A Framework for Evaluating the Cost-Effectiveness of Demand Response

Prepared for the National Forum on the National Action Plan on Demand Response: Cost-effectiveness Working Group

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A Framework for Evaluating the Cost-Effectiveness of Demand Response was developed to fulfill part of the *Implementation Proposal for The National Action Plan on Demand Response*, a report to Congress jointly issued by the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) in June 2011. Part of that implementation proposal called for a "National Forum" on demand response to be conducted by DOE and FERC.

Given the rapid development of the demand response industry, DOE and FERC decided that a "virtual" project, convening state officials, industry representatives, members of a National Action Plan Coalition, and experts from research organizations to work together over a short, defined period to share ideas, examine barriers, and explore solutions for demand response to deliver its benefits, would be more effective than an in-person conference. Working groups were formed in the following four areas, with DOE funding to support their efforts, focusing on key demand response technical, programmatic, and policy issues:

1. Framework for evaluating the cost-effectiveness of demand response;
2. Measurement and verification for demand response resources;
3. Program design and implementation of demand response programs; and,
4. Assessment of analytical tools and methods for demand response.

Each working group has published either a final report or series of reports that summarizes its view of what remains to be done in their subject area. This document is one of those reports.

The Implementation Proposal, and the National Forum with its four working groups' reports, is part of a larger effort called the National Action Plan for Demand Response. The National Action Plan was issued by FERC in 2010 pursuant to section 529 of the Energy Independence and Security Act of 2007. The National Action Plan is an action plan for implementation, with roles for the private and public sectors, at the state, regional and local levels, and is designed to meet three objectives:

1. Identify requirements for technical assistance to States to allow them to maximize the amount of demand response resources that can be developed and deployed;
2. Design and identify requirements for implementation of a national communications program that includes broad-based customer education and support; and
3. Develop or identify analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, states, utilities, and demand response providers.

The content of this report does not imply an endorsement by the individuals or organizations that are participating in NAPDR Working Groups, or reflect the views, policies, or otherwise of the U.S. Federal government.

A Framework for Evaluating the Cost-Effectiveness of Demand Response was produced by Cost-Effectiveness Working Group co-chairs Tim Woolf and Erin Malone (Synapse Energy Economics), and Lisa Schwartz and John Shenot (Regulatory Assistance Project), for Lawrence Berkeley National Laboratory, who is managing this work under a contract to the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability under Contract No. DE-AC02-05CH11231.

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Regarding the National Action Plan on Demand Response, visit:

http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf

Regarding the Implementation Proposal for the National Action Plan for Demand Response, visit:

http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp

OR

http://energy.gov/oe/downloads/implementation-proposal-national-action-plan-demand-response-july-2011

Regarding the National Forum for the National Action Plan for Demand Response project, visit:

http://energy.gov/oe/national-forum-demand-response-what-remains-be-done-achieve-its-potential

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Executive Summary

The Demand Response Cost-Effectiveness Framework

Demand-side programs have different impacts on different parties. As a result, five cost-effectiveness tests have been developed to consider demand-side program costs and benefits from various perspectives. The California Standard Practice Manual has become the industry standard for defining these tests and applying them to energy efficiency programs. **Table ES-1** summarizes some of the key implications of each of the five cost-effectiveness tests.

We recommend the use of these five tests for the demand response program cost-effectiveness framework. The cost-effectiveness framework that has successfully and frequently been applied to energy efficiency programs is also appropriate for demand response programs. The framework can be adopted for demand response purposes with minimal, albeit important modifications, and this is becoming common practice in states screening demand response programs for cost-effectiveness.

We use the five cost-effectiveness tests as our starting point for the framework, and then discuss the ways in which costs and benefits of demand response programs might require special consideration in applying the framework, as distinct from energy efficiency programs (see Table ES-1). Although it is clear that the framework is appropriate for assessing the cost-effectiveness of demand response programs, we note that applying the framework is not a straightforward matter; the associated issues can be extremely complex and occasionally contentious.

Table ES-1. The Five Principal Cost-Effectiveness Tests

Test	Key Question Answered	Summary Approach	Implications
Societal Cost	Will total costs to society decrease?	Includes the costs and benefits experienced by all members of society.	Most comprehensive comparison but also hardest to quantify.
Total Resource Cost	Will the sum of utility costs and program participants' costs decrease?	Includes the costs and benefits experienced by all utility customers, including program participants and non-participants	Includes the full incremental cost of the demand-side measure, including participant cost and utility cost.

Program Administrator Cost	Will utility costs decrease?	Includes the costs and benefits that are experienced by the utility or the program administrator.	Identifies impacts on utility revenue requirements. Provides information on program delivery effectiveness, i.e. benefits per amount spent by the program administrator.
Participant Cost	Will program participants' costs decrease?	Includes the costs and benefits that are experienced by the program participants.	Provides distributional information. Useful in program design to improve participation. Of limited use for cost-effectiveness screening.
Rate Impact Measure	Will utility rates decrease?	Includes the costs and benefits that affect utility rates, including program administrator costs and benefits and lost revenues.	Provides distributional information. Useful in program design to find opportunities for broadening programs. Of limited use for cost-effectiveness screening.

Demand Response Program Costs

There are many different types of demand response program costs that must be accounted for when evaluating cost-effectiveness. **Table ES-2** provides a list of potential demand response (DR) program costs, and indicates which of the costs should be considered in each of the cost-effectiveness tests.

Table ES-2. Demand Response Program Costs

Cost	Participant	RIM	PAC	TRC	Societal
Program Administrator Expenses	--	Yes	Yes	Yes	Yes
Program Administrator Capital Costs	--	Yes	Yes	Yes	Yes
Financial Incentive to Participant	--	Yes	Yes	--	--
DR Measure Cost: Program Administrator Contribution	--	Yes	Yes	Yes	Yes
DR Measure Cost: Participant Contribution	Yes	--	--	Yes	Yes
Participant Transaction Costs	Yes	--	--	Yes	Yes
Participant Value of Lost Service	Yes	--	--	Yes	Yes
Increased Energy Consumption	--	Yes	Yes	Yes	Yes
Lost Revenues to the Utility	--	Yes	--	--	--
Environmental Compliance Costs	--	Yes	Yes	Yes	Yes
Environmental Externalities	--	--	--	--	Yes

Demand response programs sometimes result in costs that do not exist or are not as significant for energy efficiency programs. For example participants may experience reduced electricity services as a result of curtailing load in a demand response program. To the extent practical, this “value of lost service” should be factored into the cost-effectiveness analyses. Similarly, the transaction costs associated with demand response programs might be much higher than those associated with energy efficiency programs, depending upon the program and the requirements placed upon the customer for participation in the program. These two types of costs faced by participants are extremely difficult to quantify accurately but are also very important to consider, because they can significantly affect whether a demand response program will pass the Participant Cost, TRC, or Societal Cost test.

Another cost that may need to be considered is the cost of increased electricity consumption, for those programs that result in load shifting. Similarly, for those programs that rely on customer back-up generators to assist with load curtailment, the costs associated with operating those generators, including the environmental impacts, should be considered in the cost-effectiveness analysis.

Demand Response Program Benefits

There are also many different types of demand response program benefits that should be accounted for when evaluating cost-effectiveness. **Table ES-3** provides a list of potential demand response program benefits, and indicates which of the benefits should be considered in each of the cost-effectiveness tests.

Table ES-3. Demand Response Program Benefits

Benefit	Participant	RIM	PAC	TRC	Societal
Avoided Capacity Costs	--	Yes	Yes	Yes	Yes
Avoided Energy Costs	--	Yes	Yes	Yes	Yes
Avoided Transmission & Distribution Costs	--	Yes	Yes	Yes	Yes
Avoided Ancillary Service Costs	--	Yes	Yes	Yes	Yes
Revenues from Wholesale DR Programs	--	Yes	Yes	Yes	--
Market Price Suppression Effects	--	Yes	Yes	Yes	--
Avoided Environmental Compliance Costs	--	Yes	Yes	Yes	Yes
Avoided Environmental Externalities	--	--	--	--	Yes
Participant Bill Savings	Yes	--	--	--	--
Financial Incentive to Participant	Yes	--	--	--	--
Tax Credits	Yes	--	--	Yes	--
Other Benefits (e.g., market competitiveness, reduced price volatility, improved reliability)	depends	depends	depends	depends	depends

Avoided capacity costs from demand response—based on the ability to defer or delay the need for new generation capacity—are typically the most significant benefit associated with demand response programs. However, proper estimates of avoided capacity costs for demand response programs require many more considerations than those for energy efficiency programs, because of the nature, timing and uncertainties associated with demand response programs. Furthermore, estimating avoided capacity costs is very complex, often contentious, and there appears to be little consensus among industry stakeholders as to how they should be calculated.

To correctly value avoided capacity costs, one must take into account: (a) the extent to which different types of demand response programs can be relied upon to provide capacity benefits; (b) the timing of when the demand response program will be available; (c) various other operational constraints facing demand response programs; and (d) the different implications of demand response programs in regions with and without wholesale electricity markets. As with energy efficiency, it is also important to account for benefits associated with reduced reserve margins and avoided line losses.

Demand response programs can also provide benefits in terms of avoided transmission and distribution costs, particularly for local areas that are particularly stressed or in regions that are experiencing significant growth in transmission and distribution infrastructure needs.

In regions of the country with organized wholesale energy and capacity markets, an expansion of demand response programs can reduce peak wholesale energy and capacity prices in the short-term, potentially resulting in price suppression effects across the entire market.

Demand response program can also provide benefits in terms of reduced ancillary service costs. Furthermore, demand response programs may be able to provide low-cost load following and frequency regulation services to assist with integrating increasing levels of intermittent renewable resources over time.

Other benefits of demand response programs may include enhanced wholesale market competitiveness; reduced price volatility; insurance against extreme events; customer control over their bills, and more.

Applying the Cost-Effectiveness Framework

Demand response programs raise several issues that regulators and other stakeholders should consider in assessing cost-effectiveness. Some of these are summarized below.

Study Period: Ideally, cost-effectiveness analyses should be conducted over a study period that includes all the years over which costs and benefits are expected to accrue. Identifying the appropriate study period can sometimes be challenging because different types of demand response programs may result in benefit streams that occur over different periods. In addition, there may be uncertainties associated with customer participation and attrition. Program administrators should identify the appropriate study period for each program based on the expected stream of costs and benefits, giving careful consideration to the different time periods that might be relevant for different types of programs.

Baselines: One of the key issues in assessing the benefits of demand response programs is identifying "baseline" levels of customer consumption patterns to quantify the savings from demand response programs. Developing baselines can be challenging because different customers have different end-uses, different customers have different usage patterns, customer usage patterns may change over time, and customer usage patterns may vary with different pricing schemes.

Customer Participation and Response Levels: The level of customer participation and customer response will have a significant impact on the savings, and thus the benefits, of demand response programs. For some types of programs (especially price-based programs), customer participation might be challenging to predict. Customer participation levels may also fluctuate over time due to program fatigue, changing priorities, and the operating lives of demand response technologies.

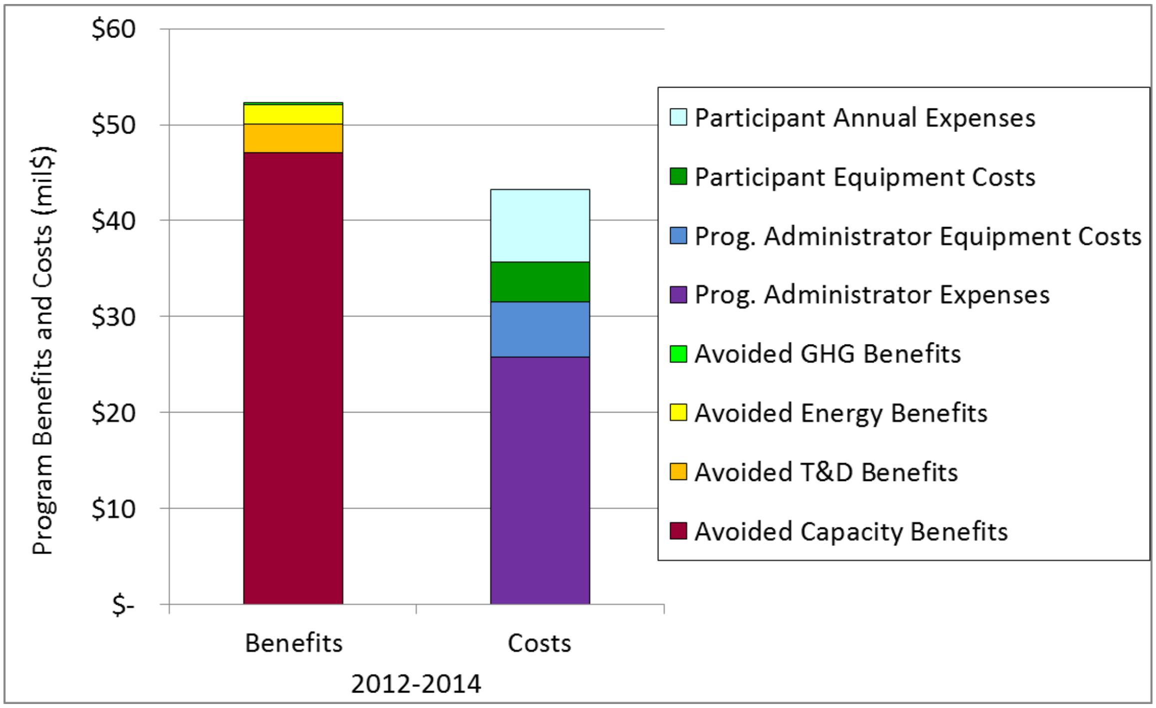
Sensitivity Analyses: Due to the many uncertainties associated with the costs and benefits of demand response programs, particularly the benefits, it may be appropriate for program administrators to conduct sensitivity analyses reflecting some of the key uncertainties. Some of these key uncertainties include: (a) avoided capacity costs; (b) participant value of lost service and transaction costs; and (c) customer participation and response levels.

Transparency: Given the complexities and uncertainties associated with demand response program cost-effectiveness assessments, it is important that program administrators use models, inputs, assumptions and methodologies that are transparent and well documented.

Illustrative Example of Applying the Framework

Figure ES-1 presents a summary of the benefits and costs (as measured by the TRC test) of the portfolio of demand response programs offered by a California utility. We present these results as an illustration of the types of costs and benefits that may be identified in assessing demand response programs. Different programs offered by different utilities may have very different results.

Figure ES-1. Illustrative Example of Cost-Effectiveness Results



Note that avoided capacity costs represent the majority of benefits. Avoided transmission and distribution, as well as avoided energy benefits are relatively small portions of the overall benefits, while avoided greenhouse gas (GHG) benefits are an even smaller portion of total benefits.

The largest portion of demand response program costs is the program administrator's expenses. The second most significant portion of costs is the equipment costs, borne partly by the program administrator and partly by the participating customer.

Recommendations for Further Research

We identified the following topics for which further research is most needed and would be most useful. Additional details are provided in Section 7.

- Avoided capacity costs.
- Participant value of lost service.
- Transaction costs.
- Ancillary service benefits.
- Avoided transmission and distribution costs.
- Relationship between wholesale market impacts and retail customer impacts.
- Reliability benefits.

- Interaction between demand response and energy efficiency programs.
- Wholesale market benefits.
- The cost-effectiveness implications of different program designs.
- Technology performance.
- Role of demand response in integrated resource planning.
- Role of back-up generators in demand response programs.
- Demand response programs suitable for small commercial and industrial customers.

1. Introduction

Objective

The objective of this report is to develop a framework for assessing the cost-effectiveness of ratepayer-funded demand response programs, to be used by regulators, program administrators,[1] and other stakeholders. The two key questions that the report addresses are:

- What framework should be used to evaluate the cost-effectiveness of ratepayer-funded demand response programs?
- What are the key costs and benefits to account for in evaluating the cost-effectiveness of demand response programs?

Most existing cost-effectiveness screening tools for demand-side measures were designed to evaluate energy efficiency and legacy load management programs. Although some utilities and regulators have used the same tools to determine the cost-effectiveness of demand response programs, these screening tools have not been significantly modified or expanded to handle contemporary demand response programs (with a few exceptions, as further discussed below). In addition, the valuation of the demand response benefits associated with smart grid projects and proposals has proven to be difficult.

Demand Response Cost-Effectiveness Working Group

By design, membership in each of the National Forum's working groups consists of volunteers from a diverse set of state officials, industry representatives, members of the National Action Plan Coalition,[2] and experts from research organizations. Leadership of each working group was drawn from state officials, practitioners and researchers with extensive background and experience on the subject.

[1] Throughout this analysis we use the term "program administrator" to refer to the entity that implements demand response and/or energy efficiency programs, whether it is a vertically integrated utility, a distribution utility or a third party administrator.
[2] The National Action Plan Coalition was formed in 2010 for the purpose of providing support for the implementation of FERC's National Action Plan on Demand Response.

The focus of the Demand Response Cost-effectiveness Analysis Working Group is to develop a framework for assessing the cost-effectiveness of ratepayer-funded demand response programs, to be used by regulators, program administrators and other stakeholders.

The Demand Response Cost-effectiveness Working Group held several conference calls during the course of this project to review the scope and the various drafts of this report. The working group members provided invaluable knowledge and expertise to help draft this work product. The Working Group served as an advisory group in preparing the report, and the co-chairs sought agreement from the work group where possible. However, the report was prepared by and represents the findings of Synapse and RAP.

Scope of This Report

Types of Demand Response Addressed in This Report

FERC defines demand response as "changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" (FERC 2011a. p. 21).

There are many types of demand response programs, and they can be designed to serve many purposes. This report focuses on demand response programs administered by electric utilities and funded directly by retail electric customers. For the purposes of this report, "utilities" include regulated investor-owned utilities, public power agencies, municipal utilities, and cooperatives. Utilities sometimes hire third parties to administer demand response programs, but the key issue that we are focusing on is rate-payer-funded demand response programs. These programs are of interest to utility regulators because regulators have the responsibility to ensure that the benefits of such programs outweigh the costs.

This report does not address demand response programs that are offered by or in organized wholesale electricity markets. We recognize that there are many initiatives to develop and expand upon the demand response programs offered through wholesale electricity markets, and that these programs offer significant opportunities for improving the efficiency of wholesale electricity markets.[3] However, the purpose of our report is to offer utility regulators and related stakeholders a framework for evaluating the cost-effectiveness of rate-payer-funded retail demand response programs, and the same framework may not apply to wholesale market demand response programs.

[3] See, for example, FERC 2011b.

Nonetheless, the presence of wholesale demand response programs has implications for ratepayer-funded retail programs, and *vice versa*. We do account for the effects of wholesale demand response programs in our cost-effectiveness framework for retail programs.

This report does not address "smart grid" technologies or programs.[4] While there is often overlap between smart grid and demand response programs, our scope is limited to demand response programs. However, our framework accounts for enabling technologies that can be used for both demand response programs and smart grid deployments, such as automated controls, in-home displays, and advanced meters, to the extent that they are a distinct element of a demand response program. The key consideration that we use to define our scope is whether a particular program is intended to modify electricity consumption when system reliability is jeopardized, when providing ancillary services, or in response to electricity prices.

Examples of smart grid technologies and applications that do not fall within our scope include those targeted to distribution system upgrades or to providing utilities with better data about distribution system usage or customer usage, and advanced meter initiatives designed to offer a variety of benefits such as automated meter reading capabilities and enhanced billing information.

We note that some demand response programs allow customers to curtail their electricity consumption through the use of customer-owned distributed generation. In some cases, customers may use a dispatchable, fossil-fired back-up generator. We include this type of demand response program in our cost-effectiveness framework, and account for the unique costs or benefits associated with distributed generators, including fossil-fired back-up generators.

Types of Demand Response Programs

There are many different types of demand response programs. The North American Electric Reliability Corporation (NERC) has developed a Demand Response Availability Data System (DADS) to collect historic demand response data (NERC 2011). As part of the DADS effort, NERC established a framework for categorizing the different types of demand response programs based on the services each program provides (e.g., reliability benefits).

FERC also uses the DADS framework when it periodically surveys electric utilities, demand response providers, and governmental entities to assess the penetration of

[4] Smart grid refers to the "integrated array of technologies, devices and systems that provide and utilize digital information, communications and controls to optimize the efficient, reliable safe and secure delivery of electricity" (EPRI 2010).

demand response programs in the electric power industry in the United States (FERC 2011a. p 2). **Table 1-1** presents the types of demand response programs recognized by NERC and FERC, and how FERC defines these programs.

There are also several ways to categorize demand response programs into functional or programmatic groups. As one example, a report for the National Action Plan for Energy Efficiency placed demand response programs into two categories: price-based programs and incentive- or event-based programs.

Price-based programs vary the price of electricity over time to better align customer energy consumption and the costs they impose on the electric utility system. They are implemented through approved utility tariffs or through contractual arrangements between demand response providers and retail customers.

Incentive- or event-based programs reward customers for reducing their electric loads upon request or for giving the program administrator some level of control over their electricity-using equipment. Table 1-1 presents a summary of the types of programs that fall within these two categories.

Table 1-1. 2010 FERC Survey Program Classifications[5]

Type of Demand Response	FERC Definition
Direct Load Control or Direct Control Load Management	A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment on short notice. Direct load control programs are primarily offered to residential or small commercial customers.
Interruptible Load	Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.
Critical Peak Pricing with Load Control	Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, which may be triggered by system contingencies or high wholesale market prices.
Load as Capacity Resource	Demand-side resources that commit to making pre-specified load reductions when system contingencies arise.
Spinning/Responsive Reserves	Demand-side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an Emergency Event.
Non-Spinning Reserves	Demand-side resource that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of

[5] Source: FERC 2011a, App. C.

	ten minutes or more.

Regulation Service	A type of demand response service in which a demand resource increases and decreases load in response to real-time signals from the system operator. Demand resources providing Regulation Service are subject to dispatch continuously during a commitment period. This service is usually responsive to Automatic Generation Control to provide normal regulating margin.
Demand Bidding and Buyback	A program which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.
Time-of-Use Pricing	A rate where retail electricity prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods.
Critical Peak Pricing	Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours. The total number of critical peak periods is typically capped for a calendar year.
Real-Time Pricing	Rate and price structure in which the retail price of electricity typically fluctuates hourly or more often to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.
Peak Time Rebate	Peak time rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like Critical Peak Pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.
System Peak Response Transmission Tariff	The terms, conditions, and rates and/or prices for customers with interval meters who reduce load during peaks as a way of reducing transmission charges.
Other Demand Response Program/Tariff	A company or utility's service/product/compilation of all effective rate schedules, general terms and conditions and standard forms related to demand response/AMI services for customers that are not residential, commercial and industrial, or other.

Incentive- or event-based programs reward customers for reducing their electric loads upon request or for giving the program administrator some level of control over their electricity-using equipment. **Table 1-2** presents a summary of the types of programs that fall within these two categories.[6]

[6] Readers may also be interested in the North American Electric Reliability Council (NERC) framework for categorizing demand response programs, which focuses on reliability benefits (NERC 2011. p 11).

Table 1-2. Demand Response Program Types[7]

Price-Based Options	Incentive- or Event-Based Options
Time of Use (TOU) Rates	Direct Load Control
Real Time Pricing (RTP)	Demand Bidding/Buyback Programs
Critical Peak Pricing (CPP)	Interruptible/Curtailable
Peak Time Rebates (PTR)	Emergency Demand Response Programs
	Capacity Market Programs
	Ancillary Services Market Programs
	Critical Peak Pricing (CPP)
	Peak Time Rebates (PTR)

Another way to distinguish between demand response programs is to separate those that are provided through organized wholesale electricity markets (FSC 2008. p 1). **Table 1-3** presents three categories of demand response programs: price-based, incentive-based programs, and wholesale market-based.

Table 1-3. Demand Response Program Types, With Wholesale Programs Separate[8]

Price-Based Options	Incentive-Based Options	Wholesale Market Options
TOU Rates	Direct Load Control	Emergency Demand Response
Real Time Pricing	Demand Bidding/Buyback	Capacity Market Programs
Critical Peak Pricing	Interruptible/Curtailable	Energy Market Programs
Peak Time Rebates		Ancillary Services Market Programs

The cost-effectiveness framework developed in this report can be applied to all of the price-based and incentive-based options listed in Table 1-3.[9] However, as noted above, the cost-effectiveness framework developed in this report is not designed to be applied to wholesale market demand response options.[10]

[7] Table 1.2 is based on a table in NAPEE 2010, p 2.2, with modifications by the working group. The source document categorized CPP and peak time rebates as price-based options only. The working group agreed that CPP and peak time rebates should also be considered incentive- or event-based options because the structure of CPP or peak time rebates may reward customers for reducing their electric loads upon request or for giving the program administrator some level of control over their electricity-using equipment.

[8] The categories shown here are indicative of how each program type would most typically be offered. Some of the program types shown in Table 1.3 could fit into more than one column/category, depending on the program design, how it is offered, and by whom it is offered. For example, emergency demand response programs and ancillary services programs could be offered as incentive-based options by vertically integrated utilities operating outside of wholesale markets.

[9] Incentive-based programs are easier to evaluate in a cost-effectiveness framework. To evaluate the cost-effectiveness of price-based programs, it is necessary to make assumptions about how participants will respond to prices with and without the price-based program in place.

[10] Note that, in situations where a program type is categorized as a wholesale market option in Table 1.3, and is offered by a utility as an incentive-based option, then the framework developed herein *would* be applicable to the wholesale market demand response option.

One might question whether there is a need for a cost-effectiveness framework for some of the price-based programs, such as time-of-use (TOU) rates. If a price-based option such as TOU rates simply involves changing customers' rates with no technologies or specific incentives involved, then are there any costs, and is there a need for a cost-effectiveness framework?

We believe it is appropriate to apply a cost-effectiveness framework to all price-based options, even those that only involve a change in rates. First, there may be costs associated with such a program, including administrative costs, metering costs,[11] data collection and assessment costs, or others. This is particularly true for new programs. Second, applying a cost-effectiveness framework requires an assessment of the likely benefits, including an assessment of the likely participation and response rate of customers. This will be very useful information for regulators in assessing the value of price-based demand response programs. Finally, regulators may wish to compare across different types of price-based demand response programs (e.g., TOU rates versus critical peak pricing). Applying a consistent cost-effectiveness framework across the different types of programs will allow for an even comparison.

The costs and benefits associated with any given price-based demand response program may differ significantly depending on whether the program is mandatory for all customers, a default option that customers can opt out of, or a voluntary program that customers can opt into. Price-based demand response programs can also introduce challenging issues related to distributional impacts within and across customer classes, which may not be apparent through the cost-effectiveness tests but are nevertheless very important to regulators. This distributional impact issue and other related regulatory issues are discussed in the following section.

Related Regulatory Issues

Demand response programs raise several important regulatory and policy issues. First is the issue of potential cost-shifting between customers. Demand response programs may result in some customers paying lower electric costs while others pay higher electric costs. Concerns about cost-shifting can be one of the most significant barriers to implementing demand response programs. As noted above, this cost-shifting can occur even in the context of price-based demand response programs where there are little or no costs incurred by the host utility.

However, it is important to recognize that cost-shifting is not a matter of cost-effectiveness. Cost increases to one customer that are offset by cost reductions to another customer can lead to no net additional cost. In economic terms, this is referred

[11] Metering costs should only be included in the cost-effectiveness analysis of demand response programs to the extent that the costs are incurred as a result of the demand response program, and not for other reasons.

to as a “transfer payment” from one customer to another, and according to economic theory these payments should not be considered as either a cost or a benefit because they cancel each other out.

Nonetheless, cost-shifting is a very important issue that should be considered by regulators and other stakeholders when evaluating the public policy implications of demand response programs. We recommend that this consideration be made separately from the cost-effectiveness evaluation. Regulators should first determine whether a particular demand response program is cost-effective. For those that are cost-effective, regulators should then consider whether the program is in the public interest given the implications of cost-shifting.[12]

Another key issue is whether a retail customer should be allowed to participate in demand response programs in wholesale capacity markets, independently of the customer’s electric utility. This type of participation may not result in the savings that are expected from the demand response program, because the retail customer’s utility may not be able to coordinate its procurement activities with the retail customer’s demand response participation, and may not account for the savings in their planning and in their interactions with the wholesale market. The retail customer’s utility may even incur additional reliability costs (e.g., deviation charges) and acquire unnecessary operating reserves to serve a portion of the retail customer’s load that is being curtailed. While this issue has been a concern in several states, we expect that it can be addressed through improved communication and reporting requirements. This issue of whether to allow retail customers to participate in wholesale demand response programs independently of the customer’s utility is a public policy issue rather than a cost-effectiveness issue and thus outside the scope of our report. The issue of how to account for the impacts of demand response programs in the context of wholesale electricity markets is addressed in Section 5.

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[12] Regulators might conceivably choose to implement rate-based demand response programs that *fail* a cost-effectiveness test if they consider the rates to be in the public interest for other reasons, such as adherence to cost causation principles, avoidance of cross-subsidies, expansion of customer choice, etc.

2. Recent Experience with Demand Response Cost-Effectiveness

Literature Review

With the assistance of the working group members, we conducted a literature review as a foundation for this report. The Bibliography/References section provides a complete listing.

Much of the literature focuses on the benefits of demand response programs rather than cost-effectiveness frameworks for screening demand response programs. While there has been less effort to assess the cost-effectiveness of demand response programs compared to energy efficiency programs, several notable efforts have been undertaken in recent years.

Most of the literature that is relevant to our report was generated by several regions that have specifically investigated the issue of cost-effectiveness frameworks for demand response. Since 2007, the California Public Utility Commission (CPUC) has investigated the appropriate framework to use for screening the cost-effectiveness of demand response programs, building off of its Standard Practice Manual (SPM) for evaluating the cost-effectiveness of energy efficiency programs (see CPUC 2001). The Pacific Northwest Demand Response Project (PNDRP) developed a framework for the valuation of demand response, based on the California approach. Several other regions, such as Ontario and the Mid-Atlantic, also have addressed demand response cost-effectiveness issues.

Furthermore, there has been substantial activity in the United States regarding the cost-effectiveness of smart grid programs. While our report is limited to demand response programs, there is overlap between the cost-effectiveness issues regarding demand response and smart grid programs. We have reviewed some of the recent smart grid cost-effectiveness initiatives to inform our framework for demand response programs.

California Demand Response Protocols

The CPUC developed and adopted a method for estimating the cost-effectiveness of most demand response activities.[13] These protocols use the cost-effectiveness tests described in the SPM to determine the cost-effectiveness of each demand response activity.

There are four SPM tests, designed to measure cost-effectiveness from four perspectives—those of society, the program administrator, the ratepayer, and the participant.[14] The details of the SPM tests have been modified to make them more appropriate to demand response (CPUC 2010. Decision, p 30). These tests are described in more detail in Section 3.

In a few significant aspects, the California demand response protocols deviate from the SPM framework, either to accommodate specific demand response program elements or to elaborate on certain aspects of the SPM framework. The significant aspects of the California demand response protocols are summarized below. Many of these concepts are incorporated into the discussion in Sections 4 and 5 of this report.[15]

- Avoided cost calculator. The protocols require the use of a statewide, common avoided cost calculator. This calculator separately determines the avoided costs of generation capacity, energy, transmission and distribution (T&D), greenhouse gas emissions, ancillary services, and renewable portfolio standards.[16] By requiring utilities to use the same public and transparent cost-effectiveness model, the protocols promote consistency and minimize confusion (CPUC 2010. Att. 1, p 7).
- Adjustment factors. The protocols require each utility to calculate adjustment factors to apply to avoided costs for each demand response program. The adjustment factors take into account a demand response program's availability, trigger, notification time, and other characteristics. These adjustment factors are intended to reflect the likelihood that a demand response program will be available to operate when needed (CPUC 2010. Att. 1, pp 9, 23). The protocols do not specify *how* utilities must make these adjustments.

[13] The California protocols state that they may not be fully applicable to permanent load-shifting programs, especially if those programs are non-dispatchable. Additionally, the California protocols are not designed to measure "pilot" programs, which are done for experimental or research purposes, technical assistance, educational, or marketing and outreach activities which promote DR or other energy-saving activities in general (CPUC 2010. Att. 1, p 5).
[14] Note that the SPM refers to the Societal Cost test as a variation on the Total Resource Cost test. We consider the Societal Cost test a separate test, leading to five tests in our framework.
[15] Note that at the time this report was being prepared the California Public Utility Commission was holding workshops to update and improve upon its demand response protocols (CA PUC 2012).
[16] The same avoided cost calculator is used in California for all demand-side programs, including energy efficiency and distributed generation cost-effectiveness evaluation (CPUC 2010. Att. 1, p 7).

- Optional inputs. The protocols identify impacts that the utilities have the option to quantify, to the extent practicable, and include in their cost-effectiveness analyses. Optional benefits include environmental benefits (other than the avoided environmental costs for greenhouse gas emissions), market and reliability benefits, and other program impacts (OPIs)[17] (CPUC 2010. Att. 1, p 8). Where it is not possible to approximate any one of these inputs, qualitative analysis of that benefit should be provided. Qualitative analysis is a descriptive analysis of the possible magnitude and impact of that cost or benefit. The purpose of the qualitative analysis is to compare demand response programs to each other in those instances in which a particular demand response program clearly has a different amount of a particular benefit (CPUC 2010. Att. 1, p 13).
- Sensitivity Analyses. The protocols require sensitivity analyses that focus on the variables expected to be the key drivers of each program's cost-effectiveness. The key drivers include participant costs, generation capacity values, T&D capacity value, load impacts, and others. The sensitivity analyses provide a sense of the impact of any error in the calculation of the major inputs driving the final results. Given the uncertainties inherent in many of the estimated values included in any cost-effectiveness analysis of demand response programs, the required sensitivity analyses provide a picture of the range of circumstances under which the various programs would be cost-effective (CPUC 2010. Decision, p 24; Att. 1, pp 12-13).
- Participant costs. Participant costs are equal to the sum of the participant's transaction costs and the participant's value of lost service. Because those two quantities are extremely difficult to quantify, other costs are used as a proxy. Since it is assumed that customers only participate in programs when the benefits exceed the costs, the protocols determine that 75 percent of the financial incentives paid to the participant is a sufficient proxy for the participant's costs (CPUC 2010. Att. 1, p 12).
- Application of cost-effectiveness tests. The protocols require calculation of all four cost-effectiveness tests and make no judgment regarding their relative importance in making program decisions. These tests are not intended to be used individually or in isolation. Rather, the tests are to be compared to each other and tradeoffs between the tests considered. The determination of which tests are most important for program approval and the relative weight of the tests is made in individual program budget proceedings (CPUC 2010. Decision, 30; Att. 1, pp 11, 14).

[17] See Section 3.2 of this report for a discussion of OPIs. Utilities also have the option to directly quantify transaction costs and the value of lost service, rather than using default methods.

Pacific Northwest Demand Response Project

The PNDRP began in 2007 and produced *Guidelines for Cost-Effectiveness Valuation Framework for Demand Response Resources in the Pacific Northwest* (NPCC 2010. p H-21). These guidelines were designed as a demand response screening tool for consideration by state utility regulators and public utility boards in the Pacific Northwest.

As part of this effort, PNDRP developed several principles for assessing the cost-effectiveness of demand response programs. These principles are useful for our purposes, and thus are presented in their entirety in Section 6.1 below (NPCC 2010. pp H-22–H-23).

The PNDRP guidelines recommend the use of the same cost-effectiveness tests that were identified in the California SPM, as modified to account for unique aspects of demand response programs. The PNDRP guidelines also provide guidance and recommendations on how to account for different types of costs and benefits of demand response programs. Many of these concepts are incorporated into the discussion in Sections 4 and 5 of this report.

Other Valuation and Cost-Effectiveness Initiatives

Other attempts have been made to value demand response and determine the cost-effectiveness of demand response programs. Some of these initiatives are still in the process of development, are outdated, or are not entirely relevant to our goal of developing a cost-effectiveness framework. Below we mention two initiatives that provide insight to our report.

The Ontario Power Authority (OPA) has been investigating cost-effectiveness frameworks for demand response, including several workshops with system planners and other stakeholders (FSC 2008. pp 11-15). OPA has been using the Total Resource Cost test for evaluating the cost-effectiveness of demand response programs. The OPA does not report to a regulatory commission; it is an independent, non-profit corporation that reports to Ontario's Ministry of Energy. The OPA applies the framework according to the protocols in its annual cost-effectiveness report. These reports have historically not been made public, but the OPA is expected to make annual reports publically available going forward and set guidelines for cost-effectiveness analyses by local distribution companies.

The Mid-Atlantic Distributed Resources Initiative (MADRI) seeks to identify and remedy retail barriers to the deployment of distributed generation, demand response and energy efficiency in the Mid-Atlantic region.[18] Cost-effectiveness of demand response programs has not been the group's key focus. However, in order to inform the development of prudent policies and investments, MADRI sought to quantify the benefits of demand response by commissioning a study to investigate the benefits (Brattle 2007. p 2). The results of this study are discussed in more detail in Section 5 of this report.

Smart Grid Cost-Effectiveness Initiatives

In recent years the US DOE has prepared smart grid reports, undertaken various smart grid initiatives, and sponsored many smart grid pilot programs throughout the United States in compliance with the American Recovery and Reinvestment Act of 2009.[19] As part of this activity, US DOE has prepared several materials that pertain to the costs, benefits, and cost-effectiveness of smart grid programs. Some of these materials are relevant to our demand response cost-effectiveness framework because of the overlap between demand response and smart grid.

Most notable for our purposes is the US DOE's analytical framework for assessing the benefits and costs of smart grid projects. This framework includes guidance regarding the metrics for identifying and tracking the benefits of smart grid programs, as well as methods for estimating the benefits and costs of these projects (US DOE 2009; EPRI 2010). The US DOE's framework additionally provides a Smart Grid Computational Tool that allows users to calculate the costs, benefits, and cost-effectiveness of specific smart grid programs (US DOE 2011a).

These materials provide a wealth of information, some of which is directly relevant to demand response cost-effectiveness. We build off of this material in developing our framework below. It is useful to note that the US DOE recommends the use of the cost-effectiveness tests from the California SPM when assessing smart grid programs (EPRI 2011. p 4-53).

Furthermore, many states have undertaken initiatives to assess the cost-effectiveness of smart grid programs. In one example, Illinois established a statewide smart grid collaborative, which was established for the purpose of developing a strategic plan to guide the deployment of smart grid in Illinois. The collaborative produced a report that provides guidance on many key smart grid issues, including a cost-effectiveness framework (ISSGC 2010). We refer to some of this material in developing our framework below.

[18] MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with US DOE, the U.S. Environmental Protection Agency, FERC and PJM Interconnection.
[19] See, for example, http://energy.gov/oe/technology-development/smart-grid.

3. The Cost-Effectiveness Framework

Rationale for the Proposed Cost-Effectiveness Framework

We recommend using the California SPM framework as the foundation for our demand response cost-effectiveness framework. There are several reasons for this choice.

First, the general framework outlined in the SPM has been widely used in North America for the purpose of screening energy efficiency programs and is familiar to most utility regulators. We believe that the same general framework that has been successfully applied to energy efficiency is appropriate for screening demand response, because both programs are typically ratepayer-funded and regulators are interested in the same types of costs and benefits. Also, what makes the California SPM framework universally applicable is that it includes results from several key perspectives, as described in more detail below. Obtaining results for these perspectives is important for both energy efficiency and demand response programs.

Second, as noted above, California has recently investigated the applicability of the SPM framework to demand response programs and has modified some of the costs and benefits of the framework to account for the unique aspects of demand response. Thus, we can benefit from the recent work undertaken in California on this very issue.

Third, as noted above, the PNDRP considered this same issue recently and reached the same conclusion that the SPM provides an appropriate framework to measure the cost-effectiveness of demand response. Again, we can benefit from the work of that group.

Fourth, the smart grid cost-effectiveness frameworks that we have reviewed, including that used by US DOE, rely upon the California SPM framework. There are many parallels to assessing the costs and benefits of smart grid and demand response, and we see no reason to apply a different framework for demand response.

Finally, in our review of the literature to date we have not seen examples of other frameworks for evaluating the cost-effectiveness of ratepayer-funded retail demand response. The California demand response protocols appear to be the most complete, the most vetted, and the most adaptable framework developed to date. [20]

In this report we use the California SPM framework as our starting point. We then investigate how California and other regions have defined the costs and benefits of demand response differently from energy efficiency and account for those different costs and benefits that are unique or tailored to demand response programs in our framework.

The remaining sections in this chapter provide background information on the SPM cost-effectiveness tests as they are applied to energy efficiency, as well as a brief summary of how the tests are used across the United States today. In Section 4, we discuss the types of costs that should be considered in the tests as they are applied to demand response, and in Section 5, we discuss the types of benefits that should be considered when evaluating demand response programs.

Description of the Cost-Effectiveness Tests

The costs and benefits of demand-side programs are different from those of supply-side resources in that they have different implications for different parties. As a result, five cost-effectiveness tests have been developed to consider demand-side costs and benefits from different perspectives.[21] Each of these tests combines the various costs and benefits of energy efficiency programs in different ways, depending upon which costs and which benefits pertain to the different parties. These tests are described below.

- The Participant Cost test. This test includes the costs and benefits experienced by the customer who participates in the demand-side program. The costs include all the direct expenses incurred by the customer to purchase, install and operate a demand-side measure. The benefits include the reduction in the customer's electricity bills, as well as any financial incentive paid by the program administrator.
- The Ratepayer Impact Measure (RIM) test.[22] This test provides an indication of the impact of demand-side programs on utility rates. The results of this test provide an indication of the impact of the program on those customers that do not

[20] The California protocols specifically recognize that demand response programs are in a transitional period, moving from programs that have historically been emergency-based, to more incentive-based programs that operate within new markets and use advanced technologies. Therefore, the California protocols emphasize the importance of using methods to measure demand response costs and benefits that are flexible enough to capture emerging benefits (CPUC 2010. Att. 1, p 4). Furthermore, the California protocols recognize that there are a wide variety of demand response programs with differing attributes, and that the protocols may be flexibly applied to fully reflect the attributes of some demand response programs (CPUC 2010. Att. 1, p 6).
[21] These tests are sometimes defined slightly differently by different public utilities commissions. For more discussion of these tests, see CPUC 2001, NAPEE 2008, and Synapse 2012a.
[22] This has previously been referred to as the Non-Participant test and the No-Losers test.

participate in the programs, because if those customers' rates increase their bills will also increase. The costs include all the expenditures by the program administrator, plus the "lost revenues" to the utility as a result of having to recover fixed costs over fewer sales. The benefits include the avoided utility costs.

- The Program Administrator Cost (PAC) test.[23] This test includes the energy costs and benefits that are experienced by the demand-side program administrator. The costs include all expenditures by the program administrator to design, plan, administer, deliver, monitor and evaluate demand-side programs. The benefits include all the avoided utility costs, including avoided energy costs, avoided capacity costs, avoided transmission and distribution costs, and any other avoided costs (e.g., environmental compliance costs) that would otherwise be incurred by the utility to provide electric services (or gas services in the case of gas energy efficiency programs).
- The Total Resource Cost (TRC) test. This test includes the costs and benefits experienced by all utility customers, including both program participants and non-participants. The costs include all the costs incurred, including the full incremental cost of the efficiency measure, regardless of whether it was incurred by the program administrator or the participating customer.[24] The benefits include all the avoided utility costs plus any benefits experienced by the participating customers.
- The Societal Cost test.[25] This test includes the costs and benefits experienced by all members of society. The costs include all of the costs incurred by any member of society: the program administrator, the customer and anyone else. Similarly, the benefits include all of the benefits experienced by any member of society. The costs and benefits are the same as for the TRC test, except that they also include externalities, such as costs associated with environmental impacts and reduced costs for government services. Under this test, any adjustments to federal, state or local taxes would be considered a transfer payment rather than a cost or benefit.

Table 3-1 presents a summary of the different components of the five cost-effectiveness tests. Note how each test has a unique combination of costs and benefits. This is a relatively simplistic presentation of the tests as they are typically applied to energy efficiency programs. Demand response programs include additional costs and benefits that we discuss in Sections 4 and 5.

[23] This is sometimes referred to as the Utility Cost test or the Energy System test.
[24] The incremental measure cost is the difference between the cost of the efficiency measure and the cost of the most relevant baseline equipment that would have been installed in the absence of the efficiency program.
[25] As mentioned previously, the California Standard Practice Manual considers the Societal Cost test a variant on the TRC test (CPUC 2001. p 18). Many states and studies depart from the SPM by drawing a more complete distinction between these two tests (see Synapse 2012a).

Table 3-1. Components of the Cost-Effectiveness Tests

	Participant	RIM	PAC	TRC	Societal
Energy Efficiency Program Costs:					
Program Administrator Costs	---	Yes	Yes	Yes	Yes
Measure Cost: Rebate to Participant	---	Yes	Yes	Yes	Yes
Measure Cost: Participant Contribution	Yes	---	---	Yes	Yes
Lost Revenues to the Utility	---	Yes	---	---	---
Energy Efficiency Program Benefits:					
Customer Bill Savings	Yes	---	---	---	---
Measure Cost: Rebate to Participant	Yes	---	---	---	---
Avoided Generation Costs	---	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	---	Yes	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	---	Yes	Yes	Yes	Yes
Other Program Benefits[26,27]	participant	utility	utility	participant	societal

When identifying the appropriate costs and benefits to include in each of the five tests, it is important to properly account for transfer payments. Transfer payments occur when a cost to one party is experienced as a benefit to another party, leading to no net additional cost across the two parties. According to economic theory, transfer payments should not be considered either a cost or a benefit because they cancel each other out.

Whether a cost is to be considered a transfer payment depends upon the perspective being applied, i.e., the cost-effectiveness test being used. For example, lost revenues should be accounted for in the RIM test, because the lost revenues are a cost that affects electricity rates. However, under the PAC, the TRC and the Societal Cost tests, the lost revenues are a transfer payment from the customers that do not participate in the efficiency program to the customers that do participate. Lost revenues are considered a transfer payment under these tests and thus are not included.

There are several instances where certain costs of demand response programs are transfer payments and thus should not be included in the cost-effectiveness tests. We identify those instances where they occur, in Sections 4 and 5.

[26] We use the term "other program benefits" to describe what are commonly referred to as non-energy benefits. Other program benefits are those costs and benefits that are not part of the costs, or the avoided costs, of the energy provided by the utility that funds the energy efficiency program. In addition to non-energy benefits, other program benefits also include other fuel savings, which are the savings of fuels that are not provided by the utility that funds the energy efficiency program. For more information on including other program benefits in energy efficiency programs, refer to Synapse 2012a.

[27] Benefits accruing to the participant are the only "other program benefits" that should be included in a Participant or TRC test. Similarly, only "other program benefits" accruing to the utility should be included in a RIM or PAC test. Other program benefits accruing to society as a whole should be included in the Societal Cost test.

The results of any of the cost-effectiveness tests can be expressed in terms of net benefits, i.e., the sum of all benefits minus the sum of all costs. They can also be expressed as a ratio of total benefits to total costs. An efficiency program is said to "pass" the test if the benefit-cost ratio is greater than one (or if the net benefits are greater than zero). One shortcoming of using just the benefit-cost ratio approach is that the magnitude of net benefits can be obscured.[28] For this reason we recommend that both the benefit-cost ratio and the net benefits be reported when assessing demand-side resource cost-effectiveness.

Implications of the Cost-Effectiveness Tests

In theory, all of the above cost-effectiveness tests should be considered in the evaluation of ratepayer-funded energy efficiency programs, to provide the most complete picture of the impacts on different parties. However, most states rely upon one or two tests as the *primary* standard for screening energy efficiency programs, due to the challenges of working with multiple tests that provide different results.

Also, it is important to recognize that the different tests provide different types of information and should be used for different purposes. For example, the RIM test and the Participant Cost test provide "distributional" information (i.e., information regarding how the impacts of demand-side programs are distributed across different customer types). In particular, the RIM test provides an indication of the primary impacts of demand-side resources on those customers who do not participate in the programs, because the main impacts on these customers are the adjustments in rates. The Participant Cost test, on the other hand, provides an indication of the primary impact of demand-side resources on the program participants. These two tests together provide a rough indication of how the benefits are distributed between program participants and non-participants.

In the paragraphs below we discuss some of the key implications of each of the five cost-effectiveness tests. **Table 3-2** summarizes the key points.

[28] For example, Program A might have benefits of $2 million and costs of $1 million, while Program B has benefits of $50,000 and costs of $10,000. Program A has net benefits of $1 million, compared to just $40,000 for Program B, but Program A has a benefit/cost ratio of 2.0 which superficially appears modest compared to Program B's 5.0 ratio.

Table 3-2. The Five Principal Cost-Effectiveness Tests[29]

Test	Key Question Answered	Summary Approach	Implications
Societal Cost	Will total costs to society decrease?	Includes the costs and benefits experienced by all members of society.	Most comprehensive comparison but also hardest to quantify.
Total Resource Cost	Will the sum of utility costs and program participants' costs decrease?	Includes the costs and benefits experienced by all utility customers, including program participants and non-participants	Includes the full incremental cost of the demand-side measure, including participant cost and utility cost.
Program Administrator Cost	Will utility costs decrease?	Includes the costs and benefits that are experienced by the utility or the program administrator.	Identifies impacts on utility revenue requirements. Provides information on program delivery effectiveness, i.e. benefits per amount spent by the program administrator.
Participant Cost	Will program participants' costs decrease?	Includes the costs and benefits that are experienced by the program participants.	Provides distributional information. Useful in program design to improve participation. Of limited use for cost-effectiveness screening.
Rate Impact Measure	Will utility rates decrease?	Includes the costs and benefits that affect utility rates, including program administrator costs and benefits and lost revenues.	Provides distributional information. Useful in program design to find opportunities for broadening programs. Of limited use for cost-effectiveness screening.

<u>The Societal Cost test</u> is the most comprehensive standard for evaluating the cost-effectiveness of efficiency, because this is the only test that includes all benefits and costs to all members of society. Ideally, the Societal Cost test should include all costs and benefits, regardless of who experiences them, including externalities. However, externalities by their very nature are often difficult to quantify. For this reason, defining

[29] This table is adapted from NAPEE 2008 and Synapse 2012a. In each case, the key question is asked in light of the effects of the demand-side program when viewed in isolation from other cost and rate drivers. For example, when viewed in isolation a utility's demand-side program might be expected to lead to a decrease in utility rates, and thus pass the RIM test. But rates might actually increase for reasons that have nothing to do with the demand-side program.

the appropriate cost and benefit inputs to a Societal Cost test is quite difficult and controversial.

The TRC test is the next most comprehensive standard for evaluating the cost-effectiveness of demand-side resources, by including all the impacts to the program administrator and its customers.[30] It offers the advantage of including certain impacts that are important in planning energy efficiency programs, including other fuel savings, and low-income benefits.

The PAC test is more restrictive than the TRC test, in that it only compares the program administrator costs to the costs of avoided supply-side resources. One way to think of this test is that it is limited to the impacts that would eventually be charged to all customers through the revenue requirements; the costs being those costs passed on to ratepayers for implementing the demand-side programs, and the benefits being the supply-side costs that are avoided and not passed on to ratepayers as a result of the demand-side programs.[31]

The Participant Cost test is fundamentally different from the other tests, in that it uses customer bill savings as the primary benefit of the programs. Customer rates are typically higher than the marginal avoided costs of the energy system, leading to higher demand-side program benefits per unit of energy saved.[32] Also, the only costs in this test are the customer costs, which in many cases are lower than the costs incurred by the program administrator to plan, design, and deliver the demand-side programs. Consequently, this test is typically the least restrictive of all the other cost-effectiveness tests. As noted above, it provides an indication of the distributional effects of the demand-side programs, along with the RIM test, and may be useful in optimizing program design for participation. When applied to *voluntary* programs, the Participant Cost test is of limited usefulness to regulators because programs that do not pass the test are rarely if ever proposed, since customers generally will not voluntarily participate in a program that does not decrease their net costs. Most regulators still prefer to have confirmation that a voluntary program passes this test, particularly for newly proposed programs.

The Rate Impact Measure test tends to be the most restrictive of all the tests, because the utility's lost revenues can make very large contributions to the demand-side program costs. Most, if not all, states have ruled that the RIM test should not be used as the

[30] The name of this test is misleading, because it does not include "total" costs of a demand-side program. A more accurate and descriptive name for this test would be the All Customers test, because it includes the total costs and benefits to all customers.

[31] The name of this test is a little misleading, because it does not include the costs and benefits to the program administrator itself (e.g., utility profits). A more descriptive name for this test would be the Revenue Requirements test.

[32] Customer rates are often *lower* than marginal avoided costs during periods of peak demand in much of the country. In the Pacific Northwest, it is common for customer rates to be lower than marginal avoided costs even during off-peak hours.

primary test for evaluating energy efficiency cost-effectiveness. There are several reasons advanced to support this position.

- Applying the RIM test to screen demand-side programs will not necessarily result in the lowest cost to society or the lowest cost to customers on average. Instead, it will lead to the lowest electricity rates (all else being equal). However, achieving the lowest rates is not necessarily the primary goal of utility planning and regulation, especially if lower rates lead to higher costs and bills to customers on average.
- The RIM test is heavily influenced by the lost revenues to the utility. The RIM test is the only cost-effectiveness test that considers lost revenues a cost. However, lost revenues do not represent an incremental cost to society. As noted above, lost revenues represent a transfer payment between demand-side program participants and non-participants; the bill savings to program participants result in lost revenues collected from all customers, including non-participants.[33] Lost revenues are not a new or incremental cost in the same way that program administration costs are a new and incremental cost of implementing energy efficiency programs, and they should not be applied as such in screening a new demand-side program.
- A strict application of the RIM test—i.e., its use without taking into account the results of other cost-effectiveness tests—can result in the rejection of large amounts of potential demand-side savings and the opportunity for large reductions in many customers' bills in order to avoid what are often small impacts on non-participants' bills.
- The RIM test does not provide useful information about what happens to rates as a result of program implementation. A RIM test benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact.
- Screening demand-side programs with the RIM test is inconsistent with the way that supply-side resources are screened, and creates an uneven playing field for the two types of resources. There are many instances where utilities invest in new power plants or transmission and distribution facilities in order to meet the needs of a subset of customers, (e.g., new residential housing divisions, new industrial parks). These supply-side resources are not evaluated on the basis of their distributional or equity effects, nor are the "non-participants" seen as cross-subsidizing the "participants."

[33] In jurisdictions where utilities are not allowed to collect lost revenues and whose rates are not decoupled from sales, between rate cases the transfer payment is actually from utility shareholders to program participants.

Nonetheless, demand-side programs can lead to increased rates, and rate impacts are an important consideration for regulators and other efficiency stakeholders. However, it is important to recognize that the rate impacts of demand-side programs are not a matter of cost-effectiveness for the utility or for society. (As noted above, the lost revenues are simply a transfer payment and do not represent an incremental cost.) Instead, rate impacts are a measure of equity between program participants that experience reduced bills and non-participants that experience increased bills.

Therefore, we recommend that the RIM test not be used in screening demand-side programs for cost-effectiveness. Instead, program administrators should take steps to: (a) analyze rate and bill impacts in a fashion that provides much more information than what is available from the RIM test; (b) design demand-side programs in a way that mitigates rate impacts without sacrificing efficiency savings; [34] and (c) work to increase the number of program participants so as to mitigate the equity concerns between participants and non-participants.

Current Use of the Tests for Screening Energy Efficiency Programs

A recent survey by the American Council for and Energy-Efficient Economy (ACEEE) provides a useful summary of how the cost-effectiveness tests are used across the states.[35] Nationwide, a total of 45 jurisdictions have some level of formally approved ratepayer-funded energy efficiency programs in operation. All of these jurisdictions use some type of benefit-cost test in connection with these programs.[36] Most states have some type of legal requirement for the use of such tests, either by legislation or regulatory order (ACEEE 2012. p 30).

Many states examine more than one cost-effectiveness test. The ACEEE survey found that 36 states (85 percent) consider the TRC test; 28 states (63 percent) consider the PAC test; 23 states (53 percent) consider the Participant test; 22 states (51 percent) consider the RIM test, and 17 states (40 percent) consider the Societal Cost test (ACEEE 2012. p 12).

[34] Since the financial incentive provided for customer participation is often a major cost element for demand-side programs, the benefit-cost ratio for the RIM test can be adjusted substantially through incentive design.
[35] The ACEEE report provides the results of a comprehensive survey and assessment of the current "state of the practice" of utility-sector energy-efficiency program evaluations across the 50 states and the District of Columbia. The report examined many aspects relating to how states conduct their evaluations and the key assumptions employed, including the use of cost-effectiveness tests (ACEEE 2012).
[36] This is not the case for demand response programs or renewable energy programs, where only 67 percent and 28 percent of states, respectively, report using benefit-cost tests for those ratepayer-funded programs (ACEEE 2012. p 30).

However, regulators tend to adopt one of these tests as the primary guideline for screening energy efficiency programs. The ACEEE survey found that 95 percent of states rely on a single, primary screening test:

- The TRC test is used by 29 states (71 percent) as the primary methodology for defining energy efficiency cost-effectiveness;
- The Societal Cost test is used by six states (15 percent) as the primary methodology for defining energy efficiency cost-effectiveness;
- The PAC test is used by five states (12 percent), as the primary methodology for defining energy efficiency cost-effectiveness; and
- The RIM test is used by one state (2 percent), as the primary methodology for defining energy efficiency cost-effectiveness (ACEEE 2012. p 13).[37]

[37] Shortly after ACEEE published its findings, the one state using the RIM test as the primary test (Virginia) enacted a new law providing that a program or portfolio of programs "shall not be rejected solely based on the results of a single test" (see Code of Virginia, C. 821, §§ 56-576 (Approved April 18, 2012)). The practical impact of this new law on cost-effectiveness screening in Virginia is not yet clear.

4. Demand Response Program Costs

There are many different types of demand response program costs that must be accounted for when evaluating cost-effectiveness, depending on the test being applied. **Table 4-1** provides a list of demand response program costs, based upon the literature that we have reviewed on this topic. The table also indicates which of the costs should be considered in which of the cost-effectiveness tests. Each of the costs is discussed in more detail in the sections below, including how the cost is defined and issues to consider when identifying and calculating the cost.

Note that we have attempted to make the list of costs as comprehensive as possible. Not all demand response programs will have all of the costs listed below. Table 4-1 presents a comprehensive list to provide readers with the universe of costs that could be relevant when analyzing the cost-effectiveness of demand response programs.

Table 4-1. Demand Response Program Costs

Cost	Participant	RIM	PAC	TRC	Societal
Program Administrator Expenses	--	Yes	Yes	Yes	Yes
Program Administrator Capital Costs	--	Yes	Yes	Yes	Yes
Financial Incentive to Participant	--	Yes	Yes	--	--
DR Measure Cost: PA Contribution	--	Yes	Yes	Yes	Yes
DR Measure Cost: Participant Contribution	Yes	--	--	Yes	Yes
Participant Transaction Costs	Yes	--	--	Yes	Yes
Participant Value of Lost Service	Yes	--	--	Yes	Yes
Increased Energy Consumption	--	Yes	Yes	Yes	Yes
Lost Revenues to the Utility	--	Yes	--	--	--
Environmental Compliance Costs[38]	--	Yes	Yes	Yes	Yes
Environmental Externalities	--	--	--	--	Yes

Program Administrator Expenses

Program administrator expenses, sometimes referred to as administrative costs, include the operations and maintenance costs, program costs, information technology expenses,

[38] As further discussed below, if a participating customer incurs environmental compliance costs, these costs should be included in the Participant Cost test.

demand response system operation and communication costs, marketing and outreach costs, and evaluation, measurement, verification (EM&V) costs associated with the program.[39,40]

Only the incremental costs of the program should be included in the cost-effectiveness tests. While the incremental costs may be obvious for some expenses, such as EM&V studies of programs, teasing out the specific demand response costs for other activities, such as billing system upgrades, can be more challenging (CPUC 2010. Att. 1, pp 17-18; NPCC 2010. p H-26).

The California demand response protocols require that "when a utility calculates the administrative costs of each program, it must include all costs attributable to the program, including those costs that may be included in a separate budget category. Costs that are considered in these calculations include, but are not limited to, the costs of program design, development, marketing, outreach, overhead, and information technology. Costs that promote demand response in general and are not specific to or caused by an individual program, such as statewide marketing program costs, should only be included in the evaluation of the utility's overall demand response portfolio"[41] (CPUC 2010. Decision, p 22).

Utilities and aggregators may find that participation in wholesale market demand response programs requires longer lead times, financial guarantees, and unique administrative costs that need to be factored into program administrator expenses. For example, system operators may allow demand response to be bid as a resource in day-ahead, real-time, ancillary services, and forward capacity markets. Utilities and aggregators that choose to do so may experience administrative costs associated with registering for market participation, certifying baseline customer load, submitting market offers, participating in auctions, etc. that are unique to participating in wholesale markets and incremental to the administrative costs of offering retail demand response programs.

Program administrator expenses should be included in the all of the cost-effectiveness tests except for the Participant Cost test.

[39] Some parties may argue that EM&V is a regulatory requirement and should not factor into a determination of whether a demand response program is cost-effective. We disagree with this interpretation because EM&V creates expenses for the program administrator that arise only as a result of the need to evaluate the cost-effectiveness of the demand response program, and therefore should be accounted for in program administrator expenses.
[40] EM&V costs for new programs or pilot programs may be greater than for established programs. Although these costs may be incurred in a single year for a multi-year program, for cost-effectiveness purposes the costs are sometimes assumed to be spread out evenly over each year of the program,
[41] The California protocols require that cost-effectiveness analyses be provided for each demand response program and for the entire portfolio of demand response activities, which is why program administrator expenses are required to be calculated as described above (CPUC 2010. Decision, p 14).

Program Administrator Capital Costs

Program administrator capital costs include the costs incurred for equipment with relatively long lives, such as information technology equipment, communications technologies, and demand control technologies. These costs are distinguished from the program administrator contribution to the demand response measure cost.[42] Program administrator capital costs include the costs for equipment installed to support the program administrator; while demand response measure costs include equipment installed to support the participating customers.[43]

These costs should be identified separately from the program administrator expenses so that they can be treated with different accounting practices. Expenses should be accounted for in the year in which they occur, while capital equipment costs should be amortized over the lifetime of the equipment (CPUC 2010. Att. 1, p 29).

Aside from this different accounting treatment, program administrator expenses and capital costs are treated the same in the cost-effectiveness tests. Program administrator capital costs should be included in the all of the cost-effectiveness tests except for the Participant Cost test.

Financial Incentive to Participant

Some demand response programs provide participating customers with a direct financial incentive to modify their electricity consumption. For example, peak time rebate programs offer customers direct rebates for curtailing demand during peak hours.

It is important to distinguish the financial incentive to a participant from a program administrator's contribution toward the measure cost. Some demand response programs, such as peak time rebates, may include only a financial incentive to curtail load, but no corresponding payment to offset measure costs because there is no measure, technology, or device involved. Conversely, other demand response programs, such as direct load control programs, may offer customers a financial incentive to curtail load and also a rebate to offset the cost of a control technology.

It is important to distinguish between these two types of costs because they should be treated differently in the different cost-effectiveness tests. As indicated in Table 4-1, the

[42] The term demand response "measure" refers to any technology or device used to provide customers with usage information, provide two-way communications, enable automated load control, enable the utility to control load from off-site, or perform some other demand response function

[43] It is notable that California's protocols, which are cited as an example in many parts of this report, do not distinguish between program administrator capital costs and the program administrator's contribution to measure costs. Both components are lumped into the category of capital costs in California.

program administrator contribution toward the measure cost should be included in the RIM, PAC, TRC and Societal Cost tests. They are included in the RIM and the PAC tests because they are costs incurred by the program administrator. They are included in the TRC and the Societal Cost tests because they are part of the total cost of the demand response measure, device, or technology. That is, the sum of the participant cost and the rebate to the participant equals the total cost of the measure.

The financial incentive to the participant should be included in the RIM and the PAC test, because it is a cost incurred by the program administrator. However, it should not be included in the TRC or the Societal Cost test, because this cost is a transfer payment under these perspectives. The financial incentive to the participant is a transfer of money from all customers to the participant. The net effect on all customers (in the TRC test) or to society (in the Societal Cost test) is zero. Therefore they should not be included in these two tests.

In those cases where a utility hires a third-party aggregator to deliver demand response programs, the "financial incentive to participant" should include the total costs paid by the utility to the aggregator. These costs would include both the financial incentive paid to the participant and the costs paid to support the aggregator's activities (CPUC 2010. Att. 1, p 32).

Demand Response Measure Cost: Program Administrator Contribution

Some demand response programs may include a measure, technology, or device to provide customers with usage information, provide two-way communications, enable automated load control, enable the utility to control load from off-site, or perform some other function. These measure costs may also include equipment operations and maintenance costs removal costs (less salvage value), and any other equipment-related costs associated with demand response enabling technologies installed by the participant (CPUC 2010. Att. 1, p 29).

When a program administrator contributes to paying for the demand response measure, either through a rebate, a direct installation, or some other form of payment, these program administrator measure costs should be accounted for in the cost-effectiveness tests. As explained above, these costs should be included in the RIM, PAC, TRC and Societal Cost tests.

Demand Response Measure Cost: Participant Contribution

When a participating customer is required to make a contribution toward a demand response measure, that contribution should be accounted for in the cost-effectiveness tests. Participant contribution costs should be included in the Participant Cost test. They should also be included in the TRC and the Societal Cost tests, because these costs are a portion of the total cost associated with the demand response measure.

Participant Transaction Costs

This cost includes the opportunity costs associated with education, equipment installation, program application, energy audits, developing and managing a load shed plan, and other opportunity costs to the participant. Examples of transaction costs are the personnel costs associated with time spent on activities such as filling out a demand response program application, making decisions about whether or how to install demand response equipment, and shutting off equipment during a demand response event. (CPUC 2010. Att. 1, pp 35-36).

While the participant's transaction costs may be significant, some of them can only be approximated, even by the participant, and thus they may be extremely difficult for evaluators to quantify (CPUC 2010. Att. 1, pp 35-36). Further, few studies have been conducted that attempt to develop an appropriate approximation of such costs. Participant transaction costs should be included in the Participant Cost, TRC and Societal Cost tests.

Participant Value of Lost Service

This category includes any losses in productivity that occur because of demand reductions, e.g., reduced production when a business shuts down some of its equipment during a demand response event. (If any of this productivity is shifted to another time period, the value of lost service would be based only on *net* productivity losses plus any costs associated with shifting work from one time period to another.) This category also includes any other losses due to modified electricity consumption, such as losses in comfort that participants may experience when particular end-uses become unavailable (e.g., higher household temperatures during an air conditioning cycling event) (CPUC 2010. Att. 1, p 35; NPCC 2010. p H-22).

These costs can be significant to the participant, depending upon the type of demand response program, the type of demand response measure, and the type of demand response event. However, these costs can be extremely difficult to estimate, partly because of the challenge of placing a monetary value on lost productivity or lost services, and also because the costs might vary considerably between demand response programs, between classes of customers (e.g. residential versus commercial), and between individual participating customers (CPUC 2010. Att. 1, pp 35-36).

In the absence of better data, some jurisdictions use a fraction of the program financial incentives and bill savings as a proxy for the participant's value of lost service. (In California, for example, the Public Utility Commission suggested that the utilities assume that 75 percent of the program financial incentives and bill savings is a reasonable proxy for the combined value of the participant transaction costs plus the value of lost service.) The assumption underlying this practice is that a customer will accept a loss of service if and only if the customer believes the incentive and bill savings exceed the value of the lost service plus any transaction costs[44] (see NPCC 2010. p H-27). However, it must be understood that the specific number chosen as a proxy is not based on empirical data. More research on this topic is needed. In the meantime, sensitivity analyses using different proxy values can reveal the relative importance of this assumption to the calculated benefit/cost ratios.

Participant value of lost service costs should be included in the Participant Cost, TRC and Societal Cost tests.

Costs Associated with Increased Energy Consumption

Costs associated with increased energy consumption include any costs incurred by the utility in providing additional electricity to customers as the result of a demand response program. For example, a demand response program that shifts load from peak to off-peak hours may result in a net increase in the total consumption of energy. These costs from increased energy generation, transmission, and delivery represent an incremental cost that should be attributed to the demand response program.

Note that in Section 5 we include avoided energy costs as one of the benefits of a demand response program. When demand response programs result in load shifting, costs associated with increased energy consumption in some hours will be offset by reduced energy costs in other hours, i.e., avoided energy costs (CPUC 2010. Att. 1, p 32). It is useful to present the costs of increased energy consumption separately from the avoided energy costs, as opposed to presenting the *net* impact on energy, so that

[44] If the full value (100 percent) of the incentives is used as a proxy, the value of lost service will in all likelihood be overestimated, making it harder for the program to pass the cost-effectiveness test. Also note that some jurisdictions may, as a simplification, include the program financial incentives in all relevant cost-effectiveness tests for demand response programs (which as noted above should theoretically be excluded from the RIM and TRC tests), but not include the value of lost service in any of the tests.

regulators and other stakeholders will be able to see how the demand response program results in both increases and decreases of energy consumption in different hours.

In calculating the energy costs associated with increased consumption, it is important to account for the price of purchasing electricity or the cost of generating electricity at different times. Electricity purchases or generation during off-peak hours will generally cost less than during on-peak hours, typically resulting in net savings once the avoided costs of generation are factored in.

Costs associated with increased energy consumption should be included in the RIM, PAC, TRC, and Societal Cost tests because they are costs incurred by the program administrator.

Lost Revenues to the Utility

Lost revenues are calculated only for the purpose of the RIM test. The reason for calculating lost revenues is to provide an indication of the extent to which electricity rates might have to be increased to account for reduced sales from the demand response program.

Lost revenues can be calculated using a bottom-up approach. Lost revenue from any one utility customer is equal to the change in the customer's consumption due to the demand response program, multiplied by the customer's variable electricity rate. The utility's total revenue loss is equal to the sum of this amount for all program participants. Ideally, this calculation should account for the fact that demand response participants may move from one rate class to another when joining a demand response program. (CPUC 2010. Att. 1, p 34).

Some demand response programs may result in periods of *increased* sales and revenues as well as other periods of reduced sales and revenues. Lost revenues should be calculated based on the net reduction in sales, accounting for both reductions and increases. Also, the lost revenue calculations should account for the different retail prices in effect during different times, to the extent that there are any such retail price differences (CPUC 2010. Att. 1, p 34).

While lost revenues can have a significant impact on the RIM test when applied to energy efficiency programs, they are likely to have a much smaller impact on the RIM test when applied to demand response programs. Demand response programs typically save much less energy as a proportion of the total energy and capacity savings, relative to energy efficiency programs.

Environmental Compliance Costs

Some demand response programs may increase the costs required to comply with current and future environmental regulations. For example, a load curtailment program might require a customer to operate a fossil-fired backup generator that produces SO_2, NO_X, greenhouse gases such as CO_2, and other air emissions. If the backup generator is located in a state or region where such emissions are regulated or otherwise constrained, then the cost of complying with the environmental regulation should be accounted for in the cost of the demand response program.

If this cost is borne by the program administrator, then the cost should be included in all of the cost-effectiveness tests except the Participant Cost test. If this cost is borne by the customer, then the cost should be included in the Participant Cost test, the TRC test and the Societal test.

These costs of environmental compliance should not be confused with environmental externalities. Instead, these costs represent the anticipated costs that will be incurred by utilities in the future to comply with environmental requirements. These costs will eventually be passed on to ratepayers, and thus are clearly within the definitions of the RIM, TRC, PAC, and Societal Cost tests (Synapse 2012a).

Environmental Externality Costs

Some demand response programs may result in negative environmental impacts, even after all environmental regulations have been complied with. These environmental impacts are typically referred to as environmental externalities, because the costs are external to the party that is causing them, do not appear in the utility accounts, and are not passed through to ratepayers. Any such environmental externality costs that are considered to be significant should be accounted for in the Societal Cost test (Synapse 2012a).[45]

Environmental externality costs can occur, for example, with a load curtailment program that includes fossil-fired backup generators, if some of the pollutants (e.g., CO_2 or greenhouse gases more generally) are not regulated in that state or region. Externality costs can also exist if compliance with the existing environmental regulations does not eliminate all of the environmental impacts resulting from the pollutants emitted.

Environmental externality costs can also occur when a demand response program causes load shifting that results in increased net electricity generation, which has associated

[45] In theory, all societal externality costs should be included in the Societal Cost test. However, demand response programs are not expected to produce significant societal externality costs beyond environmental externalities.

environmental externalities. For example, load shifting might result in increased generation in off-peak hours that exceeds the reduced generation in on-peak hours. Environmental externality costs can also occur from load-shifting programs that do not increase net electricity generation if the emissions from the electricity system during off-peak hours are significantly greater than the emissions from the electricity system during on-peak hours.

The air emission impacts of demand response programs can vary significantly by customer, by program, by utility and by region. The air emission impacts of curtailing or increasing electricity demands will depend upon what power plants are operating at the system margin at the time of reduced or increased demand. The emissions from marginal power plants can vary significantly across regions, as well as during different times of the day, season or year. Ideally, estimates of the environmental impacts of demand response programs should account for these important factors.

We expect that, in general, the environmental externality costs of demand response programs will be small, particularly those programs that focus on capacity and have a small impact on energy.[46] However, demand response programs that involve the use of fossil-fired backup generators could have significant environmental externality costs. For such programs, it is especially important to account for these costs.

[46] In general, the environmental consequences of shifting loads from peak to off-peak might improve over time if renewable energy generation and efficient natural gas generation continue to replace older and less efficient oil and coal-fired generators.

5. Demand Response Program Benefits

There are many different types of demand response program benefits that must be accounted for when evaluating cost-effectiveness, depending on the test being applied. **Table 5-1** provides a list of demand response program benefit, based upon the literature that we have reviewed on this topic. The table also indicates which of the benefits should be considered in which of the cost-effectiveness tests. Each of the benefits is discussed in more detail in the sections below, including how the benefit is defined and issues to consider when identifying and calculating the benefit.

Note that we have attempted to make the list of benefits as comprehensive as possible. Not all demand response programs will have all of the benefits listed below. Table 5-1 presents a comprehensive list to provide readers with the universe of benefits that could be relevant when analyzing the cost-effectiveness of demand response programs.

Table 5-1. Demand Response Program Benefits

Benefit	Participant	RIM	PAC	TRC	Societal
Avoided Capacity Costs	--	Yes	Yes	Yes	Yes
Avoided Energy Costs	--	Yes	Yes	Yes	Yes
Avoided Transmission & Distribution Costs	--	Yes	Yes	Yes	Yes
Avoided Ancillary Service Costs	--	Yes	Yes	Yes	Yes
Revenues from Wholesale DR Programs	--	Yes	Yes	Yes	--
Market Price Suppression Effects	--	Yes	Yes	Yes	--
Avoided Environmental Compliance Costs	--	Yes	Yes	Yes	Yes
Avoided Environmental Externalities	--	--	--	--	Yes
Participant Bill Savings	Yes	--	--	--	--
Financial Incentive to Participant	Yes	--	--	--	--
Tax Credits	Yes	--	--	Yes	--
Other Benefits (e.g., market competitiveness, reduced price volatility, improved reliability)	depends	depends	depends	depends	depends

When estimating values for these benefits, it is important to ensure that they are properly characterized in order to avoid double-counting. For example if the cost of a natural gas combustion turbine (CT) is used to estimate the value of avoided capacity costs (because CTs are often used for peaking purposes), then only the capacity cost of the CT should be used to represent the avoided capacity cost. The avoided energy and avoided ancillary service costs associated with the CT should be removed from the avoided capacity cost calculation, because avoided energy and ancillary service costs should be captured by other elements in the cost-effectiveness evaluation. We recommend that demand response benefits be identified separately to the greatest extent possible as indicated in Table 5-1, in order to provide the greatest amount of accuracy and transparency for the calculation of each benefit.

Avoided Capacity Costs

One of the primary reasons for implementing demand response programs is to defer or postpone the need for new generation capacity, or otherwise reduce the cost of peaking generation capacity. Therefore, avoided capacity costs are one of the most important and significant benefits associated with demand response programs. Avoided capacity costs should be considered a benefit in the RIM, PAC, TRC and Societal Costs tests because they represent a reduction in costs to electric customers.

However, avoided capacity costs for demand response programs are very difficult to determine with a great degree of certainty, and there remains significant and contentious debate within the industry about the best approach for estimating these avoided costs. Proper estimates of avoided capacity costs for demand response programs require many more considerations than those for energy efficiency programs.

There is general agreement that different types of demand response resources have different characteristics, and therefore adjustments should be made to the amounts and types of capacity avoided through demand response programs based on the availability and exhaustibility of the demand resources, limits on event duration or number of hours the demand resource can be dispatched, and amount of advance notification required. The capacity avoided, in other words, very much depends upon the specific characteristics of the demand response resources. There remains a vigorous debate, however, on *how* such adjustments should be made. This is a critically important issue because experience has shown that avoided capacity costs are typically the largest benefit of demand response programs, but the estimated benefits and benefit/cost ratios can be dramatically different based on how these avoided capacity cost adjustments are made.

In this subsection we address several of the key issues that arise when estimating the avoided capacity costs of demand response programs, including: (a) determining the extent to which different types of demand response programs can be relied upon for providing capacity benefits; (b) challenges with estimating avoided capacity costs in regions with wholesale electricity markets; (c) practices for estimating avoided capacity costs in regions without wholesale electricity markets; and (d) accounting for some of the operational constraints of demand response programs.

The Extent to Which Demand Response Can be Relied upon for Capacity Needs

One of the issues to consider in determining avoided capacity costs is the extent to which any particular demand response program can be relied upon to provide a capacity resource at the time it is needed. Some demand response programs may be more likely to meet capacity needs than others. For example, incentive-based demand response programs (such as direct load control) may be more likely to provide capacity when it is needed than price-based demand response programs (such as TOU rates).[47]

Furthermore, there may be instances where a demand response program does not provide the capacity resource expected, e.g., when a customer decides not to respond to a curtailment request as part of an interruptible program. On the other hand, there is likely to be some capacity benefit from the combined effect of all the customers on a particular demand response program, regardless of whether some of the customers do not participate as planned.

One of the challenges in estimating the avoided capacity costs for demand response resources is in accounting for the variability of customer responses to the program, and properly comparing that variability to the characteristics of different types of generation capacity that might be avoided. This variability can differ by program, by customer type, and even by individual customer.

NERC has undertaken initiatives to address this issue. The goal of NERC's Demand Response Availability Data System (DADS) is to:

> collect demand response event information to measure the ongoing influence of demand response on reliability and provide a basis for projecting both dispatchable and non-dispatchable (price-driven) demand response towards planning (demand reduction) and operational reliability. This demand response data collection proposal provides a basis for counting and validating demand response resources toward meeting operational and resource adequacy requirements (NERC 2011, p.2).

The DADS framework for demand-side management categories helps, among other things, identify the extent to which demand response programs are dispatchable, as well as what role the programs play in providing capacity value versus other types of value (NERC 2011, p. 25).

[47] Section 1 provides a summary of the different types of demand response programs.

Regions with Wholesale Capacity Markets

For regions with organized wholesale capacity markets, the value of capacity (and thus the value of avoided capacity) is determined by market prices. This value will depend on the relative abundance or scarcity of available capacity and it will vary over time. For the purposes of cost-effectiveness calculations, the basic approach should be to forecast the market price for capacity for each year in which the demand response program will be operational.

Over the short-run, while sufficient capacity resources exist on the system, the capacity market prices would be driven by the mix of existing capacity resources needed to meet the capacity requirement in each year. Systems with large surpluses of capacity would be expected to have relatively low capacity market prices. In general, these prices would be expected to increase over time as the surpluses become smaller, until new capacity is needed on the system.

Over the long-run, when new capacity is needed to meet demand, the capacity market prices would be driven by new entrants to the market. While the new entrant to the capacity market could be any type of generator (baseload, cycling, peaking), with any type of fuel (natural gas, coal, oil, wind, solar, nuclear), the new entrant's capacity-only cost is likely to be consistent with the cost of a new gas-fired combustion turbine facility, which is built primarily for the purpose of providing capacity. For this reason, forecasts of wholesale market capacity prices typically assume that those prices will trend toward the capacity cost of a new natural gas-fired CT over the long-term (Synapse 2011a).[48]

However, one of the challenges of wholesale capacity markets is that it is not always clear whether and how much a particular demand response load reduction will actually result in reductions in capacity costs. This is particularly true in the case of a forward capacity auction, such as the Forward Capacity Market in New England. In a forward capacity auction, a demand response program can affect capacity needs in one of two ways.

The first way is when the demand response program administrator bids the program savings into the wholesale capacity market, and the bid is accepted. In this case, the demand response program will avoid the need for some capacity, and the value of that avoided capacity will be indicated by the wholesale capacity market price for those months and years where the demand response program operates and participates in the market. However, program administrators are sometimes required to submit their bids well in advance of when the capacity will be needed in the market. (In the case of New England, there is a three-year lead time between the forward capacity auction and the time that the capacity must be delivered.) Therefore, in estimating avoided capacity costs

[48] The long-run capacity value would be equal to the CT's "residual" capacity value (i.e., the annualized fixed cost minus the net revenues) it would earn through participation in the real-time energy and ancillary services markets.

it is important to account for this time lag between bidding into the capacity market and providing service in that market.[49]

The second way a demand response program can affect capacity needs is when the program administrator implements the program but does *not* offer it into the wholesale capacity market. This can happen if an electric utility offers customers time-of-use pricing, real-time pricing, or some other demand response program where the utility does not have sufficient confidence about the customer response to offer the program into the wholesale capacity market. In this case, the demand response program will help reduce customer demand as soon as it begins operation. However, this reduction in customer demand will not help reduce the cost of the wholesale capacity markets for several years, because of the way the markets are designed. In New England, for example, the cost of meeting capacity needs is set three years in advance of the actual capacity need, through the forward capacity auction. Reductions in demand during these three years will not reduce the cost of meeting that capacity need. Further, the Independent System Operator in New England does not translate a reduction in demand into a reduction in the need for capacity until one year after the market delivery date, at the earliest. Thus, there is at least a four-year delay between the time a non-bid demand resource reduces a capacity need and the time that this benefit is accounted for in the capacity market. In estimating avoided capacity costs it is important to account for this time lag between program operation and the reduction in capacity market prices.

Regions with Organized Wholesale Energy Markets, But Not Capacity Markets

For regions with organized wholesale *energy* markets that do not have wholesale *capacity* markets, the market price for energy may include both the cost of energy and the cost of capacity. In this instance, one option is to use the market price for energy to reflect both the avoided capacity and avoided energy costs. Another option is to identify the avoided capacity price separately. For example, in Ontario the energy market is designed to reflect the value of capacity directly, and there is no separate capacity payment or capacity market. In practice, the Ontario Power Authority has adopted a capacity value in its generation contracts. The contract contains provisions for Contingent Support Payments which are designed to balance the revenue flow for peaking generators and to ensure they are paid enough to cover their estimated capacity

[49] Some demand response program administrators may choose to bid programs once they are operational, resulting in a three-year lag before the capacity costs are reduced. Other program administrators may anticipate demand response program savings, and bid those into a forward capacity market three years before the program is operational. Either way, the point is that the estimate of avoided capacity costs should include values only for those periods when the demand response program is operating and reducing costs in the market.

costs. This type of value could be used to separate out the capacity costs from the energy costs (FSC 2008, pp. 16-18).

Regions without Organized Wholesale Electricity Markets

For regions of the country that do not have organized wholesale energy markets, avoided capacity costs can best be estimated using integrated resource planning practices.[50] To summarize, utilities should prepare two long-term, optimized electricity scenarios, one without demand response programs and one with, and compare the difference in present value revenue requirements between the two scenarios. Energy costs and capacity costs should ideally be estimated separately for clarity and transparency.

The forecast of avoided capacity costs should ideally include both a short-run and a long-run component. The transition point between the two occurs in the resource balance year, (i.e., the first year in which new capacity resources may be needed to meet the growth of peak load and reliability requirements).

In the short-run, one would expect the avoided capacity costs to be driven by the mix of existing capacity resources needed to meet the capacity requirement in each year. Over the long-run, one would expect the avoided capacity costs to be driven by the new generation resources needed to meet reliability requirements. Ideally, the capacity costs associated with these new generation resources should be separated from the energy costs. Again, one would expect the long-term capacity costs to trend toward the capacity cost of a new gas-fired CT. In fact, this cost is frequently used as a benchmark, or a proxy, to represent the long-term cost of avoided capacity.

Some regions that do not have organized wholesale markets might nonetheless have bi-lateral capacity markets. In these cases, in may be appropriate to obtain avoided capacity costs by analyzing the bi-lateral trades.

Accounting for Demand Response Program Constraints

Some demand response programs operate under various limits or constraints. For example, a program may have limits on: the months, days, and hours in which curtailment events can be called; the maximum duration of curtailment events; the number of consecutive days on which program events can be called; the notification requirements for curtailment events; the maximum number of events seasonally or annually; and others. These program operational constraints will affect the amount of demand response that is available to reduce capacity needs and the types of generation

[50] There are many important methodologies and assumptions required for proper integrated resource planning. A discussion of these is beyond the scope of this document.

capacity that are likely to be avoided. Both factors should be accounted for in estimating avoided capacity costs (CPUC 2010. Att. 1, pp 18-25; NPCC 2010. pp H-23–H-28; FSC 2008. pp 16-18).[51]

This is particularly true in those cases where the cost of a CT is used as a proxy for avoided capacity costs because CTs do not have as many operational constraints as demand response programs.[52] Adjustments for operational constraints will result in a reduction of avoided capacity costs.

There are a variety of ways that avoided costs can be adjusted to account for the operational constraints of demand response programs, and no industry consensus on which way is best. Here we summarize the approach that California uses as an illustration of one approach that could be used, while acknowledging that the California method like other adjustment methods is imperfect and contentious.[53]

The California protocols account for program limitations by applying three adjustment factors to the avoided capacity cost of a new combustion turbine (called the A, B, and C factors). These factors are intended to reflect the likelihood that a demand response program will be able to operate when needed. They are determined and applied separately by each load serving entity for each demand response program. Depending on the program's operating constraints, stochastic analyses may be necessary to develop adjustment factors that average the performance of the demand response across various scenarios (CPUC 2010. Decision, p 35-36; Att. 1, p 23).

- The A factor adjusts the avoided generation capacity cost based on the probability that the program will be available when needed. It represents the portion of capacity value that can be captured by the demand response program based on the frequency and duration of calls permitted. A program that could be called in every hour that a generation capacity constraint might be experienced by the utility would have an A factor of 100 percent. The A factor can be calculated using Loss of Load Expectation or Loss of Load Probability models. Alternately, the A factor can be based on the likelihood of an outage on load levels alone (CPUC 2010. Decision, p 35-36; Att. 1, p 23).
- The B factor takes into account the varying notification times associated with different demand response programs. Because programs with shorter notification times are more valuable, the B factor is used to reduce the value of programs with longer notification times. The B factor calculation can be done by examination of past demand response events to determine how often the additional information

[51] On the other hand, a large number of demand response programs may not be limited this way in total, because of the benefits of a diverse set of demand response products with different constraints.
[52] The main operational constraints of a CT are forced outages, and forced outage rates are relatively low.
[53] Furthermore, as noted above, at the time this report was being prepared the California Public Utility Commission was holding workshops to update and improve upon its adjustment methods (CA PUC 2012).

available for shorter notification times would have resulted in different decisions about event calls. In other words, decisions about when to call day-ahead events are based on the best available information the day before the event occurs. However, the need for demand response is based on conditions (particularly weather), which can change in the course of 24 hours. By examining past events, an estimate can be made of how often a curtailment event would have been accurately predicted, not predicted but needed, or predicted but not needed in advance of the notification time required by a particular program (CPUC 2010. Decision, p 35-36; Att. 1, p 24).

- The C factor determines the relative value of programs with different triggers, de-rating those with less flexible triggers to reflect their lower value. [54] Program administrators consider customer acceptance and transparency in establishing demand response triggers. However, in general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions. Therefore, a C factor should be determined so that programs with less flexible triggers can be de-rated. The C factor could be calculated through a number of different methods. Similar to the B factors, the C factor could be calculated by examination of past demand response events to determine how often a different trigger would have resulted in different decisions about event calls. By examining past events, an estimate can be made of how often a different trigger might have resulted in a different number of demand response events, thus giving an approximation of the additional value of the flexible trigger. Conversely, the C factor could be determined by creating a ratio of the number of events called to the maximum number of events permitted for each program. By comparing these ratios for the different demand response programs, it may be possible to get a sense of the relative values of the different triggers (CPUC 2010. Decision, p 35-36; Att. 1, p 24).

Reduced Reserve Margins and Avoided Line Losses

By reducing end-use load, demand response helps to reduce the need for capacity in two ways: (a) it reduces the capacity needed to meet customer demand; and (b) it reduces the capacity needed to help maintain the reserve margin used for reliability planning purposes. Avoided capacity costs for demand response programs should be adjusted upward to reflect the fact that demand response reduces the capacity needed for the reserve margin. For example, in a system with a reserve margin of 14 percent, a demand response program of 1.0 MW should be credited with saving 1.14 MW of capacity.

[54] The California protocols refer to triggers as the conditions that permit the utility to call each demand response program (i.e., a demand response event is triggered via an emergency, price-based signals, etc.) (CPUC 2010. Att. 1, p 24).

Similarly, demand response programs reduce the transmission and distribution line losses that occur between the point of generation and the point of delivery to retail customers. Avoided capacity costs for demand response programs should be adjusted upward to reflect the fact that demand response reduces lines losses. For example, in a system where line losses are estimated to be 12 percent, a demand response program of 1.0 MW should be credited with savings 1.12 MW of capacity. When calculating line losses, it is important to recognize that losses during high load levels tend to be significantly higher than losses at average load levels (RAP 2011; NPCC 2010. p H-24).

The reserve margin and the avoided line losses adjustment have an additive effect on demand response savings. For example, in a system with a 14 percent reserve margin and line losses of 12 percent, a demand response program of 1.0 MW should be credited with 1.28 MW of capacity.[55]

Avoided Energy Costs

Demand response avoids energy costs as it typically results in load curtailments in which customers forego consumption for short time periods. Demand response programs can also reduce energy costs by shifting demand from high-priced hours to lower-priced hours.[56] These avoided energy costs are likely to be much less significant than avoided capacity costs, but they are an important benefit to include in the cost-effectiveness analysis nonetheless.

Calculations of avoided energy costs should be based on analyses of hourly energy generation or purchase costs, because energy costs and prices can vary significantly throughout the day and throughout the year. The hourly avoided energy prices used should correspond to the hours in which the demand response resources are expected to operate. Demand response program events are most likely to be called in peak hours when energy costs are highest, but the exact hours can vary considerably by the type of demand response program, and some programs will result in load-shifting with increases in total energy consumption where the costs of providing increased energy should be measured using off-peak energy costs (CPUC 2010. Att. 1, p 25).

Over the short-run, the avoided energy costs should equal the marginal cost of operating the existing set of generators in the region in each hour of the year that the demand resources are operating. Over the long-run, the avoided energy costs should equal the variable operating costs associated with new generation resources installed on

[55] 1.28 = 1.14*1.12.

[56] As noted in Section 4, if a demand response program results in load shifting there may be a net increase in the consumption of energy. Both increases and the decreases of energy should be accounted for. The increases and decreases should be accounted for separately because they occur at different times with different prices.

the system to meet reliability needs, since these will be the resources displaced by demand response.

For regions with organized wholesale energy markets, the avoided energy cost should be based on the best available forecast of those energy market prices. Because distribution utilities can typically buy or sell electricity in the wholesale energy market, the market electricity price in each hour is a good indication of either the actual cost or the opportunity cost of energy avoided by demand response.

For regions without organized wholesale energy markets, the avoided energy cost can be estimated using integrated resource planning practices, as described above for avoided capacity costs.

Avoided energy costs should also be adjusted upward to reflect the avoided transmission and distribution line losses associated with demand response savings, as described above for avoided capacity costs. Avoided energy costs should be considered a benefit in the RIM, PAC, TRC and Societal Costs tests because they represent a reduction in costs to electricity customers.

Avoided Transmission and Distribution Costs

Demand response programs may defer or otherwise reduce utility T&D capacity investments in local areas that are particularly stressed or in regions that are experiencing significant load growth. Given the growing demand for new transmission investments around the United States, this may be one of the more significant benefits of demand response programs, second to avoided capacity costs (CPUC 2010. Att. 1, p 26; RAP 2012. pp 2-3).

T&D capacity value should be considered separately from avoided capacity and energy costs. This helps to reflect the potential for demand response to target specific T&D capacity constrained areas and to provide for the direct application of adjustment factors to reflect differing T&D impacts across demand response programs (CPUC 2010. Att. 1, p 20).

T&D investments are often driven by peak demands. While generally coincident with the need for generation capacity, the peaks used for transmission planning are sometimes more local and do not exclusively coincide with the system peak. In order to offset transmission investments, load must be reduced at the right time periods and at the right location. In other words, the impact of the load reduction on the power flow matters (FSC 2008. p 19).[57]

The extent to which demand response programs actually avoid or defer T&D investments is somewhat uncertain and is subject to debate. Avoided T&D costs for demand response programs may depend 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 demand response program; and (5) the level of uncertainty associated with the projected load impacts of the demand response program (NPCC 2010. p H-25).

In California, the avoided T&D costs are modified by a Distribution Factor that accounts for various factors that could limit avoided T&D costs by considering whether programs "(1) are located in areas where load growth would result in a need for additional delivery infrastructure but for the demand-side potential; (2) are located in areas where the specific demand response program is capable of addressing local distribution capacity needs; (3) have sufficient certainty of providing long-term reduction that the risk of incurring after-the-fact retrofit/replacement costs is modest; and (4) can be relied upon for local T&D equipment loading reliefs" (CPUC 2010. Att. 1, p. 27).

The PNDRP Guidelines recommend two general methodologies for estimating avoided T&D costs:

- Develop default avoided T&D costs which may be applied to demand response programs that meet pre-established criteria regarding locational value and certainty of load reductions. The default avoided T&D costs can be calculated by using marginal costs associated with local transmission and distribution substation equipment, which are principally related to transformer capacity.
- Estimate avoided or deferred T&D capacity investments on a case-specific basis. The case-specific method for estimating avoided T&D costs should be designed to limit application of avoided T&D costs to demand response programs that: (1) are located in areas where load growth would result in the need for additional delivery infrastructure; (2) are capable of addressing local delivery capacity needs; (3) provide sufficient certainty that the risk to the utility of incurring after-the-fact distribution system replacement costs is modest; and (4) can be relied upon for local T&D equipment loading relief.

In California, T&D capacity value is allocated to individual hours based on the hourly temperatures in each climate zone. This approach results in an allocation of T&D value to several hundred of the hottest (and likely highest local load) hours of the year. Utility-

[57] While demand response within a constrained area could offset the need for a transmission upgrade, it is also possible that load reduction immediately outside a constrained area might not offset the need for a transmission upgrade, and in some cases may instead exacerbate the need for a transmission upgrade.

specific T&D capacity values are used to calculate a system-wide average T&D capacity value for each month. These values are also reported separately for sub-transmission and for distribution. (CPUC 2010. Att. 1, pp 26-27).

Avoided T&D capacity costs should be considered a benefit in the RIM, PAC, TRC and Societal Costs tests because they represents a reduction in costs to electricity customers.

Avoided Ancillary Service Costs

Depending on the market rules and on how quickly and reliably the demand response can be deployed, demand response programs may be able to provide the operating reserves necessary for the system to respond quickly to transmission or generator failures, to assist in responding to short-term and mid-term fluctuations in generation, and to ensure grid reliability. Operating reserves are one example of the many ancillary services necessary to operate the electric system. Other ancillary service examples include frequency regulation, VAR support, and black start capability (FSC 2008. p 21).

The primary ancillary service benefits of demand response programs are due to reduced operation of generation facilities, more efficient use of generation facilities, and better integration of variable energy resources. These benefits should be reflected in lower ancillary service costs. In regions with organized wholesale markets, including markets for ancillary services, these benefits should be estimated using forecasts of market prices for ancillary services, to the extent possible.

However, the impact of demand response programs in organized wholesale markets will depend upon the specific program and how it interacts with the market. In California, the independent system operator (CAISO) has determined that demand response currently would not impact the procurement of ancillary services in the day-ahead market, but could reduce the quantity of ancillary services procured in the real-time market. Eighty-five percent or more of ancillary services in California are procured in the day-ahead market, thus ancillary services costs are expected to be a relatively small percentage of the overall demand response benefits. Because of this conclusion, combined with the fact that ancillary services in general represent a small portion of electricity market costs, California does not include any ancillary service benefits in evaluating the cost-effectiveness of demand response programs (CPUC 2010. Att. 1, p 20).

On the other hand, there is increasing interest in using demand response programs as a relatively low-cost option to integrate variable energy resources such as wind and solar photovoltaics into the electricity system. Certain types of demand response programs can provide load following and frequency regulation services that can help maintain system stability and reliability when relatively high levels of intermittent resources are added to the system. Demand response programs and technologies could be specifically designed to provide load following and frequency regulation benefits, e.g., through pre-programmed responses to real-time prices, or through direct minute-by-minute or even second-by-second control of equipment such as water heaters, chillers, or batteries or other storage devices (LBNL 2011).

As another example, the batteries in plug-in electric vehicles can be used for load following and frequency regulation. As these vehicles become more broadly employed, they could offer significant ancillary service benefits to the electricity system if combined with supportive price-based demand response programs (US DOE 2011b).

Thus, while the ancillary services benefits of demand response programs may be expected to be relatively small in the near-term as the California example suggests, these benefits could increase significantly as (a) increasing amounts of intermittent resources are added to electricity systems, and (b) increasing amounts of end-use demand response technologies, particularly storage technologies, are installed in homes and businesses.

In the *Western Wind and Solar Integration Study* prepared for the National Renewable Energy Laboratory, the estimated benefits of using demand response instead of spinning reserves from thermal generators in high wind scenarios was on the order of $310 to $450 per kilowatt-year (kW-year) (LBNL 2011, citing GE Energy 2010). In high wind scenarios in the Texas organized market (ERCOT), the benefit of using real-time pricing for all customers to help balance the system was estimated to be $6 to $10 per MWh of wind generation (IEEE 2009).

Avoided ancillary service costs should be considered a benefit in the RIM, PAC, TRC and Societal Costs tests because it represents a reduction in costs to wholesale electric customers, which are passed on to retail electric customers.

Revenues from Wholesale Demand Response Programs

In some of the country's organized wholesale electricity markets, demand response programs for wholesale electricity customers and aggregators of retail electricity customers have been in existence for more than a decade. These programs include emergency demand response, capacity market demand response, energy market demand response, and ancillary services demand response programs. Programs in other wholesale markets are still in the process of being developed, while some wholesale markets do not currently offer any of these programs. Wholesale programs already represent over 40 percent of all demand response potential in the country, according to FERC 2010 survey data (FERC 2012, Appendix G). We expect that this will be a growing area, and that over time there will be increasing numbers of wholesale demand response programs in increasing regions of the country.

Many utilities offer demand response programs to their retail customers, using ratepayer funding to cover program costs. These ratepayer-funded demand response programs can, in some instances, participate in wholesale market demand response programs. In these instances, the utility receives revenues just as a wholesale customer or aggregator would. Any revenues earned from the wholesale market demand response program should be considered a benefit to the retail ratepayer-funded demand response program.

Note that these revenues should be considered a benefit in the RIM, PAC and TRC tests because they represent an increase in revenues to the program administrator.[58] However, these revenues should not be considered a benefit in the Societal Cost test because they represent a transfer payment from all the customers in the wholesale market to the participating customers in the retail ratepayer-funded demand response program.

Market Price Suppression Effects

In regions of the country with organized wholesale energy and capacity markets, an expansion of demand response programs can reduce peak demands, which can then lead to reduced wholesale energy and capacity prices. Because wholesale energy and capacity markets provide a single clearing price to all wholesale customers purchasing power in the relevant time period, the reductions in wholesale energy and capacity clearing prices are experienced by all customers of those markets. Thus, even a small reduction in a market clearing price can result in significant cost reductions across the entire market. This effect is referred to as the market price suppression effect[59] (Synapse 2011a. pp 1-14–1-16; Synapse 2012a).

The market price suppression effect is expected to primarily occur over the short-term period after a demand response event is called. Over the long-term, when new physical capacity is needed to maintain the reliability of the system, the capacity price is likely to be set by the long-run marginal cost of new capacity and will hence be less sensitive to small reductions in demand. Even then, it is sometimes suggested that capacity prices could be lower with demand response than without because the long-run capacity supply curve is likely to have a less steep slope. One of the challenges in estimating the impact of demand response on market prices is distinguishing between the short- and long-term market price impacts (Brattle 2007. pp 27-28).

[58] This is true if the demand response program administrator is the retail electric utility. If instead the demand response program administrator is an independent aggregator, then the revenues from wholesale market demand response programs should not be included in the RIM test because those revenues will not affect electric rates.

[59] In wholesale energy markets, the price suppression effect is not necessarily limited to demand reduction during peak periods. At any hour of the year, a reduction in demand could potentially reduce the market clearing price for energy.

It is important to recognize that market price suppression effects are different than the avoided costs of capacity and energy. The former is a benefit that accrues across the entire market as a result of small reductions in wholesale prices, while the latter is a benefit that results from consuming less energy and capacity.

It is also important to note that there remains disagreement among industry stakeholders as to the magnitude of the price suppression effect, and even whether it is appropriate to include this effect when evaluating demand response cost-effectiveness. If wholesale market price suppression effects are included in demand response cost-effectiveness evaluations, it is very important that they be properly estimated. This would include accounting for the attenuation of the effect over time, and modeling the future resource scenarios with and without the demand response programs in a way that properly isolates the wholesale market price effect without double-counting the benefits associated with avoided capacity and energy.

The market price suppression effect should be considered a benefit in the RIM, PAC and TRC tests because it represents a reduction in costs to wholesale electric customers, which are passed on to retail electric customers. However, this effect should not be considered a benefit in the Societal Cost test because it represents a transfer payment from the generators that receive lower energy and capacity payments to the wholesale market customers.

Avoided Environmental Compliance Costs

Some demand response programs may reduce the costs required to comply with current and future environmental regulations. This would happen for those demand response programs that result in reduced energy consumption, leading to lower emissions of regulated pollutants such as SO_2, NO_X and others. In those states and regions with CO_2 or greenhouse gas constraints or regulations, reduced energy use will help lower the cost of complying with such regulations. Over the longer-term, reduced energy use is likely to assist every state with the cost of complying with federal climate change regulations (Synapse 2012b).

When estimating avoided environmental compliance costs it is important to account for the net impact on energy use of the demand response programs. Those demand response programs that only reduce peak demand can be expected to result in a net reduction in environmental compliance costs and environmental impacts.[60] Some programs, such as those that result in load-shifting, may result in a net increase in energy consumption and may therefore increase air emissions and associated compliance costs.

[60] In most of the country peak demand occurs during hot summer days, which is also when ozone air pollution is worst.

It is also important to recognize that the air emission impacts of demand response programs can vary significantly by customer, by program, by utility, and by region. The air emission impacts of curtailing or increasing electricity demands will depend upon what power plants are operating at the electricity system margin at the time of reduced or increased demand. The emissions from marginal power plants can vary significantly across regions, as well as during different times of the day, season or year. Ideally, estimates of the environmental impacts of demand response programs should account for these important factors.

The avoided costs of compliance with environmental regulations should be accounted for in the RIM, PAC, TRC, and Societal Cost tests. These avoided costs of environmental compliance should not be confused with avoided environmental externalities. Instead, these costs represent the costs that will be incurred by utilities to comply with environmental requirements; costs that will eventually be passed on to ratepayers. Because environmental compliance costs may in some cases be embedded in avoided capacity costs and avoided energy costs, care must be taken to avoid double counting of these benefits.

Avoided Environmental Externalities

In addition to reducing the cost to comply with environmental regulations, demand response programs can reduce environmental impacts of electricity generation, transmission and distribution.

There are several types of environmental impacts that might be avoided by demand response programs. The two main categories are (a) public health impacts resulting from air emissions, and (b) natural resource impacts associated with avoided generation capacity and transmission lines. The benefits of avoided air emissions can vary significantly, depending upon time of day, time of year, the emissions profile of the regional generation resource mix, as well as the participating customer's demand response strategy (e.g., load curtailment, load shifting, or onsite generation).[61]

The natural resource benefits associated with less generation capacity and fewer transmission lines can include a variety of benefits such as aesthetic benefits, reduced land use impacts, reduced water quality impacts, reduced noise impacts, and others (CPUC 2010. Att. 1, pp 30-31; see also EPRI 2008). The extent to which demand response will result in such natural resource benefits depends upon its ability to defer or avoid new generation capacity and transmission lines.

Avoided environmental externalities are not included in the Participant, RIM, PAC, or TRC tests because the costs are not directly experienced by the parties that these tests are

[61] As noted in above, some demand response programs could result in net increases in air emissions.

meant to represent. Avoided externalities are included only in the Societal Cost test, because these costs are experienced by society in general.

Participant Bill Savings

Bill savings are included only in the Participant Cost test. They are calculated from the perspective of end-users who participate in demand response programs. It is possible that participation in a demand response program could increase participant bills, making this a cost category rather than a benefit category, but for simplicity it is listed here as a benefit on the assumption that most customers will not enroll in a program that increases their bills.[62]

This calculation can be complex because end-users sometimes switch from one rate to another when signing up or defaulting to a demand response program. Hence, a participant's bill reduction (or increase) is the difference between the actual bill received by the participant and the bill the participant would have received had the participant not been enrolled in the demand response program.

Demand response programs that provide new customers with bill protection should be able to generate this information fairly easily. [63] However, for other programs, the expense of accurately calculating these bill reductions and increases may be large and not worth the cost. It may also be easier for the utility to calculate one number that is the sum of customers' bill reductions, which is acceptable for the Participant Cost test (CPUC 2010. Att. 1, p 28).

Financial Incentive to Participant

Some demand response programs (e.g., peak time rebates, direct load control) offer participants a financial incentive for curtailing their demand during peak hours. These payments should be accounted for as a benefit in the Participant Cost test.

Under the PAC test, the financial incentives to participants are a cost to the program administrator, not a benefit. Under the TRC or the Societal Cost tests, the financial incentives to participants should not be included, because they are transfer payments from non-participants to participants and thus are neither a cost nor a benefit from these perspectives.

[62] Hypothetically, a customer might participate in a program that increases their bills if the participant compensation more than offsets the bill increase.
[63] Bill protection guarantees that program participants will pay no more under the demand response program than under their standard cost-of-service rates – or within a certain percentage increase. If offered, it is typically in place only for an initial transition period.

Tax Credits

Tax credit benefits associated with demand response programs include any federal, state or local tax credits which may become available to participants for demand response equipment installation (CPUC 2010. Att. 1, p 34). These credits should be considered a benefit in the Participant Cost test and the TRC test. They should not be considered benefits in the RIM or the PAC tests because the program administrator does not receive the tax credits. They should not be considered a benefit in the Societal Cost test because they are a transfer payment from taxpayers to the program participants.

Considerations Regarding Improved Reliability

One of the benefits frequently cited for demand response programs is improved reliability at a relatively low cost. Reliability benefits are presumed to result from the fact that demand response programs typically reduce customer demand at peak hours when the system is most stressed. Also, some demand response programs, such as emergency response programs are specifically designed to improve the reliability of the electricity system when existing generation capacity may not be able to meet demand.

However, the reliability benefits of demand response programs are difficult to quantify and there is some dispute as to the extent of these benefits. One thing that is clear is that identifying the reliability benefits of a demand response program requires careful consideration of the nature of the program, as well as the other benefits that are attributed to the program.

As noted above, estimates of avoided capacity costs are frequently based on avoided supply-side capacity, such as the capacity from a CT generator. The supply-side capacity that is displaced by the demand response program would have provided reliability benefits to the electricity system. Thus, in order to prevent double-counting of benefits, the reliability benefits attributed to demand response programs should include only those benefits that are above and beyond the benefits offered by the displaced supply-side capacity. Put another way, all other things being equal, if demand response acts as a perfect substitute for generation, it has no net impact on reliability (CPUC 2010. Att. 1, p 32; NPCC 2010. p H-25).

The characteristics of a demand response program will determine how well it can substitute for generation capacity at a lower cost. For example, a direct load control program capable of providing load reductions at system peak within seconds may produce more reliability benefits than a CT generator. Conversely, if a generator with black start capability is displaced on a one-to-one basis with a day-ahead demand response program that has limits on how often and how long it can be called upon, the demand response may in fact reduce long and short term reliability (FSC 2008. p 23).[64]

As described in Section 5.1, the avoided capacity cost may be adjusted, i.e., de-rated, by a performance factor in order to arrive at deliverable capacity and allow for direct comparison with avoided generators. A demand response program's performance factor adjustments may have implications regarding the extent to which the program will provide reliability benefits because these adjustments account for the availability of the demand response resource.

Another consideration is the timing of when an emergency situation occurs. If the emergency situation occurs during the system peak, when most demand response programs were expected to be deployed anyway, then they may provide little reliability benefit. On the other hand, if an emergency situation occurs during an off-peak period when demand response resources were not expected to be deployed, those programs that can be deployed may provide a significant reliability benefit to the system.

Of course, demand response programs that are specifically designed to provide emergency capability may provide a significant reliability benefit. When all available resources have been deployed and customer load cannot be met, curtailments under an emergency demand response program will reduce the likelihood and extent of forced outages.

Other Benefits

Other benefits from demand response programs may exist that are not as well defined, analyzed, quantified, or accepted as the benefits discussed above. Several such benefits are summarized below, though this list is not intended to be exhaustive. Some of these benefits may be significant, e.g., enhanced market competitiveness, while others may be less so. State utility commissions may want to consider, at least qualitatively, these additional benefits in assessing the cost-effectiveness of demand response programs (NPCC 2010. p H-26; CPUC 2010. Att. 1, p 33; see also EPRI 2008).

- <u>Enhanced market competitiveness</u>. Many market observers have noted that, particularly during high-load periods, electricity markets suffer from structural problems that increase the incentive and ability for generators to exercise market power, including the fact that most customers are not exposed directly to spot prices, so they have no incentive to reduce even their lowest-value consumption when spot prices spike. Because of this regulatory construct, the market demand

[64] NERC defines black start capability as a documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan (NERC 2012. p 8).

curve is almost completely inelastic. Enhanced competitiveness could result in lower energy prices and lower capacity prices both in the short term and the long term (Brattle 2007. p 26). Some believe that it is inappropriate to include enhanced market competitiveness in the cost-effectiveness of individual demand response programs because such benefits arise as a result of market structural changes that favor demand response, not as a result of the individual demand response programs themselves. Regardless, enhanced market competitiveness is a benefit that should be considered by regulatory authorities when considering the efficacy of actively pursuing demand response programs.

- Reduced price volatility. Many customers are risk-averse and value rate stability, for example because they need to be able to forecast their costs accurately for budgeting purposes. However, retail rates can fluctuate in response to spot prices (for customers on real-time pricing) or expected wholesale prices (for other customers). To the extent that demand curtailment reduces volatility in the spot market, it improves rate stability for at least some customers (Brattle 2007. p 26).
- Demand response modularity. Most generation and transmission infrastructure investments are large and require years of planning and construction. Demand response programs can typically ramp up or ramp down more quickly and at a more granular or incremental levels than generation. As a result, they reduce the lumpiness of infrastructure investments, produce cash flow benefits, and lessen the likelihood of "rate shock" that could result from a large infrastructure project. They also add an additional tool in meeting resource adequacy needs in case of an earlier forecasting error or in case expected generation and/or transmission infrastructure lags behind schedule (FSC 2008. p 23).
- Insurance against extreme events. Demand response may have disproportionately more value under tighter market conditions. Although fairly unlikely, a reliability event occurring in conjunction with other system constraints would result in high-cost outcomes. Reducing the risk of such asymmetric consequences could add disproportionately to the overall probability-weighted value of demand response. Such events include the coincident outages of major generators and transmission lines or extreme heat waves occurring in shoulder months when many generators are on maintenance. The value of a demand response program could be quantified more completely by simulating such extreme, low-probability events (Brattle 2007. pp 26-27).
- Customer control over their bills. With most rate structures today customers are provided little or no incentive or ability to shift their loads to lower-cost periods. Demand response programs provide customers with additional options for reducing their bills (CPUC 2010. Att. 1, p 33).
- Overall productivity gains by better utilizing industry investment. Better pricing and the interaction of demand and supply can produce overall productivity gains by better utilizing the fixed investments of power plants that comprise one of the

largest capital investments made in a region. Improved capacity factors should result in improved electric system efficiency (CPUC 2010. Att. 1, p 33).

- Non-Energy Benefits. Some *energy efficiency* programs can provide a variety of non-energy benefits. These include utility-perspective benefits (e.g., reduced bad debt, reduced arrears); customer-perspective benefits (e.g., increased safety, improved health, increased productivity of workers and students, improved aesthetics), and society-perspective benefits (e.g., environmental benefits) (Synapse 2012b). Some of these non-energy benefits may be relevant to *demand response* programs as well. However, we expect such benefits to be less significant for demand response programs, relative to energy efficiency programs, because these two types of programs have very different impacts on customers and their homes and buildings.
- Innovation in retail markets. Providing a demand response framework can result in new retail product and pricing innovations, ultimately benefiting the customer through increased choice and a better matching of the customers' needs with choices offered by electric markets (CPUC 2010. Att. 1, p 33). Examples of new retail products could include comprehensive energy service bundling of demand response with energy efficiency, distributed generation, supply contracts, or performance-based contracts.

6. Applying the Cost-Effectiveness Framework

The cost-effectiveness tests described in Section 3 can be applied to demand response programs in much the same way they are applied to energy efficiency programs. However, demand response programs raise several issues that are either less important for or not relevant to the screening of energy efficiency programs. Here we mention some of those issues that regulators and other stakeholders should consider in applying the demand response program cost-effectiveness framework.

Various Issues to Consider

Overall Principles

As noted in Section 2 above, the PNDRP developed several principles for evaluating the cost-effectiveness of demand response programs. These principles are useful for our purposes, and are presented below in their entirety:

1. Treat demand response on par with alternative supply-side resources and include them in the utilities' integrated resource plans and transmission system plans.

2. Distinguish among demand response programs with respect to their design purpose, dispatchability, response time, and relative certainty regarding load response (e.g., firmness).

3. In assessing cost-effectiveness of demand response, it is important to account explicitly for all potential benefits, including avoided/deferred generation capacity costs, avoided energy costs, avoided transmission and distribution 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 demand response programs systematically (e.g., estimate avoided costs at hourly level, treat transmission congestion zones separately). Most of the benefits of demand response 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.

5. All demand response program incentive and administration costs, costs of enabling technology, and participant costs should also be included. For demand response programs in which customers have to voluntarily enroll, it can be assumed that total costs incurred by participants are less than or equal to the benefits, otherwise they would be unlikely to sign up and participate.

6. Demand-side management programs are often screened using a set of benefit-cost tests that compare and assess the benefits and costs from different perspectives (i.e., society, utility, participants, and non-participants). These tests are not intended to be used individually or in isolation; results from the various tests should be compared and trade-offs between tests considered.[65] These benefit-cost tests may need to be modified and adapted in some areas to account for the distinctive characteristics and features of demand response.

7. Utilities should consider conducting sensitivity analyses on key benefit and cost variables that have significant uncertainties which can have a major impact on program cost-effectiveness.

8. Initiate and conduct demand response 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" demand response with a view to identifying a fraction of the resource that could be treated as firm for planning purposes.

(NPCC 2010. pp H-22–H-23).

Study Period

Ideally, cost-effectiveness analyses should be conducted over a study period that includes all of the years over which costs and benefits are expected to accrue. Identifying the appropriate study period can sometimes be challenging because different types of demand response programs may result in benefit streams that occur over different periods. In addition, there may be uncertainties associated with customer participation and attrition.

For those programs that are based on load control technologies, the costs may be incurred in a single year while the benefits are experienced for the life of the technologies. For those programs that are based on financial incentives, such as peak time rebates, the costs and savings may last for many years. For those programs that are

[65] The PNDRP guidelines note that "PUCs and utilities may consider using the Total Resource Cost test or the Societal Cost test as the primary test in screening DR programs" (NPCC 2010. p H-23).

based on price signals alone, such as time-of-use rates or real-time-pricing, there may be small costs upfront but savings for many years. Adding to this complexity is the difficulty in tracking new and existing customers separately, so as to not double count costs and benefits over the long-term.

In California the time period for the cost-effectiveness evaluation is limited to the length of the demand response program planning cycle, which is usually three years, unless it is demonstrated that a longer period of analysis is necessary. The California protocols allow capital investments that are expected to provide benefits beyond the current program cycle to be amortized over an appropriate period. The protocols also state that since demand response programs experience some level of customer turnover and technology changes rapidly, the utilities should demonstrate that installed capital equipment will actually be "used and useful" in providing load reductions over the assumed useful life (CPUC 2010. Att. 1, pp 6,10).

Truncating the study period as California does can make the analysis simpler, but can also make some programs look less cost-effective than they truly are—especially programs that are expanding or that involve significant up front technology costs. As noted above, the California Public Utility Commission is currently modifying and updating its demand response cost-effectiveness protocols, including the practice of limiting the study period to three years. One of the proposals is to expand the cost-effectiveness analysis to include the length of the benefit stream, e.g., at least five and potentially ten years.

In conducting demand response cost-effectiveness analyses, program administrators should identify the appropriate study period for each demand response program based on the expected stream of costs and benefits, giving careful consideration to the different time periods that may be relevant for different types of programs. Program administrators should provide regulators with a justification for their choice of study periods (ISSGC 2010. p 239).

Baselines

One of the key issues in assessing the benefits of demand response programs is identifying "baseline" levels of customer consumption patterns (i.e., what would the consumption pattern be in the absence of the demand response program). The baseline consumption pattern should be compared to the expected consumption pattern under the demand response program to determine the savings, and thus the benefits, of the program.[66] The accuracy of the demand response cost-effectiveness assessment may be very dependent upon the accuracy of the baseline assumptions.

Developing baselines for demand response programs can be challenging because different customers have different end-uses, different customers have different usage patterns, customer usage patterns may change over time, and customer usage patterns may vary with different pricing schemes. Also, it is important to develop baseline assumptions that prevent customers from gaming the system in their favor, for example intentionally increasing their loads during a period of time when baselines are being developed so that it is easier for them to curtail load as part of a demand response program.

The Electric Power Research Institute has proposed some general criteria for establishing baselines for assessing the cost-effectiveness of smart grid projects. These criteria are useful considerations for establishing baselines for demand response programs as well. They include the following:

- Representativeness. Is the baseline a good approximation of what the customer usage patterns would have been in the absence of the demand response program?
- Acceptability. Is the baseline likely to be acceptable (i.e., does it make sense) to program stakeholders, utilities, and regulators?
- Operational. Is the baseline data defined in such a way that it can be collected for both the baseline information and the comparable demand response program information?
- Precise. Is the baseline data sufficiently precise with respect to the key performance indicators?
- Consistency. Can the baseline definition or methodology be consistently applied across other demand response program types, or at least other demand response programs offered to the same customer sector?

(EPRI 2010. p 4-39)

Baselines can be developed using historical data, or they can be forecasted to account for anticipated events that might change customer usage patterns. For demand response programs that have been in operation for some time, measurement and verification studies should be used to update and refine baseline assumptions.

[66] For further discussion of this issue, refer to the forthcoming report by the National Action Plan for Demand Response, Demand Response Measurement and Verification working group, one of the three other working groups associated with the National Forum.

Baselines estimates can incorporate volatility analyses to account for the variability of prices and consumption. For those demand response programs expected to operate when the electric system is under stress, the baseline estimates can also incorporate stress cases to account for how the electricity system and the relevant customer might react under extreme events. For those demand response programs expected to operate under extreme weather conditions (e.g., an air conditioner load control program), the baselines should be based on consumption under those extreme weather conditions. Baseline estimates may need to incorporate the use of control groups, either to develop the baselines or as a means of confirming the validity of the baselines over time (EPRI 2010. p 4-42).

Over time, technology advancements have the potential to improve estimates and calculations of a customer's baseline consumption patterns. As customer adoption of smart meters and two-way communications increase, more accurate data should become available from which to better determine a customer's baseline consumption. In the meantime, additional research would be useful to more precisely assess baselines so as to ensure accurate cost-effectiveness analyses.

Customer Participation and Response Levels

The level of customer participation and customer response will have a significant impact on the savings, and thus the benefits, of demand response programs. For some types of programs (e.g., direct load control) customer participation and response might be relatively easy to predict and plan. For other types of programs (e.g., time-of-use rates, real-time pricing, and peak time rebates), customer participation may be challenging to predict and plan for.

Pilot programs and results from other jurisdictions might be helpful in preparing estimates of customer participation and response. However, these may be of limited value depending upon the type of programs offered, the designs of the programs, the customers targeted, the customers that chose to participate, the types of incentives offered, the types of technologies offered, and more.

Furthermore, there may be some uncertainty about the sustainability of customer participation and response over many years. Customers may experience fatigue or changing priorities over time, resulting in reduced participation and response over the long-term. On the other hand, customer participation might stabilize after the introduction of a demand response program, once the most suitable customers are enrolled. [67] Furthermore, customers may install demand response technologies that allow

[67] One member of the working group noted that several program evaluations recently conducted by his company indicate that customer participation is fairly persistent. It is normal for some customers to exit from

for automated responses to price signals and utility controls, resulting in long-term customer participation and response.

Demand response cost-effectiveness evaluations should include the best available assumptions regarding customer participation levels, customer response levels, and the persistence of customer response over time (ISSGC 2010. p 238). Given the importance of customer participation in determining the benefits of demand response programs, it should be one of the key assumptions that is tested through sensitivity analyses.

Sensitivity Analyses

Due to the many uncertainties associated with the costs and benefits of demand response programs, particularly the benefits, it may be appropriate for program administrators to conduct sensitivity analyses reflecting some of the key uncertainties. Sensitivity analyses can provide program administrators, regulators, and other stakeholders with a sense of the range of possible outcomes under alternative assumptions (ISSGC 2010, p. 237).

Some of the key assumptions that should be considered for sensitivity analyses include: (a) avoided capacity costs; (b) participant value of lost service and transaction costs; and (c) customer participation and response levels.

Transparency

Given the complexities and uncertainties associated with demand response program cost-effectiveness assessments, it is important that program administrators use models, inputs, assumptions, and methodologies that are transparent and well documented. This will be necessary to help regulators and other stakeholders to fully understand the cost-effectiveness assessments, as well as the uncertainties involved and the implications of the assumptions and methodologies used.

Illustrative Example of Applying the Framework

This section provides one example of how the demand response cost-effectiveness framework has been applied, in order to provide some context for the discussions above. We present the results of a recent analysis by a California electric utility for its demand response programs. The purpose of this cost-effectiveness evaluation was to determine which programs the utility was to pursue and at what level.

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programs after a no-risk trial period, but otherwise changes in participation usually reflect increased (not decreased) participation as a result of program expansion or better targeting of potential participants.

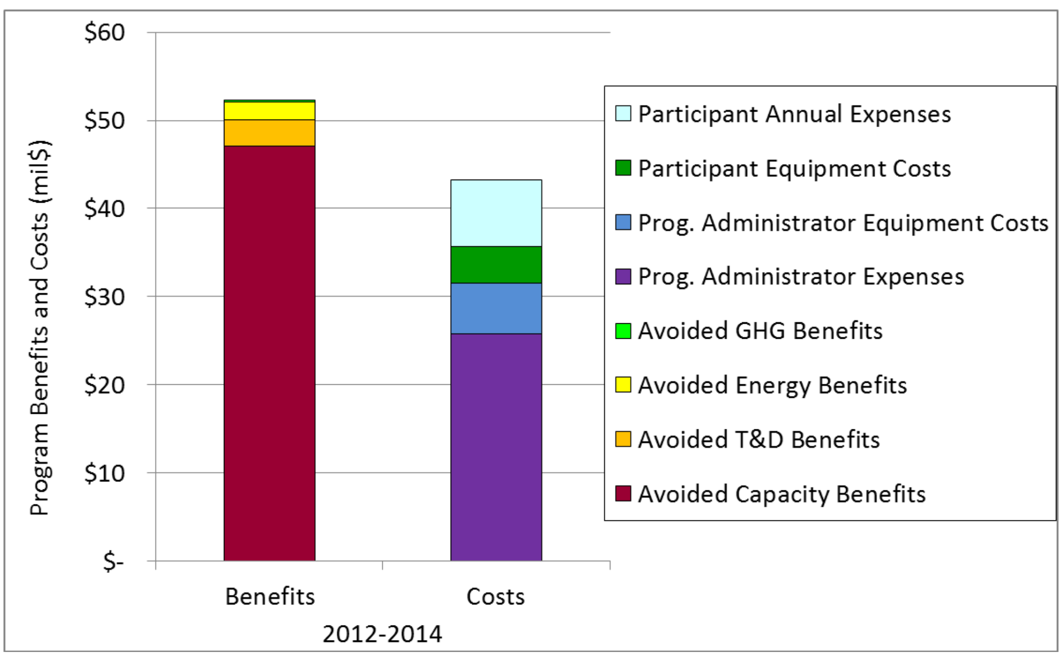
We present these results merely as an illustration of the types of costs and benefits that may be identified in assessing demand response programs. Results can vary considerably for different programs and different jurisdictions. We present results from California because it has considerable experience in identifying and assessing demand response program cost-effectiveness.

Figure 6-1 presents a summary of the benefits and the costs of the portfolio of demand response programs offered by the utility. We present the combined results of these programs to show the general types and magnitudes of costs across many demand response programs; the individual programs have benefit-cost results that differ from those presented here.

The results in Figure 6-1 are for the TRC test. The company also prepares these results using the RIM, PAC and Participant Cost tests. Under the TRC test, the proposed demand response programs are expected to have a benefit-cost ratio of 1.2.[68]

Note that the avoided capacity benefits represent the majority of benefits (roughly 90%). Avoided transmission and distribution and avoided energy benefits are relatively small portions of the benefits (roughly six percent and four percent, respectively). The avoided cost of complying with greenhouse gas requirements is a very small portion of the total benefits (roughly one percent).

Figure 6-1. Example of Demand Response Cost-Effectiveness Results



[68] As noted above, California program administrators include only three years of costs and benefits in the demand response cost-effectiveness analyses. Extending the study period out for more years would likely indicate that the demand response programs are more cost-effective than indicated here.

The biggest portion of the costs is the program administrator’s expenses (roughly 60 percent).[69] The next biggest portion is the equipment costs, borne partly by the program administrators (roughly 13 percent) and partly by the participating customer (roughly 10 percent).

[69] The financial incentive paid to the participating customer is not included in the TRC test as a cost. As indicated in Table 4-1, this cost is considered a transfer payment under the TRC test and thus is not included.

7. Recommendations for Further Research

While considerable work has been conducted to identify the different costs and benefits of demand response programs, there are many areas that could benefit from further research. This is particularly true for the *benefits* of demand response programs, which are typically more difficult to quantify than the *costs*. Below we list a number of specific topics on which further research is most needed and would be most useful.

<u>Avoided capacity costs</u>. As described above, there are many complexities and uncertainties associated with estimating avoided capacity costs, and there remains considerable debate about the best way to make such estimates. It would be very useful to conduct additional research on the various methodologies that are appropriate for this purpose, both in regions with organized wholesale markets and those without. These methodologies should take into consideration some of the issues addressed above, including overlap with other benefits; the extent to which demand response can be relied upon for capacity benefits; accounting for demand response program constraints; and the role that demand response plays in reliability planning practices.

<u>Participant value of lost service</u>. These costs can be significant to the participant, but they can be difficult to estimate, partly because of the challenge of placing a monetary value on lost productivity or lost services, and also because the values might vary considerably between customers, between homeowners, and between businesses. It is sometimes assumed that a participant's value of lost service combined with its transaction costs are equal to some fraction of the financial incentives offered through participation in a demand response program; but this is understood to be an overly simplistic approximation. Further research is needed to determine a more detailed and accurate representation of a participant's value of lost service.

<u>Transaction costs</u>. It would be useful to have improved data and methods for estimating participants' transaction costs for enrolling and participating in demand response programs. It would also be useful to gather more data on the program administrator's costs of acquiring customers for demand response programs.[70]

[70] Consumer behavior studies arising from the US Department of Energy's Smart Grid Investment Grants have identified a need to better understand the cost of acquiring customers.

Ancillary services benefits. Some demand response programs offer the potential to provide significant ancillary service benefits, particularly to help balance the effects of intermittent resources such as wind and photovoltaics. This area is ripe for further exploration, and will become increasingly important as regions install increasing amounts of intermittent resources.

Avoided T&D costs. Some demand response programs offer the potential to offset transmission and distribution costs, but there remains considerable uncertainty as to the extent to which demand response programs will actually affect T&D investments, and the role that demand response should play in long-term T&D planning. Additional research could help address some of these uncertainties, and may be especially important as transmission and distribution investments around the country increase in the future.

Relationship between wholesale market impacts and retail customer impacts. Better data and methods are needed to assess how the participation of retail customers in demand response programs affects wholesale markets, and vice versa.

Reliability benefits. Demand response is often cited as a means of improving the reliability of the electricity system; yet there is little empirical data to demonstrate or quantify this benefit. It might be useful to conduct research into ways to demonstrate and quantify the magnitude of these benefits. This research should include assessing the value of dispatchability, for those demand response programs that are dispatchable.

Interaction between demand response and energy efficiency programs. When both types of programs are implemented side-by-side, there are common components (e.g., avoided capacity costs, lost revenues and environmental benefits) that will appear in both cost-effectiveness analyses. In addition, there may be marketing and participation benefits from offering both types of programs to customers. On the other hand, a customer's adoption of energy efficiency measures may reduce the impacts of that same customer's participation in the demand response program. Further research may result in improved assumptions regarding both the costs and the benefits of demand response programs.

Wholesale market benefits. Demand response is often cited as a means of improving the efficiency of wholesale markets and helping to mitigate against market power problems; yet there is little empirical data to demonstrate or quantify this impact. It might be useful to conduct research into ways to demonstrate and quantify the magnitude of these benefits.

The cost-effectiveness implications of different program designs. Changes in demand response program designs may lead to significantly different cost-effectiveness results. For example, the choice of using an opt-in versus an opt-out program will likely lead to very different benefits. It might be useful for demand response program administrators to share program design best practices and lessons learned, for the benefit of those program administrators that are developing new programs. A related area of inquiry would be to assess the costs and benefits of tiered rates vs. TOU rates.

Technology performance. Technology cost and performance can have significant implications for both the costs and the benefits of some demand response programs. If we are going to increasingly rely on automated controls to augment or supplant customer-controlled efforts, we need to better understand performance of the associated technology.

The role of demand response in integrated resource planning. Research could help to identify and disseminate best practices from those utilities, states or regions that model demand response resources, as well as energy efficiency resources, on an equal footing with supply side resources in long-term planning assessments.

The role of back-up generators in demand response programs. The use of back-up generators will have significant implications for the costs and benefits of a demand response program, especially with regard to the environmental costs. It may be useful to know the types of participating back-up generators and the frequency with which they are used in demand response programs.

Demand response programs suitable for small commercial and industrial customers. Small commercial and industrial customers are sometimes difficult to sign on to demand response programs, due to the many market barriers that they face; yet these customers often represent a considerable portion of peak demand, and it is important that these customers are provided with opportunities to benefit from demand response programs. It may be useful to conduct research into program designs that best meet the needs of these customers.

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