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Disclaimer

Analytical Frameworks to Incorporate Demand Response in Long-term Resource Planning

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Acronyms and Abbreviations

BGE	Baltimore Gas and Electric
CIS	customer information system
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
DLRP	distribution load relief program
DR	demand response
DRMS	demand response management system
DSM	demand-side management
EE	energy efficiency
FERC	Federal Energy Regulatory Commission
IOU	investor-owned utility
IRP	integrated resource plan
ISO	independent system operator
LSE	load serving entity
NERC	North American Electric Reliability Corporation
PG&E	Pacific Gas and Electric
RTO	regional transmission organization
T&D	transmission and distribution
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association

Abstract

Many utilities are obligated by state regulatory or legislative requirements to consider demand response (DR) as part of their resource planning process. There are several ways to incorporate DR into resource planning modeling and each has its advantages and disadvantages. We explore the current analytical frameworks for incorporating DR into long-term resource planning. We also consider whether current approaches accurately and realistically model DR resources in capacity expansion and production cost models and whether barriers exist to incorporating DR into resource planning models in a more robust fashion. We identify ten specific recommendations for enhancing and expanding the current approaches.

1. Introduction

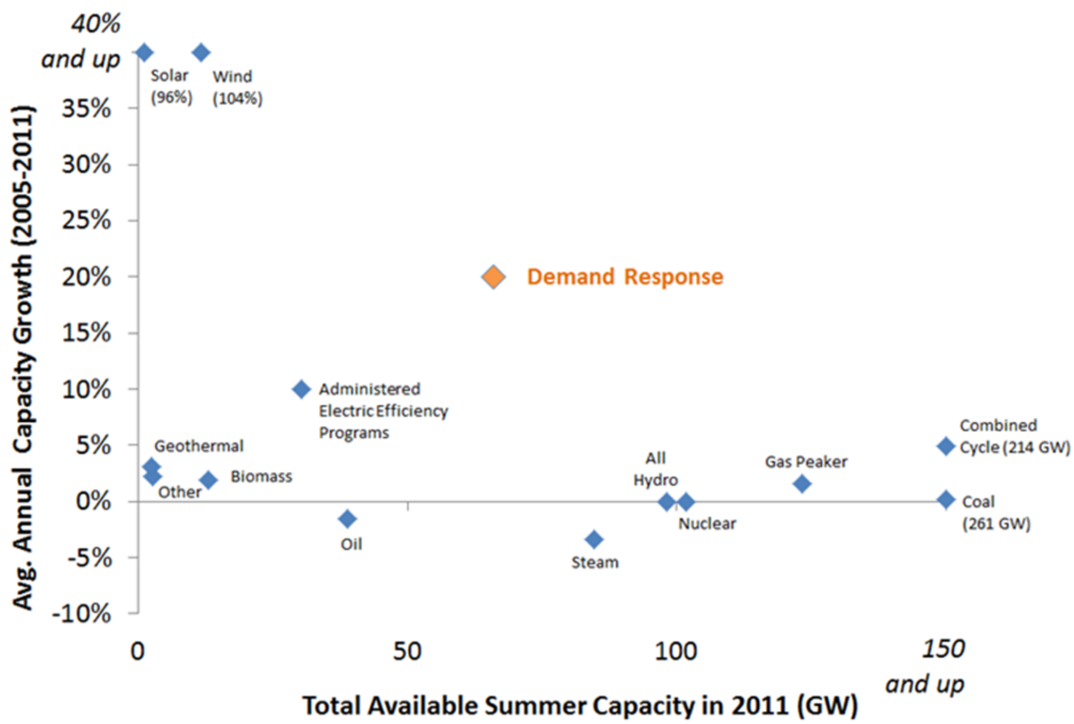
Traditionally, demand response has served as a resource to reduce peak system load and defer or avoid generation capacity and transmission and distribution system upgrades. Such deferral or avoidance of new capacity can lessen the utility's revenue requirement, reduce customers' utility bills, and provide environmental and other societal benefits. DR can also improve the resource-efficiency of electricity production (e.g., as customers are subjected to time-differentiated rates) and reduce exposure to high wholesale electricity prices due to avoiding the use of higher-cost peaking units. In the future, many are hoping that DR can be used around-the-clock to facilitate the grid integration of intermittent renewable generation resources.

DR resources are increasing in both size and importance in resource planning. The FERC reported in its *2012 Assessment of Demand Response and Advanced Metering* that peak reduction capability in existing programs was 66,351 MW in 2012, a more than 10,000 MW increase from 2010. In fact, according to FERC survey data, DR capability in the U.S. has grown at an average rate of 20 percent per year, relative to zero growth in U.S. peak demand during that same timeframe (EIA 2013). That is a faster growth rate than any non-renewable generating source during those years. And at 66 GW, DR represents more capacity than any renewable resource other than conventional hydro (which was roughly 79 GW in 2011 with virtually no growth over the past decade) (see Figure 1).

The FERC survey respondents also reported 20,256 MW of *actual* peak reduction (~31% of potential peak reduction) in 2012, demonstrating that DR resources are frequently used as a means to reduce and/or shift system peak load, but also demonstrating that there may be opportunities to expand utilization of the resource.

Whether the full value of this rapidly growing DR resource is being fully utilized depends in particular on the extent to which it is being represented and accounted for in utility resource planning initiatives.[1] Many utilities are obligated by state regulatory or legislative requirements to consider DR as part of utility resource planning either implicitly (e.g., least-cost planning requirement) or explicitly (e.g., consider all cost-effective demand side resources). There is also interest among regional reliability organizations and other system planners for long-term regional and national generation and transmission expansion planning that considers a range of load and resource scenarios and public policy considerations. FERC has recognized the importance of DR as planning resource in its Order 1000 that established the consideration of "non-wires alternatives" (e.g., energy efficiency, DR) as eligible resources in transmission planning activities. FERC Order 1000 also required regional transmission planners to incorporate public policy goals, including DR policies and programs.

[1] In this study, we are generally assessing the way DR is incorporated into system planning, whether for the purposes developing new generation resources or expanding the transmission system. Terms such as "resource planning," "system planning," and "capacity expansion planning," are used interchangeably throughout to refer to this process.



Notes:
Source of generation capacity data is Ventyx Energy Velocity Database
Demand response data from FERC 2013 Assessment of Advanced Metering and Demand Response
Energy efficiency data based on actual peak reduction estimates from EIA-861
Summer capacity is total for generating units classified as "operating" with commercial online date before January 2012
Assumes 50% peak coincidence for solar and 25% peak coincidence for wind; all other types assume 100% availability for simplicity

Figure 1: U.S. Available Capacity and Recent Growth in Demand- and Supply-Side Resources

There are several ways to incorporate DR into resource planning (e.g., load decrement, competing supply option) and each has its advantages and disadvantages. In addition, the DR market is continuing to evolve in response to new grid challenges. For example, integrating variable generation resources (e.g., wind and solar) is causing changes in RTO/ISO market rules that allow DR resources to operate in multiple (e.g., capacity, energy, ancillary services) markets and respond at a sub-hourly level (see sidebar for discussion of this issue). Thus, new and complementary approaches for incorporating DR into long-term resource planning may be necessary.

Regulators and policymakers are typically more familiar with valuing DR resources through "traditional" DR program cost-effectiveness screening. These cost-effectiveness frameworks calculate the expected costs and benefits of DR resources at the measure, program, and/or portfolio level. The expected stream of benefits from DR resources is typically measured in administratively determined avoided costs for generating capacity, energy, and transmission and distribution capacity. But, this approach often overlooks potential additional sources of value that DR can provide relative to supply-side resources (as discussed later in this paper). Similarly, representing the operational characteristics of DR programs in an oversimplified manner may not fully capture some of the unique limitations of the DR programs. This can result in under- or over-estimating the amount of DR resources to be developed through the resource planning process, and may produce sub-optimal utility transmission and capacity expansion plans.

This paper explores methods for better integrating DR into resource planning. We build on work for the Western Governors' Association (WGA) and Western Electricity Coordinating Council (WECC) in modeling DR in production cost and capacity expansion models. Specifically, we explore the analytical frameworks for incorporating DR into long-term resource planning and consider whether current approaches accurately and realistically model demand-side resources in capacity expansion and production cost models and whether barriers exist to incorporating DR into resource planning models in a more robust fashion.

The paper describes various analytical approaches for incorporating DR into resource planning and identifies considerations and tradeoffs among the various approaches with respect to different types of DR programs. The paper draws upon utility resource plans and demand side management (DSM) program filings to provide specific examples of the frameworks and approaches. The paper concludes with a discussion of what regulators and key industry stakeholders should consider when evaluating DR in future resource plans.

2. Review of Current Frameworks and Approaches in Utility Resource Plans

We reviewed 19 resource plans of the largest load serving entities (LSEs) in the Western Interconnection focusing on their most recently filed IRP (see Table 1). The resource plans included in our review of current frameworks and approaches captures a significant geographic area, as well as a large amount of DR resource capacity. This review built on work for WGA and WECC in which balancing authority non-firm load (i.e., DR) forecasts for WECC's transmission expansion planning studies were validated based on individual LSE IRPs and other public documents (Satchwell et al. 2013). We also limited our review of LSEs to the Western Interconnection because most do not participate in a wholesale electricity market (i.e., RTO or ISO) and, thus, DR programs would be limited to retail markets and likely be characterized within individual LSE resource plans.

Table 1: LSE IRPs Included in Review of Current Approaches

LSE	Region/Country[2]	Year of Study
Arizona Public Service (APS)	SW US	2012
Avista	NW US	2011
BC Hydro	NW CAN	2012 (Draft)
Idaho Power (IPC)	NW US	2011
Los Angeles Department of Water and Power (LADWP)	SW US	2012
Nevada Power (NPC)	SW US	2012
NorthWestern	NW US	2011
PacifiCorp	NW US	2013
Pacific Gas and Electric (PG&E)	SW US	2012
Public Service Company of New Mexico (PNM)	SW US	2011
Public Service Colorado (PSCO)	NW US	2011
Puget Sound (PSE)	NW US	2013 (Draft)
Southern California Edison (SCE)	SW US	2012
Seattle City Light (SCL)	NW US	2012
San Diego Gas and Electric (SDG&E)	SW US	2012
Sierra Pacific Power (SPPC)	SW US	2011
Sacramento Municipal Utility District (SMUD)	SW US	2010
Salt River Project (SRP)	SW US	2011
Tuscon Electric Power (TEP)	SW US	2012

We developed a multi-part categorization of the LSE IRPs to summarize the current frameworks and approaches to incorporating DR into resource plans. This categorization is based on two dimensions: 1) the construction of the LSE's candidate DR portfolio and 2) the treatment of the

[2] Northwest United States (NW US) includes Washington, Oregon, Montana, Idaho, Wyoming, Utah, and Colorado; Southwest United States (SW US) includes California, Nevada, Arizona, and New Mexico; Northwest Canada (NW CAN) includes British Columbia.

candidate DR portfolio in the LSE's resource plan.[3] We used these two dimensions because many utilities, often as a result of state regulatory requirements, have parallel or sequential planning processes for DR resources.

Many states have regulatory processes for utilities to propose and seek approval of DR programs. These often take the form of DSM planning processes and may include the consideration of energy efficiency (EE) programs, as well. In these processes, DR programs are screened by cost-effectiveness frameworks that often rely on administratively determined benefit streams (e.g., avoided capacity costs). But, these processes may fail to capture additional benefits of DR programs in capacity and transmission expansion (e.g., reductions in production costs, lower reserve margins, and lower transmission utilization). Additionally, some states have IRP processes that guide the long-term supply-side resources and demand-side loads and resources balance. Some utilities use the IRP process to demonstrate short-term resource acquisition needs (e.g., power purchase agreements) but do not necessarily use the IRP process to identify a portfolio of cost-effective DR programs.

We performed a qualitative review of the LSE IRPs focusing on portions of the resource plans that dealt with DSM and modeling approaches. We note a lack of consistent terminology among the IRPs and that many of the IRPs were structured according to different state regulatory guidelines and requirements. There were a few IRPs that did not distinguish between EE and DR, and we had to make judgments on whether the LSE's use of "DSM" included DR programs.

Five of the 19 LSE IRPs (~26%) did not assume or incorporate DR resources into their resource plans for several reasons. One LSE did not offer DR programs at the time of the IRP study and used the results of the IRP to demonstrate a need to develop DR programs due to a short-term capacity shortage. Another LSE offered some DR programs only for emergency events and reliability purposes and was re-designing programs for more frequent utilization that would provide a larger demand-side resource for planning purposes. Loading order, in which certain resource types are prioritized in a pre-determined order, also affected the inclusion of DR resources in the case of one LSE where higher-ordered EE resources provided sufficient peak demand and energy savings to eliminate the need for DR.

Of the remaining 14 LSE IRPs that assumed some amount of DR resources in their plan, we categorized them according to our two dimensions. We first considered whether the candidate DR portfolio was an *input to* or an *output of* the resource plan. A significant majority (12 out of 14; ~86%) of the LSE IRPs developed the candidate DR portfolio outside the planning process and then subjected that portfolio to production cost and/or capacity expansion modeling as an input.

The candidate DR portfolios developed outside the resource planning model occurred mostly through DSM planning processes (9 out of 12; 75%) adhering to standard cost-effectiveness screening tests. Other LSEs used a variety of approaches to develop the candidate portfolio. One LSE calculated the levelized cost of the DR programs and only assumed them in the resource plan mix if they were lower-cost than supply-side alternatives. Another LSE used a

[3] We defined "candidate DR portfolio" as a DR program or set of programs presumed to be cost-effective based on an individual utility's cost structure and regulatory framework.

"coordinated" but separate planning process based on a regulatory directive to avoid "double-counting" savings from DSM programs.

An important consideration in using parallel or sequential DR and resource planning processes is the timing of the analysis period for candidate DR portfolio and whether it is consistent with the IRP analysis period. A majority of the LSEs (7 out of 12; ~58%) with separate processes for developing the candidate DR portfolio and the IRP had different time periods for the separate processes. In many cases, DSM planning processes assumed DR programs for three years, whereas the IRP looked 10- to 20-years forward. In the cases where the candidate DR portfolio ended before the IRP analysis period, the LSE assumed a constant level of peak demand savings. This approach highlights a potential shortcoming of the separate planning process for DR resources as it may noticeably under-represent the growth of DR programs in later years of the IRP.

We found only two LSEs (2 out of 14; ~14%) that assumed some of amount of DR resources and appeared to use resource planning models to develop and evaluate the candidate DR portfolio. In both instances, the LSEs had a parallel process for DSM potential studies and used DSM program-level market potential as inputs to the resource planning models. The market potential was based on program-level technical potential and included expected program participation rates and event participation rates. The market potential was used to derive supply curves of demand-side resources, in which resources were ranked according to levelized cost of conserved energy. One LSE incorporated risk and sensitivity analyses in its evaluation of the candidate DR portfolio. The resource planning models essentially allowed these demand-side resources to compete with supply-side resources and develop a least-cost resource portfolio. Figure 2 summarizes the qualitative categorization of LSE IRPs along our first dimension.

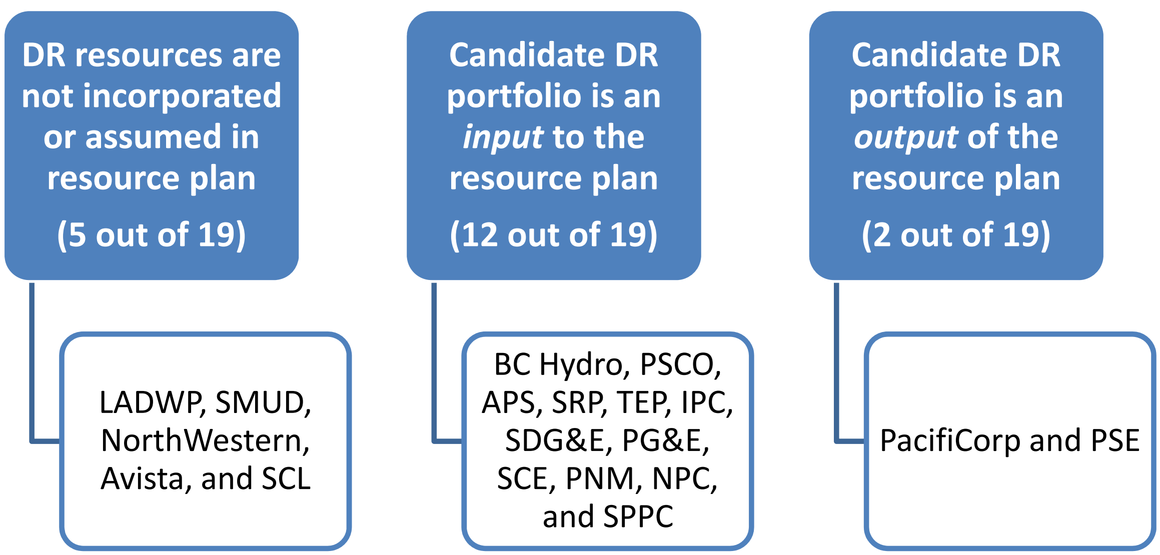


Figure 2: Summary of LSE IRP Construction of Candidate DR Portfolio

The second dimension of our qualitative categorization of LSE IRPs addressed the treatment of the candidate DR portfolio in the resource planning model. We found two primary approaches for the modeling of DR in resource plans.[4] The first, and most prevalent approach in our review of LSE IRPs, was to use DR as a peak load reduction (12 out of 14 IRPs that assumed some amount of DR resources). In these cases, DR resources were assumed to be available at 100% capacity and deducted from the resource plan peak load forecasts. This approach, however, assumes that DR resources (and respective programs) are dispatched to be perfectly coincident with the utility annual peak demand and does not dynamically optimize the dispatch and operations of the DR resources.

The other approach was used by those LSEs who created and evaluated the candidate DR portfolio through the resource planning model. In these cases, noted earlier, the LSE used supply curves of DSM resources (including some DR programs) and allowed the demand-side resources to effectively compete with LSE defined supply-side resources. Many details about the characterization and dispatch of the demand-side resources were not clear in the IRPs, and results for various portfolios were expressed in present-value revenue requirements over the entire analysis period instead of on an annual basis. While supply-side comparability approaches are more sophisticated than peak load reduction modeling approaches in terms of the more detailed inputs and assumptions necessary to build DR supply curves, they have some important limitations. DR programs are used by utilities for planning, operational, and reliability purposes in different ways and DR resources are dispatched in a manner distinct from supply-side resources. For example, DR programs are often subject to program rules limiting their operation to a maximum number of hours per year, and have restrictions on the minimum or maximum number of continuous hours of operation and on the frequency with which the customers can be curtailed. Current supply-side comparability approaches do not always fully capture such operational characteristics of DR.

[4] We note that these two primary approaches correlate with the approach for constructing the candidate DR portfolio. We do not believe this is necessarily causation, where the creation of the candidate DR portfolio requires a particular treatment of the candidate DR portfolio, but may be a result of the way DR programs are designed (e.g., for peak load reduction).

3. Enhancing and Expanding Current Approaches

Our research has identified a range of methods that are currently being employed by utilities to integrate DR into their resource planning efforts. Each approach has been shaped by the specific needs and requirements of the entity that is developing the resource plan. Previous studies on the role of demand-side resources in resource planning also detailed how integrated resource planning differs from traditional utility planning, and identified the need for additional work in the treatment of DSM as capacity and energy resources (Goldman and Hirst, 1991). Based on our review of the literature and experience working with resource planners and DR program administrators, we offer recommendations for ways in which the current approaches may be enhanced and expanded in order to more fully account for the benefits and limitations of DR.

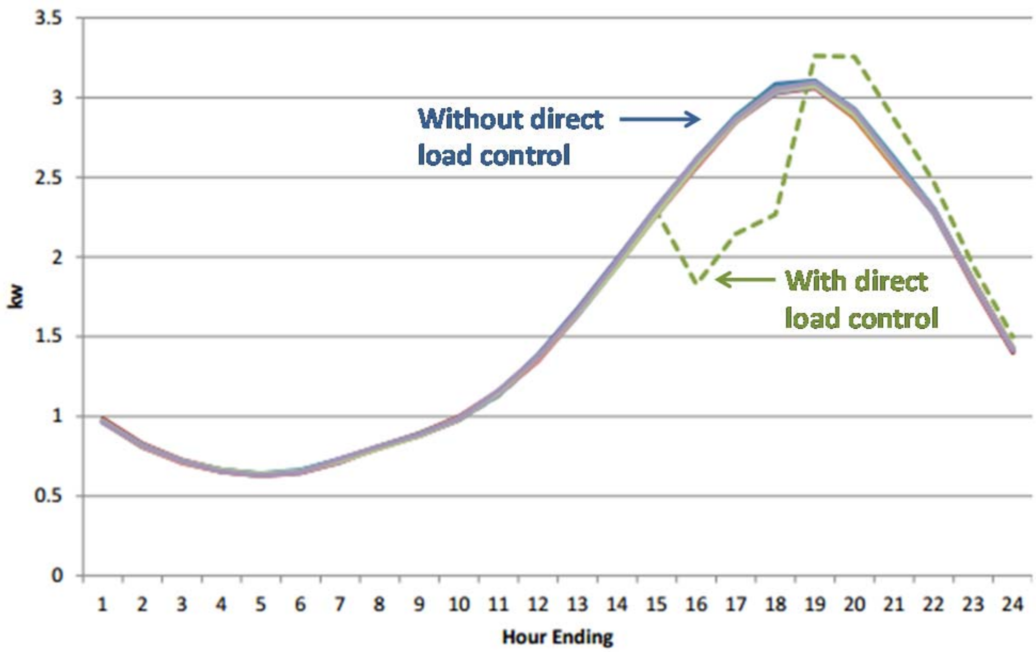
3.1 Expanding the representation of DR as a competing resource

As discussed above, DR measures are often included in resource planning models as resources that "compete" with supply side options. There are several ways in which the representation of DR in this context could be expanded to more fully capture its benefits and limitations.

1. *Recognize the option value of DR.* Resource planning models often rely on point estimates for key input variables like load forecasts, fuel prices, and generating unit availability. The resource planning process then typically considers a limited number of scenarios that are composed of a few different combinations of assumptions about these variables. By limiting the analysis to a few discrete scenarios, the full spectrum of extreme events that could occur on a system is often underrepresented. In fact, it is in response to uncertain and extreme events that DR has been found to provide the most value (see Sezgen et al., 2005). For example, an unlikely event like a large unit outage in a constrained part of the grid (e.g., Southern California Edison's San Onofre Nuclear Generating Station outage), when combined with higher than expected load conditions due to hot weather, could severely threaten system reliability. Studies have shown that being able to avoid blackouts in these situations through the use of DR programs could justify investment in the programs even if they happen only every five or ten years (Violette et al., 2006). This is known as the "option value" of DR.

   Capturing the option value of DR can be achieved by incorporating Monte Carlo Simulation techniques into resource planning. Rather than assessing a few discrete scenarios, probability distributions can be created around each key uncertain variable, and correlations can be established between the variables. Then, random draws are taken from the probability distribution for each variable and the resource planning model is run with these assumptions. The process is repeated many (e.g. hundreds or thousands) of times. The result is a probability distribution for a range of possible outcomes that more fully represents future uncertainty. When DR is included as a resource option in this approach, the result will more accurately capture the ability of DR to address extreme reliability situations. A key barrier to be overcome in this approach is simplification of the resource planning model to reduce run time and allow for multiple iterations. The creation of probability distributions may also be subject to political challenges, in addition to the technical challenges.

2. *Account for increased electricity consumption immediately before or after DR event periods.* Resource planning models often only account for reductions in peak load during a DR event. However, load impacts may also occur immediately before or after the event. For example, when an air-conditioning unit is cycled as part of a direct load control program, there is typically load building immediately following the event as the air-conditioning unit works to return the building to the desired temperature. The result potentially could be the creation of a new peak outside of the DR event period. This is illustrated in Figure 3 for PG&E's residential direct load control program ("SmartAC").



Source: Adapted from Mike Perry, Christine Hartmann, Liz Hartmann, and Stephen George, "2012 Load Impact Evaluation for Pacific Gas and Electric Company's SmartAC Program," prepared for Pacific Gas and Electric Company, April 1, 2013, p. 12. http://fscgroup.com/reports/2012-smartac-evaluation.pdf

Figure 3: Hourly Impacts of PG&E's Residential SmartAC Program on a Peak Day

To address this issue, hourly load impact profiles of each DR measure could be established based on impact evaluation studies and incorporated into resource planning models. This is the approach that is used, for example, in FERC's Demand Response Impact and Value Estimation (DRIVE) model.[5]

3. *Assess the optimal dispatch of the portfolio of DR programs.* Resource planning approaches may assume that all of a utility's DR programs will be simultaneously dispatched during the same system peak hours. This may understate the actual peak reduction that could be achieved through optimized dispatch of the programs. Specifically, the effectiveness of the reduction during the event hours could be limited by the highest load hour that exists outside of the event period. This phenomenon is

[5] The model was developed as part of FERC's National Action Plan on Demand Response and can be used to evaluate the hourly impacts of DR and other customer-side programs on power grid operations. The DRIVE model is available at: http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/action-plan.asp.

illustrated in Figure 4. In the illustration, while the DR program is producing a 20 percent reduction during the top 100 peak load hours of the year, the net result is only a nine percent reduction in peak demand due to high load in the 101st peak load hour.

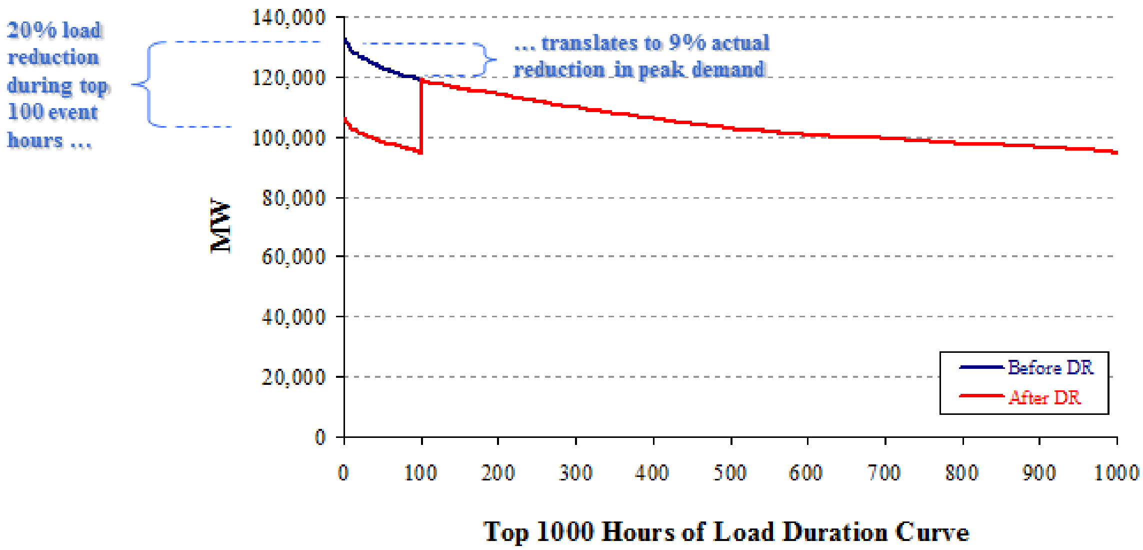


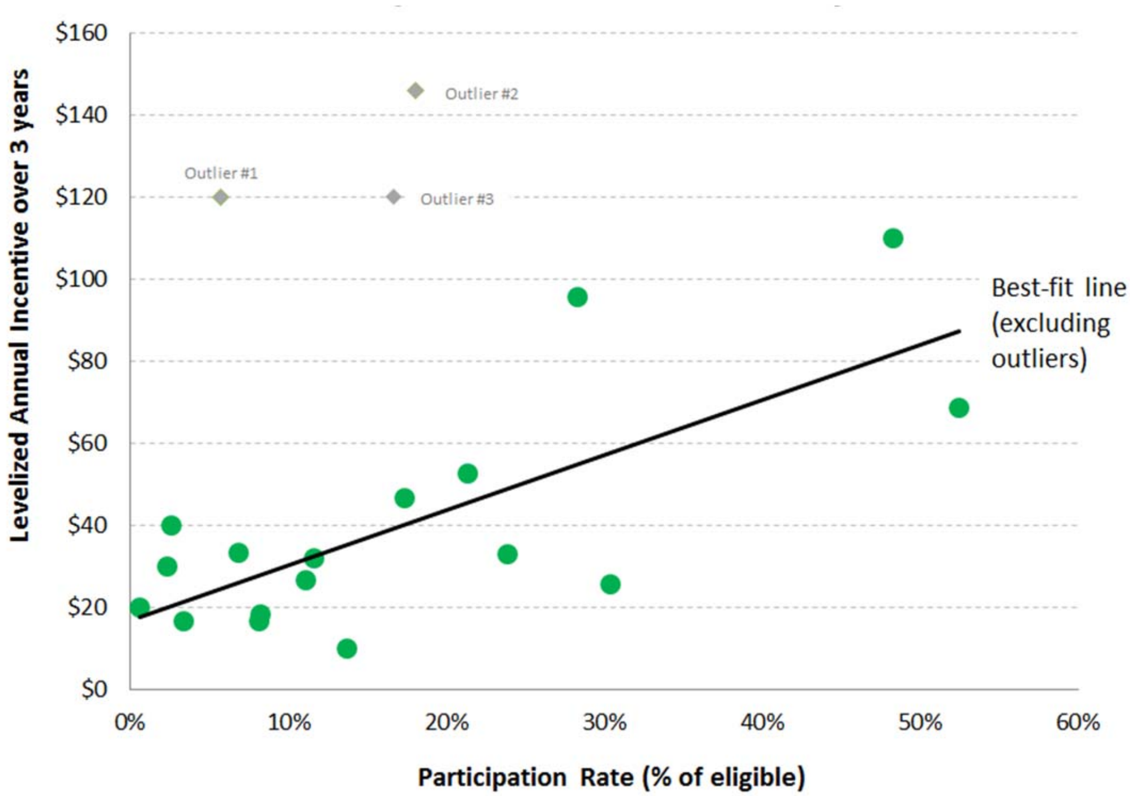
Figure 4: DR Impact on the System Load Duration Curve

To address this issue, dispatch of the DR programs could be staggered to "spread out" the reductions over a broader number of peak hours, without having to expand the peak period definition of the programs (which would otherwise reduce the attractiveness of the programs to potential participants). Doing so would require careful analysis of the system load shape, knowing the geographical location of program participants, and sophistication in selectively communicating the DR events to the pool of customers. It would also require close coordination between resource planners and utility DR program staff.

4. *Account for the geographical distribution of DR participants.* Geography is a very important consideration when using DR to relieve transmission congestion and defer the need for new transmission upgrades. For example, Con Edison's Distribution Load Relief Program (DLRP) offers customers in congested parts of the grid incentive payments that are twice as high as they would otherwise receive for participating in the program.[6] Further, with new smart meter data, it may be possible to address reliability concerns even at the distribution level – this could become increasingly important with the rising market penetration of rooftop solar and electric vehicles. However, doing so would require granular geographical detail when representing DR in transmission and distribution planning. DR programs could be valued differently depending on whether the participants are in geographically constrained areas (Kirsch et al., 2008). Locational marginal pricing can help to facilitate such geography-specific valuations.

[6] ConEd Website. Tier II customers receive payments of $6/kW-month and Tier I customers receive payments of $3/kW-month. http://www.coned.com/energyefficiency/DR_comparison_chart.pdf

5. *Account for the relationship between incentives and participation.* A review of DR program participation suggests that there is a correlation between program enrollment and the level of participation incentive payments that are being offered to customers. Figure 5, for example, shows enrollment versus participation payments for residential air-conditioning direct load control programs among the 20 largest utilities in the U.S.



Sources: Developed using data from FERC 2012 Assessment of Demand Response and Advanced Metering (December 2012) and company websites

Figure 5: Participation versus Incentive Payments among Residential Direct Load Control Programs at 20 Largest U.S. Investor-Owned Utilities

To recognize this relationship between incentive payments and participation, a feedback loop could be established in resource planning models such that, at times when DR is more valuable (e.g. reserve margins are tight), higher participation incentives are assumed to be offered and enrollment is assumed to increase accordingly. The specific relationship could be informed through market research conducted among the utility's customers. An empirical meta-analysis of incentives and enrollment levels in existing DR programs across the U.S. would also provide insight to this relationship (while controlling for factors such as the age of the program or the program's marketing budget). Design of the DR program incentive payments would also be informed through this process.

3.2 Enhancing DR cost-effectiveness screening techniques

Earlier in this paper, we demonstrated that many utilities use a cost-effectiveness screening process to select the candidate DR portfolio that will be incorporated into their resource planning process. The following are recommendations for enhancing these cost-effectiveness screening techniques relative to current standard practices.

6. *Fully account for the operational constraints of DR resources.* Unlike the around-the-clock availability of a combustion turbine peaking unit, DR programs are typically constrained by the number of load curtailment events that can be called during the course of a year. Further, there are often pre-defined limitations on the window of hours of the day during which the events can be called, and sometimes even on the number of days in a row that an event may be called. It is also often the case that hour-ahead or day-ahead notification must be given to participants before calling an event. All of these constraints can limit the capacity value of a DR program. California's investor-owned utilities (IOUs) account for this through a derate factor that is applied to the avoided capacity costs that are estimated for any given DR program. The derate factor is program-specific and is estimated through an assessment of the relative availability of DR during hours with the highest loss of load probability. Historically, depending on program characteristics and utility operating conditions, some derate factors have ranged from 0 percent to roughly50 percent of the capacity value of the programs.[7]

   Of course, the relative availability of peaking units should also be taken into account when establishing these derate factors. If rarely-used peaking units are found not to be reliable when needed during times of system emergencies, then the relative disadvantage of DR is not as significant as it may initially appear. For example, a recent analysis found that of 750 MW of peaking units in the San Diego area of Southern California, roughly 60 percent were available when called due to startup issues.[8] DR could be a relatively reliable peaking resource in comparison. The New England ISO (NE-ISO) dispatched DR resources on July 19, 2013 for system reliability purposes and 95 percent of dispatched DR resources responded.[9] This also highlights the very system-specific nature of the derate calculation. It must be developed on a case-by-case basis with careful consideration for factors like the system load profile, DR program characteristics, and generating unit performance.

7. *Account for potential environmental impacts.* DR has the potential to avoid generation from highly inefficient – sometimes oil-fired – peaking units that would otherwise be running during times of peak demand. The result of this avoided generation could be a net reduction in harmful emissions. While the number of hours during which this would happen is constrained by the number of load curtailment events being called, the reductions could be particularly valuable in densely populated areas during times when

[7] For further detail on the derate factor, see the CPUC website.
http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

[8] SNL Financial, "Cal-ISO: Huntington plant revival crucial for summer if San Onofre outage continues," by Jeff Stanfield, April 12, 2013.

[9] NE-ISO presentation to Demand Resource Working Group. *July 19th 2013 OP4 Action 2 Initial Real Time Demand Resource Performance*. July 31, 2013.

air quality is a concern. The alternative is also a possibility. In regions where gas-fired units are on the margin during peak hours and load is shifted to off-peak hours when coal is on the margin, there could be a net increase in emissions. One study found that DR could result in either a slight increase or a slight decrease in CO_2 emissions, depending on the region of the U.S. in which the DR program was being deployed (Hledik, 2009).

In the future, DR may play a role in integrating clean energy resources like wind and solar (see the sidebar for further discussion). Further, to the extent that peak demand reductions result in avoided investment in new generation capacity or T&D capacity, the result would be a smaller physical footprint of the grid. This could reduce the impact to wildlife, habitat, and sensitive ecosystems.[10]

The challenge in capturing these potential environmental impacts in a cost-effectiveness assessment is in assigning a cost to emissions (and, hence, a benefit to emissions reductions). That will be largely driven by the politics of the state or region in which the resource planning effort is being conducted. One state that appears poised to address the broader societal benefits of DSM is California. The California Public Utilities Commission (CPUC) is discussing a new proposal to develop a Societal Cost Test that would account for externalities such as avoided emissions when evaluating the cost-effectiveness of DSM programs.[11]

8. *Consider other hard-to-quantify benefits of DR.* There are other benefits of DR programs that are difficult to quantitatively factor into a cost-effectiveness screen but should be kept in mind when comparing DR options to other resource options. Examples include the potential for improved post-outage power restoration, improved customer satisfaction due to an expanded selection of product offerings and bill savings opportunities, and in the case of dynamic pricing, more equitable and economically efficient retail rates (Woolf et al., 2013).

[10] For further discussion of the environmental impacts of DR and load shifting, see Ahmad Faruqui and Ryan Hledik, "Time-Varying and Dynamic Rate Design," prepared for the Regulatory Assistance Project, July 2012.
[11] CPUC website. http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm

Sidebar: DR and Renewables Integration

Of emerging relevance to resource planning is the potential future role of DR to facilitate the integration of variable and intermittent sources of generation, such as wind and solar. While this is largely an operational issue, it also has relevance to long-term resource planning where decisions are being made about when and how to integrate renewables to meet renewable portfolio standards (RPS) requirements.

Many regions of the U.S. are seeing unprecedented levels of growth in the adoption of these resources. While this has environmental benefits, it poses a challenge to maintaining system reliability. Wind and solar resources quickly – and somewhat unpredictably - ramp up and down depending on weather conditions. Additionally, the times when these resources are generating electricity do not always coincide with the times when electricity is needed (and vice versa). Specifically there are four reliability-related problems that must be addressed when variable generation is adopted at high levels (Kiliccote et al., 2010):

- Increased intra-hour variability in supply
- Large magnitude of overall ramping requirements
- Over-generation concerns
- Near-instantaneous production ramps

As adoption of these resources continues to grow, system operators will increasingly look for effective, flexible resources to ensure that grid reliability is maintained. In addition to supply-side options (such as fast-ramping gas-fired peaking units), many consider DR to be another possible solution. Rather than solely ramping generation up and down to respond to fluctuations in supply from renewables, load might also be controlled dynamically to balance the system.

The concept of "flexible demand" has generated significant interest but is still in the early developmental stages. The topic has been qualitatively explored through studies by organizations such as Lawrence Berkeley National Lab (LBNL), the National Renewable Energy Laboratory (NREL), the Demand Response Research Center (DRRC), the California Public Utilities Commission (CPUC), GE Energy, EnerNOC, and others. These studies have focused primarily on the theoretical capabilities of DR to integrate renewables, the types of load that may be good candidates to provide such services, barriers that are preventing DR from being utilized in this manner, and policy recommendations for overcoming these barriers.

In addition, a few demonstration projects have tested the actual capability of loads to be controlled in order to provide ancillary services that are needed to address the challenges of renewables integration. For example, Mason County Public Utility District #3, in partnership with Bonneville Power Administration (BPA), tested the ability to increase or decrease water heating load with short response time through direct control of the water heater in 100 homes in Northwestern Washington (Mason Country PUD 3, 2012). Operation of the water heater was tied directly to the output of wind units on BPA's system, to time the load changes to coincide with periods when wind generation was ramping up or down.

While these studies suggest that there is potential for DR to be used to integrate renewables, the concept has not yet been tested on a large scale. Several factors are preventing this from happening. Among the key barriers are operational constraints of historical and current DR programs, DR programs that are focused primarily on peak reductions, lack of retail dynamic pricing, wholesale markets or other resource adequacy constructs that do not facilitate demand-side participation, uncertainty around customer willingness to participate, and economic feasibility (Cappers et al., 2011 and Perlstein et al., 2012).

Without more experience, demonstrations, pilot studies, and full-scale rollouts, it is difficult to quantify the size of the potential role that DR could play in integrating renewables. However, the recent studies on this topic have identified several end-uses and customer segments that could be attractive candidates for providing ancillary services in the future. These are loads that could be automated with near-instantaneous control and rapid feedback, and could be decreased or (in some cases) increased in response to fluctuations in supply. Some sources of load that meet these criteria and are already often tapped through DR programs include pumping capacity, compressor capacity, refrigeration, water treatment, and water heating (Kiliccote et al., 2010). Additionally, emerging technologies like thermal energy storage, battery storage, and electric vehicles could potentially be attractive candidates in future "flexible demand" programs.

Overall, there is not yet enough experience with flexible DR programs to precisely quantify their likely enrollment or impacts. This area is ripe for future research and is of particular relevance to resource planning efforts, given the expectation for significant future additions of variable resources. It is a topic that should be explored in more detail through future potential studies and regional pilot programs.

3.3 Other considerations for incorporating DR into resource planning

In addition to the above recommendations for incorporating DR as a competing resource option and for enhancing cost-effectiveness screening, there are other general considerations that should be accounted for in the resource planning process.

9. *Consider uncertainty about the long-run performance of DR resources.* The dependability of DR is a key factor to account for in resource planning, particularly when DR is being relied upon in large quantities. It is important that the amount of DR that is likely to actually be delivered - as opposed to the amount that is simply enrolled - be accounted for. This is relevant not only to resource planning among vertically integrated utilities but is an important consideration in competitive wholesale capacity markets. In PJM, where DR commitments have cleared the forward capacity market auctions in excess of 7,000 MW over the last several years, the resource has been quite reliable when needed thus far. Since 2009, the amount of load curtailed has exceeded the capacity commitment by between seven percent and 18 percent during test events. During actual events, performance (i.e., the actual load reduction compared to the maximum potential load reduction) ranged from a shortfall of nine percent to a surplus of four percent (PJM, 2012). Looking forward, DR is showing up in increasingly larger quantities in the PJM capacity market and it will likely need to be relied upon more heavily - and dispatched more frequently - in coming years, thus, increasing the importance of overcoming uncertainty in DR resource dependability and performance (Newell and Spees, 2013). In fact, PJM recently proposed tariff revisions that would establish enhanced protocols for determining the reliability of DR resources that had been bid into its capacity market.[12]

   To address uncertainty in DR availability in resource planning, empirical assessment of historical DR performance data could help to establish confidence intervals around the reliability of DR impacts. Such analysis could be conducted based on a given utility's own experience with its DR programs, or parallels could be drawn from utilities in other regions that offer similar programs with a longer history or more significant enrollment.
   A related issue is concern regarding the reliability of "behavior-based" DR programs (e.g., dynamic pricing) relative to programs for which load reductions are automated. What is often underappreciated about behavior-based programs, particularly when deployed to the mass market, is that the impacts of these programs can be very consistent and predictable due to the fact that they are based on the collective response of a large number of participants. In other words, while a given customer may change their behavior from one load curtailment event to the next, this impact is significantly muted when it is being averaged over thousands of other participants. In fact, studies have shown that impacts from behavior-based programs persist from one event to the next across multiple years and even when called on consecutive days. According to a four-year residential dynamic pricing study by BGE, there was no erosion in impacts among participants across all for years of the study (Lessem, Sergici, and Faruqui, 2013).

10. *Account for price response in load forecasting models.* The load forecast is a key input to any resource planning process. Many load forecasting models, both at utilities

[12] PJM Interconnection L.L.C., Docket No. ER13-2108-000, filed August 2, 2013.

and ISOs, do not include a price term that accounts for customer load reductions as prices rise or as prices become more volatile. Incorporating a term that accounts for both overall reductions in response to rising prices, as well as changes in demand patterns that are related to time-varying rates, would improve the overall accuracy of the model.

4. Conclusions

Our survey of existing frameworks for incorporating DR into long-term resource planning finds that there is a wide variety of approaches currently being used. A sizeable portion of the utilities we surveyed (roughly one quarter) do not incorporate DR into resource planning, choosing instead to treat it as a last-resort reliability option. The majority of utilities (roughly 65 percent) pre-determined their DR portfolio through a cost-effectiveness screen based on administratively determined avoided costs, and then established a capacity expansion plan with the implementation of this DR portfolio taken as given. A small fraction of the utilities that we surveyed (roughly 10 percent) fully integrated DR into their resource planning process by creating a supply curve of DR resource options and allowing them to "compete" against supply side options when determining the optimal mix of new resources to be added in the future.

Enhancing and expanding upon the current approaches would provide material financial benefits to utilities and their customers. In some of the instances described in this study, the benefits of DR are not being fully represented in IRP planning processes, and are therefore likely leading to underinvestment in DR resources. Nationally, if the 66 GW of existing available DR represented even only a 10 percent underinvestment in the resource, the financial benefits that are being left on the table in terms of avoided capacity alone could be worth over $5 billion.[13] Conversely, in other instances, we have identified deficiencies in resource planning that may be leading to over-investment in DR, or sub-optimal use of the resource. This could have similar financial implications for utilities and their customers.

Now is a good time to consider enhancing the current approaches. Many utilities around the U.S. are temporarily experiencing a generation capacity surplus and substantial reserve margins. This presents a low-risk opportunity to experiment with more sophisticated DR modeling approaches, so that optimal demand-side resource investment decisions can be made before supply and demand conditions tighten and further capacity resources are needed.

Utilities that do not currently incorporate DR into the resource planning process may consider moving toward a framework that recognizes the capacity avoidance/deferral benefits of DR and begin to utilize these programs more regularly on an operational basis. Where cost-effectiveness screening is used to determine the optimal DR portfolio, recognition of the unique benefits and limitations of DR that are described in this paper can help to refine the screening methodology. And when representing DR in resource planning models, there may be value in accounting for issues such as expectations around long-run DR resource performance, the link between incentive levels and DR program enrollment, locational benefits of DR, and the option value of DR.

Of course, when exploring opportunities to expand and enhance the representation of DR in resource planning, utility resource planners and regulators should be particularly attentive to barriers to achieving some of the incremental enhancements. For example, the integration and

[13] Assumes 6.6 GW of additional potential avoided capacity at $75/kW-year over a 20-year period, represented as a present value discounted at a seven percent annual discount rate. Represents benefits only and does not account for incremental costs of DR. FERC's 2009 *National Assessment of Demand Response Potential* identified significantly more cost-effective DR potential than the 6.6 GW used in this example.

collection of DR program data (particularly DR event data) can be a major barrier to improving the characterization of DR in resource planning models. To address this, some utilities are using demand response management systems (DRMSs) to potentially integrate DR data with other utility systems (e.g., customer information system [CIS]). Data for utilities to benchmark DR program size and performance may become available as NERC is collecting DR enrollment and performance data across multiple program types, including dispatchable, economic, and ancillary service DR programs.

There are also some regulatory and utility cultural barriers that should be addressed. Some of the parallel and/or sequential regulatory processes for screening and evaluating DR program portfolios and for utility resource planning are often treated as disparate processes. Utility resource planning staff and DR program staff are also not necessarily coordinated within the utility and this can lead to uncoordinated planning efforts and divergent viewpoints on the role and capabilities of DR resources.

Careful analysis, coordination, and planning will be critical to overcoming these barriers. Regulators that oversee planning processes and approve IRPs and utility investment will play an important role in this process, as they consider whether and to what extent DR programs and policies are reflected in utility resource plans, along with requests for approval of utility investments. Utility resource planners, as they look to better integrate a growing DR resource into their planning studies, have and will continue to confront these issues. Utility DR program staff may also benefit from these recommendations, as recognition of specific long-term planning issues could play a key role in optimizing the design of future DR programs.

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