How to Measure Cost-Effectiveness of Demand Response

A Piece to Elicit Discussion

T. Foley

This paper is one of three papers that will be used to stimulate discussion among stakeholders at a May 2, 2007 meeting at the Northwest Power and Conservation Council (Council) offices in Portland. The meeting and follow on work will be aimed at supporting an October 2007 report to the utility regulators in the Northwest states of Washington, Oregon, Idaho, and Montana. This paper focuses on measuring the cost-effectiveness of Demand Response (DR). The two other papers address how to include transmission and distribution decisions in Integrated Resource Plans (IRPs) of utilities, and the design of retail pricing strategies to foster Demand response.

Each of the papers will have a similar approach. We begin by asking what could be done with no limitation to the data and models required to answer the questions posed in each paper. This gives us a sense of what we might want to do in the way of data development and tools development over the long term. We then raise the question of data and tool limitations to help us determine whether we can develop useable estimates of cost-effectiveness, given the limitations.

Each of the papers will be open-ended, because they are designed to elicit brainstorming among participants at the May 2nd meeting. At that meeting and beyond we will examine the available data and tools and what can be done with them in the short term. We can also discuss what should be done to improve our abilities to measure cost-effectiveness of this potentially valuable resource.

Introduction

Demand Response refers to a reduction in loads to meet resource needs of the control area operator, the utility as a whole, and customers of the utility[1]. In this light, DR can be thought of as the mirror image of a generator being called upon by the control area operator to increase output. The resource need can be driven by limited transmission availability, high congestion costs, limited or high-cost generation, or high energy costs, for examples. Cost-effectiveness of DR should be measured against the cost of supplying equivalent resources with generators, expanded transmission, or other traditional tools of control area operators. The Council's Fifth Power Plan is the first of its power plans to examine demand response (DR) as a means of reducing costs and risks of the power system. The Council's analysis and considerable recent experience[2] suggests that DR has significant potential. Part of the Plan's Action Plan is to pursue the development of that potential.

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[1] The cost-effectiveness of DR has many parts. It can be used to defer transmission, distribution lines, and peak generation, and to evade high peak prices, reduce line losses, allow for maintenance of the grid, and so forth. All of these value streams will enter into our discussions of the cost-effectiveness of DR.

[2] Businesses are offering DR services to PJM's grid operator, for example

As part of that effort, the Council has been hosting a Steering Committee comprised of its own staff, staff from the utility regulation commissions in the four Northwest states, Regulatory Assistance Project, and others. The Steering Committee has focused on technical and practical issues related to DR. The general objective of the Steering Committee has been to better understand the DR resource. The Council and participants in the Steering Committee identified a long list of issues on which to focus. From that list, participants have agreed to address in the near-term the issues stated in the opening paragraph of this paper. The goal, as stated above, is to develop a report to the regulated utilities commissioners in the Northwest by the fall of 2007. Later, if our hypothesis that DR is a beneficial resource is proven correct, the Steering Committee and stakeholders will work with others in the region to encourage its development, where appropriate. The membership of the Steering Committee is shown in Appendix A.

Background

Demand Response is a part of a larger category of resources referred to as Distributed Energy Resources (DER) that include DR, conventional conservation, distributed generation, pricing strategies to reduce demand[3], strategically located resources within the grid to limit congestion, and so forth. The report to the regulators will focus on DR, but this paper will also point out other distributed resources alternatives that should be the subject of further analyses. (See Appendix B).

DR can be used cost-effectively to reduce energy bills, defer or delay transmission and distribution upgrades, defer or delay new generation, and to provide ancillary services to control area operators. As such, DR can lower the costs of serving loads. DR can be used to serve multiple purposes, and the providers of DR should ultimately accrue to themselves revenues from the several value streams referred to above. However, in a grid lacking a central grid operator, the identification of and the ultimate payments of these benefits to the providers may be uncertain. One question we will be addressing is who in the Northwest should be the responsible party to implement DR, and to determine its ultimate value--with or without the knowledge gained by a grid-wide operator.

Discussion

Historically utilities have considered their task to simply serve all loads that appeared. Few utilities or government entities gave any concern for to managing loads. In the collective wisdom of the times, utilities were there to serve load, period. Some analysts[4] were extolling the virtues of DR, but the utility industry, with a focus on meeting loads, moves slowly.

More recently, the energy crisis in the West being a case in point, utilities have used DR as a way to avoid surges in electricity prices. But, as crises wane, DR for the most part is taken off of the table (elsewhere in the country, DR hasn't been forgotten). But this may not have been the best strategy. The grid is a giant machine and should be treated as one.

[3] Conversely DR can be used reduce prices.
[4] See RAP documents at www.raponline.org, e.g.

If the grid were considered in its entirety, by a single grid-wide operator or perhaps through IRPs that include T&D, congestion, ancillary services, etc., each component of the grid in relationship with all other components would be examined and the relative importance of each component would be discovered. In that climate DR would be a significant resource that would compete against other resources on a consistent basis to lower costs of serving loads. To date this has not been the case.

Lacking a grid-wide operator, this region is not yet ready for a comprehensive approach to planning and operating the grid. Thus, the second best strategy of including all DR opportunities in individual utility IRPs is the best option open in to the Northwest. We will propose in another paper that T&D needs should also be included in individual utility's IRPs. This will involve communication with other control area operators, and may require the development of regional data to be shared among all utilities.

Cost-effectiveness of Demand Response (DR)

It is the thesis of this paper that cost-effectiveness of DR should be measured at a very detailed level, essentially looking at the cost to utilities of DR services on an hourly basis measured against the costs of equally reliable traditional resources over the similar hours. Basing cost-effectiveness of DR on prices averaged over hours, days, or longer, would leave us with a low and faulty assessment of the true value of DR.

An illustration will be helpful. Suppose that we had a two-period day, each period was of the same duration, and the market energy price was $25/MWh in period 1 and $75/MWh in period 2. The simple average energy price is $50/Mwh, and all DR that saved energy at less than $50/MWh might be considered cost-effective, ignoring for the moment other benefits. But, suppose the DR contributed 60% of its benefits in period 2 and 40% in period 1. Then the weighted benefits of the DR would be $55/MWh[5], and all uniformly distributed DR under $55/MWh would be cost effective.

Because more DR would be provided when the prices of services and potential payments to the provider are higher, the situation in the above example will almost always be true. That is, the weighted average benefits of DR will always be higher than those based on simple averages. Thus, to deliver accurate assessment of the cost-effectiveness of DR we would like to project prices of non-DR resources on an hourly basis to the extent that we can.

Consider hourly values of all of the benefits of DR and the values of the services that DR could displace over those same hours. We would have matrices that can be filled with data from 365 days by 24 hours for the "output" of DR and corresponding 365x24 matrices for the costs avoided as a result of DR. As an example, the following matrix equations would determine the annual value of <u>generating capacity displaced</u> by DR:

(1) $[A] \times [B] = \text{SumProduct of } A \times B = \Sigma\Sigma A_{ij}B_{ij,}$

[5] .6*$75+.4*$25 = $55

Where [A] is a 365(days) x24 (hours) matrix containing capacity (or energy, or congestion relief, or transmission relief) "outputs" of DR and [B] is a 365 days by 24 hours matrix containing the avoided costs of capacity (or avoided costs of other resources), respectively for a year. The result of equation (1) would be the annual value of DR for that year measured by the value of generating capacity displaced. This annual value and corresponding values for other years, with appropriate discounting establishes the cost-effective level for DR. DR costs at or below this level are cost-effective.

There would be a similar equation for energy saved, transmission and distribution saved or deferred, congestion avoided, line losses avoided, etc.

It seems clear that we may have problems in accessing all of the data needed to populate the matrices of equation (1). Nor do we have a model to estimate these values. Therefore, we cannot estimate yet the full cost-effectiveness of DR, but we may be able to produce partial analysis that will give a floor for their cost-effectiveness, if we simply look at how DR is or may be used in the near-term[6]. Also, as stated earlier, we can think of the data needed in equation (1) as something that could be developed over the future. Hopefully, this will happen in the not too distant future.

Material for May 2nd meeting discussions and brainstorming

Starting with Equation (1) and recognizing the data and tool limitations to using it, what can we do in the near-term to estimate the cost-effectiveness of DR? This is the hope for the discussions and brainstorming that will take place at the May 2nd meeting. All options are open, including studying recent experience of other transmission systems that are relying on DR to meet their respective needs.

DR can provide relief to the control area operator is several ways. It can provide:

1. Capacity relief in all hours, depending on the prices of generating capacity,
2. Savings in grid losses,
3. Deferral of transmission,
4. Congestion relief,
5. Savings of energy,
6. Price and market power mitigation, and

For distribution utilities:
1. Deferral and possible avoidance of distribution feeders, substations and transformers upgrades.

Discussion

[6] See the paper "Integrated Planning Including Demand Response, Transmission, and Distribution " in this three paper series. In that paper we explore the transmission and distribution planners working with authors of the RFP to work iteratively to a solution. That may be needed here also. If so, it would not be surprising giving the interconnectivity of the grid.

How do we measure the cost-effectiveness of these services from DR given existing data and tools? There are generic questions on which it is probably worth spending a few minutes. These are:

- What will be the difference for individual utilities operating their own systems versus a single grid-wide operator? There might be a different answer for this question depending on what service is being discussed.

- Do the individual utilities have a good handle on their own data? That is, are the interconnections between the traditional resources and DR well understood by planners and control area operators?

- Do the individual utilities have a good handle on the data of other control area operators on the grid?

- How would we approach these issues if we had markets operating for these services versus no markets?

- What is the value of transmission on peak? On a per kWe basis? On a kWh basis? Above 75% of peak happens about 400-600 hours per year? Are their significant loads being served that cost more than revenue received? Question: What value do we ascribe in specific hours for transmission that is deferred? For distribution that is deferred? Is it the same for individual utilities as it is for the entire grid?

<u>What tools and data do we have now for measuring cost-effectiveness of DR?</u>

1. Do any tools exist among Northwest utilities?
2. Does the control area operator know and keep a record of the current costs of supplying these services using traditional resources? If not, what can be done to foster the collection of pertinent data?
3. Mid- C peak prices? How do we find? Surveys seem to be averages and miss peaks. Individual utilities know their costs.
4. If records are kept, how would the information in those records be used to formulate a strategy to determine cost-effectiveness of DR?
5. In a separate session we will examine what can be done in an IRP setting to answer these questions, perhaps iteratively.

<u>How do we achieve DR?</u>

1. Capacity relief in all hours, depending on the prices of generating capacity.
    a. Markets as in PJM
    b. Allowing the control area operator to set a fixed price in any hour that customers can choose to except of a 24/7 basis.

    c. Annual contracts that dictate terms between the control area operator and customers.
    d. Third-party entities to aggregate DR and sell it to control area operators and others?
    e. Other?

2. Savings in grid losses.
    a. Same ideas as in 1.

3. Deferral of transmission.
    a. Same delivery mechanisms as in 1.
    b. Does DR have to be on contract to defer transmission upgrades? or
    c. Can we rely on DR being statistically available on a bid-as-you-will basis?

4. Congestion relief.
    a. Similar to 1 and 2?
    b. Can we borrow from BPA's recent pilot project?

5. Savings of energy.
    a. Similar to 1 and 2?

6. Deferral of distribution feeders.
    a. Similar to 3?

Associated questions

1. Would establishing a base-case for individual loads be difficult or controversial? Do we keep the data that would allow us to do so?

2. How do conditions change from each transmission utility to another, and for the grid as a whole?

3. Is there room for arbitrage among different systems of the grid?

Appendix A
Membership of The Steering Committee

Lynn Anderson	Idaho PUC
Larry Bekkedahl	Clark County PUD
Ken Corum	NWPCC
Tom Foley	Climate Solutions
Nick Garcia	WUTC
Kevin O'Meara	Public Power Council
Pat Oshie	WUTC
Bob Raney	MTPSC
Will Rosquist	MTPSC
Rhys Roth	Climate Solutions
Rich Sedano	Regulatory Assistance Project
Lisa Swartz	OPUC
Dave Van Holde	Seattle City Light
Dave Warren	WAPUD Association
Dick Watson	Climate Solutions
Mike Weedall	BPA

Appendix B
The Broader Category of Distributed Energy Resources.

Distributed Energy Resources (DER) includes DR, but also includes energy efficiency measures and strategically placed generation. Strategically placed generation can be within the transmission and distribution system of utilities or behind customers' meters. Further these generators can be renewables, stand-alone fossil or biomass fuel burners, or co-generators-providing usable heat to local users.

DER resources, like DR resources, can also be used cost-effectively to reduce energy bills, defer or delay transmission and distribution upgrades, defer or delay new generation, reduce line losses, reduce congestion costs, alleviate environmental insults, and to provide ancillary services to control area operators. They can also improve customer service, convenience, and comfort. Energy efficiency measures have typically been considered as only providing energy savings to customers through improving the efficiency of end-users. In all cases, other associated benefits that should accrue to energy efficiency providers have not been considered in the funding of energy efficiency, in part, because of a lack of markets. These associated benefits of energy efficiency measures have not accrued to the providers, but have gone to unknown recipients. Further, the amount of funding spent on energy efficiency has been a function of energy savings only. If energy efficiency measures and other DER were funded at higher levels, it is almost certain that the costs of serving loads would be lowered.

In future work the cost-effectiveness of these DER resources should be considered. A suggested outline for that future analysis follows:

1. Conservation at the end-use
    a. Savings of Energy
    b. Savings of generation capacity
    c. Savings on T&D
    d. Savings of losses on T&D
    e. Environmental benefits
    f. Local economic development
    g. Savings in congestion relief
2. Distributed generation without heat recovery
    a. Saving of losses on T&D
    b. Savings in congestion relief
3. Distributed generation with heat recovery
    a. Savings of energy
    b. Savings of generation capacity
    c. Savings of losses on T&D Savings in congestion relief
    d. Environmental benefits and costs
    e. Savings due to limiting congestion
4. Time of use pricing of retail electricity
    a. Savings of generation capacity

b. Savings of losses on T&D
c. Savings of dollars at peak loads