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Effects of demand response programs on distribution system operation

G. Gutiérrez-Alcaraz [a,*], J.H. Tovar-Hernández [a], Chan-Nan Lu [b]

[a] Department of Electrical and Electronic Engineering, Instituto Tecnológico de Morelia, Morelia, Mich., Mexico
[b] Department of Electrical Engineering, National Sun Yat-Sen University, Kaohsiung, Taiwan

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ABSTRACT

This paper discusses an analytical approach illustrating the effects of demand response (DR) programs on network operation efficiency. The contribution of DR is estimated using price elasticity of demand under two mechanisms of dynamic pricing: Critical Peak Pricing (CPP) tariff and Hourly Pricing (HP). Numerical examples are provided to explore the effects of DR on distribution networks' operation.

Introduction

The system-wide deployment of smart meters creates a platform for providing "smart prices" to customers. The term refers to the retail prices which reflect the variable costs of electricity. Such prices have the potential for inducing DR that potentially would yield to price reduction of electricity usage for end-users, peak demand reduction, transmission congestion alleviation, power system and distribution investment deferments and other benefits [1–3]. Additional benefits in the form of cost savings associated with the reduced need for peaking generation capacity, lower peaking energy generation costs, and lower transmission and distribution costs can be achieved [4].

In restructured power systems, distribution companies purchase energy at variable prices in the wholesale market and sell it at a fixed price (static rates) at the retail level. Unfortunately, static rates do not reflect actual costs of generating and delivering power. From a rate design perspective, such rates are economically inefficient because they shield retail customers from wholesale market price volatility. As utilities move to more flexible rate options such as time-of-use (TOU), critical-peak pricing (CPP), and real-time pricing (RTP), wholesale price signals inevitably are passed through to their customers [5]. Such prices have the potential for inducing DR with the benefits pointed out above. A number of recent studies and tools attempt to estimate DR potential by using the elasticity approach [6–8], which estimates price elasticities from the usage data of customers exposed to DR programs and/or dynamic pricing tariffs. After determining an expected participation level, price elasticities are applied to estimate load impacts under an expected range of prices or level of financial incentives to reduce load. An economic model for DR is developed in [9] that considers TOU and Emergency Demand Response Program (EDRP) methods simultaneously, and uses single- and multi-period load models based on the load elasticity concept. The economic model maximizes the customer benefit by considering his demand response as a linear function, including his income and incentives. An extension of the model addressed in [10] is developed to evaluate the performance of different DR programs. The model, combined with the Technique for Order Preference by Similarity to Ideal Solution (TOPSIS), provides an opportunity for major players of the market, i.e. the ISO, utilities and customers, to select the programs that best satisfy their needs. An economic model for two DR programs presented in [11] shows that customer demand depends on the price elasticity of the demand, the price of electricity, and the incentive and penalty values determined for the relevant DR programs. This model can be used to improve load profile characteristics and customer satisfaction. In addition, it can be used by the regulator to simulate the behavior of customers for different prices, incentives, penalties and elasticities. An LP optimization model that allows a consumer to adapt its hourly load level, maximizing the consumer utility or minimizing its energy cost, in response to hourly electricity prices is reported in [12]. The model takes into account costumers' minimum daily energy-consumption level, maximum and minimum hourly load levels, and ramping limits on such load levels.

* Corresponding author. Tel./fax: +52 4433171870.
E-mail address: ggutier@itmorelia.edu.mx (G. Gutiérrez-Alcaraz).

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Network usage and operation efficiency optimization is the main goal of smart grid initiatives. Distribution network reconfiguration following hourly load variations for minimizing power losses is one of these initiatives [13]. Several proposals have been reported in the literature about distribution reconfiguration methodologies, which have the main goal of reducing network electrical losses by opening or closing switches to change the distribution electrical system configuration and keeping in mind voltage and power flow constraints. Also, the methodologies may include capacitor bank switching, in order to reach a further reduction in distribution electrical losses [14].

Many are the benefits of DR programs, including avoid or defer need for distribution infrastructure enforcements and upgrades, reliability and security improvement, among others. However, the operational effects on power losses in the distribution system due to load reduction have not been analyzed properly. In this paper, the effectiveness of a day-ahead hourly DR program is estimated by considering the behavior of customers under dynamic pricing options: CPP and HP. Network reconfiguration is then performed to study the combinational effects of DR and feeder reconfiguration in minimizing power losses under the new load profile condition. The paper is organized as follows: Section "Demand response" briefly describes the demand price elasticity concepts. The network reconfiguration problem formulation is presented in Section "Network reconfiguration". Case studies with illustrative results and discussions are presented in Section "Numerical results and discussion", and Section "Conclusions" presents conclusions.

Demand response

DR programs are classified into two categories: Incentive-Based Programs (IBP) and Price-Based Programs (PBP). IBP can be further divided into classical programs and market-based programs. In classical IBP, participating customers receive some type of payment, usually a bill credit or discount rate, for their participation. In market-based IBP, participants are rewarded with money for their performance depending on the amount of load reduction during critical conditions [10]. PBP refers to changes in usage by customers in response to changes in the prices they pay. If the price differentials between hours or time periods are significant, customers would respond to the price structure with significant changes in energy use [1]. TOU pricing is a basic version of PBP and is the easiest to implement. Traditional TOU prices which generally vary by season and time of day are fixed for relatively long periods of time and therefore do not reflect daily changes in power system costs. The most flexible and accurate retail pricing design is hourly pricing, where the retail energy prices charged to consumers vary hourly to reflect the varying cost of electricity. The hourly price signals give choices to customers for deciding whether to save money by reducing consumption during periods of high prices, or to buy at prices that reflect the power system economic conditions.

Elasticity approach for determining DR to price signal

Theoretically, demand elasticity is a preferred measure of consumer response to changes in prices. Price elasticity of demand is a measure used in economics to show the responsiveness of the quantity demanded of a good or service to a change in its price. In our context, price elasticity of demand is the customer change in electricity usage, in response to a change in the price of electricity, which can be expressed as:

$$\alpha = \left(\frac{\Delta Q}{\Delta P}\right)\left(\frac{P}{Q}\right) \tag{1}$$

where P is the price of electricity and Q is the quantity of electricity used, while ΔP and ΔQ are the price and demand changes, respectively.

Clearly, customer demand (load) reacts when electricity prices vary for different periods. For example, loads that are unable to move from one period to another might respond only in a single period, which is called self-elasticity. Self-elasticity always has a negative value. However, some of these loads could be transferred from peak to off-peak periods, which is called cross-elasticity [8,9,11]. Cross-elasticity always has a positive value. The cross-time effect that relates loads to prices during other time periods can be represented using two types of cross-time coefficients. The self-elasticity coefficient (α_{ii}) shows the effect of the price change of time period i on the load for the same time period. The cross-elasticity coefficient (α_{ij}) relates load during time period i to price change during time period j. These two coefficients can be written as:

$$\alpha_{ii} = \left(\frac{\Delta Q(t_i)/Q}{\Delta P(t_i)/P}\right) \leqslant 0 \tag{2}$$

$$\alpha_{ij} = \left(\frac{\Delta Q(t_i)/Q}{\Delta P(t_j)/P}\right) \geqslant 0 \tag{3}$$

where $\Delta Q(t_i)$ represents load changes at period t_i, $\Delta P(t_i)$ represents prices changes at period t_i, and $\Delta P(t_j)$ represents prices changes at period t_j. The quantities used to calculate the elasticity coefficient are available from spot market or computed in DR pilot test programs. Report on elasticity coefficients and their calculations are available in [6,15]. The self- and cross-elasticity coefficients can be arranged in a Np-order matrix where diagonal elements are the self-elasticities and off-diagonal elements relate the cross-elasticities:

$$\begin{bmatrix} \Delta Q_1 \\ \Delta Q_2 \\ \vdots \\ \Delta Q_{Np} \end{bmatrix} = \begin{bmatrix} \alpha_{1,1} & \alpha_{1,2} & \cdots & \alpha_{1,Np} \\ \alpha_{2,1} & \alpha_{2,2} & \cdots & \alpha_{2,Np} \\ \vdots & \vdots & \ddots & \vdots \\ \alpha_{Np,1} & \alpha_{Np,1} & \cdots & \alpha_{Np,Np} \end{bmatrix} \begin{bmatrix} \Delta P_1 \\ \Delta P_2 \\ \vdots \\ \Delta P_{Np} \end{bmatrix} \tag{4}$$

The load change during time period i caused by deviations of the initial prices from the expected prices is given by:

$$\Delta Q_i = \sum_{j=1}^{Np} \alpha_{ij}(\Delta P_j/P)Q \tag{5}$$

where ΔQ_i is the load change of time period i, and ΔP_j is the deviation of the initial price P from the expected price during time period j.

Network reconfiguration

Network reconfiguration is often performed to find an optimal radial configuration of a distribution network r, among all possible radial networks, i.e. $r \in R$, such that the resultant network, r^*, has a better operation performance to meet a specific objective. Generally, the objective is to minimize distribution electrical losses under a certain load pattern through network optimization while electrical and operational constraints are met. In this paper, the following problem is formulated to minimize electrical losses: