Complete Summary of Demand Response Cost-Effectiveness Protocols

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A. Purpose of DR C-E Framework

1. For ex ante cost-effectiveness evaluations of DR programs:
   a. Event-based and non-event-based programs
   b. Programs that "count" for RA purposes, and those that don't count
2. Will be used for
   a. Programs in the 2009-2011 and subsequent program cycles.
   b. Individual programs (proposed between-cycles)
   c. Third-party aggregation proposals (as one "key input")

B. Analytic approach

3. Compare DR costs to avoided costs of a generating plant.
4. Use expected load impacts measured using the approved load impact protocols.
5. Time horizon: the length of the DR program, but capital investments may be amortized over a longer period.
6. Use the four perspectives used in the Standard Practice Manual (Participant, Ratepayer Impact, Total Resource Cost, and Program Administrator Cost.)
7. Discount benefits and costs at each utility's cost of capital.

<u>Avoided Generation Capacity Cost</u>

8. Generating plant avoided: a new combustion turbine (CT)
   a. use annual market price ($/kW-year) of the capacity of the CT
   b. annualized using a real economic carrying charge rate
   c. reduced to reflect expected "gross margins" earned by selling energy (not agreed; subject to litigation)
   d. adjusted to reflect avoided reserve margin capacity and line losses.
9. Annual value of capacity is allocated among hours of the year in which the program can be used, in proportion to hourly LOLE or LOLP.
10. Adjusted CT cost (i.e. capacity value) is not adjusted downward when a region's capacity is greater than the adopted planning reserve margin.
11. CT cost data takes into account area-specific CT construction costs and fixed environmental costs, and inter-regional differences in wholesale electricity prices.

<u>Avoided Energy Costs</u>

12. May be based on wholesale energy prices averaged over the highest-price hours, or more complicated methods.
13. Take into account avoided line losses.
14. Will be consistent with method used to determine "gross margins" (see item 8.c).
15. After sufficient locational marginal price (LMP) data exist, calculating energy costs on a locational basis can incorporate the value of DR in avoiding transmission congestion costs. Utilities plan to incorporate any such value beginning with 2012-2014 program cycle.

<u>Avoided Transmission and Distribution Costs</u>

16. Whether DR programs avoid T&D capacity investments is often uncertain.

17. Interim method: utilities will establish a default avoided T&D cost and apply it to programs which meet "right place" and "right certainty" criteria.
18. Default avoided T&D costs will be based on marginal costs of T&D substation equipment, principally related to transformer capacity.

Other Benefits

19. Non-event-based DR programs may reduce the need for procuring ancillary services (spinning reserves, etc.). Once this becomes clearer, utilities will consider the relative ability of a new CT and a DR program to earn revenue in ancillary service markets.
20. Utilities may use a capacity value in excess of adjusted CT value for periods in which the planning reserve margin is expected to fall below the adopted standard.
21. The costs of meeting emission standards for criteria pollutants should be included in avoided capacity and energy costs.
22. Value of avoided GHG emissions should be consistent with direction in D0709024.
23. Utilities are not expected to include other benefits sometimes attributed to DR programs such as price elasticity effects, market performance benefits, reliability impacts, and "hedge" value. Such benefits are often captured in the CT proxy value. Further research would be needed to include these values in cost-effectiveness evaluations.

Sources of Input Data

24. GRC or other published data when available and up-to-date.
25. Either GRC marginal cost studies or modeling studies that underlie that utility's procurement plan may provide avoided energy cost data.

Program Costs

26. Cost of incentives paid to customers should be consistent with forecasted usage of the program.
27. Program costs should include all costs incremental to the program. Costs that are not incremental to an individual program, such as marketing and overhead, should only be included in the portfolio evaluation.

Caveats

28. Utilities may modify methods or values in future evaluations as necessary.
29. Flexibility in the application of this framework may be necessary.
30. The valuation of programs may be affected by PUC and CAISO decisions.
31. Parties may test the appropriateness of modifications to the method and the input values in the DR application process.

Status 4/29/2010:

- Consensus Framework has not been adopted by PUC.
- PUC instructed utilities to use Consensus Framework in 2009-2011 DR program applications.
- PUC is working on modified DR cost-effectiveness protocols.