The Option Value of Demand Response: Using Financial Engineering Methods to Value Customer Participation Limits

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ABSTRACT

Energy efficiency and demand response (DR) programs provide several benefits to society in general. These benefits are often compared to alternative fossil fuel generators. Because DR programs target peak hours, the cost of a combustion turbine (CT) is often chosen as the starting point for measuring DR program value. If a DR program can eliminate the need for a future CT, the program can be given credit for the avoided cost of the CT. In addition to the avoided capacity value of DR programs, it can be argued that DR programs have additional flexibility value in deployment, timing and ease of entry; and insurance value (or option value) tied to the ability to mitigate the negative consequences of reliability events. In this paper we examine each of these benefits as the starting point for unconstrained program value.

Demand Response as a Real Option

The paper uses real option theory to measure the insurance value of DR programs. In measuring the option value, we rely on the traditional Geometric Brownian Motion (GBM) computational formulation consistent with the Black Scholes formula for calculating options on financial contracts[1]. But in our case, we are measuring the option value of DR programs. The method assumes a log-normal distribution of capacity prices. The results give the value of being able to curtail demand during reliability events above the expected or weather average value traditionally used in valuation problems.

Although the benefits of DR programs can be compared to alternative fossil fuel resources, the unique characteristics of customer participation have to be considered in the final valuation. Typically, program participants set limits on how and when a program can be called. These include:

1. Hours available for the year.
2. Customer Notice (How far in advance do you have to tell the customer about an event to get them to curtail).
3. MW available to curtail.
4. Minimum Duration of an interruption.
5. Maximum Duration of an interruption.
6. Number of interruptions during the same day.
7. Number of interruptions during a week.
8. Eligible days for Interruptions (weekdays only (holidays excluded), Weekdays (holidays included), any day).
9. Eligible months for interruptions (summer only, or available all year).
10. Consecutive Days an interruption can be called.
11. Maximum number of interruption events for the year.

[1] The option pricing algorithms will generally follow those of Haug, E. G. , [1997] “The Complete Guide to Option Pricing Formulas”, McGraw-Hill; 1st edition.

Options as Value Constraints

Although these options can greatly increase participation by allowing the customer to better manage the negative consequences of power interruptions, they also reduce the relative benefits of the demand response resource compared to availability of a new CT. The more limiting the set of customer options, the less likely the program will cost effectively offset alternative fossil fuel generation.

All market participants from technology vendors and implementers, to utilities and public utility commissions benefit from understanding the impact of customer participation limits on program cost effectiveness. In this paper we measure the negative effect on the overall program benefit due to these participation constraints. We use financial engineering methods to value the relative differences between customer choices in how and when a DR program can be called. We examine approximation algorithms for optimizing program value given participation constraints. The paper is based on actual program offers to utility commercial and industrial customers and draws upon these real examples to highlight the power of this method.

INTRODUCTION

This report describes the DR Pricing Model used by Duke Energy for demand response participation calculations relative to the PowerShare and other demand participation programs. The report describes the methodology and results. The DR Pricing tool establishes a cost-based value for demand response programs and is used to measure relative changes in value as customers choose different program options. The tool measures the relative change of several different program options, both independently and jointly as options are combined to form a program best suited to the needs of the customer. The DR Pricing tool is based on several assumptions regarding the value of demand response programs and each of these assumptions are described in relation to the program options valued by this DR Pricing tool.

METHODOLOGY

This study relies on several well established pricing methods to value demand response programs and the various customer options available to program participants. Additionally, the study relies on propriety models developed by Integral Analytics to better value avoided cost. These methods are described in this section and the key elements of future avoided cost that the methods address are discussed.

The DR pricing model follows the generally accepted idea that demand response is a function of both avoided cost and market prices. Avoided costs are used to measure DR value consistent with the long-run regulatory view of installed capacity as necessary to maintain system reliability. Energy markets on the other hand accurately value the variable avoided benefits of demand side programs. The analysis for DR resources then considers both the value supply-side cost and energy prices as the total benefits are the sum of both avoided capital investment cost and avoided market-based variable energy price.

The use of an annualized combustion turbine (CT) capital cost and how the cost should be adjusted to reflect the unique characteristics of DR resources continues to be debated nationally. Many argue that a CT should be used to value DR only if the program behaves similar to a CT resource. For example, many have argued that only dispatchable programs can receive the full value associated with a CT.

A common capacity value for a demand response program is viewed as the all-in installed capital cost of a CT. In this analysis we use \$70.00/kW-year for programs in the Midwest region of the Duke service territory. Assuming there is time to site and build a CT, nationally the proxy capacity value has generally ranged between \$40/kW-year and \$95/kW-year. If a CT cannot be built in time or if the reserve margins are very narrow, the capital cost is often adjusted upwards based on loss of load probability (LOLP). That is, when LOLP is high generation related avoided costs for DR can exceed the capital cost of a CT. Likewise, when reserve margins are high LOLP may be used to decrease the capacity value of the demand response program.

In our analysis, we use a system load based proxy for LOLP and consider only the relative change from period to period rather than the absolute value. It is not necessary to know what the actual LOLP is in any one period, we only need to know how the LOLP is changing and how those changes translate into value. We assume a linear relationship whereby a percent change in LOLP above a given operational strike-price translates to a corresponding change in program value. In this way expected changes in reserve margin and the corresponding LOLP are explicitly modeled by our program. This process is further described later in this report in relation to customer constraints. The following contour charts represent the total annual unconstrained potential developed by this methodology. The charts project the relative value of peak hours for each month of service. The unconstrained program will operate during those hours when potential is highest.

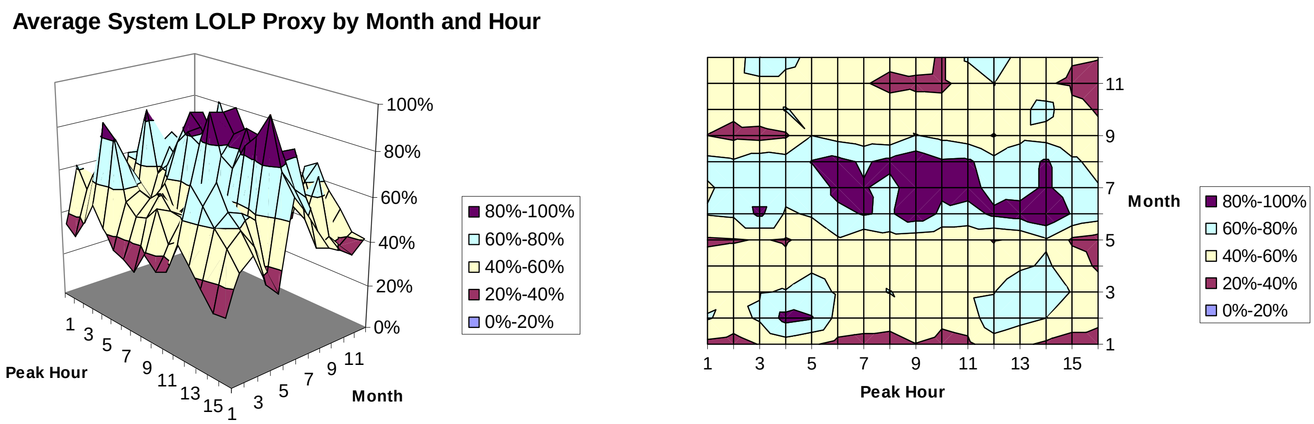

Figure 1 - System Value Potential Couture

Although the method can be further developed beyond what is necessary for this study, the CT adjustment process is able to capture local resource adequacy, including load pockets and regional congestion constraints. The approach is further enhanced by considering the impact of program size and hours of availability. We discuss these issues in an integrated resource planning context by considering the impact of a portfolio of DR resources on overall system cost. The results are charted and presented below.

In order to value demand response options, a baseline value of capacity is needed. Because DR programs target peak hours, the cost of a combustion turbine (CT) is often chosen as the starting point for measuring DR program value. If a DR program can eliminate the need for a future CT, the program can be given credit for the avoided cost of the CT. The value used is unique for each service territory reflecting the cost of installed CT capacity within that region. In this study the value of a CT is set at $70.00/kW-year.

The $70.00/kW-year CT value represents the unconstrained maximum value for a DR program. If the DR program is not able to perform as well as a CT or is limited in availability as compared to a CT, the risk associated with the resource increases and therefore the benefit offered for the resource is appropriately adjusted downward. The methodology used in the DR Pricer explicitly considers the reduction in value due to various differences in the unconstrained value of a CT. The differences are generally associated with the customer choices in setting up the program to best avoid program related inconveniences. The customer choices become constraints that reduce the benefits offered to the DR program participants.

The method used follows generally accepted energy marketing principles. The unconstrained CT generation resource is assumed to be available in those hours that are most critical for system reliability and to capture the most value from the perspective of a merchant generator. The CT resource receives 100% of the possible avoided value – in our case $70.00/kW-year. As the customers choose program options that limit availability, the program value declines. The methodology compares the value of the hours available to the DR program with the value of the hours of the unconstrained CT. The fractional difference is used to reduce the unconstrained $/kW-annual benefit of the program. For example, if we forecast that a typical new peaker will run for 380 hours and be called 63 times, be available any time of the year within 10 minutes notice, we can sum the highest Price*Load value of available during the year for this resource. Let's say for this example that value is some value $300 system market potential. The $300 market potential is viewed as the most a DR program can achieve in a least cost resource planning framework and set equal to $70.00/kW-annual benchmark. In valuing a particular program, the customer will set constraints that limit the benefits compared to a CT. The customer may only allow 100 total hours curtailed, 10 events, one event per day and 3 events per week maximum, and require day ahead notice. Given this set of program requirements, the DR Pricer algorithm finds the best Price*Load system value potential. Let's say for example that value is $90 or 30% of the unconstrained market potential. Given a linear relationship between market potential and annualized program value, the unadjusted benefit of the program would be $21.00/kW-annual. We are not constrained to assuming a liner relationship however. For many variables, the appropriate relationship is better represented as a s-curve.

In addition to the linear relationship, as an alternative we can assume a non-linear relationship between market potential and program value. We currently incorporate an optional S-curve value relationship. The S-curve assumes a theoretical maximum and minimum project value. Values between the maximum and minimum follow a normal distribution clustered around a theoretical average. This method tends to pull extreme values toward the center.

DR Pricer takes as input a vector of price/value pairs for each interruptible hour of each day in a set of weeks. (In the following, we will refer to the collection of weeks as a "year", even though the number of weeks is not necessarily fifty-two.) The program also accepts as input the various customer choices. The program uses dynamic programming techniques to compute efficiently the value of the DR options given the load vector and customer choices (see Bellman [1957], or a current algorithms textbook, for a description of dynamic programming.). The algorithm works "bottom-up" by first computing the maximum possible value of each day for each possible combination of number of interruptions and number of hours interrupted in that day. We require that there are no more than 24 hours in each day, and that no more than 2 interruptions are permitted per day (i.e. MIPD ≤ 2), this phase of the computation can be performed rather quickly.

Next, the algorithm uses dynamic programming to convert the results for the various individual days into the maximum possible values of each week for each possible combination of number of interruptions and number of hours interrupted in that week. Finally, dynamic programming is again used, this time to combine the results for the various individual weeks into an optimum interruption schedule for the entire year, given the customer choices/constraints. Pseudocode for the over-arching algorithm is available upon request.

In practice, for experiments such as those that we have conducted for this paper, the main determinant of runtime is the number of weeks in the simulation. The runtime of the algorithm increases in direct proportion to this value. However, on a contemporary PC with a 1.8GHz processor and 2GB of RAM, DR Pricer typically takes one to two minutes to run a 52 week simulation.

The DR Pricer provides the cost-based value of DR programs. Additionally, in some markets when a program is called, the participants can receive a $/kWh energy credit for the hours curtailed. We use RealVaR, a financial engineering real-option model, to value the expected energy credit. RealVaR looks at the problem from the perspective of an energy trader and the value energy marketers would assign to the program characteristics. The model focuses on the probability distribution of prices. Some markets do not provide energy credits due to regulatory preference. In these markets the capacity value will capture the full value of the program.

Although the result using a weather normal year avoided capacity price represents the average or expected program avoided cost benefit, the average benefit provides no information about the potential reliability benefits of DR programs in avoiding extreme low probability, high consequence weather events. We use financial engineering methods to assess the additional insurance or extreme weather option benefit of DR programs. We rely on the traditional Geometric Brownian Motion (GBM) formulation consistent with the Black Scholes formula for calculating options on financial contracts. But in our case, we are measuring the option value of DR programs. The method assumes a log-normal distribution of capacity prices. This results in the value of being able to curtail demand during reliability events above the expected or weather average value. The total value then has two components – the weather normal value and the option value. The first component – the weather normal avoided capacity value – is derived from the DR Pricer model described above. The second component – the extreme weather option value – is calculated by measuring the distribution of possible outcomes from all possible weather scenarios. The distribution is then used as a proxy for price volatility and applied to the Black-Scholes formula, where the strike price is set at the weather normal outcome. All events above the weather normal outcome are then included in the option value.

COMBINED BENEFITS AND CONSTRAINTS

The benefits of DR programs can be segmented into three categories – the cost-based value of a CT, deployment flexibility benefit, and the insurance value. The sum of these three benefits equals the total unconstrained value of a DR program. However, programs are designed to allow the customer to choose when and how the program may be called. These customer choices improve participation by giving customers the flexibility to minimize productive disruptions caused by curtailed energy. However, from the perspective of program value, customer choices effectively constrain the total benefit possible to the utility. Total program value, then is reduced as customers choose program options reducing the economic offer possible to the customer. Both the benefits and constraints are reviewed below.

Capacity Benefit of a Demand Response Program

In our study we are given the value of capacity as determined by the utility based upon the projected marginal cost of installed peaker capacity. This value sets the theoretical maximum that a DR program can be credited under a least-cost planning methodology. However, DR programs are flexible enough to not only contribute at the system peak but also at every point along the marginal cost curve. We call this the flexibility value of a DR program. The valuation begins by measuring the full range of possible weather outcomes and the avoided capacity value that can be achieved from each outcome. Weather mild years will result in low avoided capacity prices. Extreme weather years will result in high avoided capacity prices. And the weather normal year will result in average or expected avoided capacity prices.

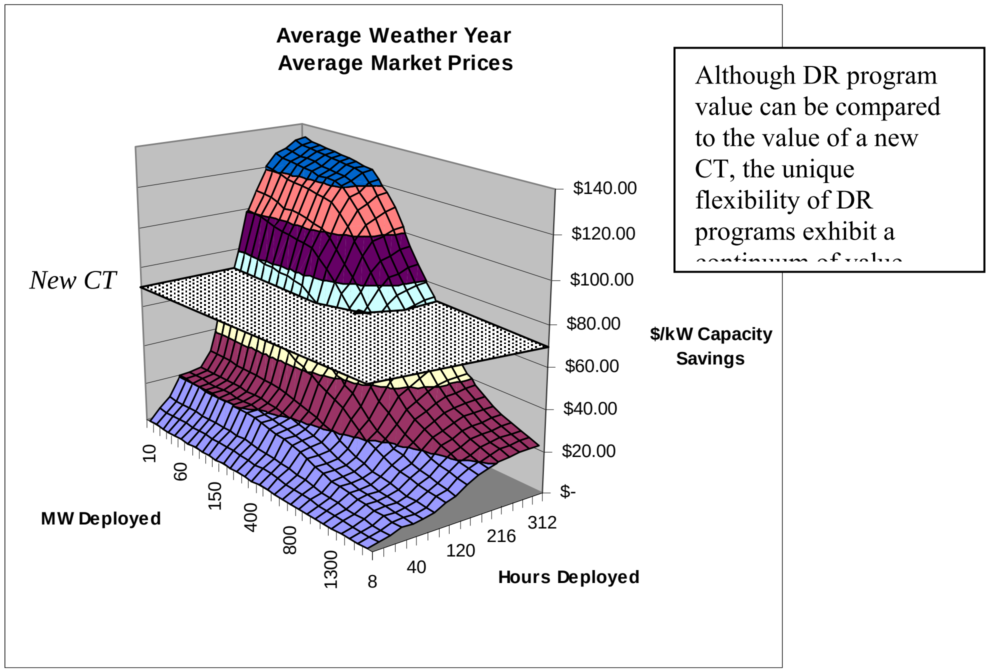

Figure 2 – Marginal Unconstrained Avoided Capacity Benefit

The DSPatch avoided capacity charts represent the net present value of all resources over the time horizon of the study. These resource include existing CT's, market based imports, new CT construction, and the full portfolio of demand side resources. By considering the order in which individual programs are deployed, the marginal benefit of new programs is easily determined. For example, in the chart above, we can consider an existing portfolio of programs and the impact of a new program on the marginal avoided capacity cost. Say for example we have an existing portfolio of 1015MW and we are adding a new program. The additional capacity attributed to the new program is valued based on its marginal contribution to system reliability. A portfolio of 1015MW represents the total demand response capacity and other demand response programs currently planned for the regional market. New programs priced using this tool represent marginal additions to the demand response capacity of the system. As programs are added to the portfolio, the marginal value of the additional programs decreases. Eventually, when resource adequacy is fully achieved, adding more capacity benefits the system very little. To avoid price discrimination, once the appropriate amount of capacity is determined, an average portfolio value is measured for all demand resources. That portfolio value in this study is set equal to the alternative CT generation resource avoided by the demand response portfolio.

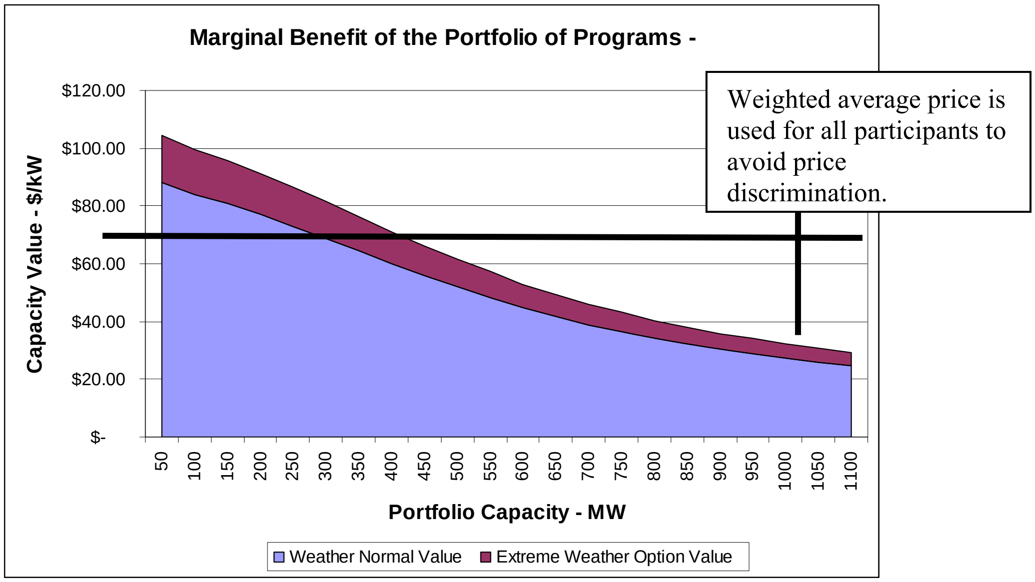

Figure 3 – DR Portfolio Value

In general as additional resources are added to the overall portfolio of programs, the marginal value decreases. Viewed as a portfolio, the first MW deployed is worth more than then the last MW deployed.

CUSTOMER OPTION VALUE CONSTRAINTS

Several program options are valued by this study. These options are offered to the program participants. However, the set of options chosen by the participants effectively change the value of the program – the more constraining the set of options, the less valuable the participation. Using this information, the appropriate payment to the participant is determined.

The program options valued by this study include the following:

1. Hours available for the year.
2. Customer Notice (How far in advance do you have to tell the customer about an event to get them to curtail).
3. MW available to curtail.
4. Minimum Duration of an interruption.
5. Maximum Duration of an interruption.
6. Number of interruptions during the same day.
7. Number of interruptions during a week.
8. Eligible days for Interruptions (weekdays only (holidays excluded), Weekdays (holidays included), any day).
9. Eligible months for interruptions (summer only, or available all year).
10. Consecutive Days an interruption can be called.
1. Maximum number of interruption events for the year.

The majority of customer constraints can be valued by considering the sum of the price*load contribution after having accounted for the loss of deployment possibilities due to each constraint. The total constrained value is compared to the unconstrained value equivalent to the operation of a CT and the ratio of these is then used to value the specific program requested by the participant. The methodology was further described above. Not all of the customer choices can be valued this way. For example, advance notice given to the participant is valued using information about ancillary service markets and bid based prices at ISO's. This and the other customer choices are further described below. It is important to note that although we only report the contribution of each individual constraint on program value, each of these works together. The total impact will not equal the sum of the individual contributions. However, by selecting any set of options, the method accurately calculates the total correlated portfolio value of the program. The results of the study are presented below. In all cases the value of the program fall and many times at an exponential rate as the customer adds constraints.

Valuing Hours of Availability

The total hours available for curtailment is valued as a continuum using the DR Pricer. The option allows the participant to limit the total number of hours that can be called during any program year. The value of this option is compared to the expected operating hours of a CT. In the study region we use 380 hours as the unconstrained hours of availability.

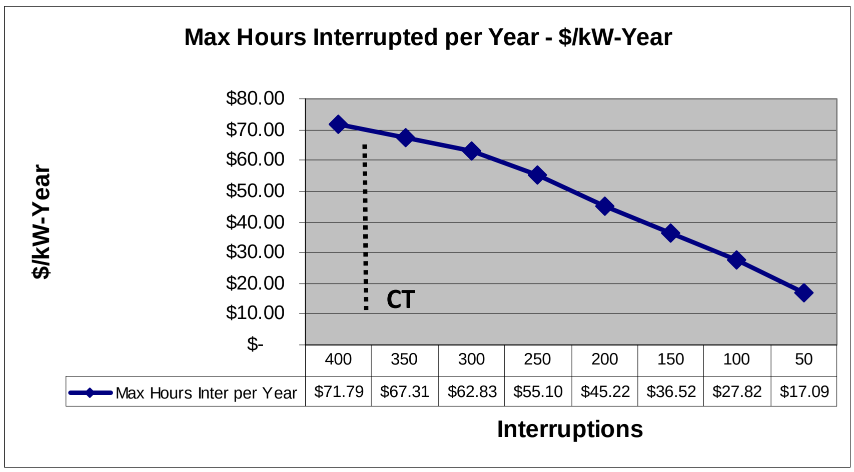

Figure 4 – Maximum Hours Annual Constraint

Customer Advanced Notice

Customer advance notice represents the amount of time given to the participant in advance of a DR event. The choices range from 10 minutes to one day ahead of the event. We use a bid based ISO reliability pricing model to value this option. Although many reliability events can be, to some degree, anticipated and forecast on a day-ahead basis by examining the supply resources available to meet anticipated demand, other reliability events as well as the severity of anticipated events are dependent on real-time weather conditions and unforeseen outages of both generation and transmission resources. From a reliability perspective, the ability to dispatch demand response resources with little notice allows the program administrator to better match resources to reliability events.

When considering the unconstrained value, the performance of a CT is used. A CT is often used as a spinning reserve resource, generally with a 10 minute advanced notice requirement. Other ancillary services are given more time. For example non-spinning resources are given 30 minutes. Replacement resources are given 2 hours. However, non-spinning and replacement resources are not as valuable as spinning reserve resources. Using historic bid-based pricing data, the progression in value is measured. This provides the shape of the constrained advanced noticed value parameter.

MW Available

In this study we are assuming that the overall portfolio of demand response programs contain the appropriate amount of capacity to achieve resource adequacy. To avoid price discrimination, we assume all capacity is valued as a portfolio such that each successive additional MW of capacity is given the same price as the previous addition. However, in general, the amount of MW available can change the marginal value of participation. The difference in value largely follows the same argument used to value additions to the utility portfolio of programs. Different levels of participation would impact the marginal contribution to the utility at a different level. Using this methodology, the first MW contribution is marginally worth more than the last MW contribution. The multiplier can be measured directly from the DSPatch avoided capacity charts. These are summarized in the table below measured around a 1000MW portfolio and 150 hours availability.

MW	0	50	100	150	200	250
	100%	94%	89%	85%	81%	77%

The results indicate that the majority of value occurs in the initial MW deployed. The table can be used to weight the total MW participation. The total value to the participant remains the same, but the relative value of each MW of participation can be distinguished.

Maximum Duration of an Interruption

The maximum duration option allows the holder the flexibility to curtail any number of hours per event up to the contracted maximum. In this study we value a continuum of curtailments from 1 hour to 16 hours. The table below values each set of options beginning with the unconstrained case whereby the holder can choose any number of curtailment hours up to 16. The fewer the hours, the more limiting and less valuable the program will be.

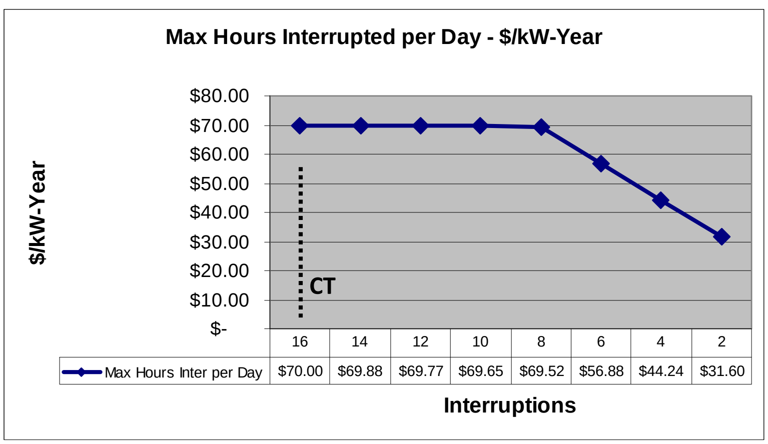

Figure 5 - Maximum Hours Daily Constraint

Number of Interruptions during a Week

By choosing the maximum number if weekly interruptions the participant has the flexibility to manage the program weekly impact if needed. The unconstrained value is 7.

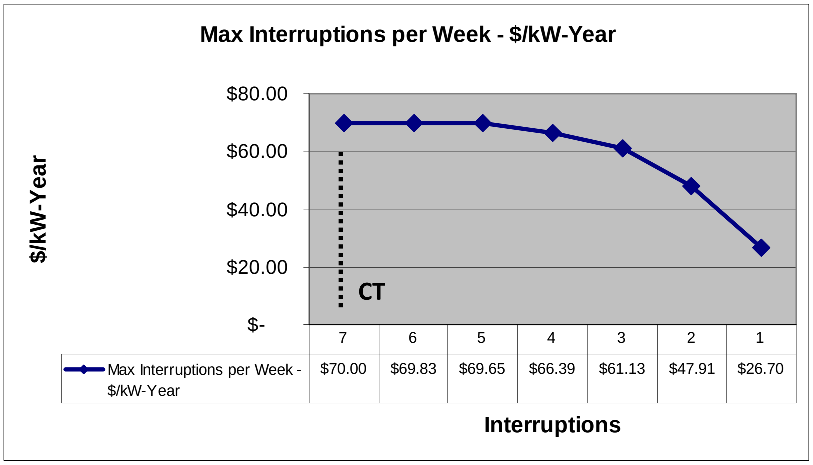

Figure 6 - Maximum Interruptions Weekly Constraint

Total Number of Hours Interrupted during a Week

The participant can additionally manage the total number of hours curtailed in a week. As with the total number of interruptions, this option allows participant has the flexibility to manage the program weekly impact if needed. The unconstrained value is 56.

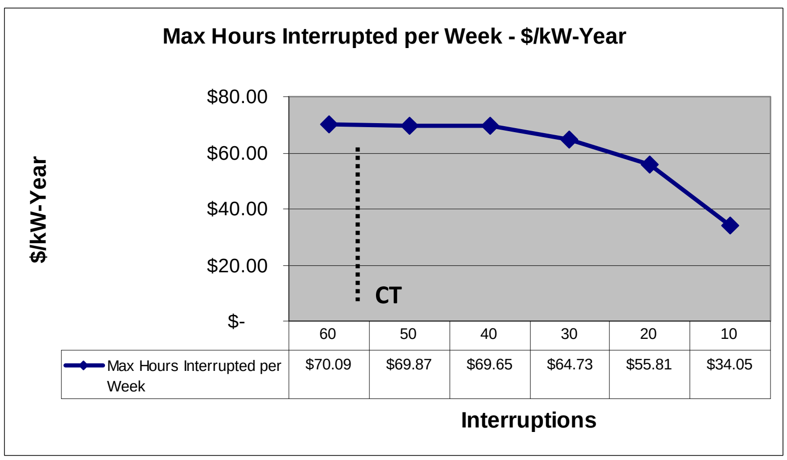

Figure 7 - Maximum Hours Weekly Constraint

Consecutive Days an interruption can be called

The maximum consecutive days interruptions can be called is valued. The option addresses the change in value a participant places on energy as the emergency persists. A participant can choose to limit the number of consecutive days the program will be call if needed.

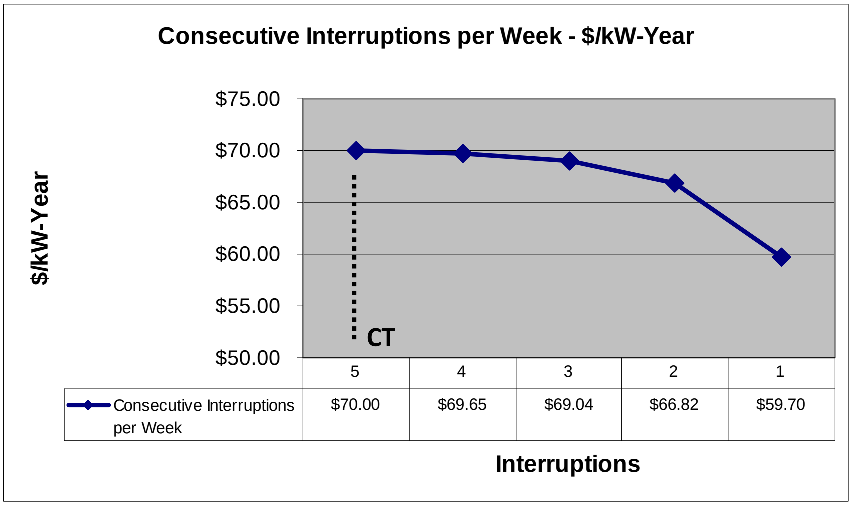

Figure 8 – Consecutive Interruptions Weekly Constraint

Maximum Number of Interruption Events for the Year

The maximum number of interruptions in a year is valued. This option allows the participant to limit the total number of times the program will be called in any one year. The unconstrained value is 62 consistent with the regional characterizes of CT.

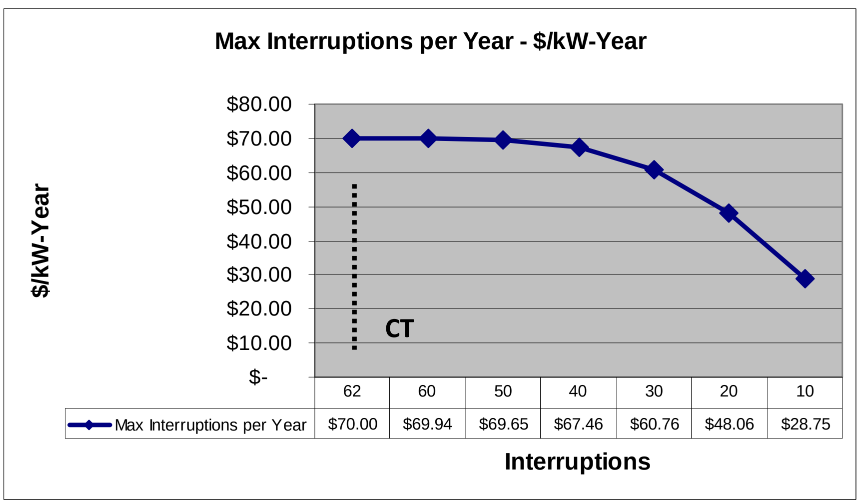

Figure 9 - Maximum Interruptions Annual Constraint

SUMMARY

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