EXHIBIT 3

DEMAND RESPONSE RESOURCES (DRR) VALUATION AND MARKET ANALYSIS: ASSESSING DRR BENEFITS AND COSTS[A]

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This paper 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. This assessment was performed as part of Subtask 4 (Demand Response Resource Valuation) of the IEA Task XIII Demand Response Resources (DRR) study. In the conclusions section, this resource planning approach is described is compared with the other methods that have been used to provide estimates of the value of DRR.

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.

Demand response 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, and provides

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[A] This effort was conducted as part of a project for the International Energy Agency (IEA). Specifically, the IEA Demand Programme, Task XIII: Demand Response Resources where this was Subtask 4 of the effort. Mr. Ross Malme of RETx (rmalme@retx.com) served as the IEA operating agent for overall IEA Task XIII.

[B] The authors can be contacted at Summit Blue Consulting, Summit Blue Consulting; 1722 14th Street, Suite 230; Boulder, CO 80302. [Phone: 720-564-1130; E-Mail: dviolette@summitblue.com and rfreeman@summitblue.com] for the interaction of demand and supply create an efficient operating market for electricity. However, 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.

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 DRR in the context of 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.[C] 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.

INCLUDING DRR IN A PORTFOLIO OF RESOURCES

Questions that need to be addressed when considering DRR in a portfolio of resources include:

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 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: <u>How should the different DRR products be sized (i.e., how many MWs or MWhs 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.

[C] A more complete discussion is in the report "DRR Valuation and Market Analyses: Volumes I and II," prepared for the International Energy Agency Demand Side Programme, Task XIII – Demand Response Resources, January, 2006.

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.

CASE STUDY – VALUING DRR USING A RESOURCE PLANNING FRAMEWORK

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 to 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.

A case study modeling effort was developed for valuing DRR using a resource planning context. 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.[D]

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.

Model Inputs

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

The key input variables around which uncertainty was dimensioned were:
1. Fuel prices – natural gas, residual oil, distillate oil, and coal
2. Peak demand
3. Energy demand
4. Unit outages
5. Tie line capacities

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

[D] Eric Hughes with New Energy Associates (EHughes@newenergyassoc.com) assisted with all of the resource planning model runs and provided insights regarding the interpretation of results.

- 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 – 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 second 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.

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

Case Study Results

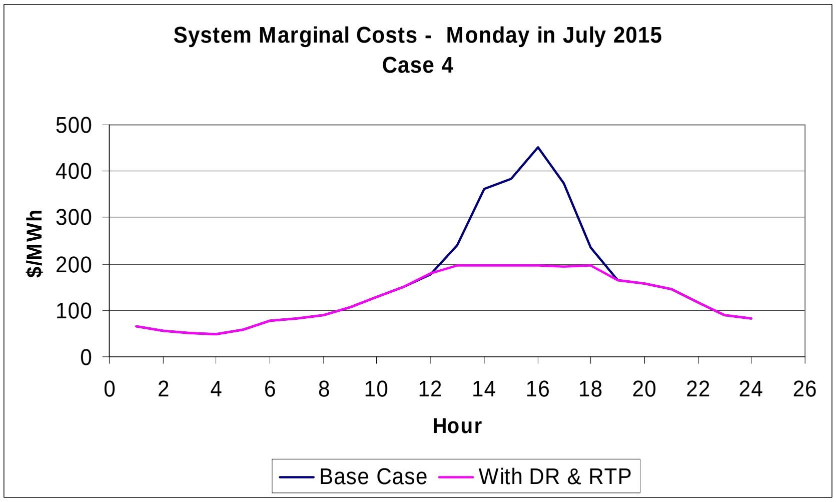
Results from these analyses include the following:

- **Uncertainty:** 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.

Range of Total System Costs for Selected Years - Base Case
($ Billions)

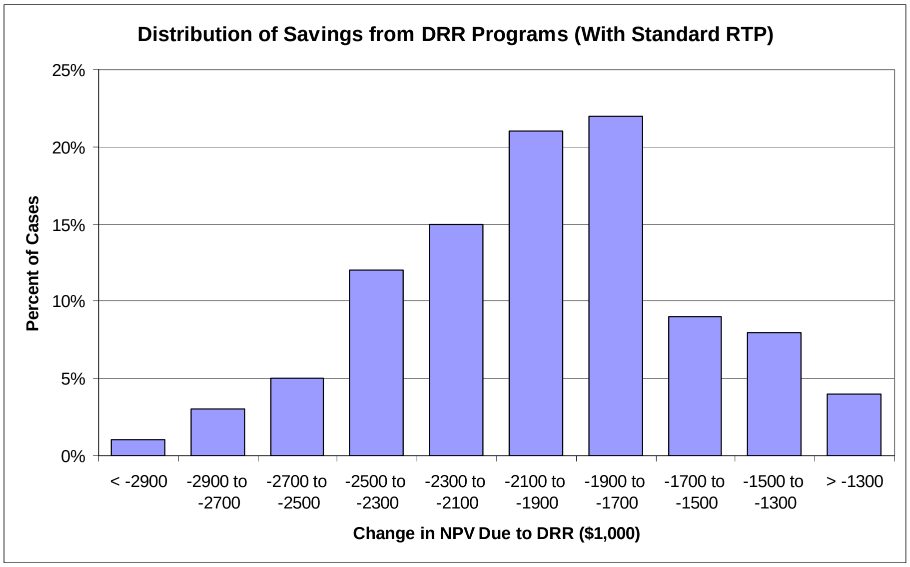
Year	2010	2012	2015	2018	2020	2023
Maximum	7.7	8.2	10.2	10.3	12.4	15.0
Minimum	3.5	3.8	5.1	5.6	6.5	7.5
Range	4.2	4.5	5.1	4.6	5.9	7.5
Ratio	118.5%	118.8%	101.7%	82.2%	89.9%	99.3%

- **Hourly Costs:** 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 costs, reducing the maximum by more than 50%. For example, in one peak day in July the total cost savings were $24.5 million.

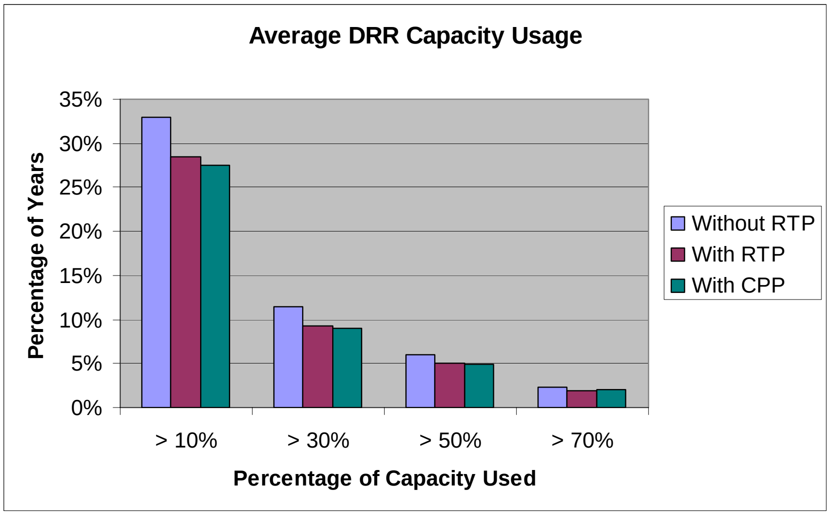


- **Capacity Charges:** A substantial percentage of new capacity charges were deferred by the model because of the DRR availability. This amounted to savings of $892 million (2004 dollars) over the 20-year period.

- **Savings in Each Year:** 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.



- **DRR Capacity Usage:** 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.



- **Cost Risk Profile:** 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

- **Loss of Load:** 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.

- **Total System Cost:** Overall, the incorporation of DRR results in some reduction in the average total system cost NPV in all three scenarios with DRR (callable DRR, DRR with CPP, and DRR with standard RTP). In the scenario with the standard RTP program, savings are about 3.5 times those in the scenario with the critical peak pricing program, and similarly, savings in the scenario with the critical peak pricing program are approximately twelve times those with only the callable DRR programs.

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

- **Incremental System Cost:** 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.

Overall, 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 it reduced the net present value of total system costs over the planning horizon.

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 earned during the process include:

1) Given that this is an initial effort, improvements can be made to the model specification. Specifically, care is needed to appropriately specify the costs and capabilities 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.

2) The incorporation of DRR into the resource plan substantially increased reliability as measured in loss of load probabilities (LOLP). No value was determined 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 production system costs.

3) 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 most new combustion turbine capacity over the study horizon. An examination of the model results showed that this resulted in some older generation units with high energy costs remaining 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

looking at the economics of these older fossil units might lower the average system energy costs in the "with DRR" scenario, leading to a greater savings.

4) 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.

5) 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.

6) 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.

COMMENTS: COMPARISON WITH OTHER METHODS FOR VALUING DRR

As part of the overall project, four approaches for valuing DRR were examined:

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, but also including the California Standard Practice Manual Tests.

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

Approach 4: The resource planning approach incorporating a portfolio of supply-side and demand-side resources; the explicit dimensioning of uncertainty around key factor influencing system costs; 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 generally been 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 have 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.

There is no question that the use of all four approaches for examining the value of DRR will continue to provide positive information. There is also no getting around the tough questions that demand response programs and 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 an electricity market that encompasses 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 costs related to generation and also 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 these resource and cost assessments is needed, if the value of DRR is to be addressed appropriately.

The use of benchmark approaches, standard practice tests such as the TRC test, and event-specific 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 benefit/cost tests likely will continue to be used in the near term and are useful as “proof-of-concept” analyses. Still, questions about how much DRR are enough and the dynamics inherent involved in the timing of DRR investment decisions will need to be addressed. These assessments likely will require dynamic resource planning constructs for both generation and T&D.