Northwest Power and Conservation Council

January 31, 2008

MEMORANDUM

TO: Power Committee

FROM: Ken Corum

SUBJECT: Meeting of cost-effectiveness workgroup, PNW Demand Response Project, January 30, 2008

The work on the Demand Response Project began in May of 2007 with an organizational meeting, which resulted in the formation of a workgroup to focus on issues related to the determination of cost-effectiveness of demand response measures. The first meeting of that cost-effectiveness workgroup was held in July of 2007. At that meeting Chuck Goldman, LBL consultant to PNDRP, was tasked wcith drafting a set of guidelines for evaluation and determination of cost-effectiveness of demand response. That draft (attached), along with a similar draft of principles prepared in California, were the focus of discussion at the meeting on January 30 at the Council central office.

The group was able to agree on most of the points of the draft guidelines. In particular, there was general agreement on which issues are of primary significance, and which are of interest for the sake of completeness, but unlikely to materially affect the determination of a cost effective demand response measures. An issue agreed to be of primary importance is the choice of the resource that is avoided by demand response. There was agreement that for most utilities that resource is a new simple cycle gas turbine (SCCT) generator, and that the cost avoided by demand response is will be dominated by the fixed cost of that generator. The group recognized that the fixed cost can be adjusted by operational savings that a new SCCT could bring, and the value of reduced energy use at peak hours resulting from demand response, and possible benefits to the transmission and distribution system, to name a few of the possibilities, but that these adjustments are unlikely to make a significant difference in the overall evaluation of a demand response measure. This doesn't mean these adjustments aren't worth considering, but it does help focus on which issues are worth spending more time and energy on. "If we are going to argue, let's argue about the things that matter the most."

The group agreed that the workgroup product should be guidelines and principles, not hard-and-fast numbers (e.g. "All demand response that reduces peak load for less than $X/kW-yr is cost effective"). The group has a week to give Chuck written comments and suggestions, after which a subgroup will put together a revised proposal, which will have an illustrative example of how

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the guidelines would apply to the evaluation of candidate demand response programs. It is expected that a revised proposal will be available by the end of February.

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Memorandum: Cost-effectiveness valuation framework for Demand Response Resources: Guidelines and Suggestions (DRAFT)

To: Pacific Northwest Demand Response Project Cost-Effectiveness Working Group

From: Chuck Goldman, Lawrence Berkeley National Laboratory

Date: 10-24-07

Background

In May 2007, the Pacific Northwest Demand Response Project agreed to form three Working Groups to explore DR issues in more detail (Cost-effectiveness, Pricing, and Integrating DR into Distribution System Planning and Investment). In July 2007, the Cost-Effectiveness Working Group met for a one-day workshop in Portland Oregon, which included presentations by a number of utilities on valuation approaches used for DR resources. Based on the discussion at that workshop plus our review of DR valuation studies and DR cost-effectiveness proceedings currently underway in other jurisdictions (e.g. CA), we offer the following suggestions on a "strawman" proposal for a cost-effectiveness valuation framework for Demand Response Resources in the Pacific Northwest.[1]

Purpose

- The primary purposes of a cost-effectiveness valuation framework for DR resources are to:
  1) Propose workable methods for state commissions, utilities and others to consider for valuing the benefits and costs of different types of DR resources in long-term resource planning
  2) Provide methods that can be used in *ex ante* screening of DR programs for cost-effectiveness and to evaluate the treatment of a portfolio of DR resources/program options in an integrated utility resource plan
  3) Document value of demand response for the purpose of rate setting

Demand Response Resources

- Demand Response resources are comprised of flexible, price-responsive customer loads that may curtail or shift loads in the event of system emergencies and system operational needs or when wholesale market prices are high.

[1] U.S. Department of Energy (2006). "Benefits of DR in Electricity Markets and Recommendations for Achieving them: A Report to U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," February 2006; CPUC (2007). "Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-effectivness Methodologies, Megawatt Goals and Alignment with California System Operator Market Design Protocols," OIR 07-01-041, Jan 25, 2007; Joint [California] IOU Framework for Evaluating Cost-Effectiveness of DR Resources (2007), September 10, 2007. Quantec 2006. "Demand Response Proxy Supply Curves," prepared for Pacificorp, September 8, 2006.

- It is useful to characterize Demand Response resources in terms of their “firmness” as a resource option from the perspective of the utility.
- Firm DSM Resources (Class 1)
  - This class of DR resources allows either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled ahead of time. These resources can include such programmatic options as fully dispatchable programs (e.g. direct load control of air conditioning, water heating, space heating, commercial energy management system coordination) and scheduled firm load reductions (e.g. irrigation load curtailment, thermal energy storage).[2]
- “Non-firm” DSM Resources (Class 3)
  - DR Resources in this group are typically outside of the utility’s direct control and include curtailable rate tariffs, time-varying prices (e.g., real-time pricing, critical peak pricing), demand buyback, or demand bidding programs.

Guidelines and Principles

1) Treat DR resources on par with alternative supply-side resources and include them in the utilities’ integrated resource plans and transmission system plans.

2) Distinguish among DR programs with respect to their design purpose, dispatchability, response time, and relative certainty regarding load response.

3) In assessing cost-effectiveness of DR resources, it is important to account explicitly for all potential benefits, including: avoided/deferred generation capacity costs, avoided energy costs, avoided T&D losses, deferred/avoided T&D grid system expansion, environmental benefits, system reliability benefits, and benefits to participating customers.

4) Incorporate the temporal and locational benefits of DR programs systematically (e.g. estimate avoided costs at hourly level, treat transmission congestion zones separately, etc.).[3]

5) In assessing cost-effectiveness, all DR program and participant costs should be included; for voluntary DR programs, total customer costs incurred by participants will be assumed equal to the present value of incentives expected to be paid.

6) OPTION A - The Standard Practice Manual (SPM) Tests provide a starting place to compare and screen different DR programs with respect to their costs and benefits from various perspectives (societal, all ratepayers, utility, participants, and non-participants) but need to be modified and adapted to account for the characteristics and features of DR resources.

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[3] Most of the benefits of DR resources are related to avoiding relatively low probability future events (e.g. unusually high peak demand or energy prices) in relatively few hours, whose occurrence could have significant economic consequences.

7) OPTION B - The Standard Practice Manual (SPM) Tests provide a starting place to compare and screen different DR programs with respect to their costs and benefits from various perspectives (societal, all ratepayers, utility, participants, and non-participants) but need to be modified and adapted to account for the characteristics and features of DR resources. In screening DR programs, the Total Resource Cost (TRC) or Societal Test should be used to evaluate overall cost-effectiveness, while the Participant and Non-Participant tests evaluate the distributional aspects of DR programs.

8) Initiate and conduct DR pilot programs to assess market readiness, barriers to customer participation and to obtain information on customer performance that can be used to characterize the timing and duration of load impacts for long-term resource planning. Pilot programs need to include exercises of 'non-firm' DR resources with a view to identifying a fraction of the resource that could be treated as firm for planning purposes.

Benefits of DR Resources

1) Avoided Generation Capacity Costs
    a. DR resources usually avoid the need for a relatively high heat rate generating capacity. The market value of that type of generating capacity will typically be based on a new natural gas-fired combustion turbine (CT).
    b. Because market prices for new capacity are not widely available, a benchmarking method that involves use of a new gas-fired CT as a proxy to derive the market value of the generation capacity avoided by DR resources is appropriate; these costs typically range between $50-$85 per kW-year.
    c. Estimates of hourly market prices for new generation capacity can be derived by allocating the estimated annual market price of generation capacity ($/kW-yr) among the hours in each year, in proportion to the relative need for generation capacity in each hour. Utilities, regulators, and other stakeholders should agree on method(s) to allocate avoided generation capacity costs to specific time periods that is appropriate for the Pacific Northwest power system.[4]
    d. OPTIONAL – There is not a consensus on methods to determine the market value of new generating capacity avoided by a DR resource. For example, in California, the utilities have proposed to offset the present value of the total fixed costs of that new CT by the present value of the gross margins that the new CT capacity is expected to earn from selling energy when wholesale electricity market prices exceed variable costs. Other parties in California disagree with the method proposed by the California utilities. Some parties in the Pacific Northwest have raised concerns about the appropriate way to value capacity when the region is long on power. In the interim, using the costs of a new gas-fired CT as a proxy to derive the market value of avoided generation capacity is a reasonable approach for screening DR programs.

[4] In California, the utilities have proposed allocating the annual market value of new CT capacity to individual hours in proportion to the loss of load expectation (LOLE) in each hour.

e. Avoided T&D losses and Reserve margin -- The resulting estimates of generation capacity costs avoided by DR program should be adjusted upward to reflect the T&D line losses avoided by that DR resource capacity and the capacity planning reserve margin avoided by that DR program.
f. The capacity benefits of a DR resource should be adjusted for differences that reflect operational program constraints (e.g., limits on the months, days, and/or hours in which DR program events can be called; limits on maximum duration of program events, limits on number of consecutive days on which program events can be called) compared to the capacity value of a new CT (including limits on the use of a CT).

2) Avoided Energy Costs
   a. DR resources typically result in load shifting from peak to off-peak periods or load curtailments in which customers forego consumption for relatively short time periods. Thus, DR resources also enable utilities to avoid energy costs.
   b. Because utilities can always buy or sell electricity in the wholesale energy market, the expected wholesale market electricity price in each future time period is the relevant opportunity cost for estimating the value of electricity that will be avoided by a DR resource.
   c. Avoided energy costs should be adjusted upward to reflect distribution system line losses that DR load reductions would avoid in event hours.
   d. Avoided energy benefits can be particularly important in evaluating DR programs from the participants' perspective as they tend to directly affect customer bills.
   e. DR program events are most likely to be called in hours when prices are higher than expected; using expected hourly prices will tend to under-estimate actual electricity market prices in the hours in which an event-based DR program is called and will reduce loads. This is one of the reasons why it is useful to use stochastic analytic techniques (e.g., Monte Carlo simulations) that explicitly address the uncertainty in future loads, prices, hydro conditions, etc in examining the value of DR resources to the Pacific Northwest regional utility system.

3) Avoid or Defer Investments in Transmission and/or Distribution System Capacity
   a. The transmission and distribution system is comprised of three key elements: interties, local network transmission, and local distribution systems.
   b. DR resources that can provide highly predictable load reductions on short notice in specifically defined congested locations on the grid may enable utilities to avoid or defer investments in transmission and/or distribution system capacity.[5]
   c. Given the need to do geographically specific T&D studies and estimate DR market potential in geographically specific areas, estimating avoided or deferred T&D capacity investments should be determined on a case-by-case basis.

4) Environmental Benefits

[5] The extent to which DR programs may defer or avoid specific T&D capital investments depends on: 1) the characteristics of the individual utility system, 2) the specific T&D investment proposed, 3) the characteristics of the customer load to be served by the proposed T&D investment, 4) the attributes of the proposed DR program, and 5) the level of uncertainty associated with the projected load impacts of the DR program.

a. DR resources have the potential to produce environmental benefits by avoiding emissions from peaking generation units as well as some potential conservation effects (i.e. through load curtailments, foregoing usage).
b. Assessing the environmental impacts of DR resources depends primarily on the emissions profile of the utility's generation resource mix as well as participating customer's DR strategy (e.g., load curtailment vs load shifting vs onsite generation).
c. For DR resources that result in load curtailments, a reasonable proxy for estimating the volume of GreenHouseGas (GHG) emissions avoided by a DR resource is to base it on the operating and emission rate characteristics of a new CT.

5) Reliability Benefits
   a. DR resources can provide value in responding to system contingencies that compromise electric system operator's ability to sustain system level reliability and increase the likelihood and extent of forced outages.
   b. In the context of long-term resource planning, joint consideration of economic (avoided capacity and energy) benefits and reliability benefits is challenging. In an IRP plan, the value of DR hinges primarily on its ability to displace some portion of the utility's peak demand. Once DR resources are included in the utility's projected capacity resource mix, they become part of planned capacity and are no longer available for dispatch during system emergencies.

   c. Customers participating in emergency DR programs are not counted on as system resources for planning purposes; they represent an additional resource for reliability assurance; distinct from DR programs that are counted among planned reserves.[6]
   d. In assessing the value of these emergency-type DR programs, a reasonable proxy for monetizing the value of load curtailments is the product of the value of lost load (VOLL) with typical values between $3-5/kWh and the expected un-served energy (EUE).[7]

DR Resource Costs

6) Program Administration Costs
   a. Utilities will incur initial and ongoing costs in operating DR programs. Incremental program costs attributable to DR resources can include program management, marketing, customer education, on-site hardware, customer event notification system upgrades, and payments to third party curtailment service providers that implement aspects of a DR program.

[6] Emergency DR programs provide incremental reliability benefits at times of unexpected shortfalls in reserves. When all available resources have been deployed and reserve margins still cannot be maintained, curtailments under an emergency DR program reduce the likelihood and extent of forced outages.
[7] Expected unserved energy (EUE) is a measure of the magnitude of a reserve shortfall which takes into account the change in the likelihood of curtailment (i.e. loss of load probability) and the amount of load at risk.

7) Customer costs
    a. Customer costs are defined as those costs incurred by the customer to participate in a DR program and can include investments in enabling technology to participate, developing a load response strategy, comfort/inconvenience costs, rescheduling costs for facility workers, or reduced product production.
    b. For a voluntary DR program, it is reasonable to assume that participant costs are less than or equal to the incentives offered by the program; otherwise the customer would not voluntarily chose to participate.

8) Incentive payments to participating customers
    a. Incentive payments are paid to customers participating in DR programs to encourage them to enroll initially and continue in the program. Incentives also compensate customers for any reduction in the value of service that they would normally receive (e.g. higher household temperatures during an A/C cycling event or increased costs when a business shuts down some of its equipment when an emergency event is called).
    b. For voluntary DR programs, in evaluating cost-effectiveness, it is reasonable to assume that total customer costs incurred by participants will be equal to the present value of incentives expected to be paid.[8]

9) Characterizing DR Resource Costs
    a. It is reasonable to ramp up enrollment in DR programs over a multi-year period (e.g. 3-4 years) and to match the time horizon of DR costs and benefits (e.g. use expected life of DR enabling technology in assessing benefits).
    b. In modeling DR program options, it is useful to categorize costs into fixed expenses (program development, ongoing administration, communication and data acquisition infrastructure) and variable costs (e.g. incentive payments to customers, participant acquisition costs, other program costs that vary with number of participants or the number of times that DR program events are called).).

10) Relationship between DR screening and portfolio analysis
    a. A long-term resource plan that includes a portfolio analysis and accounts for the uncertainties in future loads, prices, and resources, is the preferred approach to fully value the benefits of DR resources
    b. In screening DR resources and program concepts, it is also useful to establish cost-effectiveness thresholds that allow regulators and utilities to estimate whether a DR program is worthwhile to pursue.

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[8] It is reasonable to treat incentive payments in voluntary DR programs as compensation for any loss of service or out of pocket costs that participating customers expect to incur under the assumption that the customer would not participate if the incentive wasn't sufficient to offset these costs.