IEA DRR Task XIII

DRR VALUATION AND MARKET ANALYSIS

VOLUME II:

ASSESSING THE DRR BENEFITS AND COSTS

Prepared for:

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

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Dear Mr. Malme:

Please find enclosed the report titled *DRR Valuation And Market Analysis – Volume II: Assessing the DRR Benefits And Costs*. This report presents different approaches that have been used for assessing and valuing DRR. In addition, this volume presents a case study on valuing DRR using a resource planning approach, with the explicit dimensioning of uncertainty to capture the hard-to-value benefits of DRR. Volume I, a shorter version of this report targeted at the regulatory community, is being also being released today.

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

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

Q2: <u>If some DRR products are cost-effective, what specific products should be included in the portfolio</u>? 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: <u>How should the different DRR products be sized (i.e., how many MW or MWh should be accounted for in each product)</u>? 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 is 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 Objective of This Volume – Insights into Application

The objective of this Volume II is to provide insights into methods that have been used to assess and value DRR products and programs. A number of approaches are addressed in this volume. These 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 discussion of net welfare approaches for assessing DRR benefits and costs. These approaches examine total economic surplus, i.e., the sum of consumer and producer surplus with and without DRR.
- 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 effect 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;
- 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

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[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 Austrailia -- "*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.

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 model.

1.3 Organization of the Volume and Appendices

This report is organized into four sections. Following this introduction, Section 2 presents an overview of issues in the assessment and valuation of DRR. This includes subsections on the questions that need to be addressed by DRR assessments, the categories of benefits from DRR that should be addressed, and the costs of DRR that must be balanced against these benefits.

Section 3 presents several alternative DRR frameworks. These frameworks include: 1) simple approaches based on case studies and benchmark valuations of DRR that provide information used to project the future benefits of developing a portfolio of DRR products; 2) extensions of the standard practice manual (SPM) tests commonly used for the evaluation of energy efficiency programs which are adapted for the assessment of DRR products; 3) DRR assessments based on improvements in system reliability; and 4) a brief discussion of net welfare approaches for DRR assessments.

Section 4 presents a case study of a resource planning framework for the assessment of DRR products. This approach potentially offers a more comprehensive view of DRR that can address the insurance and portfolio value of DRR as well as the reliability benefits that DRR might offer.

Three appendices are included. Appendix A provides some background on New Energy Associates' Strategist® model used in the case study presented in Section 4. Appendix B presents additional input data and results from the modeling effort. Appendix C presents a number of models and tools that could be used in assessments of DRR.

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

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[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.

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 almost 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 ranging from: 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.

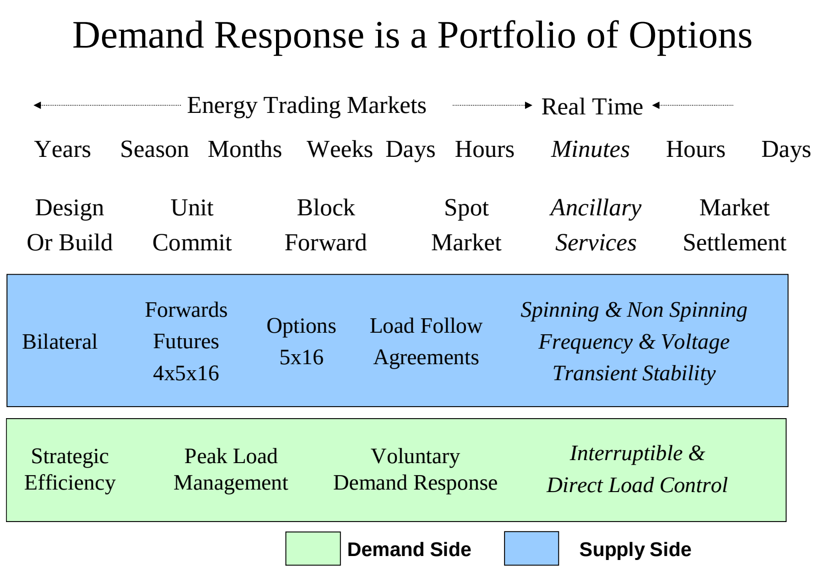
This implies that a planning process that directly addresses difficult issues such as uncertainty, a time horizon that encompasses low-probability/high-consequence events, and the electricity market encompassing demand response as well as supply-side technologies, is needed to assess impacts on overall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

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

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

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.

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

[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.

[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.

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 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.

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

[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.

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.

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. **<u>Other values (may be addressed by “side” calculations)</u>:**
   - 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.

<u>Private Entity Benefits</u>

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]

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.

[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 sense 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.

[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.

- 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 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)
   - <u>Product design and testing costs</u>. This may include pilot testing if necessary, or at least limited field testing.
   - <u>Marketing costs</u>. 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

[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 substation 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.

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.

– 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 upfront 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. 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.

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;
- 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

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[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.

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]

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

[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.

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

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] This study also develops a number of recommendations to jump start and increase demand response resources in electricity markets.

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 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 DR resources 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

[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

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

basis all feasible, comparable solutions to emerging problems including generation, transmission, and demand-response resources." Even without an assessment of the cost-effectiveness of any specific DRR options, the NEDRI collaborative was able to make recommendations on:

- Regional demand response programs, including specific program recommendations (11 recommendations);
- Pricing, metering, and default service reform (7 recommendations)
- Energy efficiency as a demand response resource (6 recommendations)
- DRR participation in contingency reserve markets (4 recommendations)
- DRR and power delivery systems (7 recommendations)

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.

[31] The large customer DR 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.

- U.S. Federal Energy Regulatory Commission's White Paper on Standard Market Design (SMD) states that:
  - *"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 administering the program, the incentives paid to the participant, decreased revenues for any

[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

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 by California Working Group 2

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]

In this assessment of DRR options, a number of modifications were made to the protocols contained in the SPM.[36] An appendix to the WG2 report contains the detailed equations that are used to evaluate programs; however, the details in the equations can obscure understanding of the tests and their objectives. It is useful to look at the equations after the present value discounting and summations have taken place. The net present value related equations are:

1) Total Resource Cost (TRC) Test:

NPV-TRC = UAC – PRC – PCN

[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).

[36] These changes are discussed on page 58 of the Second Report of WG2 and represented generally practical changes including: 1) recognizing price changes as well as quantity changes from the DRR option; 2) using total benefits and costs, as opposed to differential values that might miss certain benefits and costs; 3) discarding unconsidered benefits and costs; 4) using a continuum of benefits and costs where some benefits might change sign and rather than put them in the cost term, they were retained as a negative benefit; 5) limiting reported results to only the Net Present Value (NPV) and the Benefit-Cost ratio; and 6) eliminating the Program Administrator test as these programs were to be implemented by utilities and costs recovered by the utilities.

2) Ratepayer Impact Measure (RIM) Test:

NPV-RIM = UAC – BC – PRC – INC

3) Participant Test:

NPV-Participant = BC + INC – PC

Where:

- BC = Bill Changes
- INC = Incentives
- PC = Participant Costs
- PCN = Net Participant Costs
- PRC = Program Administration Costs
- UAC = Utility Avoided Costs

The TRC test is essentially the sum of the RIM test and the Participant test.

<u>Results of the California WG2 Benefit-Cost Analyses of DRR Options</u>

Key assumptions for these tests include:

A1. Time Horizon - An 11 year time horizon, ten years in addition to a start-up year.

A2. Discount Rate – A discount rate of 9 percent was used even though each utility might reasonably have a different discount rate. This was viewed as a reasonable simplification.

A3. DRR Option Overlap – The DRR proposals were not mutually exclusive with respect to the customers being solicited for demand reduction, i.e., some of the same customers might comprise a portion of the target market for more than one of the DRR proposals being evaluated.

Another 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. This resulted in avoided cost assumptions of:

<u>1. High Avoided Cost Case</u>	**<u>Fixed Avoided Cost</u>**	**<u>Heat Rate</u>**	**<u>Fuel Cost</u>**
New Simple Cycle Gas Turbine:	85.00 $/kW-Yr	10,000 BTU/kWh	3.50 $/mmBtu
<u>2. Low Avoided Cost Case</u>	**<u>Fixed Avoided Cost</u>**	**<u>Heat Rate</u>**	**<u>Fuel Cost</u>**
Existing Peaker:	10.00 $/kW-Yr	20,000 BTU/kWh	3.50 $/mmBtu

There are a number of entities in the Working Group 2 that proposed DRR options that were assessed in this benefit-cost framework. Results were given for proposals by:

1. California Power Authority (CPA) – The CPA Demand Reserves Partnership is a call option that has a modest reservation payment (monthly) and a modest energy payment.

2. Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) – All three utilities proposed a Demand Bidding Program (DBP) that was quite similar across the three utilities. While the programs vary in some details, they basically allow for customers to voluntarily reduce demand when requested by the utilities. The customer must submit bid commitments to reduce power via the program's Internet website. The customer needs a user ID and password to access the website. Once the customer logs on, they will be able to view the time period for the specific DBP event for which bids are being accepted.

3. Joint Utility CPP Proposal – The three utilities submitted a joint PG&E, SCE, and SDG&E's (Joint Utilities) Critical Peak Pricing (CPP) proposal designed to create a DRR offer that is more attractive for customers with large air conditioning loads, including commercial office buildings. It is based upon a conventional three period time-of-use rate, but incorporates two pricing levels for on-peak and part-peak electric usage. Specific features of the CPP rate are:
   - Offered to customers with demands of greater than 200 kW; most of these customers will already be equipped with appropriate interval meters.
   - Offered during the summer peak season (as defined in each utility's currently applicable tariffs).
   - Critical peaks will have two pricing levels, one for on-peak and one for the part-peak electric usage.
   - A fixed number of CPP operating days (e.g., maximum of 15 CPP days and a minimum of 5 CPP days, with rate design based on the assumption of a fixed number of CPP days as specified in final Phase 1 decision).
   - High-price CPP days to be communicated to customers on a day-ahead basis.
   - CPP days generally to be selected on the basis of forecasted utility-specific weather conditions within pre-determined zones.

   The proposed critical peak pricing parameters are as follows:
   - For usage between 3:00 and 6:00 p.m. on a CPP day, critical peak prices to be set at a level equivalent to five times the utility's specific otherwise-applicable total on-peak energy charge (that period most closely corresponds to the statewide system peak), and
   - For usage during the periods between 12 Noon and 3:00 PM and between 6:00pm and 7:00 PM on a CPP day, prices to be set a level equivalent to three times the utility's specific otherwise-applicable total partial peak energy charge.
4. SDG&E Hourly Pricing Option (HPO) – This DRR offer provides business customers with hourly energy prices on a day-ahead basis. Customers have the opportunity to decrease energy costs by shifting or reducing electric usage from higher priced to lower priced periods. The objective of HPO is to provide customers with price signals in an effort to shift or reduce usage from peak periods to non-peak periods. Customer benefits include reduced energy costs. System benefits include improved system efficiencies.

Each DRR offer must project the demand reduction amounts that would be attained. For the proposals outlined above,[37] the demand reductions over the hours in which the demand is reduced for each proposal are shown in Table 3-1.

[37] 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.

Table 3-1: Program Demand Reduction Amounts

Entity	Program	Demand Reduction MW	Hrs Reduced	Demand Reduction MWh
CPA	Call Option	200.0	100	20,000
Joint Utilities	CPP	140.0	84	11,760
SCE	DBP	30.0	84	2,420
PG&E	DBP	14.0	84	1,176
SDG&E	DBP	8.0	4	32
SDG&E	HPO	5.9	213	1,257

The results of the Total Resource Cost test for 1) the High Avoided Cost case, and 2) the Low Avoided Cost case are shown in Table 3-2 and Table 3-3 respectively.

Table 3-2: TRC Test Results for the High Avoided Cost Case

Entity	Program	NPV ($1,000)	Benefits/Costs	$NPV/MWh
CPA	Call Option	$69,594	2.13	0.32
Joint Utilities	CPP	$73,320	5.15	0.57
SCE	DBP	$18,296	15.25	0.66
PG&E	DBP	$7,958	9.12	0.62
SDG&E	DBP	$4,981	79.90	14.15
SDG&E	HPO	5.9	213	1,257

The results for the low avoided cost case are shown below.

Table 3-3: TRC Test Results for the Low Avoided Cost Case

Entity	Program	NPV ($1,000)	Benefits/Costs	$NPV/MWh
CPA	Call Option	-$36,478	0.41	-0.17
Joint Utilities	CPP	-$1,245	0.79	-0.17
SCE	DBP	$2,250	2.75	0.08
PG&E	DBP	$634	1.65	0.05
SDG&E	DBP	$530	9.40	1.51
SDG&E	HPO	-$263	0.57	-0.02

These results show that for the "High Avoided Cost Case" all of the proposed DRR options are cost-effective, i.e., they yield a net benefit and have a B/C ratio greater than one. Under the "Low Avoided Cost Scenario" three of the six DRR proposals are not cost-effective. The WG2 report also presents the Participant Test and the Ratepayer Impact Test, but the TRC test is the most commonly used across regions.

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. For example, none of the following benefits have been captured:

- Avoided Transmission & Distribution (T&D) upgrade costs;

• Benefit of any net reduction in air emissions (and other environmental externalities); and

• Value to customers of more timely and accurate information about electricity use.

Moreover, 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.” 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 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.

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. The ruling requests that utilities prepare similar cost-effectiveness forecasts for their 2006-2008 programs. These testimonies were filed on August 26, 2005. Each utility filing (i.e., SCE, PG&E, and SDG&E) contained some revisions to the SPM approach used in the Working Group 2 report, but the basics were the same in terms of using either an existing peaker or a new simple cycle turbine as the basis for the avoided costs.[38]

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.[39] This avoided cost study develops 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. A three period approach for forecasting prices is used in the study:

– **Period 1 (Market)**: Used through 2006, years before load-resource balance and with electricity forward trading. This period has observable forward prices.

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[38] The three sets of testimony updating the application of the Standard Practice Manual tests for DRR are:

1) “Supplemental Testimony Supporting Southern California Edison’s (U 338-E) Application for Approval of Demand Response Programs, Goals, and Budgets for 2006-2008 – Cost-effectiveness of Demand Response Programs and Overall Portfolio” Application No.: A.05-06-008, Before the Public Utilities Commission of the State of California, August 26, 2005. Witnesses – L. Ziegler, M. Whatley, S. Kiner, and D. Reed.

2) “Supplemental Testimony of David T. Baker, San Diego Gas & Electric Company,” Application Nos.: A.05-06-006, A.05-06-008, A.05-06-017, Before the Public Utilities Commission of the State of California, August 26, 2005.

3) “Pacific Gas and Electric Company Demand Response 2006-2008 Programs – Supplemental Testimony,” Application No.: 05-06-006, Before the Public Utilities Commission of the State of California, August 26, 2005. Witnesses: Antonio J. Alverez and Corey A. Mayers.

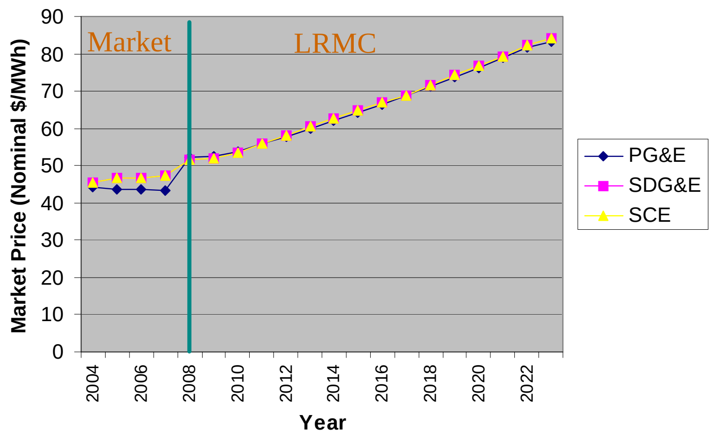
[39] See “*Methodology and Forecast of the Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*,” prepared for the California PUC, by Energy and Environmental Economics, Inc. (E3), October 25, 2004.

– **Period 2 (Transition)**: This contains the transition years between the end of Period 1 and the beginning of Period 3, (i.e., years 2006 and 2007) and is calculated as a linear trend.

– **Period 3 (Resource Balance)**: A workably competitive market environment implies a flat supply curve as defined by the Long Run Marginal Cost (LRMC), the all-in per MWh cost of new generation to meet an incremental demand profile. For the period from 2008 through the end of 2023, it is assumed that the annual average cost of electricity will be equal to the full cost of owning and operating a combined cycle gas fired generator (CCGT).[40]

The result is a forecast of average prices predicated on the avoided cost of a specific supply-side technology as shown in the Figure 3-1 (below) taken from the study.

Figure 3-1: Annual average price forecasts by utility (E3 Report)



Prices to the left of the resource balance year in 2008 are derived from energy forward and future markets, and prices after 2008 are based on the LRMC of a CCGT.

The approach to assessing the value of a dispatchable DRR product is to select the highest-cost hours given user-specified inputs such as energy strike price and maximum dispatch hours per day, month, and year. The shaping of prices to hours is based on past correlations.[41] This means that the avoided cost applied to DRR will be higher than the annual average LRMC used as the proposed avoided costs for energy efficiency programs. What these prices actually reflect is not clear, but the assumption is that an historical allocation of price patterns will continue into the future, possibly for as long as 10 to 20 years. This approach simply provides a different avoided cost for DRR that can be used in the SPM tests discussed above.

There still are no stochastic elements in the analysis that might lead to changes in reliability and insurance against low-probability/high-consequence events unless they are reflected in the historical pricing pattern used for the forecast. In addition, the pricing trend is around a fixed technology – a combined cycle gas turbine. However, this approach has some appeal over using the costs of a new simple cycle gas turbine

[40] 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.

[41] E3 allocates the annual generation prices to hours of the year using an hourly shape derived from the California PX hourly NP15 and SP15 zonal prices from April 1998 - April 2000 (p.49). Table 41 in the E3 report presents dispatchable program avoided costs as a function of hours per dispatch and dispatches per year (assumes no constraint on dispatches per month). The range of avoided costs is from $18.91 to $109.19 per kW-year depending on the number of times the resource can be dispatched (between 10 times and 160 times per year) and the number of hours allowed in each dispatch (between 1 hour to 16 hours). The report indicates that each dispatchable resource is dispatched during the highest price hours possible.

as the avoided cost for DRR, as this approach will capture price variability that has been observed in the market. If the historical period on which the forecasted hourly price pattern is based includes appropriate stress cases, then this approach will likely produce more appropriate avoided costs for DRR.

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

This section presents synopses of interviews with other entities that based their cost-effectiveness analyses of their DRR products/programs using the standard practice manual approach applying the same tests used for assessing energy efficiency programs.

Alliant Energy[42]

Alliant Energy (AE) is a medium-sized vertically integrated electric utility headquartered in Cedar Rapids, Iowa. AE's 2003 peak demand for its operations in Iowa was approximately 3,000 MW, and the company serves approximately 400,000 residential electric customers and 70,000 commercial and industrial (C&I) customers. AE offers several demand response programs to its customers, focusing on programs for its C&I customers. AE has aggressively marketed interruptible rate programs to these customers, and also offers direct load control and demand bidding or buy-back programs to them. For residential customers, AE offers a direct load control program for central air conditioners and water heaters.

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.

AE has developed a simplified spreadsheet benefit-cost analysis model, which is calibrated to a more complex model (this model uses hourly load shapes and avoided cost estimates to compute program benefits). In their 2001 filing with the IUB, AE estimates that the benefit-cost ratios are greater than one for all of their DRR programs, from all stakeholder perspectives.

Commonwealth Edison[43]

Commonwealth Edison (ComEd) is a large electric distribution company headquartered in Chicago, Illinois. ComEd's 2003 peak demand was approximately 22,000 MW in 2003, and it serves approximately 3.3 million residential electric customers and 300,000 commercial and industrial customers in northern Illinois. ComEd offers a large portfolio of demand response programs to its customers. For residential customers, they offer a direct load control program that cycles customer's central air conditioners on peak days, as well as a two-part time-of-day rate and a real-time pricing rate. For commercial and industrial customers, ComEd offers interruptible rates, TOD and RTP rates, and a demand bidding or buy-back program. ComEd is not actively marketing its DRR programs due to its projections of low spot market electric prices in its region for the near term, and has not actively used its DRR programs since 2001. However, new customers that hear about their DRR programs are eligible to participate in them, except for the interruptible rates program.

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

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

ComEd does not currently conduct long-term net-present-value based benefit-cost analyses of its DR programs. The company 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 day-ahead real-time electricity prices for the PJM power pool to the costs of activating ComEd's 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[44]

Wisconsin Public Service (WPS) is a medium-sized vertically integrated electric utility headquartered in Green Bay, Wisconsin. WPS' 2003 peak demand was approximately 2,700 MW, and the company serves approximately 450,000 residential electric customers and 45,000 commercial and industrial customers. WPS offers a large portfolio of demand response programs to its customers, focusing on programs for commercial and industrial customers. WPS offers almost every type of DRR program to its commercial and industrial customers: interruptible rates, direct load control, time-of-day rates, critical peak pricing, real-time pricing, and demand bidding or buy-back programs. For residential customers, WPS offers a direct load control program for central air conditioners and water heaters, as well as a two-part time-of-day rate and a critical peak pricing rate.

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 EGEAS generation planning modeling into their DRR program benefit-cost analysis. In their August 24, 2005 filing with the Public Service Commission of Wisconsin, they estimate that the benefit-cost ratios are greater than one for all of the DRR programs that they are planning to expand over the next four years, from all stakeholder perspectives.

3.2.4 DRR Network and Hedge Benefits – Study for the 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.[45] 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.

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

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

The analysis was done from four different perspectives. These perspectives reflect the various beneficiaries involved – total resource cost, utilities and customers as a whole, participating customers, and utilities. Similar to the approach taken in California and among many utilities in the United States, the *Standard Practice Manual*, developed by the California Public Utilities Commission and the California Energy Commission, provided the basic model for the benefit-cost analysis; however, a preliminary valuation of the benefit of network DRR to the South Australia electricity retailers as a hedge against high spot prices in the wholesale market was also incorporated in this cost-effectiveness analysis.

The scope of work for this assessment was comprised of four steps:

- *Step 1* – developing a short-list of the network areas where DRR strategies and interval meter pricing signals had high potential to defer peak capacity driven supply-side augmentation.
- *Step 2* – providing a high level review of the DRR strategies applicable to ETSA Utilities' distribution network state-wide.
- *Step 3* – undertaking a detailed assessment of the relative cost-effectiveness of using DRR or interval meter pricing signals to delay supply-side upgrades on the short-listed networks from Task 1.
- *Step 4* – defining regulatory issues that could impede the implementation of demand-side activities by ETSA Utilities, and recommending mechanisms to overcome perceived barriers.

Three network areas selected from a shortlist of nineteen provided by ETSA Utilities, for detailed analysis of the potential for DRR or innovative pricing strategies to defer supply-side capacity augmentations. The areas selected were:

- Findon-Fulham Gardens feeders;
- North Adelaide zone substation; and
- Modbury area feeders.

Key selection criteria included:

- The quantum of peak load reduction required to achieve a one-year deferral in each of the areas;
- The size and composition of the customer base that could potentially provide demand side load reduction within each area; and
- The proposed timing of ETSA Utilities' preferred supply-side option.

Together, these criteria provided a preliminary indication of the likelihood that sufficient demand-side load reduction resource is present to achieve a deferral of capital expenditure on network expansion for at least one year.

The programs examined in the report are:

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

After analysis of the above DRR programs, it was determined that there was unlikely to be sufficient DRR available in either the Findon-Fulham Gardens or the Modbury areas. In addition, it was concluded that innovative pricing supported by interval meters would not provide sufficient load reduction in these areas. Therefore, no further analysis was undertaken on Findon-Fulham Gardens or Modbury.

In contrast, the re-assessment of the network constraint in the North Adelaide area gave a very positive result. In summary, the 3.5 MVA of load reduction that could potentially be obtained from DRR programs in North Adelaide is over 6 times greater than the 0.5 MVA needed for a one-year deferral of the supply-side augmentation. This could be obtained from a suite of programs including:

- Curtailable loads, standby generation, and power factor correction in large commercial and industrial facilities (estimated load reduction of 3.2 MVA);
- Voluntary load reduction in medium businesses (estimated load reduction of 0.05 MVA);
- Direct load control in small business sites and residential premises (estimated load reduction of 0.18 MVA); and
- Interval meter based pricing strategies could potentially result in 0.48 MVA of load reduction from small business and residential customers.

Based on this analysis, DRR appears to be the preferred strategy in the North Adelaide area. No further analysis of innovative pricing supported by interval meters was undertaken for North Adelaide. A refinement of the market potential for DRR in North Adelaide was conducted based on telephone interviews with large business customers.

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;
- 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.

Table 3-4 below shows the components of benefits and costs for each of these perspectives.

Table 3-4: Benefits and Costs of Each Test

Test	Perspective	Benefits	Costs
Total Resources Cost	Change in average cost of energy services across all customers	Avoided supply-side costs (network capacity)	Capacity costs Program costs paid by utility and participant
Participant	Benefits and costs to a typical participating customer	Bill reductions Customer incentives	Bill increases Program costs paid by participant Participation fees
Utility	Change in costs to the utility	Avoided supply side costs Participation fees	Customer incentives Program costs paid by utility
Ratepayer Impact Measure	Difference between change in total revenues for utility and change in costs to utility	Avoided supply-side costs	Revenue loss Customer incentives Program costs incurred by utility

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. The study refers to these additional benefits as Retail Benefits.

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. The results of the study were that not all of the programs had a benefit-cost ratio of higher than 1 for all of the different types of ratios calculated when only network benefits were included. However, when retail benefits were also included all of the programs had a BCR higher than 1, for all of the perspectives taken, as shown in Table 3-5 below.

Table 3-5: North Adelaide DRR Impacts and BCRs (Network and Retail Benefits)

Program	Number of Customers	Estimated Load Reduction (MVA)	Utility BCR	Participant BCR	TRC BCR	ETSA Costs ($/kVA)
Standby Generation	2	0.683	4.4	18.0	6.5	184
DLC ()	222	0.230	3.2	No cost to participants	3.2	251
PF Correction	4	0.470	3.1	2.1	1.6	73
Curtailable	2	0.096	2.3	13.5	2.8	345
VLC	6	0.024	1.2	No cost to participants	1.2	1,084
Total	***236***	***1.503***				

At the request of the Commission, the additional value of utilizing the network DRR resource as a hedge against high spot prices in the wholesale market was evaluated. This resource is particularly attractive to electricity retailers who make use of physical load reduction to offset market price spikes resulting from reduced generation or network capacity. As can be seen from the summary of results presented in Table 3-6 below, the inclusion of this additional benefit significantly increases the BCR for all programs with the exception of power factor correction, and in fact, all of the DSM measures evaluated become cost-effective.

Table 3-6: North Adelaide DSM Impacts and BCRs (Network & Retail Benefits)

Program	Utility BCR	Participant BCR	TRC BCR
Standby Generation	4.4	18.0	6.5
DLC	3.2	No cost to participants	3.2
Power Factor Correction	3.1	2.1	1.6
Curtailable Load	2.3	13.5	2.8
VLC	1.2	No cost to participants	1.2

The process used to estimate the hedge value was not entirely clear from the report. It does not seem to incorporate any assessment of uncertainty. Instead, it appears to be based on a review of the highest pool prices of a historical four year period. On page 105 of the study, it states that the "savings in avoiding high pool prices was based on a review of the highest pool prices over the last four years." A weighted average pool price between 2001 and 2004 for all half hours with a price of $500 and above was $946 per kW. The study authors "assume that ETSA offers this load to retailers as a physical hedge at 50 percent of the pool price." This also assumes that ETSA has the capability of obtaining this load from some physical source to be supplied as needed. It is unclear if this would conflict with the load needed to attain the network benefits. The assumption must be that ETSA can obtain load from DRR options in excess of that needed for the network benefits. If the load used as a hedge against high pool prices is also needed to achieve a deferral of network capital expenditures least one year, then additional investment in DRR may be needed.

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 programs 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.

Expected Outages and Disconnected Load

The occurrence of outages and the magnitude of their impact can be estimated from historical data and projections based on changes in available capacity and system demand. Recent outages due in part or in whole to inadequate generating capacity can be a starting point for the analysis, as they comprise empirical data that directly relates to unserved energy. Utility projections of loss of load probability, along with the associated MW of interrupted demand can also be used.

Some utilities may have generator trip reports, which record the times that generators "trip off" due to lower system frequencies or other triggers. If generating reserves are low, or if demand response resources displace an equivalent amount of generation, then when a generator trips off there may not be another generator to take its place. In the absence of demand response, outages would occur, perhaps for the entire duration of the generator outage. Based on which generator tripped and on system conditions at the time, the magnitude (MW) and duration (hours) of the interruption can be estimated for each event on the trip reports to yield an estimate of the annual MWh of unserved energy.

Value of Lost Load (VOLL)

Forced outages impose costs on customers that range from inconveniences, such as less than ideal environmental conditions, that are hard to quantify, to costs that are amenable to measurement, like the cost of make-up or lost output, equipment damage, etc. Studies of VOLL indicate that it varies according to the timing and duration of the outage, how much notice was given of its onset, and the particular circumstances of customers.[46] VOLL values range from negligible, generally associated with minor inconveniences like having to reset clocks, to extraordinary, as is the case with some continuous manufacturing processes, for example paper production or steel melting, where a unexpected disruption produces disastrous and costly consequences. Thus, the range of VOLL values is large, from zero to over $100/kWh.

Several real-time pricing programs in the U.S. have assumed a VOLL of $3.00-5.00/kWh to set the capacity rationing component of hourly commodity prices.[47] Recently, PJM Interconnection proposed a capacity market design predicated on a VOLL of almost $20/kWh. The method adopted by ISO-NE and

[46] Lawton. L., Sullivan, M., Van Liere,, K., Katz, A. November 2003. A Framework and Review of Customers Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys, Lawrence Berkeley National Laboratory report LBNL-54365, available at www.LBNL.gov

[47] Barbose, G., Goldman, C., Neenan, B. December 2004 Survey of Utility Experience with Real-time Pricing. Lawrence Berkeley National Laboratory. LBNL-54238. Available at: http://eetd.lbl.gov/EA/EMP/drlm-pubs.html

NYISO to value their demand response programs, which has been endorsed by FERC, uses a VOLL between $2.50-5.00/kWh.[48]

Given the uncertainty, a suggested approach is to bracket the value of reliability using a range of plausible values for outages, disconnected load, and VOLL. For example, with annual outage hours in the range of 10 to 50, and the average percent of peak load affected by the outages ranging from 1% to 10%, the expected unserved energy for a 10,000 MW system would be between 1 GWh and 50 GWh (Table 3-7).

Table 3-7: Annual Expected Unserved Energy (GWh)

	(Peak Load = 10,000 MW) Portion of Load Not Served		
Annual Outage Hours	**1%**	**5%**	**10%**
10	1.0	5.0	10.0
25	2.5	12.5	25.0
50	5.0	25.0	50.0

At $2.50/kWh as an assumed VOLL, the cost of the outages would range from $2.5 million to $125 million. At a VOLL of $5/kWh, these values would be double (Table 3-8). By narrowing down the range of plausible inputs, or by assigning probabilities to these inputs, utilities can more precisely assign a value to the improved reliability achieved through demand response. This improvement in system reliability is, after all, the real value of demand response programs.

Table 3-8: Annual Value of Curtailable Load ($ millions)

	VOLL=$2.50/kWh			VOLL=$5.00/kWh		
(Peak Load = 10,000 MW)	**Portion of Load Not Served**			**Portion of Load Not Served**		
Annual Outage Hours	**1%**	**5%**	**10%**	**1%**	**5%**	**10%**
10	2.5	12.5	25.0	5.0	25.0	50.0
25	6.3	31.3	62.5	12.5	62.5	125.0
50	12.5	62.5	125.0	25.0	125.0	250.0

3.3.1 Reliability Benefits – NYISO Analysis of DRR Benefits (USA)

The New York Independent System Operator (NYISO) conducted a retrospective study[49] in 2003 that examined the benefits of its DRR programs of 2001 and 2002. As a retrospective research effort, there was no attempt to estimate the future benefits of these programs or the role that they might play in meeting future resource needs. However, this work was groundbreaking, in that it was the first to attempt to quantify benefits that accrue to the broader market (i.e., beyond those accruing to direct program participants), and thus to comprehensively measure the value of DRR. It also addressed the reliability benefits of DRR.

[48] RLW Analytics and Neenan Associates. December 2003. *An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2003.* Annual Demand Response Program Evaluation submitted to FERC. Available at www.ISO-NE.com

[49] *A Study of NYISO and NYSERDA 2002 PRL Program Performance*, Neenan Associates, January 2003

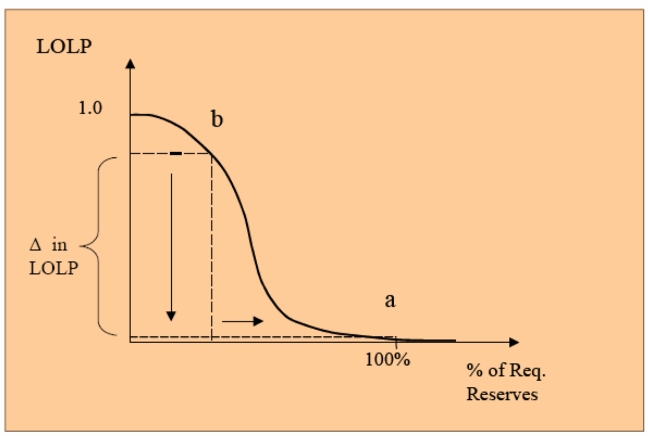
The NYISO launched two programs: the Emergency Demand Response Program, which provided the bulk of the load curtailment MW, and the Day-Ahead Demand Response Program.

- Emergency Demand Response Program (EDRP): Provides a stock of dispatchable resources to support reserves during system emergencies. Participants receive two hours' notice of impending curtailment events, and are paid the Locational Based Marginal Price or $500/MWh (whichever is higher).
- Day-Ahead Demand Response Program (DADRP): Participants submit demand reduction bids (comparable to the supply bids of generators) for load reductions scheduled for the next day, and receive market prices for actual load reductions. Curtailment shortfalls are settled at the day-ahead price or real-time market price (whichever is higher) plus a 10% penalty.

System Reliability Benefits Using LOLP

The NYISO study analyzed the effect of the Emergency Demand Response Program on system reliability. The EDRP was designed to provide dispatchers with a way to improve system reliability. In fact, the NYISO counts dispatched EDRP load as operating reserves. The benefits from the EDRP depend on the relationship between total system reserves and the Loss of Load Probability (LOLP): as reserves fall, at some point LOLP begins to rise steeply, which increases the likelihood that load will need to be shed in order to maintain system stability, thus impacting customers (as shown in Figure 3-2 below).

Figure 3-2: Value of Expected Unserved Energy



In order to quantify the reliability benefits of the emergency program, the change in LOLP due to the program needs to be determined. This is then multiplied by the amount of load subject to outages (or "expected unserved energy'), and by the Value of Lost Load (VOLL). It is common to calculate reliability benefits over a range of values of change in LOLP and VOLL, so that reasonable upper and lower bounds are set on the cost to customers of forced outages.

Total Benefit-Cost Analysis

The analysis conducted by NYISO defined and quantified benefits resulting from program participation according to three benefit categories and one cost category:

Benefit #1: Market Price Benefits – Estimated transfer (collateral) benefits. Termed "Collateral Savings" in this analysis, this is defined as the reduction in market-clearing prices in spot markets which have been impacted by DRR. Also referred to as "Benefits to Non-participant Buyers."

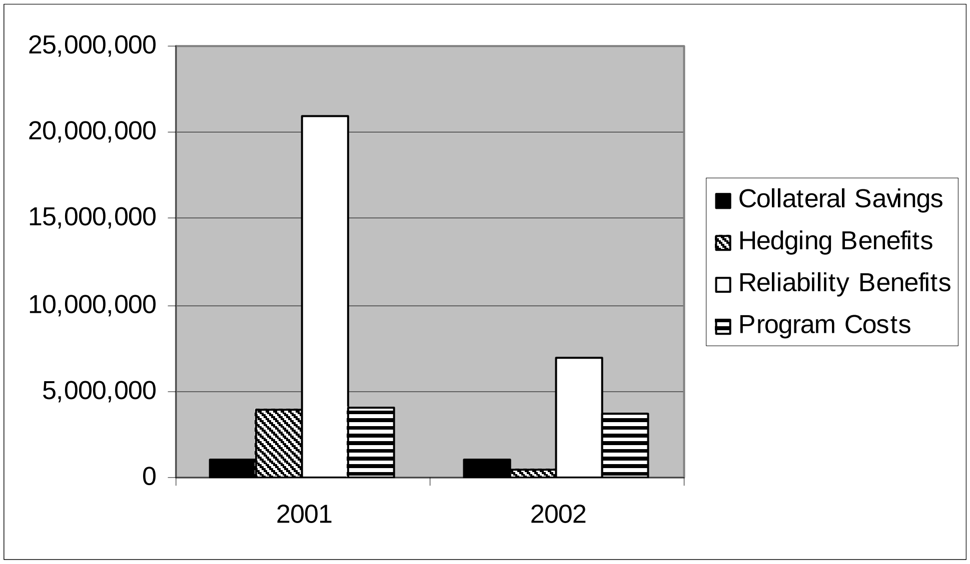
Benefit #2: Hedging Benefits – Estimated reduction in the cost of hedging loads. Termed "Hedging Benefits", this is defined as the savings due to reduced average prices and price variability in the market. This results in reduced transaction costs and improved market liquidity for all MW transactions.

Benefit #3: Reliability Benefits – Effect of Emergency Demand Response Program load reductions on system reliability. Termed "Reliability Benefits", this is defined as the reduced probability of customer outages multiplied by the outage costs.

Costs: This is defined as program costs, including payments to DRR participants for verified load reductions.

As shown in Figure 3-9 below, in the NYISO results reliability benefits were far higher than hedging or collateral benefits.

Figure 3-3: Results of NYISO'S Study



Lessons Learned from the NYISO Study

The experiences of the NYISO are instructive in several areas.

Collateral Market Benefits

NYISO encountered resistance from generators regarding the valuation of collateral benefits. Generators argued that the reduction price to the broad market was simply wealth transfer — from one pocket to another — and didn't represent any real increase in value. This, in part, caused NYISO to refine their study processes from 2001 to 2002. The conclusion reached was that it is appropriate to assign the benefits of the reduction to the MW in the real time energy market (e.g., any MW that is directly impacted by the real-time price). NYISO also concluded that the DRR participation had a direct impact on 50% of the 5-minute intervals during an event, versus the 100% they had assumed in the previous year. This refinement seems logical and more accurate.

Hedging Benefits

Hedging benefits represent the estimated savings due to reduction in both average prices and price variability in the market, resulting in reduced transaction costs and improved market liquidity. Hedging benefits, as calculated by NYISO, are an estimate of the long-term reduction in the cost of hedging load. The intent was to capture the savings over time due to DRR-influenced reductions in price volatility and transaction cost savings, and the lessened cost in forward-looking hedging instruments. NYISO attempted to include the impact on bilateral contracts in the hedging benefit calculation.

It should be noted that NYISO performed a conservative estimate of the hedging cost savings, based on the reduction in mean price. NYISO calculated the standard deviation of these mean values, as well as the coefficient of variation as an indication of the impact of DRR on price volatility. However, the NYISO did not incorporate reduced price variability into their estimation of hedging cost savings, stating that such a calculation would require information on the risk aversion characteristics of customers as a group and that such information was beyond the scope of the study.

Reliability Benefits

Reliability benefits due to DRR were estimated by using the Value of Expected Unserved Energy, which represents the costs associated with service disruptions. This is calculated by multiplying the reduction in Loss of Load Probability (LOLP) by the estimated outage cost for the amount of load at risk. The NYISO reliability estimate for 2002 is $32 million, based on the sum of April and the summer months at 25% LOLP improvement, $10,000/MWh customer outage cost, and 5% of the system load at risk. Discussions with NYISO personnel indicated that ranges between 5% and 90% were considered as possible values for "load at risk" and they decided to use what they believed was a conservative number.

Other Market Issues – Market Barriers, Innovation and Market Power

Market barrier costs remain one of the more elusive pieces of the analysis. Under current pricing structures, few consumers in the NYISO area see market prices and therefore few have any incentive to adjust consumption in response to higher prices. There is consensus in the industry that market barriers to customer response of many types exist, and that they should not be ignored when assessing the accomplishments of DRR programs.

The NYISO study did not determine numeric inputs for market barriers, innovation, or market power. The NYISO did conduct a customer satisfaction survey for both of their DRR programs, but the study did not assign a dollar value for reducing or influencing any market barriers to encouraging customer response to higher prices, and thus did not capture the quantitative impact of the barriers.

3.3.2 NYISO 2004 Update on Benefits and Costs -- Compliance Report on Demand Response Programs[50]

The three types of market effects estimated in preceeding years' benefit-cost studies were also estimated for the summer of 2004. These values are compared to those from 2001 through 2003 in Table 3-9. The lower level of scheduled DADRP bids in 2004 resulted in a 78% reduction collateral savings and reduced hedge costs. Collateral impacts measure the reduction in the cost of DAM and RTM purchases by LSEs resulting from DADRP scheduled curtailments depressing prices. Hedge cost impacts estimate the ripple effect lower prices in the DAM during curtailment hours are postulated to have on future bilateral contract supply costs.

[50] 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.

Table 3-9: Benefit Categories and Program Costs[51]

Year	Scheduled DADRP MWhs	Collateral Savings	Reduction in Hedge Cost	Total Market Effect	Program Payments
2001	2,694	$892,140	$682,358	$1,574,498	$217,487
2002	1,468	$236,745	$202,349	$439,094	$110,216
2003	1,752	$45,773	$161,558	$207,331	$121,144
2004	675	$8,996	$36,940	$45,936	$40,651

In addition to replicating the estimates from the benefit-cost methods used in preceeding years, the NYISO developed a qualitative and quantitative approach designed to better weigh program benefits against implementation and support costs. Quantitative costs include:

- Payments to market participants
- Internal labor costs
- Consultant fees
- Maintenance fees for software development and support

Qualitative rankings were determined for four significant demand response categories:

- Avoided risk
- Customer satisfaction
- Environmental impact
- Market efficiency

A judgment was developed from both these quantitative and qualitative costs and benefits. The overall cost/benefit ratio was calculated as a "ranking model" from a combination of the two approaches.

For the quantitative evaluation, a straightforward comparison of costs (including payments to participants, consultant fees, and software development and maintenance) with benefits (market impact) was done.

For the qualitative evaluation, the four aspects of program effects were ranked on a scale from 0 to 4. These were not strictly monetary values but judgmental ratings of how much the DRR influenced that category. The scoring system was as follows:

> *A score of 4 indicated "high" impact on the category. A score of "1" indicated no change, and a "0" implied that there was actually a negative effect. This qualitative scoring allowed for a core benefit matrix to be developed, such that equal 10% weightings were assigned to each category, totaling 40%. For each program year and for the total program period (2001-2004), a ratio of costs to*

[51] The 2004 NYISO benefit-cost update developed estimates for the three benefits categories used in previous years. It also attempted to assess the elasticity of the electricity demand and supply surveys based on bids in the Day-Ahead Market. From these elasticity estimates, an estimate was made of the net social welfare impacts of the DADRP program. The change in NSW reflects a change in allocative efficiency of scarce resources due to customers on a flat rate being able to express their changing value for electricity through load-curtailment bidding. This analysis showed that it was possible to have negative changes in allocative efficiency. This led to implications for program design. The NYISO intends to work with its Market Participants during 2005 to develop DADRP enhancements that facilitate the submission of standing bids and the notification of participants when their standing bids have been accepted. The goal being to have DADRP bids standing ready to be accepted in the event that prices spike to levels that make them economic.

benefits was developed. The remaining 60% of the overall evaluation used the cost-to-benefit ratio, normalized to the 0 to 4 scale. The complete ranking model is:

*0.1 * (avoided risk + customer satisfaction + environmental impact + market efficiency) + 0.6 *(4 – cost/benefit ratio)*

The results of this mixed quantitative and qualitative benefit/cost analysis for the DRR programs in the period 2001 to 2004 (as shown below in Table 3-10) show that both the EDRP and DADRP programs had a positive payback to the marketplace – 3.06 for the EDRP and 2.91 for the DADRP. This is despite there being no measured benefits for 2004 as there were no demand response events.

Table 3-10: EDRP and DADRP Cost/Benefit Analysis

EDRP Cost/Benefit Analysis

		2001	2002	2003	2004	01 - 04
Labor		$58,603	$58,603	$58,603	$48,717	$224,525
Payments to Participants		$4,167,079	$3,513,508	$7,344,377	$0	$15,024,964
Consulting		$0	$86,667	$86,667	$86,667	$260,001
Software, Maintenance		$0	$113,000	$26,000	$40,000	$179,000
Total Program Costs		$4,225,682	$3,771,777	$7,515,646	$175,384	$15,688,487
Market Impact		$8,159,000	$7,028,000	$60,137,000	$0	$75,324,000
Qualitative Criteria	Weighting					
Avoided Risk	10%	3.00	2.00	4.00	1.00	2.50
Customer Satisfaction	10%	3.50	2.50	2.50	3.00	2.88
Environmental Impact	10%	0.75	0.50	1.50	1.10	0.96
Market Efficiency	10%	2.00	1.00	2.00	1.00	1.50
Core Benefits Score	40%	2.31	1.50	2.50	1.53	1.96
Cost/Benefit Ratio	60%	0.52	0.52	0.12	N/A	0.20
Overall Weighted Score (0-4, 4=highest)		3.01	2.69	3.33		3.06

Table 10: DADRP Cost/Benefit Analysis

DADRP Cost/Benefit Analysis

		2001	2002	2003	2004	01 - 04
Labor		$20,453	$9,818	$9,818	$12,272	$52,360
Payments to Participants		$217,487	$110,216	$263,311	$120,136	$711,150
Consulting		$0	$43,333	$43,333	$43,333	$130,000
Total Program Costs		$237,940	$163,367	$316,462	$175,741	$893,510
Market Impact		$1,570,998	$439,094	$207,331	$32,802	$2,250,225
Qualitative Criteria	Weighting					
Avoided Risk	10%	2.00	2.00	2.00	2.00	2.00
Customer Satisfaction	10%	4.00	1.50	0.50	1.00	1.75
Environmental Impact	10%	2.00	2.00	2.00	2.00	2.00
Market Efficiency	10%	3.00	1.00	1.00	1.00	1.50
Core Benefits Score	40%	2.75	1.63	1.38	1.50	1.81
Cost/Benefit Ratio	60%	0.15	0.30	1.67	5.36	0.36
Overall Weighted Score (0-4, 4=highest)		3.41	2.87	1.95	-0.21	2.91

<u>NYISO Overall Assessment of the Cost/Benefit Ratings</u>

It is difficult to interpret a mix of qualitative and quantitative information with somewhat arbitrary weightings; however, the NYISO's interpretation indicated that the EDRP/SCR programs showed a payback within six months during the period 2001 to 2003. While costs continue to be incurred each year, there may be a year when there is no measured market benefit (as occurred in 2004) due to the lack of demand response events. Since earlier years reflected a relatively short payback, the lack of events over a 2-3 year period would still provide a positive overall payback to the marketplace.

DADRP is trending toward longer payback periods as a direct result of the lack of opportunity for demand-side resources to schedule reductions at cost-effective prices. The absence of these opportunities does not reflect problems with program design or implementation; they reinforce the basic balance between supply and demand, with current market conditions resulting in lower energy prices and price volatilities.

The day-ahead program shows a trend toward a longer payback period because of a lack of opportunity for demand-side resources to schedule reductions at cost-effective prices. However, the absence of these opportunities does not reflect problems with the program design, but they do confirm the existence of a balance between supply and demand, with market conditions lowering energy prices and the price volatility of the market.

3.3.3 ISO-NE 2004 DRR Evaluation[52] (USA)

A full evaluation of the DRR programs run by Independent System Operator – New England (ISO-NE) in 2004 was performed at the end of that year, including descriptions of the programs, participation rates, market impacts, process evaluation, and a market assessment. The ISO-NE implemented several programs in 2004:

1. Reliability Programs: the Real-Time Demand Response Program, with 30-minute and 2-hour notice provisions, and the Real-Time Profiled Response Program, for customers with loads capable of being interrupted within 2 hours of being notified.
2. Pricing Programs: the Real-Time Price Response Program, designed to encourage load reduction in response to high wholesale energy prices.

The reliability programs were not activated in 2004 due to there not being any reliability events. However, both programs were tested once during the summer. The pricing program paid for load curtailment on 56 days, for a total of 2,132 event hours and 9,216 MWh of load curtailment. The peak participation day was in January 2004, when there was a severe cold snap and an interruption of natural gas supplies to generators, which caused prices to rise, reaching over $900 in some hours.

<u>ISO-NE Market Impacts Estimation</u>

The study includes an estimate of the market impacts of the price responsive program in two ways – impact on real-time Locational Marginal Price (LMP) (i.e., bill savings), and indirect market impact (i.e., hedge savings) due to lower price volatility reducing the premiums paid by purchasers of bilateral contracts.

The methodology for estimating the program impact on the real-time LMP consisted of developing a statistical representation of the relationship between load and LMP in the real-time energy market. Event-specific price impacts were estimated by adding the curtailed load back into the load actually served in each event hour. The intersection of this higher load with the simulated supply curve gives an estimate of the LMP that would have been set had the DRR not been in place. The difference between the actual and simulated LMP is a good estimate of the price effect of load curtailments. The savings are calculated as the estimated price reduction times the load transacted.

The methodology for estimating the indirect program impact, or hedge savings, on the market consisted of calculating the effect of the DRR on average monthly prices, which were lower due to the lower prices in the event hours. The savings were estimated by multiplying the reduction in average prices by the amount of load purchased through bilateral contracts. The study notes that in reality, there is a time lag in market reaction, so although some impacts are realized soon after the events, others are realized only in the following months or years.

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[52] 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.

These calculations were done for three periods of the year, to account for seasonal differences in market behavior – fall/spring, winter, and summer. A Market Impact Ratio was calculated for each season by finding the ratio of total savings (bill savings plus hedge savings) to total program payments. The Market Impact Ratio for the whole year was 469%, showing that benefits exceeded payments by more than a factor of 4. The results are shown in Table 3-11 below.

Table 3-11: Price-Response Program Benefits

ISO-NE Price Response Program Impacts					
Season	Bill Savings	Hedge Savings	Total Savings	Program Payments	Market Impact Ratio
Fall/Spring	$7,313	$900,375	$907,687	$196,336	462%
Winter	$212,674	$3,405,415	$3,618,089	$801,269	452%
Summer	$2,759	$347,814	$350,573	$42,601	823%
Total	$222,745	$4,653,603	$4,876,349	$1,040,206	469%

Bill savings are the price change in the real-time market times the load that cleared in real-time

Hedge savings are the corresponding reduced change in the monthly average real-time prices times the bilaterally contracted load

The study summarizes the market impacts as follows:

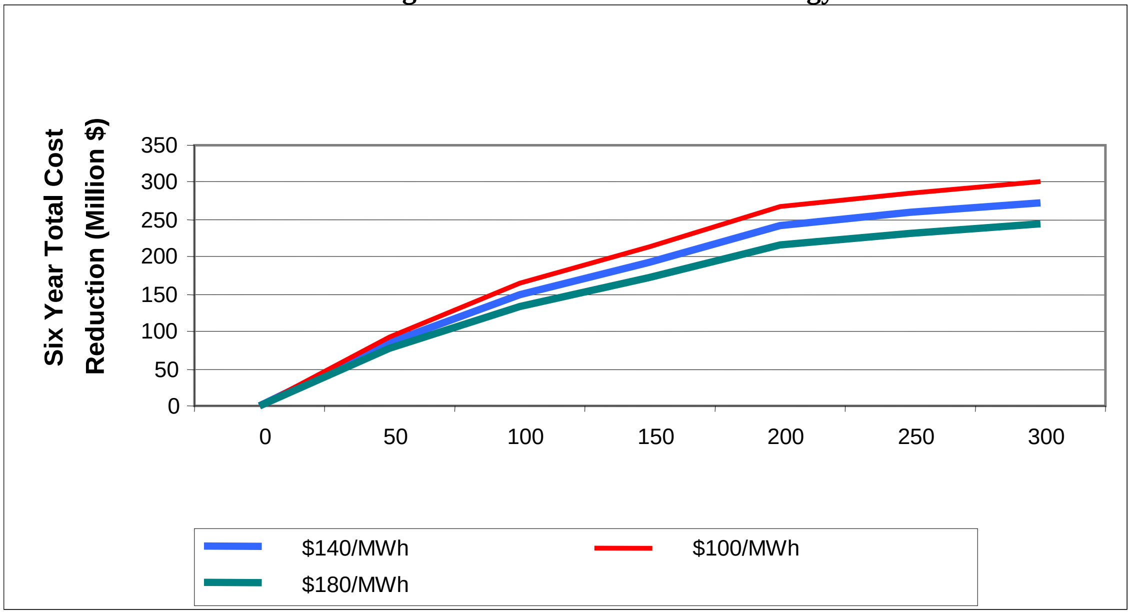
> *The Bill and Hedge savings represent transfers from suppliers to retailers, and ultimately to consumers. The savings go to retailers in the form of higher operating margins if they are selling electricity to consumers under fixed priced agreements, or under fixed tariffs in the case of utilities offering standard offer/default service. However, the combination of regulation and competition eventually will result in these benefits being passed on to retail consumers in the form of lower retail prices or tariff rates.*

3.3.4 DRR Benefits in the ISO-NE 2002 Regional Transmission Plan

The ISO-NE Regional Transmission Expansion Plan (RTEP02) is intended to provide market signals appropriate for the planning of generation, merchant transmission facilities, elective upgrades, demand-side management, and Load Response Programs. In addition, the process is intended to summarize a coordinated transmission plan that identifies appropriate projects for ensuring a reliable electric system and reducing congestion in an economic manner.

The RTEP02 study examined the benefits from DRR in various congestion areas. Figure 3-4 below represents the ability to use DRR like a generator at various trigger prices. At a market price of $140/MWh, 170 MW of DRR would reduce congestion costs by $210M over 6 years, or roughly $35M per year. This indicates that adequate levels of DRR could provide substantial benefits in selected load pockets.

Figure 3-4: ISO-NE Collateral Savings Based on RTEP02 Methodology.



Source: RTEP02 Study, p. 23.

Here are some of the major findings in the RTEP02 report:

- Load response and/or demand-side management programs in constrained sub-areas have the potential to significantly reduce forecast congestion and improve reliability.
- Taking into account transmission improvements that went into service during the summer of 2002, projected congestion costs could range from $50M to a high of $300M for 2003. However, significant peak load reductions would cause congestion costs to be reduced.
- An addition of 250 MW of load response would not only reduce average market prices, it would also significantly reduce the magnitude of forecast price spikes from $500/MWh with 0 MW of load response to $150/MWh with 250 MW of load response.

3.3.5 DRR Benefits in the ISO-NE Update in the Regional Transmission Plan for 2003

The follow-up document to RTEP02, RTEP03 (November 2003), reaffirmed the important reliability and economic impacts that DRR can bring if widely adopted. Incremental reliability and congestion analyses done in this report demonstrate that small amounts of demand response in constrained areas will significantly improve reliability and reduce congestion.

ISO New England's 2003 Demand Response Program signed up approximately 400 MW of relief for the summer 2003 period. One specific program provided 20 MW of load relief and over 60 MW of emergency generation for use during high load periods. The report also reviewed existing amounts of Distributed Generation, including renewable resources, and projections for their market growth. These projections do not indicate a rapid expansion of Distributed Generation over the next five years or so. They suggest the time frame for significant penetration will be more like 10 to 15 years.

ISO New England recommends continued expansion of the Demand Response Program. It also recommends continuance of outreach activities to enhance the adoption of distributed resources, including both demand response and distributed generation, particularly in the constrained areas of New England.

3.3.6 PJM DRR Program Evaluation

PJM's Market Monitoring Unit evaluated all the 2004 PJM DRR programs in 2004. [53] This study covered two DRR programs – the Economic Program, and the Non-Hourly Metered Pilot Program. These programs were evaluated for participation and for benefits and costs. The economic program had 1,109 MW registered in 2004, and a total of 31,719 MWh load reductions was implemented. There was very little activity for the day-ahead option of the program, and 94% of the activity resulted from the real-time option under the economic program.

Costs for the economic program were estimated in the report as less than $1/MWh of load reductions for administrative costs, and $4/MWh for payments for load curtailment by LSEs. The study states that the benefits of the program can be estimated by looking at the reduction in the market clearing price. The dollar value of the benefit is the change in market price multiplied by total load at the time. In 2004, the maximum impact of the program was estimated as $1/MWh, as the combination of mild weather and changes in supply and demand conditions resulted in lower prices overall.

Despite the low savings per MWh in 2004 (a maximum of $1/MWh as compared to a maximum of $50/MWh in 2002) the program benefits still outweigh the costs by a large amount. Even using a conservative figure of $0.50/MWh market price reduction, when it is multiplied by the average hourly load during the load reductions, 48,000 MW, and adjusted for the share of the spot market in total activity (about 40%), the market price benefits are about $22M – much larger than the direct costs of the program. No estimate of reliability or other market benefits was made.

The study did not include a figure for the benefit-cost ratio, as it was intended only to demonstrate that there are substantial net benefits to the economic program. It notes that:

> *The evaluation of the benefits associated with overall market price reductions must consider that these benefits do not necessarily represent an increase in market efficiency, but represent a transfer from generation to load, in the short term. Regardless, the potential benefits of increasing demand side responsiveness in improved efficiency of the market are extremely large and certainly exceed the relatively small program costs by a wide margin.*

3.3.7 Transmission Network Benefits of DRR (Sweden)

This study[54] examines the ability of DRR to enhance reliability and provide transmission congestion relief. It looked at both interruptible loads as well as a cost-benefit analysis of the long-term investment in fast start-up generators at selected buses on the transmission system. The study looked at various issues related to interruptible load management when used to improve system reserve margins by ISOs, especially in the case of supply-side contingencies and transmission congestion. It found that interruptible load management can provide additional generating reserves that are as reliable as normal supply-side generation, but at lower costs.

In order to model the use of interruptible load, a Congestion Relief Model was proposed by the author, based on an optimal power flow framework which can be used for the real-time selection of interruptible load offers while satisfying the congestion management objective. The model can specifically identify buses where corrective measures need to be taken for relieving congestion over a particular congested line. The scheme is very effective in handling system congestion, and the interruptible load market proves to work efficiently. The CIGRE 32-Bus system has been used for the case study.

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[53] *Compliance Report to the FERC – Assessment of PJM Load Response Programs,* October 31, 2004

[54] Le Anh Tuan, *"Interruptible Load Services in Deregulated Power Markets"* Thesis for the Degree of Licentiate of Engineering, Chalmers University of Technology, Gotenborg, Sweden, April 2002.

To evaluate the long-term congestion management solution of using fast-startup gas turbine generators, the author has developed a framework based on traditional cost-benefit analysis. This involved a planning exercise to determine the location and size of gas turbine generators at different buses in the network such that the total cost of investment in the generators and the cost of system congestion is minimized. A bus-by-bus cost-benefit analysis was carried out by solving iteratively a DC optimal power flow model. It was shown that the long-term decisions on investment in gas turbines should be very much dependent on the opportunity cost of the generators with respect to the system transmission capacity available and the associated congestion problems.

The study shows that pricing, generation re-scheduling, or even the use of interruptible load can introduce new inefficiencies into the system when used to address transmission capacity shortages and the associated congestion problems. An objective function was used, and the "opportunity cost" of not installing the turbine was termed the congestion cost (how much it costs the system per MW of overload without the gas turbine generator). This opportunity cost is the equivalent value of the physical option of installing capacity at that bus. The candidate gas turbines were considered to have a maximum capacity of 100 MW, capital costs of $400/MW, variable operating costs of $5/kWh, and fixed operating costs of $11.17/kW-yr. The total cost for the generator came to $13,180 per hour, per 100 MW. The opportunity cost was set at $200 /MWh, which is of a similar order as the gas turbine.

The model included network congestion in its objective function. A benefit-cost ratio (BCR) for each bus to see if a gas turbine would be cost-effective was estimated by the model. If not, a smaller turbine was introduced. After several iterations, each bus ended up with a turbine of an appropriate size, or none at all. The model was run with and without the generator option with the difference between the two options estimating the value of adding capacity to the appropriate buses. In the run without the generator option, the unserved energy was a total of 4,078 MWh, and in the case with the generator option, unserved energy declined to 3,678 MWh.

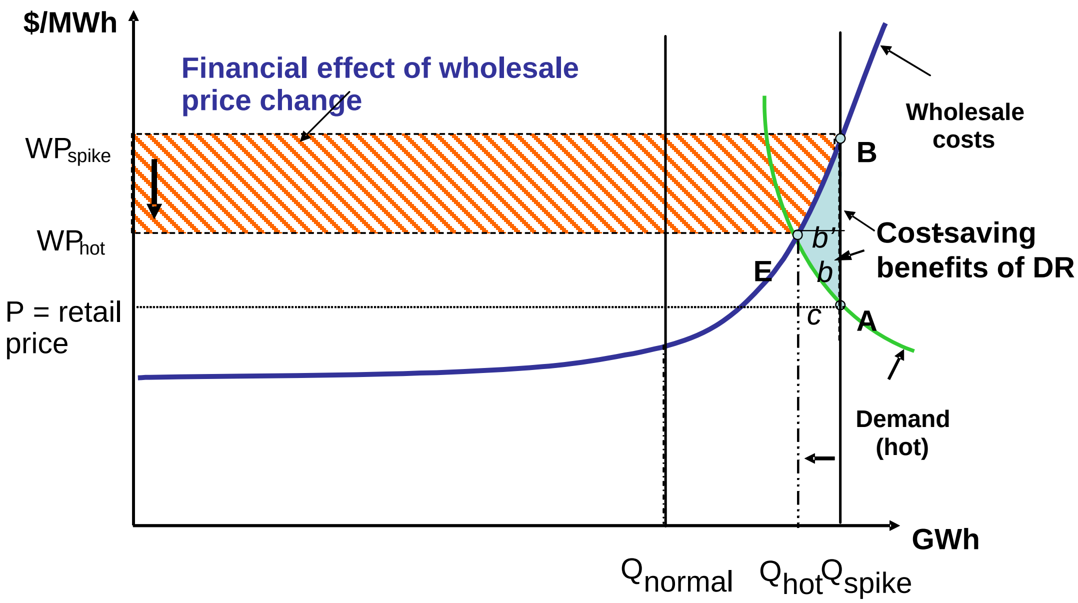
The study concludes that interruptible load services were effective in handling system congestion and that fast start-up generators can be cost-effective in reducing system transmission problems. It should be noted that the results of this study with gas turbines could be applied to the use of DRR (i.e. instead of 100 MW of gas turbine generation, 100 MW of DRR could be used with the same results).

3.4 Net Welfare Analyses of DRR – Consumer Surplus and Producer Surplus Approaches

The potential value of DRR can be illustrated through the use of demand and supply curves. Figure 3-5 represents conditions in a representative hour in the day-ahead energy market.[55] The figure shows a steeply-sloping *supply curve* at high load levels relative to available capacity. It also contains three *demand curves* – two demand curves are represented by the vertical lines (Q_{normal}, and Q_{spike}). These are non-responsive demands under "normal" and "hot" summer conditions when consumers face fixed retail prices (i.e., no price inducement to reduce or shift demand). The third demand curve represents the DRR responsive load. It is the sloping demand curve labeled "Demand (hot)," which represents price responsive loads in the presence of dynamic pricing or a DRR product/program.

[55] This analysis is based on Braithwait, S., "Demand Response: Using a Pricing Benchmark to Avoid Overpaying or Over Promising" in in "Electricity Pricing --Lessons from the Front" AESP/EPRI White Paper by D. Violette and A. Faruqui, October 2003. Available from the Association of Energy Services Professionals (www.aesp.org).

Figure 3-5: Changes in benefits and costs associated with price responsive load programs.



Key elements of Figure 3-5 are as follows:

- On a hot summer day *without price responsive loads*, consumer demand increases from Q_{normal} to Q_{spike}, causing wholesale prices to rise to WP_{spike}.
- The incremental *cost* of producing the last unit of power to meet demand under the unresponsive scenario is given by the distance from the horizontal axis to point *B* on the supply curve (which represents incremental power costs at different levels of demand). The incremental *value* to consumers of that increment of demand is shown by the height to point *A* on the aggregate demand curve (which represents consumers' incremental value of electricity at different levels of consumption), at the fixed retail price *P*.
- After taking into account the difference between total economic surplus, which is the sum of producer surplus and consumer surplus between the shift up the Demand (hot) DRR curve, and the initial equilibrium at point B, the difference between those areas (*b* + *b'*) represents the net *cost-saving benefits* of price responsive loads.

The benefits of DRR and the resulting responsive loads can be calculated if the demand curves and supply curves can be estimated. This approach has been suggested and various analyses of this type are seen in the literature.[56]

This net welfare approach works well in a static setting, i.e., a snapshot of a given hour or of a given event. However, each hour across a set of peak days across months and across years (assuming a longer

[56] Several papers that use a consumer and producer surplus approach to address the benefits of DRR include: S. Braithwait et al., "Demand Response is Important—But Let's Not Oversell (Or Over-Price)," The Electricity Journal, June 2003; Ruff, L., "Economic Principles Of Demand Response In Electricity" prepared for Edison Electric Institute, October 2002; and the NYISO DRR Evaluations cited previously.

term planning horizon) is likely to have a different demand and supply curve for electricity. In addition, the measurement of consumer and producer surplus in a dynamic, stochastic framework is complex. Unexpected changes in policy or technology can lead to changes in investment costs which are largely unobservable. Inputs which are fixed in the short run become variable in the longer run. Investments and changes in investments due to changes in expectations are often unobservable. Like much welfare economics theory, the applicability of this approach is limited by the degree to which supply and demand parameters are estimable and by the degree to which the economist can understand how producers form expectations to create the supply curve and how these expectations are changed by policy.

It is unlikely that an economic surplus approach based on the analyses of demand and supply curves will be practical for assessing the long term benefits of DRR. However, these welfare approaches are useful for addressing specific events to determine whether an event produced a net social gain. In addition, these static approaches can produce insights into the appropriate design of incentives for DRR products.

The complexity that accompanies benefit-cost frameworks based on economic surplus analyses in a dynamic setting with a long planning horizon argues for a more flexible framework. The case study using a dynamic resource planning model in Section 4 examines the value of DRR in a context that allows for many of the dynamic factors and tradeoffs between different resources to be examined.

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.[57]

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.

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[57] Appendix C lists some of the available resource planning models and tools that could be used in a resource planning approach to the assessment of DRR.

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.[58] However, most 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

[58] A description of the Strategist planning model is contained in Appendix A. 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 General and Fuel module that provides estimates of production cost of electricity for different resource mixes, and the PROVIEW resource optimization module.

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.[59]

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).

<u>Step 5</u>: 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.

<u>Step 6</u>: 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

[59] 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.

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 almost 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.[60] 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.

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. Table 4-1 presents the base case characteristics. 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

[60] 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.

nearly 6 million. The availability of interchange power is an important factor as this system was modeled as a net importer of power.[61]

Table 4-1: Base System Characteristics

2004 System Characteristics					
	Installed Capacity			Generation	
Installed Capacity	**Number of Units**	**MW**	**Percent of Total**	**GWH**	**Percent of Total**
Nuclear	8	8,663	24%	64,806	52%
Coal	27	4,369	12%	30,792	25%
Combined Cycle	24	7,429	20%	23,168	19%
Gas	95	5,356	15%	992	1%
Distillate	113	5,923	16%	597	1%
Residual	18	2,810	8%	1,000	1%
Hydro	4	527	1%	1,825	1%
Pumped Storage	2	1,280	4%	977	1%
Total	291	36,357	100%	124,158	100%
Other Characteristics					
Peak Demand	MW	30,064			
Reserve Margin	%	20.9%			
Energy Demand	GWh	145,423			
Load Factor	%	55.0			
Customers (approximate)		6 million			
System Cost	$M	4,505			
Average System Cost	$/MWh	46.39			

The base system was optimized for future generating resources over a planning horizon of 20 years from 2004 through 2023. The full range of fossil technologies was available to be selected by the model to meet energy and peak demand growth including coal, combined cycle, and combustion turbine technologies. The optimization objective function was set to meet the growth in energy and peak demand at the lowest NPV system revenue requirements, with the current system as the starting point.

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:

[61] Additional data on the system being modeled are shown in Appendix B.

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:

- Interruptible Product – 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.
- Direct Load Control Product – 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.
- Dispatchable Purchase Transaction – 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[62] 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

[62] 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.

the four fuels used in the analysis, and as an example, Figure 4-2 shows the distribution for natural gas prices with the mean and 90% confidence bands around the forecast.

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

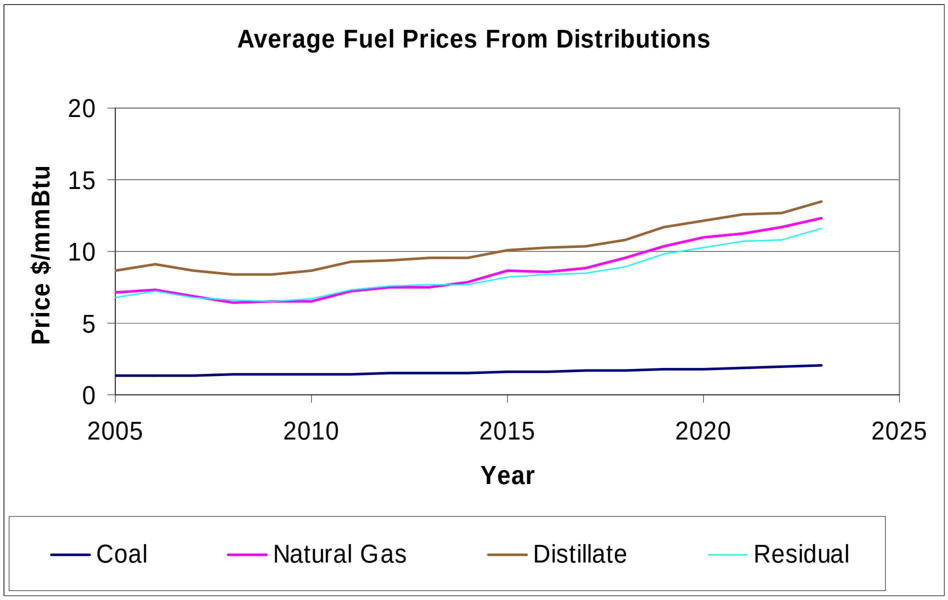
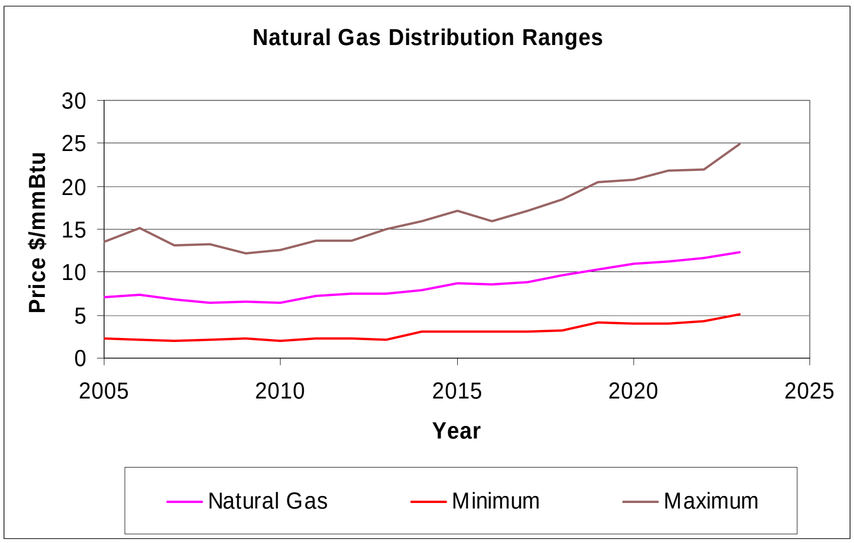
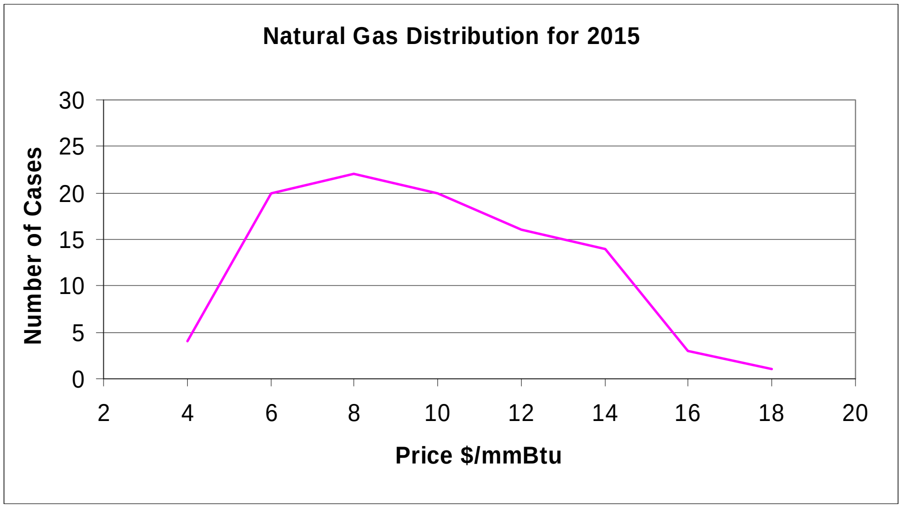


Figure 4-2: Distribution of Natural Gas Prices Over the Forecast Period



The data shown in Figure 4-2 represents distributions for each year of the forecast period. 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 (Figure 4-3).

Figure 4-3: Actual Draws of Natural Gas Prices for the 100 Cases for One Year



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.[63]

The values for distillate oil were not calculated directly, as they are almost always slightly higher than the residual price. A new distribution was created which had the range of the minimum and maximum difference between the two prices, i.e., distillate and residual oil prices, based on historical data from EIA.

The distillate, coal, and natural gas distributions were correlated with each other, based on correlation values extracted from historical fuel price data from EIA. In addition, each distribution was correlated with the same fuel type in the next year by 0.6. This provides for a positive correlation for the same fuel over time.

Distributions were run for 150 trials and then 100 trials were selected from these 150 to be put into the scenarios. Because the ranges of natural gas and distillate overlapped somewhat, there were a few trials which included years in which the distillate price was lower than the natural gas price. This has not happened very often in the past, according to historical fuel price data. As a result, these trials were replaced with another trial.

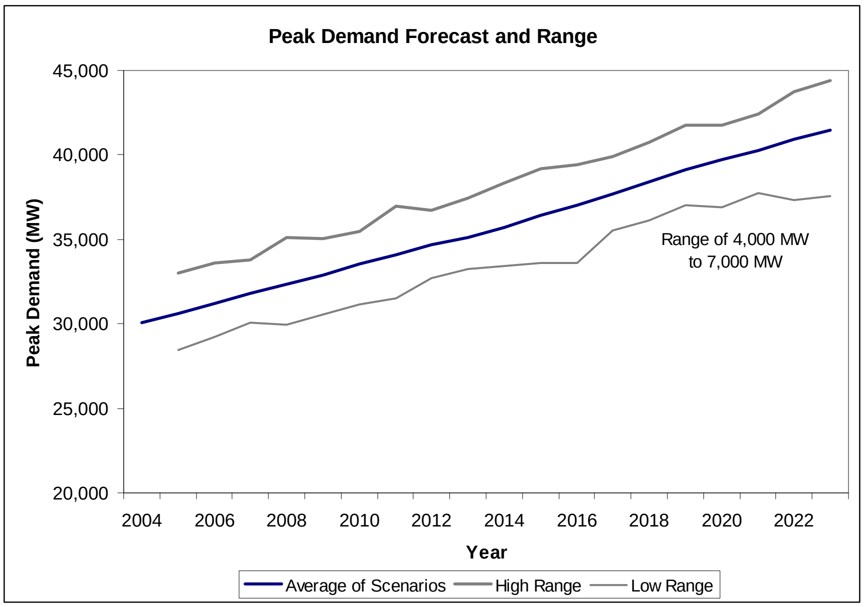
[63] There is not only correlation across fuel inputs, but also potential correlation over time. For example, if natural gas prices are higher than expected in 2010, it is likely that a higher than forecast price for natural gas will occur in the next year as well. The development of these distributions 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.

4.4.2 Peak 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 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.

Figure 4-4 below shows the average peak demand from the scenarios and the high and low range in the scenarios. This resulted in a range of 4,000 MW to 7,000 MW between the low and high demands in the cases, depending on the year.

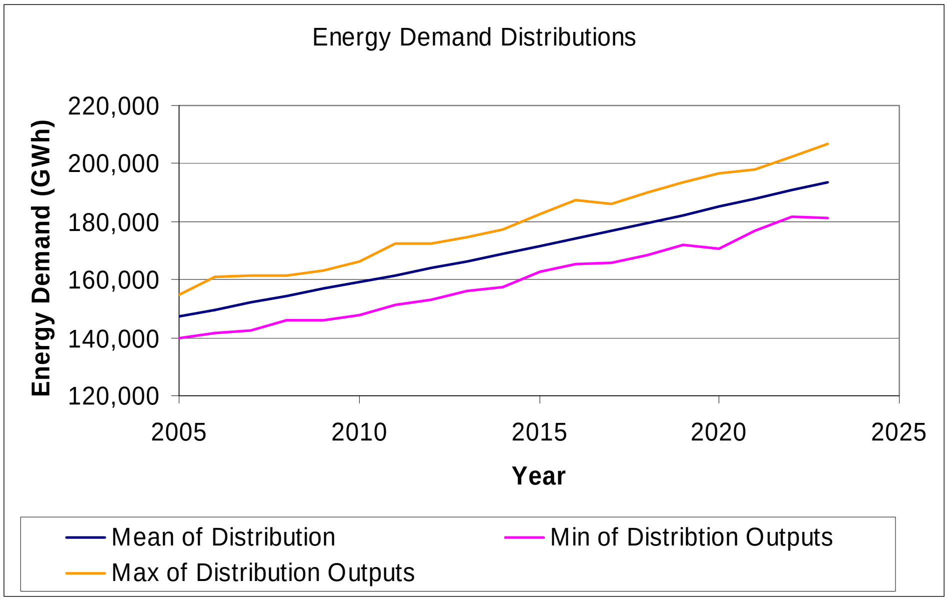
Figure 4-4: Peak Demand Forecast and 90% Confidence Ranges



4.4.3 Energy Demand Inputs

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. Figure 4-5 below shows the average energy demand for each year and the 90% confidence intervals around this forecast.

Figure 4-5: Distribution of Energy Demand



4.4.4 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. A wider range of unit outages (e.g. up to 15% of demand) could have been added to the model, to show more frequent or extreme situations.

4.4.5 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 Included in the Model

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

This detail in DRR product inputs represents a unique aspect of the Strategist planning model and required the development of a separate DRR load control module. The DRR product designs are summarized below.

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, who are assumed to have 750 kW of 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.

Costs are as follows:

- Initial equipment costs of $2000, as a subsidy to new customers.
- Annual payments to customers of $5000, for capacity.
- Product infrastructure costs of $200,000, at the utility or the DRR aggregator, for initial marketing and communications equipment, in addition to the equipment installed at the customer site.
- Ongoing annual O&M costs for product management of $150,000 per year.

Summary of product characteristics:

- Available all year.
- Call period increments of 2 hours with a maximum of 12 hours per call.
- Total number of calls per year is 20 and total hours per year is 240.
- Ramp-up rate is 75 MW in year 1, and 150 MW each year for the next 10 years, with a reduced growth rate of 37.5 MW in subsequent years.
- Capacity reaches approximately 4.5% of peak demand at the end of the period.
- Considered to be 100% firm as the program pays monthly capacity payments to have denominated capacity available.

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, with each participating customer being 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. 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.

Costs are as follows:

Costs per Customer Site:

Equipment:	$200 (thermostat) plus $80 (switch)
Installation:	$150
Software:	$200,000 total for software and communications
Initial Start-up:	$100,000 to develop marketing materials and roll out the product
Ongoing O&M:	$1 per customer annually for customer service, and for monitoring and verification

Summary of product characteristics:

- Available June to September.
- Call period a maximum of 6 hours.
- Total number of calls per year is 20 and total hours per year is 120.
- Ramp-up rate is 120 MW per year for the first 11 years, and incremental increases of 5% after that.
- Capacity reaches approximately 4.6% of peak demand at the end of the period.
- Considered to be 100% firm based on forecasted load reductions from large numbers of customers with diversified loads.

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.

The capacity and costs are designed to allow the kW commitment to increase as price increases. The initial price schedule is:

Price (2005)	Capacity per Customer	Program capacity in 2023
$300 per MWh	250 kW	1188 MW
$200 per MWh	150 kW	713 MW
$100 per MWh	50 kW	238 MW

For this program to be called upon, the hourly system marginal cost must be above the call price at each level. The prices in the schedule above are meant to parallel the way system marginal costs are calculated and include no overhead types of expenditures, to be consistent with the way in which supply-side marginal costs are treated.

In addition to the payments made to customers, the O&M costs for this program are:

Initial Start-up:	$200,000 to develop marketing and roll out the program to prospective participants.
Ongoing O&M:	$100,000 annually in ongoing costs, increasing with program size to reach $562,000 in 2023 (nominal price).
New Customer Costs:	$2000 per customer to enroll participants in the program and help offset some of the initial equipment costs that they may have.

Summary of product characteristics:

- Available all year.
- Call period a maximum of 8 hours.
- Total number of calls per year is 40 and total hours per year is 320.
- Program ramps up quickly to enroll 2400 customers in the first 5 years, and customer numbers are incremented by 5% a year after that.
- Total capacity reaches approximately 5% of peak demand at the end of the period (if all MW are called on including all of the $300/MWh price triggered load).
- Considered to be 100% firm (customers must supply load reduction once they are committed).

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.

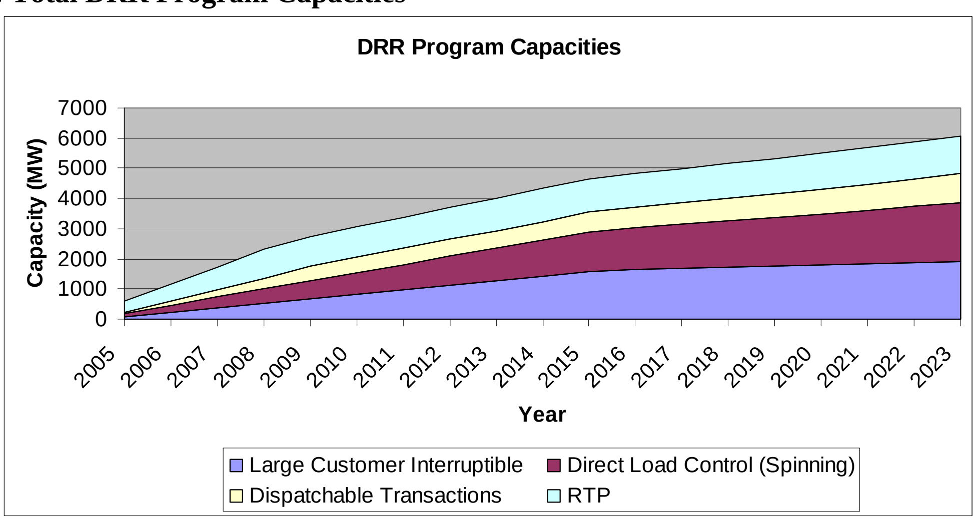
Annual costs for these pricing products are in the metering and incremental data management costs which are needed for accurate billing. New customer costs were assumed to be $500 for purchasing and installing the required meter, which records hourly electricity consumption. In addition, annual O&M costs of $50 per customer were assumed for extra data management and billing. Note that a meter that records hourly consumption but is read monthly will be less expensive than a meter that has two-way communication capabilities. In this scenario, it is being assumed that the metering costs are stand alone and a simple interval meter is installed, i.e., no two-way communication. In addition, incentives may be offered to customers that sign up for real-time pricing but these were not included in the model. The estimated metering costs for real-time pricing can vary as some planners put in offsetting cost savings for revenue gains and other benefits, as new meters replace older meters.

Separate model runs were made which included the two pricing programs, in conjunction with the DRR callable programs, with one offering the CPP product and a second offering the standard RTP option. No model runs were made that included both pricing options.

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.

Figure 4-6: Total DRR Program Capacities



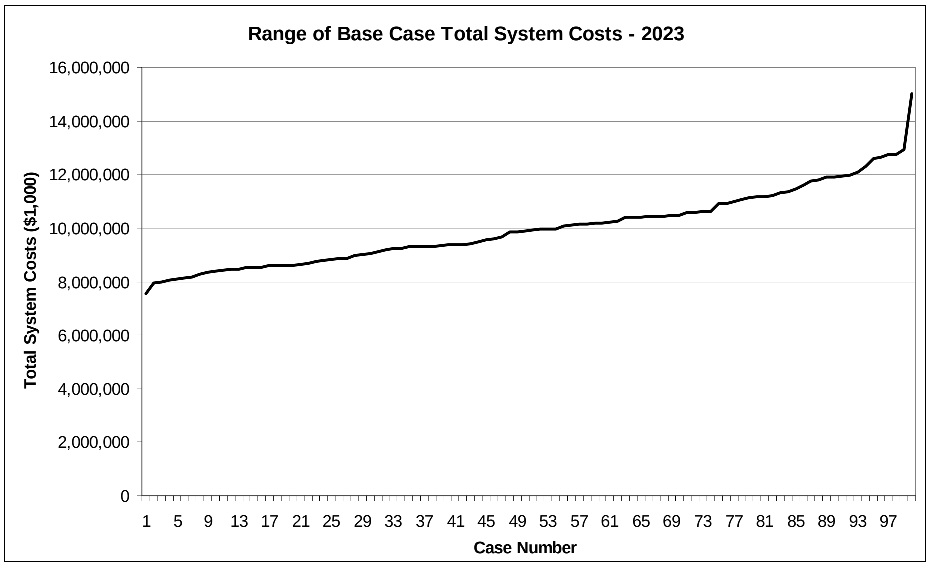
4.6 Case Study Results

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.[64]

The importance of looking at the distribution of system costs is shown in Figure 4-7. 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.

Figure 4-7: Distribution of System Costs within a Given Year



For example, costs jump by $2.5 billion in just the last three highest cases (see right-hand tail). Over the entire 100 Monte Carlo draws, system costs vary from $7.5 billion to $15 billion for just this one year. 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 4-2. 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:

[64] 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.

Table 4-2: 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.[65]

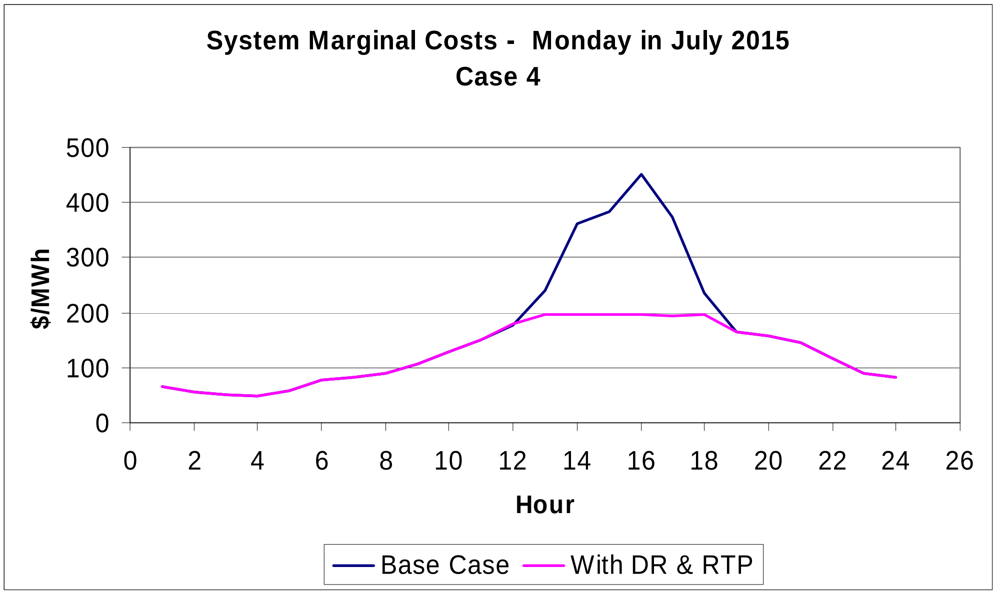
4.6.1 Changes in Prices during Peak Periods

The results shown in Figure 4-8 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 4-8 shows that, 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.

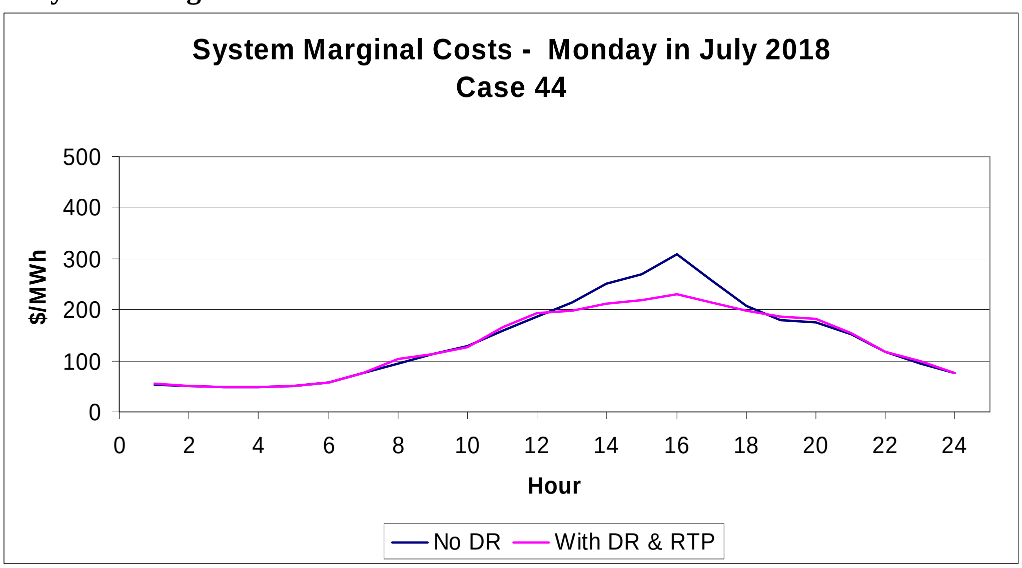
[65] Conversations with resource planners and market analysts at Southern California Edison and PG&E indicate that they are now using Monte Carlo analyses in planning tasks. In addition, the Northwest Power Planning Council (NWPPC) has been using these methods for a number of years, but just began including DRR in their analyses in 2004.

Figure 4-8: Marginal Costs During a "Stress" Day



The July 2015 example shown in Figure 4-8 is one of the stress days that were created and put into the model, in part as compensation for the way the model averages the impacts of forced outages across all days in a year. While it is a stress day, it is believed to be a realistic situation that could occur, and might happen two or three times in a 20 year period. However, DRR also provided benefits on days that were not stress days. Figure 4-9 shows a non-stress summer peak day. This was selected from a number of candidates for illustration.

Figure 4-9: System Marginal Costs with and without DRR



On this day, marginal system costs reach $310/MWh in the base scenario without DRR, and in the scenario with DRR the peak prices are reduced to $220. The system savings based on marginal production costs on this day are roughly $5.4 million. For the entire week, the savings due to DRR are approximately $7.6 million, and for the month they are approximately $30.6 million. This day was not a day where plant outages were inserted into the model to create a stress condition. This peak was created by the Monte Carlo structure of the data inputs. Again, market prices could easily exceed the marginal production costs shown here, whereas the costs of the DRR are not expected to change since they are defined by the product. As a result, the benefits of DRR on this day and during this week could be several times greater.

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 value of these deferrals is shown in Table 4-3. The total value of capacity deferrals over the 19-year time frame, expressed in 2004 dollars, is $892 million.

Table 4-3: Deferred Capacity due to DRR Availability

(Values in 2004 Dollars)

Deferral Capacity Charge for Base Scenario ($M)																	
2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
5	16	21	30	31	32	29	37	47	55	63	74	82	87	90	89	104	892

This relatively large savings value from deferring capacity was also a finding in the in the Northwest Power and Conservation Council's power plan. The NPCC's 5th Power Plan states:

> *In the long run, with growing demand for electricity, the cost of meeting peak also includes the construction and operation of new generating plants and perhaps the expansion of the transmission and distribution system. These extra construction costs can increase avoided cost by multiples of five to 20. <u>This means that 80 percent to 95 percent of the value of demand response is in avoiding construction of unnecessary generators in the long run</u>. Accordingly, this plan is concerned with long-term avoided cost.*[66] *(p.4-8)*

4.7 Impacts of DRR – Costs and Benefits

The benefits of DRR are compared to the costs within the resource planning model. The costs of each DRR option are built into the characterization of that resource and, therefore, are incorporated in the model. To the extent that the NPV of system costs is lower with DRR, then the benefits are 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 almost every year.

Figure 4-10 shows the distribution of cases across the years where DRR results in a lower system NPV, and those cases where DRR has costs greater than the benefits, for the scenario with DRR but no RTP.

[66] In some cases, costs of construction of distribution and/or transmission could also be avoided by demand response. These costs are location-specific and are not included in these avoided cost estimates. If it were possible to include distribution and transmission in the calculations, avoided costs would be higher.

Figure 4-10: Distribution of Change in Total System NPV Without RTP

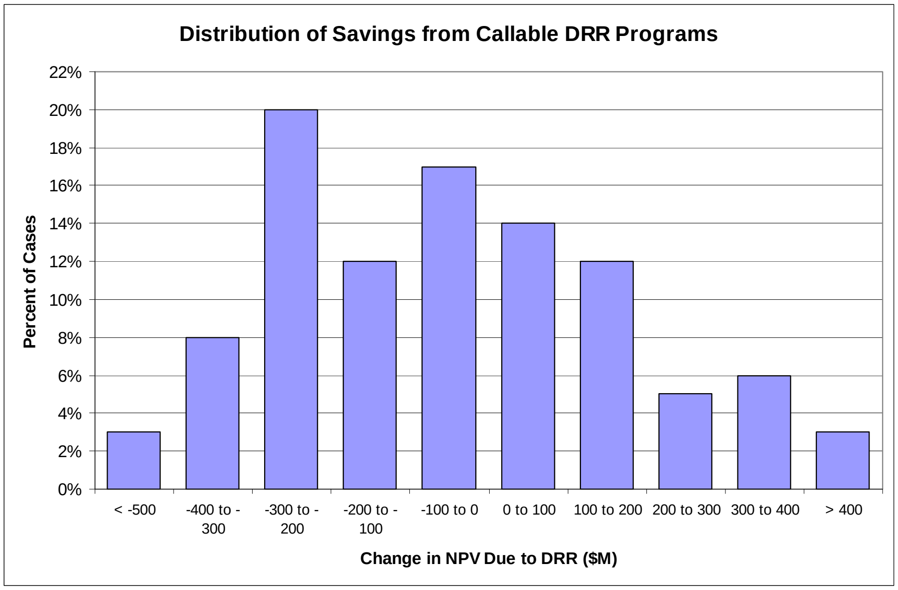
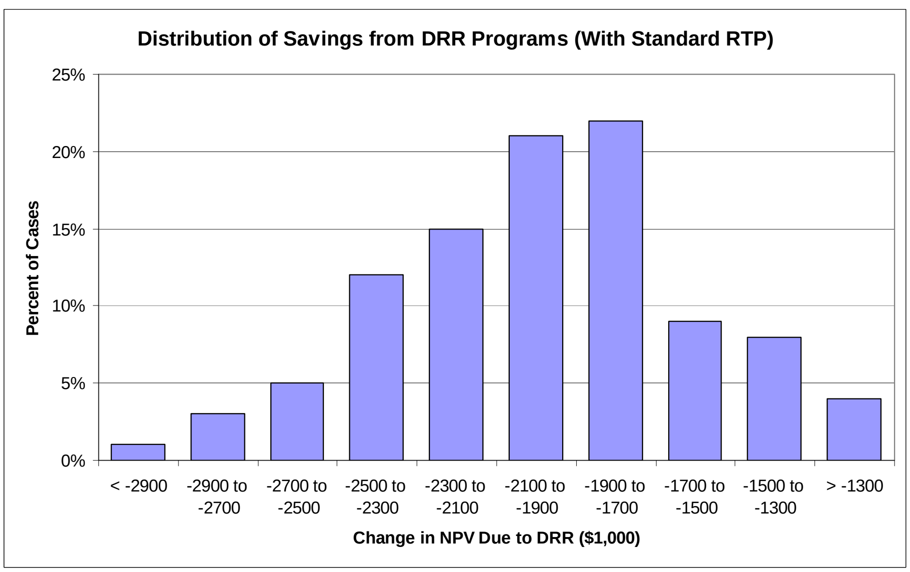


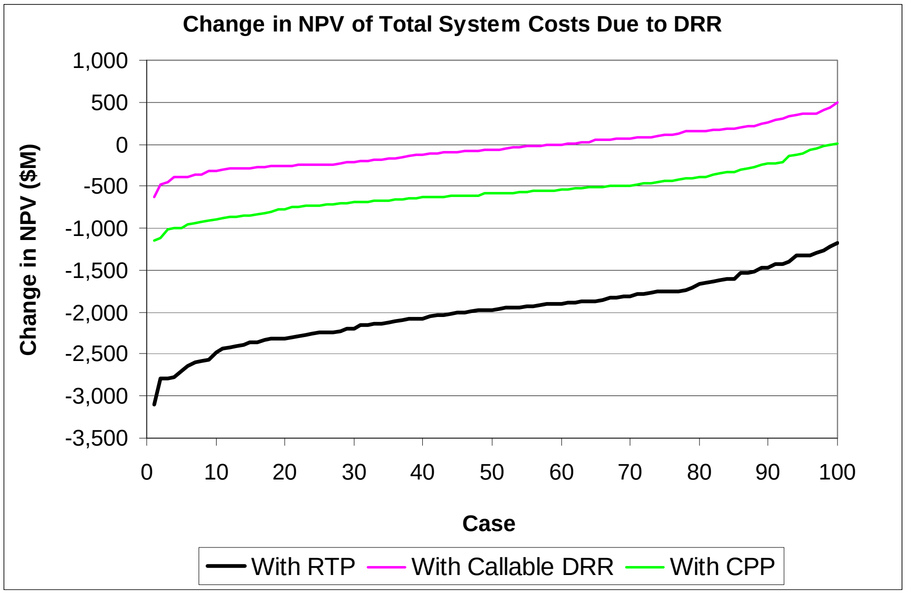
Figure 4-11 shows the same distribution but for the scenario with all the callable DRR programs and the standard RTP program. With the addition of the RTP, there were no cases where the cost in the base scenario is more expensive than the cost in the scenario with DRR.

Figure 4-11: Distribution of Change in Total System NPV With Standard RTP



Looking at the 100 cases individually, with DRR but no RTP, 60% of the 100 cases show savings in total system NPV compared with the base scenario, and with standard RTP, 100% of the cases show savings in total system NPV when compared with the base scenario. Figure 4-12 shows this distribution of outcomes, including the scenario with CPP. The greatest change in NPV due to DRR was $3.094 billion (with standard RTP).

Figure 4-12: Distribution of NPV by Case



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 4-4 below. In the scenario with a 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 4-4: 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 4-5 below.

Table 4-5: 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

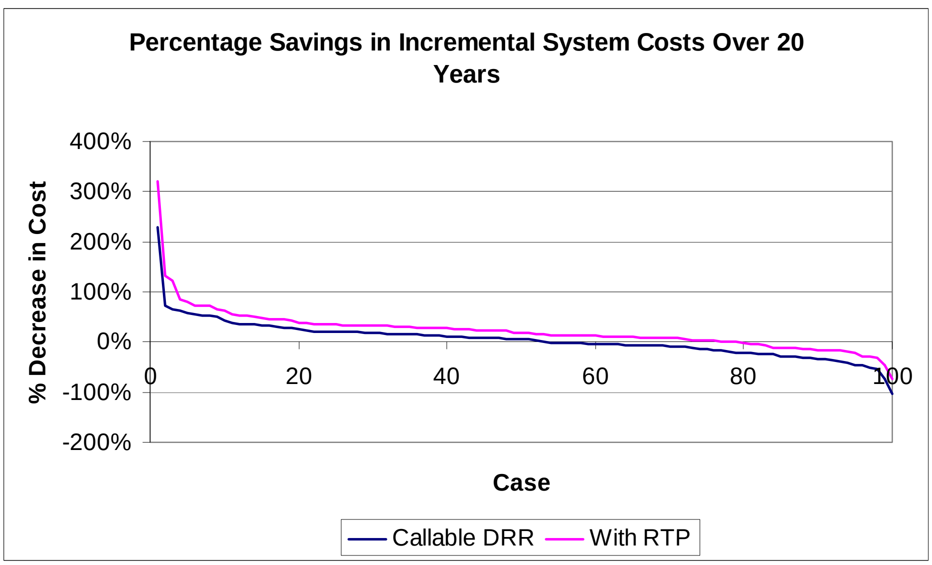
This analysis shows that there is a reduction in the average cost of the top 10% of at least $238 million, and as high as $2,673 million. For the 5% worst outcomes without DRR, savings are slightly lower, except in the scenario with standard RTP. As a result, the model shows that DRR not only reduces 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, as shown in Figure 4-13 below.

Figure 4-13: Percentage Savings in Incremental System Costs



4.8 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 Stategist model simulated 100 20-year planning cases. This produced 1,800 years in which DRR could be used (19 future years from 2005 to 2023 in each of the 100 cases). Given one year for ramp-up, demand response is available in 18 of the future years.

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. The real-time pricing product is difficult to quantify since there are no set limits to response and it is available in every hour in the planning period. Usage for the three DRR callable products is as follows:

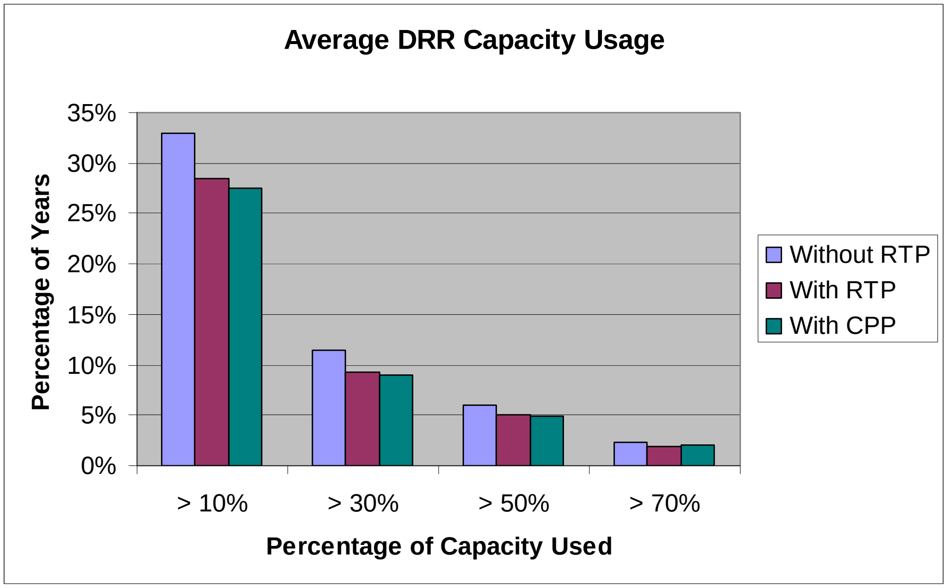
- **DRR-1: The Large Customer Interruptible Product** – This DRR product is used to at least 30% of its capacity (based on number of hours it can be called times the MW enrolled in the program) in 9% of the years, or about once in every nine years. This product was used for over 60% of its capacity in 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. Since the DRR was fixed in the “with DRR” scenario and called upon only when economic, a more efficient DRR product design could further increase the net benefits of DRR, as measured by the difference in total system costs between a with DRR and a without DRR scenario.

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 4-14 below shows this reduction in capacity usage. However, this reduction is not as great as might be expected.

Figure 4-14: Average DRR Capacity Use with Standard RTP Program



4.9 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.

4.10 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.

4.11 Other Similar 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 (January 2005). The DRR characterization was simplified compared to that used in this analysis.

For the NPCC portfolio analysis it was conservatively estimated that 2,000 MW of DRR could be developed by 2020. Its "operating" cost is assumed to be $150 per MWh, with a fixed cost of $5,000 per MW-yr for the first year and $1,000 per MW-yr thereafter (in 2004 dollars). Given this DRR resource and the comprehensive look at other potential resources, the NPCC concluded that:

> *In general the loss of demand response increases expected cost by approximately $300 to $400 million for constant levels of risk. Expressed another way, the loss of demand response increases risk in the range of $400 million to $1 billion at given levels of expected cost. These increases in expected cost and risk are largely due to increased purchases from the market at times of high prices and to the cost of building and operating more gas-fired generation.*

Based on this analysis, the NPCC recommends:

> *...developing demand-response programs - agreements between utilities and customers to reduce demand for power during periods of high prices and limited supply. The Council recommends developing 500 megawatts of demand response between 2005 and 2009 and larger amounts thereafter. Demand response has proven helpful in stabilizing electricity prices and in preventing outages. The Council's analysis shows that although it will probably be used infrequently, demand response reduces both cost and risk compared to developing additional generation.*

The work and publication of the efforts by the NPCC demonstrated the application of a similar analysis method to the one performed in this study, with results that are similar in direction, if not in magnitude. The NPCC summarized its method as follows:

> *For the "with" demand response portfolio analysis, Council staff assumed a block of 2,000 megawatts of load reduction is available by 2020, with an initial fixed cost of $5,000 per megawatts, a maintenance cost of $1,000 per megawatts per year and a variable cost of $150 per megawatt-hour when the load reduction is actually called upon. The "without" demand response assumed that no demand response is available.*
>
> *The portfolio model simulated 750 20-year futures with demand response available 16 years in each future. Demand response was used in 89 percent of years in which it is available, but the amount of demand response used is usually quite small. In 78 percent of the years in which demand response is used, it is used less than 1 percent of its capability (i.e. less than 87 hours per year). According to the portfolio model's simulations, demand response is being used more than 8 percent of its capability (equivalent to about 700 hours per year) in about 10 percent of all years. (p.H-21)*

This method is, in general terms, similar to the Monte Carlo method used in this case study assessment. This ongoing work offers the opportunity to further leverage this IEA Task XIII effort with other efforts just now being started by different organizations. This combined set of work should allow for an expanded set of lessons learned and assessments of DRR in resource planning applications.

4.12 Extension of Monte Carlo Method to the Scandinavian Market

This section includes a summary of a Nordic power system case study for valuing DRR with a resource planning model. 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.*[67]

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).

4.12.1 The Nordic Electricity System

The Nordic area is divided into ten regions with interconnections. Each region is subdivided into smaller areas, representing different markets, for example, heat markets. Hydro power is significant in Norway, northern Sweden, and also to a lesser degree in Finland; nuclear is significant in Sweden and Finland; and wind power mostly in Denmark. In dry years electricity transmission goes north, and in wet years it goes south.

The whole area is liberalized and strong competition exists. The Nord Pool power exchange has a large turnover in both physical and financial markets. In 2004, 41% of total demand was traded on the physical markets. Nord Pool spot prices are heavily influenced by the availability of hydro power. The hydro power production can vary by +/- 25 TWh per year.

Nord Pool divides the Nordic area into 7 to 9 price areas (2 in Denmark and from 3 to 5 in Norway). All international transmission lines within the Nord Pool areas are managed by the Nord Pool. Transmission capacity between the areas enables the price to be the same in all price areas 31% of the time. When there are price differences between areas, a bottleneck exists in the transmission system.

Here are details on the Nordic electricity system, in brief:

- Total available production capacity is 80,000 MW.
- A total capacity of 4,800 MW exists in connections to Russia, Poland, and Germany.
- Normal demand variation is between 58,000 MW (winter, 5-6 pm) and 37,000 MW (summer, 5-6 am) with possible peaks of 70,000 MW
- Total electricity demand in the Nordic area is 380 TWh/year

[67] 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).

Electricity generation, 2003, %	Total	Denmark	Finland	Norway	Sweden
Hydro power	47	0	12	99	40
Nuclear Power	24	.	27	.	50
Other thermal power	27	87	61	1	10
Other renewable power	2	13	0	0	0

4.12.2 The Balmorel Model

The model chosen for the effort was Balmorel. A description of this is given in Appendix C. This is a long term planning model, with typical analysis done for periods of 1 to 30 years. It is a detailed hourly optimization model and covers the whole Nordic electricity system. There is a detailed representation of production capacity, transmission lines, and demand in the four countries (Denmark, Sweden, Norway, and Finland). The area is divided into 10 price areas. The model is usually used for:

- Production and investment modeling for electricity and heat in the Nordic region.
- Modeling of international emission trading systems.
- Market power.
- Expectations in the market for, e.g., electricity prices, economy, emissions, etc.

Other characteristics of the Balmorel model are:

- Partial-, Linear-, optimization model.
    - Maximization of social surplus.
    - Equilibrium model always keeps the energy and power balance.
- Bottom-up model
    - Detailed description of technologies, e.g., capacities, fuel efficiencies, O&M costs, fuel prices, and emission coefficients.
    - Modeling behavior of different electricity plant types, e.g., extraction and backpressure units
- Calculates energy flows and electricity prices on a weekly basis divided into load periods, or on an hourly basis week by week.
- Possible output: production cost and patterns for each unit, prices for heat and electricity, transmission flows, emissions, etc.

4.12.3 Model Inputs

A Monte Carlo simulation was done to create inputs to the model. One hundred cases were created, evenly distributed based on variations in the availability of water and wind and on the temperature. The inputs were calculated with the program Crystal Ball, which was performed by Summit Blue Consulting. One hundred runs of the Balmorel model were done. Figure 4-15 below shows the variation in the water parameter, i.e., the amount of water available for electricity production over 1 year. Normal hydro production is approximately 200 TWh per year.

Figure 4-15: Variation in Water Resources Parameter

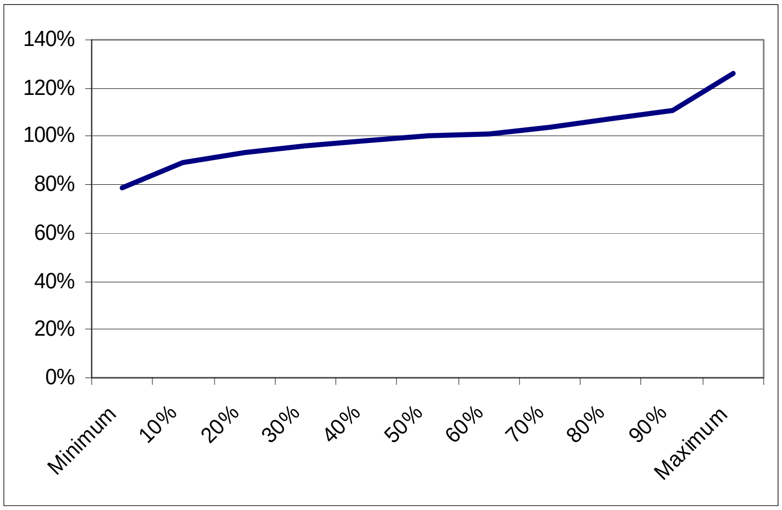
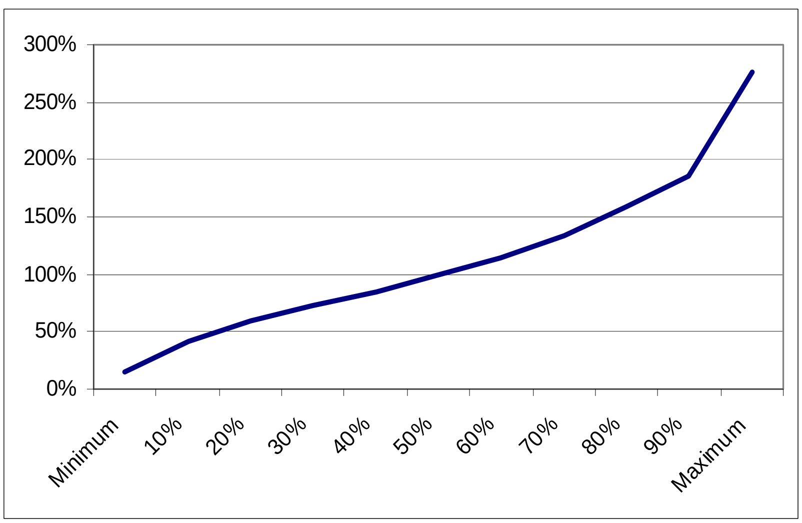


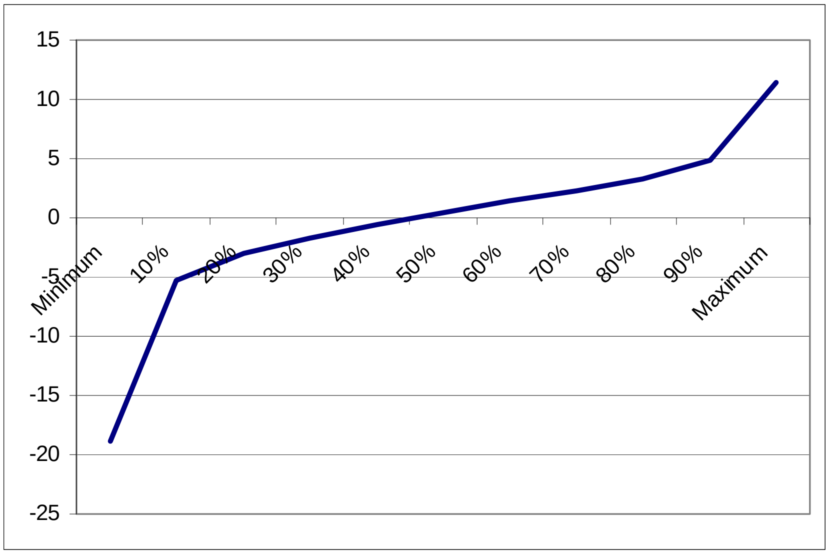
Figure 4-16 below shows the variation of the wind parameter, i.e., the wind available for electricity production over one year. The variation of wind power is very uncertain beyond 48 hours in advance. There are large possible changes in wind production in any one week. Production can vary from 10% to almost 300% of estimated wind power production.

Figure 4-16: Variation in Wind Resource Parameter



Electricity demand varies with the temperature, and this was calculated for each country in the area. An example of this is shown in Figure 4-17 below. The mean temperature was set to be the freezing point (0°C). On a very cold day there is an increase in demand of up to 12%, while on a warm winter day there is a decrease in demand of up to 18%.

Figure 4-17: Variation in Demand Parameter



4.12.4 Model Runs

Five scenarios were designed which covered a base case scenario, three DRR scenarios, and an alternative scenario with additional generation capacity. In order to evaluate the different alternatives (e.g., gas turbine versus demand response) a variety of output parameters were calculated for each alternative. As a point of departure, the following five scenarios were modeled:

1) Reference (no additional peak load technologies): When the market does not clear consumers are disconnected at a price at 5000 NOK/MWh.[68]
2) Demand Response in the from of peak clipping: The same as the reference case, but with an additional 1,000 MW in Southern Norway at 1,000 NOK/MWh (disconnecting).
3) Demand Response in the form of load shifting (NO): Same as the reference case, but with additional 1,000 MW with 6 hours flat payback (return energy) in Southern Norway.
4) Demand Response in the form of load shifting (DK): Same as the reference case, but with an additional 1,000 MW with 6 hours flat payback (return energy) in Western Denmark.
5) Gas turbine: Same as the reference case, but with an additional 1,000 MW power capacity in the form of a single cycle gas turbine.

4.12.5 Variables of Interest

The model produced several variables of interest:

<u>Reserve Margin</u>

The reserve margin is used to indicate when the system is in a tight situation, i.e., when the risk of blackouts is high. In order to evaluate this, we define the reserve margin for each hour for each area as the following:

Reserve Margin = Available capacity – Total demand + Actual transmission

[68] 1 NOK = 0.13 Euro (10.11.2005, Oanda.com)

Therefore this output parameter describes the extra capacity at the clearing in the spot market. If the reserve margin is zero, the market is cleared but at a price higher than the largest marginal costs (scarcity rent). Demand is defined as the actual demand during one hour. The actual transmission can be either positive or negative, depending on the optimization in the model. Therefore, this variable does not describe the actual capacity in the transmission line. The level of the reserve margin is evaluated through a distribution with a Value-at-Risk approach.

<u>Total Costs</u>

It was necessary to link the value of the reserve margin to total costs and prices. Total costs are used to quantify how much it can cost to reduce the Value-at-Risk measure. Therefore, it is possible to quantify how much it costs to change the Value-at-Risk measure to a given target, and, furthermore, what the trade off is between the two parameters.

<u>Prices</u>

Prices are mainly listed as output values in order to evaluate the price effects from the different demand response programs, as well as to help indicate what the critical levels of the reserve margin are.

<u>Transmission</u>

The transmission variable can, as well as prices, be used to indicate how tight the system is in each region. For example, if all transmission lines are used totally, there can be an area that is not able to support itself. However, this measure can only be used in conjunction with the reserve margin, as transmission lines can be used fully only in the case where another area has a very low price, leading local production capacity to stay unused.

<u>Activation of DR Resources</u>

The model keeps track of how many hours the DR resources are activated in each price area.

4.12.6 Results

Each alternative scenario was compared to the reference scenario with respect to electricity prices and total costs. The total costs were subdivided into the following three categories.

- Production costs
- Costs of power exchange (with countries outside the Nordic area)
- Cost of disconnecting consumers

The results show the largest differences were in disconnecting costs; they decreased by up to 230 million NOK compared to the reference scenario. The change in production costs was up to 10 million NOK, and the change in exchange costs was up to 5 million NOK.

The average benefit from each alternative scenario, without taking the necessary investment costs into consideration, was 4.1 million NOK in the DRR scenario with peak clipping, 2.9 million NOK in the DRR scenario with load shifting in Norway, 1.8 million NOK in the DRR scenario with load shifting in Denmark, and 5.7 million NOK in the gas turbine scenario. The reason why the benefit from DRR with load shifting is relatively low may be that it was interpreted as a kind of additional electricity storage in the system, with quite heavy restrictions on it, and that the value of such an additional storage in a system with lots of hydro power is quite limited.

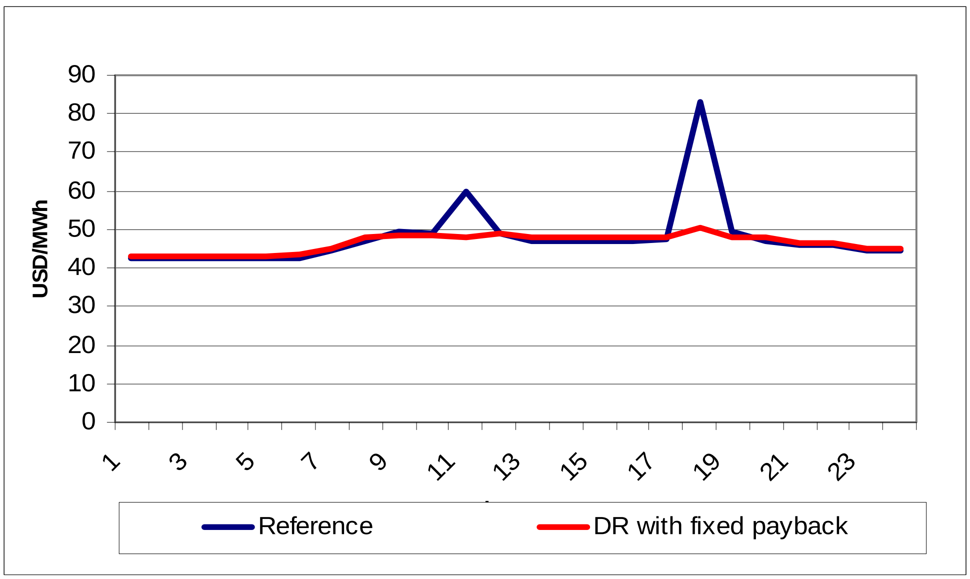
In most of the cases that were analyzed the benefits from the peak load technologies is zero, but in some cases the benefit is quite high. For instance, in the scenario with DRR peak clipping the 95% percentile is only a benefit of 0.6 million NOK, even though, the average benefit is 4.1 million NOK. Since the value is low in the majority of the cases, some market actors might not see the importance of DRR. The seldom occurring cases with a high benefit may be overlooked - especially as long as the high electricity prices as a consequence of lacking peak load technologies in the system have not yet been met in practice.

Comparing the benefits in each scenario, it is doubtful whether the gas turbine is profitable. The annual capital costs of 1,000 MW gas turbine capacity is approximately 300 million NOK corresponding to 5.7 million NOK per week. The benefit in week 5 has been estimated at 5.7 million NOK, but this week is also one of the weeks that are expected to benefit most from peak load technologies due to a low supply/demand balance. The costs of implementing DRR (peak clipping and load shifting) have not been estimated.

It should be mentioned that another possible value of the DRR technologies is that they level out the demand variation and thereby decrease the need for generation capacity in the system. The value of this has not been estimated. Furthermore, the implementing of DRR may have an additional value with respect to market power as it may decrease the consumers' possibilities of abusing market power.

Figure 4-18 below shows an example of the model results: the cost per MWh from day 1, case 1. The graph shows that the addition of the DRR with fixed payback resource smoothes the price and eliminates the “peakiness” of electricity prices on this day.

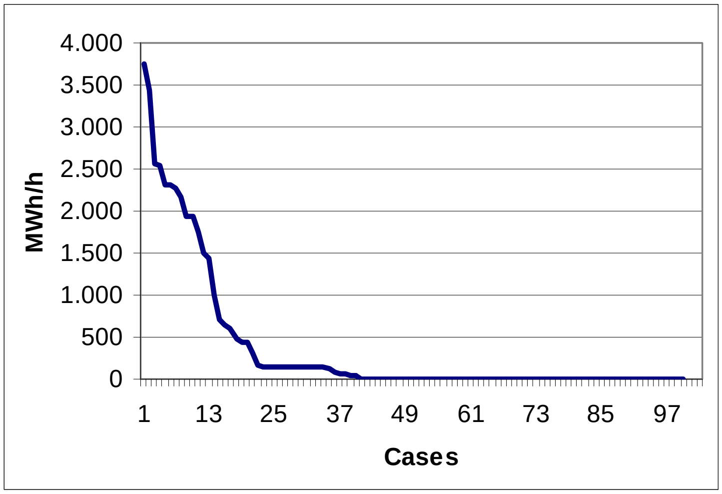
Figure 4-18: Comparison of Scenarios Reference and Demand Response with Fixed Payback



<u>Demand Response at High Prices (770$)</u>

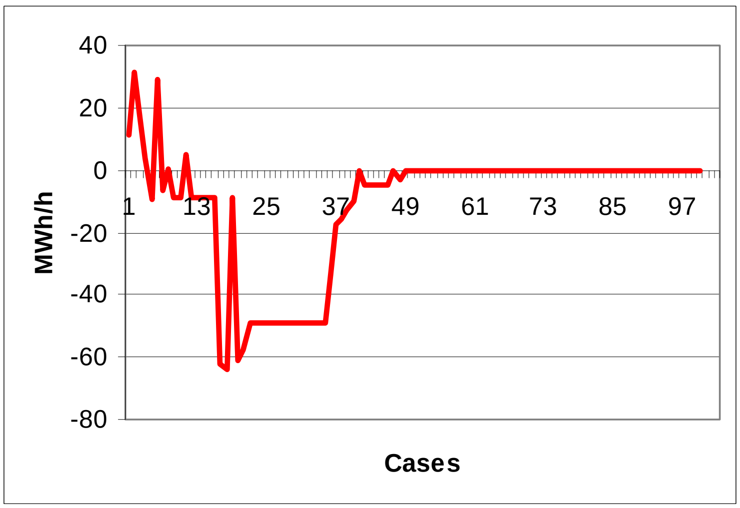
In the case of very high prices, the use of the gas turbine had a great impact on reducing the amount of DRR used. The DRR Payback scenario showed only a small amount of DRR used because of the very constrained situation. In the Reference scenario, DRR was used in 40 of 100 cases.

Figure 4-19: DRR Usage in the Reference Scenario



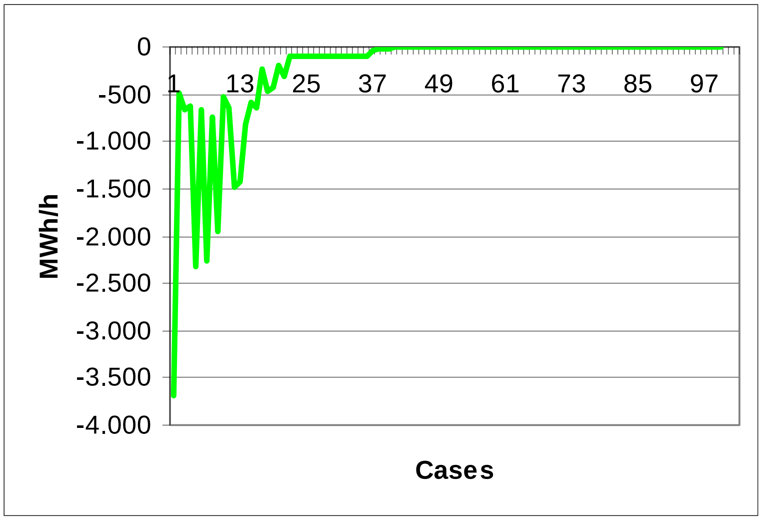
In the scenario DRR with Fixed Payback, the DRR was used much less (Figure 4-20) .

Figure 4-20: DRR Usage in the Fixed Payback Scenario



In the Scenario With Gas Turbine the DRR was used even less (Figure 4-21).

Figure 4-21: DRR Usage in the Gas Turbine Scenario



Total System Cost

The model showed that the scenario DRR with Fixed Payback had the potential to reduce prices in the cases where the prices are fluctuating, while the effect was small when the prices kept at the same level. The graph below shows mean weekly prices, which have been sorted (Figure 4-22).

Figure 4-22: Total System Cost in Reference Scenario, Compared with DRR with Fixed Payback Scenario

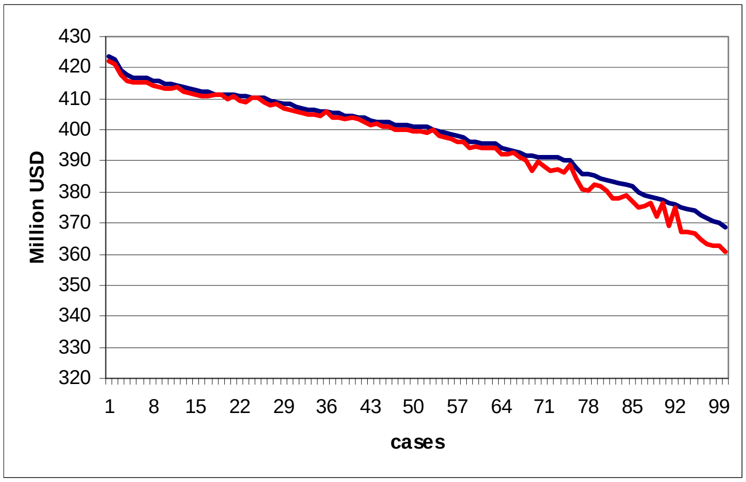
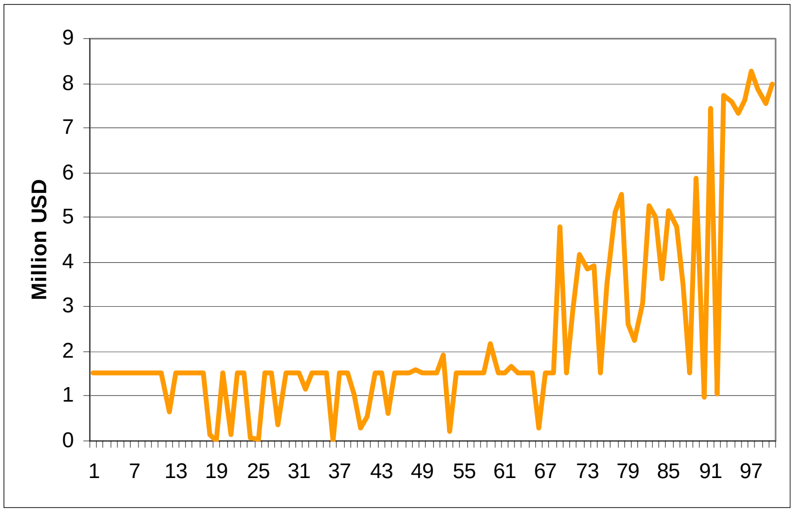


Figure 4-23 shows that the savings in total system cost due to the inclusion of DRR was small in most cases but quite large in a few cases.

Figure 4-23: Savings Due to DRR Over 100 Cases



4.12.7 Summary

Estimating the value of demand response is difficult using only one limited model. Therefore, there are several limitations to the conclusions drawn from the modeling, which are highlighted in this section. In general, it is expected that the value of demand response produced in this study is lower than in real life. Firstly, we only model the operation of part of the power market, and therefore problems which can arise on a very short notice are not included. Secondly, the assumption of full information that the model operates with creates an ideal situation. Therefore, the simulated results can be seen as optimal solutions, e.g., with the best use of the hydro power and transmission lines.

Likewise, hard-to-predict wind power and individual market actors will give grounds for more price spikes, and hence again, a higher value for demand response. Thirdly, the assumption of full competition between market actors leaves out the value of, e.g., limitation of market power. Especially, when the capacity balance is tight, the market is vulnerable for misuse of market power. Again, this will produce more price spikes.

Finally, only some of the uncertainties are included in the Monte Carlo analysis, leaving several more to further studies, which would only add to the value of demand response. Some of the parameters left out of this analysis are: availability of transmission lines, lack of capacity, and changes in prices outside the Nordic area. The next steps in this modeling effort will be to:

- Revise the Reference scenario so it is not such a tight balance.
- Calculate the value of DRR.
- Expand the time period the model is run for, from one week to possibly one year, on an hourly basis.
- Implement different types of DRR, e.g., different payback methods, DRR as load shedding at different prices, etc.
- Include more parameter variations, e.g., outages.
- Do a risk analysis.

-- Appendix A --

A Description of the Strategist® Model

A.1 INTRODUCTION

Strategist is an integrated planning system covering all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Customer demand is modeled explicitly within Strategist. Production cost simulations are comprehensive, yet fast. Financial analyses are accurate and thorough. Rate-level determinations reflect each utility's customer class definition and cost-of-service allocation factors. The system employs dynamic programming to develop an optimal resource portfolio. Sophisticated screening methodologies are available to develop and refine strategic marketing and demand side management initiatives, identify market potential, and build portfolios of initiatives.

In Strategist, integrated resource screening and optimization is accomplished within a single system that handles strategic marketing and demand side management programs, production cost simulation, environmental reporting, capital budgeting and financial, tax, and revenue forecasts on a rate class basis. Using a single, integrated software system for demand- and supply-side analysis of all resource types makes these studies much more manageable, ensures consistency in data assumptions, and provides credible, auditable results.

With Strategist, utility management can examine large numbers of options in a shorter period of time. The system has been designed to streamline the many steps in a comprehensive integrated planning effort and to handle the mechanics. This minimizes human error, inconsistencies, and repetitive data entry. For instance, if a combustion turbine's in-service date is delayed in the optimization program, the new in-service date is automatically specified to the production costing module as well as the capital budgeting and financial modules. The module also performs year-by-year "round robin" processing in order to appropriately address price elasticity.

Strategist provides a wide variety of standard reports ranging from unit by unit generating statistics to construction project accounting reports to comprehensive pro forma financial results. The system includes full input summaries and detailed diagnostics.

A.2 MODULAR STRUCTURE

Analysts use the individual modules of Strategist to develop an understanding of specific areas of interest (e.g., power system operation or rate level determination) as well as for complete integrated planning.

The configuration of a Strategist installation varies, depending on each user's applications, data availability, and staff resources. Many utilities rely on the entire system for strategic, corporate, and integrated planning. A common "subset" configuration is one designed for system planning without refined financial and rate capabilities. PROVIEW, DCE, the Load Forecast Adjustment Module, the Generation and Fuel Module, and PROVIEW Resource Optimization comprise this configuration. Other utilities utilize the financial components and rely on PROMOD IV for production costing. This configuration commonly includes the Capital Expenditure and Recovery Module, the Financial Reporting and Analysis Module, the Class Revenue Module, and Holding Company. Many utility companies which started with one or the other of these configurations have migrated to the full integrated system.

Many of the modules comprising the entire Strategist system are discussed in detail below:

A.2.1 Load Forecast Adjustment Module

The Load Forecast Adjustment Module is a multi-purpose tool for creating and modifying load forecasts and evaluating marketing and conservation programs. Using the LFA, a strategic planner may address key issues related to future electricity or gas demand and impacts attributed to each customer group. Results from this analysis can be automatically transferred to other Strategist modules to determine production costs, system reliability, cost-effectiveness of marketing initiatives, financing and revenue requirements, and a variety of other indicators affected by loads.

Load data can be defined in varying levels of detail. The degree of data aggregation is determined by the user. Any number of data "groups" may be specified. Data groups are summed to "class" totals. Class totals are summed to company totals. Data groups may correspond to end-uses, rate categories, customer categories, class totals, or even company totals.

MWH data may be input seasonally or annually. If the user desires, the MWH for each season may be specified as a percent of the annual value. Peak load in MW or as a load factor may be input. If peak loads are not input for a group, peak is determined from input load profiles.

The module provides a comprehensive demand-side program evaluation capability, with inputs for program cost, load impact, timing, and capital costs.

Load impacts may be input chronologically for each program, or may be determined by the module based on inputs for peak, energy, and program type.

Load can also be calculated by region or area. This is used directly by PROMOD IV.

Most calculations are performed seasonally, where seasons are defined by the number of seasons and number of days in each season.

The module provides a mechanism to reconcile the electric price assumption underlying the load forecast and the electric price resulting from the Strategist simulation. This mechanism is intended to reflect a company's existing load forecasting process.

Price response can be specified in a flexible manner. The LFA Module allows a variable lag structure input with lag coefficients specified for as many as ten prior years.

Block energy rates, block demand rates, time of use rates, seasonal demand rates, and seasonal customer rates can be modeled to determine revenue by load class. These revenue values are passed to the DPD module and the FIR module.

Results are reported by end-use group, by class, and by company.

Numerous diagnostics supplement the standard reports.

The LFA Module interfaces with PROMOD IV and therefore guarantees that load and DSM programs are treated in a manner consistent with Strategist.

A.2.2 Generation and Fuel Module

The Generation and Fuel Module simulates power system operation using proven probabilistic methods. It provides production costs and generation reliability measures that are essential to supply and demand planning. The GAF Module fulfills a strategic planning role in that it requires less computer resources than more detailed production costing modules, without sacrificing overall accuracy.

The GAF Module uses probabilistic production costing techniques to simulate the effects of forced outages.

Most module calculations are performed seasonally, where seasons are defined by number of seasons and by number of days per season.

Sales, purchases, and hydro generation are accounted for on a seasonal basis.

The user can explicitly define an hour-by-hour schedule for an energy/capacity transaction or simply specify when the transaction tends to occur (during peak load hours, low load hours, or randomly) and the GAF will schedule the transaction appropriately.

Thermal generating units are represented by capacity segments; each segment may have a distinct heat rate, which may be input as average, incremental, or coefficients of a quadratic input/output equation. Availability is defined for the entire unit; a partial availability may also be input to represent times when a unit may only operate at minimum capacity. The units which are classified as must-run are committed first, followed by enough other units to satisfy a user-input commitment criterion. The remaining units are committed on an economic start-up and dispatch basis, subject to fuel limits and spinning reserve requirements.

The dispatch of thermal units and economy energy may be performed on a seasonal or annual basis.

Pumped hydro projects and direct load control programs are economically dispatched on a seasonal basis, based on marginal cost. (Direct load control programs may be modeled only if the LFA Module is licensed.)

Units are dispatched to conform to upper and lower limitations on fuel usage.

Unit dispatch is performed on an 'as burned' or replacement cost of fuel basis.

Unit, company and system emissions are calculated based on actual runtimes and fuel usage. Emissions allowances are purchased or sold on the basis of system performance and the inputs for allowance cost and allowance base for each effluent. The cost of allowances is reflected in the dispatch lambda used in dispatch order decisions.

Environmental externalities are calculated for emissions, emergency energy, and direct load control.

Multicompany dispatch with interchange accounting for holding companies or power pool simulation is provided.

Numerous diagnostic reports which document detailed calculations are provided.

A.3 PROVIEW™ Resource Optimization Module

The PROVIEW Module is a resource optimization model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. PROVIEW works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system or modifying the load through demand-side management (DSM) or marketing programs.

PROVIEW allows for a full enumeration of all combinations of expansion options and/or demand-side management or marketing programs through its Dynamic Programming option. The system can thus be highly rigorous in its determination of a least-cost expansion plan for the entire planning period.

PROVIEW provides quick turn-around time by eliminating options that are not feasible and by eliminating unnecessary detail.

Production cost calculations are performed for each alternative through the execution of the GAF Module. Demand side programs and associated sales impacts are computed through the execution of the LFA Module.

PROVIEW uses the economic carrying charge as the capital cost representation during the study period optimization. After the study period rankings have been determined, the plans will be re-ranked over the planning period horizon using actual year by year revenue requirements. If these are not input, then levelized revenue requirements will be used.

PROVIEW explicitly handles end effects in determination of the least cost plan. The end effects analysis approximates the capital and production cost of replacing the resulting utility system in kind over the user-input end effects period.

PROVIEW provides for one of five objective functions to be used in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost (total resource cost), minimization of total resource costs, or maximization of total unit profitability.

PROVIEW will also evaluate any expansion plan optimized by one of the five objective functions mentioned above with regard to financial performance. The expansion plans may be re-ranked based on electric revenue, corporate value of the firm, economic value added, earnings per share, or value per share.

PROVIEW provides numerous constraints for the user to reduce the number of options to consider. Minimum and maximum number to add, minimum and maximum reserve or loss of load hours, and first year available to add are but a few. PROVIEW can define alternatives as mutually exclusive or inclusive in a year. It can also restrict alternatives to be dependent upon certain other alternatives being in service (the second unit in a station is dependent upon the first unit having been constructed). PROVIEW also allows options such as phased construction of combined cycle units to be evaluated quickly. Maximum emissions levels can also be specified to reduce the alternatives considered.

A PROVIEW optimization may be performed for the entire pool when multi-company summation logic is used. PROVIEW allows constraints to be entered at both the system level and for each company in the pool.

When using Multi-Company, PROVIEW allows the addition of alternatives which are owned by a company other than the company (or pool) which is being optimized.

PROVIEW allows complete evaluation of suboptimal plans. All plans are saved in PROVIEW's database for subsequent reporting and analysis. The user may specify the ranking of significantly different plans. Significantly different plans are developed as of a certain year of the analysis.

Numerous diagnostics which explain in detail how PROVIEW determines the optimal plan are available.

-- Appendix B --

Further Details of the Base Case and Results

B.1 Cost of DRR Capacity

Total cost of DR capacity (2005 $)					
	DLC Spinning	Large Interruptible	Dispatchable Transaction	Real Time Pricing	Total
One time Costs	300,000	200,000	200,000	100,000	800,000
Annual Costs over 20 years	691,710,777	165,721,799	14,985,064	6,996,139	879,413,780
Total Cost over 20 years	692,010,777	165,921,799	15,185,064	7,096,139	880,213,780

MW Cost of DR Capacity (2005 $)					
	DLC Spinning	Large Interruptible	Dispatchable Transaction	Real Time Pricing	Average
$/MW of capacity averaged over 20 years	51,387	7,516	2,411	476	20,438
$/MW of capacity in 2023	23,059	6,912	855	198	10,275

B.2 DRR Capacity Usage

DRR Capacity Usage Without RTP				
Capacity Used	Average	Large Interruptible	DLC (Spinning)	Dispatchable Transaction
> 10%	33.02%	18.16%	34.32%	46.58%
> 30%	11.47%	9.05%	22.21%	3.16%
> 50%	5.96%	0.84%	16.21%	0.84%
> 70%	2.33%	0.05%	6.84%	0.11%

DRR Capacity Usage With RTP				
Capacity Used	Average	Large Interruptible	DLC (Spinning)	Dispatchable Transaction
> 10%	28.46%	14.95%	27.42%	43.00%
> 30%	9.21%	7.16%	18.42%	2.05%
> 50%	5.04%	0.68%	13.95%	0.47%
> 70%	1.93%	0.00%	5.74%	0.05%

B.3 Loss of Load Hours

	Avg over 20 years	Avg of top 10%	Avg of top 5%
Base	7.64	15.72	18.89
Callable DRR	0.40	2.56	3.02
Callable DRR and RTP	0.01	0.02	0.02
	Decrease in Avg	Decrease in top 10%	Decrease in top 5%
Callable DRR	94.76%	83.72%	84.04%
Callable DRR and RTP	99.82%	99.87%	99.88%

B.4 Generating Units

Unit Name	Fuel	Capacity (MW)	Generation (GWh)	Heat Rate (Mbtu/MWh)	Forced Outage Rate (%)	Average Variable Cost ($/MWh)	Capacity Factor (%)	% of Peak Demand
SLMPSEGN 2	Uran	1,120	8,997	10.69	8.00	7.74	91.45%	2.67%
SLMPSEGN 1	Uran	1,170	8,636	10.78	6.00	7.79	84.03%	2.79%
PCHBTTOM 3	Uran	1,119	8,744	10.55	10.00	7.79	88.95%	2.66%
PCHBTTOM 2	Uran	1,119	8,012	10.44	10.00	7.74	81.51%	2.66%
OYSTRCRK 1	Uran	637	4,443	10.27	10.00	8.91	79.40%	1.52%
LMRCKXGN 2	Uran	1,205	9,282	10.51	6.00	7.17	87.69%	2.87%
LMRCKXGN 1	Uran	1,205	8,766	10.61	6.00	7.22	82.81%	2.87%
HPCRKPSG 1	Uran	1,088	7,928	10.82	6.00	8.08	82.96%	2.59%
WLMNGTON 21	Gas	513	3,218	6.40	4.08	40.29	71.41%	1.22%
LBRTYLCT 1	Gas	500	2,358	6.40	4.08	41.52	53.68%	1.19%
BTHLHMCV 22	Gas	550	1,924	6.89	4.08	43.67	39.82%	1.31%
BTHLHMCV 21	Gas	550	2,085	6.89	4.08	43.68	43.15%	1.31%
BRGNPSGF 6	Gas	675	2,084	6.21	4.08	44.45	35.16%	1.61%
BRGNPSGF 2	Gas	500	2,619	6.40	4.08	40.98	59.64%	1.19%
ASREDOAK 1	Gas	830	5,231	6.21	4.08	40.37	71.75%	1.98%
CRNYSPNT 1	Coal	267	2,021	10.07	7.16	22.59	86.14%	0.64%
CROMBY 1	Coal	147	1,123	10.35	6.50	25.84	86.99%	0.35%
EDDYSTNE 2	Coal	311	2,247	9.93	8.65	29.81	82.24%	0.74%
EDDYSTNE 1	Coal	288	2,121	10.04	7.16	31.24	83.83%	0.69%
EDGEMOOR 4	Coal	174	1,228	9.75	6.50	32.93	80.36%	0.41%
ENGLAND 2	Coal	155	1,197	9.90	6.50	29.99	87.88%	0.37%
HDSNPSGF 2	Coal	623	4,694	9.50	6.83	29.67	85.77%	1.48%
INDNRVRN 4	Coal	420	3,017	10.29	7.84	30.53	81.79%	1.00%
INDNRVRN 3	Coal	165	1,247	9.24	6.50	27.51	86.01%	0.39%
LGNGNRTN 1	Coal	218	1,656	10.90	7.16	24.01	86.48%	0.52%
MERCER 2	Coal	325	2,404	9.05	8.65	26.68	84.22%	0.77%
MERCER 1	Coal	325	2,408	9.46	8.65	28.32	84.35%	0.77%

-- Appendix C --

Modeling Tools

1. Resource Planning Models

1.1 AuroraXmp Electric Market Model

Company: EPIS Inc.
Description: AURORA is a power market simulation model. AURORA produces both short-term and long-term price forecasts for all major market zones and trading hubs in North America. AURORA simulates supply and demand on an hourly basis to provide electricity price forecasts. AURORA's sophisticated bidding logic enables modelers to understand such market subtleties as cost of emissions and shadow bidding effects by unit.
Inputs, variables and data can be modified and/or integrated with the user's own data or risk models. Outputs can be examined in mid-operation – hour-by-hour or unit-by-unit – to better understand market factors and effects during the simulation.
Known Users: Northwest Power and Conservation Council
Contact Info:
1800 Blankenship Rd. Suite 350
West Linn, OR 97068
USA
Tom LaBerge (+1 503-722-2023)
www.epis.com

1.2 Baltic Model of Regional Electricity Liberalisation (Balmorel)

Company: Balmorel Project (financed by the Danish Energy Research Program)
Description: The purpose of the Balmorel project is to support modeling and analysis of the energy sector, primarily in the Baltic Sea Region, with emphasis on the electricity and combined heat and power sectors. The Balmorel model is a tool that can be used for the analysis of future developments of the regional energy sector. The model consists of the model structure (formulated in the GAMS modeling language) and the corresponding data for the Baltic Sea Region.
The model determines the following entities:

- Generation of electricity and heat, distinguished by technology and fuel;
- Consumption of electricity and heat;
- Electricity transmission;
- Emissions;
- Investments in generation and transmission capacities;
- Prices of electricity and heat.

All these entities are specified with respect to time period and geographical entity. The solution of the model is done by solving a linear programming optimization problem. The model is open-source and free.
Known Users: The model will be used for analyses of the electricity sector in Poland and the Baltic countries.
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1.3 Electric Generation Expansion Analysis System (EGEAS)

Company: Electric Power Research Institute (originally from the Laboratory for Electromagnetic and Electronic Systems, Massachusetts Institute of Technology)
Description: EGEAS is a generation resource optimization software package developed under EPRI sponsorship for use by system planners to develop integrated resource plans, evaluate new generation

technologies, assess impacts of merchant power plants and independent power producers, and evaluate generation system reliability.

It can specifically model demand-side management options as resources in developing the “integrated” resource plan, consisting of the optimum mix of supply-side and demand-side resources. The most recent Version 9 can also perform economic dispatch based on bid prices as currently done by Independent System Operators in the deregulated market environment.

System planners have used the EGEAS model for various types of studies, including:

- Integrated resource planning studies;
- development of generation expansion plans;
- environmental dispatch and optimization of resources to comply with the Clean Air Act;
- maximize profits by selecting the optimum generation investments for development;
- assess financial viability of generation projects;
- comply with regulatory requirements for new technology resource expansion plans;
- analysis of the economics and impacts of Independent power producers;
- power pooling and economic dispatch studies;
- marginal cost, contract & other rate evaluations;
- plant life management & repowering evaluations;
- avoided energy and capacity cost analyses;
- capacity reserve and system reliability analyses.

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1.4 EMPS, EOPS, SHOP

Company: SINTEF, Norway
Description:
EMPS

- Stochastic model designed for long-term optimization and simulation of hydro-thermal system operation;
- Well suited for comprehensive studies on a national or international scale;
- Strategy evaluation part computes regional decision tables in the form of expected incremental water values for each of a number of aggregate regional subsystems;
- Simulation part evaluates optimal operational decisions for a sequence of hydrological years;
- A mid term model as in the EOPS.

EOPS

- a stochastic model for long- to mid-term optimal scheduling and simulation of general hydro-thermal electrical system, focusing on hydropower;
- Mainly used for load scheduling;
- Generally equivalent to one subsystem of the EMPS model above, except that the market price is usually externally given and treated as a stochastic variable.

SHOP

- Used for short-term scheduling;
- Finding an optimal use of resources while taking into account the boundary conditions provided by the medium-term scheduling procedures;

- The plant is modeled at the unit level with individual production schedules being defined for units;
- Production curves can be defined for any plant head;
- Optimization approach based on successive linear programming.

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1.5 EnerPrise 2.0 (based on Prosym)

Company: Global Energy Decisions/Henwood
Description: Enerprise 2.0 is an integrated software suite that supports Enterprise Portfolio Management from strategy to results using state-of-the art market, operations, and risk simulation software. EnerPrise 2.0 enables electric industry participants to quantify the cash flow risk to their management strategy, align their business units to improve execution and optimize portfolio performance, and focus business strategy on the future. Note: They view DRR as another load forecasting feed, to keep it statistically simple and the model running efficiently.
Known Users: Pacific Gas & Electric; San Diego Gas & Electric; Southern California Edison;

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1.6 GE-MAPS

Company: General Electric
Description: MAPS software is a highly detailed model that captures hour-by-hour market dynamics while simulating the transmission constraints on the system. This tool provides valuable insight into regional power markets, which are defined by physical transmission limits.
It analyzes the market opportunity for an individual company or examines the economic interchange of energy between several companies in a region. In addition, MAPS software provides the hourly spot prices at individual buses, and identifies the companies responsible for flows on specific transmission lines. These capabilities enable you to examine issues and opportunities in the deregulated power industry. Recent applications include market power studies, stranded costs estimates and project valuations.
MAPS software can define regional power markets accurately because of the way it models transmission. Instead of using a transportation model that views the flow of electricity similar to the flow of oil or gas, the program recognizes that electricity has unique properties. MAPS software models the electrical system in detail, examining the flow on each line for every hour of the simulation, recognizing both normal and security-related transmission constraints.

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www.gepower.com/prod_serv/products/utility_software/en/ge_maps/index.htm

1.7 GenManager

Company: Power Costs, Inc.
Description: A software package designed to help market participants automate their bid management process and maximize profits in an LMP, two-settlement market operation. The solution incorporates locational marginal prices and supports analysis modes for day-ahead and real-time bidding. Its modular web services architecture provides flexibility to respond quickly to varying market conditions and to interface with other systems and data sources. GenManager explicitly incorporates price-sensitive demand. The primary components of GenManager are described below.
The Bid Formulation module provides the following important capabilities:

- Creating and saving multiple bidding strategies appropriate to different market conditions.
- Automatically "updating" bid and offer prices and quantities to reflect changes in fuel costs, heat rates, etc.

The Bid Evaluation module performs the following analysis:

- Day-ahead and real-time bid analysis
- Day-ahead adjustment period analysis
- Multi-case analysis

The LMP Management module facilitates the following functions:

- Creating an LMP forecast
- Organizing LMP forecasts and historical data for easy use
- Maintaining a similar-day profile library

The Settlement module provides efficient and effective tools for:

- Creating shadow settlements and invoices and comparing them with ISO settlements
- Submitting and tracking disputes

The ISO Communication module enables:

- Data exchange between the market participant and the ISO for all aspects of the bid-to-bill process.

Known Users: Installed for 2 participants in MISO and 1 in PJM.

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www.powercosts.com

1.8 Inter-Regional Electric Market Model (IREMM)

Company: IRREM Inc.
Description: The IREMM model is based on demand/supply precepts, and is not a "traditional" cost-recovery plus pricing model. IREMM provides a broad-based, comprehensive view of competitive electric power markets:

- Forecasts market-clearing economy energy prices;
- represents all buyers and sellers within an interconnected system simultaneously;
- identifies economic energy transactions;
- is dynamic;
- analyzes the interaction of supply and demand in a competitive bulk power market;

- is not a cost-based, franchise area-specific pricing model;
- forecasts are **NOT** based on surveys or trends; and
- can be used to assess market power.

Risk analyses can easily include fuel prices; new, retired, or out-of-service electric generation plants; changing electricity demand forecasts; transmission constraints; wheeling costs; operation and maintenance costs; environmental impacts; fuel switching, etc...

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www.iremm.com

1.9 MAISY (Market Analysis and Information System): Electric Customer Revenue and Cost Management Model

Company: Jackson Associates
Description: Jackson Associates provides regulated electric utilities and competitive electricity service providers with Revenue and Cost Management (RCM) capabilities in a three phase process.

- An optional initial client RCM assessment provides a comprehensive, confidential evaluation and assessment of current potential for RCM cost savings and revenue enhancement
- Individual RCM projects focus on priority items which can be implemented immediately to reduce costs and increase revenues
- A comprehensive RCM system, composed of integrated project components, provides optimized pricing strategies, supply options, demand response programs, energy service, load management, and other strategies

Load Management Impact Analysis and Modeling are important components in the RCM system, reflecting the results of conservation, new technology applications and load management actions on individual customers, including both customer participation and energy and hourly load impacts. Jackson Associates has extensive experience representing virtually every demand side management and load management initiative or program instituted by utilities and customers over the last fifteen years.
Known Users: Many utilities, power pools, energy service providers, ESCOs, etc.

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1.10 Markal (MARKet ALlocation))

Company: Energy Technology Systems Analysis Programme (ETSAP) of the IEA
Description: MARKAL is a widely applied bottom-up, dynamic, originally and mostly a linear programming model. MARKAL depicts both the energy supply and demand side of the energy system. It provides policy makers and planners in the public and private sector with extensive detail on energy producing and consuming technologies, and it can provide an understanding of the interplay between the macro-economy and energy use. The MARKAL family of models is unique, benefiting from application in a wide variety of settings and global technical support from the international research community. The basic components in a MARKAL model are specific types of energy or emission control technology. Each is represented quantitatively by a set of performance and cost characteristics. A menu of both

existing and future technologies is input to the model. Both the supply and demand sides are integrated, so that one side responds automatically to changes in the other. The model selects that combination of technologies that minimizes total energy system cost. Some uses of MARKAL:

- to identify least-cost energy systems;
- to identify cost-effective responses to restrictions on emissions;
- to perform prospective analysis of long-term energy balances under different scenarios;
- to evaluate new technologies and priorities for R&D;
- to evaluate the effects of regulations, taxes, and subsidies;
- to project inventories of greenhouse gas emissions;
- to estimate the value of regional cooperation.

Known Users: Implemented in more than 40 countries and by more than 80 institutions, including developed, transitional, and developing economies.

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1.11 MIDAS

Company: National Technical University of Athens, Department of Electrical Engineering
Description: MIDAS is a large-scale energy system planning and forecasting model. It performs dynamic simulation of the energy system, which is represented by combining engineering process analysis and econometric formulations. The model is used for scenario analysis and forecasting.
Each national application of MIDAS is a simultaneous system of more than 2500 equations solved dynamically over a period of 20 - 25 years. The MIDAS model building project was funded by the Joule Programme of DG XII and by DG XVII, of the European Commission. MIDAS covers the whole energy system and ensures, on an annual basis, the consistent and simultaneous projection of energy demand, energy supply, and energy pricing and costing, so that the system is in both quantity and price-dependent balance. The model output is a time-series of detailed EUROSTAT energy balance sheets, lists of costs and prices by sector and fuel, and a set of capacity expansion plans including emission data.
The MIDAS database uses the following sources: EUROSTAT detailed energy balances (SIRENE), OECD/IEA energy prices and taxes, EFOM model database, UNIPEDE/Eurelectric data, BP database, MURE, FRET and DERE databases of DG XII, KRONOS (macroeconomic indicators) and several national sources for mining, refining, power generation, coal statistics, natural gas, crude-oil production and transmission.

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www.worldbank.org/html/fpd/em/power/EA/methods/istmidas.stm#BIB

1.12 Promod

Company: New Energy Associates (Siemens)

Description: A detailed generator and portfolio modeling system, with nodal LMP forecasting and transmission analysis. The model includes extensive details in generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operation conditions, and market system operations.

Manage & understand your risk

- congestion risk
- fuel & environmental risk
- regulatory risk, and performance risk

Develop rapid & reliable decision support

- analysis of return on investment for capital expenditures
- power supply planning

Integrate with other PowerBase Suite components, gaining

- Integration with our long-term capacity and market valuation software, as well as our resource planning and integration software
- Complete, regularly updated North American market data
- Risk analysis via Monte Carlo algorithm
- Drag-and-drop scenario management
- Customizable reports, graphs, and map displays - with animation

The model contains built-in benefit/cost tests, including the 5 CA Standard manual tests, but users can design their own tests as well. Promod applies a Monte Carlo algorithm that considers unit availability as the random variable. This methodology allows evaluation of the system under a variety of unit-forced outage scenarios, and incorporates DRR as a response to outages.

Known Users: Over 80 clients worldwide.

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1.13 SIVAEL, SIVAELNET, SAMLAST, METRIS, PowerWorld, MAPS, GAMS, PowerFactory, MARS

Company: Eltra, Denmark
Description:
SIVAEL

- Model for operational simulation of a power system with related heated areas;
- Operational optimization of the entire system on an hourly basis;
- Possible in each hour to compare the need for regulating the system with available resources.

SIVAELNET

- Simulation model for planning purposes of the entire system of production plants and transmission networks;
- Used as an integrating tool consisting of SIVAEL and a previously developed load flow model;
- Model enables simulation of the transmission network;
- Each hour during a whole year the optimum load dispatch of power and heat is calculated, between the production units, while considering optimum start/stop incidents as well as network capacities and network losses.

SAMLAST
- Further development of EMPS by Sefas;
- Ensures that the flow between the EMPS model's subsystems is distributed physically correct in network.

METRIS
- A probabilistic network calculation model;
- Possible to analyze the security of supply and operational costs of systems consisting of several individual sub-systems;
- Minimizes the amount of total production costs and costs of non-supplied energy in a given period.

PowerWorld
- An interactive load flow model;
- Transformers and lines can be connected and disconnected during simulation;
- Possibilities of studying differential flow and performing sensitivity analysis must be emphasized.

MAPS
- Used for calculation of power shortage risk, expected non-supplied energy in a connected power system;
- Each area in the system is described by a load and data for production plants;
- Model handles forced outages of production plants and transmission lines.

GAMS
- A general model system to solve mathematical programming problems.

PowerFactory
- An interactive power simulation tool dedicated to electrical power system analysis in order to achieve the objectives of planning and operation optimization.

MARS
- New market model for simulation of prices, production, demand and changes in the power market;
- Prices, exchanges, etc are calculated on an hourly basis;
- Designed for hydro power, thermal production, nuclear power, and wind power.

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1.14 Strategist

Company: New Energy Associates (Siemens)
Description: Software package with the following features:
- Incorporate bilateral power contracts and financial supply options with your physical supply and new alternatives;
- Simulate multiple wholesale market structures, transmission flows and constraints, and economy purchases;
- Examine the effects of capital budgets, market structures, inflation scenarios, cost structures, and capital market conditions;
- Utilize consolidated income, balance sheet and cash flow statements at the company or business unit level;
- Minimize portfolio cost, increase shareholder value, and maximize profit using PROVIEW;

- Integrate all types of physical supply alternatives into your existing portfolio, and identify retirement and mothballing opportunities;
- Screen, test, and design cost-effective demand-side marketing programs and non-firm rate offerings for a fully integrated resource portfolio;
- Determine the financial impact to customer-class cost responsibility, rates and customer profitability.

Note: Strategist does LT direct load control program, computes DRR savings, economics of controlling demand, computes system-wide or blocks of interrupt (can do multiple blocks). Benefit/costs tests available: the 5 CA Standard manual tests are included, and you can design your own test as well. This model does not run Monte Carlo simulations, but instead analyzes the entire operation of the full utility. It is a database driven model.

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2. Risk Analysis Tools

2.1 Crystal Ball

Company: Decisioneering
Description: Crystal Ball 7 Premium Edition is a suite of risk analysis, forecasting, optimization and real options analysis tools available for use within a spreadsheet program. Use your own historical data to build accurate models, automate "what if analysis" to understand the effect of underlying uncertainty, apply real options theory to enhance the value of each project by incorporating strategic flexibility in decision making, and search for the best solution or project mix.
Crystal Ball Standard Edition is Monte Carlo simulation for spreadsheets. Quickly assign ranges of values to model inputs, automatically calculate ranges of forecasted outputs and their probabilities. Record the results for in-depth analysis or summarized reporting with Crystal Ball's many reports, charts and tools.

- OptQuest® - automatically search for your optimal solution, accounting for uncertainty and constraints.
- CB PredictorT - analyzes your historical data to build the model, with time-series forecasting and multiple linear regression.
- CB Tools - automate model building tasks, simulate variability, define correlations and perform additional functions.
- Real Options Analysis Toolkit - options theory applied to management decision-making in situations with high levels of uncertainty.
- Monte Carlo (with "latin hypercubing" allows greater random variability - outliers taken into account). Demand forecasting based on historical data with cyclical and/or seasonal variability. Can select precision and forecast method.

Known Users: Northwest Power and Conservation Council; Toledo Gas

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2.2 @RISK

Company: Palisade Corporation
Description: @RISK is a risk analysis tool which lets you see all possible outcomes in your situation, and tells you how likely they are to occur. You will see what could happen and how likely it is to happen, and therefore be able to judge accordingly which risks to take and which ones to avoid.

- Shows you ALL possible outcomes;
- Helps you avoid pitfalls and identify opportunities;
- Shows you chances of different outcomes occurring;
- Lets you develop best personal strategy possible;
- Works within Excel;
- Presentation-quality graphics;
- Graphical distribution selection;
- Makes defining uncertain factors easy;
- Distribution fitting – enables accurate description of uncertainty using data;
- Uses Monte Carlo simulation to show you all possible outcomes.

Running an analysis with @RISK involves three simple steps:
1. Define Uncertainty - Start by replacing uncertain values in your spreadsheet model with @RISK probability distribution functions. These @RISK functions simply represent a range of different possible values that cell could take instead of limiting it to just one value.
2. Pick Your Bottom Line - Next, select your output cells - the "bottom line" cells whose values you are interested in. This could be potential profits for a new product launch, insurance claims payout, disease recovery rate, anything at all.
3. Simulate - Then click the "Simulate" button. @RISK recalculates your spreadsheet model hundreds or thousands of times. @RISK samples random values from the @RISK functions you entered and records the resulting outcome. The result: a look at a whole range of possible outcomes, including the probabilities they will occur.
Known Users: El Paso Energy; Cinergy

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3. PHYSICAL MODELING

3.1 Air Conditioning and Heat Pump Model, Thermal Storage Loads, Aggregation Methodologies

Company: Instituto de Ingenieria Energetica (Universidad Politecnica de Valencia), Spain
Description: Physically based load models developed by IIE-UPV.

- Air Conditioning and Heat Pump Model – evaluates the load demand flexibility and dynamic response during a control period;
- Separate the demanded electrical energy intervals from the intervals in which that energy is used by customers;

- Models external as well as internal walls;
- Thermal Storage Loads;
- An energy balance analysis has been applied to the system integrated by the housing, the external environment, and the TES device;
- Model relies on information about physical load characteristics, internal control mechanisms, usage and environmental parameters;
- Aggregation Methodologies – describing approximately the expected value of the total power demand due to the load control group;
- Uses Fokker-Planck equations, Monte-Carlo methods, or Kernel estimators.

Customer demand organization is based on the creation and economic evaluation of a set of offers and bids from the thorough analysis and packaging of consumer loads. These sets reflect the potential to schedule the consumption according to price – and potential suitability for DRR. See document: *End-User acceptance and potential for Demand Response, July, 2004.*

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2.3 USELOAD

Company: SINTEF, Norway
Description: USELOAD is a Windows NT-program for calculation of electrical load divided into end uses. This is a new model mainly for segmenting metered time series into end-use or different customers. It is based upon load curves from national load research projects. The model uses statistical methods and handles climatic dependencies and the diversification in the load from different customers. It can also estimate the coincident peak demand in a network with selected degrees of confidence.
USELOAD's origin is from the international liaison body EDEVE where load-research, demand side management and more specific consumption relations are being discussed and elucidated. The specialty of USELOAD is great flexibility, basic development of methods, and great applicability for different kinds of purposes. Detailed input data is important before the model is operative for a specific region. Typical daily load curves for i.e. lighting, heating, ventilation, hot water and other electrical appliances should be established. Based on this data, the total load curve can be calculated, divided into the hours of a day, or for a year.
Known Users: Electricité de France; Sydkraft; VTT Energy; Electricity Association; and Energy Piano in Denmark.

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