



Assessing long-term effects of demand response policies in wholesale electricity markets



Mauricio Cepeda^{a,*}, Marcelo Saguan^b

^a Paris-Dauphine University, France

^b Microeconomix, France

ARTICLE INFO

Article history:

Received 21 April 2014

Received in revised form 1 July 2015

Accepted 21 July 2015

Available online 1 August 2015

Keywords:

Demand response

Generation investment

Market design

Wholesale electricity markets

ABSTRACT

Different policies have been implemented around the world seeking to deliver demand response potential in the electricity markets. Externalities, namely the CO₂ externality, have been one of the key concerns in the debate on the effectiveness of different policies regarding demand response development. Although most previous researches have centred on the short-term assessment of different policy choices to tackle the CO₂ externality, little work has been focused on the long-term impacts, such as changes in welfare and investment dynamics, in consequence of the implementation of such policies. This paper relies on a long-term market simulation model to examine long-term dynamics of two specific policies presently used by policy makers. The first policy relates to the correction for the externality by setting a CO₂ price at a level equal to the social cost of the associated CO₂ emissions. The second policy consists in subsidizing carbon-free technologies such as demand response. We test for each policy two different scenarios regarding the possibility of internalization of the CO₂ externality. The results show that in the long-run different policies should affect both investments and social costs, a market-driven development of demand response with the internalization of the CO₂ externality being the most efficient approach.

© 2015 Elsevier Ltd. All rights reserved.

Introduction

The energy sector faces unprecedented challenges on environmental sustainability, security of supply and competition. In this context, demand side management presents a large potential which, however, has remained insufficiently addressed [17]. Demand response (DR) refers to the provision of incentives to consumers for optimally managing their electrical consumption [2]. DR has been gaining interest recently, as power systems become more congested and as renewable energy penetration increases. DR deployment may result in significant benefits for power systems by allowing a large participation of final consumers in wholesale electricity markets [23].

In this context, different programs and policies have been implemented around the world to develop DR potential [24,20,8]. These programs have taken different forms depending on the type of approach used to induce DR development, ranging from wholesale market participation and capacity mechanisms to technology-oriented programs and promotion subsidies prioritizing DR among others.

In recent years hot debates about the efficient way to incentivize DR in wholesale markets have taken place in different parts of the world [7,9]. For example, in the US, these debates have focused on two options to remunerate in the wholesale market the DR actions provided by retail customers: (i) paying DR the same wholesale price that generation when demand is reduced or, (ii) paying less than the wholesale price to DR, concretely, the wholesale price minus the (generation) rate at which retail customer would have purchased the electricity, had he consumed (LMP-G rule). In March 2011, after two years of strong disputes, FERC (the energy regulator) issued an order (order 745) in favor of the first option [21]. Parties opposed to FERC's action have taken the issue to court [1]. The debates among energy economist start again.

There is an almost general consensus among energy economists about the inefficiency of the rule chosen by FERC analyzed in a context of a “perfect” world, i.e., in a world without externalities. Indeed, it is economically justified that the retail consumer should receive less than the wholesale price when remunerated for its DR action: retail customer has to buy the energy before selling it back to the market (the term G is indeed the cost of this purchase). If DR is remunerated at the wholesale price, the incentive for its deployment will be too high and, the outcome will consequently be inefficient.

* Corresponding author.

E-mail addresses: mauricio.cepada@fondation-dauphine.fr (M. Cepeda), marcelo.saguan@microeconomix.com (M. Saguan).

However, energy economists do not agree on the efficiency of the FERC decision in the presence of externalities. The externality that is often mentioned in the debates to justify asymmetrical treatment of DR is the lack of internalization of the social cost of CO₂ emissions.¹ On the one hand, some economists argue that the option chosen by FERC is an inefficient subsidy to DR, distorting markets and investments [4,5,16]. For them other measures to tackle CO₂ externalities exist, such as pricing CO₂ emissions. On the other hand, other economists perceived the option selected by FERC as a second-best solution to compensate DR for externalities [11].

The impact assessment of different policies to cope CO₂ externalities has also been a critical issue for reflexion among regulators, policy makers and academics when designing and implementing demand response policies. Although most previous researches have centred on the short-term assessment of different policy choices to tackle the CO₂ externality [18,22,19,25], little work has been focused on the long-term impacts [15], such as changes in welfare and investment dynamics, in consequence of the implementation of such policies.

The purpose of this paper is to assess the long-term dynamic effects of alternative DR development policies. We examine three different cases of DR development: (case 1 – no policy/reference case) one driven by the market in presence of the CO₂ externality; (case 2) a second driven by specific subsidies for DR in presence of the CO₂ externality; and (case 3) the third driven by the market and with internalization of the CO₂ externality. The purpose here is to compare over time the dynamic evolutions in an electricity market for these different cases, assessing the economic performances of different policies (e.g. the evolution of generation technology mix, the amount of CO₂ emissions associated with electricity generation and the overall social cost).

We rely on a long-term dynamic model of an electricity market which simulates expansion decisions in a market regime and incorporates several DR development policies under different scenarios. The model is based on Cepeda and Finon [6] and is expanded to incorporate DR programs and policies. The model has been developed using concepts and tools from system dynamics, which is a branch of control theory applied to economic and management problems. This methodology has been extensively used in electricity market modeling to represent capacity expansion planning in wholesale markets [14,3,12,13,10]. The results show that in the long-run different policies should affect both investments and social costs, a market-driven development of demand response with the internalization of the CO₂ externality being the most efficient approach.

The paper is organized as follow. In Section ‘DR development policies, CO₂ externality and long-term impacts on electricity markets’, the question about the CO₂ externality and the DR development policy in a long-term perspective is examined. In Section ‘The structure of the model’ the long-term dynamic model is presented and in Section ‘Results’ preliminary results are discussed. In Section ‘Conclusions and further work’, concluding remarks and policy implications close the paper, highlighting pros and cons of different policy options and discussing possible further work.

DR development policies, CO₂ externality and long-term impacts on electricity markets

Long-term impacts of DR policies and the CO₂ externality on electricity markets can be analyzed using screening curves. This section introduces the question discussed in the paper and gives

economic intuitions using this standard method commonly used in electricity generation investment analysis.

Analysing generation long-term equilibrium using screening curves

The screening curve of a thermal power plant is defined as the average cost of using the plant’s capacity. The mathematical formulation is given by:

$$ACC = FC + \alpha VC \quad (1)$$

where *ACC* is the *Average Capacity Cost* (€/MW h), *FC* is the fixed cost (€/MW h), α is the capacity factor of the plant ($0 < \alpha < 1$) and *VC* is the variable cost of the plant. The fixed cost may be expressed as:

$$FC = \frac{r \cdot OC}{1 - (1 + r)^{-T}} 8760 \quad (2)$$

where *OC* is the overnight cost of the plant, in (€/MW), *r* the discount rate (in per unit per year), *T* is the life of the plant (in years). The variable costs are mainly the fuel cost (*fc*, in €/MW h) of the thermal plant, corrected by the CO₂ emission rate (*er*, in tons of CO₂/MW h) and the CO₂ externality value (*V*_{CO₂}, in €/tons of CO₂) if the externality is priced:

$$VC = fc + er \cdot V_{CO_2} \quad (3)$$

According to its screening curves, a power plant may be classified as peak-, middle- or base-load. Base-load units have the highest fixed costs, and the lowest variable costs, while peak-load units have usually the lowest fixed costs and the highest variable costs. Load rationing could be also included in the screening curve, with no fixed costs and with very high variable costs, which would be the value of lost load (VOLL).

Examples of screening curves for base-load units (yellow line), peak-load units (blue line) and load rationing (red line) are shown in Fig. 1.² The horizontal axis measures the (annual) capacity factor and is normalized to 1. The fixed cost is represented by the interception with the vertical axis whereas the variable cost gives the slope of each curve.

By comparing the different screening curves it is possible to determine capacity factor segments (or a number of hours that at technology should generate) where a technology is cheaper than other. From the Fig. 1, interception of screening curves indicates where peak capacity is cheaper than base-load capacity (yellow and blue lines) and where rationing is costs less than building peak units (blue and red lines). Combining these results with load-duration curve data (black line), it is possible to determine the optimal capacity for each technology, i.e., the capacity that ensures minimal total cost. Load duration curves indicate the amount of time that the load has been higher than a given value. In Fig. 1 the duration has been normalized to 1 (horizontal axis). Optimal capacities determined using this graphical method corresponds to generation capacities that would result in the long-run in a perfectly competitive power system, i.e., a long-term equilibrium under perfect competition.

We will now analyze the impact of DR on the long-term equilibrium, using this method. For clarity, we truncate at the “peak area” of the screening curves (grey zoom area) and we do not consider the base-load capacity in the following analysis.

¹ Reducing consumption at peak-load hours may reduce CO₂ emissions by replacing CO₂ emitting generation technologies as gas or coal power plants.

² Please note that Figs. 1 and 3 will appear in B/W in print and color in the web version. Based on this, please approve the footnote 1 which explains this.

متن کامل مقاله

دریافت فوری ←

ISIArticles

مرجع مقالات تخصصی ایران

- ✓ امکان دانلود نسخه تمام متن مقالات انگلیسی
- ✓ امکان دانلود نسخه ترجمه شده مقالات
- ✓ پذیرش سفارش ترجمه تخصصی
- ✓ امکان جستجو در آرشیو جامعی از صدها موضوع و هزاران مقاله
- ✓ امکان دانلود رایگان ۲ صفحه اول هر مقاله
- ✓ امکان پرداخت اینترنتی با کلیه کارت های عضو شتاب
- ✓ دانلود فوری مقاله پس از پرداخت آنلاین
- ✓ پشتیبانی کامل خرید با بهره مندی از سیستم هوشمند رهگیری سفارشات