefits	BENEFIT			BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Tax Credits	BENEFIT			BENEFIT
Transaction costs to participant	COST			COST
Value of service lost	COST			COST

Shaded rows indicate those costs and benefits which are not included in the SPM but have been added to these 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

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

marketing and outreach costs associated with the program, and measurement, evaluation, verification and reporting costs. LSEs are expected to provide budgets which detail these costs for each proposed DR program.

DR program administrative costs should include all costs that are caused by or specific to the program. DR programs that promote, educate or enable DR in general and are not specific to or caused by an individual program, such as the statewide marketing program, should only be included in the evaluation of an LSE's overall portfolio of DR programs. However, all activities that are specific to a particular DR program, such as program design, development, operations, management, marketing, sales, IT infrastructure, measurement, evaluation, verification and reporting shall be included in the administrative costs of that program, even if it is budgeted separately. When a program cost is budgeted separately (e.g., an IT budget which encompasses several programs), LSEs can suggest a method for apportioning that budget amongst the relevant DR programs. The budget can be apportioned on a cost basis, a load impact basis, or other method that the LSE feels is reasonable. Some explanation of why that method was chosen should be provided. LSEs are directed to work with the Commission's Energy Division, as necessary, to discuss the suggested method, or when questions arise about which costs should be included.

Section 3.B: CAISO Market Participation Revenue

Many ISO's, including the CAISO, are taking steps to allow DR to participate directly in ancillary services (AS) and other markets, such as for the newly developed Proxy Demand Resource product. Any revenues earned from CAISO markets through direct participation of DR should be counted as a benefit in cost effectiveness calculations using these protocols. The market rules and tariffs for direct participation of DR have not been finalized, nor have any utility DR programs yet been designed with the explicit intention of bidding into these markets. It is therefore not possible to adopt a specific method for incorporating such revenues earned by DR. For those DR programs that can participate directly in CAISO markets, utilities should provide information regarding how that program will be bid into the CAISO markets. Such 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. We recognize that the rules and bidding strategies for DR participation in these markets may be complex. Nevertheless, the computation of AS revenues should be presented in a clear and transparent manner.

Section 3.C: Avoided Costs of Supplying Electricity

The avoided costs of supplying electricity are the primary benefit of any demand side resource, and, in addition, are an important consideration in comparing the various supply-side options. However, the calculation of avoided costs differs depending on the nature of the options that are being compared.

Evaluations of the cost-effectiveness of DR programs are well served 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) as part of the DG Cost-Effectiveness Framework. The Avoided Cost Calculator uses a 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.

The avoided costs considered include: energy purchases; generation capacity or resource adequacy; line losses; transmission and distribution capacity; air pollution permits and 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. 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 2008 resource adequacy value of $28/kW-Yr. — the relatively low value reflects the large surplus of capacity currently available on the CAISO system. Capacity value in the years between 2008 and resource balance 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 this proceeding 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. 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, some consistency in DR incentives is necessary to attract and retain DR participants and is a valid consideration in designing programs to reflect DR's position in the loading order.

Because the Commission policy is to follow the loading order and focus on the long-term development of clean energy resources, the long-run generation capacity value will be used to determine the avoided capacity costs of DR programs.

The results of the Avoided Cost Calculator have been modified for Demand Response in four respects. First, in the Distributed Generation Framework, the avoided capacity value is based on the short-run value. For DR cost-effectiveness, as explained above, the capacity value will be based on the residual capacity value of a CT in all years. In addition to more properly reflecting the value of Demand Response, this is reflects that LSE's can, in theory, target and dispatch DR to meet identified capacity needs in a way that is not possible with customer sited and operated

DG resources. This also facilitates a direct and transparent application of adjustment factors (described below) to discount the full residual CT capacity value as appropriate.

Second, T&D capacity value will be considered separately on a $/kW-Yr basis for DR. As with the generation capacity value, this is done to reflect the potential for DR to target specific T&D capacity constrained areas and to provide for the direct application of adjustment factors to reflect differing T&D impacts across DR programs. The T&D capacity value will not be allocated to individual hours on a $/MWh basis as is done for Energy Efficiency (EE) and DG in the Avoided Cost Model.

Third, the approach for incorporating ancillary services (AS) avoided costs will differ from the standard Avoided Cost Calculator results. 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.B, above, such revenues earned by direct participation of DR programs in CAISO markets will be counted as a benefit

Finally, because energy is a small portion of the overall benefits of DR programs, the avoided renewable energy purchases procurement costs calculated in the DG Avoided Cost Framework will not be applied to DR cost-effectiveness.

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

Table 2. 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 3 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 3. 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 Environmental 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

The data and methods used in the Avoided Cost Calculator are described further below.

***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 both the DG Cost-Effectiveness Framework and 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 allocates the residual capacity value across 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. The capacity allocation factors used are a simplified proxy for relative loss of load expectation/probability (LOLE/LOLP) sometimes used to allocate generation capacity costs. This allocation will be used to create monthly generation capacity values, which will be used with the monthly load impacts in the DR Reporting Template to calculate monthly avoided capacity costs. However, LSEs may use their LOLE/LOLP models to determine alternate monthly capacity allocations for some or all DR programs. If an LSE uses alternate values, all calculations must be done both with the values generated by the Avoided Cost Calculator and the alternate values.

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 are included in the DR Reporting Template: Availability (A Factor), Notification Time (B Factor) and Trigger (C Factor). These factors should be determined by the LSE for each individual DR program.

The adjustment factors are designed to reflect the program characteristics that constrain the optimal use of DR calls. The factors calculated by LSEs should reflect the likelihood that the

DR program will be able to operate when needed. Depending on the program's operating constraints, it may be necessary for utilities to conduct stochastic analyses to develop adjustment factors that average the performance of the DR across various scenarios. Given the wide variation in DR programs, it is impractical to specify analysis requirements for each herein.

However, the Commission will expect LSEs to consider the following guidelines in performing and presenting their analysis. LSEs will enter their adjustment factors into the Energy Division spreadsheet to determine the adjusted value of generation capacity. LSEs will also provide documentation on how they derived their adjustment factors for each program. This documentation will include a description of the model, methods or procedure used to calculate each factor.

The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted. A program that could be called in every hour that a generation capacity constraint might be experienced by the utility would have an A Factor of 100%. In the past, the IOUs have calculated the A Factor using Loss of Load Expectation (LOLE) or Loss of Load Probability (LOLP) models. The traditional LOLE/LOLP model combines the probabilities of generation outage states with the probabilities of demand levels to determine the combined probability of generation being unable to serve load in each hour. The hours during which a DR program is available, based on program elements such as limitations on the timing or number of calls, is then compared against the hourly Loss of Load Expectation or Probability.

These models require substantial amounts of generator-specific information, which is especially difficult to gather for the substantial amount of new private generation being added to serve California. An alternate approach to developing a LOLE/LOLP model is to base the likelihood of an outage on load levels alone. The advantage of such an approach is that it does not require the generator-specific information and is simple enough to implement in a spreadsheet. While not as theoretically robust as the traditional LOLE/LOLP approach, this approach provides results that properly place more emphasis on the hours of the year when system demands are the highest. In this calculation as in many others, the advantage of simplicity and transparency outweigh the advantages of proprietary traditional LOLE/LOLP models. However, should an LSE provide an LOLE/LOLP model that can be shared in the public domain, along with sufficient documentation of their derivation to allow them to be verified independently, then the Commission may consider such information for inclusion in the DR benefits analysis along with the results of the required approach. In performing the A Factor analysis, utilities will be expected to explain and document the difference between the number of calls permitted by the program rules and the number of calls that have actually occurred historically in those years when generation capacity constraints were actually experienced.

In addition, similar to the allocation of monthly capacity value, LSEs will be permitted to use their LOLE/LOLP models as an alternate to the method described above. However, they must provide **both** analyses so that all parties can compare the results.

The B factor calculation should be done by examination of 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. It may not be possible to apply this method to anything other than the distinction between day-of and day-ahead programs. However, the utilities are encouraged to propose estimates of the differences in value between 15 minute, 30 minute, 1 hour, one day ahead, 2 day ahead, etc., programs, if possible. It may also be possible to determine the B factor by examining the relationship between real-time and day-ahead energy prices in current CAISO markets.

Finally, 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. Each LSE may propose a method for determining the C factor. This method should be clearly explained and each step of the process described. We suggest two methods below. LSEs are free to use either of these, or any other method, at this time. In the future, the Commission may prescribe a particular method of determining the C factor, or may decide to eliminate this factor.

- The C factor may be determined in a manner similar to the B factor. In other words, the C factor calculation could be done by examination of past DR events to determine how often a different trigger would have resulted in different decisions about event calls. Note that this includes both when a more flexible trigger might have resulted in an event call that was not actually made, and when an event call was made because a particular trigger condition was reached (such as high temperature) even though the program was not actually needed. By examining past events, an estimate can be made of how often a different trigger might have resulted in a different number of DR events, thus giving an approximation of the additional value of the flexible trigger.

- The C factor may be determined by creating a ratio of number of events called to maximum numbers of events permitted for each program. This can be done for the lifetime of the program, for a particular year, or for a particular representative time period. By comparing these ratios for the different DR programs, it may be possible to get a sense of the relative values of the different triggers.

No matter which method is used, LSEs should keep in mind that D.10-06-034 issued in Phase 3 of this proceeding adopted a multi-party settlement and reduced the amount of reliability-based and emergency-triggered demand response programs that count for Resource Adequacy from the current 3.5% of system peak to 2% of system peak in 2014. Although the settlement adopts caps on the MWs that count for Resource Adequacy, the settlement removed the current enrollment caps on reliability-based and emergency-triggered demand response program. Any C Factor analysis applied to emergency based DR 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.

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. This approach is similar to those used by the IOUs in their past DR program filings.

The hourly shapes of the day-ahead and real-time markets are derived from historical MRTU 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 Reporting Template 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 a sensitivity analysis that allows parties to value DR under alternate energy price scenarios. We will require utilities to use the simple evaluation template approach presented herein, but will allow the utilities to apply an Energy Adjustment Factor (E Factor). For consistency and transparency, we will require the utilities to use the same hourly energy price forecast produced by the DG Avoided Cost Model in the E Factor analysis. The utilities 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 adjustment factor will be provided in the utility work papers.

In this proceeding 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. Utilities may, however, incorporate an option pricing approach in the "E Factor" analysis. In that case, however, the utility shall provide justification for the adjustment factor in their work papers provided to the Commission. Such justification will include all input data and modeling in spreadsheets that will allow Energy Division and interested parties to replicate the utility'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. The conditions under which DR programs actually do avoid such investment and the amount of investment avoided is viewed by some as uncertain and speculative. Nevertheless, as an interim method, the DG Cost-effectiveness Framework T&D avoided costs will be used. Both the EE and DG Avoided Costs use T&D values based on long-term utility investment plans. This approach is appropriate for long-term EE measures or DG investments with predictable impact/generation profiles.

T&D capacity value is allocated to individual hours based on the hourly temperatures in each climate zone. This approach results in an allocation of T&D value to several hundred of the hottest (and likely highest local load) hours of the year. The originally proposed DR Reporting Template used a weighted average of the hourly allocation of T&D value by climate zone to calculate a system-wide average T&D capacity value to each month in the DR Reporting Template. In response to the comments of several parties, IOU specific T&D capacity values will be used. These values will also be reported separately for sub-transmission and for distribution separately. As with the avoided generation capacity costs, the monthly T&D capacity values will be used with the monthly load impacts to calculate program benefits.
As with the avoided generation capacity costs, the monthly T&D capacity values will be used with the monthly load impacts to calculate program benefits. The 2012 monthly T&D capacity values, by utility, are shown in Table 4 for PG&E, SCE and SDG&E. Other LSEs may input values specific to their utility or region.

Table 4 - 2012 T&D Avoided Cost Values

Utility	Transmission & Sub Transmission	Distribution
PG&E	$19.58	$57.03
SCE	$23.85	$30.71
SDG&E	$21.50	$53.28

The utilities will have the flexibility to substitute alternative T&D capacity values for those calculated by the Avoided Cost Calculator for each climate zone, but **only** for those DR programs which are targeted to defer specific utility investments in the distribution system, applying right time-right place criteria. To accommodate this possibility, LSEs will be allowed to use either system average or specifically identified T&D deferral values in the DR Reporting Template. However, if specifically identified T&D deferral values are used, LSEs will be expected to document those T&D values and their applicability based on the right time-right place criteria and the ability to dispatch DR on a location specific basis. Note that this is allowed only for those DR programs which target specific regions with constrained distribution.

Throughout this proceeding, parties have used the terms “right time”, “right place”, “right certainty” and “right availability” to describe the match of allowable DR operations to utility need and avoided costs. We agree that it is vitally important to correctly adjust the estimated benefits of DR to reflect these characteristics, which can be done through the Distribution Factor (D Factor). The various criteria are intended to limit the application of the avoided T&D costs to programs that (1) are located in areas where load growth would result in a need for additional delivery infrastructure but for demand-side potential; (2) are located in areas where the specific DR program is capable of addressing local distribution capacity needs;[13] (3) have sufficient certainty of providing long-term reduction that the risk of incurring after-the-fact retrofit/replacement costs is modest,[14] and (4) can be relied upon for local T&D equipment loading relief (e.g., can be dispatched for local needs, and not just system needs). LSEs will review specific DR programs based on these criteria, and either apply the default avoided T&D costs or apply the results of a specific investment study to the cost-effectiveness evaluation of any qualifying DR program load reduction. An explanation of the exact method used to determine the D factor, including a precise definition of the criteria used is required.

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 should define the areas which will meet “right place” criteria, and maintain that designation for the areas for a minimum of three years. As more experience with the ability of DR programs to avoid transmission and distribution investments is developed (particularly after roll-out of advanced metering technologies), it is anticipated that the utilities will be able to refine this approach and provide information on “right place” to DR providers on a continuing and ongoing basis so that both LSE and third-party DR programs can be designed to target particular areas of need.

As with the generation capacity value adjustment factors discussed above, we do not propose a specific method, but do expect the utilities to follow similar guidelines in calculating a D Factor to be applied to the T&D capacity value for each DR program. This analysis should account for such factors as: the ability to forecast local T&D capacity needs with available information, the ability to identify and call on DR customers in a specific area, and the probability that those customers can be called upon and will respond during those hours when local T&D capacity is constrained.

4) Avoided Costs and the MRTU: The CAISO implemented locational marginal prices (LMP) as part of MRTU in April 2009. After sufficient LMP price data have been accumulated, it will be possible to incorporate the value of DR programs in avoiding transmission congestion costs by calculating avoided energy costs on a locational basis. (This will also incorporate the local value of reducing transmission losses.) Utilities have stated that they plan to incorporate any such locational value beginning with the 2012-2014 DR program cycle, presuming adequate

[13] For instance, an air conditioning cycling program is unlikely to avoid distribution investments in coastal areas with low air conditioning penetration where distribution circuits typically peak as a result of evening lighting loads.

[14] For programs which do not involve direct load control technology, utilities may discount the long-term load reduction potential until there has been sufficient experience to reliably assess load impacts.

information exists by that time. We recommend that the IOUs actively explore, in their 2012-14 applications, how to incorporate locational MRTU pricing into the avoided costs.. An analysis of MRTU pricing should include (but not necessarily be limited to): 1) the relationship between Day-Ahead market prices, Real-Time market prices and the price paid for DR, 2) the relationship between the Custom Load Aggregation Point (CLAP) prices paid for DR and Default Load Aggregation Point (DLAP) prices paid for load, and 3) regional or nodal differences in congestion and losses that could be targeted with locational dispatch of DR programs. The results of this analysis could be entered in the DR Reporting Template as part of the D factor adjustment to the Avoided T&D costs or as part of the E Factor adjustment to the avoided energy costs. As emphasized throughout these protocols, this analysis should be documented with publicly available data and transparent modeling and analysis.

Section 3.D: 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.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. These costs should be amortized over the lifetime of the investment, and the annual costs applied to those years that the cost-effectiveness analysis covers. For each investment, the LSE shall explain the details of the cost (e.g., types of equipment purchased, type and use of the IT developed) 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.[15]

For each DR program, LSEs should submit a "dropout factor," reflecting the likely number of participants who will leave the program (and therefore leave any long-term investments stranded) in a given year, based on program history. The dropout factor will be used to determine a base case value for the annual cost of each capital investment. If it is not possible to determine a dropout factor for a particular program, a default value determined by Energy Division will be used.

<u>Section 3.F: Capital Costs to Participant</u>

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[16]. 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 LSEs above, for each DR program, LSEs should submit a "dropout factor," reflecting the likely number of participants who will leave the program (and therefore leave any long-term investments stranded) in a given year, based on program history. The dropout factor will be used to determine a base case value for the annual cost of each capital investment. If it is not possible to determine a dropout factor for a particular program, a default value determined by Energy Division will be used.

<u>Section 3.G: Environmental Benefits</u>

The avoided cost calculation includes capital costs incurred to comply with existing environmental regulations including acquisition of offsets for criteria pollutants (NOx, PM 10,

---

[15] For example, if a customer receives a rebate or other assistance as part of the Technical Incentives (TI) program, and subsequently enrolls in the Capacity Bidding Program, the costs of the rebate and other assistance are considered capital costs of the Capacity Bidding Program. For customers who have received rebates but 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.

[16] 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.

VOCs, SOx). Hence, the value associated with criteria pollutant-related costs are already inherently captured in the generation capacity and energy values associated with DR programs.

Currently, the avoided costs place a value on GHG emissions consistent with Synapse Consulting's meta-analysis of federal climate legislation.[17] Synapse Consulting reviewed fourteen modeling analyses of proposed climate legislation and carbon pricing schemes to develop a forecast of carbon prices specifically suitable for use in electricity sector analyses. This forecast serves as the basis for the value associated with GHG reductions resulting from distributed generation.

Just as the value of energy changes with each hour, so does the value associated with reduced emissions. Periods of high energy prices result in the operation of lower-efficiency gas generators, resulting in a higher emissions rate of carbon at the margin. As a result, the benefits associated with reduced emissions follow an hourly shape roughly approximated by the hourly day-ahead market shape. For resources such as DR, which will tend to be called upon when energy prices are high, the value of avoided emissions will be approximately consistent with the emissions of a peaking resource such as a combustion turbine. This approach to estimating the value of the GHG emissions avoided by a DR program should be re-evaluated and revised based particularly on any additional information available on federal and state legislation or programs to limit GHG emissions.

During the course of this proceeding, the IOUs have stated that the 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. 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. In fact, the State of California Public Utilities Code allows for this benefit to be considered for interruptible (emergency DR) programs:

743.1. (a) Electrical corporations shall offer optional interruptible or curtailable service programs, using pricing incentives for participation in these programs. These pricing incentives shall be cost effective and may reflect the full range of costs avoided by the reductions in demand created by these programs, including the reduction in emissions of greenhouse gases and other pollutant emissions from generating facilities that would have been required to operate but for these demand reductions, to the extent that these avoided costs from reduction in emissions can be quantified by the commission. The commission may determine these pricing incentives in a stand-alone proceeding or as part of a general rate case.

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 environmental costs

[17] The Synapse price forecasts used in the Avoided Cost Calculator are taken from the *Synapse 2008 CO2 Price Forecasts* (http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf).

associated with avoided generation capacity, as discussed above. Additional impacts include, but are not limited to:

- environmental justice concerns, particularly for supplying electricity in urban areas
- biological impacts, including human health and safety;
- 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.

As with criteria pollutants, the preferred approach is to incorporate these benefits in cost-effectiveness evaluation of DR programs by incorporating the compliance costs into the avoided cost calculation. However, as with criteria pollutants, there are residual benefits in addition to existing compliance costs, but they are difficult to quantify.

While methods may exist to calculate some of these additional environmental benefits, until such time as it can be determined exactly which methods to use and how to use them, any environmental benefits other than the one discussed above for GHG are not required in the calculation of the SPM tests. If in the future regulatory agency actions impose new or significantly higher environmental control costs or fines that could be avoided by DR, those costs or fines should be added to the valuation of DR benefits, whether or not those costs or fines are specifically mentioned in these protocols.

Although LSEs are not required to include these additional environmental benefits in their cost-effectiveness calculations for DR programs, other parties are invited to submit evidence of the magnitude of the environmental benefits or costs of Demand Response. However, only evidence based on scientific studies, rather than speculation, will be accepted by the Commission.

In addition, qualitative analysis of these benefits may be useful in certain cases, as discussed in Section 1.F above. An example of this type of analysis would be a discussion of the potential for use of Backup Generators (BUGs) by DR participants. While there is no current requirement for LSEs to track the use of BUGs, an LSE may be aware of a case in which a particular DR program is more (or less) likely than other programs to contain participants who use might use BUGs during DR events. Or, a particular DR program might prohibit program participants from the use of BUGs. In these cases, the environment impact of that program differs and should be noted.

Section 3.H: 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.

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.

Section 3.I: 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.J: Market and Reliability Benefits

This category of benefits includes increased reliability (over and above the increased reliability offered by equivalent supply-side measures, particularly when DR can provide ancillary services), increased market efficiency improvement in overall system load factors, improved market performance (e.g., decreasing price volatility), increased flexibility, portfolio benefits, and others. 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 will likely become clearer as new research emerges and as the CAISO's MRTU proceeds.

The energy efficiency decision (D. 05-1-04-024) has established the precedent of including adders for (1) reliability, and (2) the price elasticity of demand market price effect. In that proceeding, the generation capacity and energy benefits were based on forecast market prices[18]. The reliability adder is appropriate in that proceeding because reliability services are purchased through a separate ancillary services market that is not captured in the forecasts of market prices used for the energy and capacity avoided costs. Similarly, the elasticity adder is appropriate because the value of reducing load when the market is at a steep portion of the market supply curve would not be reflected in the market price forecasts. For DR protocols, however, we are directing utilities to base capacity benefits on the cost of a simple cycle CT unit, and not the market price of capacity. This makes the energy efficiency adders non-transferable. Therefore, for the purpose of these protocols the utilities are not required to include these market benefit adders in the calculation of the SPM tests[19].

Electricity markets are constantly changing, and potential developments such as a capacity market could alter the methods and benefits used to value DR. For example, if a capacity market were to become the basis for the generation capacity value, then this return to a market valuation would require a reconsideration of including reliability and price elasticity adders. However, more study is needed of these potential benefits before they can reasonably be

---

[18] Note that energy and capacity avoided costs in that proceeding are reported as combined or "all-in" hourly values, and are not reported separately.

[19] However, this does not preclude utilities from including market values in their SPM tests. For example, it is not clear that during times of supply constraint, a MW of additional supply would provide the same price suppressing effect as a MW of reduced demand (even after adjusting for losses). To be sure, one would expect the effects would be similar if one assumes no market power for generators --- but that is a significant assumption.

included in DR cost-effectiveness. The benefits that should be studied include all of the factors mentioned above as well as several other issues:

- **Equitable pricing.** An important benefit for the electricity markets is that an effective DR program places a value on an important attribute – flexibility – that may not now be fully valued. With most rate structures today, those customers who have the ability to shift loads are provided little incentive to do so. At the same time, it is more expensive to serve customers who cannot shift energy use.
- **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 include these additional market benefits in their cost-effectiveness calculations for DR programs, qualitative analysis of these benefits may be useful in certain cases, as discussed in Section 1.F above.

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

Demand response program participants receive non-monetary benefits from participation in DR programs. These benefits are sometimes referred to as non-energy benefits.[20] This category of benefits includes the benefits participants receive in lessening their impact on the environment, being good citizens by helping to prevent outages, improving their ability to manage their energy usage, having a better public image (for commercial enterprises), improving working conditions, etc.

From a societal perspective, and from the perspective of LSEs, DR programs may result in non-energy benefits, such as health and safety and secondary economic benefits.

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

[20] 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.

energy efficiency programs.[21] We recommend that this work be used as a starting point for understanding the non-energy and non-monetary benefits of DR.

Although LSEs will not be required at this time to include these additional benefits in their cost-effectiveness calculations for DR programs, qualitative analysis of these benefits may be useful in certain cases, as discussed in Section 1.F above

Section 3.L: 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.

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

These are general categories which 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

[21] 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

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, and shutting off. equipment during a DR event.

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 particular end-uses become unavailable. Examples of lost productivity costs are revenue losses incurred when a business is shut down during a DR event. Examples of comfort costs include having to walk further to use a copy machine, feeling too hot or too cold because of changes in a thermostat setting, and the cost of having to change one's work hours.

These costs are significant to the participant, but some of them can only be approximated, even by an individual participant – most people cannot state with any certainty what monetary value they place on, for example, feeling warmer than preferred, and even when values can be determined they vary widely from one person to the next. This makes it extremely difficult to quantify these costs for any group of participants. We recognize these difficulties, and acknowledge that estimates of these costs are likely to be highly uncertain.

The total participant costs calculated for the Participant Test are equal to the sum of the transaction costs, value of service lost, capital costs to participant and any bill increases. Because it can be assumed that from the perspective of participants, the total costs of a voluntary demand response program must be less than the total benefits, these costs can be assumed to be less than or equal to the total benefits, which are equal to the sum of participant's bill reductions, incentives paid, non-monetary benefits and any available tax credits. However, for voluntary demand response programs, it is not necessary to calculate the Participant Test.

The TRC test uses slightly different costs, called "Net Participant Costs," which are equal to the sum of the transaction costs, value of service lost, and the capital costs to participants, as defined in Section 3.d above.

Stating the above in a more mathematical form, we get:

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. For the purposes of this interim analysis, we will continue to assume that non-monetary/energy benefits to participants are relatively small. Hence, the net result is:

Transaction Costs + Value of Service Lost $\leq$ 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, sensitivity analysis will be done which reflects lower possible values, as shown in the DR Reporting Template spreadsheet.

We encourage LSEs or other parties 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.

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 Energy Division to determine the base case amount.