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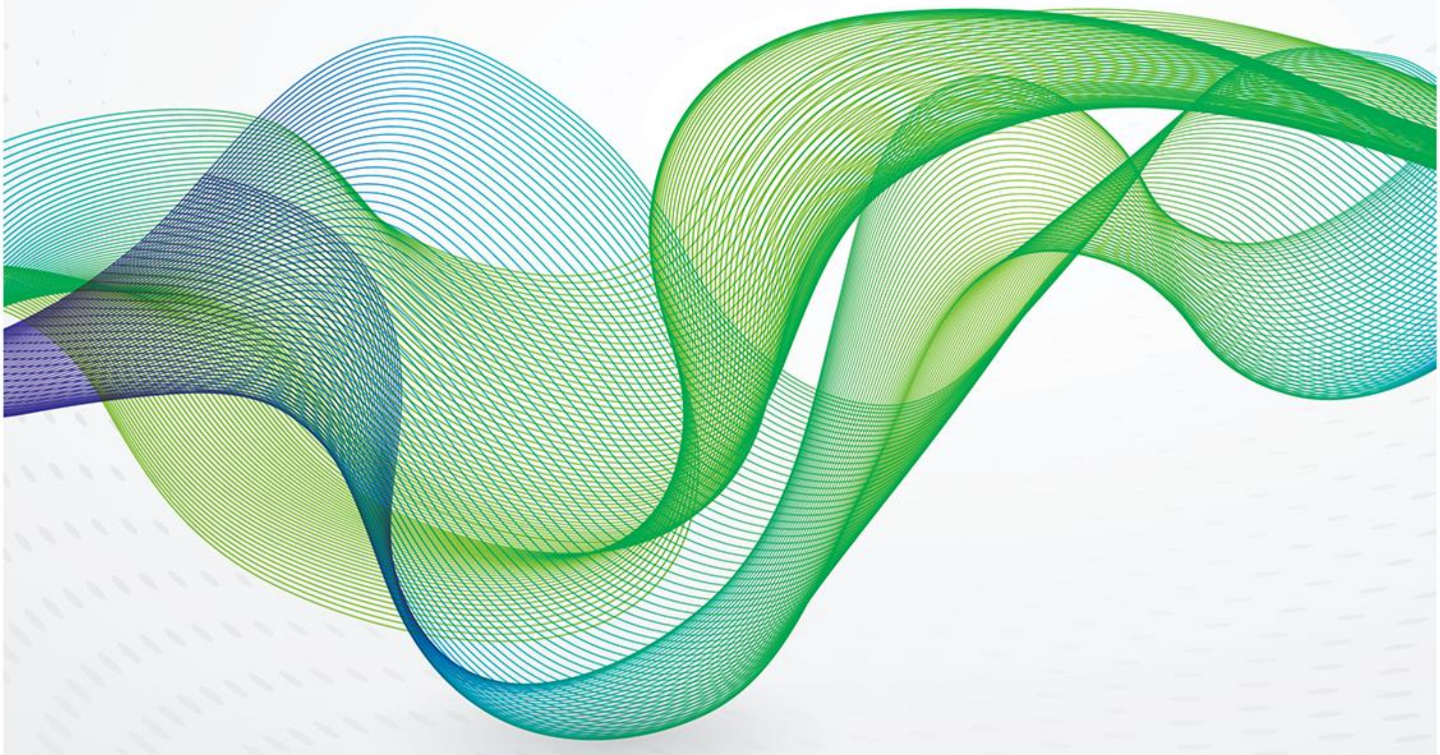
Electricity markets are broken – can they be fixed?



OIES PAPER: EL 17

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1 Introduction

The contention of this paper is that liberalised wholesale electricity markets, particularly in Europe, are broken, and can no longer fulfil their key functions. While by no means universally accepted, this contention is attracting increasing support. European markets are strained and worrying symptoms are appearing – falling wholesale prices at a time of rising generation costs; early plant closures; financial problems for utilities, which are nonetheless expected to engage in the biggest investment programme in history to meet carbon targets; the frequent occurrence of zero or negative prices; debates over the need for market reforms, in particular the introduction of capacity mechanisms to underpin investment in the plants needed to maintain supply security; complaints from consumers about constantly rising prices; and so on. These problems are discussed in a parallel OIES paper.[1] This paper considers the implications; it argues that these are more than short-term problems and are the product of a structural failure – electricity markets are designed to reflect and optimise the cost structures of the conventional technologies we are familiar with from 20th century electricity systems. They are not suited to the systems we are developing to meet 21st century needs and circumstances, and they do not give effective signals in situations where, as at present, one set of technologies is receiving support from outside the market, while other technologies are expected to remunerate themselves from the market – yet both sets of technologies are operating in the same market.

While there is increasing recognition of the problems, there has so far been less debate about the solutions. The debate that has taken place has focused mainly on capacity mechanisms, which, in the view of this paper, address only a small part of the underlying structural difficulties. New thinking is needed and it will take time to develop a consensus on a new approach. The main aim of this paper is to stimulate debate about the options; some possible solutions are aired but it is clear that no consensus on the way forward has emerged at this stage. Nonetheless, if it is accepted that the present situation is unsustainable, urgent consideration must be given to alternative market structures if we are to avoid major security and environmental risks and a consumer backlash.

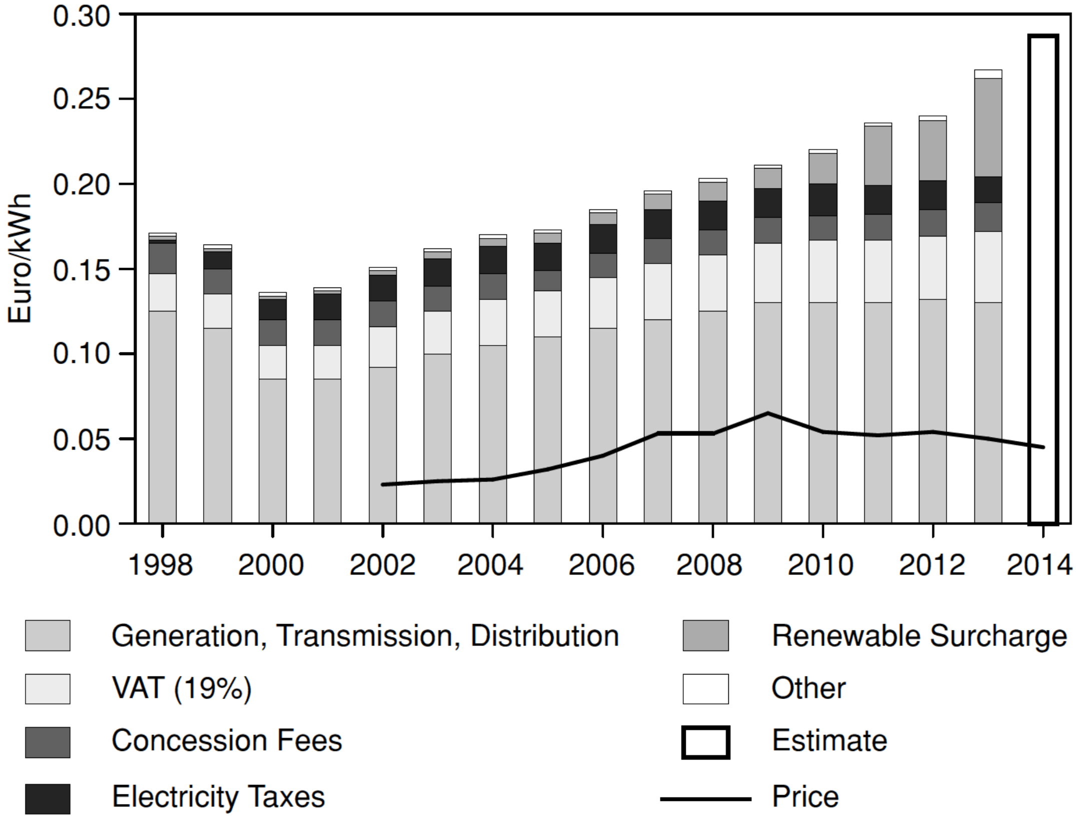
[1] OIES 2015

2 The problem in practice: current issues in European markets

There is abundant evidence that there are problems with current electricity markets in Europe[2]. A parallel OIES paper discusses many of these problems, including recession, declining demand, national policy measures and the underlying market design problems that are the focus of this paper. This paper will not repeat that analysis; the discussion in this section is mainly designed to underline why the symptoms indicate a serious underlying condition.

The symptoms include the following:

Figure 1: Declining wholesale market prices across Europe at a time of rising costs



Source: BDEW, Moody's

The chart above (like that below) focuses on Germany, where the trends have been most marked, though wholesale electricity prices have been falling in a number of markets across Europe. There are a number of factors involved, as discussed in OIES 2015, including the recession and subsequent slow growth in economic activity after 2008, but one significant element has been the growth in renewable generation. Very large quantities of solar and wind power have come onto the market over the past ten years. They receive income via Feed-In Tariffs or other government support mechanisms and are not reliant on market prices to cover their costs. But at times when they are generating, system marginal

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[2] eg OIES 2015, CGSP 2014, EC 2015a

costs are depressed because renewable sources have low or zero marginal costs themselves and their presence in the market reduces the need for higher-cost plants to generate, so market prices fall. However, this does not reflect any decline in long-term costs. The new renewable sources are generally higher cost overall than the conventional generation they replace. If they were reliant on market prices to remunerate their costs, most would be losing money. But because these sources are not reliant on the market, the market signals go unheeded; in effect, government policies (which encourage the continuing deployment of such sources) are in conflict with markets and the strains can only increase over time.

The underlying higher costs have to be recovered somehow. In practice, they are simply loaded on to consumer bills, which have been going up, along with costs, at a time when wholesale market prices have been going down, as illustrated in the graphic above. The effect is to produce two 'wedges': first, a gap between market prices and underlying costs and, second, a gap between wholesale market prices and consumer prices. The overall outcome is to prevent markets from giving meaningful signals.

. A consequent deterioration in the financial position of utilities; low 'spark spreads' and the closure of power plants, even relatively new and clean gas plants

One consequence is a deterioration in the financial position of utilities. Conventional plants are facing a 'triple whammy' – because of lower demand following the recession, lower wholesale market prices and the increasing share of renewable sources, their output and margins are declining. Many conventional plants, even efficient, clean new plants, are having to close because they are losing money; in most cases they are not covering their fixed costs, and in many cases they are not even covering operating costs. Yet these plants may well still have value to the system – they provide the flexibility needed to cope with periods of low renewable output and the capacity to ensure security of supply at times of peak demand. As a result, many governments across Europe have taken the view that it is not in the public interest for these plants to close and for new plants of this sort to be unviable. Some have therefore introduced or are exploring forms of capacity mechanism that will provide extra income for such plants, in addition to what they receive from the normal energy (kWh) markets. Others are employing more ad hoc measures to the same end (see Section 7 of OIES 2015).

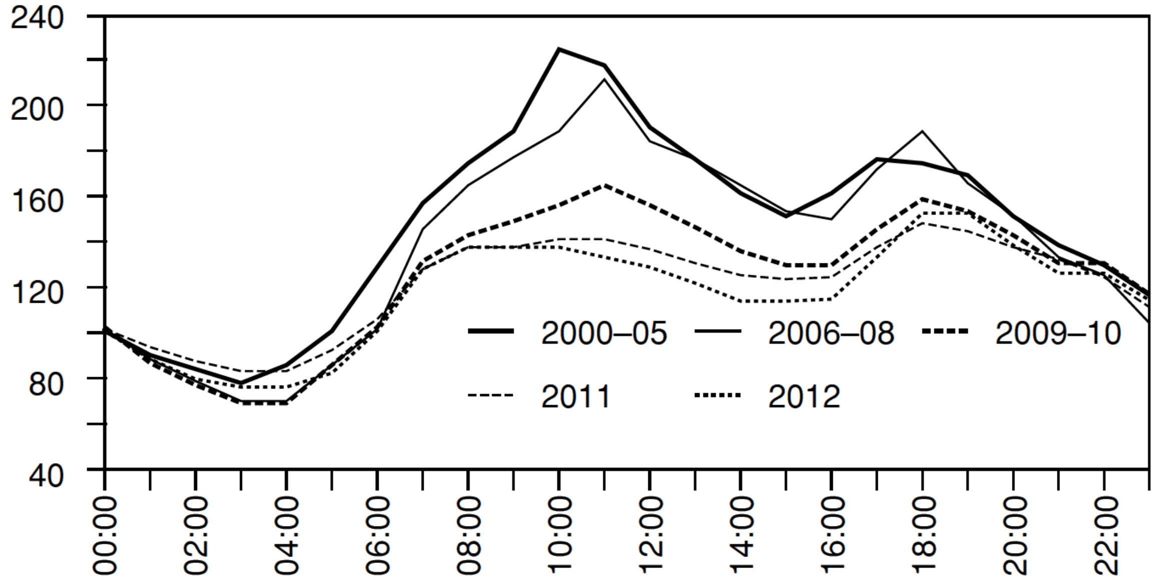
The problem of declining income and profitability has been described by a source cited in *The Economist* magazine as an 'existential threat' for utilities (Economist 2013). It is particularly perverse that at a time when the same utilities are expected to make massive investments (WEO 2014) in capital-intensive and intrinsically risky plants, (OIES 2013) their balance sheets are shrinking and their ability to take on such risks is declining – leading to a need for yet stronger measures of support if the plants are to be built.

This has led to further pressure for incentives such as capacity markets. But there is a risk that this only succeeds in introducing further distortions in order to offset the impact of earlier interventions; as discussed below, such measures arguably address only a small part of the problem.

. a flattening of the intraday price curve

Another result of the increasing penetration of the new renewable sources is a flattening of the intraday price curve – ie a decrease in the differentials between periods of high prices and periods of low prices, as shown in the graphic below. Over the past decade, the differential between the highest price and lowest price hours in Germany has declined from around three to one to less than two to one.

Figure 2: Average Intraday Price Profile in Germany 2000-2012



Source: Bloomberg

This flattening has unwelcome consequences:

- First, because it has been caused by the increasing penetration of wind and (particularly) solar photovoltaics (PV). Generation from these sources is highly correlated – plants in each technology group tend to generate at the same time and (as regards solar) in particular in the middle of the day when the sun is shining. Ironically, it is the increasing volume of sources that are **more expensive** overall (though with low marginal costs) that is resulting in a **reduction** in prices.
- Second, because it also creates uncertainty about the value of **demand response**. Even if wholesale prices were being passed through to consumers, the flattening of the price curve diminishes incentives to develop more flexible demand patterns – something that all commentators agree must be a significant element in the move to a low carbon system. Effective price signals for consumers are at the heart of this development, enabling them to make their own decisions about when and whether to reduce, forgo or defer particular types of demand. Yet markets are giving negative signals – that shifts in demand patterns have little value for the system. Once again, policy and markets are in tension. It may be possible to improve the incentives for demand response via the development of flexibility markets (as discussed in Section 4 of this paper) but this would not deal with the signals from the primary energy market.

Further symptoms of the underlying market failure can be seen in t**he frequent occurrence of zero or negative prices.** While such prices may be needed in practice to balance the system and provide security, they also indicate an underlying market tension. Such prices would normally be a market's way of saying that there was an unwanted excess of supply at particular times, which should lead to closures among the facilities responsible for the excess and discourage future investment. Yet at the same time government policy is supporting those very facilities. There may be ways of giving renewable generators stronger incentives to bid something closer to their real costs (eg by giving them stronger balancing obligations) as discussed in Section 4, and some European markets have taken measures to avoid zero or negative prices, but it is not easy to establish what is regarded as a level playing field by both renewable and non-renewable producers. Stricter balancing obligations for renewable producers may simply prove a disincentive to new investment or lead to greater uncertainty.

As elsewhere, the problems start with the policy need for low carbon investment – much, and in some systems most, new investment is financed by prices that are directly or indirectly set by governments in order to promote policy goals. With this 'second best' starting point it is very difficult to design 'first best' markets to deal with the consequential effects on operation – the repercussions extend beyond the investment stage to the functioning of electricity markets in general. This paper argues that electricity market prices have ceased (or are ceasing) to perform their main functions[3] of providing incentives for **efficient operation and investment, remunerating energy resource providers and providing effective price signals for consumers – and** the situation can only get worse as the penetration of more policy-supported sources increases. In other words, markets are broken.

[3] For a fuller discussion see OIES 2013a and OIES 2013b.

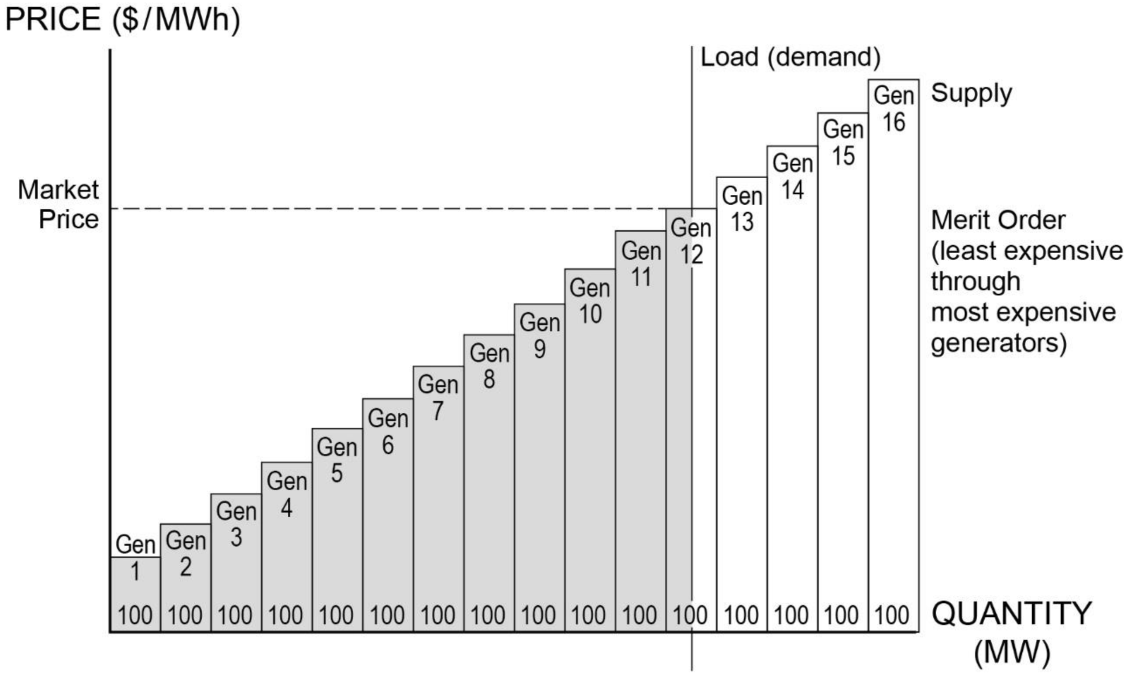
3 The problems of principle

The previous section looked at the problems that have arisen in practice within European markets. This section considers whether these problems are the product of temporary factors like the post-2008 recession and the fact that renewable sources are currently uncompetitive – but may not be so in the relatively near future, because of a combination of a fall in renewables costs, a possible rise in the price of fossil fuels, and the impact of carbon taxes. If the problems are merely a result of such temporary factors, no fundamental reform in market structures may be needed. But if the problems are inherent in the underlying change in generating technologies, they will need to be addressed. A further complication is that we do not at present have a clear model of the ultimate 'steady state' of technology – if indeed there ever is such an outcome – because it may well depend on technological options currently being developed. For instance, battery technology may advance sufficiently to make consumer storage (rather than more centralised options such as pumped storage or back-up generation) a major component of system balancing. In many ways the main task at present is to identify pricing structures that provide the right incentives for all concerned to explore the technologies and behaviours that will lead to an efficient low carbon system.

The starting point for this discussion is that **electricity markets do not have any single natural form;** they are not simply transparent windows for trading; in particular, they are not technologically neutral, but designed around the costs and operating characteristics of particular technical options. We are used to thinking of electricity pricing in terms of the price of a kWh (or MWh), whether from a consumer or producer perspective. But there are alternative ways of pricing electricity – for instance maximum demand (kW or MW) is an important element in tariffs for many industrial users. In the early stages of the development of the electricity industry, producers often charged more in terms of the service provided – eg by the number of light bulbs in a premises. It is not in principle inevitable that electricity producers should price in kWh, any more than that, say, internet access providers should charge in terms of gigabytes consumed, or that mobile telephone service providers should always price in minutes used, rather than via subscriptions for various alternative levels of service. Pricing structures should be based on user preferences and the efficiency and incentive impacts. (In principle, this is true whether we are talking about a regulated system or a market system, though in practice user preferences are likely to have a higher priority in market systems).

Market structures as they exist were designed to reflect **the technology 20th century systems used** – mainly fossil generation and hydro with some nuclear baseload – and the monopoly structure of most 20th century utilities. Consumer preferences were given low priority; instead the debate was about how most efficiently to reflect the industry's costs in prices. The conventional plants that dominated 20th century systems fell naturally into a merit order approach, with low marginal cost and inflexible plants like nuclear at the bottom, high marginal cost flexible plants like OCGTs at the top, and the workhorse coal plants in the middle. The basic model is shown in the following simplified chart:

Figure 3: Stylised Merit Order



Source: Hunt 2002, p 134

The chart shows a series of generators with increasing marginal costs arranged in a 'merit order' from least to most expensive. At any given level of demand the cheapest possible mix of plants is called on; this is achieved by dispatching plants according to marginal cost with the highest cost plant setting the system marginal price; this creates price signals which can, where practical, be passed through to consumers so that they are aware of the costs they are imposing on the system at the margin. However, prices set on this basis do not necessarily cover total costs, including capital costs, so traditional (pre-liberalisation) electricity cost recovery systems tended to include elements designed for this purpose. For example, before privatisation, the UK used a 'Bulk Supply Tariff' (BST) that had two elements, one for kWh based on a merit order along the lines described above to ensure efficient dispatch, and a separate element for capital recovery. Prices were not designed to ensure efficient investment as such. Instead, investment programmes were determined by the Central Electricity Generating Board in consultation with the government, in principle on the basis of minimising long-term marginal cost. The capital recovery element in the BST was designed to cover the actual outturn costs, which could of course turn out to be very different from the forecasts.

A broadly comparable approach was adopted for a while after liberalisation; the UK Pool inherited a generating fleet basically established in the 1960s and 1970s and operated on much the same lines. It included a similar two-part pricing structure, with a kWh element based on the system marginal price, along with a 'capacity' element based on market tightness – as demand approached available capacity, generators received payments, which increased in size the narrower the gap between supply and demand. Because kWh payments were based on the system marginal price (rather than actual bids), all generators in operation at any particular time received the same price. Inflexible plants like nuclear could therefore benefit from a price set by (higher marginal cost) fossil plants by bidding in at a very low, or zero, price. As long as those fossil plants were at the margin, the inflexible plants could thereby ensure that they were called on to generate, and receive the higher fossil fuel related price.

The main change since then – to the New Electricity Trading Arrangements (NETA – which have now developed into a wider system called BETTA) – has been to change the technology bias of the system and make it more attractive for flexible plants (and correspondingly less so for inflexible ones). BETTA dispenses with the capacity element of prices – it relies instead on bilateral agreements and self-balancing (ie all suppliers should maintain so far as possible a balance between their supply and their customers' demand. Insofar as they are unable to do so, they are exposed to the balancing market, which involves greater risk). This approach, and its adequacy for a low carbon system, is discussed further below.

In relation to the main model – of kWh pricing based on a merit order approach – many of today's electricity markets have dropped the capital recovery element of the tariff and have relied solely on the kWh price. The approach **promotes operational efficiency** by ensuring that the lowest marginal cost plants at any particular time are those called on to generate. However, there have always been questions as to whether a (short-run) marginal cost approach is adequate to recover capital costs or to incentivise the right sort of investment. In the example above, for instance, Generator 12 would be receiving only enough income to cover its marginal costs, while Generators 13 to 16 would be receiving no income at all at the level of load indicated. This does not mean that Generators 13 to 16 are unnecessary. They may well be called on to generate at times of higher demand or in case of an unexpected event like a plant breakdown. However, the shorter and less frequent such periods are, the greater the revenue needed in each of these periods if they are to recover their capital costs over the plant's lifetime, for much of which they will not be receiving any income. In other words, the price at such times needs to be considerably above their short run marginal cost of generation for them to cover their total costs.

Similarly, in the above example, Generators 1 to 11 would be making some contribution towards recovery of capital cost but it might or might not be enough to ensure full cost recovery, especially taking account of the fact that in practice plant costs would not be on the gradually ascending slope shown above. Plant costs tend to be clustered – ie most coal plants, say, have broadly similar costs so at periods when a coal plant is setting the marginal price it is unlikely that coal plants as a group would be making much contribution towards capital cost.

The system as a whole relies either on:

- very high prices during periods when supply is tight (ie prices well above the marginal cost of generation for most or all generators). Relying on these short and unpredictable periods of high prices would be inherently risky in any market, but is particularly problematic in a politically sensitive market such as electricity. High prices may prove unacceptable to governments or regulators. In practice, it is virtually impossible to distinguish between the sort of high prices resulting from the effective operation of markets and the high prices resulting from abuse of a monopoly position. As indicated in the chart, when demand is such that the top of the merit order is reached, there is almost by definition no effective competition, as all other generators are already generating anyway. So investors in generating plants must take into account the risk of government intervention or a competition investigation. Indeed, this is not just a possibility but has been almost a permanent state of affairs in liberalised electricity markets. At the time of writing, yet another investigation into the UK electricity industry is under way. This leads to a risk that there will be 'missing money' in wholesale markets, ie insufficient revenue to remunerate capital investments;
- the existence of dispatchable plants that don't need to cover their capital costs (which is what has in practice mitigated the problem). Such plants are typically old generating plants that have already covered their capital investment. They can afford to continue generating so long as there is enough income to cover their marginal costs and fixed annual costs of maintenance and the like. The trouble with this sort of capacity is that, almost by definition, it is mainly old, inefficient, and dirty (eg old coal plants) and essentially unplanned. In any event, these sorts of plants are

being forced off the system by environmental measures such as the Large Combustion Plants and Industrial Emissions Directives[4], and there is no clear incentive to replace them. This is especially so if new plants of a broadly similar character might be facing an environmental risk of enforced early closure, in addition to the risk of not covering capital cost in normal operation.

A further problem with this sort of pricing structure is that it is based on the costs of production technologies. It does not give any direct incentive to discover consumer preferences, which can be expensive and difficult to ascertain, given that there are barriers to doing so, as discussed below; similarly, there are a number of costs involved in reflecting wholesale price structures in consumer prices (and in practice there has not been any great effort to do so). Since electricity cannot economically be stored, the result of a marginal cost based system is that wholesale prices vary according to the overall level of demand, which in the past has been mainly a function of time of day and season of the year. In principle, it would be logical to reflect this variation in costs in consumer prices, which changed according to the time of day or reflected a consumer's maximum demand (in kW). In practice, however, this approach has generally been applied to larger customers only. The transaction costs of more sophisticated (time of day or maximum demand) pricing have generally been held to outweigh the advantages (ie it would have been too expensive to install the necessary metering) for smaller residential consumers. There is, in any event, a fairly high correlation between maximum demand and overall energy use among residential consumers, so the distortions arising from a failure to measure maximum demand have been regarded as manageable.

But in the 21st century all this has changed: the advantages of marginal cost pricing in promoting operational efficiency are much less relevant, while the problem of 'missing money', the disincentives to investment in peaking plant and the need to promote responsiveness on the demand side are much greater.

The underlying problem is that the new supply technologies do not fit well into a system designed to discriminate, by price, between sources with different marginal costs and different degrees of flexibility. Continuing on this basis leads to major inefficiencies, not just as a matter of particular circumstances (as discussed in the previous section) but as a matter of fundamental market design.

The problems with existing market structures are pervasive; they arise in six areas:

1) **No useful signals for operation.** Some renewable sources are dispatchable (eg most hydro plants; biomass etc) – that is they can be called on to generate on demand. However, most of the so-called new renewables, like wind and photovoltaics are not. When there are a large number of such plants and they have identical and zero marginal costs, discrimination on the basis of marginal price has little relevance to efficiency. For instance, if on the chart above most generators had identical marginal cost (ie most of the vertical bars were at the same level), there would be no single point of intersection with demand. Although, there might still be some distinction between the generators that could form the basis of useful price signals, such as geographical variation or the potential to provide flexibility and balancing services; it would not arise from their marginal costs as such though. Meanwhile the growing inflexibility of new supply side technologies means that the concept that individual plants can be dispatched by price is unrealistic, so the model shown in the chart does not work as a mechanism for dispatch. In practice, as noted above, the new plants receive priority dispatch, so are automatically dispatched whenever they are available (except where special payments are made to constrain them, or prices are so negative that they would lose money if they continued to generate).

[4] Directives 2001/80/EC and 2010/75/EU

2) **Price distortions.** Low-carbon plants with FiT or other support distort market signals when they are incorporated into the same market as plants that do not receive such support. This creates what are called '**pecuniary externalities'** (ie the FiT supported plants reduce the price being received by other plants). In a normal market, this would not constitute a distortion; rather it would reflect the process of competition by which low cost suppliers entering the market tend to pull down the price for all producers. But in a normal market the new entrant has to live (or otherwise) by market prices. In European markets today, FiT supported plants do not depend (or do not depend wholly) on the revenue they receive from markets, because they have their FiT payments independently of (or in some cases additionally to) the market revenue. If markets were performing their normal functions, the decrease in market prices from the introduction of the new sources would be a signal for closures or disinvestment (and in practice the plants would not have been built in the first place because they could not rely on getting remunerated by the market), leading to price increases back to the level where all generators would have their costs covered. So in a normal market, these plants would not exist in the quantities governments are aiming at; but since they do exist, their presence in the market along with other suppliers distorts the market for all suppliers (including the FiT supported plants themselves[5]).

3) **No exit strategy.** This also means that there is no possibility of a long term self-sustaining low carbon market based on the mixture of sources envisaged by governments. As long as governments are pushing the new inflexible plants onto a market that is designed to encourage flexible technologies, the new sources will not get a market return. That is, unless there is a fully diversified mix of such sources, which effectively mimics the conventional cost structure by having a significant element of dispatchable sources with positive marginal costs such as biomass. But it is not clear that this would be the optimum generating mix for a low carbon system. As long as investment continues to be dominated by intermittent sources and these tend to generate in a correlated fashion, they will have the effect of depressing prices. During the very high price periods when generators are covering their capital costs, it is likely that no, or very few, intermittent generators will be operating (since it is their absence that is the cause of the high prices). This means that wind generators will not be able to rely on energy markets alone to cover their capital costs.

It should be noted that this will be the case:

- **even if** the wind power is competitive in the sense of producing power at a levelised cost below that of conventional power, because the intermittent generator will receive a below average price, for the reasons explained above; and
- **even if** there is a high carbon price, since the effect of the carbon price is to push high carbon generators to peak price periods only; the price of energy will therefore be most affected in situations when there is least generation from wind and other intermittent renewables.

So even if the cost of wind or other renewable sources attains 'grid parity', and even if there is a significant carbon price, the energy market will not provide a secure basis for remunerating investment in intermittent renewables, if they are to be built in the quantities that governments want. They will continue, as at present, to need some other route to covering their capital costs, such as the FiTs being introduced by the UK government. When power generated from these sources feeds into energy only markets it will therefore produce the outcomes referred to – low prices, bearing no clear relationship to costs and providing few useful signals for the wind generators themselves. There is no obvious way out of this problem and no roadmap to a self-sustaining low-carbon market either in the Commission's Target Model6 or in the UK Electricity Market Reforms[7]. Even if the systems of support for renewables

[5] See the discussion of "pecuniary externalities" in the study OECD/NEA 2012 p 34-37.
[6] See OIES 2013b
[7] See OIES 2011

are changed in the direction of 'premia' (ie additions to the market price) rather than fixed price support via FiTs, the same underlying problem remains – as long as some (low carbon) producers receive this support, but not others, the subsidised producers will be facing different investment incentives but, by selling into the same market, will distort overall market prices.

4) **No effective signals for investment.** The consequence of the above is that **neither** for fossil plant, **nor** for intermittent renewables generators, do energy only markets provide effective signals for investment in a decarbonised system. (There are comparable problems in relation to nuclear and carbon capture and storage but for reasons of space, these are not analysed here. Hydro is probably the least affected source, but the scope for expansion in most of Europe is limited for environmental reasons). In other words, this is not just a problem that affects fossil plants, as is commonly supposed.

5) **No overall system optimisation.** It is also the case that there is nothing in the support systems which ensures the right mix of plants. FiTs and other systems of support are determined on an essentially administrative basis. They provide effective (non-market) signals for investment in the sense that they can get quantities of capacity built but they are not in general designed to secure the most efficient long-term mix of plants and demand-side resources to ensure a minimum cost system. In most cases, they do not even guarantee any particular capacity, location, or balance of types of plants. Instead, the outcome is a more or less accidental function of various contingent factors including technological progress in cost reduction for renewable technologies, the availability of suitable sites, and the accuracy with which those setting the level of FiTs have forecast these factors. It is intrinsically difficult to set prices in such a way as to guarantee a particular outcome, because of the uncertainties about future trends[8], as recent experience across Europe has showed. FiTs in many countries have been adjusted at short notice because they were leading to more (or on occasion less) investment than expected. The result is that the process is essentially haphazard – it is driven by the need to incentivise more low-carbon generation rather than any clear idea of how to optimise a low-carbon system. Meanwhile, capacity mechanisms are designed essentially to ensure that there is enough reliable plant capacity to balance the system (and usually at national, rather than European, level) after taking account of the development of plants incentivised by the FiTs and other support mechanisms.

6) **No useful signals for the demand side.** Flexibility on the demand side is growing (OIES 2013a), but not only is it not factored into the system, it is positively discouraged for the reasons discussed above: first, by the fact that market prices are in many cases not passed through to consumers; second, because market prices are in any event distorted so that even if they were passed through they would not give meaningful signals; third, by the fact that the extra costs of policy interventions, such as support for renewables and capacity payments, are in practice recovered by a premium on consumer prices. This generally has the effect of increasing prices at all times, giving distorted signals about the market price of power. Moreover, it is regressive in terms of income distribution and gives few signals about the value of shifting consumption from one time to another[9]; and fourth, by uncertainty. The volatility and uncertainty of wholesale prices have been recognised as inhibiting investment on the supply side, and are part of the justification for capacity mechanisms. The same disincentive exists on the demand side, but governments have not so far drawn the conclusion that new mechanisms are needed to promote demand side investment. It seems perverse to insist on the continuation of supply-side mechanisms (kWh hour pricing) that are designed to reward flexibility at a time when, as a result of government policy, that flexibility is decreasing, but not to reward the demand side flexibility at a time when it is increasing.

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[8] See OIES 2013c

[9] It might be possible to mitigate these problems, and in particular to produce a fairer result in distributional terms by shifting the burden of renewables support from the electricity consumer to the taxpayer.

The need for new market models

In short, there are at least six major problem areas with current markets; it is not just an issue of providing appropriate incentives, via capacity mechanisms, for the construction of the flexible plants needed to balance the system in future. Rather, it is the fundamental design of electricity markets that is the problem.

Neither of the existing approaches to market design seems to offer a robust basis for the way forward.

In very broad terms, there are two models for electricity markets today:

- **Decentralised markets** along the lines of BETTA in the UK. The aim here is to provide market participants with the maximum possible choice over the ways in which they trade energy. Given the special characteristics of electricity[10], there is inevitably a residual role for a system operator in overall balancing. However, in these markets primary responsibility for balancing rests with the market participants themselves, using their own resources, various *ex ante* markets and, ultimately, the central balancing arrangements. Market participants self-dispatch; thus the incentives for efficient operation and investment fall primarily on individual players, which may lead to stronger market signals and disciplines. Participants are likely to value generation flexibility (and often vertical integration) as ways of managing balancing risk. These markets also tend to be less transparent.
- For these reasons, they may be less easy for inflexible plants to access and a less secure basis for investment in such plants. They are particularly poorly set up for the new plants – high capital cost, high risk and inflexible. The high cost of Electricity Market Reform in the UK is at least partly due to the difficulty of incentivising new plants of this type in such a market. Inflexible intermittent plants have particular difficulty in accessing the market because they cannot easily find sources of demand to balance their output; they therefore tend to prefer to sell to larger suppliers or other intermediaries who can keep in balance by trading or by aggregating numbers of generating plants on the one hand and consumers on the other. But it may still be difficult for the intermittent plants, particularly smaller producers, to get an acceptable price through this route; their negotiating position is likely to be weak, up against a larger aggregator.
- Centralised markets in the form of **Pools**. These markets are normally based around central dispatch by the operator, on the basis of bids by participants, similar to the model set out above. Various forms of Pool are possible (eg pay-as-bid, under which participants are paid according to their bid, provided the bid was low enough to ensure they are dispatched or SMP. Under this model, all bidders are paid the system marginal price as determined by price-based dispatch as shown in the chart). Depending on the precise form of the Pool, these markets are often easier for inflexible plants to access, since generators selling into a Pool do not normally face balancing risk and Pools usually provide a liquid market, reducing offtake risk for investors. However, this only really works so long as zero marginal cost plants are in the minority. In principle, as discussed above, such plants would normally bid in at zero or close to zero in order to ensure they are dispatched. When they receive income via a Feed-In Tariff, their bids can even be negative – as long as the price is not such that it wipes out their FiT income, it will still be worth their while to generate, given their very low marginal costs. So when low marginal cost inflexible plants are a significant element of a Pool type system, prices will often be zero or negative. Even when such plants do not set the SMP, their presence in the market will usually pull down the SMP to a level at which hardly any of the plants on the system are earning a contribution towards their capital costs.

[10] For a discussion see OIES 2013a.

In addition to these options for the main markets, there are various possibilities for ancillary markets and, in particular, for capacity or reliability payments. They are not discussed in detail here, though potential developments in these areas are discussed below. In any event, the main point arising from the discussion above is that existing market models are unsuitable, in their basic design, for the new generation of plants and that fundamental reform is needed. The following section discusses possible options for reform.

4 Some suggested solutions

There are many possible starting points for considering potential reform options. One would be to seek to minimise any changes and challenge the case for major market structure reforms on the basis that existing markets have worked well. This view would stress the strong theoretical and practical reasons for basing price signals on short-run marginal costs – that it should lead to operational and (though perhaps less certainly) in investment efficiency. While there are short-term distortions arising from the support for low carbon sources, it is arguable that this should be a temporary state of affairs – over time, as carbon prices increase and renewable costs fall, that support could in principle be reduced. If this process does not result in the volume of renewables politicians want, it may simply be an indication that their approach is sub-optimal and inefficient. Instead of technology-based requirements, other, more efficient, means to meeting carbon targets would be needed (like a more comprehensive approach to carbon pricing or the use of carbon intensity targets – see OIES 2013). Furthermore, on this view, the European Target Model is only just bedding in; any fundamental changes would lead to great uncertainty and could well inhibit new investment for years. From this perspective, changes to markets should therefore be kept to an absolute minimum.

An alternative stance would be to accept that Europe's goal of decarbonising electricity is firmly entrenched. Given the EU's 2030 and 2050 targets, there is no reason to expect any change in the overall goal of creating a sustainable low-carbon electricity sector. The EU will therefore either have to accept the continuing need for intervention or to develop a sustainable market structure, one that can operate as freely as possible, minimise distortions, prove robust against future changes in supply and demand, and, in particular, accommodate a large share of inflexible renewable sources. For the reasons given above, present market arrangements do not on this view provide that robust and sustainable framework, so it is vital to start developing a more effective alternative.

However, the challenge is new and no clear consensus has emerged on alternative market structures or on whether different arrangements might be needed during the interim to foster the transition to a low carbon market and enable the long-term operation of the low-carbon electricity system. Many factors may need to be taken into consideration, and the choice between the options may depend as much as on the relative weight given to particular factors as on any theoretical arguments. For instance, policy makers may be prepared to see an increase in central control and direction in order to ensure that government objectives are met. This has been the case in current decarbonisation policies, like EMR in the UK, under which centrally determined instruments like FiTs and capacity payments have driven new investment in the system. On the other hand, their key priority might be to ensure that there is an 'exit strategy' – ie the possibility of returning to freely operating markets as soon as possible once the necessary investment in low carbon sources has taken place. Overall, there may be no single clear choice to be made; rather a range of options presenting different characteristics, and deciding between them may depend on policy priorities rather than on any absolute theoretical advantage.

Furthermore, as mentioned above, the destination is not clear – it will depend on a number of factors, including the following:

- **Consumer preferences**. At present, there is little information about how consumers would respond if they were asked to choose levels of reliability.
- **Technology development**, especially with regard to storage. Storage technology is developing fast but at present it is not clear how economic it will be (which would help determine how large role it can play) and what will be the most economic form of storage. As noted above, if battery technology advances far enough to make significant volumes of consumer storage viable, many decisions about system operation can effectively be decentralised. On the other hand, if large economies of scale remain, storage may need to be provided and operated centrally.

- **Wider policy context.** Much will depend on decisions governments make about the route to decarbonisation. Many of the options are based on the development of networks and are likely to be 'path-dependent'. For instance, if governments were to decide that the best route for low carbon transport was the use of hydrogen vehicles and encouraged the development of infrastructure for the transportation and storage of hydrogen, that might also open up new storage options; if they decide to encourage electric heating for homes, ways of storing heat within the home, whether via better insulation or by the use of heat storage technologies, could play an important role in meeting peak demand.

From this point of view, a flexible approach, aimed mainly at giving appropriate incentives for consumers and technology developers, would have advantages.

Against this background, at least seven possible responses to the market problems discussed above can be identified as worthy of further consideration. Some are relatively familiar and are not discussed here in great detail; others are more novel and are described at a little more length, but this is not intended to imply that they are therefore necessarily better. The aim is rather to present a range of possible options in the hope that this will help stimulate consideration both of the alternatives themselves and of the relevant priorities.

4.1 Drop support for particular low carbon sources

The most straightforward is simply to **stop supporting** the main renewable sources on the grounds that they are now largely self-sustaining, and focus support on emerging technologies. But, for the reasons given above, this is likely to mean that there are insufficient incentives for new investment in most renewables. Even if some renewables have attained 'grid parity' they will still not be able to remunerate themselves from the market and the existence of pecuniary externalities will act as a disincentive to investment, keeping the proportion of new renewables down below a level where they significantly affect market prices.

The clear implication of this approach is that Europe would likely miss its carbon and renewable targets. Even if the EU's relatively unambitious targets for 2030[11] are accepted, they imply a share of renewables of 50% in European electricity; the UK will be aiming for an even bigger share in the longer term if the Climate Change Committee's strategy of decarbonising electricity continues to be followed and many other European countries (like Germany) also have very ambitious targets. Furthermore, the costs of many low-carbon sources (like solar photovoltaics) are coming down rapidly, while the cost of fossil sources may well go up, either because of a rise in world prices or because the carbon externality will be priced in via a carbon price. In that case, the retention of the present market structure would not necessarily serve to produce an optimum low-carbon system, at minimum overall cost, for instance because this approach might not be sufficient to bring demand side resources more fully into play. Instead, the structure of the market would tend to drive the choice of plants, favouring flexible generation options and giving consumers little opportunity to demonstrate and act on their preferences. The risk is that this could lead to a system which is sub-optimal both in cost and in environmental terms. This option may not therefore be enough to resolve the fundamental long-term problems identified in this paper, on its own.

It could of course be improved by adding further elements: one would be to strengthen the market for demand-side resources – but there is evidence that the barriers to demand response are considerable and that it is unlikely to be developed without further incentives (see below). Another would be to replace existing methods of support for low-carbon sources by a shift towards the use of economic instruments; this could in principle resolve the underlying problem of mixing government supported sources and unsupported generation in a single market. A sufficiently high carbon tax, cap-and-trade

[11] OIES 2014

limits or carbon intensity targets could in theory provide a framework for the electricity market, within which prices would give appropriate signals for investment and operation. This is in a sense the 'first-best' solution in economic terms. However, in practice, such economic instruments have played only a minor role in decarbonisation efforts – this suggests that their theoretical advantages are not sufficient to make such economic instruments attractive to policy makers. There are serious questions (beyond the scope of this paper) about whether these instruments would work in practice, because of doubts about political acceptability, long term sustainability, and credibility.[12]

4.2 Central planning and control of the system

A second extreme option is effectively to abandon the experiment in liberalisation and revert to more centralised approaches. This need not rule out the retention of some market elements – eg auctions for new capacity – but it would put decisions on operation and investment in the hands of a central authority, rather than markets. The rationale would be that governments are already to a very significant extent driving investment decisions. As pointed out above, this then creates tensions with market operations as the government-sponsored plants lead to distortions and inefficiencies in markets. One way of avoiding such distortions would be to downplay the role of markets – the government itself, or a central planning authority, would take responsibility for planning and operating the system in a manner designed to meet environmental objectives at minimum cost. Various ways of implementing such an approach would be possible[13]: one would be for a central authority to have the responsibility for delivering these objectives via a programme of investment, planning, and coordination aimed at optimising the system as a whole. This would overcome some of the investment inefficiencies noted above – the authority could determine the quantity of particular types of plants needed for an optimised system (and could use competitive mechanisms such as auctions to minimise investment costs); it could also plan the system as a whole, for instance developing demand side responsiveness in tandem with the introduction of inflexible supply capacity to minimise overall system balancing costs.

Other versions of this approach are considered under the 'Investment Markets' heading below.

A centralised approach should lead to more effective coordination; it could in principle lead to significantly lower transaction costs by allowing the savings delivered by demand response for generation, transmission, and distribution to be aggregated straightforwardly across the whole system. It could also allow easy aggregation across geographical regions (with competitive markets, when different customers have different suppliers, aggregating the savings from all customers within a particular region can present complications). Finally, it would encourage a longer term perspective. If the central authority were tasked with, say, providing a near zero (say 50g/kWh) system by 2030, it could more easily take longer-term measures leading to this goal without having to worry about retaining customers in the interim.

But the problems with this approach are obvious. Even with the retention of some competitive elements, it would mean a huge reduction in the incentives to efficiency given by markets. It would create a monolithic structure that could inhibit experimentation, innovation, and flexibility. It would inevitably increase political pressure on the central authority, which would be in a position if necessary to pass on to consumers the costs of sub-optimal but politically attractive policy making. It would arguably increase risk by relying heavily on the decisions of a single decision-maker – the risks would effectively be passed on to consumers (or taxpayers) and in the end this might prove to be an expensive approach.

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[12] Buchan and Keay 2015, Chapter 8
[13] OIES 2013a

It is a matter of political judgement how to balance the potential risks and benefits and this paper will not attempt to do so; its aim is to consider how markets could be adapted for the new situation rather than how a centrally managed system could work.

4.3 Refine energy only markets

A less radical approach is to seek to adapt existing market structures by improving balancing markets**,** introducing **capacity mechanisms, improving balancing markets** and generally developing markets in evolutionary ways to cope with the new situation.

There are two problems with this sort of approach. The first is that they arguably address only a few elements of the problem – they are, at least on one view, essentially software patches on a fundamentally flawed operating system. Capacity payments, for instance, do not resolve the six issues listed above; instead they focus on a single, essentially subsidiary, issue – how to maintain security in a system dominated by intermittent plant – and a single solution – providing incentives for plants which will have to operate flexibly but for relatively few hours. (The arguments are explored more fully in the Annex to this paper on why 'Capacity payments are not the answer'). The second is that the more significant and complex the ancillary markets are, the more they tend to mean that main electricity (energy) market is providing only partial signals about the overall cost of supply and the less feasible it is for these energy only electricity markets to provide a level playing field, unless the ancillary (capacity and balancing) markets are also harmonised – and meaningful signals from these markets are passed through to consumers. This could be difficult to achieve; it would lead to complex and volatile price signals, which would still be driven by the underlying distortions in the market structure.

4.4 Introduce more flat rate or demand-related elements into pricing

The logic of this approach is that the future costs of the industry will be largely capital, and recovering these costs should primarily be through fixed, flatrate or demand-related (kW pricing) elements, rather than kWh pricing. This could be implemented in various ways at different stages of the system. For instance, at the supply end, the idea might be to replace revenue support for renewable sources (via FiTs) with capital support at the time of investment. That investment could be subsidised in various ways, for instance by auctions to determine the minimum level of upfront subsidy required to incentivise the quantities of low carbon plants the government was aiming at. If appropriate, the government could hold separate auctions for different sorts of capacity. But the main concept is that support should only be given at the investment stage; once built, plants should operate in the market without any special support.

On the consumer side, flat-rate elements would also become a more important (or predominant) component of prices. Indeed, some economists would argue that a two-part tariff, under which utilities charge an access fee to cover fixed costs and a separate marginal price to cover incremental production costs, is in any event the optimal pricing structure (eg Coase 1947). Some countries have already made significant moves in this direction. In Spain, for instance, as well as a move toward hourly pricing (covering about one third of the average bill) there have also been increases in the flat-rate elements in consumer bills via 'access charges' that cover fixed network costs and public policy costs. In some countries, like the UK, flat-rate elements have taken the form of simple fixed standing charges, which do not vary with consumption. But to improve the incentive's effectiveness it would be preferable for this element to be based on maximum contracted demand as happens in Spain – a consumer could subscribe for, say, 3, 5 or 7 kW of supply and pay a penalty (or have supply interrupted) if their demand exceeded that level. This would give incentives for a form of demand response, or at least for spreading demand across the day and keeping down peak demand.

This sort of approach could also help with another problem – in many countries the growth of distributed generation in such forms as solar PV installations on domestic premises has led to an increasing share of domestic electricity consumption being met by on-site (and usually subsidised) sources. The corollary is that utilities are selling less electricity to those consumers, and so enjoying less income. However, because of the intermittency of the solar generation, these consumers may still be drawing on the network to the same maximum extent at peak times, so the utility's costs in relation to those consumers are therefore likely to have gone down less than their income. In other words, the general correlation between domestic consumers' use of electricity and their maximum demand, which has underlain tariff design in the past, is increasingly breaking down. One solution to this problem is to increase the fixed element in electricity tariffs, which effectively forms an 'access fee', and to reduce the pure throughput element on the lines of the Spanish reforms.[14]

So there is considerable logic in the move towards increasing the flat-rate element in tariffs. But there are also some strong arguments against:

- **Social impacts.** The distributional consequences of a shift to flat-rate pricing at the retail level could be significant. Fuel poverty in the United Kingdom declined in the years after electricity liberalisation because of increased price competition, economic growth and low world energy prices. But in recent years, the impact of the global recession, higher world prices (at least until recently) and the costs of decarbonisation have conspired to push up electricity prices while at the same time reducing the ability of low-income consumers to absorb the increases. Flat-rate elements in pricing would likely be seen as regressive – a sort of electricity poll tax – and to exacerbate the problems of vulnerable customers. Unit pricing, despite the drawbacks, does give consumers some ability to reduce their bills by changing their behaviour. Flat-rate pricing removes or reduces this element of control.
- **Incentive effects.** This is just part of the wider problem of incentive effects. Fixed pricing elements reduce incentives to efficiency – for instance, if fixed payments are made to generators so that their capital costs are largely paid upfront, they will have less incentive to maximise generation, to forecast output accurately, or to match generation so far as possible to demand (eg by arranging maintenance schedules appropriately). Instead, their incentives (depending on how exactly the subsidies are paid) will be to reduce capital cost so far as possible; while this may introduce helpful disciplines at the individual plant level, it is unlikely to lead to optimisation across the system (for instance, it may well encourage investors to build plants where the capital costs are lowest, rather than at sites where output will be maximised).
- **Market distortions.** Nor does the approach deal with the market distortions discussed above. At least as long as subsidies continue to be given, low-carbon plants will still effectively be dumping their output on the market – ie selling it at a price at which the plant would be unable to remunerate itself, but for the subsidy – and thus reducing market prices for all producers to below the overall cost of generation.

4.5 Transactive pricing

This approach, more formally described as 'interoperable transactive' tariffs involves a much more radical move towards fully decentralised markets. The concept aims at taking forward the logic of liberalisation to its full extent by offering unbundled markets for both energy and transmission/distribution.

[14] See for instance Nelson, McNeill and Simshauser in Sioshansi 2014

While ‘transactive pricing’ in its most developed state is not really a feature of today’s electricity markets, there are moves in some US states to integrate wholesale and retail markets (eg in New York State) or (as in the UK for so-called ‘energy-only’ customers) to separate out energy from transmission costs for some larger industrial consumers. In general, because of metering and transaction costs and the overall complexity, this sort of approach has not in the past been applied to residential consumers but it would be possible to do so in a relatively customer-friendly way. There is a rough analogy in today’s markets for mobile telephone services – consumers are used to the idea that they may pay a subscription for access to a system, along with charges for particular transactions, or for transactions above a subscription threshold. This is the model which could emerge in practice from this approach.

In principle, it is simple. Electricity and transmission would be traded between producers, consumers and ‘prosumers’ (ie those who both produced and consumed energy, such as houses with solar PV panels) in forward and spot markets. Producers and consumers of these services would trade with each other for such forward periods as they wished – from seconds to years. Consumers might well be on both sides of such trades in future – eg ‘prosumers’, with solar pV may well want to sell electricity at some times and buy it at other times. On the other side of the negotiation would be central generation owners, storage owners, other distributed generation owners etc. There would be two primary products – electricity and transport of electricity – which could be bought either separately or together (although of course both would need to be purchased, in the right quantities, to ensure supply at any particular time). The result would be a flexible and decentralised market based ultimately on forward and spot transactions for unbundled energy and transportation services.

In practice of course, most consumers and other participants would not want to be trading continuously in real time. It is likely that a variety of intermediaries and trading platforms would emerge, so that a series of transactions could be packaged together, for instance into subscriptions for a period of time (such as a year) to cover a particular pattern of consumption (eg a customer’s typical profile). Suppliers would then offer prices for such a subscription package and consumers would choose the most attractive offer. Balancing would take place via spot markets; participants could choose whether to expose themselves to that market or pay for balancing services from an intermediary.

A fuller description of the idea is given in Barrager and Cazalet[15], to which the reader wishing to understand the approach in more detail is referred.

One advantage claimed for the approach is that by incorporating forward transactions for both transportation capacity and electricity, and via the use of subscription charges, it can on the one hand enable stable cost recovery, and on the other hand involve consumers in the investment decision, rather than simply passing on large fixed charges arising from central decision-making.

But there are also apparent disadvantages:

- **Complexity on the demand-side.** Because the market is so decentralised it implies regular, informed decision-making by consumers. Even if much of this is automated, it is difficult to see that most customers will be equipped for such participation, either in terms of having the necessary knowledge and understanding of the market, or in terms of having the necessary equipment to enable them to benefit. Prices are likely to be highly volatile – even more so than in the past, when prices followed a more or less predictable pattern, with high prices at periods of high demand like winter evenings. In the new situation prices are as likely to be high at times of low supply – inherently unpredictable in a system based on intermittent

[15] See Sioshansi 2014 and the following URL- http://bakerstreetpublishing.com/2014/07/08/transactive-energy-a-sustainable-business-and-regulatory-model-for-electricity/

renewables. The uncertainties could well inhibit investment in demand-side equipment, except where long term packages are available at attractive prices.

- **Supply-side investment.** The approach raises regulatory and competition issues – long-term contracts, especially those packaging together equipment and electricity supply, tend to have the effect of foreclosing the market. Indeed, if there is a significant enough volume of long-term forward contracts to provide security for investment on the supply side, the remaining scope for competition is likely to be limited; on the other hand, if there is not such a long-term contract base, there may not be a firm basis for investment on the supply side.
- **Regulatory intervention.** In such a situation, the risk of regulatory intervention will remain high. For instance, in the UK regulators have intervened to enable quick switching by consumers and discourage long-term contracts; there has also been enormous political pressure to simplify tariffs. The transactive pricing proposal seems to go in the opposite direction and it is not clear how regulators and governments would react.
- **Market distortions.** Finally, the proposal does not really address the underlying problem of mixing subsidised and unsubsidised sources in the same market; the consequent market distortions would remain in place.

4.6 Investment markets

One solution to the broken markets problem is to hive off the investment problem by creating a separate market for the long term. In some respects, this is similar to the 'centralised market' model in Section 4.2. But most proponents of this solution value the incentive effects of markets and see the model as operating on the basis of competitive arrangements like auctions. They favour the retention of short-term markets on much the same lines as at present, rather than going for fully-fledged central planning.

Many versions of such markets have been put forward. The Commission's 'investment perspectives' paper (EU 2015a), for instance, investigates some evolutionary ideas like more scarcity pricing and an EU wide capacity market. However, it also mentions another, more radical strand, which 'could be further explored' based on an EU-wide market for long-term contracts based on average cost pricing. This would be a major departure for the EU. Hitherto, it has been rather resistant to long-term energy contracts, which, as discussed earlier, tend to foreclose the market and limit competition. Marginal pricing, as in the Target Model, rather than average pricing, has also been regarded as the best way of giving effective signals to consumers about the costs they impose on the system. However, the general idea of long-term contracts for investment, supplemented by short-term markets for energy, has received some support from outside experts [Agora 2013, FTI 2015] and is similar to the model followed by a number of Latin American countries that have a high proportion of (low marginal cost) hydro plants.

EU 2015a contains a generic description of this idea:

'The main feature of this arrangement would be to shift competition from the spot market - competition **in** the market - to a long-term contract market - competition **for** the market. Under this configuration suppliers are required to cover their forecasted demand through contracts with low-carbon generators and flexible solution providers. In exchange, generators receive long-term contracts with conditions and terms allowing them to recover the total costs of their investments. The short-term market in this context acts as a balancing market to settle imbalances arising from contractual differences between generators and suppliers.'

Despite its novelty as a generic approach, in one sense this is not completely radical - contracts already underpin most renewables investment and increasing amounts of conventional plant investment, and there is some competition in awarding them, eg in the capacity and FiT auctions in the UK. The main difference from the present situation would be in accepting these contracts as the basic model and therefore moving the focus away from the short-term market as the main arena for competition. This would mean accepting that the prices in the short-term market do not contain all cost information or provide enough revenue to remunerate suppliers; that market would essentially be about short-term balancing, with most of the costs incurred in electricity supply being recovered via the long-term contract market. Much of the theory underpinning marginal cost pricing would therefore no longer be relevant.

There are various versions of the investment market. For instance, technologies can be allowed to compete on an equal basis or there can be separate low carbon and flexible generation markets (though some central authority still needs to decide on quantities and preferences). Competition can take place via obligations, premia or auctions (but there is still a need for a party capable of signing large long-term contracts). Normally the market (or central buyer obligation) would be underpinned by a reliability standard set centrally, though that may not be absolutely necessary – Chile has a decentralised investment market in which electricity suppliers do the purchasing.

A version of the investment market based on the UK capacity auctions has also been put forward by Dieter Helm (Helm 2015). The idea is to hold a two-stage capacity auction, the first operating without a carbon constraint, the second to follow if necessary and include a carbon constraint. A key feature of the auctions is that bids would need to be based on firm power (ie what is described above as self-balancing).

There are descriptions of various approaches to investment markets in FTI 2015. But they all seem to present the same basic problem: it is difficult to see how consumers can be involved in the investment market – they usually lack sufficient information and the capacity to undertake long-term commitments of the sort required. Some form of 'transactive' pricing may eventually solve this problem, but, as discussed above, this is probably a very long way off. Competition is therefore at least qualified, as compared to the liberalised system we are used to (where regulators have traditionally been suspicious of long-term contracts). It is an intrinsically more centralised approach: prices from the investment market would get through to consumers via what are essentially administrative mechanisms (as happens with FiT and capacity costs today); the main decisions about the system would be made centrally (eg on the amount of flexibility needed and how to provide it) and on a long-term basis, so creating the risk of market foreclosure, but without the overall planning and optimisation that is a feature of fully centralised approaches.

In addition, the effect of the investment market is to downgrade the importance of the short-term market, which liberalisation has always placed at the heart of electricity competition. Indeed, there is a question as to whether you actually need a short-term market as such, or if it would be better to use some version of a balancing mechanism or merit order operated by the system operator or single buyer. There is also the question of how you ensure an optimum amount of flexibility – is it all for the single buyer at the initial investment stage or can the short-term market give useful signals? These questions are beyond the scope of this paper but they are significant because demand response and consumer preferences are important factors in developing a sustainable electricity market for the future. Demand response is not primarily about long-term 'investment' in the same way as generation, and a shift of emphasis to investment markets could well inhibit or distort its development.

4.7 The two-market solution

A more radical proposal, put forward by this author, to mitigate the problem of market distortions would be to create two separate power markets for generators and to present consumers with a simple choice between two different sorts of supply. On would be 'as available' power, which would be available to consumers at a relatively low price at times when there was sufficient supply in the corresponding wholesale market for participating low-carbon generators. The other would be 'on demand' power, available at all times but at a significantly higher price. Because of its novelty, this proposal is explained in some detail.

At the consumer end, there is a rough precedent for the two-market approach in the UK 'Economy 7' and related tariffs (see Annex), which offer a lower night-time rate, via separate metering, mainly intended to encourage electric storage heating. Prices under this tariff were for a long time significantly lower than for unrestricted supply, at about 40% of daytime electricity prices; over time, they produced very significant changes in demand levels and patterns, as illustrated in the Annex. Demand for consumers in this group was over twice that of the average consumer and the peak was shortly after midnight, rather than in the early evening. These impacts are orders of magnitude greater than anything that has been achieved with traditional time of day pricing; effects on this scale would be needed to cope with the challenges described in this paper, and the responses might need to involve a model similar to Economy 7, packaging up equipment and services and creating a simple and easy to understand offering, with sustainably low prices over time.

With the development of smart metering, separate meters and circuits should not, however, be needed. Instead, consumers could have the option of using appliances fitted with micro-chips capable of reacting to the presence of 'as available' supply and designed to make best use of it. Prices in this market could be regulated or not as governments preferred. Either way, in principle, they could be based around the same general principles as with Economy 7 – unit prices could be set at around 40% of the normal unit price and the broad differential would be guaranteed over a long period, so it would be worth consumers' while making the necessary investments in equipment or storage[16]. Alternatively (and this was indeed the underlying logic of the Economy 7 approach) prices could be set to reflect the long run marginal cost of low carbon intermittent supply so as to set appropriate long term price signals for consumers, as discussed below. If the costs of renewables continue falling (as recently suggested in IEA 2015) and the carbon externality is over time fully incorporated in the cost of generation from fossil sources, prices in this market should therefore be considerably lower than in the 'on demand' market.

Consumers with the right equipment would receive the 'as available' price so long as that generation exceeded that class of demand, and have their prices calculated pro-rata between the two markets at other times (eg pay half the lower price, half the on demand price when half of generation was from as available sources). They would also have the choice, for nominated equipment, to have automatic cut-off at high price periods. Consumers who did not have such equipment would pay the more expensive 'on demand' price, incorporating the wider system costs of reliability and flexibility. There would therefore be a big incentive to have an 'as available' supply. This could be considered as entailing an element of subsidy (in that the lower price would not, at any rate initially, necessarily reflect the full current costs of production from intermittent sources). But it is, in effect, a redirection of the subsidy element present in the system today (in the form of the support for low-carbon generating sources). The significant difference being that consumers would themselves be able to benefit from the subsidy element (whereas at present they merely pick up the cost) and would be encouraged to move in the direction of greater demand side responsiveness necessary to produce an optimised system.

Wholesale markets could be constructed on the same lines. Generators would have the choice of entering either the 'on demand' (or flexibility) market, or being dispatched in the 'as available' pool. In the latter case, governments might well decide that incentives were necessary to help develop the market; qualifying generators would initially benefit from additional support mechanisms, as at present, to add to the income from the 'as available' price. The aim would be that in the longer term, once a developed 'as available' market existed, generators would be able to sell directly to this market and that no particular support would be needed – the price would reflect what the market would bear and should

[16] The 40% figure is an example; the actual differential could in practice be based on an assessment of long term cost minimization for the whole system, taking both demand and supply resources into account, given the constraint of government objectives in terms of generation types.

reflect consumers' valuations. Dispatch in the 'as available' segment would be automatic – ie the system operator would have to accept the power, or use curtailment auctions in case of excess. Prices in the 'as available' part of the wholesale market could be set in various ways: in principle, they could initially be set by government or regulator on the basis of the expected long term marginal cost of capacity in this segment of the market, but with additional support offered to producers as needed to ensure that their total investment costs were covered. In the short to medium term, the amount of capacity in that market would be determined by the additional income offered by government support mechanisms. But, over time, consumers' ability to use intermittent power effectively would grow and its value in the market should become apparent. In the long term, the prices established in this market by consumer demand would determine the volume of inflexible plants.

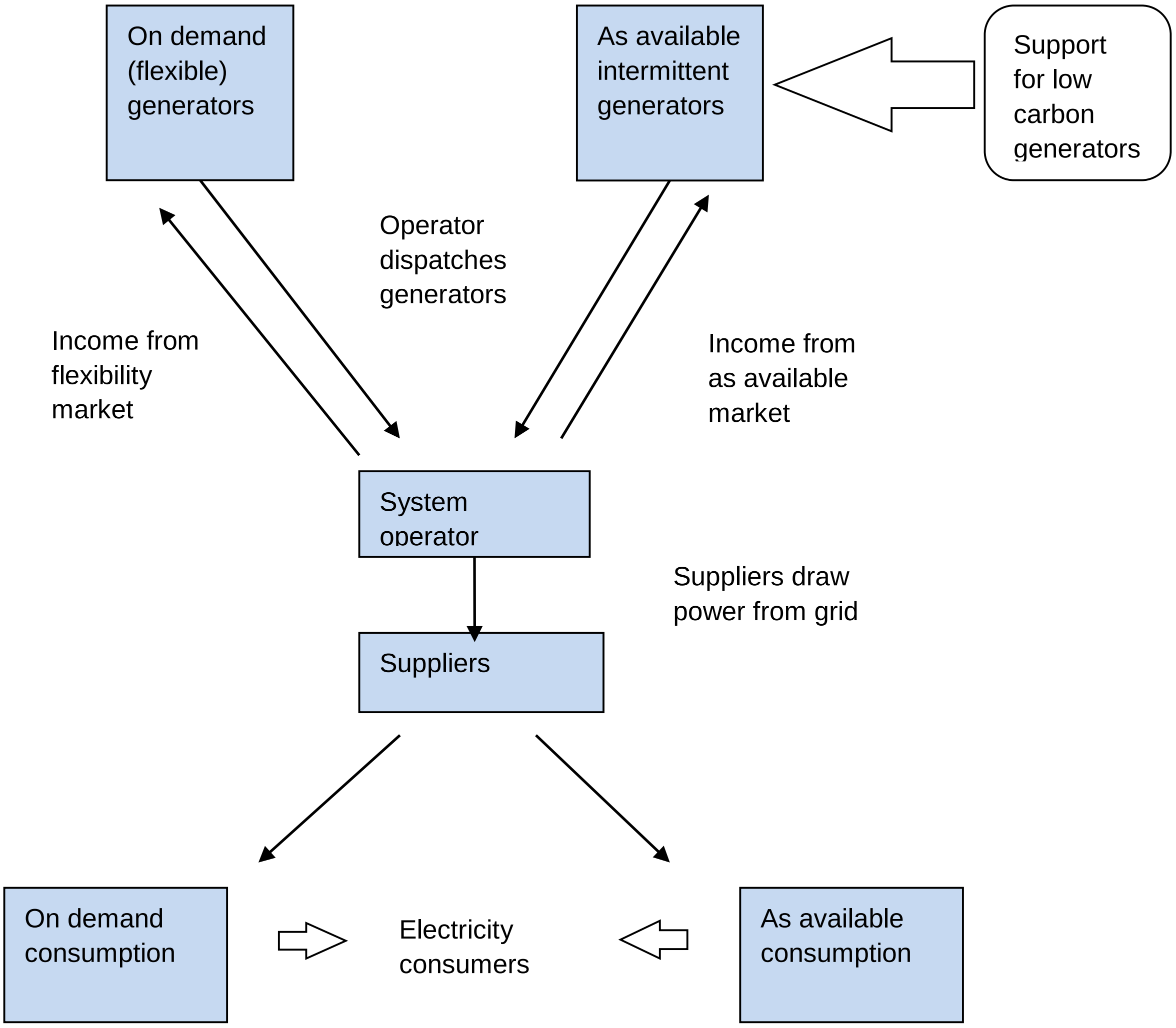
Meanwhile, in the parallel flexibility market, the operator would call on additional generating plant (or demand response) as necessary to meet overall demand. This market could involve capacity and flexibility payments, as well as a kWh market, in order to incentivize investment. It could be based on various market systems, eg with prices reflecting the actual bids accepted – 'pay as bid' - or based on the highest bid accepted – system marginal cost; the choice would depend on the circumstances of the market in question, for instance the size of the flexibility market as compared with that of the 'as available' market and the extent to which demand response had developed. But the principle is that prices in this market at the wholesale level would cover individual generators' costs; at the retail end, these costs along with overall system costs, would in turn be passed on to consumers.

Generators could choose whether or not to participate in this flexibility market. The advantage to them would be that they could benefit from the higher prices available in it. The disadvantage is that they could not rely on being dispatched except where their output was needed by the system. Over time, assuming a high carbon price was also imposed and given the expected fall in the costs of low-carbon generation, prices in the flexibility market would move significantly above prices in the 'as available' market. Assuming that the cost of low-carbon plant continues to fall as expected, the cost of generation for the 'as available' market should increasingly tend towards the value of such supply for consumers, allowing the support for such plant to be phased out. (If this does not happen, continued support might be needed – but that is a feature of the present system as well. The difference is that there would be a viable exit strategy, once a low carbon power system had been established on both demand and supply sides – an exit strategy which, as explained above, is not available in the present situation.)

While the system involves pricing interventions in the interim period, that is not itself a new phenomenon. The aim is to change the form of support in such a way that it reinforces the underlying policy goals. Current support mechanisms fail to do so – they simply 'smear' the extra cost of policy-supported generation across the whole market, by adding a standard fixed uplift to the kWh price or a fixed capacity contribution. This does nothing to mitigate the underlying distortions and gives no useful signals to suppliers or consumers.

By contrast, under the arrangements proposed here, both wholesale and retail markets would be designed around the same long-term policy objective, and synergies between them would be realized. A schematic representation of the proposal is presented below.

Figure 4: Schematic representation of on demand and as available markets



'On demand' (flexible) generators are dispatched by system operator and receive income from market, which could include capacity, energy and other payments.
'As available' generators' power output is accepted automatically by system operator (or in case of excess, curtailed by use of auctions). They receive the (relatively low) 'as available' price set, initially by government or regulator; in the long run by demand in the retail 'as available' market. In the transition period they also receive income from market support schemes for renewable and low carbon sources.
Depending on the regulatory system, suppliers could either choose to purchase separate on demand and as available supply and thus take advantage of the two generation price options, and be able to offer consumers a choice; or could be required to offer the two options to consumers.

Source: Author

Variation on the reform proposal - with one wholesale market

An alternative version of this proposal would involve the two separate retail offerings proposed above (among others), while retaining a single wholesale electricity market and central dispatch. The logic is that, in practice, one cannot distinguish between the electrons at customer premises from different sources of electricity. Furthermore, it may be unnecessary to identify two physically separate wholesale markets to correspond to the 'as available' and 'on demand' retail offers. There are at least two ways that this might work.

One is that centralised dispatch would occur as it does now, and a single energy market price would be determined for each relevant time period. Customers with 'as available' retail contracts and corresponding appliances would consume the 'as available' energy when wholesale prices were below a defined threshold, and pay the higher tariff when wholesale prices were above that threshold. In effect, customers would be buying an interruptible supply of low-cost energy to use in the appropriate appliances, with interruption being determined by a wholesale price threshold.

Another approach would also involve least cost dispatch of all plant and a single market price, but would distinguish between the volume of energy that was dispatched within the category of 'as available' plant and the volume dispatched with the category of 'on demand' plant. These two categories would need to be defined, for instance by reference to some price threshold or the type of plant that was being dispatched. Customers with 'as available' retail contracts could consume their share of dispatched 'as available' generation, as in the original proposal, but without any need to create separate wholesale markets.

The need for transition: developing the supply chain and consumer psychology

This approach is designed as a transitional measure – it will take time to set up the systems, hardware and consumer understanding for a fully self-sustaining low-carbon power supply. In particular, it will take time to delineate the demand side resource potential and it will require systems to be in place that make it simple and practical for consumers to engage with this new area.

One of the key problems in developing an effective demand response resource is the existence of transaction costs (both economic and psychological), which stand in the way of consumer involvement. If consumers are to be able effectively to express their preferences as regards reliability, they need to have the means, motive and opportunity of doing so. At present, they usually lack these. Few have the opportunity to reduce demand in response to system tightness – they do not know when such periods are occurring and have no easy way of responding, short of turning off their equipment and thus forgoing energy services. Even if price signals become both more direct and more transparent, with the introduction of smart meters and real-time pricing, it is doubtful consumers would have sufficient incentive to respond. Most consumers do not at present have to think about adjusting demand at particular times. Moreover, a cost would be involved in investing in the necessary equipment and accepting the degree of behaviour change implied by the new sort of electricity supply. The novelty of the situation itself also creates uncertainty – are this new investment and these behavioural changes worthwhile? Governments have recognised that upstream producers, faced with the volatility and unpredictability of market prices, may withhold investment; the issue is even more acute for individual consumers, who will generally have little information about or expertise in electricity markets. The Economy 7 model shows that these barriers can be overcome and one aim of the two-market system would be to produce a similar result by giving consumers a simple and understandable demand response offer with a clear and predictable pay-off.

This approach should also help provide incentives for the development of a supply chain to support a new approach to consumer behaviour in a low-carbon world. Manufacturers of appliances, storage capability, in-house displays and meters would have a target market, corresponding to demand for as available (low-carbon) energy. Retailers would develop their service offerings to reflect customer preferences in terms of their willingness to pay for different kinds of energy service; they would be free to define other service offerings as well as the specific model described above.

Another key goal is to influence consumer psychology and develop consumer understanding of the nature of electricity supply. At the moment, there is a clear tendency, among both policymakers and consumers to think that 'electricity is electricity is electricity'. In fact, as discussed in the text and reference above[17], the value (and price) of electricity is dependent on many factors such as location, time and the overall state of the system. The attractions – and distortions – of an over-simplified approach can be seen in the following instances:

- As discussed above, many policymakers believe that once new renewable sources reach 'grid parity' (where the levelised cost of generation is comparable with that from conventional sources) they will be competitive and there will be no further need for government support. In today's markets that is a misconception for the reasons set out above.
- Many customers and policy makers are attracted by the idea of 'net metering'. This is an arrangement under which customers with small-scale generation on their premises (eg solar panels) get the same price for exports to the system as they pay for imports from the system. Over the year they therefore only pay (or even receive income) for their net consumption (or production). This seems intuitively fair to many but is in fact a clear market distortion – in the situation described, the utility is required to invest in the transmission and distribution facilities and back-up generation needed to ensure uninterrupted supply. The consumer has no such obligation. Another way of looking at it is that the consumer gets a price for their exports of electricity which has no necessary relationship with the value to the system of those exports (which may at particular times be zero or negative).

In both cases described above, the situation would be seen much more clearly if it were apparent that not all sorts of electricity were equal – for instance, in relation to net metering, it is readily apparent that exports from a consumer's premises would only be entitled to the 'as available' price while imports are, more or less by definition, at the 'on demand' price – unless of course the consumer is prepared to invest in the necessary storage and equipment to enable them to qualify as an 'on demand' generator by offering an 'on demand' service.

While this approach is only intended as transitional, it could go a considerable way towards dealing with the various problems listed above, ie it would:

- provide effective **signals for operation** for flexible plants. In effect it retains the system marginal approach for short-run operation in this market. For inflexible plants, it does not involve an immediate change in system operation, but it does open the way for more effective operation in the longer term via the incorporation of demand response and storage into operating schedules.
- remove the **market distortions** in the flexible market.
- open up the possibility of an **exit strategy** with the goal of a fully self-sustaining low-carbon market**.**
- create effective **signals for investment** for flexible plants and enable a move towards effective market signals for investment in inflexible plants.
- allow governments to consider long-term **system optimisation** on the basis of a proper understanding of demand response potential.

[17] OIES 2014

- provide strong incentives for the development of **demand response** storage and the discovery of consumer preferences.

Against that, it implies a considerable degree of government intervention in the system, at least in the interim period (though arguably such intervention is taking place already, just in a less coherent manner). In particular, it would mean moving towards a form of central balancing by the system operator via the flexibility market (but this may in any event be a necessary consequence of the government's desire to promote inflexible plants, which can only play a limited part in balancing except in conjunction with an as yet to be developed demand response and storage potential). It also involves the government or central authority, at least initially, in decisions about market and price structures. Clearly there is a risk that such intervention would inhibit the development of other potential innovative and experimental approaches to tariff formulation.

Initially too, it over-simplifies the nature of the consumer offer. Just as it is not straightforwardly the case that 'electricity is electricity', it is also not straightforwardly the case that 'intermittency is intermittency'. There are many types of intermittency, some more 'intermittent'[18] and some more predictable (eg tidal power) than others. Optimising the system would involve selecting the mix which most closely matched consumer preferences.

However, aligning the system with consumer preferences is not really feasible at present – there is no effective mechanism for revealing preferences and no informed participation by most consumers in selecting their desired level of reliability. There is also a major technological uncertainty – until such mechanisms are in place there are no effective incentives to develop the technology that will provide the optimum balance. For instance, it is quite possible that a long-term outcome will involve a combination of 'as available' supply, demand response and small-scale storage on consumers' premises, rather than reliance on peaking generation plants (and this is likely to be an environmentally preferable outcome). But the precise outcome cannot be forecast with any confidence at this stage – the aim should rather be to provide the mechanisms and incentives to let such solutions emerge.

Over time, the author believes that a two-part market set up on the lines described above has the potential to develop these mechanisms and incentive structures, allowing support to be removed and the intrinsic simplifications involved in the proposed system to be relaxed. Suppliers could come up with packages aimed at providing the level of reliability consumers wanted and compete on a combination of cost, quality and accessibility. It should be possible to limit government intervention to the basic market framework, either in the form of carbon prices or (preferably) of a carbon intensity target[19] ensuring a sustainable low-carbon system.

[18] And different sorts of intermittency – eg wind vs solar. See CSIRO 2012.
[19] OIES 2013a

Conclusions

Electricity markets in Europe are facing major challenges – and may effectively be broken. The problem arises from a number of factors, but one central driver is the fact that governments are supporting a class of generation sources that have different technical and economic characteristics from those for which today's markets were designed. It raises the question of whether governments should stop direct support for these sources – or alternatively should redesign electricity markets to suit the technologies involved.

Discussion of the options has only just got under way and no clear solution has as yet emerged – nor indeed is there a clear consensus about whether fundamental change is needed. In any event, all the proposed options (including the no reform option) have their advantages and drawbacks. But if governments are serious about their long-term climate goals and about pursuing them through the development of low-carbon electricity sources, they need to think in a much more fundamental way about the design of electricity markets and whether they are fit for the low carbon future. As the Commission's own staff paper pointed out: 'In the long term, it is uncertain whether wholesale prices based on existing market arrangements will be able to provide the revenues necessary to cover the total costs of investments' and as a result 'the market design may need to evolve'. In view of what it calls 'the inertia of the energy system', it argues that 'this calls for starting a reflection already now' (EC 2015a p 73). The Commission has not yet responded to this challenge in the relatively limited proposals it has put forward for changes to its Target Model (EC 2015b); nor can it be said that a widespread debate is under way in member states on the fundamental issues discussed above – rather the focus is on such issues as capacity and flexibility markets, and scarcity pricing within broadly the current framework. But if the central contention of this paper is correct – that electricity markets are broken at a fundamental level – it is not too early to embark on a serious consideration of the possible solutions. Can we evolve a sustainable model for the electricity markets of the future?

Annex – Capacity markets are not the answer

The introduction of capacity markets is the main focus of current discussions on electricity market reform. But there is good reason to believe that such markets are not the best way forward in the longer term (though they may be necessary to ensure security in the shorter term). The underlying problem is that with capacity markets, decision-making is transferred to governments or suppliers – their decisions are inevitably essentially arbitrary (at best) or politically motivated (at worst). Capacity markets arguably represent a sort of market failure – in normal markets reliability is a matter for consumer choice; consumers can decide to pay a premium, or not, for security of supply (for instance, buying a more expensive but more reliable car) or for 'on demand' supply (for instance, paying a higher price for flexible travel bookings) and can decide for themselves when the price has gone too high (for instance, buying goods when on offer or in season).

In other words, normal markets are not based on a central decision about the appropriate level of reliability but on consumer preferences. In the past, it has not been thought practical to apply this approach to electricity. Instead, it has been argued that security of electricity supply has 'public good' characteristics, as discussed below, and needs to be determined and delivered centrally. Many would still hold this to be the case. However, others would regard this rationale as becoming outdated and in the process of being overtaken by events in the move to a low-carbon system.

Traditional arguments are based on what have been seen as fundamental characteristics of electricity supply:

1) Electricity is regarded as an **essential**, with no real substitutes across the majority of services it provides (eg lighting, appliances, controls). This, along with the fact that electricity is a 'complementary' good (ie not used on its own but in conjunction with some other good, like a refrigerator, to provide a service) means that demand tends to be inelastic – that is, it does not vary significantly, in the short term at any rate, with the price of electricity. Prices high enough for domestic consumers to choose voluntarily to forego their electricity consumption could therefore cause significant social problems even if it was practical to transmit these prices to consumers (and for consumers to respond) in real time.

2) Electricity is a **network** industry. In the past it has been regarded as impractical for consumers to have different levels of reliability in supply. In practice, when the system fails it tends to fail across an entire area (and sometimes across the whole network) because networks operate within fairly narrow bands of tolerance as regards such factors as voltage and frequency and have to be shut down if these limits are exceeded. Thus electricity reliability has been regarded as a public good in the sense that it is a 'non-excludable' good that exists at a system rather than individual level.

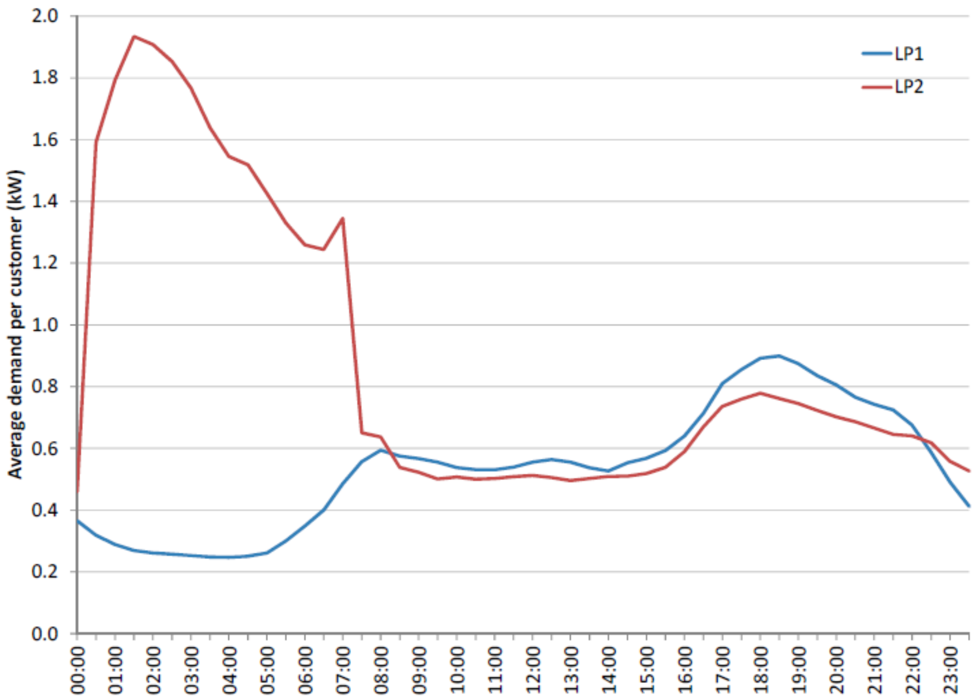
3) Even if it were technically achievable, the **transaction costs** of letting individual consumers decide their own level of reliability have been regarded as too high. It would require real-time metering and monitoring of consumption and either a consumer with a significant enough energy bill to give them an incentive to respond in real time to price changes, or sufficiently well-developed smart appliances that can themselves respond in line with the consumer's wishes. Furthermore, most consumers can provide rather little in the way of response in comparison with the more concentrated resources on the supply side, so aggregation of these responses is needed in some way to make the resource meaningful, again adding to the transaction costs. Finally, in 'unbundled' systems, the benefits of demand response are often spread across many different entities – local distribution systems, national transmission systems and generators – while suppliers do not necessarily have a solid block of customers in any given area, but a dispersed customer base across the country. Aggregating all these elements and matching them to short term system needs is enormously complicated and again adds to transaction costs.

4) In the past, security has therefore been supplied **centrally**, by the system operator controlling (largely flexible) generation on the supply side; the demand-side has been seen as essentially passive.

5) But these traditional assumptions have much less force in the 21st century:

6) While electricity remains an **essential** overall, it does not follow that all uses of electricity are equally essential. In many cases, consumers may be prepared to forego, reduce or postpone, particular sorts of consumption if there is reason to do so. The extent to which electricity can be price responsive can be shown in the following chart: the blue line shows the consumption profile of an ordinary domestic customer on an 'unrestricted' tariff, ie one which has the same kWh price for any time, day or night. The red line shows the consumption profile of an off-peak (Economy 7) customer, ie one who is equipped with separate metering that allows night-time and day-time electricity to be priced separately (and in most cases has appliances adapted to take advantage of the lower night-time prices, like off-peak storage heating). The red line has a completely different shape from the blue line and a much higher peak (over twice as high). In other words, the pattern of electricity consumption can be responsive to price, although, as in this case, it is likely to take time for the price response to emerge. Consumers have to be confident about the continuing existence of price differentials; it has to be worth their while investing in the equipment needed to make the pricing scheme effective.

Figure 5: Profiles of customers with and without off-peak metering and billing in the UK



Note: in the above chart the blue line LP1 represents the load profile of "unrestricted" customers (about 22 million) who pay a uniform rate at all times of day. The red line LP2 represents customers (about 5 million) who have separate metering for night use and are billed on a two or three part peak/off-peak tariff like Economy 7.
Source: Sustainability First 2012

1) **Network effects** in electricity remain but are not the constraint they were in the past. In particular, it is quite possible for individual consumers to opt for different levels of reliability so that in an emergency some, but not all, consumers would be cut off or some, but not all, sorts of demand. Such demand response can be provided through programmable automatic systems, not requiring continuous individual intervention or monitoring. For instance, a refrigerator or heating or cooling equipment could be programmed to turn off in response to price signals, up to a length of time pre-determined by the consumer. This is, in a sense, a form of self-disconnection but within the consumer's control and acting to her financial benefit. It is also increasingly feasible, through the development of various forms of distributed generation and capability to set up smaller scale areas – islands or potential islands – which can operate in isolation from the rest of the system if need be. Meanwhile, the development of smarter grids and grid controls and of more localised generation means that the network itself can develop greater flexibility and ability to manage fluctuations in the supply-demand balance. So the historic risk that a local overload or accident (say, a tree falling onto power lines) can lead to system-wide breakdown, while it has not disappeared entirely, is now much less likely than in the past.
2) The **transaction costs** of demand response have fallen with advances in smart technology and appliances. Providing appropriate metering and price signals for individual consumers; monitoring and aggregating their response across particular areas and the system as a whole; and responding to real time changes in the system balance, are all now practicable in a way which was not possible last century.
3) **Flexibility** on the supply side is decreasing with the growth of intermittent renewables, while flexibility on the demand side is growing for the reasons discussed above, so it is no longer axiomatic that it is for the system operator to be responsible for security as a public service.

So there is arguably no fundamental reason of principle why electricity markets should not operate on the same basis as other markets, with individuals making their own consumption decisions. That does not mean that there are not still practical problems. For instance, most consumers have no experience of demand response; do not have the appropriate equipment; and have no incentive to engage in demand response anyway. These are formidable barriers – governments will need to have a longer-term strategy for overcoming them and creating the new responsive customer base that the future industry will need. But such barriers can be overcome, and the overriding policy priority should be to introduce measures that help do so, rather than to introduce artificial instruments like capacity mechanisms and then try to graft demand response on to them, which is the current direction of travel in many countries.

The problem with such capacity mechanisms is that they are centrally determined and essentially arbitrary – ie the government, regulator or some other public body has to set a reliability and security standard that the mechanisms are designed to deliver. This is done in different ways in different systems, but in a stylised form it involves a number of steps (though in practice governments do not necessarily go through them all):

- First, a calculation is made of the Value of Lost Load (VOLL: ie the amount a consumer would be willing in principle to pay to forego one unit of consumption). This number underlay the capacity element of the first UK electricity market, the Pool, where it was initially set at £2/kWh (around £4 today). In a paper for the UK government ('the LE Report'), which was part of the background to the development of the current capacity mechanism, VOLL was set at nearly £17/kWh[20]. As the difference between the two numbers indicates, there is no single unambiguous consensus methodology on the basis of which a 'correct' figure can be calculated; despite the seemingly objective quantitative presentation, the number is essentially a judgement.

[20] LE 2013

- Next, the VOLL is translated into a security or reliability standard (eg a target of interruption of supply of no more than, say, three hours per year for the average customer; or of having inadequate generation capacity only three times a century).
- That standard is then put into practice in various possible ways. For instance, a strategic reserve may be set up of plants held back from the market in normal circumstances but which can be called on in case of need to meet the standard. An alternative approach is that the capacity mechanism can cover the majority of the market as in the UK[21] (ie nearly all controllable plants not supported by other measures like FiTs); plants can bid to be included in the mechanism. They then generate and participate in the market in the normal way, except that, in return for the payment, they effectively guarantee to be in operation at times of system stress and so enable the security standard can be met (if they are not generating, they face a penalty).

Various other options are possible, but they all face essentially the same underlying weakness: that a central authority (government or regulator) has to determine the security standard in a more or less arbitrary way and then has to use judgement (and intrinsically uncertain forecasts for demand and the probability of system stress) to translate this standard into practice. There is no reason why the eventual result should have any meaningful relationship with consumer preferences overall, much less with individual consumer preferences.

The approach is essentially based on a concept of the operation of the electricity system which reflects 20th century conditions – as indeed was made explicit in the LE report. It looks at the Value of Lost Load for a range of consumers, mainly on the basis of 'willingness to accept' (WTA) and 'willingness to pay' (WTP) estimates (derived from consumers' stated preferences about how important a power outage would be to them and how much money they would need to be offered to accept an outage; or how much they would be prepared to pay to avoid one). There are already conceptual difficulties here. Evidence suggests that people are simply not very good at judging their reactions to hypothetical future states – we tend to over-predict the intensity of our feelings about them. Furthermore, our valuations can vary significantly according to how the questions are phrased and the context in which they are asked[22]. So there could well be a systematic bias in the valuations produced by such methods.

In any event, what comes out most clearly from the LE report is the huge range of valuations according to the possible lengths of an outage, the season, day of the week, time of day, type of customer etc. In other words, producing a single figure is inherently a distortion – it does not reflect any particular customer's situation except by chance. For instance, as shown in the following table, domestic customers' VOLLs varies from around £12,000 to, effectively, nothing, and vary hugely according to the methodology.

[21] https://www.gov.uk/government/collections/electricity-market-reform-capacity-market-2015
[22] See eg Ariely 2003

Table 1: Comparison of WTA and WTP £/MWh estimates of outage – domestic customers, based on a time varying electricity demand profile

Table 1: Comparison of WTA and WTP £/MWh estimates by time of outage – domestic customers, based on a time varying electricity demand profile

	Not Winter Not Peak Weekend	Not Winter Not Peak Weekday	Not Winter Peak Weekday	Not Winter Peak Weekend	Winter Not Peak Weekend	Winter Not Peak Weekday	Winter Peak Weekday	Winter Peak Weekend
WTA (£/MWh)	**9,550**	**6,957**	**9,257**	**11,145**	**10,982**	**9,100**	**10,289**	**11,820**
WTP (£/MWh)	**2,766**	(101)	(105)	**1,805**	**2,240**	315	208	**1,651**

Note: The figures are based on figures for a one hour electricity outage. Converted based on an assumed annual electricity consumption of 3.934 MWh per annum but the numbers have been adjusted for different electricity demands across outage scenarios. This is discussed in Annex 12. Estimates in bold indicate statistical significance at the 95% confidence interval.
Source: London Economics analysis

For small industrial and commercial customers, VOLL tends to be higher (because they stand to lose revenue if production is disrupted by an outage, and electricity is normally a fairly small proportion of their production costs). Larger producers, perhaps counter-intuitively, tend to have lower VOLLs – they may well find it easier to mitigate the effect of an outage, eg by having back-up generation. Overall, VOLL for industrial and commercial customers is around £1,400, but smaller enterprises tend to have much higher VOLLs, of up to £40,000. Thus it will be seen that the overall figure emerging from the report, of around £17,000, conceals a huge range of different preferences – themselves only doubtfully quantified. It does not seem a very firm basis for measures that will lead to significant cost for consumers and significant system investment.

The report itself sets out the uncertainties and ranges with clarity; however, it seems to find itself forced into making a more or less arbitrary judgement, and it may be worth citing its rationale at some length:

As part of our project, we were asked to give our opinions on how to narrow the range of VoLL figure estimates across time periods and customer types to more aggregate headline figures. Narrowing down VoLL depends in part on how VoLL will be used; the ultimate use of VoLL is up to

Ofgem and DECC, and we are only offering illustrative scenarios. However, we suggest that since VoLL is likely to be used as a substitute for a market price for security of supply and has applications for both capacity and balancing markets, then a single simplified VoLL may be the most important figure.

In theory, VoLL is a demand-side concept that is no different from more familiar supply-side concepts; market supply and demand are symmetric. The stack of plant from least to highest marginal cost that makes up the supply side, and symmetrically, the stack of least to highest marginal value or willingness to pay makes up the demand side. If a market maker could indeed order and stack consumers in the same way as the market stacks generation plants, and consumers could respond to the resulting price signals, then security of supply would always be achieved via prices.

A major challenge with VoLL and energy policy for security of supply is that it is often difficult to determine precisely who has been disconnected and for how long during power emergencies. Thus the VoLL, while in theory a marginal concept, is in practice a weighted-average approximation of the marginal impact on a group of customers. The VoLL is thus the weighted-average of the consumer surplus plus market revenue from a typical group of customers that might be disconnected.

Further decisions about how to aggregate VoLL and which are the most appropriate figures to use were driven by discussions among the LE, Ofgem and DECC teams. In concert with the project teams from Ofgem and DECC, it was agreed that as the future energy policy landscape evolves, large customers will increasingly be able to participate in demand-side response, and should face market price signals from the energy markets directly. Therefore, our focus is on domestic and SME customers. Further, we discussed that the marginal impact on security of supply should be with reference to typical winter peak demand periods. Finally, we agreed that from a policy perspective, using the WTP figures, which suffer from the well-known downward bias due to 'entitlement' and strategic responses from consumers, would risk setting a security of supply standard that is too low; we concluded that the WTA method was the better approach.

It is this rationale which is rapidly becoming outdated – ie it is increasingly ceasing to be the case that 'customers who experience an outage cannot in general be identified or ordered in terms of preference/WTA'. It is noteworthy that, on these figures, the difference in marginal value on the demand side is much greater than the difference in marginal cost on the supply side – logic suggests that every effort should be made to get away from an averaging approach.

The essential problem goes back to the technological starting point discussed above: present markets are designed to discriminate between different marginal costs on the supply side and reward supply-side flexibility; they do little or nothing to discriminate between different marginal valuations on the demand side or to reward demand-side flexibility. Mechanisms such as capacity payments, which seek to remedy this situation but have a supply side starting point, fail to address the underlying issues and themselves introduce further distortions.

Similar arguments apply to the development of balancing markets on the supply side; they may well have a role in helping the system to operate more effectively, given the constraints imposed on it, but they do little to remedy the underlying constraints.

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