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Your Gas Network

The price of Energy Security

July 2026

Executive Summary

The wholesale electricity price in Great Britain is determined through a marginal pricing system, where the last generator needed to meet total demand sets the price for all generation. This remains one of the most efficient and widely used market designs, ensuring supply meets demand and providing the necessary signals needed for investment and system security.

Gas-fired generation is currently the primary price setter, but its role is gradually declining as renewable generation increases. Increasingly, interconnectors, battery storage and other flexible technologies are playing a larger role in setting prices. As a result, electricity prices are becoming less tied to domestic gas costs and more influenced by system conditions in external markets, particularly in Continental Europe.

It's important to distinguish between wholesale and retail electricity prices. Wholesale prices reflect the marginal cost of generation, while retail prices (what consumers pay) include policy costs, network costs and supplier margins. This means that even if wholesale prices fall, consumer bills may not fall proportionately and may increase.

As the system transitions, price formation is shifting away from a fuel-driven model to one increasingly shaped by intermittency and the need for flexibility and availability. The retirement of coal has contributed to a hollowing out of the middle price range, with the system now operating more frequently at extremes – periods of very low or negative prices during high renewable output, and very high prices during periods of low renewable generation and high demand.

Crucially, removing gas from the system does not eliminate volatility. Instead, volatility becomes driven by scarcity and the need for flexible capacity to recover costs during infrequent but critical periods, such as prolonged low-wind or high-demand events. In this context, price spikes are not a failure of the system, but a reflection of the cost of maintaining security of supply.

Marginal pricing is an efficient mechanism for dispatch, preserving clear price signals that ensure supply meets demand at least cost and supports investment in system flexibility and security. Intervening to suppress or reshape these signals risks distorting market outcomes, undermining efficient dispatch, and increasing system costs over time. As volatility reflects underlying system conditions rather than a design flaw, reforms should focus on understanding and managing consumer exposure, not weakening the price formation process that underpins reliability.

Key Findings

1. **Price formation is changing as the system changes.** The power system is transitioning away from a stable, gas-driven market towards one increasingly shaped by intermittency and the need for system flexibility and availability requirements.

2. **Gas remains the primary price-setting technology, but its role is decreasing.** In 2017, gas-fired generation set the electricity price around 70% of hours. This fell to 55% in 2025.

3. **Price setting is shifting away from gas.** Non-gas technologies are gaining a larger share of price-setting activity as gas output decreases and interconnector/storage capacity grows. This means UK electricity prices are increasingly influenced by weather conditions in Continental Europe.

4. **Volatility persists – even with less gas.** Removing gas changes what drives price volatility but does not remove it. A future system increasingly reliant on flexibility and availability drives volatility, as prices reflect the cost of maintaining and dispatching flexible capacity during periods of system stress.

5. **Extremely high prices persist even without gas.** Even in a future with near-zero gas usage, very high prices still occur during prolonged low-wind periods with high demand. The modelling shows that in a future Dunkelflaute period wholesale electricity prices could spike to around £4,000/MWh.

6. **Coal's retirement, despite its high carbon intensity, has contributed to increasing price volatility.** The loss of a short-term stable, dispatchable generation asset has amplified price swings, as it has hollowed the middle price range.

7. **The middle of the price range is disappearing.** Prices are increasingly dominated by periods of very low or negative prices (when renewable output exceeds demand) or periods of high prices (when low renewable output coincides with high demand).

Recommendations

→ **Proposal 1:**

Future policy should be designed to ensure that wholesale market arrangements continue to support efficient dispatch and investment in generation.

→ **Proposal 2:**

Reducing exposure of households and businesses to wholesale price volatility by reforming retail pricing.

→ **Proposal 3:**

Government should maximise domestic gas production which can provide low-carbon, firm capacity.

For more information on these recommendations see **page 13**.

Section 1: How are wholesale electricity prices determined today?

In the UK, wholesale electricity prices are set using a marginal pricing system. Generators are brought online to meet demand in order of cost, with the cheapest sources – typically renewables – first. However, the price paid to all generators is set by the last generator – known as the 'marginal plant' needed to meet total demand. This is usually a gas-fired power station.

For many hours of the year, gas-fired generation is the marginal plant because lower marginal cost generation such as renewables and nuclear are insufficient to meet total demand. The prevailing wholesale electricity price is therefore equal to the bids that the marginal gas plant submit. The bids account for all operating costs, including gas and carbon prices, and may also include investment costs.

Figure 1 illustrates this with the 'merit order curve' which depicts the power generation costs of the existing plant fleet, from cheapest to most expensive, that is available to supply power during each 30-minute increment. This is just a complicated name for what is conventionally a typical supply and demand curve. Each generator bids how much demand they can meet and at what price. These bids are based on the operating costs that each generator faces, considering the costs of starting up or shutting down generation. Wind and solar plants tend to have the lowest operating costs, followed by nuclear power plants. While natural gas-fired plants often have higher operating costs, this reflects the flexible, dispatchable role they play in the electricity system. Unlike wind and solar, gas-fired generation can quickly increase or decrease output to balance changes in the electricity system. When supply meets demand, this creates the marginal price or market-clearing price. All generators receive this price, and all consumers pay this price.

Marginal pricing is not unique to power markets. Commodity markets (such as wheat, oil, barley) trade on marginal pricing basis as it's the natural way prices emerge in free markets. For energy, there is consensus that this model is the most efficient for liberalised electricity markets and ensures total demand is met. Inevitably there will always be a price setter in a marginal pricing system – most probably a firm, dispatchable generator, which is also the requisite for energy system security as we move to a system increasingly reliant on intermittent renewables. Flexibility technologies, including batteries, can help reduce price volatility by storing excess power and supplying it during short periods of tightness. However, their limited duration means they cannot fully address extended low-wind periods ("Dunkelflaute"), so firm generation remains necessary.

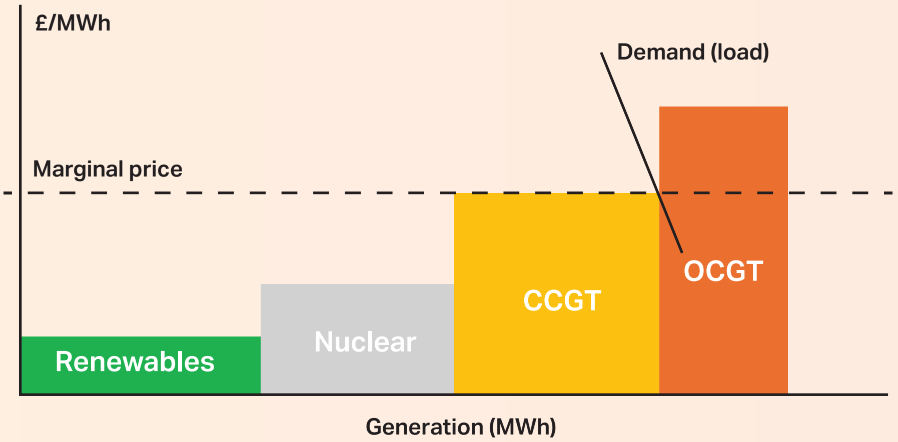


Figure 1: diagram depicting how the merit order of generation determines the marginal price. CCGT = Combined Cycle Gas Turbine. OCGT = Open Cycle Gas Turbine

Section 2: Marginal pricing in a future energy system and alternative market designs

As renewable generation has expanded, some have argued that marginal pricing is no longer compatible with a high-renewables electricity system. The concern is that prices continue to be set by the marginal generator – often gas – meaning the lower marginal cost of renewables is not fully reflected in wholesale prices. This has led to call for more fundamental reform of electricity market design.

One proposed approach is to "break the link" between gas and electricity generation – for example through a "green power pool[1]" for renewables alongside a separate market for dispatchable capacity. However, such proposals would represent a significant reset of wholesale market arrangements without fully understanding the unintended consequences such as reduced market liquidity, increased complexity and challenges in coordinating dispatch efficiently across parallel markets.

Another commonly proposed alternative is a move to pay-as-you-bid pricing, where generators are paid based on their cost of production rather than a single marginal price. In theory, this could better reflect the lower costs of renewable generation. In practice, however, generators would be incentivised to strategically bid seeking to approximate the clearing price of the higher cost generator, meaning outcomes converge back towards marginal pricing but with reduced transparency and efficiency.

Another proposed reform is Dieter Helm's "equivalent firm power" approach[2] , which would require intermittent generators to contract for firm backup capacity, reflecting the reliability value of their output and intended to better allocate system costs associated with intermittency. However, this reflects a wider tension between individual and system-level approach to minimising firming costs.

The evidence to date suggests limited value in pursuing these approaches at scale, particularly given their trade-offs and the risk of undermining investment and market integration. Indeed, recent government announcements[3] on decoupling gas and electricity have sought to pursue more incremental change by converting one-third of the wind fleet on the renewables obligation (RO) – currently receiving renewables obligation certificates (ROCs) plus the wholesale price - onto contracts for difference (CfD), thereby offering a fixed price for generation.

It is also important to distinguish the difference between the wholesale and retail price of electricity. The wholesale price is the price at which electricity is sold to the electricity grid. The retail price is what the consumer pays and represents the total cost of bringing the electricity from generation to the point of demand. Some commentators have supposed that even if wholesale price were halved, the retail electricity price could still rise[4], as increases in network investment, policy costs and support for new electricity generation (via CfDs) are all recovered through consumer energy bills.

More broadly, effective markets depend on price discovery. If pricing mechanisms are overly constrained or distorted, markets cannot function efficiently, and risks are shifted onto consumers and taxpayers. Attempts to suppress volatility may appear attractive in the short-term but can undermine the incentives needed to ensure long-term system reliability.

[1] UK renewable energy cliff brings both risks and opportunities, UCL
[2] Cost of Energy Review, Dieter Helm
[3] Decisive action to break influence of gas on electricity prices, DESNZ
[4] Cost of Energy – Oral Evidence, Energy Security and Net Zero Committee

Section 3: In today's energy system, gas is the price-setter, but decreasingly so

Through Imperial Consultants, we commissioned Imperial College London's Dr Danny Pudjianto to model how these price setting dynamics shift as the electricity system transitions to higher renewable energy penetration. By utilising historical data on the generation mix, market clearing prices, and observed correlations between price and output, the analysis identifies the technologies most likely to influence pricing.

The methodology combines analysis of the relationship between electricity prices and generation output with an assessment of how different technologies respond to system balancing needs. Technologies whose output is correlated with price, and which adjust generation in response to changes in demand, are identified as potential marginal price setters. This approach helps infer which technologies are most likely influencing prices over time.

It also recognises practical system constraints. In real-world operation, factors such as the need to maintain system stability, provide services like spinning reserve and inertia, or meet location-specific requirements can result in certain technologies being dispatched irrespective of their short-run cost. This can influence which technologies ultimately sets prices. The method therefore provides a system-informed view of price setting, acknowledging that multiple technologies may simultaneously contribute to marginal pricing outcomes.

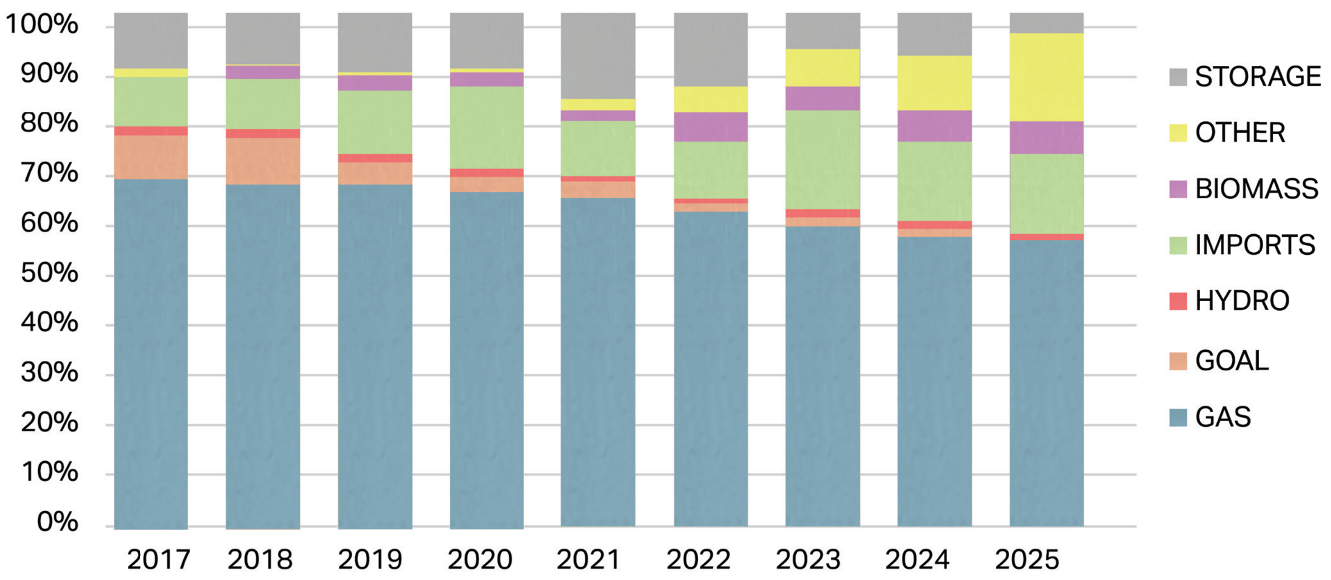


Figure 2: Number of hours in year generation technologies set the marginal price of electricity. Storage is battery energy storage. Other includes waste-to-energy. Imports refers to electricity interconnection.

The results show that gas is the primary price-setting technology; however, its influence has gradually declined over time. In earlier years, gas set the price around 70% or more of hours annually, reflecting its central role as the main flexible and responsive generation sources. As the system has evolved, particularly from 2020 onwards, the share of gas generation setting the price has reduced with other technologies increasing their role in balancing demand and supply. By 2025, gas still represents the single largest contributor but with a reduced share of setting the price around 55% of the time. This is in line with the government's estimate that gas sets the price around 60% of the time today[5]. Other technologies such as electricity imports via interconnection and battery storage have increased their contribution to price setting. Imports, in particular, have increased their share in price setting from 5-10% of the time in 2017 to setting price over 20% of the time in 2025. This reflects the growing role of interconnectors in balancing supply and demand.

Different technologies now setting the price reflects increasing system diversity and flexibility, with a broader mix of technologies influencing marginal pricing outcomes as renewable penetration increases.

[5]Decisive action to break influence of gas on electricity prices, DESNZ

Section 4: More renewables are driving a wedge between wholesale prices

The data shows that increasing renewable generation is driving a divergence in wholesale price outcomes, as the system transitions from a relatively stable, gas-led pricing regime to one increasingly shaped by intermittent, low-marginal cost renewables.

As illustrated in figure 3, between 2017 and 2020 wholesale electricity prices are concentrated within two bands - very low and mid-range band. This reflects a stable pricing environment, where gas consistently sets the marginal price but within a relatively predictable pricing band. From 2021, the distribution begins to widen, with a noticeable increase in both lower and higher price bands.

Interestingly, the lower-middle £10-50 per MWh band is reduced to less than 5% of hours, suggesting a hollowing out of the middle – fewer periods where the system sits in a steady and moderate pricing range – and a shift towards a system where prices are either low (surplus) or high (scarcity).

One of the reasons for this is the reduced role, and eventual phase out of coal generation. The system has lost a relatively stable and storable generation source, albeit higher carbon. Prices now oscillate more sharply between low-cost periods driven by renewables and high-cost periods when gas sets the marginal price. Coal previously acted as a buffer, dampening extreme price swings and providing security of supply. Its absence has amplified price variability.

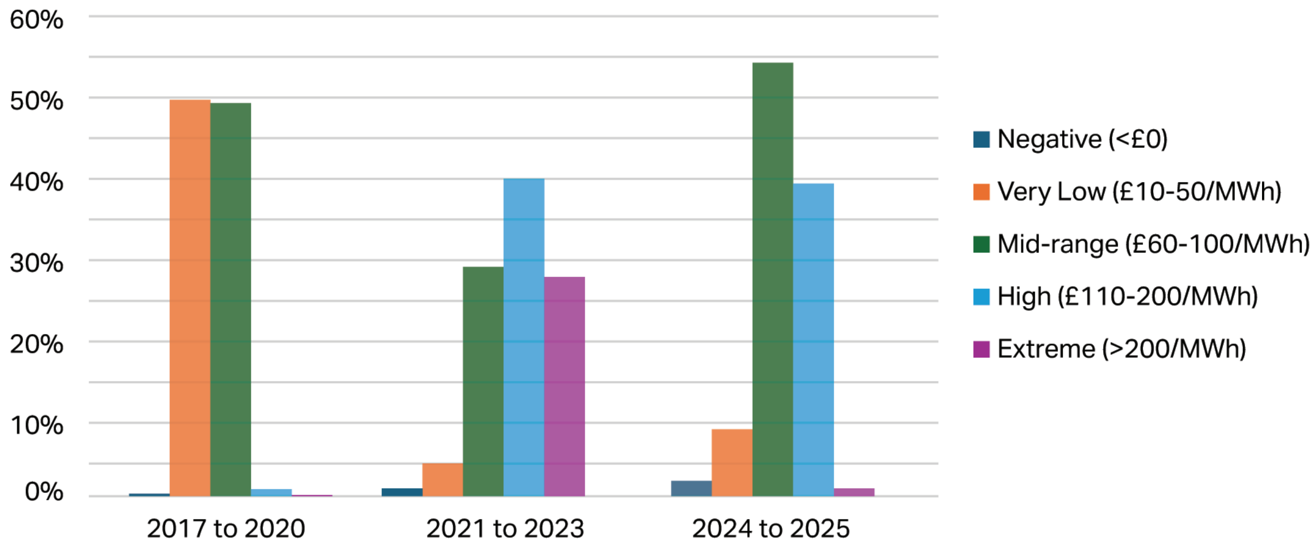
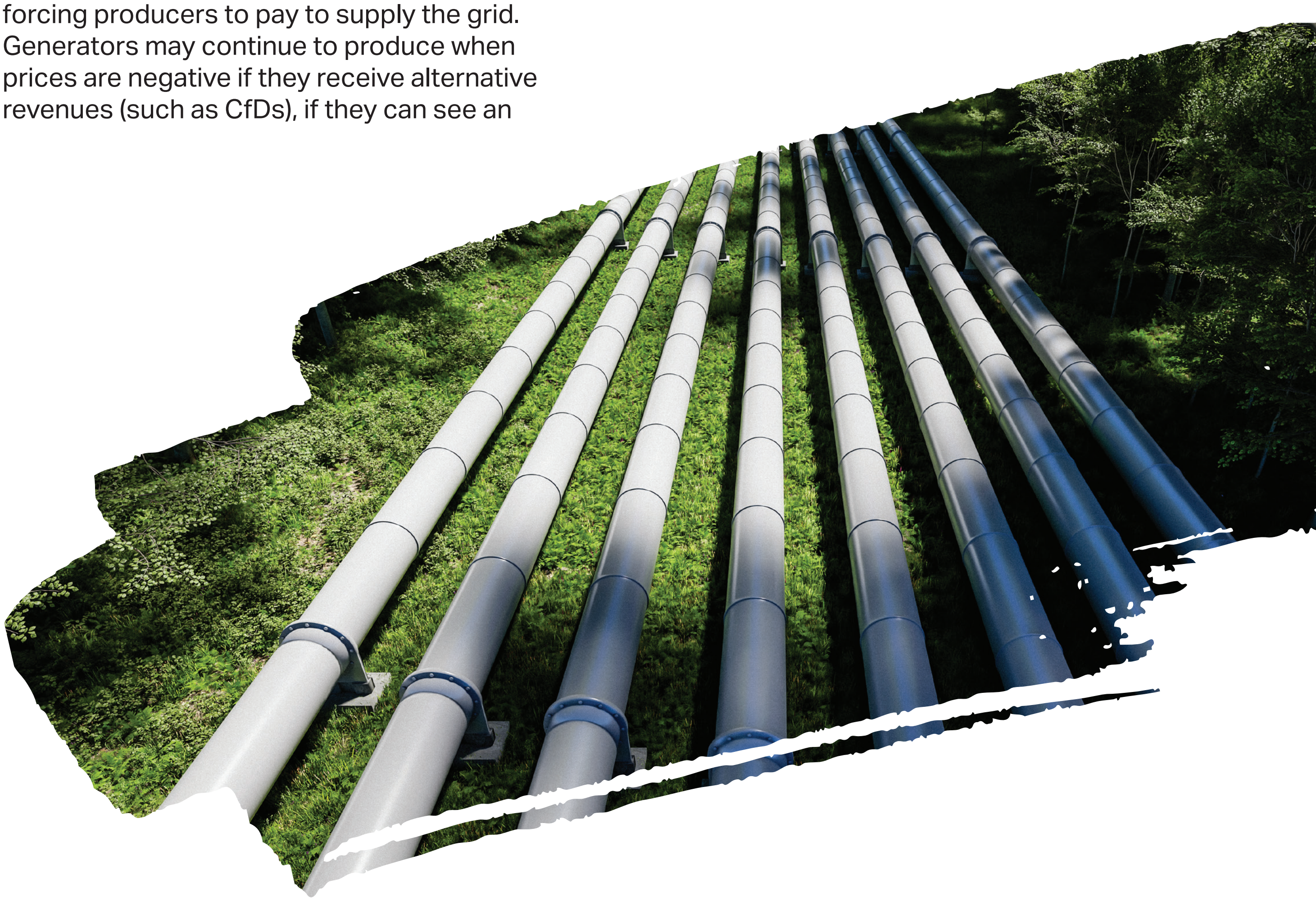


Figure 3: Distribution of marginal electricity prices by year

From 2024 onwards, the distribution shows a partial normalisation following the extreme conditions of 2022 (driven by geopolitical events in Russia/Ukraine), but it does not return to the more stable profile observed between 2017 and 2020. Compared to this earlier period, there are still noticeably fewer instances in the £10-50 per MWh band, indicating that the system is spending less time in moderate pricing conditions. A meaningful share of prices increasingly sits in the £60-100 per MWh band and £110 to £200 per MWh band. This indicates a structurally more variable pricing environment, where the system alternates more frequently between low-cost renewables driven periods and higher-cost gas-driven periods, rather than operating within a stable middle range.

Figure 3 also shows that in 2017 there were no hours where prices were negative whilst in 2025 around 2% of hours in the year saw negative prices. This occurs because there is more renewable generation than demand forcing producers to pay to supply the grid. Generators may continue to produce when prices are negative if they receive alternative revenues (such as CfDs), if they can see an opportunity cost of generating ahead of time ensuring availability during peak demand conditions and because there is a lack of flexibility as some generators don't have the capability to reduce generation fast enough.

Negative prices in the market indicates a lack of system flexibility, specifically the inability of supply to adjust to low demand. But it's a signal that there is not enough storage and flexibility in the system to absorb excess renewable generation efficiently. Battery storage is a good option for periods of oversupply lasting a few hours but for events lasting days and weeks, hydrogen storage can transform negative electricity pricing from a liability into an opportunity by storing the excess and dispatching it when it's most needed.



Section 5: Looking ahead, what sets the price?

Gas's role in setting the marginal price is decreasing and will continue to fall as other technologies increase their share and role in balancing supply and demand. Indeed, government's own analysis shows gas setting the price around half of the time in 2030[6].

The government's Clean Power 2030 ambition will see the power system use clean sources for around 95% of total generation, reducing gas's share in electricity generation from around one-third today[7] to just 5%[8] by 2030.

If gas generation is reduced to just 5% what other technologies will step in to balance supply and demand?

To understand this, Dr Pudjianto ran a scenario where gas is pushed to the margins of the generation mix. The modelling shows that energy storage - batteries (BESS) and hydro – becomes the dominant marginal technology, setting prices for around two-thirds of the year. This reflects their ability to respond rapidly to short-term imbalances and arbitrage between low and high price periods.

Interconnectors play a more active role in price formation as gas exits the margin. Their influence on prices depends on conditions in neighbouring markets. While increased interconnection generally promotes price convergence and can moderate GB prices through imports of lower-cost power, it does not fully eliminate price differentials. Evidence from interconnected market modelling shows that wholesale electricity prices can vary materially across Europe at any given time, with deviations from the group average ranging from around -£6.5/MWh to +£8.1/MWh. Great Britain itself shifts from being around £4.6/MWh above the European average and -£3/MWh below it. The recent Hitzeflaute (22nd June - 27 June) saw the UK pay £1,400/MWh to import electricity from Europe - 17 times more than the the typical wholesale price. This shows that interconnection does not eliminate price differences but exposes GB to variable external price signals driven by relative system conditions across Europe.

Thermal generation still has a role to play in setting the marginal price. During periods of high demand or low renewable output, thermal generation (hydrogen-powered turbines or gas with CCS) still play a critical role in setting the price.

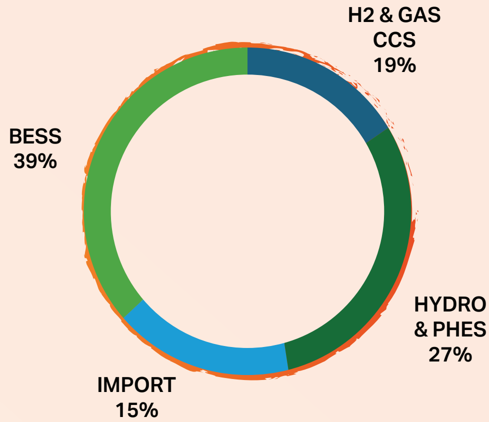


Figure 4: Share of non-gas technologies setting the price in the future.
BESS = Battery Energy Storage System
CCS = Carbon Capture and Storage
PHES = Pumped Hydroelectric Energy Storage

What the modelling shows is that by 2030, assuming Clean Power is achieved, price formation becomes less about fuel costs and more about the cost and availability of flexibility capacity.

The table on page 11 compares how non-gas price setters compare to the status quo and some of the key issues to consider. It shows that non-gas technologies shift price-setting away from fuel costs and towards prevailing system conditions. Interconnection imports external prices, storage arbitrage spreads, and low-carbon dispatchable set prices via scarcity. This means electricity price formation becomes more complicated and volatile as its increasingly driven by external conditions in neighbouring markets, levels of system flexibility and availability and system constraints rather than a single, observable, marginal fuel cost.

[6] Britain's Energy Explained: 2025 review, NESO
[7] Clean Power 2030 Action Plan, NESO
[8] The impact of interconnectors on the GB electricity sector and European carbon emissions, Energy Policy

Technology	How it sets prices	What it means for price levels	Key limitations
Interconnection	Import/exports set marginal price based on neighbouring markets	Prices increasingly reflect European market conditions, not domestic costs	Increases exposure to neighbouring market conditions, reducing the extent to which wholesale prices reflect domestic supply costs alone
Storage (BESS, hydro)	Arbitrage low/high prices; sets price when discharging	Prices reflect opportunity cost of stored energy (often higher than average system cost)	Does not create energy, can reinforce high peak prices as it recovers costs over fewer hours
H2 / gas with CCS	Dispatchable thermal sets price during scarcity periods	Prices driven by variable costs (fuel and carbon costs)	Higher marginal cost than unabated gas, particularly in peak periods
Unabated gas	Flexible marginal plant with fuel-linked pricing	Prices set by the short-run marginal cost of gas plant	Exposed to fuel price volatility

Table 1 - Comparison of technologies which will set the price in 2030

Section 6: In the future energy system, there is still price volatility

Moving away from gas as the marginal price setter does not remove volatility, it shifts what drives price formation. The modelling shows that even with minimal gas use, price profiles remain broadly similar, with very high prices still occurring during periods of peak demand and low renewable output. This reflects a structural change in costs. In a low-gas system, flexible technologies such as battery storage operate less frequently and are more capital-intensive. As a result, they must recover a greater share of their total costs – including fixed and capital costs – over a smaller number of operating hours. This contrasts with unabated gas, where marginal pricing is more closely linked to fuel costs and more continuous utilisation. Figure 5 shows this more clearly where wholesale prices spike to around £4,000/MWh over a typical Dunkelflaute event.

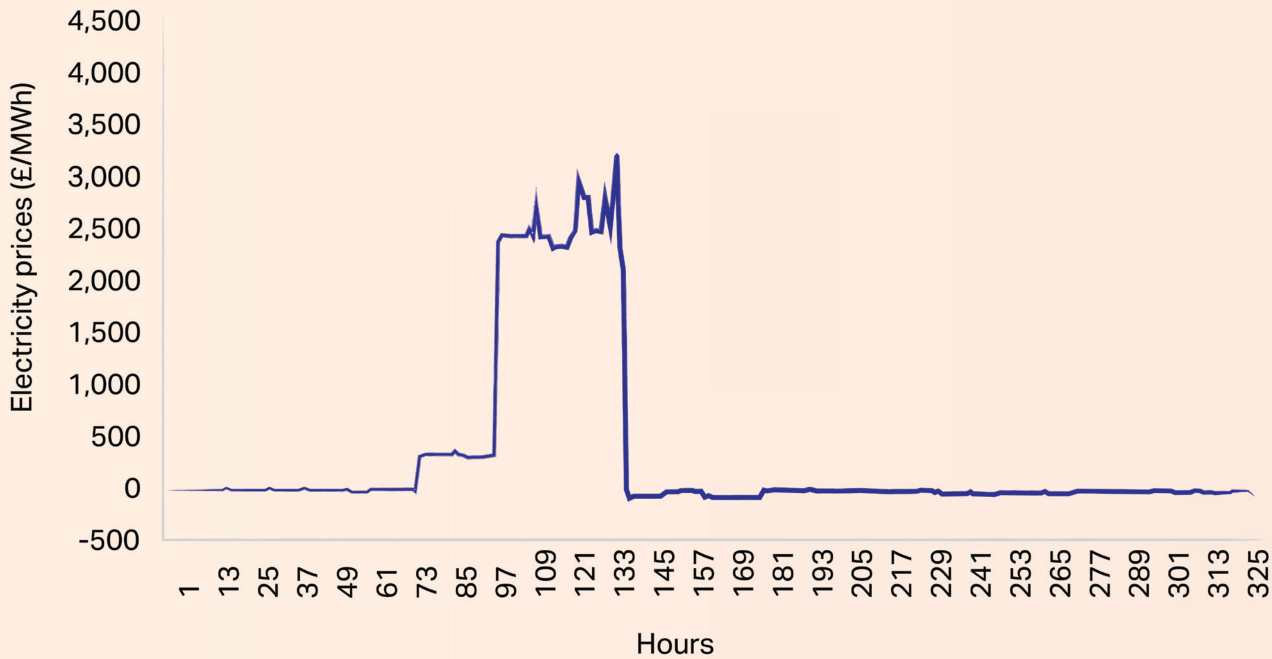


Figure 5: Price evolution over a typical Dunkelflaute period

The outcome is that when these flexible assets are required, prices must rise sufficiently to recover costs. This leads to more pronounced price spikes, not because demand is higher, but because the system relies on high-cost flexibility during tight periods. In addition, the lack of predictability in utilisation is an inherent feature of a system increasingly reliant on intermittent renewables. Flexible assets may run infrequently, but when they are needed, they are critical. Marginal pricing ensures that during these periods, prices rise sufficiently to provide a clear revenue signal, enabling investors to recover costs despite low running hours. Weakening these signals would increase investment risk, potentially undermining the availability of the very flexibility required to maintain system security.

Conclusions

Gas's role in setting the marginal price is reducing as renewable generation increases and non-gas technologies – interconnection from Europe and battery storage – set the price more often. However, they bring their own system challenges that are fundamentally different to today's power system. Any future market reform should seek to preserve efficient price signals for dispatch, investment and system flexibility, while allocating system cost as fairly and efficiently as possible.

→ **Proposal 1:**

Future policy should be designed to ensure that wholesale market arrangements continue to support efficient dispatch and investment in generation. While marginal pricing remains an efficient mechanism for dispatch, government could consider complementary mechanisms to reflect the intermittency costs created by individual generators. This would allocate system costs more efficiently while preserving the benefits of marginal pricing.

→ **Proposal 2:**

Reducing exposure of households and businesses to wholesale price volatility by reforming retail pricing. This could include strengthening supplier hedging requirements and expanding fixed tariffs. The latter may include longer-term, mortgage-style products such as two to five year fixed-price contracts. This would preserve the efficiency of marginal pricing system while limiting the transmission of short-term price spikes into consumer bills.

→ **Proposal 3:**

Government should maximise domestic gas production which can provide low-carbon, firm capacity. This decreases our reliance on imported energy sources. This could include green gases like biomethane and electrolytic hydrogen which can be used in long term energy storage and as a fuel for dispatchable power. Investing in power generation with carbon capture and progressing the hydrogen-to-power business model can also grow our own capacity to produce flexible power.