- Distribution and transmission companies looking at increasing reliability through the use of distributed resources for both short-term relief and long-term reliability.

In order to value DRR in a model according to the perspective of these other market actors, it may be necessary to use a model that has been built specifically for these types of operations. However, the methodologies which have been developed in this study, for creating inputs with a Monte Carlo approach and interpreting the results, will most likely be applicable to most types of models.

2. Overview of Applied Issues

Demand response in the context of this analysis is defined as load response called for by others and price response managed by end-use customers. Load response includes direct load control of equipment (air conditioners, hot water heaters, or any other equipment that can be isolated), partial load reductions that can be "called" by a product[4] administrator, and even complete load interruption.[5] Entities that may call for load response include Independent System Operators (ISOs), load serving entities (LSEs), utility distribution companies, and independent load aggregators. Price response includes real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buyback programs.[6]

2.1 Select Issues in DRR Product Assessment

Appropriately assessing DRR products and offers poses a number of practical challenges. These challenges include:

1. Different types of DRR will produce different types of benefits and each has to be estimated within the appropriate framework. For example, callable load programs can enhance reliability by serving as system reserves that can be called upon in response to a system event. Pricing programs can reduce peak hour demands as well as reduce demand during all high priced periods, but they are not directly dispatchable in response to a system event that might need quick response to avoid a local or regional outage or an extreme spike in prices. As a result, different DRR programs provide different types of benefits and will have different costs.
2. Many of the values associated with DRR are difficult to quantify. Such benefits can include reduced market power, insurance values that come from having a resource available to meet low-probability/high-consequence events at a low cost, and portfolio benefits through diversification, e.g., reducing reliance on fossil fuels and having locational diversity where the resources are located closer to the load centers. This means that demand response resources require a planning horizon similar to that used to assess the value of gas turbines on the supply-side, i.e., 15 to 20 years. These benefits are presented in more detail in a later section.
3. The "portfolio value" and the "insurance value for low-probability, high-consequence events" require that uncertainty be dimensioned around future outcomes. This can pose problems for planners that are accustomed to using simple avoided cost comparisons or planning paradigms such as "a one in 10 year event" without developing a distribution of outcomes that should be considered. Future changes in the framework conditions – e.g., introduction of emission trading schemes, changes in the fuel supply situation, or going from over supply to capacity shortage in liberalized markets – can affect the system so much that historically based analyses may give

[4] The term DRR product is used in the same context as a DRR program. It represents a contract between an end-user and a product or program administrator that allows for load to be reduced under certain conditions. Usually, these conditions are associated with high prices for electricity and/or conditions that threaten the reliability of the system.

[5] A complete interruption may be associated with facilities that have their own on-site generation that they can use to meet all of their needs or at least their essential needs.

[6] This definition parallels that developed by the Peak Load Management Alliance (PLMA) and documented in "Demand Response: Design Principles for Creating Customer and Market Value" prepared by the Peak Load Management Alliance, November 2002, and available at www.peaklma.com.

wrong results. Therefore, different tools for dimensioning uncertainty are needed if DRR are to be appropriately valued using new approaches.

4. Categorization of DRR programs. There are many types of DRR programs and it is not possible to develop a scheme that assesses all possible variants. This is also a problem when looking at more conventional supply-side resources. As a result, a representative subset of resources needs to be examined. This is discussed in more detail in the development of the resource planning model used as a case study in Section 4.

These four issues imply that the assessment of a portfolio of DRR products, within a regional electric system, will require approaches based on different methods and tools than have been used traditionally. However, most of these approaches use methods and tools that currently exist and have been used in a variety of resource valuation and planning assessments.

2.2 Objectives of DRR Assessments and Planning Studies – Questions to be Answered

The assessment of a portfolio of DRR products is comprised of the same questions electric system planners address in any type of resource assessment. These include:

Q1: Do any DRR products provide value to the electric system in excess of their costs? Given the large number of DRR products/programs already deployed around the world, some DRR will almost certainly be cost-effective in alalmost any system for an appropriate planning horizon.

Q2: If some DRR products are cost-effective, what specific products should be included in the portfolio? A wide variety of DRR products are available, including: 1) mass-market direct load control of appliances that can provide load relief in a matter of minutes; 2) under-frequency relays installed on specific equipment that will be tripped the second voltage drops to unacceptable levels; and 3) large customer interruptible programs where several hours' notice may be required. (A large MW response can be gained by having the largest customers participate in this last product offering.)

Q3: How should the different DRR products be sized (i.e., how many MW or MWh should be accounted for in each product)? Most DRR portfolios will be comprised of several different products. Some consideration must be given to which products provide the greatest value to a specific regional electric system or market, and which should be more aggressively deployed. A DRR program can be over-built which will reduce the benefits from the DRR portfolio, as shown in the resource planning case study in Section 4.

Q4: What is the appropriate timing of DRR deployment, expansion, and maintenance in a steady situation, or a reduction in the MW capacity of a DRR product? One of the advantages of DRR products is their flexibility. They can be deployed on a quick hit basis to aggregate a considerable amount of responsive load in a short period of time, or they can be rolled out, possibly at a lower cost, over a longer period of time. If they are not needed at the moment due to excess generation capacity, a plan can be developed to roll out DRR products when they are expected to be needed. Also, if there is a need to reduce the commitment to DRR, the programs can be down-sized simply by not enrolling new customers when current customers leave the program or, in the extreme, asking some customers to leave the program. However, the start-up costs of DRR products should not be underestimated. Eliminating a DRR product only to find that there is a need for the product, even in a five- to six-year timeframe, could cost more than

simply placing the program in a maintenance mode, in which new customers are not signed up, with the annual and variable costs reduced to minimal levels. This maintains the program and allows for increased capacity when needed. DRR has greater flexibility, as a resource that follows the need for capacity, than most supply-side technologies that have higher fixed costs which need to be recovered through operations.

Q5: Do different DRR products within a portfolio have positive and/or negative synergies? One of the questions that commonly arises is that if real-time pricing is offered as a DRR product, then how will this impact the economics and value of, for example, a large customer interruptible program. Real-time pricing will cause the demands during peak hours to be reduced as customers respond to the higher prices in these hours. This will have an impact on the value of an interruptible program, since the number of MW that may need to be reduced during a high peak demand event will be lower, due to some customers already planning to reduce their demand due to the higher pricing.

Q6: What are the portfolio benefits from DRR due to increased diversity in resources (e.g., fuel inputs) and location (distributed near end-use loads)?

Q7: How should technological advances be addressed (i.e., when should an existing product be phased out to make way for a product based on a more advanced technology platform)? This issue is seen today in mass-market AC direct load control programs which are based on simple switches, and for which operators are considering a move to thermostat or even gateway technologies. Similarly, advanced metering and AMR technologies can be used both to control equipment and to incorporate innovative pricing options. In addition, this technology can be used to provide synergies where thermostats are adjusted during periods in which prices are high, thereby providing customers with additional benefits. DRR portfolios will need periodic assessment and transition plans to address changes in technology.

These seven questions illustrate the need for a planning and benefit-cost framework that assesses both entry investment into DRR and appropriate ongoing investment in DRR products based on market and technology circumstances. In addition, there is considerable variability in DRR product specification in terms of the number of hours per season or year it can be called and the length of each event. These factors will impact the value of DRR. In addition, their impact on value will vary by system. Therefore a dynamic model is needed to assess the different portfolios of DRR products within any specific electricity market.

There is no question that examining DRR products using all four approaches addressed in this volume will continue to provide positive information. But, there is also no getting around the tough questions that DRR products pose for overall resource planning and for running efficient electricity markets. The factors that influence the electric markets are dynamic, and a dynamic process is needed to assess their contribution to the overall robustness of the electricity market.

This implies that a planning process that directly addresses difficult issues such as uncertainty, a time horizon that encompasses low-probability/high-consequence events, and the electricity market encompassing demand response as well as supply-side technologies is needed to assess impacts on overall system costs, system reliability, and risks associated with extreme events. The utility industry has become expert at applying the types of models needed to address these questions for both costs related to generation and costs related to the transmission and distribution (T&D) systems. These modeling efforts will be needed to fully value DRR. A plan for incorporating uncertainty in both generation and T&D capital budgeting, and also in developing budgets for annual operating and maintenance (O&M) costs, is

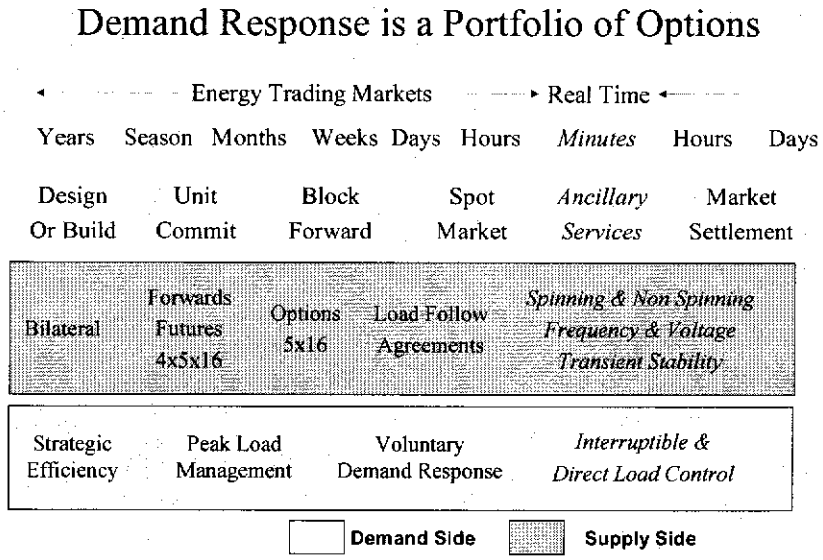
needed. In some cases, utilities are beginning to examine these issues using appropriate tools; in other instances past procedures that do not account for the increasingly dynamic nature of electricity markets are still being used.

The use of benchmark studies, standard practice tests such as the TRC test, and event reliability assessments will become more valuable and useful when an overall construct of avoided capital costs (generation and T&D) as well as avoided O&M costs is developed from a resource planning perspective. Static analyses of specific situations are best addressed once a comprehensive framework has been developed.

The benchmark approaches and standard practice tests likely will continue to be used in the near term and these are useful as "proof-of-concept" analyses, and to justify the startup of selected DRR product development. But questions about how much DRR is enough, and the dynamics inherent in the timing of investment decisions, will likely need the development of a full resource adequacy assessment for an electricity market. This assessment likely will have resource planning constructs for both generation and T&D.

2.3 Benefits and Costs of DRR

Demand response resources should be seen as a portfolio of options, each with their own relative benefits and costs.[7] As shown in the adjacent chart, demand response serves the full range of timeliness in resource needs – from months to minutes. DRR can fulfill a role in seasonal management of systems that include a high percentage of hydro power.



A portfolio of DRR options complements generation resources, and in addition DRR supports transmission and distribution asset management. Energy efficiency and distributed generation resources further complement DRR through their probable contributions to peak management. While DRR may be viewed as competing with these other options, in practice all are important as the demand for energy continues to grow.

DRR can play a significant role in the market for ancillary services. "Ancillary services are those functions performed by the equipment and people that generate, control, and transmit electricity in

[7] Joel Gilbert, "Customer Demand Response: The Four Not So Easy P's," Presented at FERC/DOE Workshop on Demand Response, February 14, 2002.

support of the basic services of generating capacity, energy supply, and power delivery. "[8] As outlined in Table 2-1, three types of ancillary services could be accommodated by DRR.

Table 2-1: Ancillary Services Descriptions

Ancillary Service	Description
Spinning reserve	Resources that can increase output immediately in response to a major generator or transmission outage and can reach full output to a specified level within 15 minutes.
Supplemental reserve	Same as spinning reserve, but need not respond immediately, since they may be off-line and still reach full output in 15 minutes.
Replacement reserve	Same as supplemental reserve, but with a 30- to 60- minute response time.

DRR can meet ancillary services in many ways. For example, municipal water-pumping, which accounts for 2-3% of electricity use in the United States, can be operated in concert with requirements for spinning reserves. For mass market programs such as direct load control of residential air conditioners, reductions of 200 MW for one utility took place within a few minutes of a request by the grid operator.[9]

It takes only a small percentage of DRR out of the total system load to affect a large percentage reduction in wholesale market prices. For example, it has been shown for the ISO NE that on a peak day in the summer of 2001, a 2% reduction in peak demand (about 500 MW) would have reduced the clearing price from $400 to $175 per MWh, or by about 56%.[10]

The fact that small amounts of load can provide sizeable benefits is an important point. DRR does not have to gain favor with all customers. For success, only a portion of customers that have the ability to adjust their loads in response to prices or program calls are needed to participate.

The value of DRR may be underestimated by focusing on the "average" customer or certain segments of customers that are not likely to participate. Instead, the focus should be on the target customers or customer segments that are likely to participate, i.e., that set of customers that can make a meaningful contribution to peak load management and to the operation of efficient electricity markets.

The challenge is to develop compelling value propositions for recruiting those customers that have the flexibility in their energy use and place a value on this important customer attribute. End-use customers need to have their benefits from participation outweigh their costs. The same holds true for potential providers of DRR products, e.g., distribution companies, infrastructure providers, and aggregators. In areas that have restructured there are many uncertainties, and the overall value proposition of DRR needs to be fairly assessed and participants provided with payments that represent this value.

[8] Eric Hirst, "Price-Responsive Demand as Reliability Resources," April 2002.

[9] Dan Violette and Frank Stern, "Cost-Effective Estimation of the Load Impacts from Mass-Market Programs: Obtaining Capacity and Energy Payments in Restructured Markets for Aggregators of Mass-Market Loads," 2001 International Energy Evaluation Conference, August 21-24, 2001.

[10] Bob Burke, Independent System Operator of New England, Remarks at the PLMA Spring Meeting on April 25, 2002. PLMA May Newsletter.

2.3.1 Candidate Benefits for DRR

This section presents categories of benefits that might be associated with the implementation of a portfolio of DRR products. Demand response occurs when customers reduce or shift electricity use in response to signals or to products/programs specifically designed to induce such actions. Demand response also occurs when distributed resources are dispatched by end-use customers for reliability or economic reasons.

There are different views on what compromises the important benefits of DRR. Seven categories of benefits are listed below:[11]

1. **System Reliability.** Customer demand management can enhance reliability of the electric system by providing reductions in use during emergency conditions. EPRI has estimated that "power interruptions and inadequate power quality already cause economic losses to the nation conservatively estimated at more than $100 billion a year."[12] Demand response can reduce those interruptions and reductions in quality.
2. **Cost Reduction.** A key driver for demand management is cost avoidance and reduction. Demand response can permit LSEs and customers to avoid incurring costs for generation, transmission, and distribution, including capacity costs, line losses, and congestion charges. Demand response can also save all customers money indirectly by reducing wholesale market prices and mitigating price volatility.
3. **Market Efficiency.** When customers receive price signals and incentives, usage becomes more aligned with costs. To the extent that customers alter behavior and reduce or shift on-peak usage and costs to off-peak periods, the result will be a more efficient use of the electric system. One study concluded that "… a 2.5% reduction in electricity demand statewide could reduce wholesale spot prices in California by as much as 24%; a 10% reduction in demand might slash wholesale price spikes by half."[13]
4. **Risk Management.** Providers of retail energy purchase power in wholesale markets where prices can vary dramatically from day to day and hour to hour. Providers can use demand response to substantially reduce their risk and their customers' risk in the market. Moreover, where retail markets are competitive, price guarantees provide substantial value to certain customers. Efficient markets are characterized, in part, by their ability to provide risk management products using all available economic tools. Retailers can hedge price risks by creating callable quantity options (i.e., contracts for demand response) and by creating appropriate price offers for those customers who are willing to face varying prices. In this manner, risk management products can be economically offered to those customers who most benefit from them. Overall, demand response helps manage risks through ready availability, high reliability, refined modularity, and rapid dispatchability.
5. **Environmental.** DRR promotes the efficient use of resources in general. This can help reduce environmental burdens placed on the land, water, and air, depending on the DRR product. Electricity generation is responsible for a significant portion of those burdens, consuming one

[11] These are based on "Demand Response: Principles for Regulatory Guidance" prepared by the Peak Load Management Alliance, February 2002. Available at www.peaklma.com.

[12] EPRI, "Technology Action Plan Addresses Western Power Crisis," *EPRI Journal*, Summer 2001, p. 5.

[13] Taylor Moore, "Energizing Customer Demand Response in California," *EPRI Journal*, Summer 2001, p. 8.

billion tons of coal annually and accounting for 90% of U.S. coal consumption in 2000.[14] Also, utility power plants consumed an estimated 3.1 quads or 13% of national natural gas usage in 2000.[15] Demand response can reduce the need to operate these plants. Demand response can also reduce or defer new plant development and transmission and distribution capacity enhancements, resulting in land use benefits for neighborhoods and rural areas where power plants might be sited.

6. **Customer Service.** Many customers welcome opportunities to manage loads as a way to save on energy bills and for other reasons such as improving the environment. In this age of choice, demand response provides customers with greater control over their energy bills.

7. **Market Power Mitigation.** Demand response programs help mitigate the market power of energy suppliers. This is especially true when demand response can occur essentially coincident (i.e., in near real time) with tight supplies and/or transmission constraints that might lead to an excess of market power. In Nordic countries, one of the major benefits of DRR is its effect in providing "improved thrust to the market". This is defined as the strengthening of market mechanisms by providing a better match between marginal supply costs and willingness to pay, which means less extreme events for the actors involved. This also reduces the risk of political interference in the market – which could mean the use of larger risk premiums.

Benefits need to be assessed in terms of whether they impact the regional market as a whole or whether they primarily accrue to private entities in the market.

Candidate Market-Wide Benefits

Market-wide benefits may accrue to the market as a whole from a DRR product, even if DRR is implemented in only a portion of the regional market. These benefits are summarized below:

MB-1. Reliability – Increased system reliability through investments at load centers, i.e., the locational value of the resource.

MB-2. Market price reductions – Reduced regional prices.

MB-3. Insurance value – Creates the ability to lower/minimize costs of low-probability/high-consequence events given current infrastructure (looking 1 to 2 years out).

MB-4. Reduced hedging costs – Lowered average prices and price volatility create a forward price curve that lowers the costs of hedging future energy prices.

MB-5. Portfolio benefits – DRR provides for increased diversity in resources over time

MB-6. Market power – Demand reductions curb market power and supply-side reliance.

MB-7. Real option value – Creates "physical options," i.e., system operators will have more options to address system events in the future, e.g., lower demand growth allows for more time to assess new infrastructure options and adapt to new or changing circumstances, making gradual changes more economic.

[14] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review*, December 2001, p. 88.

[15] American Gas Association, "Balancing America's Energy Needs," *American Gas*, October 2001.

MB-8. Customer risk management benefits – Customers are now provided with an opportunity to manage part of the electricity price and commodity risks according to their preferences.

MB-9. Efficient markets – Better pricing and the interaction of demand and supply can produce overall productivity gains by better utilizing the fixed investment that comprises one of the largest capital investments made by a country – even a 1% productivity improvement per year would be substantial.

MB-10. Environmental benefits – The efficient use of resources in general can promote reduced land, water, and air impacts, although this will vary by DRR product (e.g., distributed generation may increase certain air emissions for short periods). A full environmental analysis would require an assessment of system operations with and without the DRR portfolio.

MB-11. Customer services – Through increased comfort, customer choice, and rewards for energy management.

MB-12. Technology – Efficient markets that now provide incentives to manage what is scarce (i.e., peak energy use) also will promote the development of efficient controls and end-use technologies that enable load shifting.

These twelve market-wide benefits may be difficult to isolate and estimate individually without double counting. As a result, these twelve categories are organized into three groups. The first two groups are those that are viewed as candidates for being addressed in a benefit-cost framework, while the third group is likely to be addressed outside the framework, possibly through "side calculations" or sensitivity analyses. The three groupings of benefits that establish the focus for the benefit-cost framework are:

1. **Market-wide price benefits:**
   - Reduction in the average price of electricity in the spot market.
   - Reduced costs of electricity in bilateral transactions (over a 5 to 10 year period).
   - Reduced hedging costs, e.g., reduced cost of financial options.
2. **Market-wide reliability benefits:**
   - Increase in overall reliability.
   - Insurance value – lowered costs of extreme events, i.e., low-probability/high-consequence events.
   - Real option values – added flexibility to address future events.
   - Portfolio benefits – increase in resource diversity.
3. **Other values (may be addressed by "side" calculations):**
   - Reduced market power (situational and behavioral).
   - Overall market efficiency – better interaction of demand and supply provides appropriate incentives for the development and application of new technology, thereby increasing overall productivity, e.g., 1% per year.
   - Customer values:
     - Increase in customer choice.

- Equity for those customers whose electricity use is flexible (an important attribute of demand is now valued).
- Possible increase in services.

– Environmental benefits – can result from more efficient resource use.

The first two groups of benefits, 1) market-wide price benefits and 2) market-wide reliability benefits, are the focus of the benefit-cost framework. The third group might also be very important as market power issues are of real concern. Increasing the efficiency of the operation of one of the most capital-intensive industries in a country can provide sizeable benefits even if the increases are small. Customer values that stem from increased choice as well as any environmental values should also not be ignored. However, the calculation of these benefits would seem to require a study separate from what is generally considered a benefit-cost framework focused on electric system operations.

Private Entity Benefits

The market-wide benefits discussed above are benefits that might occur if even one distribution company in the region decided to develop a DRR portfolio and limit participation to only its own customers. Even though the DRR portfolio is limited to the service territory of the distribution company, the benefits listed above are those that would accrue to the market in general and reach beyond that distribution company's service territory. However, there are a number of benefits that can be identified that would only accrue to specific private entities. In fact, this bifurcation of benefits among different parties is viewed as a substantial practical hurdle to developing value propositions for the implementation of appropriate levels of DRR. Due to the restructuring of the electricity industry in many countries and US states, the costs of a DRR effort may be borne by one party, but the benefits may accrue to others. In some areas there are now separate distribution companies, transmission owner/operators, and generation owner/operators. These entities are often owned by different corporations or public services companies. The assets have been divested or functionally separated through the creation of independent operating entities.

DRR programs have the potential to provide benefits for all three entities – distribution, transmission, and generation. However, due to this bifurcation of interest, no single entity has a great incentive to invest in levels of DRR that might prove to be efficient for the whole electricity market. This alignment of incentives to invest in appropriate levels of DRR is an important policy consideration for all restructured markets.

Six categories of private entity benefits are delineated below. Each private entity could be the subject of its own benefit-cost test and, in fact, no single private entity can be expected to develop a DRR portfolio and incur the costs of the DRR portfolio if the costs outweigh the benefits. There has been very limited work done on these private entity benefit-cost tests.[16]

[16] One of the few studies to attempt to compare benefits across different entities within a regional energy market is "*Assessment of Demand Response Options – NSTAR and Market-Wide Perspectives*" prepared for NSTAR Demand Response Steering Committee, by D. Violette and B. Barkett, Summit Blue Consulting, Boulder, CO, December 2003. This study concluded that NSTAR as a distribution company could quickly launch a portfolio of DRR products accounting for over 200 MW of responsive load in its service territory. The market-wide benefit-cost ratio for all of ISO-NE was estimated at approximately 3.5, but from NSTAR's perspective as a distribution company the benefit-ratio was only 0.3 – well below one. Given this situation, it would not make since for NSTAR to launch this DRR portfolio unless it received cost-recovery from regulators or it was made whole by payments from all participants in the ISO-NE market that also benefited from NSTAR's DRR portfolio.

The six private entities that might receive benefits from a portfolio of DRR products are:

PE-1. Specialty DRR providers (in the United States, they are called "load aggregators" or "curtailment service providers"):

- Benefits would be payments for providing DRR, either from load serving entities or the ISO. They would also be incurring the costs of aggregating customers into their DRR portfolio.

PE-2. Distribution Companies:

- Lowered distribution system operating and maintenance costs.
- Lowered capital costs for distribution.
- Payments from others (likely the ISO) for implementing DRR.

PE-3. Transmission Companies:

- Lowered transmission and distribution operating and maintenance costs.
- Deferred capital costs.

  Note: Transmission companies are not expected to be DRR implementers so there are no payments made to the transmission companies. They simply benefit from DRR efforts by others.

PE-4. Commodity Providers (i.e., the load serving entities (LSEs) that provide electricity to retail customers):

- Lowered costs of purchasing wholesale electricity – but, if the market is fully competitive, there may be no impact on their margins. As a result, it may be questionable whether they really benefit.[17]

PE-5. Reliability Entities (e.g., ISOs or power pools):

- They are non-profit so any cost reductions they may attain by achieving given reliability levels at a lower cost would be passed through to the members. As a result, should they be viewed as only facilitators of DRR?

PE-6. End-Use Customers:

- Customers throughout the market are likely to benefit from lower retail prices for electricity.
- They will have increased reliability (although those customers in congestion areas where DRR may be located might achieve greater benefits, i.e., the reliability benefits may not be evenly spread across customers).
- Customers who participate in a DRR product offer will likely receive payments for participating. If they are on a DRR pricing product such as RTP or TOU with CPP they

[17] It could be expected that the more sophisticated LSEs would be able to better negotiate prices and better manage price and quantity risks if they deal with entities that offer DRR as a hedge against both price and quantity risks.

may receive bill savings and more control over their bills as well as more choices for managing their energy use.

Given that each of these private entities receive benefits from a DRR portfolio being provided in their market area, a benefit-cost test can be developed for each of these entities. However, many of these benefits have been hard to quantify. Estimating the avoided O&M and capital costs for distribution and transmission systems, while maintaining equivalent reliability, has been difficult. Although some attempts have been made to do this, this is an area where additional work is needed.[18] [19]

2.3.2 Costs of DRR Portfolios

Estimating the direct costs of DRR programs is a bit more straightforward. But there are still some issues related to whether reduced margins to generators should be counted as a cost such that consumer gains via lower prices are partially offset by lost revenues to generators. This issue will be dealt with in Section 3 where benefit-cost frameworks are presented and the issue of consumer/producer surplus is addressed.

In general, there are direct costs that are incurred by any entity. These costs include:

1. Costs of DRR program set-up (one-time expenditures):
   - Product design and testing costs. This may include pilot testing if necessary, or at least limited field testing.
   - Marketing costs. It is necessary to market any new product or service and DRR is no exception. Customers will not sign up if they don't know about the program, understand the program, and believe it is the right choice for them. Often, the marketing effort points out weaknesses in the customer value proposition and the DRR product design is changed to better meet the needs of customers that are the market for the DRR product.

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[18] Industry contacts and reviews of the literature have shown that ComEd in Chicago has made an attempt to estimate the avoided distribution system costs from locating DRR at key locations. The general result, as communicated, via a phone interview, was that DRR made sense when it was located at or near a substation that was nearing capacity, but demand at that substation was growing slowly. This allowed an investment in DRR to defer capital costs for a period of time that could make the investment cost-effective; however, there were few substations that met these conditions. It is the view of the authors that DRR could provide more flexibility in distribution system O&M and capital expenditures than is currently being credited to DRR. The capital budgeting and annual O&M budgeting process is based on precedent and may not allow for the full value of DRR to be captured as a vehicle for mitigating unforeseen events and providing more options to address substations issues. This value of increased "real options" and flexibility may not be fully captured.

[19] Other studies that have addressed avoided costs associated with transmission and distribution include studies performed by the ISO-NE examining the Southwest Connecticut congestion area, as well as the ISO-NE Regional Transmission Expansion Plan (RTEP02) available on at www.ISO-NE.com. Another good assessment of the potential role of DRR in reducing transmission system constraints and congestion can be found in Tuan, L. A., *"Interruptible Load Services in Deregulated Power Markets,"* Thesis, Department of Electric Power Engineering, Chalmers University of Technology, Goteborg, Sweden, April 2002. This thesis evaluates a Cigre-32Bus system which approximates the Swedish network and used load flow simulations to examine the system with and without distributed generation located at specific buses. A non-linear optimization model was used to determine how many buses would have a benefit-cost ratio greater than one given the anticipated costs that would be incurred if the "fast-start" generator were not located at that bus. The addition of DRR at specific buses produced benefit-cost ratios greater than one for a number of the buses. Timely load reduction capabilities at the same buses would provide the same result and is discussed in the thesis.

- Equipment costs. These costs can include computer hardware to manage the DRR product, signaling, and measurement. It also includes equipment that might be needed such as switches for direct load control programs or advanced programmable thermostats. Installation costs must be factored in where appropriate.
- Software costs. Most DRR programs have some software needs associated with them to allow signals to be sent that target different DRR customers. For example, you may alternate interrupting two groups of customers on some days, with major event days calling for the interruption of all participants. The software performs a variety of functions, including tracking to whom signals were sent, the curtailment, cycling or temperature setback strategy (which can vary between groups of customers), collection of data on equipment runtime, and customer overrides (if available).
- Initial Year O&M. The initial year O&M may be higher for some DRR product roll-outs, even accounting for the start-up marketing costs.

2. Ongoing annual operating costs:
   - Payments to participants. Most DRR product designs call for payments to be made to customers during every year in which they participate. Payment can vary dramatically based on the product design, but it might be a flat monthly payment for the peak months (summer or winter), or it might be based on the number of events and their duration.
   - Overhead and management. A DRR product/program does not run itself after start-up. Provisions need to be made to continue to manage and operate the program, including processing customers who drop out and customers who want to join. Also, taking calls and questions from customers, testing field equipment (e.g., making sure switches in the field are still working using a sampling approach), and operating the event notification and event strategy software (this includes establishing who is called to participate, for what length of time, and under what strategy in terms of the amount of load called, cycling, and thermostat setback).
   - Any annual license or other fees. Some vendors may have annual license and software fees.
   - Other participant costs. This refers to costs the participant bears from having to reduce electricity use or shift it to another period. This could include extra labor costs, the value of lost products, and lost productivity during the event. Generally, these costs are lumped under the umbrella of "customer opportunity costs of electricity use" but there may be other direct costs in starting up a DG unit, or having personnel go through the facility and turn off or turn down equipment. One assumption that can be made is that the up-front and ongoing payments to customers for participating in DRR fully account for the value of foregone electricity consumption and any costs incurred by the customer related to the DRR event or call for curtailment.[20]

[20] The initial costs paid to DRR participants and the ongoing costs would seem to cover any costs associated with the foregone use of electricity during an event, at least on an expected value basis. If this were not true, then the assessment the customer makes regarding their participation in DRR would show that the costs outweigh the benefits and they would not participate. However, analysts are pointing to the complexity of the decision process customers go through in deciding whether to participate in DRR. Reasons given in surveys often indicate that reasons for participation including "doing good," "helping reduce regional energy costs," and other social reasons.

Many utilities run direct load control programs and large customer interruptible programs, as well as other DRR programs. Regulated utilities are required to file their costs of program operation with the appropriate regulatory agency (in the United States, this is usually the State Public Utilities Commission) and this is one source of information on the costs of DRR programs. Reviews of DRR filings have helped determine the costs used for a benefit-cost assessment of the portfolio of DRR products (based on a resource planning construct) presented in Section 3.

An interesting development on the cost side is a view expressed by some industry experts[21] that programs should be targeted towards those customers who have lower "opportunity costs of foregone electricity use" due to a DRR event. Many interruptible customers are large commercial and industrial (C&I) facilities and they may have high opportunity costs and even higher direct costs resulting from a DRR event (e.g., a call for load reduction). An argument has been made that residential customers likely have lower opportunity costs associated with foregone electricity use and that this may make that sector more important for DRR initiatives, from the perspective of value lost due to load reductions.

One study, which supports the contention that the opportunity costs of load reductions are higher for commercial and industrial customers, examined outage costs across sectors. However, a system event that causes an interruption in service without any notice may not be an appropriate comparison point for customer costs associated with DRR programs:

- A customer participating in a DRR product may choose to isolate specific equipment to be used when a load reduction is called that is viewed as nonessential.
- A DRR product offer can encourage and help pay for the installation of backup generation. Large C&I customers are more likely to be able to afford backup generation, thereby reducing the costs of a call for load curtailment (but the costs of the backup generation have to be considered).
- Given some advance notice (2 to 4 hours), C&I customers may be able to plan for the curtailment and reduce the opportunity costs of the foregone electricity use.

Still, for some DRR products, outage costs may serve as a reasonable indicator of the opportunity costs of foregone electricity consumption. At a minimum, outage costs are important for the benefit side of DRR since one set of benefits of DRR is the costs associated with system outages that occur without notice.

Taking into account that foregone electricity consumption due to a DRR event does not directly correspond to a system outage, some recent work on the costs of outages provides insights into both the potential costs and benefits of DRR products. One recent analysis[22] shows that:

- The majority of outage costs are borne by the commercial and industrial sectors;

Improving grid reliability is important to all customers. To the extent that these reasons are important, a pure monetary benefit-cost view of a customer's decision to participate in DRR may not be fully accurate.

[21] These comments came from David Hungerford at the California Energy Commission in informal comments to a project presentation on DRR product design. Others in the presentation discussion expressed some interest in this concept of targeting DRR toward customers that have lower opportunity costs of foregone electricity use. However, estimating a customer's actual opportunity costs of foregone electricity use can be difficult and little information based on research is currently available. However, as with many policy decisions, there is an argument for following what appears to be common sense reasoning in the absence of actual empirical results.

[22] "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers" by Kristina LaCommare and Joseph Eto Environmental Energy, Lawrence Berkley Laboratories (LBL), September 2004, at http://eetd.lbl.gov/ea/EMP/EMP- pubs.html.

- As a result, although there are important variations in the composition of customers within each region, the total cost of reliability events by region tend to correlate roughly with the numbers of commercial and industrial customers in each region; and
- Costs tend to be driven by the frequency rather than the duration of reliability events. This research on outage costs found that (more frequent) momentary power interruptions have a stronger impact on the total cost of interruptions than (less frequent) sustained interruptions, which last 5 minutes or more.

The cost side of DRR is probably more easily estimated, although there remain some important issues in estimating customer participation costs, i.e., the incremental costs borne by the customer to both participate in DRR and the opportunity costs to the customer from foregone electricity use resulting from a called event, i.e., a called-for load reduction within the DRR contract terms.

While probably obvious, the cost of each DRR product option is quite specific to the terms of that option. There are many DRR product variants that can be offered and each region will be challenged to develop a DRR product that is low cost and meets its system objectives. That is why a quite specific portfolio of DRR products was specified and costed for the case study in Section 4.