VARIABILITY IN MARKET PRICES AND OPTIONS FOR ELECTRICITY TARIFFS

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Summary

1. Price variability is an inherent feature of electricity markets. It reflects and signals variations in the marginal cost of running different generating plants to meet variations in the demand for electricity – either within days or weeks or across seasons. Wholesale markets for power have highlighted the extent of such variability, but they have not created or exacerbated such variations.

2. In the past – and still, in some parts of the world – it was expected that vertically integrated electricity companies would absorb this price variability. This was feasible while they had monopoly control of electricity systems, but once the electricity sector was unbundled to separate generation, networks and energy supply, it became difficult or impossible to sustain the pooling which allowed monopoly utilities to suppress price variability.

3. Even when electricity systems are run by monopoly utilities, they have a strong incentive to offer multiperiod tariffs to encourage electricity users – both businesses and households – to shift some or most of their usage from periods when generation costs tend to be high to period when they tend to be low. Hence, peak/off-peak tariffs (Economy 7 tariffs in the UK) are offered almost everywhere.

4. The main constraint on the type of variable tariffs offered has been the capabilities of electricity meters. In many countries 50 years ago, it was necessary to install separate meters and electricity circuits for peak and off-peak use. The issue was partly one of cost. Large customers – primarily businesses – could choose to install more sophisticated meters, but they were not seen as being economic for smaller users.

5. This constraint was gradually removed with the introduction of more sophisticated electronic "smart" meters with network connections in place of older mechanical meters. For example, the Italian electricity utility Enel implemented a nationwide programme of meter upgrades in the early 2000s using meters that measure consumption in three periods as standard.

6. There have been two primary reasons for countries to promote multiperiod tariffs, which lead to different tariff structures. The first is the availability of large amounts of baseload generation with (very) low variable costs. This was often nuclear power but, in some countries, hydro power or thermal plants burning lignite or very cheap coal would also qualify. In such cases, the goal was to increase demand during the night when it might otherwise fall below the output from plants whose output could not easily be reduced. The second was the need to operate plants with high variable costs to meet peak demand, either for air conditioning or heating, during periods of high or low temperatures.

7. The first reason was generally more important in Europe, especially NW Europe where air conditioning demand is low. The second reason was important in North America and Asia, where air conditioning is more widespread. However, in most developed countries three developments have increased the underlying variability in market prices and pressure to pass at least some of that variability through to energy consumers.

8. First, the rapid increase in generation from intermittent renewable generators – primarily solar and wind plants – has increased the medium-term variability of wholesale prices. This trend is clearly apparent in the GB market and may be observed by focusing on what I call market generation. There are several reasons for this. Many renewable generators are embedded, i.e. connected to distribution networks, so that grid demand is total demand minus embedded generation. Grid-connected renewable generators have zero marginal costs and most receive subsidies which mean that they can earn an operating margin even if market prices are zero or negative. Hence, intermittent and subsidised renewable generation (ISG) is always dispatched before other forms of generation.

9. The residue – i.e. total demand minus the sum of embedded generation and ISG – is market generation which responds to and determines market prices. The higher the level of market generation, whether due to higher total demand or lower non-market generation, the higher on average will be the level of market prices. Over the period from 2015 the variability of market generation and, thus, market prices has nearly doubled. The variability in non-market generation has remained constant, but as non-market generation has displaced market generation, its variability has an increasing impact on market prices.

10. Similar trends are visible in other European countries, most notably Germany. The German wholesale market has experienced an increasing frequency of negative market prices. These are a perverse consequence of subsidies, particularly to small solar producers, which encourage renewable generators to continue exporting power to the grid even when market prices are low or negative. Negative market prices are merely the most visible manifestation of increasing price variability and are becoming more frequent both in the UK and in markets linked to Germany.

11. The second development has been the separation of energy supply from generation which means that an increasing proportion of electricity supplied to final customers is either traded on power markets or is purchased on terms that are affected by wholesale market prices. Many final customers may prefer to pay an electricity price that does not vary by time of day and is fixed for anything from 3 to 12 months or longer. To offer such contracts, energy suppliers must pay for price insurance, either by hedging or entering into power purchase agreements. With increasing variability of market prices, the cost of price insurance increases and this cost is passed on to final consumers.

12. During the early period after the liberalisation of energy markets, some generators took the view that the combination of generation and energy supply provided a natural hedge for the variability in energy prices. Low market prices for output were offset by higher margins in their energy supply businesses and vice-versa. Over time, this model was undermined by the growth in subsidised renewable generation, whose revenues were less affected by market prices and by the entry of competing energy suppliers with limited or no associated generation. Energy supply is now seen as a very competitive and often unprofitable business that is avoided by many companies who invest and operate both renewable and thermal generation facilities.

13. The third development has been the gradual switch to smart meters. The UK is behind European countries such as Italy, Spain and all of Scandinavia in this respect. One major benefit of smart meters for energy suppliers is the elimination of manual meter-reading. This allows energy suppliers to introduce flexible or dynamic prices that are linked in various ways to market prices.

14. In both Italy and Spain, many final customers are on flexible multiperiod tariffs under which (a) the standard price they pay is linked to a monthly index of the market price, and (b) multipliers are applied to this standard price for the prices in peak (a multiplier > 1) and off-peak (a multiplier < 1) periods. Customers pay either a fixed daily charge or a per kWh to cover network costs, the supplier's costs, and various levies and taxes. Such tariffs are more complicated than the familiar UK tariff, but they are much more transparent about how market prices translate to what is paid by final customers. From the perspective of energy suppliers, such flexible tariffs pass through a large portion of market risk to customers and reduce the cost of market insurance that would otherwise be built into fixed prices.

15. Most Scandinavian countries have gone further by promoting the adoption of dynamic pricing. In this case, final customers pay a price per unit of electricity used that is equal to the wholesale market price for that period. In addition, they pay separate charges to cover network and other costs based on total monthly consumption and the capacity connection. Dynamic pricing means that final consumers are fully exposed to market price variability, but typically the average price paid is much lower than customers in the UK pay. Energy suppliers bear volume risk but not market price risk.

16. Another consideration is that the increase in heavily subsidised renewable generation has greatly increased the gap between market prices and average tariffs charged by electricity suppliers. In countries where flexible and dynamic pricing is widespread, regulators put great weight in ensuring transparency about how electricity bills are made up. By contrast, Ofgem and UK governments have focused on the headline composite price per kWh used, allegedly because this facilitates simple comparisons and thus competition.

17. Perhaps coincidentally, the emphasis on a single final price hides the extent to which UK electricity bills are primarily determined by levies on consumption and network charges, both of which have risen rapidly because of the growth in renewable generation. Other countries have no difficulty in ensuring that comparison websites show the expected total cost of electricity consumption, even when tariffs are far more transparent.

18. The issue facing UK policymakers is that plans to decarbonise the electricity system by 2030 will certainly increase the variability of market prices. Preserving the current regulatory arrangement of setting a cap on prices every quarter will incur higher insurance costs, pushing up the premium over average market prices. This mechanism may not be viable if the hedging market does not have sufficient capacity. Thus, moving to flexible prices in which prices are reset every month with a defined link to the average market price in the previous month would make sense. Currently, this option is limited by the slow progress of the programme to install smart meters in all customer premises.

19. The fiasco that is the government's smart meter programme goes beyond technical issues. It has reinforced the public's general distrust of energy suppliers linked to their record of poor customer service and inept administration. The distrust fuels suspicion that smart meters may be abused to ration electricity or to monitor its use during episodes of constrained supplies. Even though such concerns are distorted and exaggerated, they are fed by an approach to developing policies for the electricity market, which relies heavily on highly optimistic assumptions reinforced by PR and lobbying.

20. Despite the resistance from policymakers and public suspicion, the increase in the variability of market prices that will accompany the commitment to increase the share of total generation supplied by intermittent renewables is likely to force a transition from fixed tariffs to flexible multiperiod and even dynamic tariffs. The question, then, is whether this change can be managed properly and presented to the public as a reasonable option.

21. Given the pattern of short-sighted and incompetent policymaking in the energy sector over the last two decades, this would be asking for a radical shift. It is probably too much to hope for significant improvements in the next 5 or even 10 years. As Sam

Freedman and many others have argued, the UK is patently a failed state,[1] and its decision-making processes are unlikely to change without some major crisis. Hence, the evidence and analysis in this paper are presented partly for future reference when the issues discussed here come to the forefront of wider public debate, and partly to promote a wider understanding of how electricity markets work.

1 See Sam Freedman – *Failed State: How Nothing Works and How We Fix It*, London: Macmillan, 2024. The diagnoses offered by Freedman are a long way from practical remedies that can be implemented over the objections of those who have little to gain from radical change.

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Introduction

Recently there has been a spat in UK media over a proposal by Ofgem to devise a price cap that would apply to so-called "dynamic" tariffs alongside the price cap that applies to fixed tariffs. Much of the reporting only confirms the despair that many energy economists have over the ignorance and insularity of UK politicians and journalists, even ones working for media outlets that purport to be relatively serious.

Some of the comments are prompted by concerns about the effects of the large increase in solar and wind generation on both the level and variability of wholesale electricity prices. For example, what happens when there are very large spikes in hourly or half-hourly electricity prices? In truth, such issues are easy to solve and have been dealt with elsewhere.

The deeper problem is the combination of consistent incompetence and lack of honesty on the part of policymakers and regulators in designing and implementing energy policies in the UK over the last two decades. The adoption of multi-period or dynamic tariffs is linked to the rollout of smart meters which has been an almost unmitigated failure. A quite unnecessary failure as other countries have achieved similar transitions at greater speed and less cost.

Further, energy suppliers in the UK have a well-deserved reputation for poor customer service. It is easy to convince the public that nothing good will come of changes to the way in electricity is priced. For most people, the default position is that if anything can go wrong with energy supply, it will go wrong!

Notwithstanding this background, we must remember that large variations in electricity prices are nothing new. In the 1970s and 1980s many countries in Europe were promoting electric heating by offering off-peak or night-time tariffs to utilise a surplus of low-cost generation from nuclear plants. Technological and institutional changes – including the spread of smart meters, sophisticated data processing, power trading, and the unbundling of electricity utilities – mean that such variability is now more obvious and can provide opportunities that some users may wish to build on.

Many of the arguments against the variable pricing of electricity reflect a longstanding complaint against more reliance on markets. The resources and willingness to take advantage of opportunities offered by markets are not evenly distributed in the population, so that uniform pricing is seen as being fairer and protecting the poor and the vulnerable.

This is akin to Cnut (or his courtiers) attempting to turn back the tide. The efficiency costs of ignoring price and cost variability are large for businesses. That is why markets were liberalised in the past, since businesses account for about 64% of electricity use in the GB market. Once markets and pricing are liberalised for small businesses, it is difficult or impossible to enforce uniform pricing for households as smart meters become more widespread.

To use another cliché, the stable door is open and the horse has bolted. That is why Ofgem is slowly – and perhaps reluctantly – responding to market incentives that are stimulating the more widespread adoption of dynamic pricing, following what has happened in various other countries.

Hence, this paper sets out to explain how variability in wholesale market prices for electricity affects retail prices in different European countries and the options which may determine the evolution of retail pricing in Britain.

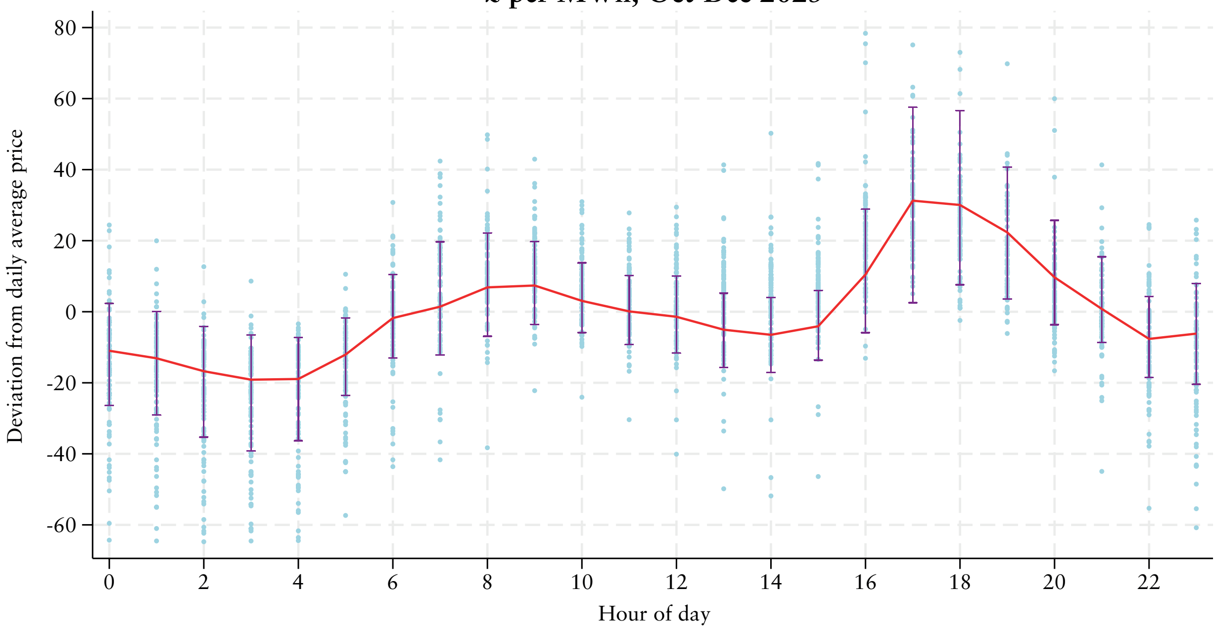
Variability in market prices

The starting point is that the cost of meeting electricity demand varies almost continuously. The reason is that electricity demand varies from minute to minute, from hour to hour, from day to day, and so on. The same, of course, is true for the demand for milk or TV sets or haircuts. The difference is that milk and TV sets can be stored with relative ease and at low cost. When that is not possible, as in the case of haircuts, demand can be rationed or shifted to other periods. However, for electricity both storage and rationing are expensive and sometimes disastrous, as when rationing leads to power cuts.

Figure 1

Average within-day variation in market prices

£ per MWh, Oct-Dec 2023



Source: Author's calculations based on Elexon and Nordpool data

Figure 1 illustrates the variability of GB market prices in the last quarter of 2023. The vertical axis is the deviation between the daily average price and the market price for the relevant hour. The prices are the day-ahead market prices as reported by Nordpool's N2EX power exchange. The solid red line shows the average deviation for each hour over the quarter, while the blue dots show the distributions of daily values around the quarterly averages. Note that each hour is indicated by the beginning of the hour so that the hour from 08.00 to 09.00 is recorded as 08.00. For context, the average market price during the quarter was £82.6 per MWh, while the range between the minimum and maximum values of the hourly mean price was £67.2 per MWh.

The figure shows a systematic pattern with market prices at their lowest in the middle of the night – roughly between 02.00 and 05.00 – and an evening peak from roughly 16.00 to 20.00. There is a secondary peak in the morning and a brief dip in the middle of the day. While this pattern is important and predictable, it is also crucial to be aware that the daily deviations from the hourly average show large variation. The vertical purple lines mark the range between the 10th and 90th percentiles of hourly deviations – i.e. there are roughly 9 days in each quarter in which the deviations fall below the range shown and 9 days in which the deviations are above the range. The ranges of variation are particularly large from 23.00 to 05.00 and to a lesser extent from 17.00 to 19.00.

To handle the variability of demand, any electricity system must rely on various types of short- and medium-term flexibility, which include system inertia and capacitors as well as sources of generation whose output can easily be increased or decreased as instructed. Providing such flexibility costs money and those costs must be recovered, ultimately from electricity customers.

Most electricity systems define a standard pricing period, which may vary from 10 or 15 minutes to one hour, on the basis that generators, energy suppliers and large consumers – i.e. the various participants in the electricity market – can manage flexibility between periods while the system operator manages flexibility within periods. In Britain[2] that standard period is the 30-min settlement period used for the electricity trading arrangement. Germany uses a standard 15-min trading period, while France and Spain use an hourly trading period.

Managing within-period variability in both demand and supply is called "system balancing", whose costs are recovered via balancing charges paid by generators (sometimes) and electricity consumers. Two examples illustrate what is involved:

- In the past, during breaks or at the end of popular TV programmes, there would be a sharp spike in electricity demand as households switched on lights, kettles and other electrical equipment for various purposes. The system operator planned for such spikes, partly by having production capacity on standby (spinning reserve) to feed into the grid

2 There are two electricity markets in the UK. One covers Great Britain, i.e. England, Scotland and Wales. Northern Ireland is part of the Single Electricity Market which covers the island of Ireland, i.e. the Republic of Ireland and Northern Ireland. All references to Britain in this paper relate to the GB market and electricity system. From October 2024 this has been managed by the National Electricity System Operator, a public corporation which has been created by separating NG-ESO from National Grid.

and partly by allowing the system frequency and voltage to fall slightly to absorb the spike in demand. These adjustments kept the operation of the grid stable and within prescribed technical limits.

- Today, solar and wind plants make commitments to deliver certain amounts of electricity to the grid in each period based on detailed forecasts of wind speeds and solar radiation. These forecasts are not always accurate and, in any case, only refer to period averages, while actual wind speeds and sunlight vary randomly from minute to minute. Some of these variations cancel out but the system operator must be able to draw upon flexible reserve generation at short notice.

Total charges for balancing the GB electricity system (called BSUoS charges) have grown sharply over the last decade from about £1 billion per year in 2013-14 to an estimate of £2.9 billion for 2023-24, even though total electricity use has declined by about 20% over the decade. Further, there has been a shift in the incidence of balancing costs. Up to 2023 they were split between generators and users, but now they fall on users alone.

There are large period to period variations in the balancing cost per MWh used. In 2023-24 the minimum value of the balancing cost per MWh was just below zero and the maximum value was £69. A smoothing mechanism is applied so that the BSUoS charge levied in the first 3 months of 2024 was £14.03 per MWh, but this masks rather than removes the underlying variability.

The second dimension of price and cost variability in electricity markets concerns inter-period variations – i.e. from one settlement period to the next. Most European countries rely upon trading between market participants – either explicitly via power exchanges or by contracts that are linked to reference prices determined by power exchange trades – to determine wholesale prices.

The standard model is that daily auctions are held to determine what are called day-ahead wholesale prices for each settlement period in the following day. Participants submit bids to buy or sell power for each period. The bids consist of sell or buy curves – i.e. combinations of volumes and prices which define a full set of offers to buy or sell power from very low (negative) prices to very high prices. The power exchange aggregates these bids for each settlement period and determines the price at which offers to buy and sell power are just matched.

Many power exchanges operate spot markets which allow traders to adjust their positions after the day-ahead prices have been fixed, but it is the day-ahead market that is used to set wholesale prices. Power exchange trades are settled financially as Seller A cannot physically deliver power to Buyer B. The trading system is anonymous, so all that A and B know is that their bids have been matched at the day-ahead price. Instead, A tells the system operator that it has contracted to deliver X MWh to the system, while B tells the system operator that it has contracted to buy X MWh.

There are, of course, many technical complications but the key point is that what are called Final Physical Notifications to the system operator are matched trades, meaning that supply and demand must be equal. The imbalances arising due to deviations from these notifications are what the balancing system described above deals with.

The critical point about such trading systems is that the market clearing price for each settlement period is equal to the bids made to buy or sell the marginal or last unit traded in the auction for that period. Participants who were willing to sell at a lower price or to buy at a higher price receive or pay the auction price irrespective of what their bids were. Not all transactions pass through a power exchange because generators and customers may have long-term sale and purchase agreements that are quite separate. In such cases, power exchanges may be used to adjust demand and supply volumes according to circumstances.

Average prices and pooling system costs

Even though the arrangements for trading electricity are complex and may differ across countries, day-ahead prices provide a robust measure of the marginal costs of matching supply and demand in different settlement periods.

There are two distinct threads to arguments that some or all customers should not be exposed to variability in wholesale prices.

- First, it is suggested that households and small businesses have better things to do than respond to half-hourly or hourly variations in market prices. Perhaps more important, many do not have the flexibility and/or resources required to change their consumption patterns. This argument is presented as one of fairness, but it is rarely repeated when supermarkets offer discount coupons or special offers in-store. Willingness to invest time and money is not evenly distributed across the population. This argument raises the broader issue of whether we should discourage all forms of variable pricing since not everyone responds in the same way when offered such opportunities. Or is electricity pricing a special case with respect to the role of variable pricing?
- The second argument is not directly about variable pricing but challenges the idea of using prices which reflect marginal costs rather than average costs. In economic terms the argument assumes that the marginal cost of electricity supply may rise sharply with relatively small variations. Hence, it is suggested that the small tail of high marginal costs is wagging the large dog of average costs that are much more stable over time.

The first argument is easily addressed by ensuring that variable prices are offered in parallel with fixed prices – or, at least, prices that are adjusted quarterly or monthly. In every European country where dynamic prices – i.e. prices directly linked to hourly market prices – are offered, households and small businesses also have the option of choosing either (i) prices that are fixed for 12 months or longer, or (ii) prices that are varied monthly according to changes in a standard market index. The outcome is a market equilibrium in which customers who prefer stability and insurance can pay for this, while other customers accept price variability in the belief that this will save them money.

The second argument is less easy because it reflects expectations about how electricity prices ought to be set that were created by decades of utility policies and regulatory practice. For much of the 20th century the electricity systems in European countries were managed by vertically integrated utilities which operated as either regional or national monopolies. They were expected to keep the lights on and invest to assure the future stability of the system. In exchange, they were allowed to earn revenues to cover their operating costs and earn a reasonable return on their invested capital. Prices were adjusted infrequently, though utilities might be encouraged to offer special off-peak prices to stimulate consumption during periods when both industrial and household demand would be relatively low.

Aside from special off-peak prices, which relied upon a separate meter to measure off-peak consumption, electricity prices were based on the average cost to serve different groups of customers. So, the belief that average cost pricing is the normal and, indeed, the "right" way to set electricity prices is deeply ingrained in popular and political discourse.

The difficulty is that average cost pricing is both inefficient in economic terms and difficult or impossible to reconcile with the operation of unbundled and competitive electricity systems. The reason is that any mechanism to implement average cost pricing requires pooling either all generation costs or all system costs. This leads, inescapably, to what economists call single buyer arrangements under which all generators supplying the electricity system have power purchase agreements with a central agency, usually the system operator. That is the way in which liberalised electricity systems used to work. Many electricity systems in the Middle East and developing countries continue to operate in this way.

To meet decarbonisation targets, the UK is moving back to a partially pooled arrangement for paying generators, even though this is rarely acknowledged. Under what was called the Electricity Market Reform (EMR) adopted in 2011, the UK established a potential single buyer agency called the Low Carbon Contracts Company (LCCC). It offers Contracts for Differences (CfD) contracts to new generation projects that meet certain technology requirements with the allocation determined by an auction process subject to an overall budget limit. In addition, it offers capacity contracts – i.e. fixed monthly or annual payments – so that plants that do not receive other subsidies continue to be available to supply power when output from intermittent renewable sources is low.

The CfD contracts are disguised power purchase agreements guaranteeing an index-linked price but with no provisions concerning the amount of power delivered to the electricity system. The incentives ensure that generators will deliver as much power as they can whenever they can, though recently CfD contracts have been revised to remove any incentive to deliver power when market prices are negative. Politicians claim that, at some time in future, CfD contracts will yield a consistent surplus because market prices will exceed the prices guaranteed to generators. In the real world rather than the parallel political world, that outcome is extremely unlikely within the next decade because the indexation provisions for guaranteed prices are very generous.

In practice, what is happening is that, via CfDs and capacity contracts, the LCCC is picking up the difference between average costs and market prices for an increasing proportion of the GB generation fleet. The pooled costs of guaranteeing prices for generators are paid by consumers via levies on electricity suppliers, which are, of course, passed on to their customers. The shift in the allocation of balancing costs to customers only and covering those costs by charges adjusted annually or quarterly reinforces the shift towards cost pooling.

As (a) the share of generation supported by LCCC contracts increases, and (b) balancing costs increase as a share of total system costs, the UK system is moving in the direction of a pooled, average cost, pricing system for electricity. This shift is not understood by politicians, commentators, and consumers. Even most academic specialists have little understanding of the way in which the electricity market is changing out of public view.

There appears to be no consistent policy intention behind the shift since many of the changes seem to be *ad hoc* responses to current events and pressures. In as far as any general policy goal can be discerned, this seems to be a consistent desire to hide – and socialise or pool – the costs of promoting low carbon forms of generation. There is nothing unusual about this: the regulation of network costs and charges has operated in the same way for more than two decades.

Renewables and price variability

Variability in market prices is an inevitable consequence of choices about how to meet varying levels of demand in an efficient manner. Different modes of generation have different economic characteristics. Some, like nuclear power or hydro plants, have high capital costs and low operating costs. Others, like gas turbines and diesel engines, have low capital costs and high operating costs. In the middle are coal-fired steam generators and gas combined cycle units.

A centrally managed electricity will minimise operating costs by following what is called the plant **merit curve**. The merit curve is derived by ranking plants from left to right in increasing order of their variable operating cost. The y-axis is variable operating cost, while the x-axis refers to the total capacity of plants with a variable operating cost of £2 or £20 or £100 per MWh of generation. If 20 GW of generation is required, then one looks for the 20 GW point on the x-axis and then up to the point on the merit curve corresponding to that value. The y-value for that point on the merit curve gives the minimum price required to ensure that 20 GW of plants will be willing to run and supply electricity. In the familiar terms used by economists, the merit curve is the supply curve for electricity in each period.

Unfortunately for outsiders, power engineers and economists often refer to the **merit order**. Using the implicit assumption that being top of the ranking is good, the merit order ranks plants from top (plants with the lowest variable operating cost) to bottom (plants with the highest variable operating cost). So, mentally, it is necessary to translate from top of the merit order (the best or cheapest plants) to the left of the merit curve.

For practical reasons, the merit curve will vary somewhat between periods to take account of the costs of plants starting up, shutting down, or running as standby reserve. The merit curve may shift if fuel prices change or water levels in hydro reservoirs are particularly high or low. Subject to those adjustments, the cost of running the highest cost plant required to match supply and demand in any period establishes the implicit or explicit marginal price for that period.

In a decentralised system, such as one with day-ahead auctions, aggregate offers to supply electricity in each period will follow the merit curve, and on average, the market prices will match the outcome based on the intersection between total demand and the merit curve. However, the advantage of a decentralised system is that a central operator does not – and cannot – have all the information about each plant in each period required to implement an efficient centralised system. While market trading seems to be a messy and even expensive activity, the core of the process is stimulating participants to reveal information which cannot be obtained reliably in any other way.

The introduction of intermittent renewable generation, perhaps along with subsidies for low carbon forms of generation, does not change the basic logic by which the least expensive way of matching supply and demand is identified in each period. Intermittent renewable generators have similar characteristics to hydro – high capital costs and low operating costs. They are also simpler because wind and sunlight cannot be stored, whereas hydro plants with storage reservoirs have the option, so long as the reservoir is not full, of storing water for some later period.

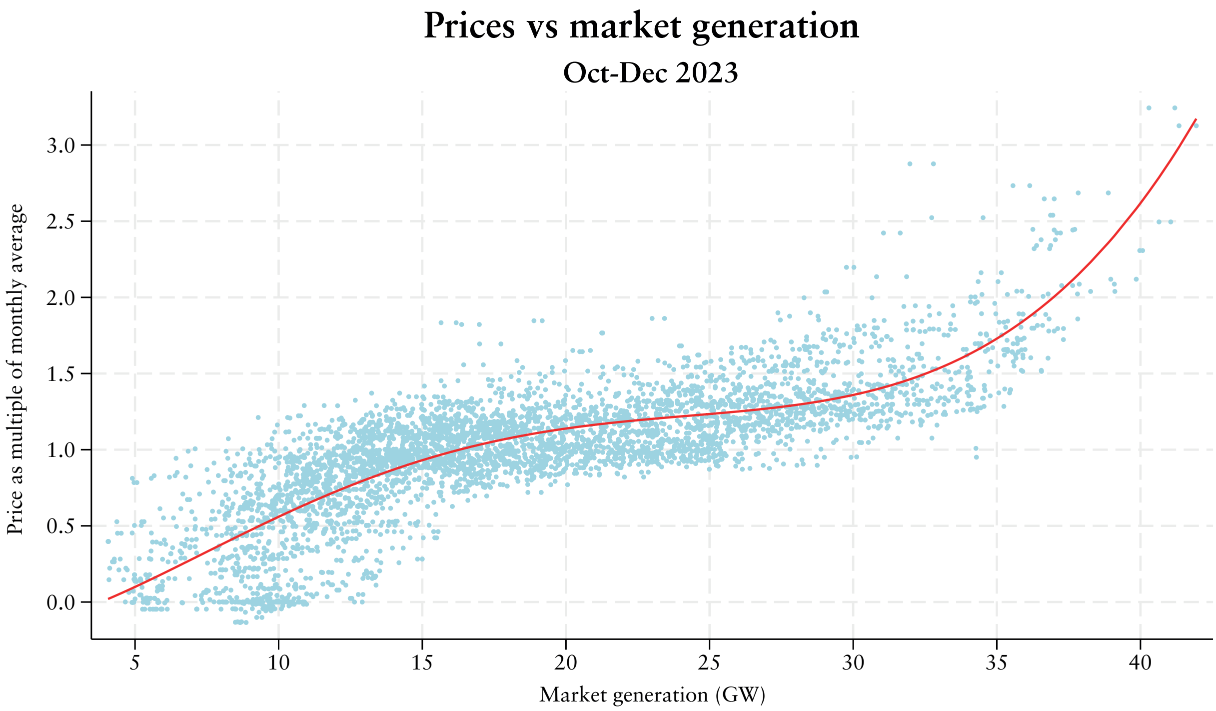
In terms of the merit curve, solar and wind plants come at the left side with zero or minimal operating costs. They will operate whenever they are able to generate unless total demand is less than the potential output from solar and wind plants. In such conditions, supply must be curtailed either following instructions from the system operator or via economic incentives, including negative prices, which encourage generators to shut down production.

A separate category consists of renewable generators that do not have zero or very low operating costs, but which receive subsidies per MWh of output. The main sub-group consists of plants that burn biomass, primarily wood pellets, and receive either (i) a subsidy via Renewable Obligation Certificates (ROCs) in addition to the market price, or (ii) a guaranteed price via CfDs. Other, smaller, sub-groups include plants using landfill gas, sewage gas, anaerobic digestion, and other forms of gasification using bio-residues. In all cases the subsidy exceeds the cost of the feedstock used, so plants operate when there is sufficient feedstock available. While they are not technically intermittent generators with very low operating costs, the subsidy regime ensures that they behave in the market in the same way as solar and wind plants.

Intermittent output from solar, wind and subsidised bioenergy plants causes the merit curve to shift. When output from these plants is high, only small amounts of generation are required from other plants to match a fixed level of demand and hence the market price will be low. On the other hand, when solar and wind output is low, much higher amounts of generation from other sources are required and the market price will be higher. How much higher depends on the slope of the merit curve, i.e. how much the market price must increase to persuade an additional 1 GW of generation capacity to start up.

The broad shape of the merit curve in Britain in the last quarter of 2023 is illustrated in Figure 2. The overall level of market prices is closely related to the wholesale cost of gas because gas plants provide almost all the flexibility that is required to accommodate intermittent output from solar and wind plants. To remove the influence of gas prices, the market prices in each period are divided by the monthly average wholesale price of electricity for each month. Thus, the vertical axis shows relative changes in the market price. The horizontal axis shows total demand **minus** intermittent and subsidised generation, which is the amount of generation determined by market price.

Figure 2



Source: Author's calculations based on Elexon and Nordpool data

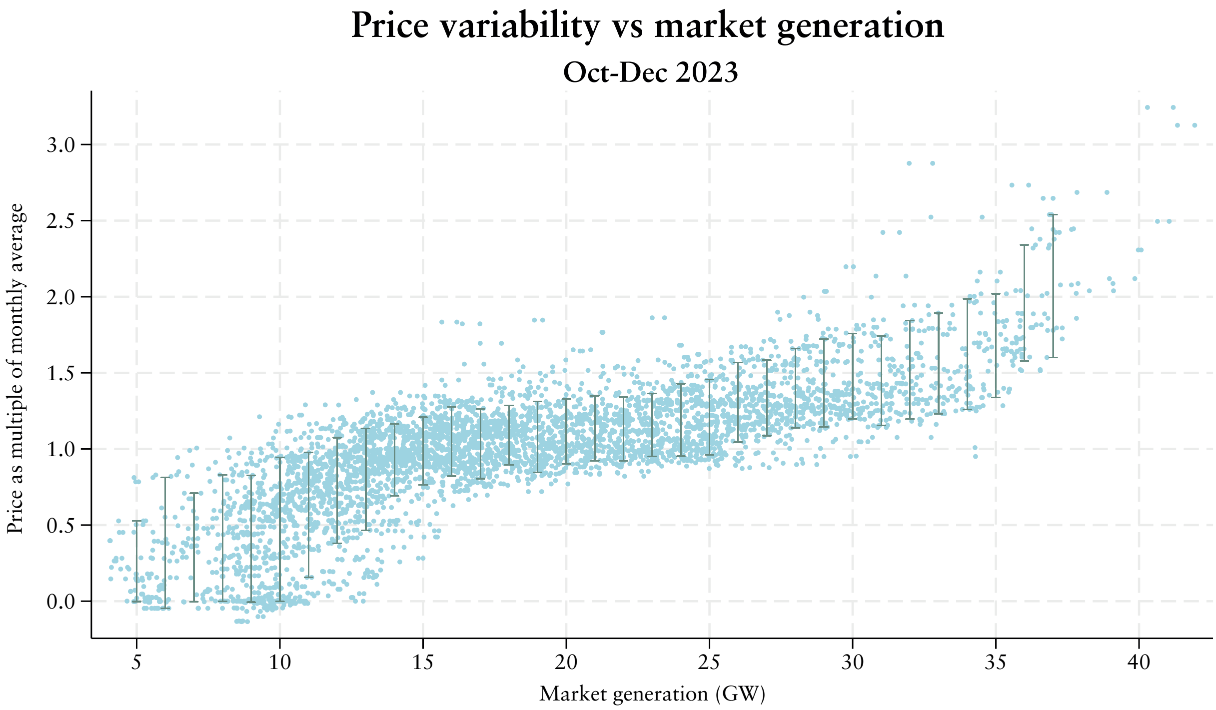
The blue points in the graph are combinations of normalised market price and market generation, while the red line is the best polynomial fit to the points. The fitted curve rises quite steeply as the amount of market generation increases from a low level to about 15 GW. Above 15 GW, the line is less steep until market generation reaches 30 GW, after which the market price starts to increase more steeply to obtain more market generation.

To understand the graph, consider a period in November 2023 for which total demand for electricity is an average of 35 GW. Total supply from intermittent and subsidised generators for the period is 15 GW, leaving 20 GW to be covered by market generation. Based on the fitted line, the expected market price associated with market generation of 20 GW is 1.14 times the average monthly price, which translates to £91 per MWh.

This logic differs from the way in which economists usually deploy demand and supply curves. The figure shows the price-responsive component of electricity supply rather than the more conventional intersection of price-responsive supply and demand curves. The crucial assumption is that neither total demand nor output from intermittent and subsidised generators is significantly affected by the market price. This reflects reality and implies that within each period the demand for market generation is independent of price.

On the demand side, few customers currently pay prices that are linked to the market price in the current period and even those which do pay such prices – some industrial customers and other customers on dynamic tariffs – have limited opportunities to switch consumption. Well-publicised examples of demand response focus on switching off sources of demand for grid supplies when prices are or are likely to be very high. This is not the kind of price response that economists usually capture in their demand curves. On the supply side, intermittent and subsidised generators have large incentives to supply whatever they can generate whatever the level of market prices. The only exception is special provisions concerning the payment of subsidies during periods of negative prices, which were of minimal relevance in 2023.

Figure 3



Source: Author's calculations based on Elexon and Nordpool data

We may distinguish two sources of variability in market prices. First, in the example above, market generation of 20GW is not associated with a certain price of 1.14 times the monthly average market price. There are many other factors that may be purely random which affect the market prices – for example, plant or grid outages. So, instead of a certain price, we should expect that a specific level of market generation is associated with a range of market prices. This is illustrated in Figure 3. The red line showing the polynomial curve which best fits the data is replaced by vertical bars showing the ranges between the 10th and 90th percentiles of the distribution of outcomes for each level of market generation rounded to the nearest whole number.[3]

Returning to the example above, if the level of market generation is 20 GW, there is an 80% chance that the market price will fall between 0.9 and 1.33 times the monthly average price. The ranges exclude the bottom 10% and the top 10% of the distributions for each level of market generation. They provide a good idea of the likely variability of market prices given market generation. This variability is high for relatively low and high values of market generation, i.e. below 14 GW or above 30 GW. As the example illustrates, there is significant price variability

3 Range bars are not shown for market generation of less than 5 GW or more than 37 GW because the number of observations for each level of market generation below or above these thresholds is too small to derive reliable estimates of the 10th and 90th percentiles.

when market generation falls between 15 GW and 30 GW, but it is less than for the two ends of the distribution.

Second, there is price variation caused by variations in demand for market generation. For practical purposes, the amount of market generation required is determined by exogenous factors – primarily weather conditions, seasonal patterns, and time of day. Anyone wishing to understand variations in market prices can either examine such external factors or simply look at the observed variation in market generation.

For example, the average demand for market generation in November 2023 in the settlement period from 18.30 to 19.00 GMT was 27 GW with a minimum of 16 GW and a maximum of 37 GW. That variation translates to a range for the expected relative price from 0.99 to 2.01 using the central estimates or from 0.82 to 2.54 using the full 80% ranges discussed above. In money terms, the range of central estimates is £80 to £161 per MWh, while taking account of uncertainty in the estimates increases this to a range from £65 to £203 per MWh.

That variation is for one settlement period in the month. Extending the comparison to the whole of November but excluding the lowest 1% and the highest 1% of values, the range of market generation was from 5 GW to 37 GW. These translate to a range of market prices in money terms from £0 to £203 per MWh.

These calculations show that the variability of market generation in one month gives rise to a very large range of market prices because of the upward-sloping relationship between market generation and market prices. With some basic statistics, we can go further than this by asking the following question: has the increase in intermittent and subsidised generation (ISG) over recent years increased the variability of market generation? If that is true, then we may infer that this change has increased the variability of market prices.

To do this, it is necessary to define how to measure variability or dispersion in this context. The most common statistical measures of the dispersion of a variable are (a) its variance, which is the mean of the sum of squared deviations between values of the variable and its average value, or (b) its standard deviation, which is the square root of the variance and is of a similar order magnitude to the average.[4] Note that the use of the square in the variance gives greater weight in the sum to large deviations from the average, and that characteristic remains after taking the square root to obtain the standard deviation. However, the values of the variance and the standard deviation are not independent of the unit of measurement and mean of the variable. Instead, in this discussion I will focus on the coefficient of variation, which is the standard deviation divided by the mean value, as this has the dimension of a pure number.

Recall that market generation is the difference between total demand[5] and ISG. Empirically, the correlation between the two variables is very close to zero, so they are approximately inde-

4 There are alternative measures of the dispersion of a variable. One of the more widely used alternatives is the mean absolute deviation, which is the average value of the deviation between the value of the variable and its mean expressed as a positive value. The variance and its transforms give more weight to extreme values of the variable, i.e. values furthest from the mean. This seems reasonable in a context where we are particularly concerned about very high or very low values.

5 Note that the estimate of total electricity demand used here differs from total system demand reported by the system operator, which only covers electricity demand seen by grid meters. My estimate includes demand that is met by "embedded" generators which are not grid-metered because they are connected to distribution networks. These include almost all solar plants, many onshore wind plants, a small number of offshore wind plants, and many small

pendently distributed. There is a standard proposition in statistics which states that the variance of the **difference** between two independently distributed variables is equal to the sum of the variance of each variable. Hence, so long as total demand and ISG are independently distributed, the variance of market generation **must** be greater than the variance of total demand.

Table 1 – Variability of demand and market generation

Year	*Total demand (GW)*			*Market generation (GW)*		
Oct-Dec	*Mean*	*Standard deviation*	*Coefficient of variation*	*Mean*	*Standard deviation*	*Coefficient of variation*
2015	39.0	7.1	18%	31.4	7.2	23%
2016	39.6	6.9	17%	32.4	7.2	22%
2017	39.8	7.6	19%	28.4	8.0	28%
2018	38.5	6.9	18%	24.9	7.2	29%
2019	38.7	6.8	18%	24.7	7.2	29%
2020	36.8	6.6	18%	22.4	7.8	35%
2021	37.1	6.6	18%	21.3	7.6	36%
2022	36.7	6.0	16%	20.4	8.0	39%
2023	35.8	6.1	17%	18.7	7.6	41%

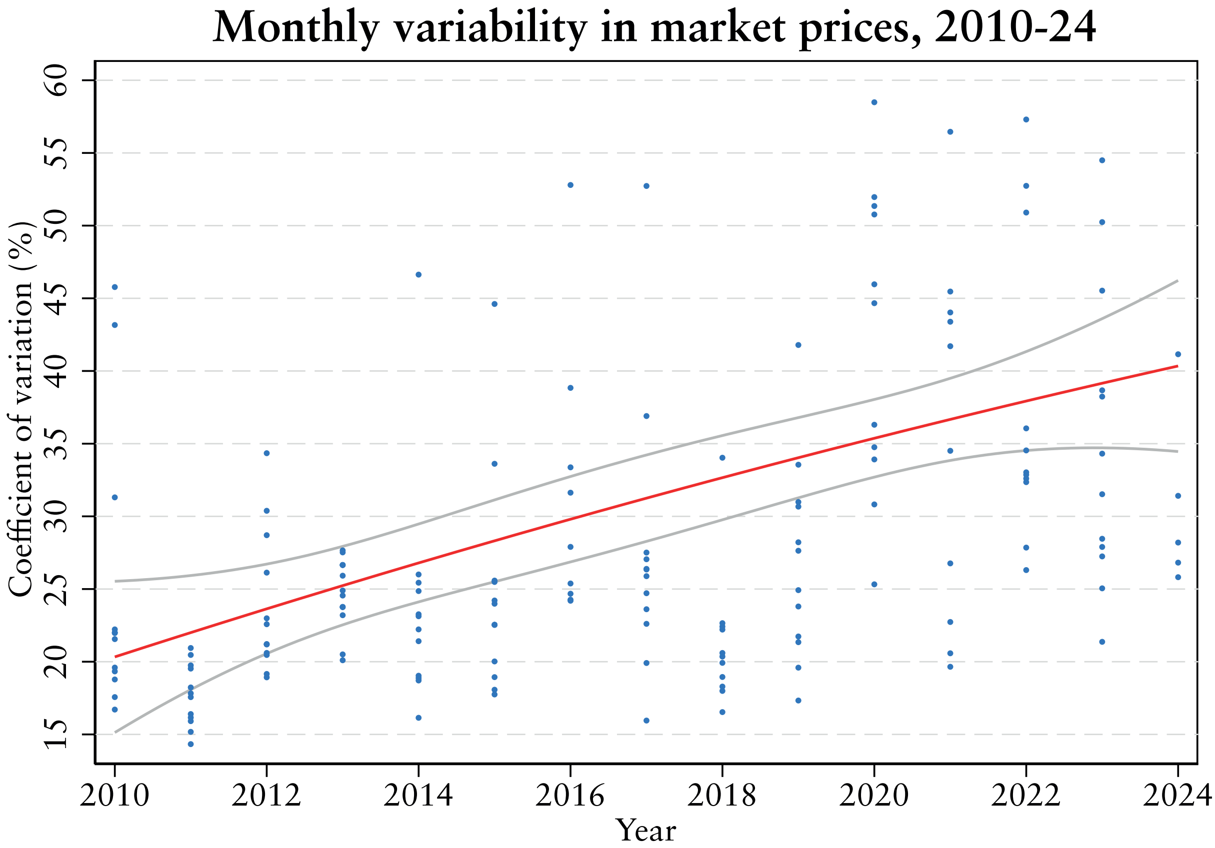
Source: Author's calculations based on Elexon data

Table 1 shows the mean values, standard deviations and coefficients of variation for total demand market generation for October to December for each year from 2015 to 2023. Both the mean and standard deviation of total demand have fallen while the coefficient of variation has remained roughly constant. In contrast, the mean of market generation has fallen sharply, because of the growth in the amount of intermittent and subsidised generation but its standard deviation has risen slightly. Thus, the coefficient of variation of market generation has nearly doubled over the 8-year period.

These results clearly show that, on any reasonable assessment, the variability of market generation has increased substantially over the medium term. This increase in variability is due to the increase in both the average amount and variability in the level of intermittent and subsidised generation. This translates to a greater variability in market prices. Further, it seems reasonable to infer that the trend towards higher variability in market prices will continue in the medium-term future because the growth in intermittent and subsidised generation is expected to continue for at least a decade.

bioenergy plants. From the point of view of the grid, embedded generation reduces the system demand that must be met by grid-connected generators.

Figure 4



Source: Author's calculations based on Elexon and APX data

Figure 4 shows how the monthly variability in market prices has increased since 2010.[6] The red line shows a quadratic fitted to the full dataset, while the grey lines show the 90% confidence intervals for the fitted line. The blue dots are the monthly values of price variability. The coefficient of variation has clearly increased substantially from 2010 to 2024, and by 2024 it was nearly double its level in 2010. This change is fully consistent with the impact of growth in intermittent renewable generation on the variability of market prices discussed above. Note also that the number of months with extreme levels of price variability has increased very markedly since 2020. In part, this reflects the volatility of gas prices during and after the pandemic, but this was reinforced by the impact of commissioning large offshore wind farms during the same period.

Retail supply and price variability

The increase in the variability of market prices poses an ever-greater problem for regulators and energy suppliers because of the disconnect between customer expectations and market reality.

6 The figure is based on the variability in Elexon's market price index, which uses data on spot market prices supplied by APX in the period 2010-24. The data series extends back to 2005, but the spot market was relatively thin with low volumes traded before 2010, so estimates of price variability were erratic. Price variability is measured by the coefficient of variation in hourly average prices during each month. A small number of outliers with coefficients of variation > 60% have been excluded from the figure to ensure that it is readable.

For understandable reasons, most households and many small businesses expect electricity prices that are fixed over some extended period – varying from a quarter to a year or longer. This is what a large majority of households and businesses are used to, not only going back to the period of vertically integrated monopolies but due to the way in which regulators have promoted market competition over the last two decades. The ideal was that customers should use price comparison sites to switch to an energy supplier that would offer the lowest fixed price for 12 months or longer.

The reality is that this regulatory ideal was and is not commercially viable in the face of the increasing variability of market prices. The outcome has been an increasingly unrewarding game of whack-a-mole by which suppliers have sought ways to satisfy regulatory and customer pressures to offer extended periods of fixed prices while the costs of purchasing insurance against price variability have inevitably increased. This balancing act collapsed due to the large movements in average market prices between March 2020 and March 2022 because of first the Covid-19 pandemic, then the rapid upswing in prices during the 2021 recovery, and finally the impact of the Russian invasion of Ukraine. It is entirely wrong to believe that all the problems of retail electricity supply can be ascribed to the last factor. That was merely the final element in what had been a rapidly deteriorating situation for nearly a decade.

There has been another factor which has undermined the competitive model promoted by regulators and politicians. Commitments to expand the use of renewable and low carbon energy translate to a whole slew of schemes ranging from the Renewables Obligation to upgrading networks and ensuring sufficient capacity as backup for intermittent sources of generation. All these programmes cost money, in some cases a lot of money. Energy suppliers have been deputed to collect the various levies from their customers, but they are discouraged from doing so in a transparent manner.

In many countries in Europe, your electricity bill shows the wholesale cost of the electricity which you consume, network charges, mandated levies to fund green programmes, the retailer's margin, and taxes. Energy supplier and comparison websites provide similar information and make it clear that network charges, mandated levies and taxes are pure add-ons, outside the supplier's control.

In the UK, most of the emphasis is on a single figure, the gross cost per unit of electricity with (typically in smaller type) a daily standing charge – and even that is heavily criticised by some consumer advocates. There are generous and more cynical interpretations of this emphasis. The generous one is that most consumers don't or can't absorb more than the most basic information and so competitive information must be presented in the simplest possible way. The more cynical view is that this justification rather conveniently hides the extent to which the wholesale price of electricity constitutes a decreasing share of the retail price of electricity. This is easily verified: over the last two decades, the wholesale cost of electricity has fallen from a little above 40% of retail electricity bills to about 20%, and that trend is likely to continue.[7]

7 These figures are based on calculations by the author using (a) electricity prices in the wholesale market, and (b) average retail prices paid by households reported in the official publication Quarterly Energy Prices. The period covered was from 2005 onwards.

It is, of course, convenient for politicians and regulators to treat energy suppliers as designated villains, and they live up to their role all too often. Even so, this pantomime view of competition in energy markets is deeply dysfunctional. The costs of papering over the variability in wholesale prices are increasing, whether this is done by market hedging or implicit price smoothing by suppliers. It is not clear that the hedging market has sufficient capacity to handle the full volume of consumer demand, and there is always the possibility of disruption due to bankruptcies caused by hedges that go wrong. But, relying on price smoothing is even more risky for undercapitalised suppliers, as many found to their cost following the large price rises in 2021-22.

In the longer term, the central question is whether households and small businesses want or need to be protected from the variability in market prices. The standard economic argument is that if customers pay fixed prices, they have no reason to adjust their consumption to the level of market prices; indeed, doing so may be difficult and expensive. While this point is correct, the counter argument is that the scope for adjusting consumption to real-time changes in prices is quite limited and many customers given the opportunity do not take it up.

Customers in the UK and many other countries can sign up for multi-period tariffs that may offer significant price discounts for off-peak periods. In the past, this was cumbersome because separate meters and electricity circuits were required, but smart meters make the process very easy. Multi-period tariffs are the default in countries like Italy and Spain where coverage of smart meters is nearly universal.[8]

The experience in the rest of Europe does not suggest that there is no or very limited demand for variable pricing. Indeed, the reverse is true if the option is properly presented and seen as being fair. To understand this, it is helpful to define terminology more carefully. In Scandinavia and other countries in Western Europe, the following terms are used widely:

- **Fixed tariffs** are prices fixed for a minimum of three months and sometimes longer. They include multi-period tariffs such as peak and off-peak rates where off-peak rates apply from, say, 11 pm to 7 am local time and sometimes on Sundays.
- **Flexible tariffs** are prices that are adjusted monthly, usually by reference to a standard index of market prices in the previous month. For example, flexible tariffs in Italy are linked to what is called the PUN, which is a national index of prices computed by the power exchange GME in Milan according to a procedure approved by the regulator.
- **Multi-period tariffs** can be either fixed or flexible. The price paid varies in a pre-determined manner according to the time of day. At a minimum, there is an off-peak period from late evening to 07.00 or 08.00 and a peak period for the rest of the day. Three period tariffs include a shoulder or middle period from mid-morning to late afternoon. Sundays are usually treated as off-peak, while the treatment of day-time hours

8 The design of smart meters varies a lot across European countries. In Italy smart meters record consumption for three standard periods, whereas in Spain they record hourly consumption. In most countries, the meters are relatively simple and rely on electricity networks for reporting consumption. The UK, sadly, adopted an over-engineered and poorly thought-through specification based on half-hourly reporting by wireless. The consequence is a slow roll-out plus a significant proportion of smart meters which don't work properly or at all.

on Saturdays varies across countries. The standard formula for multi-period tariffs is to define a fixed or flexible base tariff (such as the PUN in Italy) and apply pre-defined multipliers to the base tariff for each period.

- **Dynamic tariffs** are prices that are directly linked to the current market price – usually these are hourly prices, but in Britain this could be half-hourly. In Scandinavia, dynamic tariffs are based on the Nordpool hourly market price for the bidding zone in which the consumer is located. In Spain there is a special PVPC dynamic tariff, designed for low-income households, which is a regulated price calculated by the system operator that combines the OMIE hourly market price with an allocation of network costs based on usage by hour of the day.

The central point of flexible, multi-period and dynamic tariffs is that they transfer different degrees of risk from the energy supplier to the consumer. For dynamic tariffs in particular, the electricity supplier may add an element of insurance by offering a floor and a cap on the prices charged, so that customers are not exposed to extreme spikes in market prices, though the trade-off is that they will not benefit from very low, zero or negative prices. Such insurance costs money, either by foregoing very low prices or via a charge levied by the supplier, but many customers are willing to pay for protection against price spikes.

While it is difficult to obtain up-to-date figures, the evidence suggests that many – perhaps the majority of – households in Scandinavia are on dynamic tariffs. For Spain it is reported that nearly 40% of households are on the PVPC dynamic tariff. Flexible multi-period tariffs are the default in Italy and are gradually spreading in Northern European countries, including Austria, Germany and the Netherlands, as well as among those not on dynamic tariffs in Scandinavia. As an example, the penetration of smart meters in Germany is low, so flexible tariffs have been adopted as the first step towards dynamic pricing. The current German government has promised to accelerate the roll-out of smart meters from 2024 onwards, expecting that this will lead to a widespread adoption of dynamic tariffs in future following the Scandinavian model.

Flexible and dynamic tariffs have overlapping but basically different purposes. Flexible tariffs are a form of risk-sharing between suppliers and customers. They eliminate the necessity for suppliers to hedge market prices for more than a month ahead. Most forward contracts are for baseload, so hedges don't cover hourly price variations which must still be managed in other ways by suppliers. For countries with limited forward markets, flexible tariffs offer the best way of ensuring that energy suppliers are protected against uninsurable risks while offering a degree of price certainty to customers.

Dynamic prices transfer all price risk from suppliers to customers, but volume risk remains and may be enhanced by the response of customers to price fluctuations. Since market prices are day-ahead prices, customers have time to adjust their consumption to avoid periods in which prices will be high. In practice, manual responses to price changes are usually seen as involving too much effort for the savings that can be made. Instead, adjustments in consumption patterns tend to fall into two categories.

First, dynamic prices are treated as a more elaborate variant of peak and off-peak (multi-period) pricing, so timers and other mechanisms are used to transfer consumption from periods when prices are high on average to other periods when they tend to be low. Simple rules of thumb – more formally, heuristics – can save customers significant amounts of money at relatively low cost. Once suppliers understand the average response of customers on dynamic prices, they can easily manage the volume risk and, indeed, seek to influence the behaviour of customers by notifications or other interventions.

Second, both suppliers and third parties may offer automated solutions to allow their customers to optimise their electricity consumption. Such solutions usually focus on a small number of activities that account for a significant fraction of electricity consumption and whose timing can be adjusted – e.g. charging electric vehicles and backup batteries or heating and cooling. There has been a business market for such automated responses to dynamic prices for more than two decades. The costs of management can exceed the potential benefits of reducing electricity bills. Still, as dynamic prices become more widely available, learning is likely to mean that the adoption of automated management systems will grow. Energy services companies that specialise in both energy conservation and management have a niche in the business sector, but it is unclear whether their costs can be low enough to be viable for households and small businesses.

Arbitrage and storage

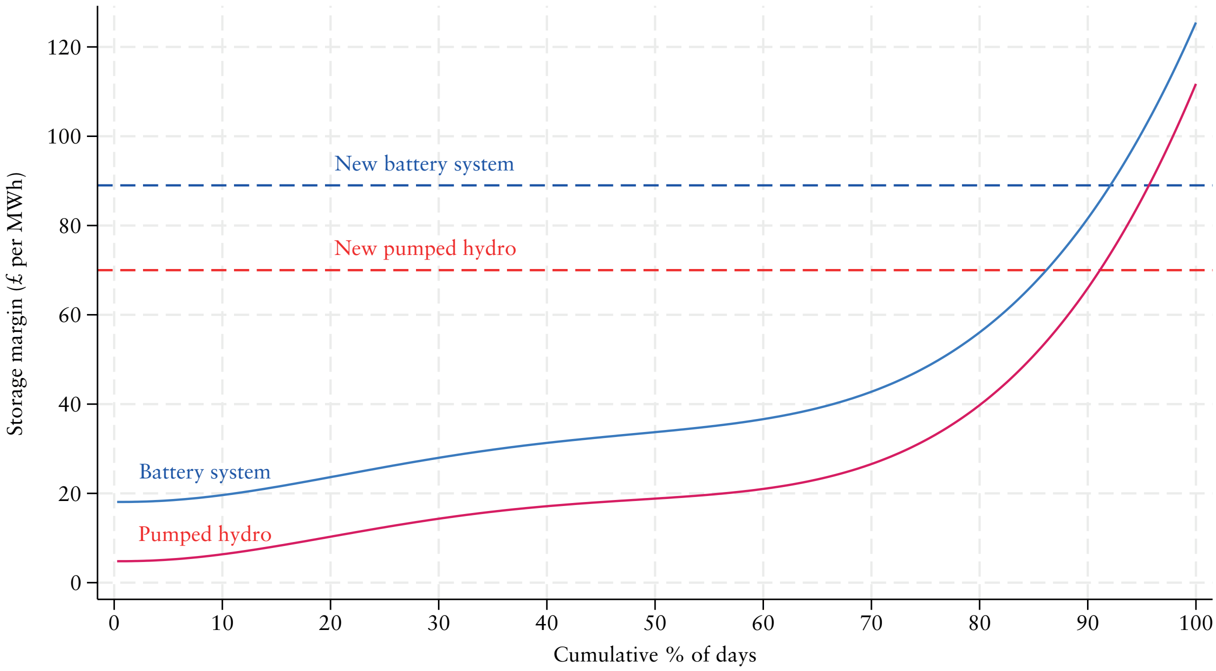
With large amounts of potentially predictable variability in electricity, most economists will ask why there isn't more arbitrage in electricity markets – i.e. buying when prices are low and selling when prices are high. The reason, of course, lies in the difficulty and expense of (a) shifting the timing of demand, and (b) building and operating storage systems. Patterns of demand are heavily influenced by social arrangements and working patterns, which in turn depend on climate as well as changing weather conditions. Attempts to shift demand patterns by offering price discounts when demand is low and market prices tend to be low have rarely had more than a small impact on the extent and timing of peak demand for residential consumers. Industrial and commercial customers have long been able to take advantage of lower off-peak prices, but they too are heavily constrained by standard working arrangements.

Any discussion of electricity storage that focuses on separate storage arrangements is rather misleading. The primary source of storage in most electricity systems has always been and remains the use of fossil fuels, supplemented by reservoir hydro and biomass fuels. The greater the energy density of a fuel the more suitable it is as a storage medium. Thus, the transition from burning fossil fuels to renewable generation implies a progressive loss of storage capacity for electricity systems, which must be replaced at great expense.

Figure 5 provides some key data required to understand the economics of investing in electricity storage in the UK. The storage margin for two forms of storage – pumped hydro reservoirs and lithium-ion battery systems – is calculated as the difference between the average market price during the hours in which electricity is generated from storage and the average market prices during the hours in which the storage is replenished. The standard storage capacity for battery systems is four hours and, allowing for what are called round-trip losses, battery systems are replenished over five hours or more. In the case of pumped hydro, the usual generation period is six hours, with replenishment (pumping) over seven hours. I have assumed that this cycle occurs daily with generation during the hours in which the market price is highest and replenishment during the hours in which the market price is lowest. The average round-trip losses incurred over the full cycle are assumed to be 10% for battery systems and 20% for pumped hydro.

Figure 5

Cumulative distributions of storage margins in 2023



Source: Author's calculations based on Nordpool data

The solid lines in Figure 5 labelled pumped hydro and battery system show the cumulative distributions of the daily storage margins in £ per MWh generated from storage. Thus, for 40% of days in 2023 the pumped storage margin was less than £20 per MWh (the intersection of the red line with the vertical line for 40% of days), while for only 20% of days in 2023 was the pumped storage margin greater than £40 per MWh. The battery storage margins are consistently greater than the pumped hydro margins for two reasons: (a) the round-trip losses are lower for modern battery systems than for pumped hydro, and (b) battery systems operate for a few hours per day, so that the average market price will be higher during periods of generation and lower during periods of replenishment, assuming that the battery system is operated flexibly and efficiently.

Any potential investor in electricity storage needs to believe that the average storage margin over the life of its plant will cover capital costs and annual fixed operating and maintenance (O&M) costs. I have used estimates from a standard US source – the National Renewable Energy Laboratory (NREL) – to calculate these costs converted to a total amount per MWh of generation in the year for battery systems[9] and pumped hydro[10]. These are shown as the blue (for a battery system) and red (for pumped hydro) dashed lines in Figure 5. The average storage margin required to cover capital and fixed O&M costs is higher for a battery system than for pumped hydro because (a) the expected life is shorter, and (b) the expected number of hours of generation is only 1460 per year for a battery system vs 2190 for pumped hydro. Neither battery systems nor pumped hydro are suitable for storage for periods of significantly more than a day.

For both battery systems and pumped hydro, the required storage margins to justify investment correspond to approximately the 90th percentile of the cumulative distributions – i.e. such margins were only exceeded in roughly 10% of all days in 2023. The average storage margins over the whole year were £42 per MWh for a battery system and £28 per MWh for pumped hydro. These average margins were less than 40% of the storage margins required to cover the cost of capital on their project investments.

More important, in no year from 2015 onwards has the average storage margin at 2024 prices been sufficient to cover the required storage margin to cover the fixed costs for either type of storage project. The average storage margins were highest in 2022, and even in that year the average storage margins were only 85-90% of the break-even margins. Without large subsidies or a much lower cost of capital, investments in electricity storage serving the GB electricity system are not financially viable. The outlook for alternative forms of electricity storage such as compressed air or hydrogen is much worse.

Even if, as some assume will happen, the costs of building battery systems fall by 50% in the next decade, they will still not be financially viable at current levels of variability of market electricity prices. Both now and for the next decade, the future of large-scale electricity storage will be entirely determined by the amount of money that is available to underwrite the subsidies that will be required. At the same time, since price variability will not be constrained by investment in commercial arbitrage, the variability of market prices is likely to continue to increase along with the share of non-market renewable generation.

An alternative form of arbitrage is via changes in the volume and direction of interconnector flows, i.e. imports and exports of power from neighbouring countries. However, we should remember that these countries are also moving – in some cases even faster – towards greater reliance on non-market renewable generation. The factors which lead to large variations in the

9 See: https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage. The NREL is notoriously optimistic about the rate at which typical costs will decline in future. I have used estimates based on their "Moderate" scenario for 2025 converted from USD to GBP at an exchange rate of £1=$1.24. The capital cost is for their standard utility-scale battery system with generating capacity of 60 MW and 4-hour storage. The life of the plant is assumed to be 20 years and the cost of capital is 6% – both values are optimistic under current conditions.

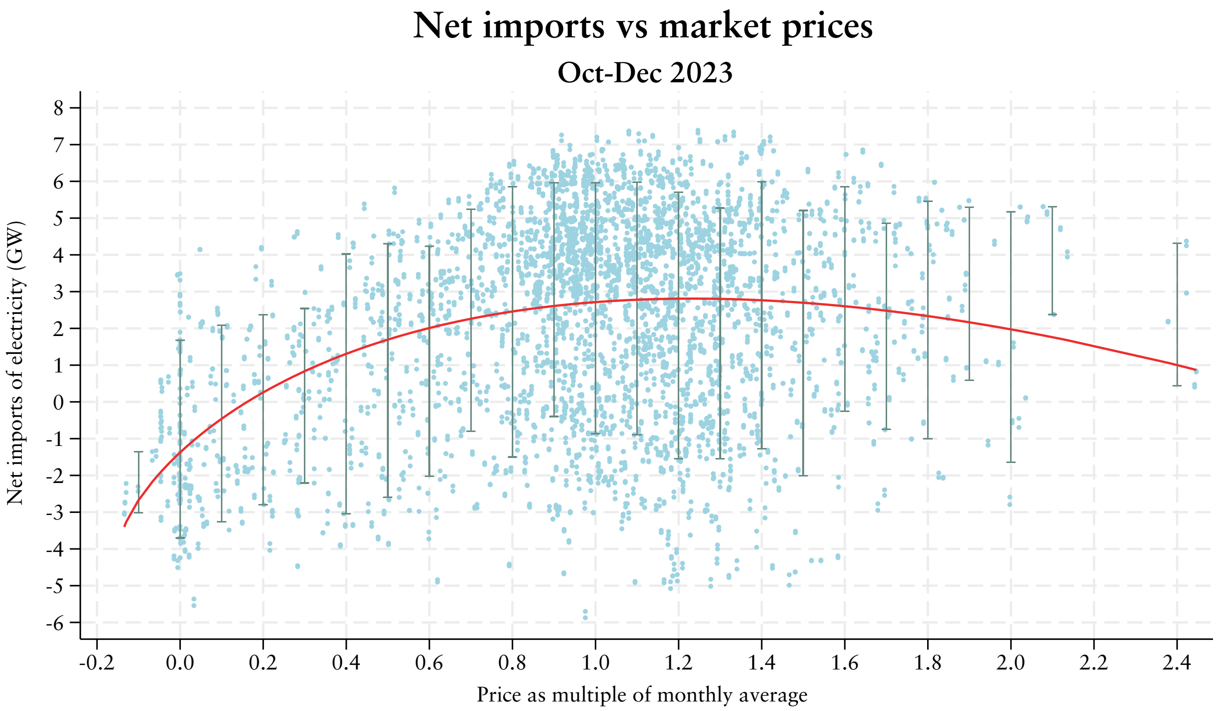
10 See: https://atb.nrel.gov/electricity/2023/pumped_storage_hydropower. The standard NREL costs are based on a National Class 3 resource with an average capital cost of $2.7 million per MW of generating capacity, a generating capacity of 600 MW and a planned life of 50 years with a cost of capital of 6%. For a Class 1 resource the average capital cost is $1.5 million per MW, but such favourable conditions are quite rare. Drax claims that the cost of its Cruachan 2 development will be about £0.83 million per MW – https://www.drax.com/press_release/drax-given-green-light-for-new-500-million-underground-pumped-storage-hydro-plant . Even allowing for the cost advantages of building an extension to an existing plant, that seems very optimistic. SSE, which is planning to develop a pumped hydro scheme at Coire Glas – https://www.sse.com/news-and-views/2023/03/britain-s-largest-pumped-hydro-scheme-in-40-years-gets-100m-investment-boost/ – quotes a total cost of about £1.15 million per MW of generating capacity for a 1,300 MW scheme. Based on experience, the final cost is likely to be at least 50% higher than that figure, so the standard NREL estimate is a reasonable guide.

volume of renewable output are highly correlated across countries and markets. Most obviously, this applies to seasonal and diurnal variations in solar output. Since the North Sea basin accounts for a large share of both offshore and onshore wind generation in NW Europe, weather systems covering the North Sea affect many countries in similar ways.

Figure 6 illustrates the relationship between net imports and market prices in the final quarter of 2023. The total capacity of GB interconnectors was 7,900 MW in October 2023, which increased to 8,7000 MW when the Viking Link started to operate in December 2023, though with a restricted capacity of 800 MW until the completion of a transmission link in Denmark in 2025. The interconnectors are rarely used at close to full capacity. The 1st and 99th percentiles of net imports in the quarter were exports of 4.3 GW and imports of 6.8 GW.

The solid line in the figure, which is the best fit fractional polynomial, suggests that net imports increase with market prices but only up to the middle of the full range of prices over the quarter. Beyond that point, any relationship between market prices is very poorly determined and may be counter-intuitive, with higher prices being associated with lower imports. Most likely, periods of high market prices reflect low levels of solar and wind generation in both Britain and West Europe, so that imports to Britain are constrained by limited supplies and high prices in West European markets.

Figure 6



Source: Author's calculations based on Elexon and Nordpool data

The vertical bars show the ranges between the 10th and 90th percentiles of imports for different pooled prices. These confirm the large variations in the empirical relationship between net electricity imports to Britain and market prices in the GB market.

Overall, Figure 6 suggests that price arbitrage via imports and exports of electricity is a very weak stabilising force in the GB electricity market. There is no reason to suppose that either the current level of interconnector capacity or the larger capacity planned for 2030 will have any major impact on reducing the increase in price variability in the GB market, which is likely to be an inevitable consequence of the transition to greater reliance upon intermittent solar and wind generation.

Adapting to greater variability in market prices

The large increase in the variability of electricity market prices that has occurred over the last decade is a structural change that has occurred during a period when the attention of policy-makers has focused on short-term factors which have a more immediate impact on household and business finances.

Much of the public commentary on market electricity prices focuses on the repeated claims that intermittent renewable generation is "now" cheaper than conventional generation. Even if this were true, the claims are based on contracts to supply power 8 or 10 years in the future. The renewable generators operating today have, on average, been guaranteed prices that are much higher than the general level of market prices except during the worst period of the price spike that occurred from mid-2021 to mid-2023.

The misconception that renewable generation is "cheap" has encouraged those who want to switch to a single buyer system with average cost pricing. This would suppress any direct transmission of the variability of market prices through to retail prices. The UK's energy regulator has reinforced this position by, in effect, promoting competition between energy suppliers based on offers to supply electricity at a price that is fixed for 6 or 12 months ahead.

During the 2010s, policymakers and the regulator acted to constrain flexible prices by imposing a cap on what are called standard variable tariffs. This intervention was designed to prevent suppliers from taking advantage of customers who do not have the inclination or resources to switch their energy supplier regularly. The, perhaps unintended, consequence of this intervention has been to impose a uniform pricing regime for most electricity customers who pay a regulated fixed tariff that is adjusted initially at half-year intervals and now at quarterly intervals. Rather than a market-based price system similar to arrangements in many European countries, what has developed is an administrative price regime tied to the derivatives market for baseload power.

This arrangement is inefficient in economic terms and probably unsustainable as structural change in the electricity market increases price variability. By imposing a fixed tariff for most customers, it removes incentives to respond to periods of high and low electricity prices. Even modest changes in consumption patterns can mitigate the combined impact of intermittent renewable generation and within-day variations in electricity demand.

One way forward would be to encourage the adoption of dynamic pricing in the UK. This is widely available for business customers but is rare for household customers with one main supplier offering the option – Octopus and its Agile tariff. Ofgem is clearly aware of the potential merits of dynamic pricing and has announced a consultation on how price cap arrangements should be applied to dynamic prices.

On the other hand, the reluctance to be explicit about the various components which determine retail prices and the desire to focus on a headline price per kWh as the basis of competition had led to a particularly poor choice about how to recover non-market costs under the Agile tariff. When the tariff was first introduced, the retail price was set at 2 times the equivalent market price. The multiplier has been increased to 2.2 but with price insurance offered via a cap and floor on the retail price.

Since transmission and distribution charges plus levies to recover the costs of various subsidy schemes do not vary with market prices, there is no economic justification for adopting this pricing structure. Perhaps intentionally, it masks the reality that non-electricity components account for an increasing share of the retail cost of electricity. Most other countries where dynamic pricing is widespread have adopted an arrangement where the various components comprising retail electricity bills are explicitly identified and passed through to customers. A lowish markup – up to 20% – may be applied to the market price to cover the energy supplier's trading costs.

The key point is that Ofgem appears to be obsessed with an overly simplistic model of price competition in energy supply. It may be correct to believe that many retail customers have limited interest or capacity to assess more complicated pricing structures, but regulators in many other European countries have taken the view that transparency is at least as important as simplicity when setting rules for competition in electricity markets.

As an alternative to dynamic pricing – or in parallel with it – several countries have encouraged the widespread adoption of multi-period tariffs – either (a) two period (peak/off-peak) tariffs, or (b) three period (peak/standard/off-peak) tariffs. These are widely offered in Southern Europe – France, Italy, Spain and Portugal. The UK has had the Economy 7 tariff and other variants of peak/off-peak tariffs for more than five decades. In its original form this was a clumsy arrangement that required two meters – a standard meter and a "white" meter – with separate distribution circuits. By contrast, in Italy smart meters allowing multi-period tariffs have been standard for nearly two decades. Current smart meters in the UK can used for multi-period tariffs with minimal effort.

There is a lot of variation across countries in the ratio of off-peak to peak tariffs. In part this reflects differences in the degree of price variability in domestic power markets, while in part it reflects different regulatory or supplier choices about how to recover fixed costs. In France, Italy and the Netherlands, the typical peak to off-peak ratios were less than 1.3, whereas in Spain and the UK, this ratio was over 2.0. As the degree of price variability in electricity markets increases, the ratios of peak to off-peak prices should increase, perhaps quite substantially.

Stepping back from the details of electricity tariffs, there is a broader conclusion about the way in which the electricity market functions – or rather does not function – in the UK. This can be illustrated by a single figure. The regulated retail price of electricity per kWh in the middle two quarters of 2024 is approximately 5 times the average values of the spot price and the day-ahead market price of electricity for the first 5 months of 2024. Other than during periods of extreme market stress, the relationship between the regulated retail prices paid by customers and average wholesale prices is minimal.

If questioned, most household customers would probably say that variations in retail electricity prices reflect variations in the underlying market price of electricity. Certainly, all the politicians who think that "cheap" renewable electricity should lead to a reduction in electricity bills make that assumption. It is a complete myth. From 2005 to mid-2024, the spot price of electricity rose from £36 to £63 per MWh in nominal terms – i.e. from 3.6 p/kWh to 6.3 p/kWh. The average retail price paid by households increased from 8.1 p/kWh to 29.5 p/kWh.

Had the ratio between retail prices remained the same in 2024 as in 2005, the average retail price in mid-2024 would have been 14.2 p/kWh. Just over one-half of the retail price in 2024 is comprised of levies of various kinds imposed on electricity consumption that did not exist or were not as high in 2005.

There is a related and even more important issue for the longer term. Is it either efficient or reasonable to link subsidies for renewable energy to market prices, whether via guaranteed prices (CfD strike prices) or price top-ups (Renewable Obligation Certificates)? One very specific detail of such arrangements concerning what happens when market prices are negative is discussed in the next section.

The larger question is whether subsidies should be tied to output rather than availability. This flows from the widespread misperception discussed above. Households and other electricity customers think that they are paying primarily – even solely – for electricity. That is simply wrong! What they are paying for is: (i) a whole set of services involved in building and operating an electricity system capable of meeting high variable demand, and (ii) a set of levies or taxes established to pay for activities that policymakers and regulators have deemed to be desirable but which they prefer not to be too open about.

There is a large element of sheer stupidity underpinning current arrangements. The UK has adopted many policies which seek to promote the replacement of heating and transport using fossil fuels by electrified options including heat pumps and electric vehicles. And yet what do policymakers then do? They impose policy levies in a way that doubles the customer price of electricity relative to what would have prevailed in the past and deliberately discourage any acknowledgement that the level of such charges is unrelated to the amount of electricity used.

As always, it is possible to provide an explanation for why this arrangement has been adopted. In essence, policymakers want to avoid the distributional consequences of imposing fixed charges per household. Nonetheless, other countries have found better ways of doing this. The real problem is a failure of imagination and honesty combined with a desire to shift the blame for high energy costs away from government policies and onto either external factors or "greedy" energy suppliers, which are the pantomime villains in the current regime. The result is typical of UK policymaking – an incoherent, expensive and self-defeating muddle.

This brings us back to the way in which subsidies for renewable generation are structured. Under current arrangements, renewable generators face a cliff-edge with a large drop in revenue per unit of output when eligibility for CfDs or ROCs expires. The arrangements reward high levels of operating costs up to that point but often lead to a rapid decline in output after that. A much better arrangement would be to rely upon fixed capacity payments and provide no payments linked to output. That would change bidding behaviour, leading to a recognition that

(a) variable operating costs are not as low as often, and (b) zero or negative market prices are largely a consequence of distorted incentives rather than an outcome of the operation of an efficient market.

What might the future look like?

Variability in market electricity prices is a natural by-product of variability in demand for electricity due to a combination of random factors plus seasonal, daily and hourly patterns of economic and social life. Higher prices are required when demand is high to pay for generating capacity that is used infrequently but needs to be available all the time. Even when fixed availability or capacity payments are made to such generators, they have (relatively) high variable costs per unit of output, since otherwise it would be economic to run the plants for many more hours in the year.

This natural variability in market prices has been substantially increased by policies which have favoured investment in capital-intensive forms of generation with low variable costs – both nuclear power and renewable sources of generation. Economists have realised for decades that the efficient way of rewarding such operators is a two-part tariff[11] – a combination of a fixed capacity or availability payment plus a much lower operating payment to cover variable costs.

Unfortunately, rather than apply well-known lessons from other areas of economics, energy policymakers and regulators in the UK have tried to force pricing and subsidies for energy into a framework of uniform payments per unit of energy delivered or used. Rather than encouraging the adoption of multi-part tariffs, the emphasis has been on competition focused on headline uniform tariffs. That preference has also encouraged the adoption of completely irrelevant measures of the costs of alternative sources of generation, such as the levelized cost of generation.

The addition of increasing amounts of intermittent renewable generation has increased the variability of market prices, and this trend will continue for at least 5 or 10 years. The probable outcome will be a price regime characterised by:

- extended periods of very low or negative prices when either (a) demand is relatively low, and/or (b) renewable generation is relatively high; and
- periods of high prices necessary to induce either gas generators or battery systems to provide backup power when renewable generation and imports cannot meet total demand.

Until 2030 and beyond, almost all renewable generation will be subsided under contracts that provide no or minimal incentives to avoid negative market prices, so, as in Germany, these will become more frequent. Excluding periods of very low demand during the pandemic in 2020,

11 The issue is known as the "fixed cost" problem and was first examined in detail by economists considering investments in transport infrastructure – roads, railways, etc. The direct parallel is with the pricing of capacity required to meet peak demand for rail travel in cities. The fixed cost problem is perhaps most familiar in the context of transport, it arises in almost all areas of infrastructure and, though less obviously, in health, education and other areas of public economics.

market prices during 2019 to 2022 were negative for an average of 0.2% of annual hours. That share increased to 1.4% in 2023 and is on track to exceed 2% in 2024. If the German case is any guide, it is likely that market prices will be negative for nearly 10% of hours by 2030. Similarly, the frequency of low positive prices (between £0 and £10 per MWh) increased significantly from 2023 onwards.

At the other end of the price distribution lies the issue that current plans for a decarbonised electricity system, whether by 2030 or 2035, cannot achieve that objective on their own. Even with vast investments in renewable generation plus batteries plus nuclear plants, some amount of gas generation will be required for between 40% and 60% of annual hours. For genuine decarbonisation, it will be necessary to replace existing gas plants by new plants with some form of carbon capture. These will be expensive to build and even more expensive to operate. Other alternatives, such as reliance on hydrogen, are even more expensive and are unlikely to be feasible before 2040 at the earliest.

It is unclear how far politicians are willing to go in pursuing the goal of full decarbonisation. The claims that this is technically feasible and affordable rest on broad-brush claims about technology and future costs. These have been either discredited as relying on extremely optimistic assumptions or disproved by later experience. The painful conjunction of magical thinking and unforgiving reality is likely to lead to reconsideration of both the timetable for and the extent of decarbonisation, even if neither is admitted in any explicit way.

Still, large amounts of backup generation, almost certainly relying upon gas, will be required in the decade after 2030. The current fleet of gas plants is ageing and inefficient, burning much more gas than would be required by modern plants. However, under current regulations and market incentives investors are unlikely to build any substantial amount of new capacity to operate as merchant generators – i.e. relying upon market prices to recover their operating and capital costs.

There are two primary scenarios which reflect alternative political options.

A. The new government may accept (implicitly) that (i) the target of full decarbonisation by 2030 is not feasible, and (ii) some large amount of backup generation is required to maintain reliable supplies of electricity. This leads them to adopt the strategy put forward by the current government of underwriting a large programme of investment in new gas plants with the condition that these should be capable of being retrofitted with carbon capture whenever the technology is viable. No one asks too hard what that means, because the fundamental goal is to avoid power outages. Under this scenario, new plants are awarded 15-year capacity contracts which cover their capital and fixed operating costs. They bid into the wholesale market at prices that cover their fuel and variable operating costs, including carbon taxes. Since new plants should be substantially more efficient than existing ones, the level of market prices required to meet demand when renewable output is low should be no greater than current prices adjusted for changes in the international price of LNG.

B. The new government sticks its head in the sand and refuses to underwrite or even permit the construction of new gas plants. In this scenario, the current fleet of gas plants – including units built primarily for local network support – will provide backup generation at an ever-increasing cost. Even if they are awarded short-term capacity contracts, their variable operating costs will be high. The top end of the distribution of market prices will increase substantially to induce such plants to operate regularly. In the first five months of 2024, the hourly day-ahead market price exceeded £96 per MWh – 150% of the average market price – in less than 4% of hours. That is likely to be greatly exceeded under this scenario, since residual gas generators are likely to incur variable operating costs of greater than twice the average market price if they are to run frequently enough to avoid power outages.

While the recognition of reality implicit in Scenario A would be welcome, experience of energy policy in the UK over the last two decades suggests that such a change will be slow and grudging at best. Consequently, the most probable outlook for the top-end of the market price distribution is an increase in the frequency of price spikes exceeding 150% of the quarterly average market price. If this is correct, the variability of market prices will continue to increase with a higher coefficient of variation and, as a corollary, an increase in the costs of providing insurance for household customers via prices that are fixed quarterly.

There is another aspect of current policies that may cause major problems in future. Up until 2017, new renewable plants received varying amounts of Renewable Obligation Certificates (ROCs) per MWh of generation, which have an index-linked minimum value. These top up the market price and mean that generators will operate even if the market price is negative so long as the value of ROCs received exceeds the negative market price. If the System Operator needs to constrain output from the generator, the generator must be compensated by an amount at least equal to the sum of the market price and the value of ROCs.

The alternative system of subsidies, introduced in 2014 but operating fully from 2017 is a system of guaranteed prices implemented via Contracts for Differences (CfDs). Under the initial series of CfD contracts, generators receive their guaranteed (strike) price even if market prices are negative. However, in the most recent round of contracts and in future generators receive nothing if market prices are negative.

The change leads to a large asymmetry between the incentives facing renewable generators of different ages. Generators covered by the new contracts have very large incentives to bid in ways that will ensure the market price stays just above zero. Among the options available are (a) to withdraw associated non-subsidised generation from the market, and (b) to create vehicles to buy large amounts of electricity when prices are very low, even if the power is effectively dumped, but more probably to put into heat storage as batteries are rather expensive in this context. For a group owning a 1 GW wind farm with a CfD price of £100 per MWh, any option that raises the market price from -£10 per MWh to £0.10 per MWh would yield revenues of £100,000 per hour or about £88 million over a year in which prices would otherwise be negative for 10% of annual hours. This illustrates how asymmetry in market incentives can stimulate and justify what might otherwise appear to be bizarre behaviour.

Even without major changes in how generators respond to variability in market prices, the costs of managing the electricity system, mainly represented by what are called balancing costs, are expected to increase significantly up to the end of the decade. Looking back 20 years, annual balancing costs were in the range £600-£800 million per year between 2005-06 and 2010-11. After 2011, they increased gradually to £1.2 billion in 2018-19 and then more rapidly to £2.4 billion in 2023-24, with a spike to £4.1 billion in 2022-23 due to very high market prices. Recent projections from the system operator[12] indicate that total balancing costs are expected to rise to close to £5 billion per year in 2030.

Individually, items such as the increase in system balancing costs and the costs for energy suppliers of insuring against price variability are not large. If balancing costs in 2030 are £5 billion, that is little more than £60 per year per household, while the regulated average price in mid-2024 translates to £850 per year per household. Even so, these developments increase the gap between market and retail prices, thus attenuating any incentive to respond to variations in prices – either by shifting the timing of electricity usage or by managing total electricity consumption.

Conclusions

Variability in market prices for electricity is an unavoidable by-product of variability in electricity demand. Such variability has been increased by policies which have promoted investment in intermittent sources of electricity with very low variable costs. Since countries in Europe are all committed to moving away from dispatchable sources of generation – i.e. plants whose output can be readily controlled to meet demand – the variability of prices will increase in future. Further, by supporting such investments via guaranteed prices or other mechanisms linked to output governments have weakened or removed the feedback from prices to output that has previously been a key part of market functioning. One manifestation has been an increase in the frequency and magnitude of negative prices in day-ahead markets.

While policies affecting electricity generation have increased the variability of market prices, the UK government and regulators have opted to reduce or suppress the transmission of price variability through to household customers. Their reasons for doing this have been partly to protect vulnerable consumers and partly to hide the extent to which the average prices paid by household customers have a very limited connection to market prices.

In many other European countries, energy suppliers are required to provide detailed information on the composition of the energy bills, including electricity costs, network charges, various levies and taxes. Such transparency allows – even encourages – energy suppliers to offer tariffs which are linked either directly to variable market prices or to some moving average of such prices. Dynamic or flexible tariffs are familiar for business customers in the UK but they have, in practice, been discouraged for household customers by regulatory arrangements which impose price caps on both tariffs and aggregate bills.

12 NG ESO – Balancing Costs: Annual Report and Future Projections, Technical Report, May 2024, https://www.nationalgrideso.com/document/318521/download.

This policy bias against transparent pricing creates conditions in which simplistic and/or misleading claims are made by politicians and lobbyists about the impact of increasing reliance on intermittent renewable generation. Since the share of retail electricity bills required to cover the market cost of electricity will continue to fall because of the costs of supporting such generation, public support for pricing arrangements nominally based on market prices may collapse.

The new Labour government may welcome the adoption of a centralised single buyer arrangement to underpin a shift to average cost pricing. However, this is very strongly a case of beware of getting what you ask for. The issue is that a single buyer will necessarily be a public corporation – almost certainly the new National Energy System Operator. At that point, all power agreements, CfDs, etc., will be public contracts and liabilities under those contracts will count as public debt. As a consequence, the UK's public debt will immediately increase by up to 20% of GDP, and new investments will rapidly increase those liabilities. This is precisely what privatisation was designed to avoid!

Market prices – and their variability – are a key indicator of how the electricity system is functioning. The increase in the variability of market prices over the last decade and the almost inevitable increase in the next decade reflect the tensions that exist between (a) ensuring a stable and reliable electricity supply, and (b) the desire to rely more heavily on intermittent and, at least for now, expensive forms of low carbon generation.

On current evidence it may be assumed that the commitment to renewable generation outweighs any concerns about reliability of supply. Hence, policymakers and regulators need to accept that a combination of pricing transparency and broadly based incentives to adjust patterns demand to price variations is essential for the efficient operation of the electricity system.

The European Union accepted that logic when implementing its Clean Energy Package in 2019. The Directive establishes an entitlement to a dynamic price electricity contract and mandates that any supplier with more than 200,000 customers must offer such a contract to customers with a smart meter.[13] The implementation of that article has been slow, in part because management of the rollout of smart meters has been notably poor in some countries – as in the UK. Even so, member countries have accepted the proposition that retail customers should have the option of managing their consumption in response to variations in market prices.

Customers may not wish to be exposed to the risks posed by infrequent but extreme variations in price. Since 2013, the maximum hourly day-ahead price in a year has exceeded £500 per MWh in 3 years – 2016, 2021 and 2022 – while in 6 years it has been less than £200 per MWh. These probabilities are so small that any energy supplier can offer insurance by, for example, capping the price charged at 3 times the monthly average price.

Perhaps more important is the issue of dealing with negative prices. It is not desirable for the stability of the grid and distribution networks to encourage households to open their windows and put heaters on at full output when prices are negative. Hence, setting a floor of zero on dynamic prices might be a reasonable adjustment to minimise technical risks.

13 Article 11, Directive (EU) 2019/944 of the European Parliament and of the Council, *Official Journal of European Union*, 14 June 2019, L158/125.

Many customers may not wish to track hourly prices. As an alternative, multi-period prices linked to an index of the average market price, which is a standard arrangement in Italy, provide a substantial incentive to shift consumption away from peak periods to off-peak periods while limiting supplier exposure to the risks associated with price variability. However, there is a case for rethinking the length and timing of the pricing periods.

While pricing periods should be based on data for more than a single quarter, the pattern shown in Figure 1 is broadly consistent with the averages over the 5-year period from 2019 to 2023. Market prices are significantly above the daily average price during the evening peak from 17.00 to 21.00, while they are a similar amount below the daily average price during the middle of the night from 01.00 to 05.00. The off-peak period might be extended to cover the period from 00.00 to 06.00, but the remaining 14 or 16 hours clearly comprise a standard price period with prices falling within a narrow range around the daily average price.

If full dynamic pricing is resisted on the grounds that it transfers too much pricing risk to household customers, some variant of three period pricing with the base price linked to a standard market index goes a considerable way to restoring incentives to manage consumption in response to varying market prices.