IEA DRR Task XIII

DRR VALUATION AND MARKET ANALYSIS

VOLUME I: OVERVIEW

Prepared for:

INTERNATIONAL ENERGY AGENCY
DEMAND-SIDE PROGRAMME
TASK XIII: DEMAND RESPONSE RESOURCES
TASK STATUS REPORT

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Dear Mr. Malme:

This is the companion document, *Volume I: Overview*, that accompanies the more detailed report, *DRR Valuation and Market Analysis – Volume II: Assessing the DRR Benefits and Costs.* This work represents a continuation of the ongoing research and debate regarding the role of demand response resources (DRR) in electricity markets, resource adequacy, and portfolios of resources. This Volume I draws out key elements of Volume II in a shorter, less technical paper.

We sent a draft of these two volumes at the end of September and received a number of comments from participating countries. We have worked to incorporate these comments into these two volumes. This effort is meant to illustrate the different approaches for valuating DRR, and it includes an examination of how DRR might be incorporated into a forward planning process such that DRR products can be appropriately offered and deployed to achieve market-wide objectives in electric markets.

Sincerely,

Dan Violette

VOLUME I – OVERVIEW: ASSESSING BENEFITS AND COSTS OF DRR

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E. EXECUTIVE SUMMARY

This report presents the results of an assessment of different approaches for determining the value of Demand Response Resources (DRR). It also includes a case study modeling effort which addresses a resource planning approach for valuing DRR. These efforts examine Subtask 4 (Demand Response Resource Valuation) of the IEA Task XIII Demand Response Resources (DRR) study. Specifically, different approaches for assessing DRR are presented, including basic benchmark approaches, applications of standard practice benefit-cost tests, and an approach for valuing DRR using a resource planning context. This last approach is described and compared with the other methods used to provide estimates of the value of DRR.

E.1 Benefits and Costs of DRR

An efficiently operating electricity market depends upon the appropriate interaction of supply and demand. Barriers to demand response are inherent in electric markets that have a history of regulated retail pricing, and which have been restructured – this has bifurcated the benefits of demand response. This bifurcation of benefits is an important issue. Demand response has the potential to provide benefits to commodity providers, reliability organizations, transmission companies, distribution companies, and electric end-users. However, it is difficult for a provider of DRR products and services to aggregate the market-wide benefits such that an efficient amount of DRR will be provided into the market.

The market-wide benefits of demand response include:

- Lower electricity prices;
- Reduced price volatility;
- Increased efficiency in one of the most capital intensive industries;
- Risk management, i.e., a physical hedge against extreme system events that are difficult to incorporate in planning and valuation frameworks;
- Increased customer choice and customer risk management opportunities;
- Possible environmental benefits; and
- Market power mitigation.

In addition to these market-wide benefits, there are a number of private entity benefits that include reduced capital, operation, and maintenance expenses for transmission and distribution systems. These benefits accrue to the owners of these systems. There is also the potential for benefits to accrue to aggregators of demand response resources for sales to commodity providers or reliability organizations.

DRR benefits do not come without associated costs. As with any product or service, DRR requires marketing, start-up capital, and ongoing operational costs in terms of both servicing the product and paying participants for their demand responsiveness. This latter cost is important in that a vital component of customer value is now realized, i.e., those customers that can vary their demand for electricity from peak periods to off-peak periods are now provided with a financial incentive to take these actions.

Simply stated, the electricity industry can only be viewed as efficient if it appropriately prices what is scarce, i.e., on-peak electricity use.

E.2 Approaches for Assessing and Valuing DRR Products

A number of approaches have been used to evaluate the benefits of developing products and programs that would allow for the demand for electricity to be more responsive to price or to events that reflect system reliability issues. The most common have used extensions of the standard practice tests that have been utilized to evaluate energy efficiency programs. These tests typically include the Total Resource Cost (TRC) test, the Participant Test, and the Ratepayer Impact Measure (RIM) test. Other approaches have examined the influence increased demand responsiveness can have on the reliability of a system, and have tried to develop measures of the change in reliability due to the availability of DRR, and then estimate values for that change.

To date, most frameworks for assessing DRR have been retrospective in nature, i.e., they value load management events that have occurred in the past and do not take a forward-looking view of the role DRR can play in a longer-term resource portfolio. This report presents a number of DRR assessments from different points of view – the application of standard practice tests to DRR and the estimation of the impact of DRR on system reliability – that are generally based on past cases where DRR has been utilized. Few approaches have taken a comprehensive view of DRR that can account for the major benefits this unique resource can provide and answer the basic question inherent in determining the appropriate role of DRR in long term planning.

E.3 Case Study – Valuing DRR Using a Resource Planning Framework

A case study modeling effort was developed for valuing DRR using a resource planning context. This approach was also compared with other methods commonly used to provide estimates of the value of DRR. Changes in system costs with and without DRR included in a portfolio of resources were examined. The difference in system costs over a 19-year time horizon provides an estimate of the value of DRR for the electric system. The specific model used for this effort was New Energy Associates' Strategist® Strategic Planning Model.

The base case for the model was developed to realistically represent an electricity market that allows for appropriate trade-offs between resources – both supply-side and DRR – and is able to address issues such as off-system sales/purchases and system constraints (e.g., transmission constraints). The base case system was developed using data compiled by New Energy Associates, based on publicly available information for a selected region in the National Electric Reliability Councils (NERC), i.e., the Mid-Atlantic Area Council (MAAC) region. The initial data came from the Platts-McGraw Hill Base Case database for the region with some adjustments to the data based on New Energy Associates and Summit Blue's experience.

One hundred cases were created as data inputs to the Strategist model. They were calculated to represent a variety of possible futures. Monte Carlo methods were used to create the different future cases that represent the uncertainty in key future inputs. The key input variables around which uncertainty was dimensioned were: fuel prices (natural gas, residual oil, distillate oil, and coal); peak demand; energy demand; unit outages; and tie line capacities.

Four DRR products were included in the model as potential resources to meet future system needs, in combination with the full range of supply-side options generally modeled in resource plans. The products were: Large Industrial Interruptible, Mass-Market Direct Load Control, Dispatchable Purchase Transaction, and Real-Time Pricing. Real-time pricing was added to the model not as a callable program, but as a reduction in peak demand and/or a reduction in energy demand, depending on the size of the program.

Four sets of model runs were developed addressing the following DRR and pricing options: 1) a base case resource option; 2) a resource option with three new DRR callable programs; 3) an option with the three callable DRR programs and a peak-period pricing program; and 4) a resource option with the three callable DRR programs and a full Real-Time Pricing (RTP) product.

E.3.1 Case Study Results

Results from these analyses include the following:

- In the base case, the overall uncertainty in total system costs for each year (100 cases per year) is quite large across these cases – indicating that the uncertainty in the modest number of variables selected does result in a wide range of net system costs for each year in the 20 year planning horizon. On average, the range was 100%, i.e., the highest cost in the range was roughly double the lowest cost for almost every year in the planning horizon.
- On a peak demand day with additional system stresses, such as 10% of generating capacity being offline, savings in marginal production costs are substantial. The addition of DRR to the system greatly reduced the "peakiness" of the hourly prices, reducing the maximum price by more than 50%. For example, in one peak day in July the total cost savings were $24.5 million.
- A substantial percentage of new capacity charges were deferred by the model because of the DRR availability. This amounted to savings of $892 million (2004 dollars) over the 20-year period.
- DRR provided significant benefits in those years in which it was used. While DRR provides considerable amounts of benefits on select days, there is a cost to building and maintaining the DRR capacity which is paid for in every year and in every case, even if DRR is not used. This results in there being some cases where there are costs but no savings from DRR. Looking at the 100 cases individually, in the scenario with DRR but no RTP, 36% of the 100 cases showed savings in total system net present value (NPV) compared with the base case, and with the full RTP scenario 97% of the cases showed savings.
- Large amounts of DRR were used about once in every four years. Across all resource scenarios, small amounts of DRR were used in most of the years in the planning horizon, with near capacity use of DRR happening infrequently. The amount of DRR that was called upon did not vary much across the three scenarios, e.g., the "with full RTP" resource option only resulted in a 10% reduction in DRR hours called across the 20-year planning horizon. As a result, the callable DRR retained their value as a hedge against extreme events even with pricing options that resulted in better utilization of system resources across all hours.
- There was a change in the risk profile associated with the planning scenarios with the addition of DRR. There were significant savings when looking at value at risk (VAR) at the 90th percentile (VAR90) and at the 95th percentile (VAR95). Results for the three scenarios are shown below.

Risk Metrics – Reduction in System Costs at Risk ($M)		
	VAR 90	VAR 95
Callable DRR	238	213
Callable DRR with Critical Peak Pricing	924	966
Callable DRR with Real Time Pricing	2,673	2,766

- The addition of DRR decreased the loss of load (LOL) hours substantially across all cases. The base case had an average value for loss of load hours of 7.64 hours across the cases, but values for some individual cases were as high as 30 hours. For the DRR with Peak Pricing, the average loss of load hours averaged across all cases was lowered to 0.33 hours. The magnitude of the savings due to enhanced reliability across all the years in the planning horizon could be quite high, but no estimate has been calculated at this time and this estimate may vary by the number of customers impacted and the characteristics of different systems.

In conclusion, this case study shows that a Monte Carlo approach, coupled with a resource planning model, can address the value of DRR given uncertainties in future outcomes for key variables, and can also assess the impact DRR has on reducing the costs associated with low-probability, high-consequence events. In this case study, the addition of DRR to the resource plan reduced the costs associated with extreme events and the likelihood of those events, and it reduced the net present value of total system costs over the planning horizon.

E.4 Summary and Conclusions

Four basic approaches were examined in this work effort:

Approach 1: Benchmark methods – Assessment of the impacts of DRR on a given day based on an actual event.

Approach 2: Application of the standard practice benefit-cost tests with a focus on the Total Resource Cost (TRC) test.

Approach 3: Assessments based on the increased reliability resulting from DRR, generally taken from historical data.

Approach 4: A portfolio approach based on explicit dimensioning of uncertainty; an assessment of the impact of DRR on the risks associated with high-cost, but low-probability events; and the overall impact of DRR on system costs.

Each approach produces valuable information as each represents a way of organizing data and information to address the value of DRR in a specific context. The first three approaches have been generally applied in a static framework and examined specific DRR products singularly rather than in a portfolio context. It is useful to know, for example, what the price reduction might have been if X amount of DRR had been available on a given day when electric price spikes occurred; or if DRR products are in place, how they impacted price and reliability on a given high demand day. However, these studies do not address important forward-looking questions regarding the potential role of DRR among a portfolio of resources.

E.4.1 Including DRR in a Portfolio of Resources

Questions that may arise when considering DRR as a resource in a portfolio of resources include the following:

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 almost any system given 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 in the future. 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, eliminating a DRR product, only to find that there is a need for the product later on, could cost more than simply placing the program in a maintenance mode. 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. 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, and 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.

E.4.2 Recommendations for Approaches to Valuing DRR

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

This implies that a planning process that directly addresses difficult issues such as uncertainty, a time horizon that is long enough to include 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.

E.4.3 Lessons Learned from the Resource Planning Case Study

The modeling effort done for this study was an attempt to use a Monte Carlo approach in combination with the Strategist model framework in order to value DRR as part of a resource plan. This work demonstrates the key steps that need to be carried out in order to perform this type of analysis, and also presents the types of results that can be produced. Some lessons were learned during the process, including:

- Improvements can be made to the model specification, including the specification of DRR products and pricing products. Feedback loops can be incorporated in the model to take into account the ability of DRR to ramp up or go into a maintenance mode as needed, and this would avoid the “over building” of DRR capabilities which was shown to occur in this effort. This would have reduced the costs of the DRR without affecting their system benefits.
- The incorporation of DRR into the resource plan produces substantial increases in reliability as measured in loss of load probabilities (LOLP). No value was accorded to DRR for this increased reliability. Methods for developing estimates of the dollar value of this increase in reliability are important in that these benefits might be large – possibly as large as the decrease in net system costs found in this case study.
- Within the model, DRR was allowed to compete only with combustion turbines in providing capacity. The addition of DRR capacity resulted in the full deferral of all new combustion turbine capacity over the study horizon. A close examination of the model results showed that as a result some older generation units with high energy costs remained on-line in the latter years of the planning horizon. This increased the costs of providing energy that in some cases was not fully offset by DRR since the number of hours that DRR can be used is limited. A “re-optimization” task, which would look at whether some fossil units might be economic by considering both capacity and energy, might lower the average system energy costs in the “with DRR” scenario, leading to greater savings.
- The system being modeled is very large, with several hundred generation units, and therefore not as vulnerable as a smaller system to stress. It is not clear if the “stress” scenarios which were inserted into the model were really as extreme as could be the case for this system. For example, none of the stress cases (i.e., the cases in which there were significant unit outages) included a simultaneous reduction in tie line capacity and import capability from other regions. It is also possible that some might think the stress cases were too extreme. Either way, further work would improve upon the development of realistic stress cases.
- Care should be taken when discussing “price” and “marginal costs” as they are not interchangeable terms. The model that was used estimated engineering-based marginal costs and not electricity prices. In fact, open market prices may not be strictly related to marginal costs. To estimate prices more accurately, an overlay model may be needed which relates marginal costs to market prices.
- The electricity system used in this case study was a very large one, and so the savings due to DRR, as a fraction of total system costs, appear to be very small. This is due to an enormous amount of money already having been invested in the system over the preceding 30 to 50 years. However, the savings due to DRR are a much higher fraction of incremental system costs, or the "total cost to serve new load.” Looking at savings in total system costs, when billions of dollars have already been invested, is not as relevant as looking at the cost of serving incremental loads and reducing costs on the margin.

1. INTRODUCTION

The objective of this effort is to focus on three work areas related to assessing appropriate levels of investments in demand response resources (DRR). These work areas are:

1. Consider benefit-cost frameworks that appropriately assess the economic case for DRR as part of a resource plan. These frameworks would be used to evaluate the cost-effectiveness of DRR, if installed DRR is cost-effective or not, and if additional DRR would be cost-effective or not. The objective is to establish a level playing field in the assessment of DRR against other resources when making planning decisions.

2. Identify approaches for determining the value of DRR in a resource portfolio. This would be only one part of a full benefit-cost test, i.e., the value of DRR. This then must be compared to the appropriate cost factors. The issues around the valuation of DRR within a resource portfolio are believed to be substantive enough to warrant a separate focus.

3. Discuss approaches for evaluating and verifying the benefits and costs of DRR once placed into the field. The purpose is to determine if DRR capacity, once attained through the offering of DRR products and/or programs, continues to have value exceeding costs.

1.1 Volume I Objective – Insights into Application

The objective of this Volume I is to focus on the lessons learned from the more detailed Volume II review of methods and case study application. Approaches for assessing DRR addressed in this work effort include:

- Benchmark approaches that examine DRR in the context of short-term or single events, e.g., the California energy crisis. The information from these benchmark events are used as a guide to what DRR might be able to accomplish in the future.
- The application of Standard Practice Tests traditionally used to evaluate energy efficiency programs, but adapted to address DRR products/programs. These tend to be evaluations of utility or distribution company DRR programs.
- Assessment of DRR in the context of improved reliability. These studies tend to focus on DRR programs offered by reliability organizations, e.g., independent system operators (ISOs). Some of these studies used as examples also include a more comprehensive look at DRR benefits and costs, but an assessment of reliability is one of the focal points of these applications.
- A case study application using a resource planning framework that explicitly dimensions and examines uncertainty to allow for an assessment of the "insurance" benefits of DRR as a hedge against low-probability, high-consequence events. This framework also examines the portfolio benefits of DRR, as the model allows for an explicit economic tradeoff between different types of DRR products and supply-side resources.

1.2 Application in Different Markets and for Different Market Actors

This report may be used to gain insight into valuing DRR in many different counties and electricity markets around the world. Although many of the test cases and methodologies shown in this report have originated in the USA, the approaches are general and can be adapted to suit specific markets. Most countries have their own equivalent tests to the California Standard Practice Manual[1] tests – which include the Total Resource Cost (TRC) and Ratepayer Impact Measure (RIM) tests – and these country-specific tests can be substituted for the California Standard Practice Manual tests where appropriate.[2] In fact, the California Standard Practice Manual tests are really international in their scope and development, and they have been adopted widely, across many countries. The "California" designation is used to simply indicate the specific document that was used as a basis for this set of approaches.

A test case for a resource planning approach to valuing DRR was performed for the Nordic market, and a summary of that modeling effort is included in this report. It may be interesting for the reader to compare the Nordic model with the US one, and note the differences between them. These differences are apparent in both the methodology and the results, and they are partly due to the different mix of resources in the two markets (the Nordic model has a large hydro and wind component). A comparison of these two models can be useful for anyone designing a DRR valuation study in their own market, as it may contain aspects of both the US and Nordic markets.

The case study outlined in this report was done from the perspective of a regional planning organization. For markets that have not restructured, the vertical utilities have the responsibility for procuring electricity to meet the needs of their customers, and this case study approach is directly applicable to planning efforts for such utilities as well as regional planning entities.[3] However, this case study modeling effort is equally applicable to liberalized markets. Other market actors who could make use of the methodology given in this study are:

- Reliability organizations in Europe such as UCTE (continental Europe), JESS (UK), and Nordel (Nordic countries) which may have overall responsibility for ensuring that future demands for electricity can be met by the market. While some indicate that long term supply planning is not a mandate for reliability organizations, there is a need to assess 10-year to 20-year resource plans for the electricity markets, even in competitive markets, to ensure that appropriate structures and prices are in place to incent appropriate long-term planning by market participants.
- Commodity providers as they will want to meet their customer demands with the least cost resource plan. This might include procuring supplies from supply-side resources as well as integrating DRR to address short-term peaks and to manage both price and quantity risks.
- Government departments and regulating authorities, to assess the system benefits of DRR and evaluate the need for support – e.g., R&D funds, pilot studies, and removing barriers to DRR.

[1] *California Standard Practice Manual – Economic Analysis Of Demand-Side Programs And Projects,* California Public Utilities Commission, October 2001.

[2] For example, a set of benefit-cost tests are shown in "Guidebook for B/C Evaluation of DSM and Energy Efficiency Service Programs" prepared for the EU Commission in 1996, provided by Mr. Casper Kofod, of Energy Piano (epiano@image.dk). In addition, the four California Standard Practice tests were used as the basis for assessing the investments in distribution resources in Australia -- "*Assessment of Demand Management and Metering Strategy Options,"* produced for the Essential Services Commission of South Australia by Charles River Associates, August 2004. This shows that these approaches to benefit-cost analyses of demand response programs are truly international, and can essentially be judged as one approach

[3] In the Northwestern States (Oregon, Washington, and Idaho) of the United States, the individual utilities conduct resource planning incorporating both supply-side and demand-side resources, but the Northwest Planning and Conservation Council also prepares regional plans that are presented to regulators in each State.

- 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.

be appropriately valued using new approaches.

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.

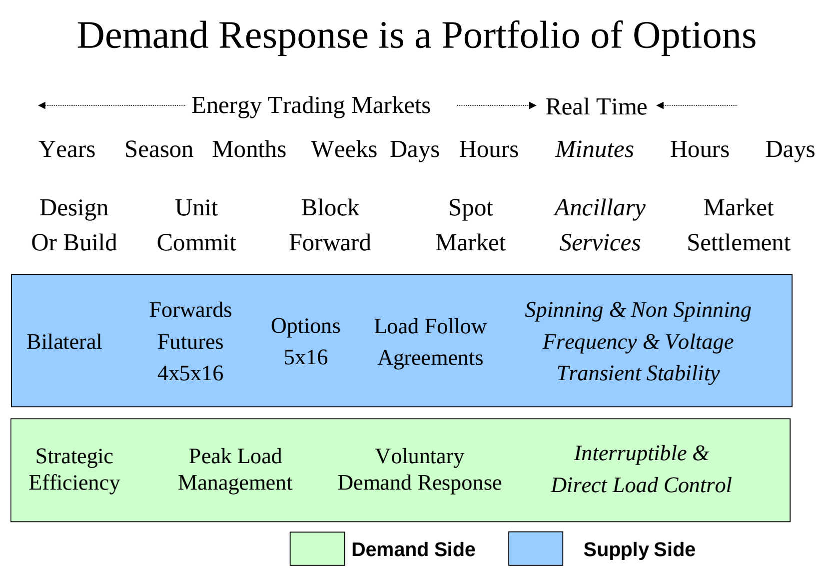
This implies that a planning process that directly addresses difficult issues such as uncertainty, a time horizon that encompasses low-probability/high-consequence events, and the electricity market encompassing demand response as well as supply-side technologies is needed to assess impacts on overall 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.

3. DRR BENEFIT-COST FRAMEWORKS

The literature on how to assess the benefits and costs of DRR within a consistent framework is quite dispersed and varied. In general, it is fair to say that there has been no consensus on how to even approach this problem. In some regions, very rough cut analyses are performed indicating what the impact on market prices would have been had a certain amount of DRR been available on an extreme high price day. Rather than rely on formal benefit-cost tests, some policies have been based on benchmark analyses and what might be termed "views of the electric system" that when taken together seem to imply an obvious conclusion that some DRR is needed.

3.1 Benchmark Assessments of DRR

These benchmark studies take estimates of electricity supply elasticity (how much prices would have dropped in a given market for a given reduction in demand) and estimate the impact of price for a given reduction in demand. As examples:

- An EPRI study examining demand response in California indicated that "… a 2.5% reduction in electricity demand statewide could reduce spot wholesale prices by as much as 24%; and a 10% reduction in demand might slash wholesale prices by half."[23]
- A study of the United States market showed that having about 10% of retail load on a real-time pricing scheme would have mitigated the United States Midwest price spikes of 1998 and 1999 by about 60%.[24]
- A report by the U.S. Government Accountability Office (GAO) indicated that a 5% reduction in peak demand could have reduced California's highest peak prices by as much as 50%.[25]
- The GAO report also states that "reducing the need to build and maintain few peaking plants, the industry will need to build and maintain fewer [plants] overall, which will improve the overall efficiency of the industry."
  - 1,000 MW of peaking plants are estimated to cost about $300 million to build and avoiding their construction can substantially reduce industry investment committed to these little used plants.
  - Power plants in the United States with a total generating capacity of between 84,000 MW and 134,000 MW operated less than 10% of the time. In 2003, these seldom used plants accounted for about 14% to the total installed capacity in the United States.[26]

Similarly, general statements about the need for an efficient market to be based on the interaction of supply and demand abound in the literature, accompanied by a listing of the barriers to demand response that exist in current industry structures.[27]

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

[24] D. Caves, K. Eakin and A. Faruqui, "Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets," The Electricity Journal, April 2000.

[25] United States Government Accountability Office (GAO), *"ELECTRICITY MARKETS -- Consumers Could Benefit from Demand Programs, but Challenges Remain"* Report to the Chairman, Committee on Governmental Affairs, U.S. Senate, August 2004, p. 27.

[26] United States Government Accountability Office (GAO), August 2004. Ibid.

One problem with these general statements is that they are static and focus only on select days with a retrospective view. Solutions need to be assessed in a dynamic environment. For example, it is true that if demand were reduced by 5 to 10 percent on days where prices spiked, there likely would have been a substantial reduction in the magnitude of prices. It is also possible that, if on these days there had been more generation available, prices likely would also have been lower. Going forward, these general statements do not provide a framework against which different resources and system options can be assessed. Such a framework is still needed.

The issue of "not enough demand response" has been recognized across countries in work conducted by the International Energy Agency (IEA) and the Organization of Economic Co-operation and Development (OECD). "Demand response in existing markets is typically low, since market participants lack both the incentive and the means to respond. Regulated retail prices, out-dated metering technologies, a lack of real-time price information reaching consumers, system operators focused on supply side resources, and a historical legacy in which demand response was not considered important – all of these factors combine to produce the low levels of demand response seen in electricity markets today."[28]

In the United States, working groups and regional study efforts developed similar views without developing an estimation framework for estimating DRR value and costs. The New England Demand Response Initiative (NEDRI) was a collaborative effort spanning all the New England states and also included the U.S. Department of Energy and the U.S. Environmental Protection Agency, as well is the ISOs in New England and New York. Thematic statements from this collaborative effort include:

- There is "a growing realization among market participants and policy makers that the efficient integration of demand response resources (DRR) would be central to the long-term success of restructured electricity markets, power portfolios, and delivery systems."
- NEDRI members "agree that such demand responsiveness is an essential component of the wholesale market, and can be compatible with both competitive and franchise retail markets, implying that DRR is essential in both restructured as well as in vertically integrated markets."
- "Without effective demand response opportunities, customers who would be willing to reduce their consumption and balance the system at a lower price are not given a market opportunity to do so … this problem has weakened the functioning of wholesale power markets. Both market participants and regulators have focused a great deal of attention on the need for short-term, price-responsive load curtailments." [29]

The NEDRI effort also concluded that the issue was not confined to just the development of demand-side products to create responsive loads, but that "wholesale market rules that support short-term, price-responsive load curtailments are an essential element of an efficient wholesale market structure." Broadly stated, DRR include all intentional modifications to the electric consumption patterns of end-use customers that are intended to modify the quantity of customer demand on the power system in total or at

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[27] See "*Demand Response: Principles for Regulatory Guidance*," by the Peak Load Management Alliance, February 2002. Available at www.peaklma.com.

[28] "THE POWER TO CHOOSE: Demand Response in Liberalised Electricity Markets," prepared by the International Energy Agency (IEA) and the Organization for Economic Co-operation and Development (OECD), Paris, 2003.

[29] "Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets." Report and Recommendations of the New England Demand Response Initiative (NEDRI), July 23, 2003. Available at: http://nedri.raabassociates.org/Articles/FinalNEDRIREPORTAug%2027.doc.

specific time periods. There are many opportunities for customer-based DRR to add value to power systems and markets, and there are many types of DRR to call upon.[30]

The NEDRI effort was comprehensive in many respects and provides a good overview of the issues, particularly those that bridge the gap and help integrate wholesale and retail electricity markets. Still, the NEDRI effort did not address a planning framework or benefit-cost framework outside of making the recommendation that “the regional power system planning process should evaluate on an even-handed basis all feasible, comparable solutions to emerging problems including generation, transmission, and demand-response resources.” The NEDRI report did develop 35 recommendations spanning DRR products, pricing and metering, energy efficiency, and power systems.

This shows that, at least in some regions of the United States, some policy statements can be made and actions taken without a detailed development and estimation of the benefits and costs of DRR. However, to sustain these into the future, NEDRI and other working groups[31] recognize that a planning process that does appropriately account for DRR along with all other system options will be needed.

A consistent assessment of DRR benefits is a difficult task as many of the benefits are hard to quantify. As a result, market actors commonly examine these benefits, as NEDRI did, and then are able to express a management or political judgment that the benefits of certain actions are likely to exceed their costs. However, making implicit judgments more explicit by using a structured analysis usually provides important insights, even if the structured assessment is only a first-order analysis which quantifies the judgments about benefits and costs and who receives them.

Comments that illustrate statements of belief by different parties regarding the role of DRR in markets include:

- California Energy Commission Order Instituting Rulemaking (June 17, 2003) states that the Commission will consider the acquisition of 2,500 MW of DRR (approx. 5% of peak demand) to moderate price increases and improve system reliability.
- ISO-NE’s *Regional Transmission Expansion Plan* states that DRR can have significant benefits in terms of reliability and savings in congestion costs.
- New England Demand Response Initiative’s *Final Draft Report* states that a small amount of DRR can enhance system reliability and substantially reduce market-clearing prices, producing significant benefits to consumers.
- The *ISO-NE 2002 DR Program Evaluation* states that magnitudes of DRR sufficient to clear the market at lower bid prices will reduce the price of energy for all purchasers in the spot market.
- The NYISO states that it has had a successful DRR program in operation through two summers which has delivered benefits to the grid in terms of reduced market price and improved system reliability.
- U.S. Federal Energy Regulatory Commission’s White Paper on Standard Market Design (SMD) states that:

[30] NEDRI, 2003. Ibid. p. 6.

[31] The large customer DRR working group (i.e., California Energy Commission DR Working Group 2) has recommended that a process for valuing DR be instituted as a next phase of work, and a working group on DRR valuation is being sponsored by the Northwest Planning and Conservation Council (NPCC) with a strawman proposal released on September 16, 2005.

- *"Demand response is essential in competitive markets to assure the efficient interaction of supply and demand."*
- *"Demand response options should be available so that end users can respond to price signals."*

- California Public Utility Commission's R. 02-06-001, Order Instituting Rulemaking, June 6, 2002. states that "Demand Response is a vital resource to enhance electric system reliability, and reduce power purchase cost and individual consumer costs. "
- California Energy Commission's *2002 – 2012 Electricity Outlook Report* estimates that an increased level of DRR could have saved California $2.5 billion in the year 2000.

These quotes all pertain to the market benefits of DRR and do not distinguish which entities should be paying for the programs, and how benefits are distributed among market entities. This is a question that stands directly in the path of delivering DRR, even if there is a consensus that market-wide benefits exceed costs.

3.2 DRR Benefit-Cost Frameworks – Extensions of Standard Practice Tests for Energy Efficiency Programs

The vast majority of benefit-cost analyses of DRR have used an extension of what has become known as the "Standard Practice Manual" (SPM) which was originally developed in California for evaluating energy efficiency programs.[32] Since it was originally adopted in 1983 it has been updated a few times, with the 2001 version being the most recent. Some version of the SPM is in use in most regions in the United States, and it has been adapted to apply in other OECD countries as well.

The October 2001 SPM sets out four groups of tests for evaluating demand-side management programs. Each test group examines the program from a different perspective. The SPM describes those test groups and their perspectives as:

- **Total Resource Cost (TRC) Test:** "This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel...The benefits calculated in the Total Resource Cost Test are the avoided supply costs – the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost – for the periods when there is a load reduction...The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased." (SPM, p. 18)
- **Ratepayer Impact Measure (RIM) Test:** "The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased ...The costs for this test are the program costs incurred by the utility, and/or other entities incurring costs and creating or

[32] *California Standard Practice Manual -- Economic Analysis Of Demand-Side Programs And Projects*, California Public Utilities Commission, October 2001. It can be found at the California Public Utilities Commission (CPUC) website at www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/resource5.doc

administering the program, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased." (SPM, p. 13)

- **Participant Tests:** "The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received... The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s)." (SPM, p. 8)
- **Program Administrator Test:** "The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction…The costs for the Program Administrator Cost Test are the Program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased." (SPM, p. 23)

3.2.1 Application of the SPM to Assess DRR in California

The clearest example of how the SPM has been applied to DRR products is found in the CPUC and CEC Working Group 2 (WG2) proceedings. The California Working Group 2 is comprised of the California Power Authority and the three California IOUs, and it was established by the California Public Utilities Commission. Chapter IV of their third report[33], on Cost-Effectiveness Analysis, illustrates an effort made in response to a CPUC ruling that the WG2 should develop a plan for large customers that includes "a complete benefit-cost analysis."[34] The CPUC offered as an option that the "Standard Practice Manual (for DSM programs) methodology be used as a tool since it allows an assessment of demand reductions from multiple viewpoints: society, customer, utility, and ratepayer." Based on this direction, cost-effectiveness analyses for all DRR programs used the SPM. However, the WG2 also recognized that there were some concerns with using the SPM that should be addressed in future proceedings.[35]

A critical assumption concerns the costs that are avoided by the MW included in the DRR option. The only avoided costs used in this DRR benefit-cost application were those associated with a simple cycle gas turbine – in the high case a new turbine would have to be constructed and in the low avoided cost case, it was assumed that an existing peaker comprised the avoided costs. Avoided T&D costs were not addressed. The avoided cost assumptions for the simple cycle gas turbine used by the WG2 were:

Avoided Cost Case	Fixed Avoided Cost	Heat Rate	Fuel Cost
New Simple Cycle Gas Turbine:	85.00 $/kW-Yr	10,000 BTU/kWh	3.50 $/mmBtu

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33 *R.02-06-001 Third Report of Working Group 2 on Dynamic Tariff and Program Proposals: Addendum Modifying Previous Reports*, January 16, 2003 – California Public Utilities Commission Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.

34 These California working group reports on cost-effectiveness analyses of DRR can be found at www.energy.ca.gov/demandresponse/documents/index.html#group2.

35 As of the time of writing this report, no additional work on benefit-cost frameworks for DRR has been done in California, although some different ways to apply the SPM have been developed (as discussed in the text).

Each DRR offer must project the demand reduction amounts that would be attained. For the proposals outlined above,[36] the demand reductions over the hours in which the demand is reduced for each proposal are shown in Table 3-1.

Table 3-1: Program Demand Reduction Amounts

Entity	Program	Demand Reduction MW	Hrs Reduced	Demand Reduction MWh
California Power Authority (CPA)	Call Option for Interruptible Loads	200.0	100	20,000
Joint Utilities	Critical Peak Pricing	140.0	84	11,760
SCE	Demand Bid Program	30.0	84	2,420
PG&E	Demand Bid Program	14.0	84	1,176
SDG&E	Demand Bid Program	8.0	4	32
SDG&E	Hourly Pricing option O	5.9	213	1,257

The results of the Total Resource Cost test for the Simple Cycle Turbine Avoided Cost Case is shown in Tables 3-2.

Table 3-2: TRC Test Results for the Simple Cycle Turbine Avoided Cost Case

Entity	Program	NPV ($1,000)	Benefits/Costs	$NPV/MWh
CPA	Call Option	$69,594	2.13	.32
Joint Utilities	CPP	$73,320	5.15	.57
SCE	DBP	$18,296	15.25	.66
PG&E	DBP	$7,958	9.12	.62
SDG&E	DBP	$4,981	79.90	14.15
SDG&E	HPO	5.9	213	1,257

These results show that for all of the proposed DRR options were viewed as cost-effective, i.e., they yield a net benefit and have a B/C ratio greater than one.

Limitations of the California WG2 SPM Benefit-Cost Application

The WG2 participants have noted that other items identified in the CPUC rulings have not been captured in this SPM-based analysis. The CPUC indicated that "a complete cost-benefit analysis … should include environmental values, insurance/reliability value, market effects, fuel price stability, and other criteria that are more difficult to quantify." And importantly, to assess the insurance and reliability values in a "complete cost-benefit analysis" requires that uncertainty be dimensioned around key inputs, e.g., demand forecasts, fuel costs which are assumed constant in the SPM analysis, and system events such as plant outages or transmission constraints. Key benefits related to enhanced reliability and the insurance/hedge value of providing options for meeting low-probability/high-consequence events are not addressed in this

[36] There were more DRR proposals than those cited here, but this listing covers most of the different variants considered by the Working Group in California.

form of static analysis with no dimensioning of uncertainty. The WG2 report recognized these issues in the benefit-cost framework used and recommended that alternative frameworks be considered in future work. [37]

3.2.2 Updated Avoided Cost Method Proposed for DRR in California

A study from October 2004 looked at developing avoided costs for DRR based on market prices.[38] This avoided cost study estimates hourly prices by developing a forecast of prices and looking at the highest price hours. DRR products differ from energy efficiency programs that reduce load without a utility's active involvement. The DRR products studied were dispatchable load products, which typically give a utility the right, but not the obligation, to curtail a customer's load under agreed-upon circumstances. The utility's right is defined by program parameters such as advance notice requirement, maximum operation frequency per month or year, and maximum duration per operation.

3.2.3 Application of SPM Benefit-Cost Tests for DRR by Other Entities

A number of interviews were conducted with utilities in the U.S. and a study was obtained from Australia that produced a cost-effectiveness assessment based on the standard practice tests.

<u>Alliant Energy</u>[39]

Alliant Energy (AE) is a medium-sized vertically integrated electric utility headquartered in Cedar Rapids, Iowa. Conceptually, AE conducts benefit-cost analyses for its DRR programs in the same manner as its energy efficiency programs. They use the four California stakeholder perspectives: participants, non-participants/rate impacts, utility revenue requirements, and societal cost tests. AE estimates the avoided costs from DRR programs from avoided peaking generation capacity and energy costs, as well as avoided transmission and distribution costs. The Iowa Utilities Board (IUB) requires utilities to increase avoided costs estimates for electric DSM measures by 10% to account for environmental benefits from DSM programs. However, they do not include reliability or other benefits from DRR programs in their benefit-cost analyses. They also do not attempt to quantify the participants' costs of participating in the programs.

<u>Commonwealth Edison</u>[40]

Commonwealth Edison (ComEd) is a large electric distribution company headquartered in Chicago, Illinois. ComEd does not currently conduct long-term net-present-value based benefit-cost analyses of its DR programs. ComEd conducts short-term DRR program benefit-cost analyses that are focused on deciding whether or not to activate the DRR programs during a peak period. These analyses compare the

[37] The CPUC requested in a July 27, 2005 Ruling that the California investor owned utilities file supplemental testimony that provides cost-effectiveness results for their 2003, 2004, and, to the extent possible, 2005 programs, and their overall demand response (DR) portfolio, using the Standard Practice Manual (SPM) tests as the starting point. These testimonies were filed on August 26, 2005.

[38] See "*Methodology and Forecast of the Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*," Prepared for the California PUC, by Energy and Environmental Economics, Inc. (E3), October 25, 2004.

[39] This information was gathered during a telephone interview with Tom Balster, AE DSM Programs Manager, on August 31, 2005.

[40] This information was gathered during a personal interview with Jim Eber, ComEd Product Portfolio Manager, on October 15, 2004.

day-ahead real-time electricity prices for the PJM power pool to the costs of activating the DRR programs. When the short-term costs that ComEd would avoid by activating one or more of its programs exceed the short-term program costs, including rate discounts and program operating costs, the company activates the programs that are cost beneficial.

Wisconsin Public Service[41]

Wisconsin Public Service (WPS) is a medium-sized vertically integrated electric utility headquartered in Green Bay, Wisconsin. Conceptually, WPS conducts benefit-cost analyses for DRR programs in a similar manner as for energy efficiency programs. WPS estimates the avoided costs from DRR programs solely from avoided peaking generation capacity and energy costs. They do not include avoided transmission and distribution costs, nor reliability or other benefits. They also do not attempt to quantify the participants' costs of participating in DRR programs. They assume that program impacts will last for 20 years at 100% of the initial impacts. WPS has developed a simplified spreadsheet benefit-cost analysis for its DRR program evaluation. The inputs for this spreadsheet were derived from their class-cost-of-service model that they used for their most recent rate case. WPS does not incorporate results from their generation planning modeling into their DRR program benefit-cost analysis.

Essential Services Commission of South Australia

A study commissioned by Essential Services Commission of South Australia includes benefit-cost analysis of five different programs run by ETSA Utilities, the distribution company of South Australia.[42] This study is unique in that it applied the cost-effectiveness analysis to examine whether it was possible to defer augmentation of constrained network elements on ETSA Utilities' distribution system. Constraints on the South Australian distribution system are the result of short-term peak loadings on extremely hot summer weather weekdays. Delaying the need to build or acquire additional supply-side capacity to meet these short-term peaks, through DSM or innovative pricing strategies, will result in reduced capital expenditure for network expansion, and ultimately lower energy prices to the consumer.

The programs examined in the report are:

1. Standby Generation
2. Curtailable Load Control
3. Power Factor Correction
4. Medium Business Voluntary Load Control (VLC)
5. Residential and Small Business Direct Load Control (DLC) of Air Conditioning

The cost-effectiveness of the DRR programs was assessed from three perspectives. This approach, which is based on the Standard Practice Manual (SPM) reflects the fact that benefits and costs accrue to different stakeholders, as follows:

- Participant Benefit-Cost Ratio (BCR) – measures the quantifiable benefits and costs of a demand-side program to a participating customer;

[41] This information was gathered during a telephone interview with Mary Klos, WPS Customer Value and Support Services Analyst, on August 31, 2005.

[42] "*Assessment of Demand Management and Metering Strategy Options,*" produced for the Essential Services Commission of South Australia by Charles River Associates, August 2004.

- Utility BCR – measures the change in total costs to the utility resulting from implementation of a demand-side program; and
- Total Resource Cost (TRC) BCR – measures the change in the average cost of energy services across all customers.

Benefits and costs were estimated over the regulatory period 2005 to 2010 using standard discounted cash flow analysis to estimate the present value of future benefits, costs, and net benefits. These network-driven DRR programs focused on dealing with least-cost solutions to capacity constraints. However, they can also deliver additional benefits to the network service provider, such as being able to bid short-term load reductions in the spot price market in response to high wholesale prices. This resource is particularly attractive to electricity retailers who require physical hedges to offset market price spikes resulting from reduced generation or network capacity.

Program benefits were calculated by looking at the Distribution Network augmentation avoided cost savings, and at the revenue income for the ETSA of selling physical hedges to retailers, at a 50% sharing ratio. Based on network benefits only, not all of the programs had a benefit-cost ratio of higher than 1 for each test.

3.3 DRR Cost-Effectiveness Frameworks Based on Reliability Benefits

A number of ISOs have developed DRR products. Given that the principal goal of an ISO is to maintain system reliability, a number of cost-effectiveness studies of ISO DRR products have focused on the reliability benefits of DRR. These programs provide resources that can be dispatched to maintain reliability at acceptable levels. However, treating controllable loads as supplemental reserves necessitates development of a method for quantifying the value of such reserves. The valuation philosophy adopted by some ISOs in the United States focuses on the marginal value of the additional reliability provided by the curtailment capability.

This marginal value is realized from reductions in the probability of forced outages and in the severity of the outages. The more likely a system is to experience outages, the greater the value of curtailable load will be. The severity of an outage can be measured by its impact on customers. If conditions warrant disconnecting a single feeder, the impact is smaller than if a large portion of the system load must be disconnected. The number of consumers and the collective load affected are also important; the more widespread the outage, the greater the costs to consumers.

Establishing the value of curtailable loads to the system therefore involves determining the following:

1. Expected reduction in the occurrence and duration of outages.
2. Expected load disconnected during outages if they were to be necessitated by system conditions.
3. Impact on customers, in terms of the value of the time without electrical service.

The first two items, taken together, can be used to estimate the reduction in expected "unserved energy" (in MWh per year), defined as:

Expected Unserved Energy (MWh per year) = **(Eq. 1)**
Expected Outages (hours per year) x Expected Disconnected Load (MW)

Expected unserved energy normalizes the implications for changes in system reliability by converting any situation into an equivalent level of energy. To those customers who lose service, unserved energy equates to monetary losses in the form of reduced production, lost sales, spoiled goods, and any other losses associated with a business activity or the value of services received by non-business customers. The lost value to customers from outages is described as the value of lost load (VOLL), expressed in dollars per unit of unserved energy ($/MWh). The expected value of the curtailable load in avoiding or mitigating outages can then be expressed as the product of the Expected Unserved Energy (the consequences in physical terms) and the VOLL (the monetary measure of those consequences).

Value of Curtailable Load ($ per year) = **(Eq. 2)**
Expected Unserved Energy (MWh per year) x VOLL ($/MWh)

Substituting the formula for Expected Unserved Energy (Eqn. 1) yields the following equation:

Value of Curtailable Load ($ per year) = **(Eq. 3)**
Expected Outages (hrs per year) x Expected Disconnected Load (MW) x VOLL ($ per MWh)

According to this formula, the value of curtailable load, and by association the value of the demand response program that creates it, is based on the *expectations* of future outages, not on a *retrospective* look at how many times the curtailable load was called upon. This reflects the fact that demand response programs have value as a hedge against generation outages and higher-than-expected demand, regardless of whether they are ultimately needed, or how much they are actually used in any given year. Outage history may affect future expectations, and therefore value, but it is the expectations upon which value is estimated.

In order to estimate the value of demand response programs, estimates must be derived for the three inputs to the Value of Curtailable Load formula (Eq. 3). These estimates can be based on information available to most utilities and on appropriate use of the body of knowledge on the value of lost load.

In general, most applications of the value of reliability approach have been in DRR assessments conducted by the New York ISO and the ISO New England.[43]

[43] ISO studies that have addressed the value of reliability include: 1) *A Study of NYISO and NYSERDA 2002 PRL Program Performance*, Neenan Associates, January 2003; 2) NYISO Seventh Bi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation in Docket No. ER01-3001-00, December 1, 2004; and 3) An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2004, prepared by RLW Analytics and Neenan Associates, December 29, 2004.

4. CASE STUDY – A RESOURCE PLANNING FRAMEWORK FOR DRR VALUATION

This section includes the background and results of a case study for DRR valuation within a resource planning context. Section 4.1 describes this approach and compares it to other methods which can be used to provide estimates of the value of DRR. It should be noted that the resource planning approach to DRR valuation is a somewhat labor-intensive analysis method, and the simpler benefit-cost tests or benchmark valuation methods presented in Sections 3.1 and 3.2 can also be used.

There are unique aspects of DRR, when viewed as a resource, that make a resource planning construct a useful valuation tool, as compared to the alternatives of using standardized benefit-cost tests or other approaches that tend to focus on past events, or frameworks that are not dynamic over time. However, each approach has strengths and weaknesses, and each can be useful in addressing specific situations.

4.1 Background: Valuing DRR in a Resource Planning Framework

One of the stated objectives of this valuation analysis is to develop a framework that appropriately supports the analysis of DRR as part of a forward-looking resource plan. This can only be accomplished if the framework appropriately addresses both the costs and benefits of DRR, and also allows for tradeoff analyses to be conducted with other resource options, e.g., peaker plants such as gas combustion turbines.

The case study approach used in this section is not meant to represent a specific resource plan for any region. The results of the case study results, by themselves, are not meant to indicate that any specific resource should be deployed or preferred to any other resource. A more detailed resource planning study, based on the specifics of the system and region being addressed, would be needed before a specific conclusion can be reached.

This case study approach does illustrate how the unique attributes of DRR can be represented in a resource planning study. Resource planning has a long history in the electric utility industry. A wide range of models has been developed over the years that compare the costs of various electric generation resource mixes to meet given weekly, monthly, or annual electricity demands. These tools can be used to examine how changes in the mix of resources can influence the system costs, i.e., the costs of meeting the system electric demand.

One premise underlying this approach for DRR valuation is that if the costs and attributes of DRR are appropriately incorporated within these models, then a comparison of a resource plan without DRR available as a resource can be compared to a plan with DRR. The difference in costs between the two resource plans is one measure of the "value of DRR." Resource planning has been the process that the electric industry has used for years to assess cost-effective resource plans and examine tradeoffs between different resource alternatives. Given this history, it seems appropriate to address the value of DRR within this planning context.

As discussed in Section 3.2, many of the early attempts to place values on DRR have used benefit-cost tests that were designed originally for energy efficiency programs. These tests can provide useful results and serve as benchmarks when comparing different DRR products, e.g., direct load control of water heaters, or load reductions at large end-user facilities. Energy efficiency programs generally produce reduced energy use across a large number of hours. For example, replacing a refrigerator with a more efficient refrigerator saves energy during every hour in which the refrigerator is operating.

Demand response differs in that it is a peaking resource that is meant to be used only for a few hours, and only during periods of very high electricity prices and/or periods where there are reliability issues. In the assessment of the energy savings from a high efficiency refrigerator, it is appropriate to use average energy costs since the appliance operates all the time. However, DRR tend to be used during extreme events, when energy costs can be very high. These might be hot summer days or cold winter days, when the electric system is under stress in terms of being able to meet the demand, or during periods when major generating units are unexpectedly off line and there are system reliability concerns. Therefore, models and market representations that can address both average and extreme events are best suited for examining the cost-effectiveness of these two types of resources.

One of the most commonly used benefit-cost tests for demand-side management assessment is the Total Resource Cost (TRC) test. This test includes a variety of benefits characterized as avoided costs or avoided cost adders.

- Avoided generation costs
- Avoided transmission costs
- Avoided distribution (T&D) costs
- Line loss reductions
- A reliability adder
- Waste heat utilization benefits
- A price elasticity adder

Avoided generation costs, avoided transmission costs, and avoided distribution costs are likely to be dramatically different for energy efficiency alternatives and demand response alternatives. During peak periods and periods of high system stress, when DRR is most valuable, the avoided generation costs will represent high-cost peaking units; transmission costs may be high due to congestion on the lines (and due to lower throughput capacities on hot days); and distribution costs may also be high as the capacity of a substation is reached or nearly reached.

DRR benefits need to be calculated for events such as high peak demand and extreme system stress. These events may only occur once in every five years. As a result, DRR may not see much use for a number of years. However, DRR could provide substantial benefits for that one-in-five- or one-in-ten-year event, when a combination of circumstances stresses the system and leads to unusually high system costs. As a result, one week or month with several extreme events might result in benefits from DRR large enough to cover the costs of the DRR products for five to ten years.

4.2 Case Study – Resource Planning Analysis Framework

The basic approach taken during this case study was to examine the change in system costs, over a 19-year time horizon, with and without DRR included in the portfolio of resources. This difference in costs provides an estimate of the value of DRR to the electric system being examined. The specific model used for this effort was New Energy Associates' Strategist® Strategic Planning Model.[44] However, most

[44] The full Strategist model contains a number of different modules including financial, load forecasting, and market decision modules. For the purposes of this effort, the modules used were the Load Forecast Adjustment module, the

production planning/capacity expansion models can be used by following the basic template outlined in this case study. The goal of this effort is not to advocate the use of any specific model or modeling techniques, but to illustrate a process that can be used to appropriately credit DRR with the benefits it provides.

It is important to note that this is one of several activities that are being undertaken in this area. This effort focuses on modeling a North American electric system that is based on fossil and nuclear fuel. A model of the Nordic system was also be run to examine the use of DRR under a different pricing regime, different system constraints, and with substantial hydro resource availability (see Section 4.11) . In addition, another ongoing task is the development of benefit-cost frameworks for assessing DRR that may not require the use of a full resource planning model.

This section outlines the structure of the model framework which was used. The basic approach for the case study was presented at the IEA Task XIII experts meetings, as well as at other expert forums.[45]

Appropriately incorporating DRR in forward-looking resource plans requires the planning effort to embody two critical capabilities:

1. A planning framework with a sufficiently long time horizon to allow for the benefits of DRR to be captured. DRR has the potential to reduce the costs of low-probability, high-consequence events that impact system reliability, but these events may occur only every 5 or 10 years.
2. DRR can reduce the risks of high electricity prices during periods when several factors combine to create shortages or high system costs. To address this risk management aspect of DRR, the planning framework must explicitly address the uncertainty that is present around key factors, including fuel prices, weather, and system factors such as transmission constraints and plant operation. If the risks that impact the costs of electricity are not dimensioned in the planning process, then the value that DRR offers in terms of risk management cannot be assessed.

Overall, the process used included developing system planning “scnarios” that represent different futures against which DRR was valued. This process can be summarized as consisting of six steps:

<u>Step 1</u>: Determine pivotal factors influencing the market costs of electricity.

<u>Step 2</u>: Assess uncertainty around these factors and express that uncertainty via probability distributions.

<u>Step 3</u>: Create a combination of these factors, i.e., combine the probability distributions to create a joint probability surface.

<u>Step 4</u>: Draw a set of discrete futures (termed “cases”) from the probability surface. Each draw includes a value for each key factor (100 draws).

General and Fuel module that provides estimates of production cost of electricity for different resource mixes, and the PROVIEW resource optimization module.

[45] Presentations have been made at the ***Eighth National Symposium on Market Transformation,*** Washington, D.C., 2004, sponsored by the American Council for an Energy Efficiency Economy, and at the ***Demand Response Program Seminar***, sponsored by the California Energy Commission, Public Interest Energy Research Program, February 2004.

Step 5: Run each future through a resource planning model, which provides 100 values for system costs, which can be incorporated into a distribution of costs for a given set of available resources.

Step 6: Repeat Step 5 for different portfolios of resources to determine the cost differential and reliability differential for "with DRR" and "without DRR" options.

It should be noted that the emphasis on modeling the costs of meeting low-probability, high-consequence events stretches the current abilities of most planning models, including the model used in this analysis. Models designed to minimize overall system costs to serve a given load projection often make simplifying assumptions and trade-offs regarding these peak events, to better estimate the costs of serving the vast majority of the hours in the planning period. This is appropriate for typical planning, but a task that is focused on looking at the resources and costs of serving peak periods suffers somewhat from the standard planning assumptions. One example is the way unforced and forced outages are handled by Strategist (and by alalmost all planning models):

- Unforced Outages – These are planned plant outages and are scheduled to occur during specific times, usually for regular maintenance or, in the case of nuclear units, refueling of the plant. The model builds in this scheduled maintenance at specific times and the plant is assumed to be unavailable for those periods.
- Forced Outages – These are unplanned plant outages and stem from the unplanned need to repair or replace equipment. Roughly speaking, annual forced outage rates are around 15% for nuclear units, 10% for coal units, and around 5% for gas units. Since these occur unexpectedly, it is not possible for a planning model to consider all the possibilities for the time and duration of forced outages. Therefore, the forced outage rate is built into the model by derating the generation unit. For example, the capacity of nuclear units are derated by 15% for every hour of the year. As a result, the operational, cost, and reliability impacts of having a number of units be simultaneously off-line because of forced outages is considered only indirectly. Rather than use this average derating approach, this case study included three "stress" events in which the timing of forced outages at major facilities was specified, similar to what can actually occur in electric systems.

Most business and policy planning models, across many sectors, use averaging assumptions when the number of possible variations is extremely large, or when extreme events are few and occur in a somewhat unpredictable manner. This approach produces good estimates of expected system costs, but less precise estimates of the cost impacts of extreme events.[46] This is not an inherent weakness of the models, however, because they were not designed specifically to examine extreme events.

Finally, planning models should be viewed as producing strategic or tactical decision making information from a framework that requires that a consistent set of assumptions be used. Planning models are approximations of the systems they are meant to represent. As a result, models provide useful information to decision makers, but they do not produce decisions themselves.

[46] The forecasting and analysis of extreme events is almost always a more complex problem than estimation of the expected value (or average) of system costs (or other objectives) over a planning horizon. As a result, most models use assumptions that average out the effects of extreme events since they happen unexpectedly and infrequently.

4.3 Base Case Electric System

This process uses a base case against which alternative resources can be assessed. The base case was developed to realistically represent an electricity market that will allow for appropriate trade-offs between resources – both supply-side and DRR – and in which issues such as off-system sales/purchases and system constraints can be addressed, e.g., transmission constraints. The base case system was developed using data compiled by New Energy Associates, based on publicly available information for a selected region in the National Electric Reliability Councils (NERC), i.e., the Mid-Atlantic Area Council (MAAC) region. The initial data came from the Platts-McGraw Hill Base Case database for the region, with some adjustments to the data based on New Energy and Summit Blue's experience.

This approach allowed for the use of baseline data that had already been compiled for other client resource planning analyses. This saved time in specifying the base case, and allowed the analysis to focus on representing uncertainty around key pivot factors and defining the DRR products. The starting point database was a large system that included five distribution utilities, interchange capabilities with two other regional systems, and a customer base of nearly 6 million. The availability of interchange power is an important factor as this system was modeled as a net importer of power.

4.4 Modeling Methodology

One hundred cases were created as data inputs to the Strategist model. They were calculated so that a wide variety of possible futures was represented. Monte Carlo methods were used to create these different future cases that represent the uncertainty in key future inputs. To accomplish this, a number of pivot factors were identified and the uncertainty around these factors was dimensioned. Data was provided for the years 2005 to 2023. In addition, data sets for four demand response programs were developed as inputs to the model.

The key input variables around which uncertainty was dimensioned were:

1. Fuel prices – natural gas, residual oil, distillate oil, and coal
2. Peak demand
3. Energy demand
4. Unit outages
5. Tie line capacities

Four DRR products were included as potential resources to meet future system needs, in combination with the full range of supply-side options. The four DRR programs were:

- <u>Interruptible Product</u> – A known amount of load reduction based on a two-hour call period. Customers are paid a capacity payment for the MW pledged and there are penalties if MW reductions are not attained.
- <u>Direct Load Control Product</u> – A known amount of load reduction with 5 to 10 minutes of notification. This is focused on mass market customers. As a result, it has a longer ramp-up time to attain a sizeable amount of MW capacity.
- <u>Dispatchable Purchase Transaction</u> – A call option where the model looks at the "marginal system cost" and decides to "take" the DRR offered when that price is less than the marginal system cost. This program can also be classified as a day-ahead pricing program.

- Real-Time Pricing Product – Modeled as a resource using price elasticity factors to calculate demand reduction. It is important to model the value of other DRR products when a pricing program is also in place as the price elasticity due to RTP will lower peak demand on extreme days, and this mitigates some of the price and cost volatility in the market. In turn, this might reduce the value of other DRR programs.

It should be noted that this is the first time that the Strategist Model has been combined with a Monte Carlo front end to analyze the value of DRR. As a result, there was little past work that could be relied upon to provide some guidance on what types of DRR would be most effective, what would actually constitute an extreme event in a system that was this large, and how various assumptions made in the model (e.g., the treatment of forced outages) influenced the results – estimates of the value of the DRR products and estimates of system costs. Resource planning is a learning process, in which information is gained by testing different inputs to the model. This case study is meant to be part of this learning process, providing information on the factors and model assumptions that are important in assessing DRR as part of a resource plan.

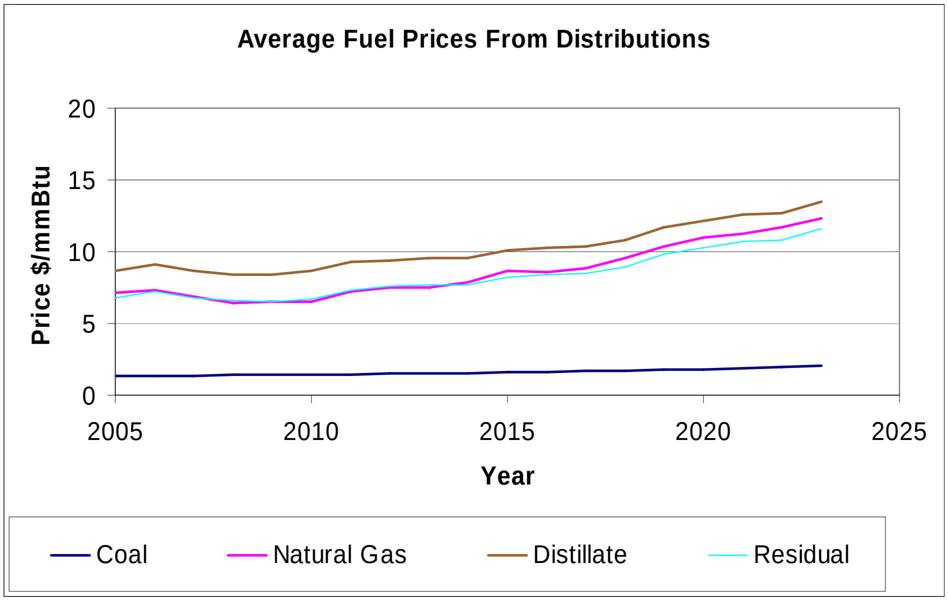
4.4.1 Incorporating Fuel Prices into the Model

Distributions for fuel prices were developed for natural gas, coal, distillate oil, and residual oil. They were based on the Annual Energy Outlook (AEO) forecast and scaled up to the current futures prices taken from the published sources. A range was created for each fuel type. In developing this range, past prices were examined along with forecasts available from various sources. The mean value of the range was based on the prices contained in the base case Strategist data base.

The range for natural gas was fairly wide. Prices as recently as those seen in 2002 are about 50% of the current price, which resulted in a fairly wide range. A minimum extreme distribution[47] was used, with the 90% percentile set to the top end of the range and the likeliest value set to the forecast value, and the distribution truncated slightly below the lower end of the range. Figure 4-1 shows the mean values for the four fuels used in the analysis.

[47] This distribution is one of the options contained in the software product "Crystal Ball" from Decision Engineering. Crystal Ball was used to create the probability distributions and perform the Monte Carlo analyses that provided the future cases used to create input data sets for the Stategist model.

Figure 4-1: Mean Values for the Fuel Price Forecasts



For each year, 100 random draws were made from this distribution (and all other fuel price distributions, including the correlation factors). These 100 random draws were then used as the price for natural gas used in the 100 input cases (which include values for all fuels and other variables) that create the input deck for 100 runs of the Strategist Model.

It is important to note that the distributions of fuel prices were not assumed to be independent. In fact, the amount of correlation assumed between the various distributions used as inputs to the model can influence the value of resources designed to meet the needs of extreme events. For example, if the price of natural gas and the price of oil are positively correlated, then there is likely to be a greater number of events with overall high fossil fuel prices. Similarly, if fuel prices are positively correlated with high levels of energy and peak demand, then there may be a higher incidence of high electricity cost days. The fact that many resource planning approaches do not explicitly consider these distributions, both in terms of their end-point ranges and in their correlations, might mean that the number of extreme days that need to be met are underestimated by the modeling process. In turn, this could bias the selection of resources away from those that meet these extreme days most cost-effectively.[48]

4.4.2 Peak and Energy Demand Inputs

Peak demand data for the selected region was calculated based on the 2005 value from the base case database used by Strategist for that region. Growth rates in peak demand were taken from the NERC region appropriate to this system (MAAC). A normal distribution was created for each year, with the

[48] There is not only correlation across fuel inputs, but also potential correlation over time. For example, if natural gas prices are higher than expected in 2010, it is likely that a higher than forecast price for natural gas will occur in the next year as well. The development of these distributions tried to take into account the historical relationships between fuels, the positive partial correlation (i.e., a positive correlation that is much less than 100%) in fuel prices across fuels, and the partial correlation in the price of the same fuel over time.

90% percentile set to the peak demand value plus a percentage increase of 2 times the growth rate. No truncation was used. One hundred trials were selected from this distribution.

Energy demand data for the selected region was calculated based on a 2005 value taken from the selected region's data, and growth rates taken from the NERC region appropriate for this system (MAAC). A normal distribution was created for each year, with the 90% percentile set to the energy demand value plus 3%. No truncation was used. 100 trials were selected and used in the modeling process.

4.4.3 Unit Outages

New Energy Associates provided the maintenance schedules for the 27 generating units with the highest GWh outputs. Additional forced unit outages were added to the maintenance schedule in order to simulate a stress on the system. The forced outages were taken at one nuclear unit and at one or more fossil units such that a minimum of 10% of peak demand was made unavailable all at once. These "stress forced outages" were added in three years – 2005, 2015, and 2020. The percentage of peak demand for each instance, as taken from the data for the 100 cases, was 12.78%, 10.33%, and 10.96%, respectively. All other years had the base case unit outage data, with forced outage rates across plants treated as a derating of the plant capacity across the entire year.

4.4.4 Tie Line Outages

The system being modeled is a net importer of power during peak periods. As a result, the availability of power from neighboring regions is important. Substantial import capability is available into the region, and this import capability is available from two adjoining regions, via between three and five transmission lines.

There is 7000 kV of transmission capacity between the region and each of the two connected regions. Having all the import capability go down was viewed as too extreme. For this analysis, the tie line capacity was reduced by approximately 30% for one of the peak months, in six different years. The years chosen were different than the years chosen for the additional unit outages.

After the model was run, it was apparent that the tie line outages had not had a significant effect on the system operation and that higher tie line outages could have been added. In addition, the tie line outages could have been combined with high unit outages to create a more extreme stress event.

4.5 Demand Response Programs Assessed

Four demand response programs were modeled: large customer interruptible, direct load control, dispatchable purchase transaction, and real-time pricing. The MW capacities of the programs were calculated to start at a low value in 2005, grow at a quick rate in the first ten years to a level of about 4% of peak demand, and thereafter grow at a slightly higher rate than the peak demand.

The real-time pricing program posed a challenge in that there is no feedback loop built into the model that looks at the marginal hourly cost and the demand for that same hour. As a result, two pricing products were examined:

1. One was a peak-period pricing program which produced a reduction in peak demand and little impact on load in other hours. This is similar to a critical peak pricing product, with the overall monthly and annual energy demand largely unaffected.

2. The other was a standard RTP program that produced a reduction in peak demand and also an overall energy efficiency effect, resulting in reductions in weekly, monthly, and annual energy demand – this is consistent with the RTP literature.

The data for the other three DRR programs were developed from specific DRR product designs. Data from each product design were then used to develop inputs to the Strategist model such that each program could be treated consistently by the model. All dollar values were inflated at a rate of 2.5% per year. The following data was supplied for each product for the years 2005 to 2023:

- One Time Costs
- New Customers per Year
- New Customer Cost
- Annual Customer Cost
- Annual O&M Cost
- MW/Customer
- Total MW Capacity
- Months in Year Available
- Firm %
- Maximum Control Actions per Day
- Maximum Control Actions per Year
- Maximum Control Hours per Action
- Maximum Control Hours per Year

4.5.1 Large Customer (over 500 kW) Interruptible Product – Reserves Call Option Program (DRR-1)

This product is available for large C&I customers, which are assumed to have 750 kW load reduction capacity each. Two hours' notice is required before curtailment of load, and as such this product is not considered to be available for spinning reserves, but it can be counted towards an overall reserve requirement.

4.5.2 Mass Market Direct Load Control Product – Call Option (DRR-2)

For this product a direct load control device is installed at the customer site which can be controlled remotely. Customer sites are assumed to be residences or small commercial properties. While there may be a number of types of equipment that can be controlled at the site, this product is modeled as a control on HVAC equipment. For the purposes of this scenario, it is assumed that each participating customer is provided with a programmable thermostat and a switch for an AC compressor.

It is assumed that up to 6,000 customers can be enrolled by an aggregator per year, with 2 kW controlled per customer on average. It is also assumed that ten aggregators can offer this mass market product, providing a total of 60,000 new customers each year, with 120 MW of capacity. Since this is a direct load control product, the notification time is simply the time it takes to send out the signal to all the sites. The response time is expected to be less than 15 minutes. The dispatchability of this program allowed for it to be counted towards meeting spinning reserve requirements.

4.5.3 Dispatchable Purchase Transaction – Day-Ahead Commitment Product (DRR-3)

This is available to C&I customers. The aggregator would display a price schedule for curtailed load one day ahead of the required load curtailment. For example, a price schedule would be posted on a web site or e-mailed to participants at 4:00 PM each day that would show prices for curtailed load for each hour during the next day. If the price were attractive to a customer, they could offer to curtail a specified number of kW during the hours when prices were deemed to warrant the commitment. The number of kW provided would depend upon the price. Elements of the Strategist planning model can be used to include this type of contingent provision of MW, up to the specified capacity and number of hours.

4.5.4 Real-Time Pricing Products (CPP – DRR-4a and RTP – DRR-4b)

This was the most difficult product to model because real-time pricing means that the demand changes at the same time as the price becomes known. As mentioned above, the approach taken to incorporate this DRR pricing option into the model used two pricing variants:

1. A Critical Peak Pricing product that just reduced demand in the peak hour each month.
2. A standard RTP option that produces reductions in demand during all high-priced hours.

For the CPP product, there was a ramp-up from 5% of the load participating in year 1 to 25% of total system load participating at the end of year 4 and thereafter. It was assumed that all customers on the CPP program (i.e., representing 25% of peak demand) would reduce their load by 15% at the peak hour each month; however, no change was made to total monthly or annual energy demand.

The standard RTP option assumed the same four-year ramp-up period as the CPP program, with 25% of total system load participating at the end of year 4 and thereafter. Under standard RTP, those customers who are in the program reduce their peak hour load by 12% and, in addition, there is a reduction in energy demand of 4% in their annual electricity consumption.

4.5.5 Total DRR Capacity

Total DRR capacity was totaled up across all four DRR options to be approximately 15% of system peak demand in 2015. A large DRR capability was initially viewed as appropriate for this case study. As the results section indicates, this level of DRR capability was found to be an over build for this system, i.e., DRR values of between 7% and 10% of total system peak would probably have been more appropriate for this system. This indicates that any resource will have diminishing returns at some level and, as with any resource, it can be overbuilt.

4.6 Case Study Results

This case study analysis produced a number of interesting results, and it also generated some questions and issues to be addressed in future work. There are two general conclusions that can be drawn from this analysis:

1. It is important to look at the distribution of system costs across the different future cases.
2. The DRR products examined seem to be quite successful at addressing those days that had extremely high marginal production costs - either due to the random confluence of events or due to the plant outage stress days that were introduced into the model.[49]

The distribution of potential system costs in this year for each of the 100 cases in the base scenario is quite large, and there are a few cases where costs can be much higher than average. For example, costs

[49] One reason the high plant outage stress days were introduced into the model was the fact that the model (as does other resource planning models) treats forced outages by reducing the capacity factor of the unit. This essentially averages the impact of the outages across all days and hours in the planning horizon and does not provide a case where there might be a total plant outage on a given day, or even multiple plant outages on the same day.

jump by $2.5 billion in just the three highest cases in 2023. Over the entire 100 Monte Carlo draws in 2023, system costs vary from $7.5 billion to $15 billion. While 2023 was the last year in the planning horizon and might be expected to have the largest range, similar analyses were conducted for 2010, 2012, 2015, 2018, and 2020. These results are shown in Table 4-1. All of these years showed a range of cases with total system costs that in every case had the highest cost be roughly twice the lowest system cost case.

Table 4-1: Ranges of System Costs for Select Years

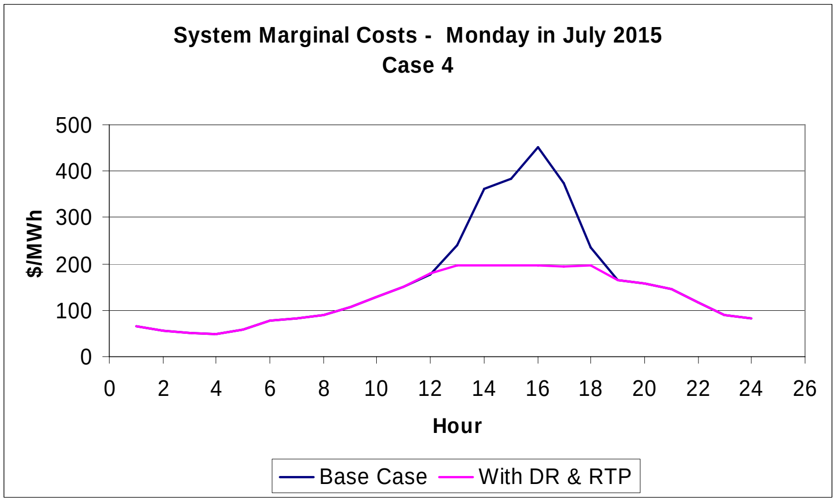
Range of Total System Costs for Selected Years - Base Case ($ Billions)						
Year	2010	2012	2015	2018	2020	2023
Maximum	7.7	8.2	10.2	10.3	12.4	15.0
Minimum	3.5	3.8	5.1	5.6	6.5	7.5
Range	4.2	4.5	5.1	4.6	5.9	7.5
Ratio	118.5%	118.8%	101.7%	82.2%	89.9%	99.3%

Examining this range of potential system costs and the factors that drive these costs can help planners develop resource plans that provide hedges against high cost outcomes. While this can be done through simple scenario analyses (i.e., using a high and low case), the information contained here shows that there may be multiple factors that cause a high cost case. In addition, the software tools for performing these types of analyses are widely available and more utilities are using these tools.

4.6.1 Changes in Prices during Peak Periods

The results shown in Figure 4-2 below are for one of the three outage stress days that were incorporated into the model. On this day, one major nuclear plant was out along with one major fossil plant, resulting in reduced generation of approximately 10% of the peak demand on that day. (If needed, additional plants were taken off line.) This figure shows the system costs without having new DRR products available (i.e., the base scenario) and the system costs with all three callable DRR products and the critical peak pricing program available. Prices over the long term are assumed to equal the marginal costs of production. This peak day combined with a capacity stress scenario shows that, without DRR, the system marginal production cost reaches $450/MWh. The same case modeled with the DRR products shows that the peak prices are clipped, with a high price of $200 – a reduction of over 50 percent.

Figure 4-2. Marginal Costs During a "Stress" Day



On just this one day in July, the total cost savings are $24.5 million. For the entire week, the cost savings are $45.2 million, and for this month the savings are roughly $180 million. It is important to recognize that these savings are based only on marginal production costs and that there are also deferred capacity savings, which over the planning horizon can prove to have considerable value. In addition, in open markets electricity prices tend to substantially exceed the marginal cost of production – which generally provides a lower bound for market prices on high demand days. Market prices can be three to five times the marginal costs of production, which might increase the benefits of having DRR available to help address low-probability, high-cost events.

4.6.2 Deferred Capacity Charges

The previous section showed the savings in marginal production costs that can be made as a result of having DRR available on extreme peak days. In addition, the capacity provided by DRR can defer having to build additional peaking units. The Strategist model competed DRR directly with combustion turbines to provide peaking and reserve capabilities (where appropriate). This resulted in the model deferring all the capital costs for new combustion turbines, which were included in the base run. This was true for all four scenarios. Even the addition of just the three callable DRR programs caused this capital deferral. The total value of capacity deferrals over the 19-year time frame, expressed in 2004 dollars, is $892 million.

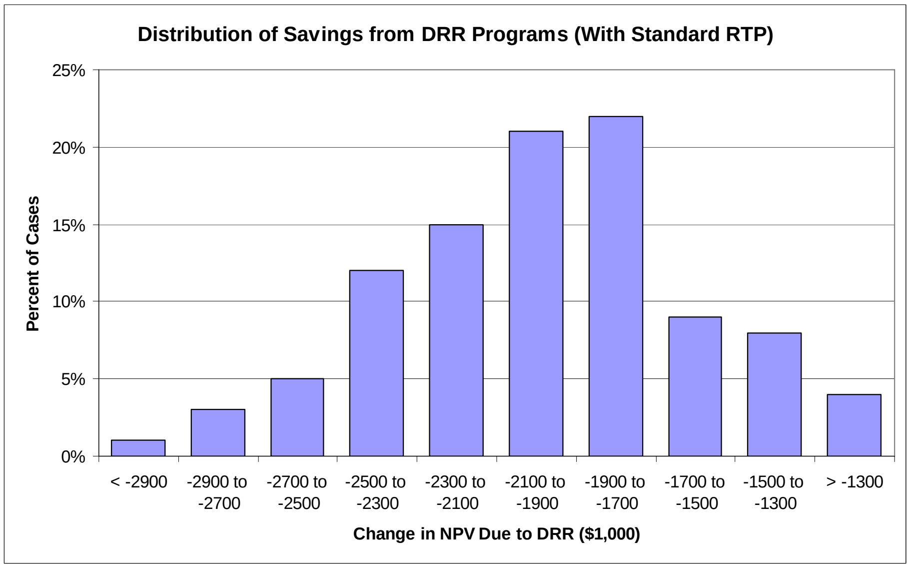
4.7 Overall Impacts of DRR – Costs and Benefits

The benefits of DRR were compared to the costs within the resource planning model. The costs of each DRR option were built into the characterization of that resource and, therefore, were incorporated in the model. To the extent that the NPV of system costs was lower with DRR included in the model, then the benefits were greater than the costs.

4.7.1 Distribution of Savings by Case

It is important to recognize that while DRR provides considerable amounts of benefits on select days, there is a cost to building and maintaining the DRR capacity which is paid for in every year and in every case, even if DRR is not used. This results in there being some years where there are costs but no savings from DRR, i.e., DRR was used very little in that year. However, this was not true for the scenario with the standard RTP program; in that scenario there were savings in every year. Looking at the 100 cases individually, with DRR but no RTP, 36% of the 100 cases show savings in total system NPV compared with the base scenario, and with all the callable DRR programs and the standard RTP, 100% of the cases show savings in total system NPV when compared with the base scenario. Figure 4-3 shows the distribution for this second scenario.

Figure 4-3. Distribution of Change in Total System NPV with Standard RTP



4.7.2 Total Average Savings

Overall, the incorporation of DRR results in some reduction in the average total system cost NPV in all three scenarios (DRR without RTP, with CPP, and with standard RTP), as shown in Table 4-2 below. In the scenario with the standard RTP program, savings are about 3.5 times those in the scenario with the critical peak pricing program, and, similarly, savings in the scenario with the critical peak pricing program are approximately twelve times those with only the callable DRR programs.

Table 4-2. Savings in Average System Costs

System costs savings ($M)	
	Average NPV over 20 years
Callable DRR Only	48
Callable DRR with Critical Peak Pricing (peak hour load reduction only)	574
Callable DRR with Standard RTP – (reduction in demand in all high price hours)	1,984

4.7.3 Impact of DRR on System Cost Risk Profiles

There was a change in the risk profile associated with the planning scenarios with the addition of DRR. This can be illustrated by looking at the impact DRR had in the extreme cases, where DRR has the greatest value. Two ways were used to characterize the impact of DRR on risk – a 90% value at risk (VAR90) where the 10% highest system cost cases are examined, and a 95% value at risk (VAR95) where the highest 5% of the cases, in terms of the total system cost, are considered. Results for the three scenarios are shown in Table 4-3 below.

Table 4-3: Savings in System Costs for Highest Cases

Risk Metrics – Reduced System Costs at Risk ($M)		
	VAR 90	VAR 95
Callable DRR	238	213
Callable DRR with Critical Peak Pricing	924	966
Callable DRR with Real Time Pricing	2,673	2,766

This analysis shows that there is a reduction in the average cost of the top 10% of at least $238 million, and as high as $2.673 billion. For the 5% worst outcomes without DRR, savings are slightly lower, except in the scenario with standard RTP. As a result, the model shows that DRR not only reduces the expected value of total system costs, it also reduces the risk associated with adverse scenarios.

4.7.4 Savings in Incremental System Costs

As the system being studied is a very large system, it is meaningful to look at the incremental costs of meeting energy demand, as opposed to a percentage of the total system cost. On average, the savings in incremental costs due to DRR (year on year) were 10% for the scenario with peak pricing and 23% for the scenario with standard RTP. For the scenario with the standard RTP program there was a range of savings of -73% to +320%, and in 53% of the cases the incremental costs in the callable DRR scenario were less than or equal to those in the base scenario. In a few cases the DRR provided large reductions in incremental costs.

4.7.5 Frequency of Use of DRR Resources

The results show that a high percentage of the DRR capacity is used infrequently, but the DRR provides significant benefits when it is used. The results show that the DRR capability is used in most years in which it is available, but in approximately 70% of the years it is used to less than 5% of its capacity. This capacity takes into account the number of hours the DRR product can be called and the MW contained in each of the three callable DRR products. Usage for the three DRR callable products is as follows:

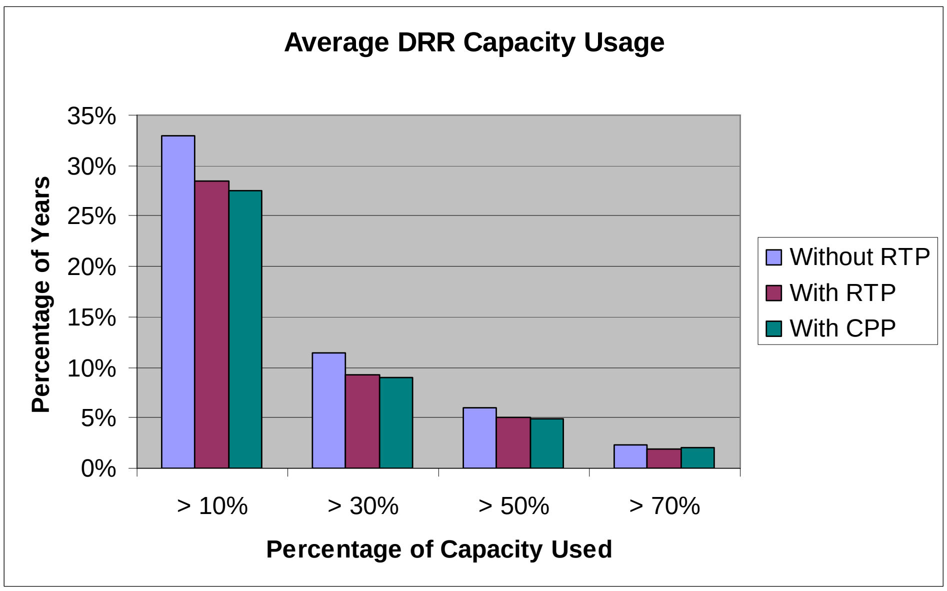
- **DRR-1: The Large Customer Interruptible Product** – This DRR product is used to at least 30% of its capacity (based on number of hours it can be called times the MW enrolled in the program) in 9% of the years, or about once in every nine years. This product was used for over 60% of its capacity in only 5 years.
- **DRR-2: Mass Market Direct Load Control Product** – This product is used to at least 30% of its capacity (based on number of hours it can be called times the MW enrolled in the program) in 22% of the years, or about once every four years. This product is used for over 80% of its capacity in about 3% of the cases.

- **DRR-3: Dispatchable Purchase Transaction Day-Ahead Product** – This product is used to at least 30% of its capacity, based on the three price triggers, in only 3.2% of the years. This product was used to over 80% of its capacity in only 1 year.

In summary, small amounts of DRR are used in most years, but large amounts of DRR were used infrequently – at the most, once in every four years. In addition, there was less than a 1% probability that essentially 100% of the DRR capacity (based on number of hours it can be called times the MW enrolled in the program) would be used for each of the three DRR products incorporated into the "with DRR" scenario. Given that DRR can be ramped up as needed, this indicates that the DRR products likely could be better designed so that the size of the program fits the need for DRR in the system, thereby lowering the overall costs of the programs.

With the addition of the standard RTP program the other three DRR programs were used slightly less than with the peak pricing product, or with only the callable DRR programs. Figure 4-4 below shows this reduction in capacity usage. However, this reduction is not as great as might be expected.

Figure 4-4: Average DRR Capacity Use with Standard RTP Program



4.7.6 Reliability Benefits of DRR

DRR was shown to have significant reliability benefits in the modeling process. However, it is difficult in this effort to place dollar values on these reliability benefits. As a result, the net benefits figures do not include a value for the higher level of reliability achieved with the addition of DRR to the available resources.

DRR decreases the estimated loss of load hours substantially across all cases. The base case had an average value for loss of load hours of 7.64 hours across the cases, but values for some individual cases were as high as 30 hours. For the DRR with Peak Pricing, the average loss of load hours averaged across all cases was lowered to 0.33 hours. The magnitude of the savings due to enhanced reliability across all the years in the planning horizon could be quite high, but no estimate has been calculated at this time, and this estimate may vary by various factors, including the number of customers impacted and the characteristics of the system.

Loss of load was significantly reduced in every one of the 100 cases. It should be noted that these reliability enhancements could be a significant benefit of DRR that system planners would want to pursue, regardless of the calculated dollar savings.

4.8 Overall Conclusions and Findings – Resource Planning Framework

The purpose of this analysis was to conduct a test case resource planning analysis that appropriately accounts for the benefits and costs of DRR. This way of looking at the benefits of DRR stems from the use of an objective function that calls for serving customer loads at the lowest possible overall system cost. The net benefits of incorporating DRR in a resource plan are then estimated as the difference between total system costs of meeting the system needs without DRR included as resource that can be called upon, and the total system costs of a resource plan that includes DRR.

This case study shows that a Monte Carlo method can address inherent uncertainties in evaluating the impact DRR has on reducing the cost associated with low-probability, high-consequence events.

Findings from this analysis effort include:

1. The resource planning approach to obtaining a value for DRR, which was used in this analysis, seems to work, but it is predicated on:
   - Dimensioning uncertainty around pivotal factors that impact system costs. In this case, developing the necessary probability distributions seemed quite tractable and substantially better than using average or point estimates in the planning effort.
   - The dimensioning of uncertainty and the use of Monte Carlo methods allow for the attributes of DRR to be better represented in the resource planning effort.
   - Since much of the benefit of DRR occurs when it is used to ameliorate the high costs associated with low-probability/high-consequence events, a planning horizon of sufficient duration is needed to capture this value.
2. It was possible to characterize a variety of DRR programs within the Strategist modeling framework.
3. The results from this case study showed that DRR did reduce the costs associated with extreme events and that the use of DRR in a resource plan both:
   - Reduced the net present value of the system costs for the planning horizon – by at least $100 million.
   - Reduced the risks associated with high cost planning cases, i.e., the costs associated with the cases where DRR produced the greatest value were reduced substantially – by at least $300 million.

Lessons learned and areas for future research include:

1. The incorporation of DRR into the resource plan produces substantial increases in reliability as measured in loss of load probabilities (LOLP). No value was accorded to DRR for this increased reliability. Methods for developing estimates of the dollar value of this increase in reliability is

important in that these benefits might be large – possibly as large as the decrease in net system costs found in this case study.

2. This was the first time a Monte Carlo approach was used to address the value of DRR using the Strategist model framework. A number of issues came up during the modeling work that could be improved upon in next generation efforts. It is not believed that these issues favored DRR, but they could generally result in giving DRR more value. Areas that could be explored include:

    - To expeditiously perform the 100 resource planning model runs, DRR was allowed to compete only with combustion turbines in providing capacity. The addition of DRR capacity resulted in the full deferral of all new combustion turbine capacity over the study horizon. A close examination of the model results showed that as a result some older generation units with high energy costs remained on-line in the latter years of the planning horizon. This increased the costs of providing energy that in some cases was not fully offset by DRR since the number of hours that DRR can be used is limited. A "re-optimization" task would look at whether some fossil units might be economic by considering both capacity and energy. This re-optimization might lower the average system energy costs and would not be expected to lower the use of DRR (but this should be tested). This should result in lower overall system costs in the "with DRR" scenario, leading to a greater difference between with and without DRR scenarios.
    - The DRR products should be reconsidered and refined. Certain costs may be too high or too low, and the full capacity of the DRR included was rarely used. As a result, the DRR products could be made to better meet the needs of the system, given the information obtained from the modeling effort to date.

3. The "stress cases" used to analyze extreme events should be reviewed. The system being modeled is very large, with several hundred generation units, and therefore not as vulnerable as a smaller system. It is not clear if the "stress" scenarios were really as extreme as could be the case for this system. For example, none of the stress cases included a reduction in tie line capacity and import capability from other regions, which in this case study was large. It is also possible that some might think the stress cases were too extreme. Either way, further work would improve upon the development of stress cases.

4. There are a number of improvements that can be made to the model specification, given what has been learned during this first attempt at using the Monte Carlo approach in conjunction with the Strategist model.

4.8.1 Other Studies

Other entities are starting to explore similar methods. Utilities in California are looking at Monte Carlo methods with resource planning as a way to value DRR, and the Northwest Power and Conservation Council (NPCC) incorporated DRR in their resource planning efforts for the first time in their 5th Power Plan of January 2005. The DRR characterization that they used was simplified compared to that used in this analysis.

In addition, a Nordic power system case study for valuing DRR with a resource planning model was done. The study is presented in full, along with an analysis of the model and the results, in the paper

Valuation of Demand Response: A Monte Carlo Analysis for the Nordic Power System.[50] This modelling effort aimed to develop a framework for DRR valuation that includes more extreme cases than are normally included in traditional scenario analyses. The purpose of the study was to illustrate that demand response may not be profitable in normal power market conditions, but that considering more extreme cases may change the picture.

The paper discusses the necessity of demand response in the power market in order to ensure the most comprehensive distribution of resources, and thereby the largest welfare-economic gain to society. Furthermore, the paper presents results of a Nordic case study, in which some of the benefits of implementing DRR have been estimated by the use of a Monte Carlo analysis approach combined with the Balmorel model. In this approach, 100 cases with equal probability of 1% have been analysed in different scenarios. The cases differ with respect to hydro power generation, wind power generation and electricity demand. The analyses were carried out for a week in winter in 2010 (a week with a relatively low supply/demand balance).

[50] This study was presented at the Coordination Meeting for Nordic Interests in the IEA-DRR Project, in Helsinki, Finland, on October 13 2005, and at the IEA TASK XIII: DRR 3rd Experts Meeting in Stockholm, Sweden on June 13, 2005. The paper was written by Stine Grenaa Jensen (Risø), Thomas Engberg Pedersen (COWI), Mikael Togeby (Energinet.dk), and Magnus Hindsberger (ECON).