Power System Engineering, Inc.

Demand Response: How Much Value is Really There?

(And How to Actually Achieve It)

By Power System Engineering, Inc. (PSE)

Capital costs are often driven by the peak demand placed on the system.

Introduction

In the generation, transmission, and distribution functions of electric utilities, capital costs are often driven by the peak demand placed on the system. It is no surprise, then, that many utilities have deployed or are considering demand response (DR) programs that attempt to lower peak demand. These programs come in many forms, including load control and alternate rate schedules, such as peak time rebates and critical peak pricing.

DR: The Basic Premise

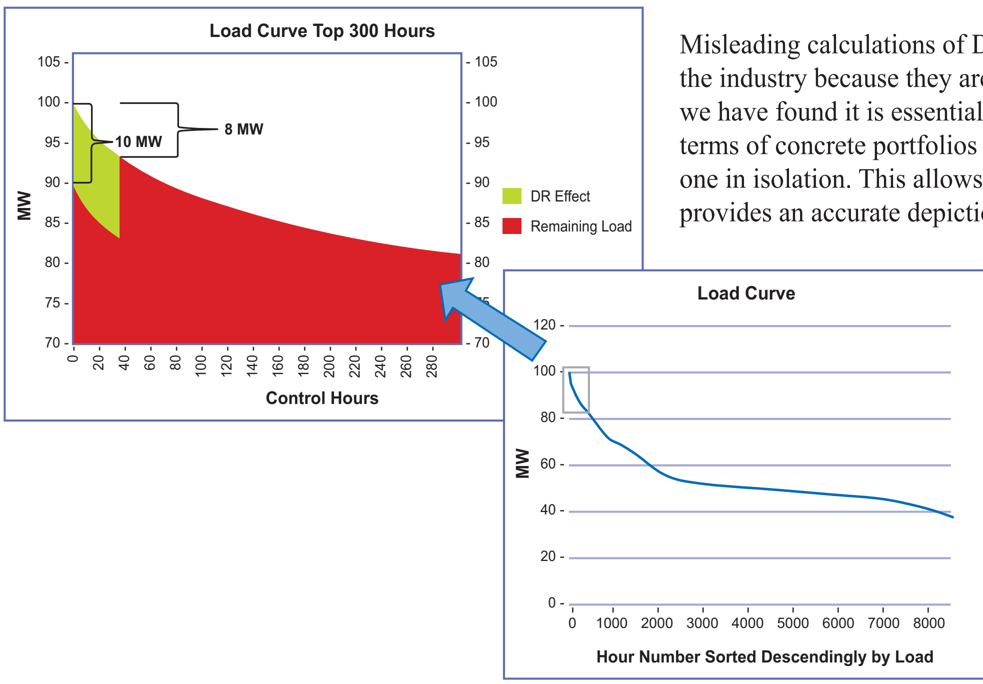
The basic premise behind DR sounds simple: reduce system peak by reducing energy use during high demand hours, thus lowering capital infrastructure costs and/or avoiding demand charges. Unfortunately, reducing system peak is not actually that simple. Utilities often ask themselves some of the following questions, both prior to and after implementing DR programs:

- How much can we reduce peak demand, given our hourly load profile, DR program impacts, day-ahead or day-of forecasting inaccuracy, and weather fluctuations?
- What can we actually achieve in real-time (not just theoretically achieve with perfect foreknowledge and unrealistic assumptions)?
- How much demand reduction can we achieve in years with normal weather versus years with abnormally hot or cold temperatures?

Questions Continued

Building on our DR experience, PSE developed the DR Optimizer model.

Figure 1: **Top 300 Hours of a Load Curve**



* *In this paper we focus on demand response programs; however, the model can also be used to determine the value of other programs such as energy efficiency, energy storage, distributed generation, and conservation voltage reduction.*

** *This is true even with the (unrealistic) assumption that the top forty demand hours are predicted perfectly, so that all events are called on the top forty demand hours.*

- How will different demand response programs interact with each other? What DR programs should be deployed, expanded, or discontinued? What impact will revenue erosion have on our utility's finances?
- How do we deploy these programs in the best manner, and when?

DR Optimizer Model

Building on our experience in the demand response area, PSE developed the DR Optimizer model*. The DR Optimizer uses a probabilistic method to perform thousands of weather scenarios using local historical weather data. The model analyzes the impacts and value of different demand response portfolios (i.e. combinations of DR programs) during the full range of weather outcomes, all customized for a particular utility. It models the real-time decision-making process to evaluate how each portfolio reduces demand, how each program is best deployed and when, and what programs would be beneficial to add or eliminate. All programs are evaluated based on the expected benefits and costs of the entire portfolio.

Misleading calculations of DR benefits is commonplace throughout the industry because they are often evaluated individually. Therefore, we have found it is essential to evaluate demand response programs in terms of concrete portfolios rather than evaluating programs one-by-one in isolation. This allows us to optimize the entire DR portfolio and provides an accurate depiction of DR value.

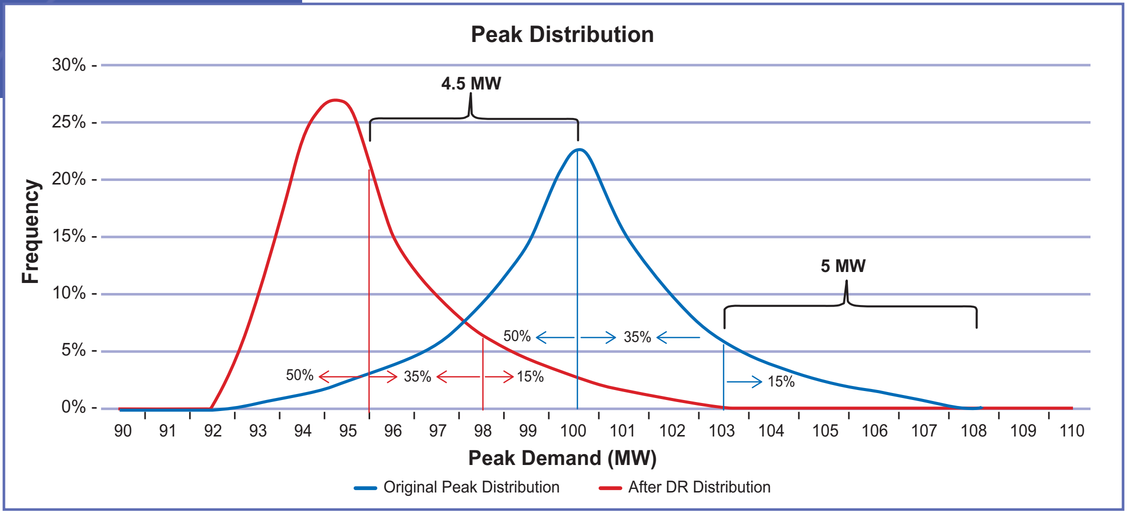
Overestimation of demand response benefits occurs when the possibility of a new peak is not factored in and adjusted for. Many industry studies that we have reviewed evaluated programs based on how much demand they reduce in the highest demand hour. However, reducing demand during that one hour may create a new peak in the second highest demand hour. The same problem can occur even if DR is used on many hours, such as the 40 highest demand hours of the year.

Consider a hypothetical utility ABC, which has a DR program that can reduce peak demand on the 40 highest demand hours of the year (from 100 MW to 90 MW, from 99 MW to 89 MW, etc.). If hour forty-one, which is not controlled, has a peak of 92 MW, then the new peak demand is not 90 MW, but is 92 MW** (see Figure 1). In other words, the peak demand impact on the system is not the demand reduced in one peak hour, but rather the difference between the original peak demand and the new peak demand.

A utility needs to understand the system's predicted peak load given different weather scenarios, not simply the "on-paper" maximum reduction.

Figure 2 shows the effect of a DR portfolio on a hypothetical utility's peak. The blue line displays what the system's distribution of annual peak demands would be absent DR programs. Without any DR programs in place, the most common annual peak is 100 MW. Thus, in an average year, this utility would expect its peak demand to be at 100 MW. However, in any random year, there is a 15% chance that peak load would exceed 103 MW.

Figure 2: **Distribution of Annual Peak Demands**



Furthermore, rebound energy from programs can create new (and possibly higher) peaks if not properly dispatched. In most cases, there will in fact be a rebound and/or a secondary peak.

The exact reduction depends on many different factors and assumptions, and the DR Optimizer accounts for all of these factors by conducting an hour-by-hour simulation of the utility's load curve to determine the realistic demand reduction expected from a given portfolio. It can also be used to find the best portfolio, and when and how to optimally dispatch each of the programs within that portfolio.

PSE's DR Optimizer can model the expected real-world results from each DR portfolio by making realistic assumptions on real-time forecasting errors, variable portfolio load impacts, and rebound energy effects.

Another important variable is weather: some years are average, some are hot, and some are mild. A utility needs to understand the system's predicted peak load given the different possible weather scenarios, not simply the "on-paper" maximum reduction. The DR Optimizer runs thousands of weather scenarios to examine how your possible DR portfolios will function. One of the key considerations is how the program will perform in unusually hot or cold weather conditions, or in normal years.

The red line shows the annual system peak load distribution after the modelling process by the DR Optimizer. With an optimized DR portfolio, the average peak load is now reduced to 95.5 MW, and there is now a 0% chance that the load will exceed 103 MW. Note that the shape of the distribution curve changes from symmetrical to lopsided, and thus the mean (average) peak for the "after DR" scenario is no longer at the most common annual peak. The peak under the most extreme conditions drops from 108 to 103 MW (5 MW), but the mean peak load only drops from 100 MW to 95.5 MW (4.5 MW).

An important distinction to make is while analyzing the reduction in peak under extreme conditions is crucial for utilities attempting to avoid capital infrastructure costs, a mean-to-mean analysis is more suitable for utilities attempting to avoid demand charges. Optimal DR portfolios and dispatch strategies will vary based on the different goal(s) of the utility.

Figure 2 provides a lot of useful information. It shows the average impact of how the demand response portfolio will respond given the different weather scenarios that are possible. For utilities with a demand charge, this provides an outline of the expected benefits per year (or per month) of the program. It shows the extreme performance and system load with the program functioning in unexpected conditions. This is highly relevant to utilities that are conducting generation and transmission planning. It can also be relevant to distribution utilities in the process of sizing substations or attempting to defer or eliminate substation expansions.

Continued

> "PSE's model provided the insight needed to grow our DR programs and included a strategy to deploy them that maximized value."
>
> *Michael Volker*
> *Director of Reliability and Energy Services*
> *Midwest Energy, Inc*

Case Study

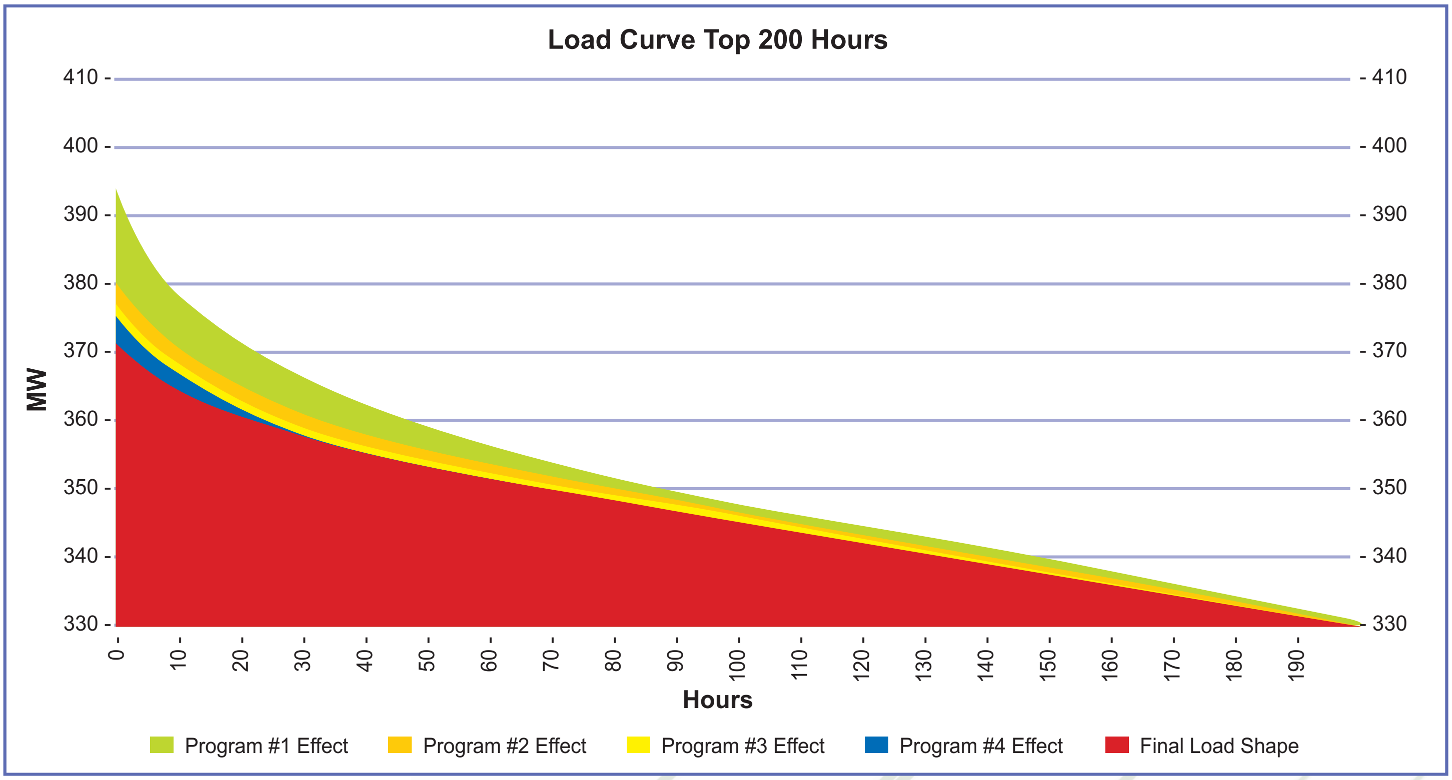
PSE recently assisted Midwest Energy, Inc. located in Kansas. The utility was spending quite a bit of money per year on its DR programs. They had three in place, but was unsure about how and when to best deploy the programs. Midwest Energy was also wondering whether it should expand its program and possibly add new DR programs to its portfolio.

PSE customized the DR Optimizer model to determine the optimal deployment strategy for the three existing programs. The factors involved were somewhat complicated, as deployment of the three programs during weekdays would (under certain weather scenarios) create a new demand peak on the weekend. PSE's models enabled the utility to avoid these hazards and find a deployment strategy that maximized its DR value. The optimal deployment strategy considered both the combination of DR programs used and the time at which DR events were called.

Our team determined that adding a fourth DR program would be a cost-effective way for Midwest Energy to increase its DR value, and we also enabled the utility to integrate its day-ahead forecasting with its DR called-event threshold. In the end, the utility received a clear and actionable DR deployment strategy that will result in substantial and confirmable added value from its DR programs.

Figure 3 shows what the utility's top 200-hour load shape is expected to look like with and without each of the four programs. PSE found that if the four programs are dispatched properly, the utility will be able to shave an average of 16 MW from its load, even while taking all simulated weather variables into account (for example, 21 MW could be shaved in an extremely hot year). Overall, the estimated value of the optimized DR portfolio is around $1,000,000 annually.

Figure 3: **Midwest Energy, Inc.'s Effect of DR Programs on Top 200 Load Hours**

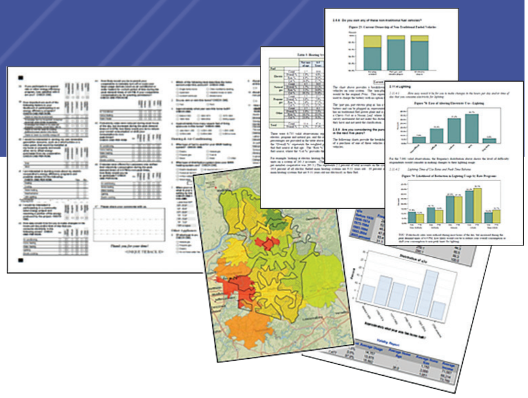


Conclusion

PSE's DR Optimizer may help your utility answer some of its demand response questions. Some of the results our research can offer include:

- The demand impact your current or contemplated demand response portfolio can realistically deliver under a full range of scenarios
- The financial value of your current or contemplated program
- Recommendations on new programs that will increase the value of your portfolio, or recommendations on programs or restrictions that should be eliminated or modified
- Strategy development for how to optimally deploy the portfolio to maximize value
- Hourly forecasting of system load to reduce forecasting errors and increase program value
- Determination of the maximum amount of profitable DR that should be deployed on a system
- Geographic targeting to alleviate substation or feeder constraints

PSE can help you uncover the value of the demand response available on your system and provide concrete next steps on how to actually achieve maximum value.



About the Authors

Steve Fenrick

Practice Lead – Benchmarking and Economic Studies

Steve received a BS in Economics and MS in Agricultural and Applied Economics from the University of Wisconsin-Madison. Steve has been a consultant in the energy utility industry for twelve years. He is an expert in utility performance benchmarking, incentive regulation, value-based reliability planning, productivity analysis, and DSM. Steve has provided senior-level consulting services, presented findings, and conducted expert witness testimony for locally-owned utilities, IOUs, regulatory commissions, trade associations, and consumer advocates. He has published a number of peer-reviewed journal articles on these and other topics.

Contact Steve at 608-268-3549 or fenricks@powersystem.org with any questions you might have regarding PSE's market research capabilities.

Co-Authors

Chris Ivanov

Practice Lead – Economics and Market Research
ivanovc@powersystem.org

Matt Sekeres

Economic Analyst
sekeresm@powersystem.org

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Madison, WI
1532 W. Broadway
Madison, WI 53713
(608) 222-8400

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Minneapolis, MN – (763) 755-5122

Marietta, OH – (740) 568-9220

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