Using Utility Information to Calibrate Customer Demand Management Behavior Models

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Abstract

In times of stress customers can help a utility by means of voluntary demand management programs if they are offered the right incentives. The incentives offered can be optimized if the utility can estimate the outage or substitution costs of its customers. This report illustrates how existing utility data can be used to predict customer demand management behavior. More specifically, it shows how estimated customer cost functions can be calibrated to help in designing efficient demand management contracts. **Keywords**: Demand management, contract design, customer cost, data calibration, load curtailment, system security.

Introduction

The best resource for a utility to solve its operational problems, when problematic situations arise, may be its own customers. Many transmission and most distribution problems can be addressed by having effective demand management programs [4]. Mechanism design theory [6] has been utilized to optimize the contracts to maximize utility benefit and to make sure customers will see a benefit by signing up (this formulation was developed in [5]). This report shows how a cost function satisfying the conditions for mechanism design can be developed and *calibrated*. Utilities around the country are using nonlinear pricing to sell their power (anytime a utility offers different rates based upon customer size, it is using nonlinear pricing). The demand management contracts proposed in [5] are using nonlinear pricing to buy it back in case of emergencies. Estimated customer cost function plays a crucial role in designing demand management contracts. In [1, 2] authors suggest different ways of estimating the outage costs of customers mainly by way of interacting with the

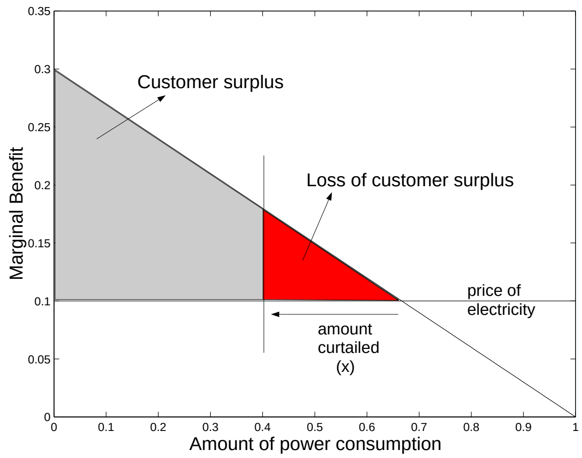

Figure 1: Marginal benefit for a customer. Areas in this figure denote total surplus.

customers. In [9], the main goal is to design priority electric service options for the customer and part of the process is to estimate the customer outage costs by way of surveys. This report proposes the use of existing utility data to estimate these customer cost functions. Customer outage costs or substitution costs (from this point on we will use the term 'outage costs' to include substitution costs) can be modeled using a variety of general functions. Several functions with general coefficients are proposed and their coefficients are calibrated using real data obtained from existing utility demand management programs. The data available provides information on how much each customer gets paid by providing a certain amount of relief. The main goal of this calibration process is to find a practical cost function that accurately models the demand management behavior of customers, and to use it to design contracts. Existing data and the calibrated cost functions are then used to validate the formulation by means of some examples.

1 Customer Cost Function Characteristics

The first assumption made in designing a cost function is that it costs the customer progressively more to shed more load. Figure 1 shows a possible predicted marginal benefit of a customer from electricity consumption. The dark shaded area in Figure 1 shows the loss of surplus as a customer curtails its power. This loss of surplus due to shedding load is the outage cost for the customer. Once the marginal benefit is assumed to be linear, as the customer sheds power its loss of surplus is quadratic (see Figure 2).

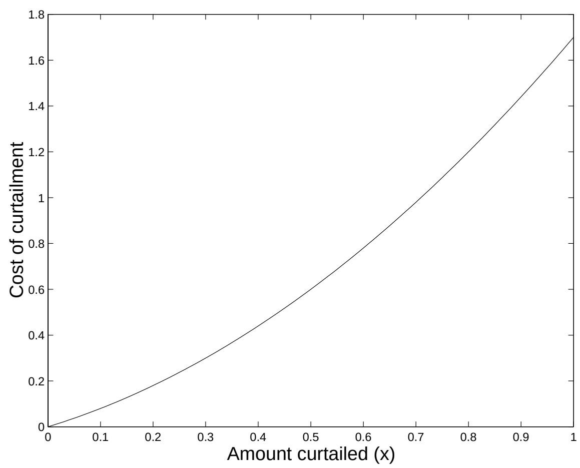

Figure 2: Predicted outage cost function for a customer.

If the shape of the customer outage cost function is assumed to be a quadratic, a general quadratic form for each type of customer (different types of customers are parameterized by θ) is defined as:

$$c(\theta, x) = K_1x^2 + K_2(1-\theta)x = K_1x^2 + K_2x - K_2x\theta \qquad (1)$$

where x is the amount of power curtailed, K_1 and K_2 (both non-negative) are the coefficients of the general cost function that needs calibrating. The "$-K_2x\theta$" term is included so that different values of θ[1] lead to different values of $\frac{\partial c}{\partial x}$ (marginal cost for the customer). As θ increases the marginal cost decreases. That is, θ "sorts" the customers from "least willing" to "most willing" to shed load. This form of the cost function suggests that the customer with the lowest θ will have the highest marginal cost and hence the lowest marginal benefit. This provides a good way of modeling the *willingness* of each customer to shed load by way of θ.

A quadratic form is one of the many forms a customer cost function can take. It is possible to design different cost functions as long as the *sorting* (or "single crossing") *condition* [6] is satisfied. If the customers are sorted from least willing to most willing the sorting condition dictates that:

$$\frac{\partial}{\partial \theta}\left(\frac{\partial c}{\partial x}\right) < 0. \qquad (2)$$

Likewise, if the customers are sorted from most willing to least willing the condition becomes:

$$\frac{\partial}{\partial \theta}\left(\frac{\partial c}{\partial x}\right) > 0. \qquad (3)$$

[1]The parameter θ is normalized and takes values in the interval $0 \leq \theta \leq 1$.

Whether one sorts customers according to increasing or decreasing willingness is a matter of preference and is irrelevant. The important issue is that the outage cost function be monotonic in θ and non-decreasing in x.

Following the same design process, one can assume a decreasing quadratic marginal benefit for the customer, which will yield a cubic outage cost function:

$$c(\theta, x) = C_1 x^3 + C_2 x^2 + C_3 x - C_3 x \theta \tag{4}$$

where the number of coefficients to be calibrated is now 3 (C_1, C_2 and C_3 all non-negative).

Another possibility is the use of exponential functions to model the outage costs of customers. One estimated function is:

$$c(\theta, x) = k_1 \exp^{\frac{k_2 x}{\theta}} \tag{5}$$

where k_1 and k_2 are the coefficients to be calibrated. This function sorts the customers from least willing to most willing to shed load since the marginal cost of shedding load decreases as θ increases. However, this function could be redesigned to sort the customers from most willing to least willing:

$$c(\theta, x) = k_1 \exp^{k_2 \theta x} \tag{6}$$

Figure 3 shows how the cost of curtailing power (equation (6)) is higher to a customer with a higher θ, hence they will be less willing to shed load.

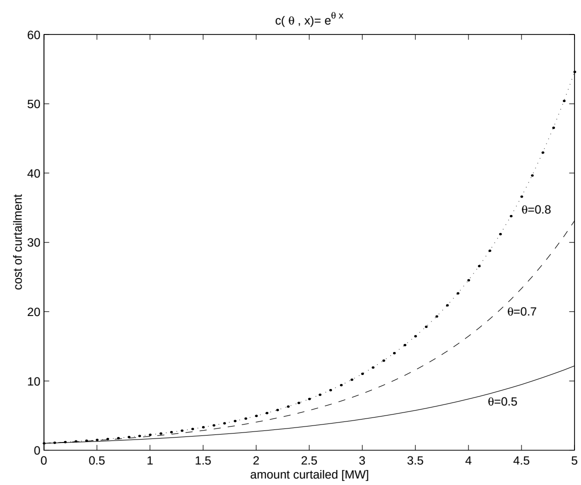

Figure 3: Predicted outage cost functions

2 Calibration of Cost Function Coefficients

The next step is to use utility data in order to estimate the coefficients of the assumed quadratic outage cost function. Assume that the utilities providing the data have different rates for different types of customers. A customer which provides x kW of relief at a rate of r dollars per kW receives rx dollars of monthly credit[2]. Hence the benefit function for a customer under a demand management contract is:

$$b_c(\theta, x) = rx - c(\theta, x). \tag{7}$$

A customer who wishes to maximize its benefit will choose to curtail x kW of load, where x satisfies the first order condition of its benefit function:

$$r - \frac{\partial c}{\partial x} = 0 \tag{8}$$

In order to illustrate how the calibration is performed the quadratic form of the cost function is assumed, and the first order condition (8) yields:

$$r - 2K_1x - K_2 + K_2\theta = 0 \tag{9}$$

Assume n customers in the provided data, using the first order condition (9) for each customer gives n equations and $n+2$ unknowns (K_1, K_2 and all the θ's). Since θ is normalized, a range within the interval $[0, 1]$ can be assumed by selecting a θ value for the most and least willing (able) customer to shed load. This yields n equations and n unknowns. The rate r and selection of curtailment x for each customer is known from the utility data. This method will provide values for K_1, K_2 and estimates for customer types (θ's).

3 Using Calibrated Cost Functions for Contract Design

After the cost function is calibrated, mechanism design can be applied to design the demand management contracts. In [5] a general formulation was developed where θ was a random variable with a uniform distribution in the interval $[0, 1]$. This report develops the formulation where θ can take discrete values, each with a presumed probability p.

Assume n number of customers, each with a cost function:

$$c_i = K_1x_i^2 + K_2x_i - K_2x_i\theta_i, \tag{10}$$

for $i = 1, 2, ..., n$. The object of mechanism design formulation is to determine the optimal amount of payment for each customer who agrees to curtail x kW. Let the monetary payment be y, then customer benefit for each customer becomes:

$$u_i = y_i - (K_1x_i^2 + K_2x_i - K_2x_i\theta_i). \tag{11}$$

[2] Contracts proposed in this report offer incentives per curtailment, hence a conversion need to be made from pay per month to pay per curtailment.

The benefit to the utility[3] of not delivering power to a specific customer under conditions of system stress is λ_i dollars per kW. Under these conditions the utility benefit function is:

$$u_0 = \sum_{i=1}^{n} \lambda_i x_i - y_i \tag{12}$$

The objective is to maximize the expected benefit for the utility:

$$\max_{x,y} \sum_{i=1}^{n} [\lambda_i x_i - y_i] p_i, \tag{13}$$

subject to,

$$y_i - (K_1 x_i^2 + K_2 x_i - K_2 x_i \theta_i) \geq 0 \tag{14}$$

for $i = 1, 2, ..., n$, and

$$\begin{aligned} y_i - (K_1 x_i^2 + K_2 x_i - K_2 x_i \theta_i) \geq \\ y_{i-1} - (K_1 x_{i-1}^2 + K_2 x_{i-1} - K_2 x_{i-1} \theta_i) \end{aligned} \tag{15}$$

for $i = 2, ..., n$. Constraint (14) is the *individual rationality constraint* which makes sure every customer is encouraged to participate, and constraint (15) is the *incentive compatibility constraint* which makes sure the customers do not try to take the adjacent contracts, by offering them extra money to take the contract designed specifically for them. When a customer takes an adjacent contract, this reduces the available curtailment capacity and the utility benefit. After solving these set of equations, optimal x and y are given by:

$$x_i = \frac{p_i \lambda_i - K_2((1-\theta_i)p_i + (\theta_{i+1} - \theta_i)\sum_{k=i+1}^{n} p_k)}{2 p_i K_1} \tag{16}$$

for $i = 1, 2, ..., n-1$, and

$$x_n = \frac{\lambda_n - (1-\theta_n) K_2}{2 K_1} \tag{17}$$

$$y_1 = K_1 x_1^2 + (1-\theta_1) K_2 x_1 \tag{18}$$

$$\begin{aligned} y_i = y_{i-1} + K_1 x_i^2 + (1-\theta_i) K_2 x_i - K_1 x_{i-1}^2 \\ -(1-\theta_{i-1}) K_2 x_{i-1} + (\theta_i - \theta_{i-1}) K_2 x_{i-1} \end{aligned} \tag{19}$$

for $i = 2, ..., n$. Similar derivations are used to come up with the contracts using exponential customer cost functions.

The contracts are governed by customer type and customer location. Customer cost function calibration helps identify the types and the locational value can be calculated using sensitivity methods [7], or efficient optimal power flow routines [3, 8].

[3]When the system is under stress it is not beneficial for the utility to deliver power to certain locations.

4 Numerical Examples

Initially we compare the proposed contracts to the existing contracts, then a comparison is made between the proposed contracts designed with different kinds of cost functions.

4.1 Quadratic Customer Cost Function Example

The first example consists of 10 customers selected from utility-provided data. These customers are currently on a demand management program that pays them a fixed rate of \$3.25 per available kW for curtailment. After applying the proposed cost function calibration and designing new contracts using mechanism design, there is an increase in both total amount of available relief and total profit by the utility (see Table 1). Comparison of the range of contracts is show in Figure 4.

The utility benefit is maximized after the contracts are designed using mechanism design. However, the amount of available relief depends on the value of power at each customer node. Table 2 shows another case where a sample of 15 customers is taken from the utility-provided data. This time total relief is less than the total under the existing contracts even though the total benefit is increased as a result of incorporating the effect of location (see below). Existing contracts are paying these customers \$3.25 per kW if the customer is signed up for relief under 500 kW, and \$3.00 per kW for relief above 500 kW (comparison of the range of contracts for this case is shown in Figure 5).

Mechanism design generally deals with tradeoffs and the design of contracts of products that have a unique value to a principal. Such is not the case for electric power. The value of a contract depends on the location of the customer. In order to do this, we have extended mechanism design to permit the incorporation of locational attributes. This is done by a parameter λ as shown in previous sections. In order to demonstrate how locational value can help increase both the total available relief and the total benefit for the utility, the locational value for 5 of the customers, who are more willing to curtail power than the others, are increased. Since the developed formulation takes advantage of locational attributes of the customers the proposed contracts yield increased total available relief and total utility benefit (see Table 3).

Total available relief is very sensitive to changes in locational value. The same is true for total utility benefit, but when mechanism design is used to design the contracts, the utility benefit always increases in comparison to the existing contracts. There is no such guarantee for the total available relief. However, when location is incorporated into the contract design process, it provides a tool which lets the utility get demand management contracts at critical locations. More valuable contracts are offered at high impact locations in the grid. System problems can now be solved more efficiently by having demand management contracts at the right locations.

Table 1: Comparison of Contracts with 10 Customers, value of power equal at each customer location (quadratic outage cost function assumption)

	Total Relief	Total Utility Benefit
Proposed Contracts	2919.70 kW	$2011.84
Existing Contracts	2760.00 kW	$1518.00
Increase in Relief = 159.70 kW		
Increase in Benefit = $493.84		

Table 2: Comparison of Contracts with 15 Customers, value of power equal at each customer location (quadratic outage cost function assumption)

	Total Relief	Total Utility Benefit
Proposed Contracts	11069.51 kW	$10930.95
Existing Contracts	12000.00 kW	$9225.00
Reduction in Relief = 930.49 kW		
Increase in Benefit = $1705.95		

4.2 Comparing Contracts Proposed by Quadratic and Exponential Cost Functions

Another study was performed where the contracts designed with a quadratic cost function assumption was compared to the contracts designed with an exponential cost function assumption. The contracts designed using an exponential cost function for the customer outage cost function yield the most monetary benefit for the utility, furthermore this is achieved by using the least amount of available relief (see Table 4). Hence, if indeed the behavior of customers is according to an exponential outage cost function the benefit to a utility will be greater. The range of the contracts in this example is depicted in Figure 6.

If the contracts are offered with the exponential cost function assumption and the actual behaviour is quadratic (or vice versa), further studies need to be performed to determine the consequences. These studies are currently underway.

5 Conclusion

The key to having efficient demand management contracts is having a good estimate of the customer cost function for outages. If the estimated cost function is correct utilities can optimize the amount of compensation they offer in return for curtailment. The developed formulation maximizes total utility benefit and makes sure the available relief is coming from the right locations. Available data on current demand management contracts can be used to calibrate the customer cost function and help design better demand management contracts for the future.

Table 3: Comparison of Contracts with 15 Customers, value of power *not* equal at each customer location (quadratic outage cost function assumption)

	Total Relief	Total Utility Benefit
Proposed Contracts	12092.63 kW	$14155.33
Existing Contracts	12000.00 kW	$11825.00
Increase in Relief = 92.63 kW		
Increase in Benefit = $2330.33		

Table 4: Comparison of Contracts Designed with Different Cost Function Assumptions

	Total Relief	Total Utility Benefit
Proposed Contracts (quad)	2864.69 kW	$1903.72
Proposed Contracts (expo)	2546.59 kW	$2435.85
Existing Contracts	2760.00 kW	$1518.00
Increase in Relief (quad) = 104.69 kW		
Increase in Relief (expo) = -213.41 kW		
Increase in Benefit (quad) = $385.72		
Increase in Benefit (expo) = $917.85		

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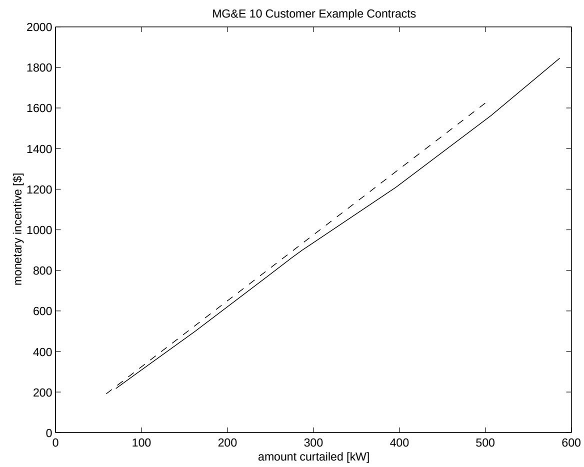

Figure 4: Existing Contracts (dashed line) vs Proposed Contracts (solid line).

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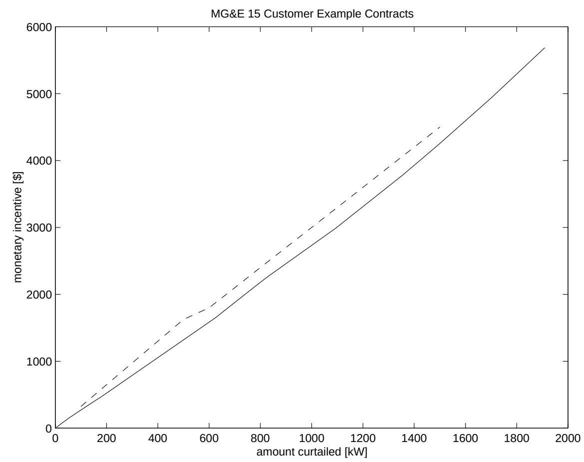

Figure 5: Existing Contracts (dashed line) vs Proposed Contracts (solid line).

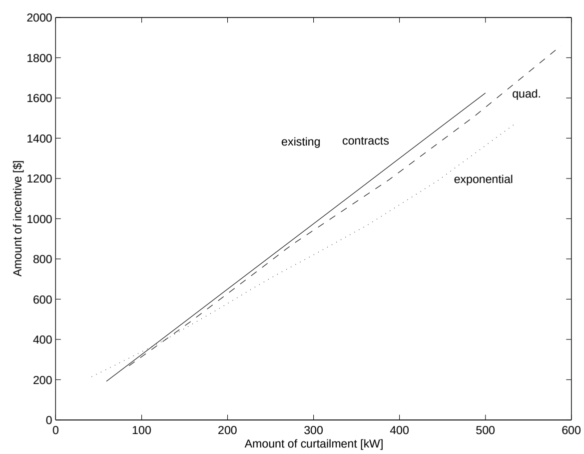

Figure 6: Existing Contracts (dashed line) vs Proposed Contracts (solid line).