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Load-shift incentives for household demand response: Evaluation of hourly dynamic pricing and rebate schemes in a wind-based electricity system

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ABSTRACT

Applying a partial equilibrium model of the electricity market we analyse effects of exposing household electricity customers to retail products with variable pricing. Both short-term and long-term effects of exposing customers to hourly spot market prices and a simpler rebate scheme are analysed under scenarios with large shares of wind power in a Danish case study. Our results indicate strategies that could be favourable in ensuring high adoption of products and efficient response by households. We find that simple pricing schemes, though economically less efficient, could become important in an early phase to initialise the development of household demand response. At a later point, when long-term dynamics take effect, a larger effort should be made to shift consumers onto real-time rates, and an increased focus on overall adoption of variable pricing will be required. Another finding is that demand response under variable pricing makes wind power more valuable. These gains in value reduce the need for support, and could be redistributed in further support of demand response.

KEYWORDS

Dynamic electricity prices, load-shift rebate, demand response, household consumers, partial equilibrium model, wind power.

1. INTRODUCTION

Incentives for household electricity consumers to provide flexibility are increasingly being discussed to support the integration of intermittent renewable energies [1]. To do so, incentives need to be highly dynamic, and real-time pricing is frequently mentioned as providing highest economic benefits. Households may perceive dynamic pricing as complex and as potentially colliding with their preference for stability, predictability and low risk [2,3]. Because individual behaviour shapes household consumption [4], it will barely be planned ahead of time and will most often not be automated or remote controlled. Demand response in this segment may therefore face a dilemma in that the economically most efficient pricing schemes will be too complex for the majority of customers to become interested in or react upon. If schemes are simplified, on the other hand, they will generate far less economic benefits, especially in systems with large shares of renewable generation. In this paper we contribute to evaluating this trade-off between economic efficiency and product simplicity by determining the effect of a simple rebate scheme as compared to dynamic hourly pricing.

While our analysis builds on general economic principles, we derive results in a stylised Danish setting, to illustrate the interplay of demand response with large-scale development of intermittent production. With Danish energy policy aiming at a fossil-free electricity supply in

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2035 [5], wind energy is going to play a major role in the future [6]. In 2020 electricity generation from wind energy should make up close to 50% of annual consumption [7]. The increasing volumes of wind power require sufficient flexible capacity to maintain a stable system, and with conventional power plants replaced by renewable generators, the Danish electricity system operator, amongst several other initiatives, aims at a better utilisation of demand-side flexibility [8]; though this still is subject to removing various barriers within the regulatory framework [9].

We focus on household consumption, because in this segment we expect the trade-off between efficiency and effectiveness of incentives to be most significant. It has been established that household consumers hold a technical potential to provide flexibility [10]. Several studies show that, when provided with economic incentives, they will utilise their potential and thus reveal some extent of elasticity towards short-term electricity prices (see Faruqui and Sergici [11] for an overview). For competitive retail markets it should be acknowledged, though, that consumers cannot be forced into specific schemes. They rather choose their pricing plans themselves and determine which products for demand response are going to be adopted.

Possible products have been discussed thoroughly [12] and may be categorised into price-based and volume-based schemes, depending on whether customers receive varying prices or are subject to direct constraints on their level of consumption [13]. Demand response of households without the use of automation will typically have to occur under price-based schemes. Here we can distinguish three major types of rate designs [14]: 1) time-of-use pricing, 2) critical event pricing, 3) real-time pricing. The first type consists of a mostly static pattern of prices that make it less efficient in a system based on wind power like the Danish one. The latter two are more dynamic schemes. In critical event pricing customers are subject to a significant price increase or rebate at specific times considered critical. With real-time pricing customers receive frequently updated price signals reflecting system cost. While all of these schemes provide an incentive for demand response, they differ in their theoretical economic potential and in how effective they will be in practice.

Real-time pricing is the ideal scheme from an economic point of view [15] and should be well suited in a dynamic environment with large fluctuations from wind power. Recent experience shows, however, that real-time prices work best with automated control and may be less applicable to manual response [16,17]. Comparisons of dynamic pricing studies also reveal that higher elasticities are achieved under critical event pricing or time-of-use schemes than under real-time pricing [18]. Schemes with higher economic potential tend to be more complex from a customer point of view [19] resulting in higher transaction costs [20], which in turn may reduce effectiveness by lowering adoption and response potential. Figure 1 is an attempt to illustrate this trade-off by putting different types of pricing schemes into the two mentioned dimensions. So although real-time pricing in theory should be the best solution, it might not be in practice, when taking into account behavioural aspects of households like: response fatigue [21], risk aversion [22] and resistance to increasing transaction cost [23].

In this paper we evaluate the economic benefits of an electricity retail product for demand response that is less complex than real-time pricing. We therefore compare economic gains of switching customers from a flat rate to hourly pricing to those of switching customers to a rebate product that customers should be better able to foresee the implications of. For that purpose we set up a partial equilibrium model of the electricity market based on hourly values (Section 2) and derive results for two different scenarios of wind production in a Danish

setting (Section 3 presents the underlying case study assumptions). We then compare outcomes for the different retail price regimes (Sections 4 and 5).

As we will show in the following brief review of related work, elements of our study have been addressed in the literature previously. Economic analyses of demand response have been conducted in various studies and within different market and regulatory contexts (for an overview see Conchado and Linares [18]). Where we identify a gap and contribute with this paper is in economic benefit analyses of different retail pricing schemes including long-term dynamics in a setting with intermittent renewables. Based on such analyses we will be better able to evaluate the gap in economic benefit that we might have to accept in order to achieve effective incentives in terms of adoption and response levels.

A number of studies conduct their analysis in a static setting assuming the response has no impact on prices. Many of these works consider real-time or hourly pricing: e.g. analysing heating and cooling in Texas [24], household appliances in Ireland [25] and Germany [26,27] or storage-like loads under German [28] and Danish [29] conditions. Static prices simplify the analysis of different retail pricing structures, which might be the reason that besides real-time pricing also many analyses of simpler rate structures have been performed. Some of them study critical event pricing [30,31], but most works look into the effects of time-of-use rates from the perspective of utilities [32–34] or customers [35,36].

We choose an approach based on economic equilibrium modelling in order to account for the dynamic market impacts of demand response. After all the impact on prices and generation capacities has been one of the main arguments in favour of demand response. Even though many studies use a similar equilibrium approach, they do not necessarily take long-term dynamics into account. Such works acknowledge the price impact of the response, but keep supply capacities static. Analyses with a short-term focus have been carried out examining real-time or day-ahead pricing (e.g. in the US [37–39], the UK [40,41], Slovenia [42] or Denmark [43]), time-of-use and critical peak pricing [44,45] as well as incentive-based response schemes [46,47]. A short-term equilibrium approach provides a bit more insight into the market dynamics of demand response. To fully evaluate the impact of policies, however, the short-term approach should be accompanied by an analysis of the long-term equilibrium [48]. One particular formal equilibrium framework developed for demand response by Borenstein and Holland [49] has been applied several times in different variations, showing how real-time pricing and resulting response of elastic demand generates significant benefits even with limited elasticities, for example, for US electricity markets [50,51] and Norway [52]. A related approach has been developed and applied to four weeks of Danish wind and demand data [53].

Long-term models result in the construction of an electricity system with optimal generation capacities. Usually this neglects existing capacity in a market, assuming divestment from overcapacity. As long as the state of the system is not taken into account, the long-term equilibrium found remains somewhat theoretical. Energy system models take a step further. They require a high level of detail in representing the energy system often resulting in extensive computation requirements. Analyses have been carried out, for example, with a focus on demand response from residential appliances [54–56], heat pumps [57–59] or electric vehicles [60–62].

Besides one analysis quantifying the impact of time-of-use pricing [50], the above long-term equilibrium studies do not take into account retail products that are less complex than hourly

pricing. While hourly pricing may be the efficient and a realistic option, one has to take into account the restrictions of individual consumers in reacting to hourly prices and their potential reluctance in adopting such schemes [63]. The impact of rebate pricing or other critical event pricing has only been analysed in short-term modelling frameworks [44,45] or estimated on the basis of empirical data [64,65].

Increasingly renewable energies have become an argument in favour of demand response and benefits are expected to become even more distinct. The economic impacts of large shares of renewables have been studied in equilibrium settings, without including demand response (e.g. for Southern [66,67] and Central European markets [68,69]). Some studies take into account demand response and renewables but limit analysis to a local grid [70], apply a static market setting [71–73], or derive short-term equilibria [39–41]. The long-term interaction of renewable energies with demand flexibility is most thoroughly analysed in the energy system studies mentioned above. These studies however assume optimal response to real-time system prices and do not consider specific retail product structures. This is where we set in with this paper.

2. METHOD

2.1 Market model

The model developed is a closed-market model without interconnections to other systems. To find a short-term equilibrium requires a specification of demand and supply curves based on the characteristics of generators and consumers and their respective marginal cost and benefit functions.

The demand side is characterised by a price elasticity of demand that may be defined in several ways depending on the underlying model of individual utility [74]. Moreover one has to distinguish between elasticity of demand due to price changes of the good itself (own-price elasticity) and of other goods (cross-price elasticity). Here we focus on own-price elasticity. We use constant elasticities defined as the percentage change of quantity Q given a percentage change of the price P [75]:

$$\varepsilon = \frac{dQ}{dP}\frac{P}{Q} \tag{1}$$

Our focus lies on the short-term elasticity of electricity demand, which is expressed in adjustments along a demand curve that is static within the analysed time horizon. Sometimes this is referred to as the real-time price elasticity [76]. We do not consider structural changes in electricity demand due to investments in appliances on the basis of the long-term price level [77]. Moreover, potential effects from changes in income are not included [78]. This is a simplification we consider acceptable, as individual changes in income based on savings from variable pricing will be relatively small.

Our constant-elasticity demand curves have the form:

$$D_t = D_{0,t}\left(\frac{P_t}{P_0}\right)^{\varepsilon} \tag{2}$$

With

D_t: Demand in hour t
$D_{0,t}$: Baseline demand in hour t
P_t: Price in hour t
P_0: Anchor price
ε: Price elasticity

The model requires a baseline demand $D_{0,t}$ and an anchor price P_0 as a starting point for any response. While P_0 is a fixed anchor price, $D_{0,t}$ changes on an hourly basis. P_0 is set such that it reflects the efficient level of the flat-rate tariff in the reference case.

The marginal benefit function is derived from the demand function incorporating both the demand from consumers on a flat-rate tariff and consumers on a variable tariff such that:

$$D_t = D_{0,t}\left(\alpha\left(\frac{P_t}{P_0}\right)^{\varepsilon} + (1-\alpha)\left(\frac{P_f}{P_0}\right)^{\varepsilon}\right) \tag{3}$$

With additional parameters:

α: Share of consumers on variable prices
P_f: Flat-rate price

Rearranging for the price P_t to find the inverse demand function [79], provides us with the aggregate marginal benefit function:

$$MB_t = P_0\left(\frac{1}{\alpha}\left(\frac{D_t}{D_{0,t}} - (1-\alpha)\left(\frac{P_f}{P_0}\right)^{\varepsilon}\right)\right)^{\frac{1}{\varepsilon}} \tag{4}$$

Here we have to ensure that $D_t > D_{0,t}\,(1-\alpha)\,(P_f\ /\ P_0)^{\varepsilon}$, i.e. total demand will never be less than the demand of flat-rate customers.

With a flat rate P_f equal to P_0 and a 100% share of flat-rate customers the model simply yields the load curve $D_{0,t}$. If a share of customers is exposed to spot prices, total demand follows the curve described by equations (3) and (4). For increased elasticity ε and increased share of customers on variable prices α market demand becomes more elastic. For a given price elasticity ε, Figure 2 illustrates the shape of the demand curves at different adoption levels of the variable pricing scheme.

To model generation we use a step-wise supply curve. Supply is based on wind power and three generic thermal technologies: base load, mid-merit and peak load capacity. The short-term marginal cost function is a piecewise linear function as illustrated in Figure 3 and described by:

$$MC_t = \begin{cases} c_{var,wind} & \text{for } D_t \le Q_{wind,t} \\ c_{var,base} & \text{for } Q_{wind,t} < D_t \le Q_{wind,t} + K_{base} \\ c_{var,mid} & \text{for } Q_{wind,t} + K_{base} < D_t \le Q_{wind,t} + K_{base} + K_{mid} \\ c_{var,peak} & \text{for } Q_{wind,t} + K_{base} + K_{mid} < D_t \le Q_{wind,t} + K_{base} + K_{mid} + K_{peak} \end{cases} \tag{5}$$

With

$Q_{wind,t}$: Quantity supplied by wind in hour t
$K_{base/mid/peak}$: Installed capacities of respective technology
$c_{var,base/mid/peak}$: Variable costs of respective technology

A computational difficulty occurs at the shift of one technology to the next, as well as when demand exceeds supply capacity. We therefore insert steep slopes at these positions of the supply curve to avoid vertical curve sections. These enable us to determine equilibrium prices at any point and ensure market clearing in every case. Most importantly, we may approximate finite price spikes without having to set a price cap. The sloping sections are defined such that:

$$MC_t = c_{margin,t} + k\left(D_t - Q_{sum,infra,t}\right) \qquad \text{for } K_{sum,infra} < D_t < \frac{c_{var,extra} - c_{margin}}{k} \tag{6}$$

With

$c_{margin,t}$: Variable costs of the marginal technology in hour t
$Q_{sum,infra,t}$: Sum of inframarginal production incl. wind in hour t
$c_{var,extra}$: Variable costs of next extramarginal technology
k: Emergency slope

In theory the factor k, representing the slope between steps, has an infinite value. Using a sufficiently large number will result in practically vertical slopes. We can interpret the minor additional capacity as emergency generation only utilised during short periods of time [80]. We use a constant value for k of 10^6.

2.2 Determining equilibrium

The above supply and demand curves enable us to calculate a short-term equilibrium by setting marginal cost equal to marginal benefits in every time step. We derive a set of hourly prices that, in combination with the respective technologies' cost structures, determines generator revenues. Profits are then determined as:

$$\Pi_{gen} = \sum_{t=1}^{T} \left(Q_{gen,t} \left(P_t - c_{var,gen} \right) \right) - K_{gen}\, c_{fix,gen} \tag{7}$$

With

$Q_{gen,t}$: Quantity supplied by generation technology in hour t
K_{gen}: Installed capacity of generation technology
$c_{var,gen}$: Variable cost of generation technology
$c_{fix,gen}$: Fixed cost of generation technology

In the long run generators have the possibility to adjust their capacities. New entrants may join the market, or plants may be shut down. This process continues until capacity reaches a new long-term equilibrium, where adding additional capacity would result in overall losses, while reducing capacity would result in profits attracting new entrants and a capacity increase.

Retailers will have to buy volumes supplied to their customers at the equilibrium wholesale prices. The retail market will reach equilibrium, when retailer profits become zero.

Eventually, consumers will therefore pay a price exactly covering whole-sale procurement costs of their suppliers, and retailer profits would be determined as:

$$\Pi_{retail} = \sum_{t=1}^{T} \left(\left(P_f - P_t\right) D_{0,t} (1-\alpha) \left(\frac{P_f}{P_0}\right)^{\varepsilon} \right) \tag{8}$$

Equation (8) is valid as long as variable pricing customers exactly pay the wholesale market price, thus, not affecting retailer profits. Below we define a slightly different version of the retailer profit function if the variable retail price and the wholesale price are not necessarily equal (as in the analysed rebate pricing schemes).

Figure 4 illustrates the steps to take in determining short-term and long-term equilibria. As a reference we first establish an equilibrium without any variable retail rates largely resembling the situation of today ($\alpha = 0$). We determine a set of generation capacities that results in a profit of zero for all generators. This is done by: 1) setting peak generator capacity to supply all of demand at zero profits, 2) substituting peak generator capacity with mid-merit capacity until both produce at zero profits, and 3) substituting mid-merit capacity with base-load generation until all generators, except for wind, produce at zero profits. We then find the flat retail rate that exactly covers wholesale market procurement cost of the retailer if consumption equals D_0 (which will be the case at $P_0 = P_f$).

When customers switch to variable prices ($\alpha > 0$), consumption and price in all of the hours changes according to the price elasticity of demand. To compensate for the retailer profits generated by a change in wholesale prices a new flat rate has to be determined. A change in consumption also affects producer revenues. In order to fulfil the equilibrium condition of zero profits will therefore require adjusting capacities until we reach a new long-term equilibrium state with both generator and retailer profits at zero.

2.3 Determining the economic benefits

Overall economic benefits are determined as the net-change in consumer and producer surplus. Due to retail market competition retailer profits will be at zero. Producer surplus, defined by the difference between costs and revenues, will also be at zero in long-term equilibrium as revenues exactly cover fixed costs. This does not, however, apply to wind power producers; here we allow for the exception of non-zero profits. The relatively high investment cost of wind power would usually result in losses that we assume support payments to compensate for. We can then account for a change in support payments caused by the introduction of variable pricing in the overall net benefits.

The change in consumer surplus, from a situation with all costumers on fixed prices to a new option with variable pricing, can be measured using the demand curve and the new set of prices. Figure 5 illustrates the change during one time step *t* as an area to the left of the marginal benefit curve in equation (4). As the marginal benefit curve is the inverse of the demand curve the area in Figure 5a corresponds to the area under the demand function shown in Figure 5b. We can thus take the integral of equation (3) over the price difference to determine the following expression for a change in consumer surplus per time step *t*:

$$\Delta CS_t = \alpha\, D_{0,t} \frac{\mathrm{P_0} - \mathrm{P_t}\,(\frac{\mathrm{P_t}}{\mathrm{P_0}})^{\varepsilon}}{\varepsilon + 1} + (\alpha - 1)\, D_{0,t} \frac{\mathrm{P_0} - \mathrm{P_f}\,(\frac{\mathrm{P_f}}{\mathrm{P_0}})^{\varepsilon}}{\varepsilon + 1} \tag{9}$$

2.4 Modelling of rebate pricing schemes

In modelling the load-shift rebate we want to reward only volumes shifted – payments for all other volumes stay the same as for flat rate customers. Although the rebate is not applied to the full volume, customers will have a marginal benefit on their consumption of the full rebate. Demand of rebate customers can thus be determined in line with equation (3) as:

$$D_{reb,t} = \alpha\, D_{0,t} \left(\frac{(1+r)\, P_f}{P_0} \right)^{\varepsilon} \tag{10}$$

To settle such a product we need to establish a baseline in order to measure the load shift. The base-line consumption $D_{BL,t}$ is determined as the expected consumption of rebate customers at a rebate of zero:

$$D_{BL,t} = \alpha\, D_{0,t} \left(\frac{P_f}{P_0} \right)^{\varepsilon} \tag{11}$$

The aim of the product is to react upon system conditions. Therefore the rebate will depend on the difference between the average flat rate price and the price during a predefined critical period. If during a particular rebate period T_{reb} spot prices on average show a price difference to the flat rate, then the rebate gets triggered. A threshold value r_{thr} may be added to avoid the provision of large rebates for relatively small deviations. During every single rebate period the rebate r is thus based on a predefined percentage rebate level r_{level} and determined as:

$$r = \begin{cases} r_{level} & \text{for } \overline{P}_{t \in T_{reb}} > (1 + r_{thr})\, P_f \\ -r_{level} & \text{for } \overline{P}_{t \in T_{reb}} < (1 - r_{thr})\, P_f \\ 0 & \text{otherwise} \end{cases} \tag{12}$$

Depending on whether customers are expected to increase or reduce consumption in a given period the rebate r will now be either negative or positive. With the rebate determined by equation (12) during critical periods the electricity cost of a customer is calculated as:

$$C_{rebate,t} = P_f \left(D_{BL,t} + (1+r)\big(D_{reb,t} - D_{BL,t}\big) \right) \tag{13}$$

Equation (13) should result in savings only if $D_{reb,t}$ deviates from $D_{BL,t}$ in the requested direction. Otherwise r should equal zero and costs will simply be based on the consumed volume times the flat rate P_f. This is important in contractual terms, but we do not add this condition here, because with demand determined by equations (10) and (11) this will always be the case due to the sign of the rebate.

Dividing equation (13) with the consumption of rebate customers $D_{reb,t}$ yields the average price a rebate customer pays for the full consumed volume during a rebate period – again provided the customer reacts as requested. The result may be simplified to:

$$P_{rebate,t} = P_f \left(1 + r - r \frac{D_{BL,t}}{D_{reb,t}} \right) \tag{14}$$

Figures 6 and 7 illustrate the changed marginal price level, which is the flat rate adjusted for the rebate, and the resulting relative average price ($P_{rebate,t}/P_f$) during critical periods for a

rebate of 50%. While customers never pay more than the original flat rate, the marginal values under this scheme always create an incentive to shift demand in the required direction.

A long-term equilibrium is not easily established for the rebate pricing scheme. As for other averaging variable pricing schemes, like for example time-of-use pricing, convergence is not guaranteed [50]. In our case, rebates should ideally be based on the actual price outcome, which in turn is affected by the behaviour of rebate customers. We avoid such feedback loops by setting rebates once for all based on prices in the reference case. Price changes in the variable pricing case are not allowed to further affect rebate levels.

As for the hourly pricing cases we establish a retail market equilibrium by requiring zero retailer profits. The rebate customers do not pay the wholesale price, though, and thus affect retailer profits. We therefore need to adjust equation (8) accordingly:

$$\Pi_{retail} = \sum_{t=1}^{T} \left(\left(P_f - P_t\right) D_{0,t} (1-\alpha) \left(\frac{P_f}{P_0}\right)^{\varepsilon} + \left(P_{rebate,t} - P_t\right) D_{reb,t} \right) \tag{15}$$

3. CASE STUDY ASSUMPTIONS

3.1 Demand side

3.1.1 Consumption profiles

A fundamental input to the model is the baseline demand D_0. We use the aggregate Danish consumption profile of 2012, however, only of consumers not settled on an hourly basis [81]; that is, consumers with an annual consumption of less than 100 MWh. We focus on this particular group of customers, because we want to isolate the impact of a shift to variable pricing for customers without access to variable pricing schemes in the current regime.

The price elasticity of demand is another crucial input. Although the exact elasticity will affect the overall absolute results, for our purpose it is most important that customers are price elastic at all. We therefore assume a fixed elasticity value and use -0.1 in line with various previous publications [18,76,82]. Table 1 summarises the main features of the demand assumptions.

3.1.2 Retail pricing schemes

We analyse four different retail pricing schemes. The first one is an hourly real-time pricing scheme reflecting wholesale market prices. The three remaining cases are variations of the rebate pricing scheme as described in section 2.4.

The parameters of the rebate scheme should be kept simple from a customer point of view. Therefore customers will only be asked to shift volumes relative to a time window of three hours. The difference between the analysed cases lies in the time of day defined as rebate periods. In two of the cases periods are fixed, while the third case operates with a dynamic time window. As the response potential of household customers, in particular, is expected to be highest in the evening hours we analyse cases covering the early evening hours (16.00-19.00) as well as later hours (20.00-23.00). In the following we refer to these products as "*Rebate Evening*" and "*Rebate Night*". In the dynamic case ("*Rebate Dynamic*") we determine the daily rebate period such that it covers the three-hour period with the largest price deviation, in any direction.

The input parameters for the rebate cases are summarised in Table 2. In all cases shifted volumes generate a rebate of 50% of the retail price. A signal to customers is triggered, whenever the average hourly price level within the defined time window differs from the flat rate price with more than 10%. This built-in threshold is to ensure that the response generates sufficient value at wholesale level.

To not further complicate social benefit calculations all levies and taxes are left out of the picture. This is important to keep in mind, when interpreting the results. The consumers thus respond to prices as if taxed on an ad valorem basis instead of the usual unit tax.

3.1.3 Adoption scenarios

We calculate results for different adoption rates of variable pricing, and a reference case with all customers on a flat retail rate. For all of the different retail pricing cases, we calculate the effects of 20% of customers under the scheme and of all customers adopting the scheme. The 20% scenario should reflect a realistically achievable potential, while the 100% is calculated as a reference showing the maximum potential under the different schemes.

3.2 Supply side

3.2.1 Generation

We use fixed and variable costs for three stylised thermal generation technologies and wind power as shown in Table 3. Cost and technology data are based on the Technology Catalogue of the Danish Energy Agency [83]. All costs are adjusted for inflation to the price level of 2016. Prices of fuels and CO_2 are based on a simple average of forecasts over the lifetime of the respective technologies [84].

3.2.2 Wind power scenarios

Two wind power scenarios are defined to determine the impact of an increase of variable production. The first scenario ("Base wind") applies an hourly profile of the wind share in consumption in 2012. Using shares instead of the actual production values allows us to scale the wind profile to the share of consumption that we analyse. The annual share of wind power in consumption for this case is around 31%. In the second scenario ("High wind") we increase the share to 50% of consumption.

To estimate the costs of wind power we weight the assumptions in Table 3 to reflect the relative shares of onshore and offshore wind installations. In the base wind scenario we use a share of 25% offshore wind installations approximately reflecting current levels, while in the high wind scenario we assume an increase of offshore installations to 35% of installed wind power in line with scenarios by the Danish TSO [85]. The installed wind power capacity is determined based on the maximum annual wind production assuming that the production peak will lie at 92% of installed capacity.

4. RESULTS

4.1 Base wind scenario

4.1.1 Hourly pricing

Table 4 provides a summary of the results for the hourly retail pricing scheme under the base wind scenario showing the different cases horizontally and the results within several

categories vertically. We will present results in similarly structured tables for all cases throughout this section.

The first vertical section of the Table 4 provides an overview of consumption and generation. For the consumption total annual volumes and the annual peak level is shown. On the supply side the installed capacities are shown together with the full load hours for each of the three dispatchable generation types: base load, mid-merit and peak load. Wind volumes are not shown as they are constant throughout all the cases within the same wind scenario.

In all simulated cases total consumption increases as compared to the reference case. A part of the increase will again rebound towards the reference level in the long-term, however. The usual expectation is that the peak consumption decreases due to the customers' response to high peak prices. This is the case for all but one of the simulations. Quite contrary to intuition, we do notice an increase in peak consumption in the short-term simulation results for 20% of customers on hourly pricing. This is due to a reduction of the flat rate in combination with the variable production profile of wind power (see also the discussion in Section 5).

The generation capacities in the short-term simulations are kept at the reference case levels. In the long term they are adjusted by the model as expected, such that peak and mid-merit capacities are reduced, and base load capacity increased. These adjustments are due to the respective generator profits provided in the third vertical section of Table 4. In the short-term they become negative, because of the changes in wholesale prices caused by demand response. In particular, the peak prices are clearly reduced, but also the average is lower than in the reference case. The wholesale price is shown in the second vertical section of the results table. The capacity adjustments increase peak as well as average prices from their short-term levels, and generator profits return to zero. The long-term price peaks are lower than in the reference scenario, while the outcome for the average price level in both adoption scenarios is a slight increase.

Besides wholesale prices the second vertical section of Table 4 also shows the cost of serving total load, reflecting the wholesale procurement cost of retailers, and the average prices paid by retail customer on either flat rate or variable rate. In all cases the cost of serving load is reduced compared to the reference. The described changes in wholesale market prices are reflected onto the flat retail rate that is reduced by more than 9 €/MWh as compared to the reference case in the short term. In the long run, however, the rate may as well increase. So while consumers immediately gain from responding to variable prices, not all customers will necessarily profit after generation capacity has been adjusted.

The overall costs and benefits are presented in the lower sections of Table 4, where we show the change in consumer surplus for different customer groups in absolute terms and relative to total reference cost of serving load. Here we can observe that it is not even required for all of the consumers to switch to variable rates in order to find short-term gains of around 16%. The short-term result in the 100% adoption case is not much higher. The effect of capacity adjustments in the long run is evident in the results and reduces the change in consumer surplus to about 4.2% for 100% adoption and down to 1.18% for 20% adoption.

We already mentioned thermal generator profits; besides those the total profit of wind generators is shown. The figures are negative due to high investment costs and reflect their need for support payments. The line showing total change in generator profits is the difference in profit compared to the reference case, which we consider as the relevant benefits

on the supply side. It is worth noting that for wind generators the change in profits is positive and their losses are reduced in all of the cases. The heightened value of wind power will result in reductions in the need for support payments and thus may also have a positive impact on consumers.

Netting the effects in the lowest two lines of Table 4 provides us with the ideal economic gains of hourly pricing under given assumptions. These are 3.95% relative to total costs for serving load including the support to finance wind power in the reference case. With a more realistic adoption level of 20% the long-term results point at a relative annual improvement of 1.12%.

4.1.2 Rebate pricing schemes

Results for the rebate pricing schemes are presented in Table 5 showing the different rebate schemes horizontally. We only present the final long-term equilibrium results here. The relation between short-term and long-term results is similar to the previous calculations of the hourly scheme. Note also, that we have not repeated the reference case results, so the presented numbers should be held up against the first column in Table 4.

The rebate pricing scheme as defined for this analysis only covers a daily three-hour period. Therefore effects are limited as compared to the hourly pricing scheme. The most significant impact comes from a rebate during the early evening hours (Rebate “Evening”), because this is the time of the wholesale price peak in the reference case, given the used hourly data. Having a rebate during later hours (Rebate “Night”) is not very effective if using the same elasticity. The net effect of the “Night” rebate is only around 25% of the “Evening” rebate.

A dynamic rebate turns out slightly better. But although this scheme catches the highest daily differences between flat rate and hourly prices, it could not improve on the result of the evening rebate. The major reason for the weak performance of the dynamic rebate is that the level of the flat rate lies above the simple average of wholesale prices, and thus the difference to peak prices is usually less than the difference to base prices, resulting in rebates to increase consumption during off-peak hours on many days. Only during very high price spikes will the dynamic rebate be triggered at peak times. At off-peak times, however, the rebate is often not sufficient to affect prices, and this is also a reason for the negative impact on wind power profits under the dynamic scheme.

Similar to the hourly scheme two of the rebates may result in an increase in total consumption. But while the hourly scheme reduces total cost of serving load in spite of increased consumption, this is not the case for all of the rebate simulations. On the other hand the rebate products are able to consistently increase the consumer surplus and the net effects including the change in generator profits are positive as well. Just as in the hourly case, we also note that passive flat rate customers in the 20% scenario may be affected negatively. However, this only happens in the “Night” rebate case which has a very limited impact anyway.

4.2 High wind scenario

4.2.1 Hourly pricing

Results for hourly pricing under the high wind scenario are summarised in Table 6. At first it is important to note the difference in the results of the reference case with 100% flat rate pricing as compared to the base wind scenario. In the reference case of the high wind scenario

total costs of supply are reduced by around 40 million EUR. At the same time the net support to wind power is increased by 160 million EUR, mostly because we require higher capacities to be installed and a larger share of them will be offshore and thus more expensive. Moreover, base load capacity is lower compared to the base wind scenario, while required peak capacity rises. Full load hours are decreased for all dispatchable generation technologies, most significantly, though, for the base load capacity. We can also observe higher price peaks than in the base wind scenario. Consumption on the other hand is at a similar level for all cases in both wind scenarios, with a less pronounced increase under hourly pricing in the high wind scenario.

Again we see the expected relation between short-term and long-term effects. A more surprising result is the extent of the negative impact on passive flat rate customers in the 20% adoption case in the long run. While in the short term all customers gain as expected, the flat rate is required to rise significantly above the reference level in the long-term in order for the retailers to break even. The result in this case is that the 80% flat rate customers loose three times as much as the 20% variable pricing customers gain.

The net effect is still positive for all of the cases. In absolute terms the net effect is higher than in the lower wind scenario, while relative to the reference cost the gains are slightly lower. This is because, even in the case affecting flat rate customers the worst, the effect on revenues of wind power producers is positive. Their increased income on the wholesale market more than compensates for the losses of flat rate consumers. If these gains are evenly distributed amongst customers then the 80% flat rate consumers will be compensated, because 80% of the gains for wind producers exceed the reductions in the 20% adoption case.

Overall we observe the net effect to be similar to the base wind scenario. But while in the base wind scenario gains primarily come from an increase in consumer surplus, they will to a larger extent result from the increase in the value of wind power in the high wind case.

4.2.2 Rebate pricing schemes

Table 7 provides an overview of the simulation results for the rebate pricing schemes. A striking result is that for all of the partial adoption cases the consumer surplus gains of rebate customers are insufficient to compensate for losses of remaining customers due to a rise in the flat rate. In order to maintain the same flat rate across all customers, pure flat rate customers will contribute to compensate a reduction in revenues to the retailer caused by rebates. This will not necessarily be the case in practice, where rebate customers may have to compensate for inefficient response on their own.

The short-term results, not shown in the table, are very positive in all the rebate cases. In the long-term, though, one might see an increase in prices and thus cost as compared to the reference level. Although we are observing these effects in the high wind scenario, the rebate schemes still provide a positive contribution to wind power producers. Therefore the overall net results in all of the cases stay positive.

The 100% cases for the “Night” and the “Dynamic” rebate schemes show that a poorly designed scheme would result in long-term losses for the participants. As compared to the base wind scenario, however, the dynamic rebate has a much more positive effect on the value of wind power. In the reference case for the high wind scenario, wind is the marginal technology in more than 1000 hours of the year as compared to 40 hours in the base wind case. The dynamic rebate reduces the number of hours by 365 in the high wind scenario,

which is much more than what could be achieved in the base wind case. This stresses the importance of dynamic instruments in a setting with high wind production.

5. DISCUSSION

The results of our case study illustrate some general effects of variable pricing in line with findings in other studies on real-time pricing. As we used the case of Denmark applying two scenarios of wind power production, we are able to observe some additional effects specific to systems with high shares of fluctuating, non-dispatchable generation. We also used alternative rebate pricing schemes to investigate whether the economic effects under such schemes may justify their implementation, assuming they could reach higher levels of adoption and response than hourly pricing.

Some generally expected effects of variable pricing can be observed in our simulation results. Maximum price peaks are significantly reduced under hourly pricing. In the short term reduction will be quite strong, while in the long-term prices return to a higher level due to adjustments in generation capacity. Another observation confirming previous findings [86] is that low adoption rates, with hourly pricing in particular, are sufficient to generate very attractive results from a consumer point of view in the short term, while increasing adoption does not change results significantly. In the long term, however, we find adoption to be more important in generating economic benefits, underlining the importance of analysing these effects.

The impact of wind power is reflected in some effects we found to be different from results in other studies. Usually peak consumption would be decreased with variable pricing, however, the irregular pattern of wind production allows for increasing peak consumption without increasing costs in some of the analysed cases as well. The reason for that is a significant decrease in the flat retail rate with flat rate customers increasing their consumption in response. This is only possible, because due to the wind production during the consumption peak, this is not the hour determining demand for dispatchable capacity.

Variable pricing will on average lead to price reductions in the short term that affect other customers on fixed rates positively as well. In the long run this is not necessarily the case and the immediate cost of flat rate customers may even rise in specific cases. It has been stated in previous analyses that a switch of customers to real-time pricing makes all customers better off [49]. The intuitive explanation of such a result is that the efficient retail rate is equal to the volume-weighted average wholesale prices. Customers on variable pricing schemes reduce peak prices, at times when demand is usually high. In contrast, our results show that in a system with high shares of variable production it is possible to observe an increase in the flat rate. While demand response customers still reduce price peaks, these peaks, because they also depend on the wind power production, must not in any case coincide with the highest consumption of flat-rate customers. Therefore, depending on the profiles of wind and consumption, retailer costs to supply flat-rate customers are not necessarily reduced as it should be expected without the effect of wind. This effect seems to become more pronounced with larger shares of wind power in the system.

Besides the impacts on consumers we note direct implications for wind producers. The value of wind production increases in all but one of the rebate cases under the base wind scenario. For the high wind scenario we find a consistent positive effect in all of the pricing schemes. This effect reduces the requirement for support payments to wind producers. On the other hand the positive effect of variable pricing on consumer surplus is reduced in the high wind

scenario due to increasing prices for flat rate customers. The gains from savings in the support should therefore be returned to the consumers via lower electricity bills or taxes.

The analyses of the rebate schemes have shown that simple rebate structures are necessarily less effective from an economic point of view than customers responding directly to wholesale price signals. Under rebate pricing the long-term peak prices are almost at the same level as in the reference case. Only in the short term significant peak price reductions can be attained under such schemes. If we compare the effect of the rebates to the ideal schemes we see that we can still achieve up to about 18% of the hourly pricing long-term effect with a much simpler rebate scheme as well. It should be kept in mind that this level is achieved by only sending a simple signal regarding three consecutive hours to the customers per day. The signal will only contain the information of whether increased or reduced consumption will generate savings, and the benefit to the consumers will always be the same. This is much to the contrary of conditions under a real-time pricing scheme. Moreover, in the short-term the relative effect of a rebate can be shown to be up to around 50% of gains under real-time pricing.

In the rebate pricing schemes the timing of rebate periods is critical. A problem of fixed rebate periods, as applied in two of the cases, will be that in the long-term price peaks are likely to occur at times outside of the rebate time window. The integration of higher shares of wind will require more dynamic schemes [87]. Accordingly we find the dynamic rebate to have the most positive impact on wind power revenues in the high wind scenario. The design of the applied rebate structure, however, could certainly be improved. Due to simplification in the modelling of the dynamic rebate scheme in particular, it does not improve results as much as it should be expected.

The model presented and applied above provides indications of how demand response affects consumer and producer surplus in a system with high shares of wind power. To keep the model versatile and enable testing of different pricing structures we limited its complexity and left out a couple of conditions. In the following we briefly discuss how these may affect results.

The most substantial concern may be that we look at a closed economy and do not allow for other sources of flexibility to react upon prices. This would clearly reduce the economic benefit of these kinds of pricing schemes, because the flat-rate benchmark will not have such extreme price spikes as we see them in the model. It could still be argued that for political reasons, from a national perspective, production capacities should be held available for security reasons, even though peak demand is covered by interconnection capacities with neighbouring countries. This approach has been used previously [71,72,88] and ensures that isolated system operation will be possible. The capacity will then be idle at peak times and would not gain scarcity rents as in the model. They would still have to be financed, though, so consumers would have to cover this cost. In that case however, demand response could not directly contribute to avoiding the costs, as payments for such capacity most likely will be independent of the timing of consumption.

The model uses a simplified representation of production capacities, only incorporating the major categories of plants. Using a more detailed model of plants may provide more accurate numerical results. The general conclusions, however, would stay the same. In practice generators would have more technical restrictions limiting their flexibility. In Denmark, for

example, combined heat and power production is an important factor. Such restrictions of plant flexibility could be expected to add to the value of demand response.

6. CONCLUSION

Using a partial equilibrium model of the electricity market we were able to derive a couple of new insights regarding the economic benefits of different retail pricing schemes for household customers. Applying case study data for Denmark we were able to analyse the interplay of demand response with different levels of wind power. Our results indicate favourable strategies in such a setting to ensure high adoption and efficient response to load shifting incentives for households.

Simple pricing schemes could become important in an early phase to initialise the development of household demand response. Our results confirm that variable pricing, whether in the form of real-time pricing or less complex structures, will have an overall positive economic impact. As expected, real-time pricing is clearly superior to the analysed rebate pricing schemes in a long-term equilibrium producing significant benefits of around 4% of total costs. Although the effects of the rebate structures may be limited in the long term, it can also be observed that the simple schemes could provide quite sizable gains in a short-term equilibrium. This result suggests that it could be recommendable to implement simplified pricing schemes in building up a base of demand response to begin with.

At a later point in time when the long-term dynamics begin to take effect, a larger effort should be made to shift consumers onto real-time rates. As households would have gathered experience with variable pricing schemes, the barriers to adoption should be expected to be lower. Moreover, automation equipment should be more widely available enabling a more active response. Such an approach would also accommodate the point that with higher shares of variable production, more dynamic schemes are preferable.

Benefits are not evenly distributed among customers on different rates. With increasing shares of variable production passive customers may even become negatively affected. While initially this should be evaluated as a welfare reduction, it could also increase the incentive for such customers to switch to variable rates and become more responsive.

Demand response under variable pricing can also be found to make wind power more valuable. The resulting reduction in the need for support should be returned to consumers in a way that preserves incentives for demand response, and could maybe even reward flexible customers specifically. Such compensations could become recommendable due to the diminishing long-term benefits for responsive customers; but also because customer gains may be far lower in the high wind settings, even though in absolute terms total economic benefits from demand response increase with more wind.

Our findings also suggest that an increased focus on adoption rates will be required in the long term. While harvesting the short-term gains could become an incentive for first-movers, the decrease in benefits over time could have an adverse effect and result in customers moving back to flat rates. As flexibility will be required even more in the long run this situation should be avoided. The more exact timing of long-term over short-term effects is an important aspect that requires further research.

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NOMENCLATURE

D_t: Demand in hour t
$D_{0,t}$: Baseline demand in hour t
P_t: Price in hour t
P_0: Anchor price
ε: Price elasticity
α: Share of consumers on variable prices
P_f: Flat-rate price
MB_t: Marginal benefit of consumption in hour t
MC_t: Marginal cost of supply in hour t
Q: Quantity supplied
$Q_{wind,t}$: Quantity supplied by wind in hour t
$K_{base/mid/peak}$: Installed capacities of respective technology
$c_{var,base/mid/peak}$: Variable costs of respective technology
$c_{margin,t}$: Variable costs of the marginal technology in hour t
$Q_{sum,infra,t}$: Sum of inframarginal production incl. wind in hour t
$c_{var,extra}$: Variable costs of next extramarginal technology
k: Emergency slope
Π_{gen}: Generator profit
$Q_{gen,t}$: Quantity supplied by generation technology in hour t
K_{gen}: Installed capacity of generation technology
$c_{var,gen}$: Variable cost of generation technology
$c_{fix,gen}$: Fixed cost of generation technology
Π_{retail}: Retailer profit
ΔCS_t: Change in consumer surplus
$D_{reb,t}$: Demand of rebate customers in hour t
$D_{BL,t}$: Rebate customer baseline demand in hour t
r: Rebate
r_{level}: Rebate level in percent
r_{thr}: Rebate threshold in percent
T_{reb}: Set of hours subject to rebate
$C_{rebate,t}$: Cost of rebate customers in hour t
$P_{rebate,t}$: Effective price of rebate customers in hour t

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FIGURES

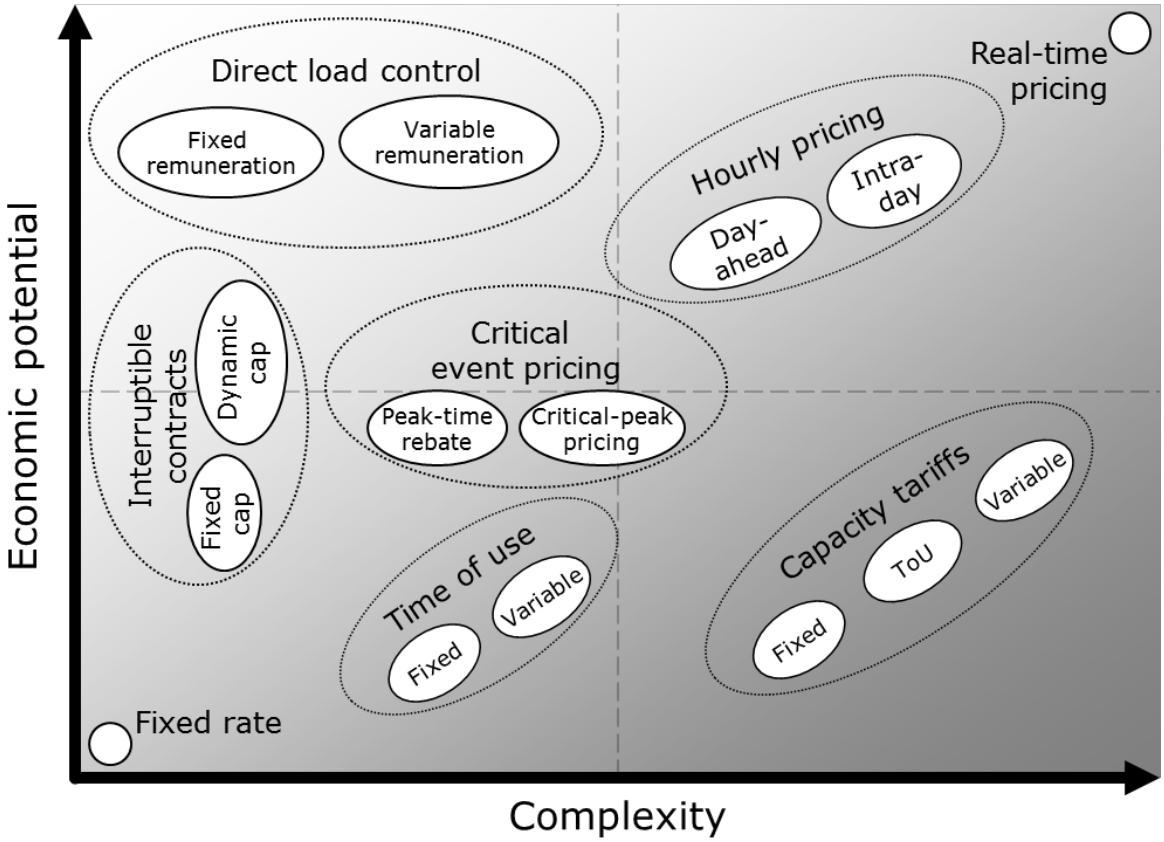


Figure 1: Complexity and economic potential of different pricing schemes

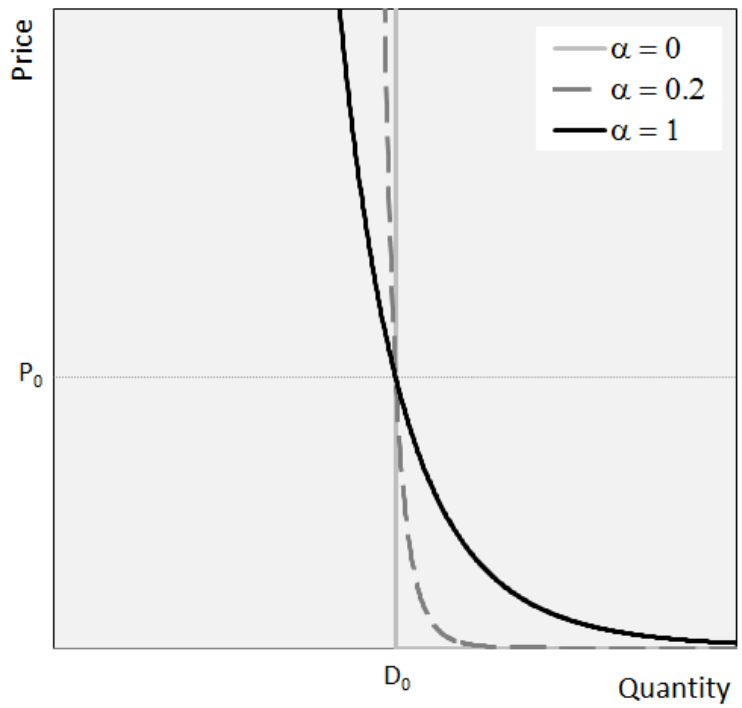


Figure 2: Aggregate demand curve for different shares of variable price customers

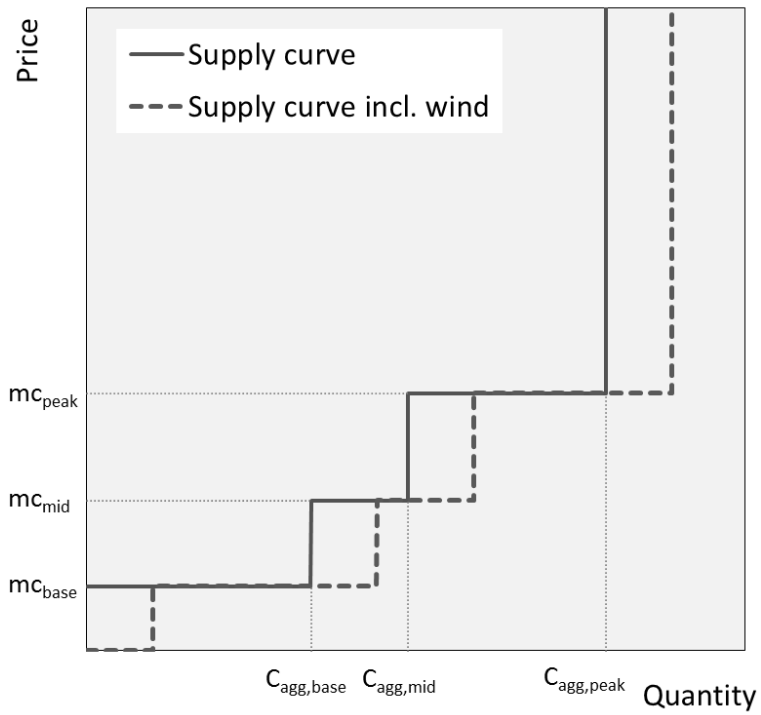


Figure 3: Stylised supply curves with and without wind production

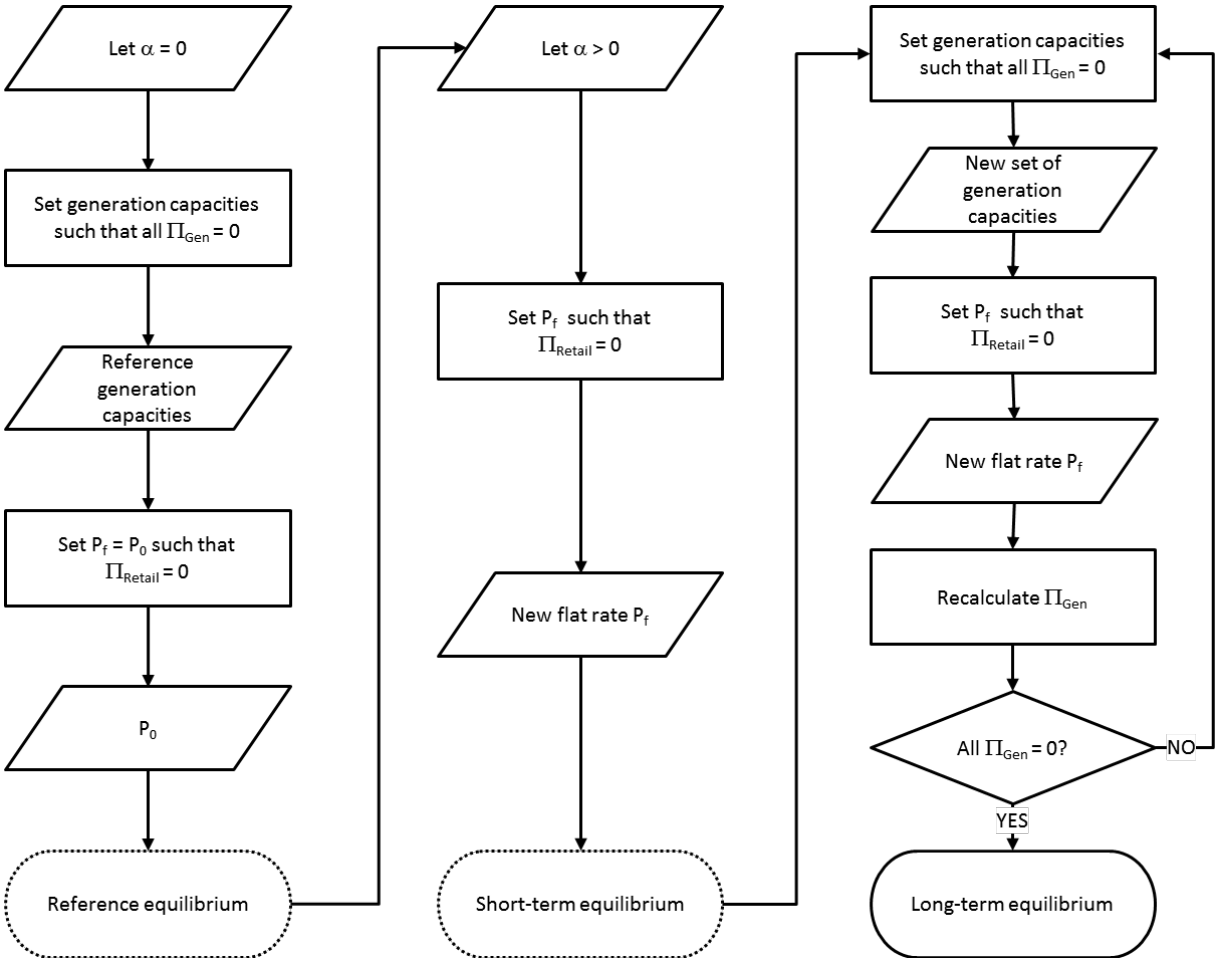
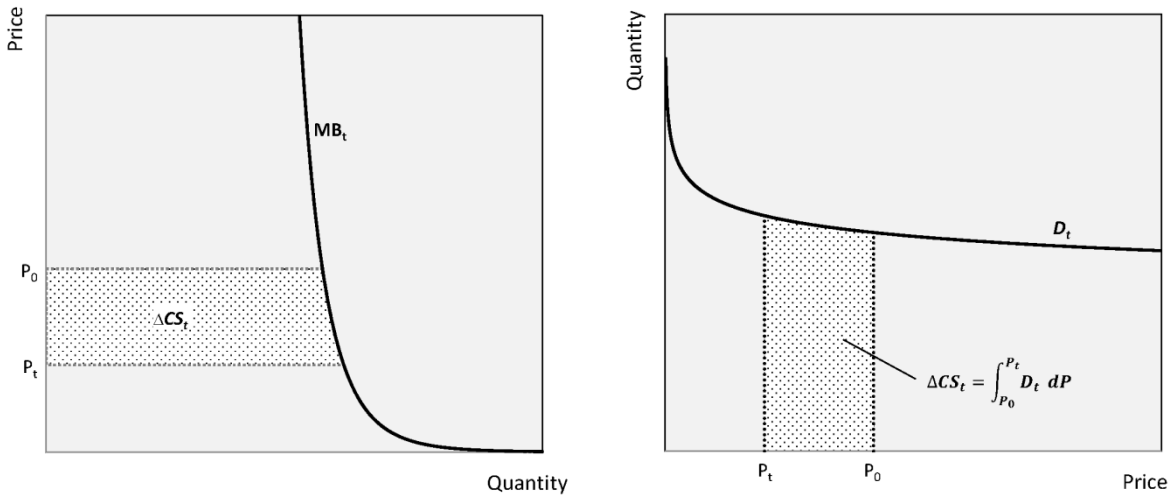


Figure 4: Algorithm to determine short and long-term equilibria



(a) **(b)**

Figure 5: Change in consumer surplus to the left of the marginal benefit curve (a) and equivalent area under the demand curve (b)

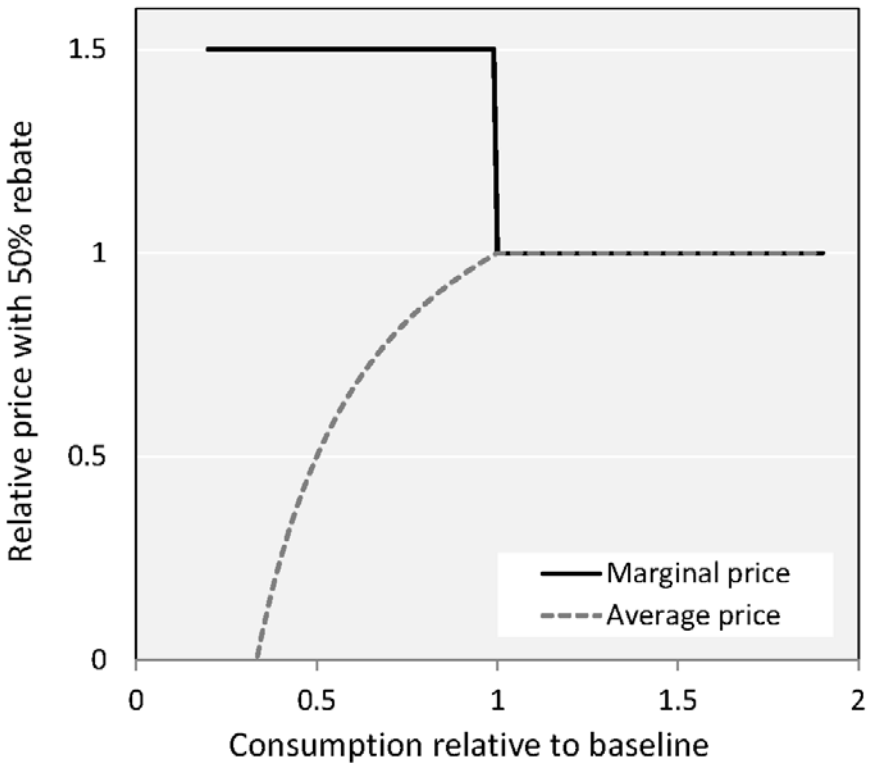


Figure 6: Rebate for reduced consumption

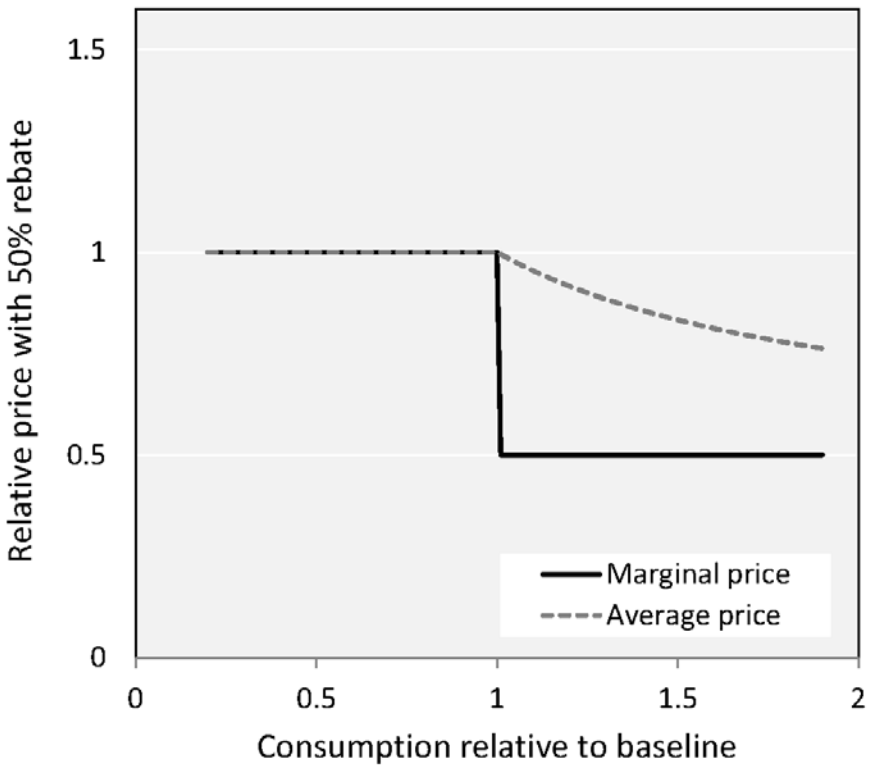


Figure 7: Rebate for increased consumption

TABLES

Table 1: Main features of demand input data

		Demand input
Total consumption	GWh	15,729.4
Max. consumption	MW	3700.8
Min. consumption	MW	824.6
Elasticity	-	-0.1

Table 2: Input data for rebate pricing cases

		Rebate		
		Evening	*Night*	*Dynamic*
Rebate	% of flat rate	50%	50%	50%
Rebate period	Hours of day	17-19	21-23	3 hours with largest Δ
Rebate threshold	% of flat rate	10%	10%	10%

Table 3: Input costs of stylised generation technologies

		Base	**Mid**	**Peak**	**Wind (onshore)**	**Wind (offshore)**
Fixed costs						
Specific investment	M EUR/MW	2.19	0.93	0.70	1.29	3.61
Lifetime	years	40	25	25	20	25
Discount rate	%	4%	4%	4%	4%	4%
Equivalent annual cost	EUR/MW	110,764	59,849	44,715	94,891	231,140
Fixed O&M cost	EUR/MW	61,471	32,240	0	0	0
Total fixed costs	**EUR/MW**	**172,235**	**92,089**	**44,715**	**94,891**	**231,140**
Variable costs						
Plant efficiency	%	46.0%	56.5%	39.5%	-	-
Fuel	-	Coal	Gas	Gas	-	-
Emission	ton/GJ-fuel	0.094	0.056	0.056	-	-
Fuel price	EUR/GJ-fuel	3.05	7.14	7.14	-	-
CO_2 price	EUR/t-CO_2	14.47	12.97	12.97	-	-
Fuel cost	EUR/MWh	23.90	45.48	65.06	0.00	0.00
CO_2 cost	EUR/MWh	2.96	1.29	1.84	0.00	0.00
Variable O&M cost	EUR/MWh	2.15	2.69	3.44	10.75	20.42
Total variable cost	**EUR/MWh**	29.00	49.46	70.34	10.75	20.42

Table 4: Simulation results for hourly pricing schemes in base wind scenario

Case		Reference	Hourly pricing			
Adoption rate	%	0%	20%		100%	
Equilibrium		long-term	short-term	long-term	short-term	long-term
Consumption						
Total	GWh/y	15,729	16,033	15,815	16,134	16,106
Max	MW	3,701	3,737	3,658	3,622	3,613
Generation capacities						
Base	MW	1,302	1,302	1,316	1,302	1,372
Mid	MW	284	284	268	284	205
Peak	MW	1,864	1,864	1,572	1,864	856
Full load hours						
Base	h/y	7,045	7,200	7,091	7,406	7,256
Mid	h/y	3,116	3,294	3,114	3,262	3,093
Peak	h/y	488	516	565	430	882
Wholesale price						
Avg.	€/MWh	48.54	44.39	48.61	44.36	48.61
Max.	€/MWh	44,785.07	117.64	12,328.52	70.34	1,749.17
Cost of serving load						
Total	T€/y	891,570	761,060	882,073	756,461	857,867
Specific	€/MWh	56.68	47.47	55.77	46.89	53.26
Average retail rate						
Flat rate	€/MWh	56.68	47.61	56.73	-	-
Variable	€/MWh	-	46.89	52.06	46.89	53.26
Consumer surplus change						
Flat rate	T€/y	0	115,096	-571	0	0
Variable rate	T€/y	0	29,915	11,123	150,121	37,447
Total	T€/y	0	145,011	10,552	150,121	37,447
*Relative**	%	0%	16.26%	1.18%	16.84%	4.20%
Generator profits						
Thermal	T€/y	0	-143,304	0	-144,988	0
Wind	T€/y	-236,276	-235,494	-234,239	-234,556	-229,135
Total change	T€/y	0	-142,522	2,037	-143,268	7,141
Net effect						
Total	T€/y	0	2,489	12,589	6,853	44,588
*Relative***	%	0%	0.22%	1.12%	0.61%	3.95%

* *Relative to total reference cost of serving load*
** *Relative to total reference cost of serving load and wind support*

Table 5: Simulation results for rebate pricing schemes in base wind scenario

Case		Rebate "Evening"		Rebate "Night"		Rebate "Dynamic"	
Adoption rate	%	20%	100%	20%	100%	20%	100%
Equilibrium		long-term	long-term	long-term	long-term	long-term	long-term
Consumption							
Total	GWh/y	15,728	15,726	15,745	15,804	15,749	15,819
Max	MW	3,671	3,709	3,701	3,700	3,701	3,701
Generation capacities							
Base	MW	1,305	1,317	1,306	1,321	1,305	1,309
Mid	MW	282	273	283	275	282	276
Peak	MW	1,836	1,721	1,862	1,853	1,858	1,858
Full load hours							
Base	h/y	7,045	7,035	7,047	7,045	7,054	7,096
Mid	h/y	3,121	3,128	3,118	3,118	3,111	3,109
Peak	h/y	488	492	484	473	489	488
Wholesale price							
Avg.	€/MWh	48.60	48.61	48.54	48.54	48.61	48.61
Max.	€/MWh	44,784.86	44,784.80	44,784.92	44,784.86	44,784.84	44,784.67
Cost of serving load							
Total	T€/y	890,706	885,791	892,022	894,177	890,658	892,423
Specific	€/MWh	56.63	56.33	56.66	56.58	56.55	56.41
Average retail rate							
Flat rate	€/MWh	56.68	56.56	56.70	56.80	56.59	56.58
Variable	€/MWh	56.45	56.33	56.48	56.58	56.42	56.41
Consumer surplus change							
Flat rate	T€/y	0	0	-244	0	1,211	0
Variable rate	T€/y	712	5,537	618	1,496	802	4,051
Total	T€/y	712	5,537	374	1,496	2,013	4,051
*Relative**	%	0.08%	0.62%	0.04%	0.17%	0.23%	0.45%
Generator profits							
Thermal	T€/y	0	0	0	0	0	0
Wind	T€/y	-235,401	-233,818	-236,242	-235,936	-237,513	-237,708
Total change	T€/y	875	2,458	34	340	-1,237	-1,432
Net effect							
Total	T€/y	1,587	7,995	408	1,836	775	2,619
*Relative***	%	0.14%	0.71%	0.04%	0.16%	0.07%	0.23%

* *Relative to total reference cost of serving load*
** *Relative to total reference cost of serving load and wind support*

Table 6: Simulation results for hourly pricing schemes in high wind scenario

Case		Reference	Hourly pricing			
Adoption rate	%	0%	20%		100%	
Equilibrium		long-term	short-term	long-term	short-term	long-term
Consumption						
Total	GWh/y	15,729	16,001	15,770	16,110	16,069
Max	MW	3,701	3,727	3,646	3,682	3,682
Generation capacities						
Base	MW	1,029	1,029	1,036	1,029	1,086
Mid	MW	385	385	369	385	309
Peak	MW	2,007	2,007	1,690	2,007	909
Full load hours						
Base	h/y	6,050	6,238	6,113	6,514	6,394
Mid	h/y	3,097	3,204	3,094	3,165	3,082
Peak	h/y	460	478	534	398	857
Wholesale price						
Avg.	€/MWh	46.88	44.06	48.61	43.90	48.61
Max.	€/MWh	44,785.07	102.65	23,692.33	70.34	2,589.32
Cost of serving load						
Total	T€/y	850,818	739,813	863,535	733,354	838,582
Specific	€/MWh	54.09	46.24	54.76	45.52	52.19
Average retail rate						
Flat rate	€/MWh	54.09	46.38	55.78	-	-
Variable	€/MWh	-	45.66	50.81	45.52	52.19
Consumer surplus change						
Flat rate	T€/y	0	97,761	-21,158	0	0
Variable rate	T€/y	0	25,577	7,028	130,515	13,596
Total	T€/y	0	123,339	-14,130	130,515	13,596
*Relative**	%	0%	14.50%	-1.66%	15.34%	1.60%
Generator profits						
Thermal	T€/y	0	-147,308	0	-150,238	0
Wind	T€/y	-398,437	-372,343	-370,650	-372,172	-363,524
Total change	T€/y	0	-121,214	27,787	-123,974	34,913
Net effect						
Total	T€/y	0	2,124	13,656	6,542	48,509
*Relative***	%	0%	0.17%	1.09%	0.52%	3.88%

** Relative to total reference cost of serving load*
*** Relative to total reference cost of serving load and wind support*

Table 7: Simulation results for rebate pricing schemes in high wind scenario

Case		Rebate "Evening"		Rebate "Night"		Rebate "Dynamic"	
Adoption rate	%	20%	100%	20%	100%	20%	100%
Equilibrium		long-term	long-term	long-term	long-term	long-term	long-term
Consumption							
Total	GWh/y	15,729	15,741	15,734	15,777	15,728	15,799
Max	MW	3,671	3,782	3,699	3,699	3,696	3,696
Generation capacities							
Base	MW	1,030	1,039	1,031	1,039	1,028	1,036
Mid	MW	382	371	382	371	383	373
Peak	MW	1,981	1,872	2,006	2,008	1,984	1,986
Full load hours							
Base	h/y	6,057	6,081	6,056	6,088	6,062	6,115
Mid	h/y	3,100	3,104	3,095	3,104	3,097	3,090
Peak	h/y	462	471	457	451	465	464
Wholesale price							
Avg.	€/MWh	47.00	47.00	47.09	47.09	47.50	47.50
Max.	€/MWh	44,784.89	44,785.04	44,784.83	44,784.89	44,784.85	44,784.80
Cost of serving load							
Total	T€/y	851,736	846,711	854,366	855,504	860,503	862,217
Specific	€/MWh	54.15	53.79	54.30	54.23	54.71	54.58
Average retail rate							
Flat rate	€/MWh	54.19	54.09	54.34	54.42	54.75	54.75
Variable	€/MWh	53.98	53.88	54.15	54.23	54.57	54.58
Consumer surplus change							
Flat rate	T€/y	-1,292	0	-3,137	0	-8,237	0
Variable rate	T€/y	329	3,254	-210	-2,227	-1,542	-7,761
Total	T€/y	-963	3,254	-3,347	-2,227	-9,780	-7,761
rel.	%	-0.11%	0.38%	-0.39%	-0.26%	-1.15%	-0.91%
Generator profits							
Thermal	T€/y	0	0	0	0	0	0
Wind	T€/y	-395,782	-394,794	-394,676	-394,246	-387,201	-387,397
Total change	T€/y	2,655	3,644	3,761	4,191	11,237	11,040
Net effect							
Total	T€/y	1,692	6,898	414	1,965	1,457	3,279
rel.	%	0.14%	0.55%	0.03%	0.16%	0.12%	0.26%

* *Relative to total reference cost of serving load*
** *Relative to total reference cost of serving load and wind support*