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Keep it simple: time-of-use tariffs in high-wind scenarios

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Abstract: Price signals have been suggested to bring about greater demand side flexibility and thus support the integration of variable sources of energy, such as wind. A conflict exists between keeping these signals simple for consumers, while making responses appropriate for increasingly complex supply–demand balancing dynamics in future. This study reviews some of the demand responses observed in time-of-use (ToU) tariff trials and assesses their effectiveness in scenarios with higher levels of wind. The authors simulate wholesale real-time prices for high-wind scenarios as a benchmark tariff. Simple tariff structures are compared against real-time prices for the extent to which they can ‘nudge’ demand in the ‘right direction’. They present results which suggest that even in high-wind scenarios, simple ToU tariffs could have a beneficial effect on overall system costs. The load shifting and reduction behaviour observed under ToU trials could lower energy costs by between 4 and 6% without the need for complex price signals.

1 Introduction

The decarbonisation of our electricity systems brings with it unprecedented challenges. In the short term, the UK and other European countries face the closure of significant parts of the present generation fleet in response to the Large Combustion Plant Directive [1]. This is expected by some to reduce capacity margins to potentially insecure levels [2]. In the medium term, the introduction of larger shares of renewable energy could pose new challenges of providing flexibility [3] and in the longer term, electrification of heating and transport could put further strain on system integration [4].

A more flexible demand side could help with all of the above challenges [5, 6]. If incentivised appropriately, demand could become more responsive to system needs. In the first place, this could address peak demand concerns. For the UK, peak demand periods are reasonably well understood and tend to occur on winter weekdays about 5:30 pm. A simple time-of-use tariff (ToU), which charges a premium for consumption during this period, could potentially reduce peak demand and avoid supply shortages and costly peak generating capacity. Such tariffs have been trialled in Ireland and in the UK. Results show a reduction in peak demand in some cases by between 8 and 10% [7, 8].

The introduction of large amounts of wind may complicate the times at which demand should increase or decrease. The simple and static ToU tariffs may no longer send the appropriate signal and more dynamic tariffs may be

required. The gold standard in terms of neo-classical economics would be to expose consumers to real-time prices, as they are experienced in wholesale markets [9]. This would convey the ‘true’ cost of electricity to consumers who could make a rational decision over whether to use electricity depending on their own utility value. Their ‘choice’ to use or forgo the use of electricity would, according to this theory, lead to an economically efficient allocation of supply and demand.

For fully automated appliances real-time responses are mostly a technical issue. Fridges and other thermal loads can conceivably be cycled in response to external signals, such as price signals, without necessarily inconveniencing their user [10]. A large part of energy uses have, however, a very direct interaction between users and technology. Practices and behaviour play an important role in the timing and extent of this type of energy use. Influencing these through price signals is arguably more challenging than mere device automation [11].

And here lies a dilemma: more complex signals place a higher burden on consumers, potentially deterring engagement and increasing uncertainty over bills. Darby and Pisica [12] compared the acceptability of different tariff structures to consumers and found real-time prices were seen as less acceptable than ToU tariffs while Dütschke and Paetz [13] show that consumers are open to dynamic pricing, but prefer simple programs to complex and highly dynamic ones. Star *et al.* [14] further describe how potential savings from real-time price schemes have not led

to significant uptake among consumers in Illinois. Even with mostly static flat tariffs, the energy regulator and consumer groups have perceived UK tariffs as ‘too complex’, preventing consumers from being able to make informed choices [15].

How can the need for more complex signals be reconciled with the consumers preference and need for simple messages? In this paper, we simulate future price volatility to explore whether price signals necessarily have to be complex and what contribution in terms of system cost savings demand response could offer under simple ToU tariffs.

The focus of this paper is on behavioural responses, rather than automated or other technical solutions, such as storage. Behavioural responses are seen as a contributor to system balancing and are expected to operate alongside a range of other measures. The modelling does therefore not assume that demand has to respond substantially more during extreme stress events. Rather, demand response would make a small contribution in the ‘right direction’, thus reducing the extent to which other measures are required, without necessarily fully displacing them.

In Section 2, we set out how we compare ToU tariffs and the responses observed in field trials, with real-time prices derived from wholesale market simulations for high-wind scenarios. The impact on consumer bills and the energy system are reported in Section 3 and we explore the possible shape of future ToU tariff profiles. Sections 4 and 5 draw out some of the implications for future tariff design and point to limitations and need for further work in this area.

2 Methodology

The model used here builds on work published by Grünwald *et al.* [16]. To estimate the cost saving potential of demand response to future systems, we expanded this model to combine empirical data from ToU tariff trials with wholesale price simulations for different future scenarios.

Although the tariff bands for ToU trials were not designed with high levels of wind in mind, we explore the demand response observed under these tariffs for their hypothetical use with high levels of wind. Half-hourly settlement periods are simulated, such that the impact of tariffs can be assessed against the system requirements at the time. From this, we seek to identify whether a demand response was beneficial or indeed counter-productive.

It is important to note that future prices – and volatile prices in particular – are difficult to predict and carry a significant amount of uncertainty. Prices simulated here assume similar market arrangements, dynamics and levels of competition to the present market against which the model is calibrated. However, even if the scale of the price volatility may differ, this paper deliberately follows a simple method to discriminate high-price and low-price periods, for which the assumptions of this simulation are expected to be sufficient.

2.1 Demand response in ToU tariff trials

The underlying dynamics of electricity use in households are still poorly understood. An increasing body of evidence is being built up through a range of studies, which attempt to better understand the energy use in households (see [11]) and trials are growing in size and statistical validity [17–19].

Among the statistically most robust studies to date is the trial of static ToU tariffs by the Commission for Energy Regulation in Ireland [7]. Household loads for a total of

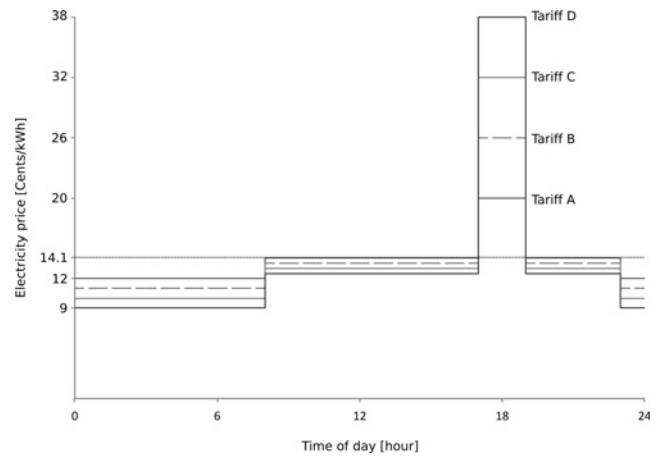


Fig. 1 ToU tariffs as used by The Commission for Energy Regulation (CER) [7]

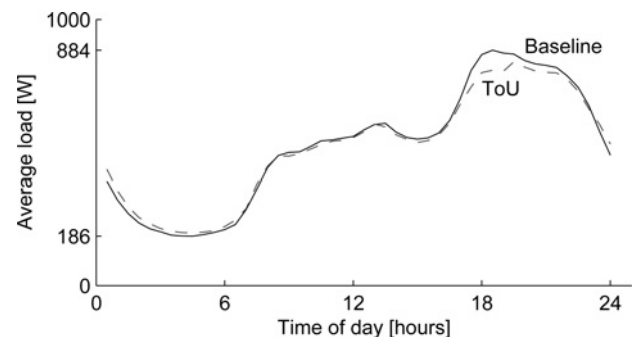


Fig. 2 Comparison of demand profile for baseline and corresponding test period for 108 consumers subjected to the ToU tariff D

Based on [7] data

over 5000 participants were recorded from 1 July 2009 until 31 December 2009 under conventional tariffs and again for the following year, this time subjected to one of four ToU tariffs and one control group, which remains on their standard tariff. Average load reductions in response to ToU tariffs on the order of 2.4% were observed and peak demand reduction reached 8.8%. The tariffs are shown in Fig. 1, but it was noted that the extent of the price increase is less significant for response behaviour than the sheer presence of differential pricing [7]. The tariff periods reflect the characteristics of the typical load curve, which peaks between 5 pm and 7 pm and has relatively low consumption between 11 pm and 8 am. We focus this analysis on a group of 108 households exposed to the highest peak time prices (Tariff D). Fig. 2 shows the shift in load profiles for this group between the period before the trial on conventional tariffs (baseline), and once these consumers were exposed to ToU tariffs. Both peak reduction and a slight increase in night-time consumption are apparent.

We further limit the analysis to the same time of year as monitored during the baseline period, such that seasonal effects can be minimised. The load profile before and after introduction of the ToU tariff are shown in Fig. 2. The reduction in peak load is clearly visible, as is the slight increase in night time consumption. The overall reduction in consumption for this group is about 3.8%.

2.2 Wholesale price formation

To estimate the wholesale market price of electricity, and thus the 'ideal' real-time price, we assume a simple merit order stack with four classes of generation: (i) uncontrollable generation (e.g. wind) with low short-run marginal costs, (ii) baseload generation (e.g. nuclear) with the technical ability to ramp up and down, but little economic incentive to do so, (iii) mid merit plants, which can load follow within their ramping constraint and (iv) peaking plant which deliver energy during peak demand and may support fast ramping. The latter category has by definition lower load factors and only remains viable to operate by being able to realise wholesale prices well above its marginal costs of generation.

The model seeks to meet demand through the lowest cost of generation, while maintaining system stability and ensuring that sufficient 'responsive' plant remains on the system. In the absence of significant amounts of storage any surplus generation from wind is assumed to be curtailed.

The wholesale prices are based on the short-run marginal costs of generation of the marginal plant and the state of the system at the time. So long as sufficient capacity is available the wholesale price only rises linearly, such that once a class of generation is fully deployed, the wholesale price reaches the marginal cost of the next more expensive generator, which enters the market at this point.

For peaking plants the situation is slightly different. Since they are the 'last resort', prices tend to rise exponentially as the available capacity reaches its limits. This effect is known as the 'price uplift' and can be empirically observed in the balancing market and has been theoretically analysed and simulated by Green and Vasilakos [20] and was also applied by Cox [21, 22] and others.

In this model, we simulate the price up lift as

$$U(t) = \kappa \times e^{\alpha(L(t)/C(t)-L(t))} \quad (1)$$

where U is the factor by which marginal costs are marked up. L is the total system load and C is the generation capacity available at the time to meet this load. κ and α are used to calibrate the function to empirically observed market behaviour.

The same approach is applied to curtailment events, where bidding occurs in the opposite direction. The more generators are requested 'not to generate' the higher the price for not generating becomes, such that electricity prices can become negative. Such curtailment events are becoming more common. The empirical evidence for market price developments under these conditions is, however, not yet sufficient for calibration and we assume the same

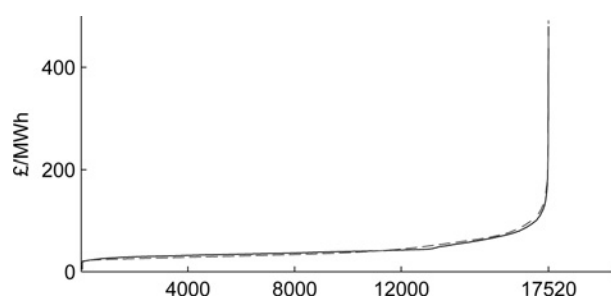


Fig. 3 Price duration curve for balancing market data for 2010 against simulated prices (dashed line)

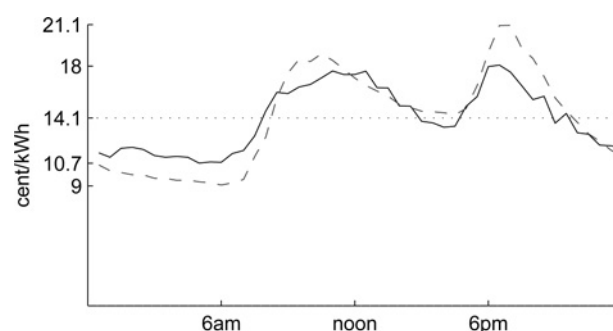


Fig. 4 Average electricity market prices for 48 settlement periods of the day, averaged over one year

Solid line: based on [23], dashed line: simulated

Table 1 Model parameters

Parameter	Value	Unit
wind capacity	5–30	GW
baseload capacity	20	GW
mid-merit capacity	30	GW
plant availability	95	%
ramp limit	750–1500	MW/h
α	1.5	
κ	10	
marginal cost wind	1	£/MWh
marginal cost baseload	8	£/MWh
marginal cost mid merit	24	£/MWh
marginal cost peaking	33	£/MWh

underlying characteristics and parameters as for the price uplift.

Fig. 3 compares the price duration curve for empirically observed prices based on Great Britain market data [23] and simulated results. The simulated results were further validated for temporal accuracy against daily price distributions as shown in Fig. 4.

The price profiles are a function of both total load and ramping requirements. Assumption about the ability of mid-merit plants to load follow has important ramifications for the role of peaking plants and thus the price profiles. For the present GB system a ramping constraint of 1500 MW per hour produce a good match with observed results. However, the flexibility of the system may change in future and we will return to its implications. Further details about model assumptions can be found in Table 1.

2.3 Other model inputs

The simulated prices are based on load profiles for the GB and Ireland, wind profiles and a set of assumptions about future system scenarios.

Half-hourly load profiles are available from National Grid for GB [24] and from EirGrid for the Irish market [25]. The default for this study is 2010 data to be consistent with the Irish ToU trial data. For verification purposes, we have also used GB demand data dating back to 2003.

The wind resource is based on an optimised portfolio of wind turbines across GB. Wind speeds were obtained from the British Atmospheric Data Centre's MIDAS dataset for a selection of 16 sites [26]. The conversion into a wind energy resource is described in [16].

3 Results

3.1 ToU tariff responses in high-wind scenarios

Based on the wholesale price formation observed in current markets we estimate the effect of higher penetration of variable wind sources in future markets. The additional wind resource displaces some mid-merit capacity, such that peaking plant capacity is accommodating greater variations in wind power. The load factor for some of these plants reduces and wholesale prices during peak net-demand (demand minus wind power) can increase substantially.

In the spirit of our real-time pricing assumptions, wholesale prices have been converted directly to retail prices. Our model suggests that prices would rise. However, the focus of our analysis is to compare the shape, rather than the magnitude of the price profiles. Thus, prices are normalised to an average electricity price of 14.1 cents per kWh (the rate used for the control group in the CER trial).

Fig. 5 shows the average price distribution for each settlement period of the day. Compared to the current prices in Fig. 4, two trends are apparent. Firstly, the spread between high-price and low-price periods has become more pronounced. Off peak prices are depressed as a result of the low running costs of wind, while peak prices increased because of the increased peak net-demand events being met by peaking plants.

Of particular interest for this analysis is the overall shape and timing of high-price and low-price events. These have not shifted substantially, suggesting that even with wind capacity of 50% of peak load (i.e. about 30 GW on a system with 60 GW peak), the highest prices are still closely related to demand levels. This persistence of demand profiles is shown in Fig. 6. Owing to the stochastic nature of wind profiles, the daily pattern of demand remains apparent, even after the wind generation has been subtracted. Both the morning ramp up and the afternoon peak remain clearly visible, especially during winter months, which correspond to the higher load days in this graph.

The profile shape is also related to the degree of flexibility that was necessary to operate the system with more wind. Mid-merit plant are displaced by peaking plant, which responds to changes in wind levels. In this case, demand response would not be needed to balance the system continuously in response to wind and the primary trigger remains peak load. The simple ToU tariffs, which are tailored to these periods may therefore remain appropriate.

It is worth noting, however, that the above system flexibility comes at a cost. Mid-merit plants are cheaper to

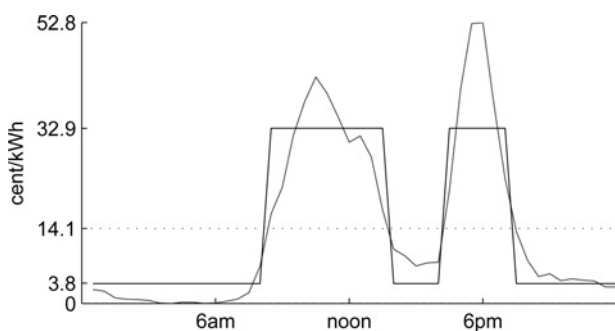


Fig. 5 Price profile for one year with wind capacity of 50% of peak demand

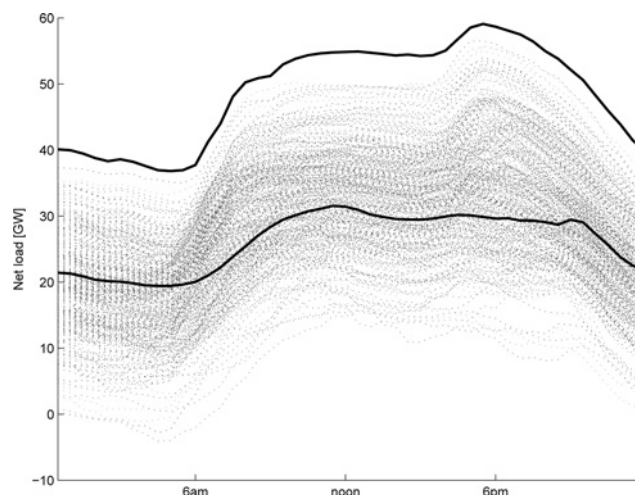


Fig. 6 Daily pattern of demand is still apparent after wind generation has been subtracted

Based on one year half-hourly data with wind capacity of 50% of peak demand. Thick lines indicate the highest and lowest gross demand for each half-hour in this year.

operate than peaking plants. The same simulation with a less flexible system, which has less capacity to respond to changes in wind, suggests that price rises can occur at any time of day. Even during low demand periods costly spinning reserve may need to operate to ensure system stability. A less flexible system may thus demand more flexibility at less predictable intervals from the demand side.

These results indicate that ToU tariffs may remain relevant even in high-wind scenarios, provided other forms of flexibility are present as well. In the following section, we will take a closer look at how different pricing structures would affect consumers and how the demand responses observed in the CER trial may align with future system needs.

3.2 ToU demand response and real-time pricing

The demand data in the CER trial provides a baseline measurement, which was taken during the 171 days preceding the trial when households were still on flat tariffs, and the comparison profile when these households were subjected to the ToU tariffs. We now use these data to explore hypothetical billing situations and the effect different tariffs would have on household bills and in turn, how much the observed ToU response would help in reducing these bills. To this end, we multiply the demand of each customer in each half-hour period with the RTP simulated by the model for this period. The total is aggregated for the period July to December prior to the participants being subjected to the ToU tariffs (baseline) and again for the same period after they operated under ToU tariffs (shifted demand). The comparison between these two periods allows us to estimate whether the load shift would have led to a reduction in bills.

The reduction in bills is used here as a proxy, not so much for household savings, but for potential system savings: real-time prices are the result of a least cost allocation of generation, so a lower bill under real-time prices implies that the cost of provision could be reduced under this load shifted behaviour. The marginal cost on which our simulated prices are based, reflect the cost that would be incurred for additional load, or the avoided cost when load

is reduced at this point in time. They therefore present a proxy for generation cost changes. In addition, operational savings may result (such as avoided spinning reserve) as well as network savings from deferred or avoided reinforcements. These are not captured by this model and savings therefore constitute a lower bound of possible system benefits.

Table 2 shows the effect on household bills resulting from different tariff structures for the 108 households on tariff D in the CER trial. During the baseline period, when households were still on flat tariffs, an average electricity bill for the July to December period would amount to about 291 Euros. Even though the ToU tariffs were constructed to have the same average cost to consumers, a higher share of consumption occurs during the high-tariff periods, resulting in slightly higher bills if the same load profiles had been billed with dynamic tariffs. The same effect is responsible for the higher bills in the case of RTPs. Since the overall cost of provision has not changed, one could argue that the tariffs should be set lower, such that the average cost is below 14.1 cent per kWh and the billed amount remains the same. The CER trial ensured that participants would not suffer higher bills by compensating them for any increase through a direct repayment.

The right column in Table 2 shows the reduction in electricity bills as a consequence of load reduction and load shifting as performed in response to tariff D. As one would expect, bills are reduced when ToU tariff D is applied, relative to the cost that the original demand profile would have incurred, since this is the price signal the occupants did respond to. Interestingly, however, bills are also reduced had they been calculated based on real-time tariffs. This is to say that the response provided was beneficial under RTP considerations, without the households in this study even being aware of the signals this tariff would have sent them. For both, the Irish and the UK example the benefit increases with higher levels of wind on the system. This is significant, because it suggests that the response that was triggered by the ToU remains valuable and may even increase in value over time.

The rationale for RTP is to reflect the true cost of electricity. If the ToU response leads to lower bills under assumed RTP billing, then we can conjecture that the costs of provision would have been reduced also.

Thus the ToU tariff has had a positive impact on system costs, even and especially in high-wind scenarios. What these results do not tell us is whether and how much more households may have saved if their response had indeed been informed by real-time prices. It is safe to assume that for some households greater savings are possible and empirical work on price responses will help to better understand this additional potential.

Table 2 Demand shift exercised by households responding to tariff D, would lower bills, even if these had been calculated based on RTP tariffs

Tariff	Bill [Euro], baseline demand	Saving [Euro (%)], from shifted demand
ToU (D)	318	18 (5.6)
RTP IE (5% wind)	314	15 (4.7)
RTP IE (50% wind)	414	24 (5.8)
RTP UK (5% wind)	326	12 (3.7)
RTP UK (50%wind)	372	15 (4.1)

Period July–December using Irish (IE) and UK wind resources

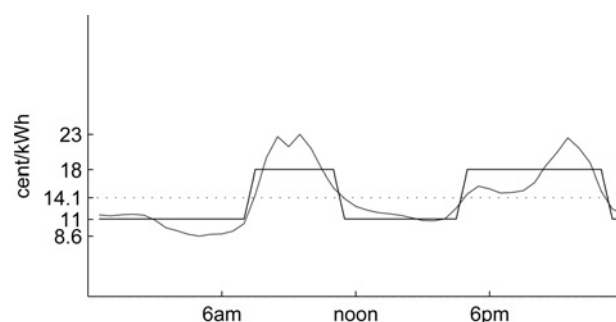


Fig. 7 Simulated price profile for one year with wind capacity of 5% of peak demand

3.3 Effect of higher levels of wind on price profiles

The tariff bands shown in Fig. 1 were designed to suit present load profiles and supply challenges. We will now explore how such a simple tariff may be derived from future real-time prices.

Figs. 5–9 show real-time profiles (red lines) averaged over given periods for low and high-wind scenarios. For consistency with the available baseline data from [7] study we focus on the period July to December and single out December separately as a month commonly experiencing peak demand events.

Two periods of above average prices are apparent from the real-time price profiles. One during the morning hours, which is a result of ramping constraints, which were simulated as 1500 MW per hour for the relevant mid-merit plants. Greater deployment of fast ramping plants could reduce the price rises during the morning ramp up, but could drive up overall operating costs. The second peak in the late afternoon is more related to capacity constraints. This becomes especially apparent in Figs. 8 and 9, which show price curves for December only. Here national demand reaches its highest level about 5:30 pm with the corresponding peaks in prices are most pronounced around that time.

The simulation of higher levels of wind power on the system, assumed to be 50% of national peak load in Figs. 5 and 9, increases the spread between high-price and low-price periods [This effect has been somewhat tamed through the normalisation of the tariffs to an average price of 14.1 cent]. It is noteworthy, however, that the timing of high prices have not changed fundamentally with respect to the low-wind cases in Figs. 7 and 8. This supports the observation that consumer signals, which are presently informed by demand profiles and seek to reduce peak demand, could remain valid in high-wind futures.

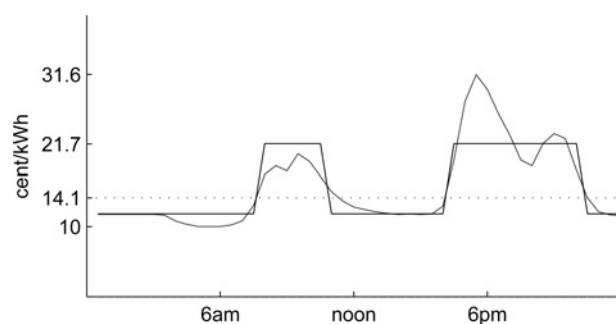


Fig. 8 Simulated price profile for December wind capacity of 5% of peak demand

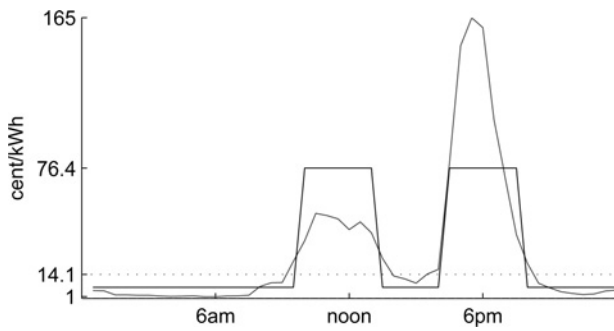


Fig. 9 Price profile for December with wind capacity of 50% of peak demand

The main change that can be observed from these simulations between low and high-wind scenarios is that the off peak price reduces significantly with higher levels of wind, thereby potentially sending a stronger signal to ‘shift’ demand to off-peak periods.

3.4 Approximating RTP with ToU

Real-time prices are the ‘gold standard’ from a neo-classical economics standpoint. Subjecting consumers to such prices relates the ‘true’ cost of provision to them and is said to allow them to make appropriate choices. In practice, however, people may have other things to do in their life than monitor and evaluate the electricity prices, plan future consumption and adjust their behaviour in real-time. A compromise may therefore need to be reached between the accuracy of the price signal and the simplicity of the message passed on to the energy user.

We do not have experimental data to suggest what the demand response by consumers might be under the real-time prices shown in Figs. 5–9. For the purposes of this paper, however, we continue to follow the premise that consumers would prefer and would be more likely to engage with simple tariffs and price signals. The simplest price signal is binary: a high price to suggest using less electricity and a low price when consumption is less critical (or a higher load would indeed be beneficial from a system stability standpoint). The daily RTP profile is translated into ToU bands by dividing each settlement period into either being below or above the mean price. Each half-hour period above the mean is assigned the mean price of all periods above the mean and conversely for all periods below the mean, leading to a binary price signal. Figs. 5–9 show what the binary ToU price signal equivalent to the real-time prices would look like (black lines).

While such simplified price signals might offer benefits to consumers, their accuracy with respect to real-time prices remains a concern. Fig. 10 shows the error between different levels of tariff complexity and the ‘gold standard’ RTP. The errors are recorded as the root-mean-square difference between the tariff and the RTP for each half-hour period in each month. Owing to the increased price volatility in a scenario with wind installations equivalent to 50% of peak demand, the flat tariff can lead to substantial discrepancies with the real-time price, which are reduced through the adoption of ToU tariffs.

A static ToU tariff (middle graph), which is based on the simple binary price signal and applied across the year, leads to a reduction in error. However, winter months remain problematic.

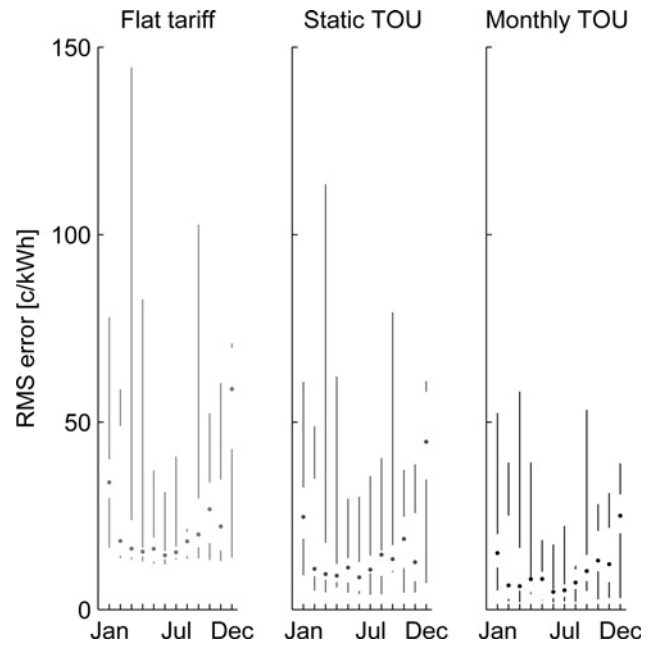


Fig. 10 RMS error between selected tariff types and a real-time price for a scenario with wind capacity at 50% of peak demand

Data represents six years of wind profiles and demand profiles for 2010
Dots mark the median error, whiskers indicate the outer quartiles

The graph on the right in Fig. 10 is based on ToU tariffs that are specific to each month. These still adhere to the simple binary principle of one high-price and one low-price level. Month specific ToUs reduce winter errors to levels broadly below those experienced during the summer months with a flat tariff.

As Figs. 7–9 illustrate, the binary tariff levels are a crude approximation of real-time price profiles. Yet, as Fig. 10 illustrates, they can substantially reduce the error and therefore improve on the signal sent to consumers.

Fig. 11 shows the distribution of false price signals over one year. In this illustration ‘false negatives’ are low price periods when a demand reduction would have been desirable from a system perspective, while ‘false positives’ are periods when the price was high, yet demand reduction was not necessarily required from the system. These periods indicate when a simplified ToU price signal might produce demand response behaviour that would be counterproductive from a system balancing perspective. False negatives are lower in number (3.3% of the half-hour periods), however, these are the periods when wholesale

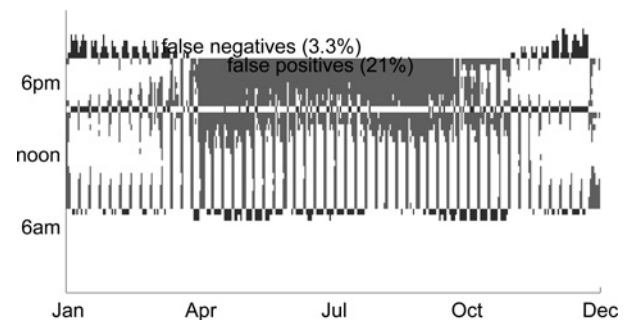


Fig. 11 False ToU signals from the binary tariff in Fig. 9

Demand reduction outside high-price periods would have been beneficial in 3.3% of settlement periods, especially in winter, while higher day time prices can send a false signal 20% of the time, predominantly in summer

prices can reach very high levels. The seasonality of the need for demand response is evident from both Figs. 10 and 11. Especially in winter months errors can be large, with December and January displaying the highest median errors.

4 Discussion

The trade-off between accurate price signals and the simplicity of the message sent to consumers is complex. We have begun to review the price accuracy aspect. For a better understanding of the impact of different messages and signals to consumers on the effectiveness of their response, detailed and extensive field trials are necessary.

We hypothesise, based on preliminary work in this area, that energy users prefer simple messages and may be able to respond to consistent messages by adjusting and developing new practices and habits of energy use.

This analysis has shown that binary price signals, sending a message as simple as ‘use less during these periods’ and ‘shift load to those periods’, can have a positive impact even in high-wind scenarios.

Despite higher levels of wind, the critical periods remain largely around morning and late afternoon peak loads. Provided other means of system balancing are available, residential demand response can make a positive contribution towards system balancing, even when following such relatively simple messages. These data used in this study constitute one of the best sources of household load profiles to date. With the arrival of new energy use practices, such as electric heating or electric vehicles, and changes to use patterns, the load shape may change and the level and shape of ToU tariffs would need to be adapted accordingly.

The simulation further suggests that the critical months remain to be winter months and particular attention needs to be given to the messages sent out during these months. On the one hand, it could be argued that price signals should be limited to these critical months, thereby focusing attention to the most valuable responses. Tariffs could be structured to charge a flat rates for the majority of the year and switch to ToU for the winter months, alerting customers to the particular sensitivity of electricity provision then.

Conversely, even if the need for ToU responses is less during the summer months, a consistent tariff throughout the year may help in establishing standard routines and influence appliance purchasing decisions which involve lower consumption during peak hours. Practices may adjust such that dishwashers and washing machines are routinely run outside peak hours, for example.

Aside from reduced cognitive demands on consumers, ToU tariffs are easier to implement technically. No two way real-time communication between the grid and ‘smart meters’ is required. Dual-rate meters, as have been in use for decades, especially in combination with night storage heaters, would suffice for this task.

Tariffs which are designed to encourage reductions in demand during peak hours are by definition punitive to high consumption during these periods. From a system perspective, one would want to entice households with presently high peak time consumption onto these tariffs, since these might have most load reduction to offer. However, these households would perceive such tariffs as more expensive and might favour flat rate alternatives, so

long as these are available. Some level of regulation may therefore be required to complement such market-based tools.

Although we have shown that ToU tariffs remain to be a useful tool for demand response stimulation with a view to reduce overall system costs, other tariffs may deliver better results. The trade-off between those gains and their impact on consumers deserves detailed attention and further study.

5 Conclusions

We have explored the extent to which relatively simple ToU tariffs provide appropriate signals to consumers to respond to future electricity system requirements. The analysis was motivated by the suggestion that simple tariff structures and messages could be more effective in engaging consumers to adjust their demand patterns, but that such signals would become increasingly inappropriate as more wind is added to the system.

The simulation of real-time prices in scenarios with high levels of wind has, however, shown that peak demand periods could remain to be critical periods in future systems. Even though wind output is stochastically distributed and not strongly correlated to demand, the most pressing demand response periods continue to be related to high and low demand. Put simply, never is the need for downward response greater than when low wind coincided with high demand, and conversely, the greatest upward shift in demand is needed during low demand periods meet high wind output. Even simple ToU tariffs may therefore have a beneficial impact in such systems and the value of their contribution could rise over time. For the cases simulated here, a ToU tariff may reduce costs by 4.1% in the UK and 5.8% in Ireland.

The shape of a desirable tariff profile may change slightly for high-wind scenarios. Depending on the flexibility of the overall system, prices could become more volatile with high prices throughout the day, but especially during afternoon peaks (5–7 pm). On the other hand, night time consumption may need to be encouraged through further reductions in prices, which in some scenarios could result in near zero electricity price bands.

Simple messages to consumers are potentially more effective at changing behaviour, practices and patterns of electricity use, and thereby make a beneficial contribution to future energy systems. However, these measures rely on other forms of flexibility provision, such as automated demand response, storage and flexible generation, which could be more amenable to rapidly changing real-time prices.

Consumer studies suggest that simple tariff structures are preferred by consumers. This paper hypothesises that behaviour-based demand patterns may be more effectively shaped by simple tariff signals. Further research and trials into the response dynamics for different tariff types would be important to test this hypothesis and to explore whether inaccuracies of simpler tariffs are offset by better customer engagement. In this context, it might be valuable to explore the role simple tariffs could play in consumer learning, which could facilitate the transition from simple to more complex tariffs over time and deliver greater demand flexibility than might be available in the early trials used here. Furthermore, the assessment of marginal cost of generation performed here, could be enhanced by directly modelling the system costs and explicitly estimating savings associated with system operation, generation capacity requirements and network infrastructure.

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