**The cost of your electricity bill, what it consists of and a way to offset infrastructure investment for the transition**

Matthew Porter and Professor John R. Underhill

Centre for Energy Transition, The Interdisciplinary Institute, Aberdeen University

## Executive Summary

The cost of electricity affects everyone, yet many consumers are unaware of what makes up their bill and why prices appear so high. This paper aims to explain the structure of the UK electricity market and outline how specific components contribute to the final cost.

UK electricity prices remain elevated in part because wholesale prices are often set by gas-fired generation. The UK's heavy reliance on imported gas, rising network and infrastructure costs, increasing standing charges, and the impact of supplier failures have all added upward pressure. More recently, Ofgem's evolving regulatory priorities—such as the Clean Power 2030 initiative—require substantial investment in transmission infrastructure.

Under current arrangements, consumer bills are unlikely to fall, as future system costs still need to be recovered. Both bill payers and taxpayers will ultimately fund the expansion of the electricity grid as the UK increases electrification and builds sufficient baseload generation to cover periods of low renewable output.

The scale of the required "rewiring" of Britain calls for structural change. This includes strategic gas licensing and storage, shifting certain costs into general taxation, and phasing investment over a realistic and deliverable timeline.

These investments align with the decarbonisation goals of the energy transition. However, their contribution to national energy security should also be recognised. Some costs could justifiably be treated as defence spending rather than solely as decarbonisation or consumer energy costs.

## PART 1: Current Market Structure and heavy reliance on Gas

In the UK's wholesale electricity market, the marginal cost of the most expensive generator sets the price for each half-hour period. Because gas-fired power plants are often the last—and priciest—units needed to meet demand, wholesale electricity prices frequently track gas prices. Even low-cost renewables such as wind and solar are paid this higher "gas-linked" rate due to the market's design.

The UK is not unique in Europe in having international gas prices set the marginal price, but the frequency with which this occurs creates particular exposure to gas price volatility. When gas prices are low, this is less of an issue, as electricity prices fall accordingly. But the current market structure effectively ties UK electricity prices to international gas markets.

In 2024, the UK generated more than half of its electricity from renewable sources for the first time. However, around 26% of generation still came from natural gas during periods when renewables were insufficient and a further 14% were derived from imports. Gas storage provided for 1.2% of our domestic needs over the course of the year.

Of the renewables mix, wind was the largest the source of electricity with c.30%, followed by biomass (7%), solar (5%) and hydro (2%).

[Wind Britain's top electricity source in 2024 | Reuters]

| | |
|---|---|
| WIND | 30 |
| GAS | 26.3 |
| IMPORTS | 14.1 |
| NUCLEAR | 14 |
| BIOMASS | 6.8 |
| SOLAR | 5 |
| HYDRO | 2 |
| STORAGE | 1.2 |
| COAL | 0.6 |
| | 100 |

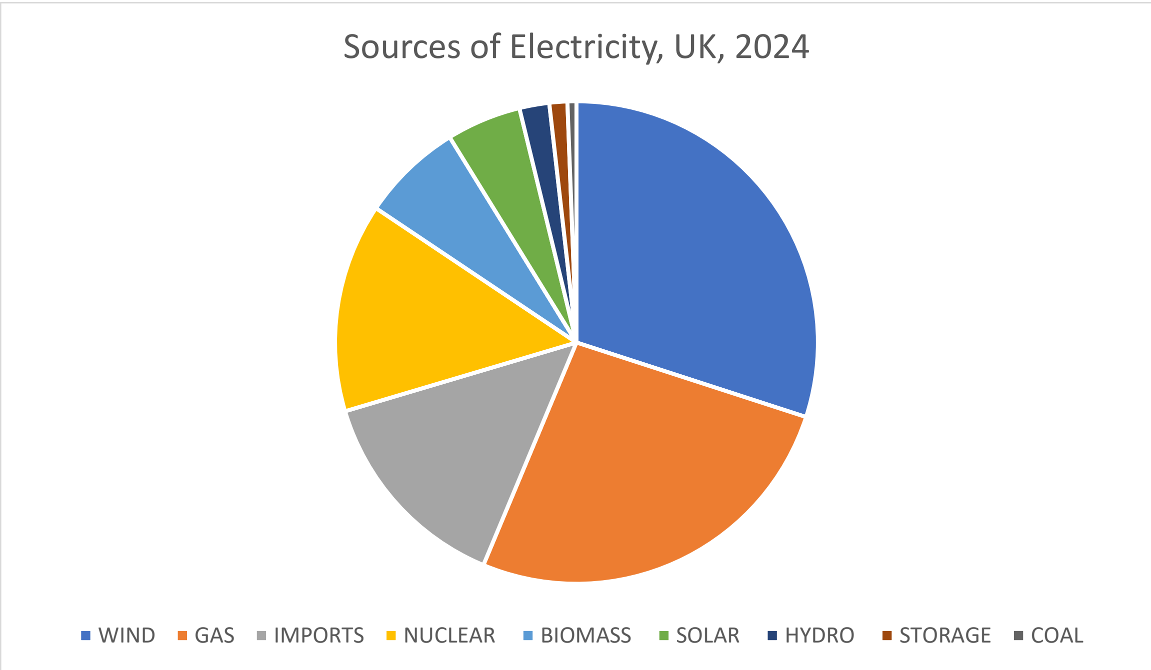



Figure 1: Electricity sources expressed as a percentage averaged over 2024

[Britain's Electricity Explained: 2024 Review | National Energy System Operator]

Of significant note was that coal, for the first time in 142 years, ceased to be in the generation mix with the decommissioning of the Ratcliffe power station in September. *Prima facie*, the renewables market looked healthy and operating as expected.

However, the weather in the first half of 2025 was both calmer and colder than the same period in 2024. Gas powered generation stepped in to plug the gap during Q1 2025 to meet nearly 40% of demand.

Energy Trends June 2024

Of further note was that it was not UK (domestic) gas production that meet demand, but **gas imports** from the international markets. Increased gas demand was driven by a 19% increase in gas used for electricity generation, driven by the weather in Q1 2025.

**Key headlines**

**Gas demand increased in Quarter 1 2025**, up 8.5 per cent on Quarter 1 2024. This was driven by increased gas demand for electricity generation, as well as an increase in domestic (household) and services demand in part due to colder temperatures compared to the same period last year.

**Production fell while imports increased, and exports remained stable**. Gas production decreased by 6.9 per cent in Quarter 1 2025 as output from the mature North Sea basin continues to decline. Imports increased by a fifth while exports remained stable, returning to ‘typical’ levels following the near-record highs of 2023, when the UK saw substantial exports to Europe in a move away from Russian gas.

As a result, total natural gas demand increased by 8.5% in Q1 2025, compared to the same period in 2024, the highest quarterly increase since 2021.

In the same period, perhaps counterintuitively, **indigenous gas production decreased by 6.9%**, whilst exports were stable, meaning demand was met with increased imports.

Imports of **LNG from the US increased by 42 per cent**, and America remained the UK’s largest LNG import source. Imports of LNG from Qatar, Trinidad & Tobago and the USA all increased compared with Quarter 1 2024.

The UK’s dependency on LNG imports comes despite UK domestic seasonal gas demand being relatively predictable. Unhelpfully the UK has **very little gas storage** to prepare for this probability, which exacerbates the exposure to global gas prices when the wind doesn’t blow and the sun doesn’t shine.

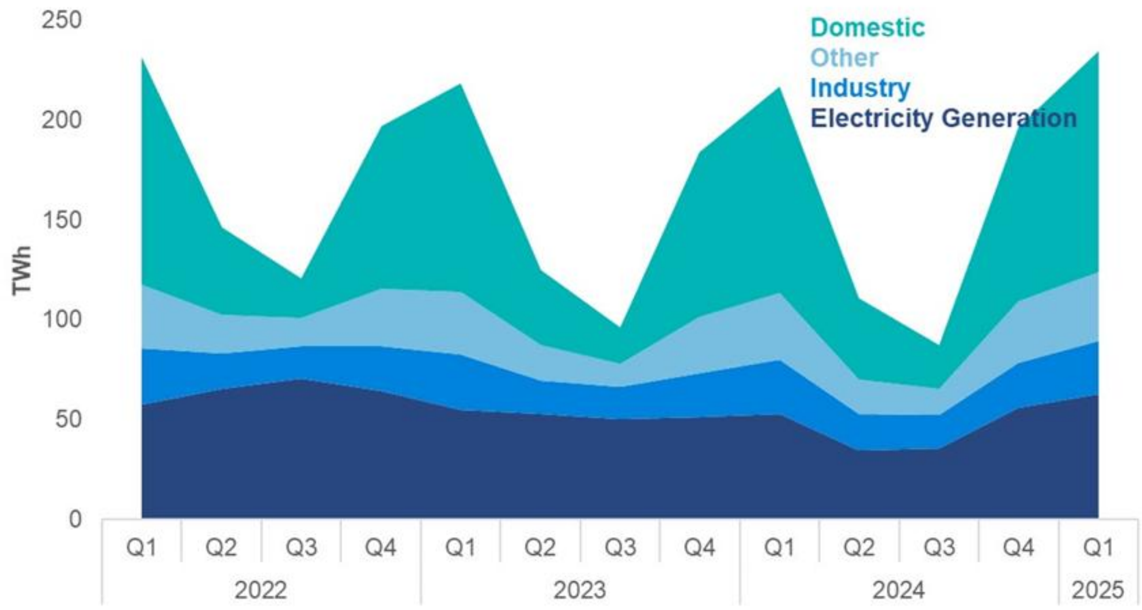



Figure 2: UK natural gas demand since 2022. The rise and fall in domestic use reflects the fact that >20 Million homes are reliant on gas supplies for their heating and cooking needs, and electricity supplies are underpinned by gas in the winter months.

Fuelling-the-Future-The-role-of-gas-in-heating-homes.pdf

In the case of Norway, UK gas imports are disproportionately weighted to one single pipeline, Langeled that connects the Ormen Lange gas field with the Easington terminal on the east coast of England. Langeled is a single critical point of failure and should anything happen to it, ranging from routine maintenance causing down time to malevolent forces, the UK would be even more reliant on LNG supply chains and costs.

**What happens when gas supplies get tight?**

The UK had enough gas production to meet is domestic needs for a decade between 1994-2004, but its subsequent decline means the country is now reliant upon piped imports from Norway and Liquid Natural Gas (LNG) deliveries from Qatar, USA, Algeria, Trinidad etc.).

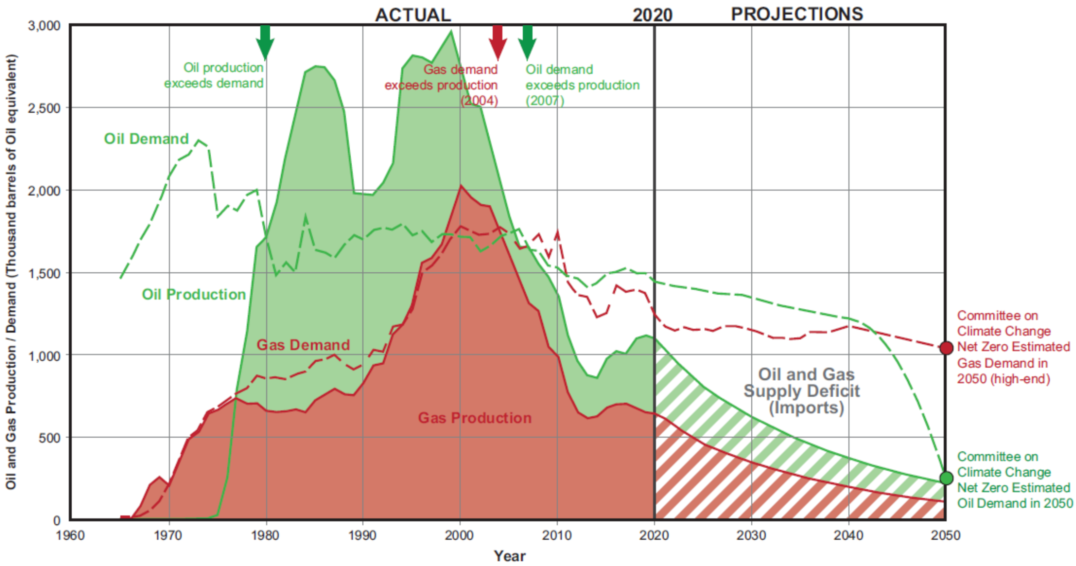



Figure 3: Oil and Gas production curves for the UK Continental Shelf
(Underhill & Richardson, 2022).

Whilst the gas imported from Norway has a lower carbon intensity than domestic production, LNG deliveries have a far higher carbon footprint, something that is detrimental to the global climate yet does not appear on our emissions scorecard.

For the years when domestic production exceeded demand, the UK could stockpile gas in subsurface stores such as Morecambe and Rough fields and release into the gas network when it was needed.

However, as gas production declined, those supplies were needed and stored gas volumes diminished to a point where the country only has four days' worth of gas stored and the UK relies on overseas imports when supplies are tight.

The consequence is that the country has come close to not having enough gas to meet its needs over the past 12 years, most notably in March 2013, when an LNG delivery from Qatar arrived in Milford Haven with hours to spare.

A second example occurred as recently as January 8th. The day before NESO sent out a National Systems Warning alerting businesses and industry that a shortfall in gas supplies put electricity supply at risk, particularly during the peak period between 5-8pm on the 8th.

On the 8th, the cost of a MWh reflected the challenge and charges rose from £60/MWh to peak at £2900/MWh in the early evening. As a comparison, prices were between £80-£120/MWh during the height of the Ukraine crisis.

System Prices Analysis Report: January 2025 - Elexon BSC

A crisis and power cuts were averted by the Government paying Vitol and Uniper to generate from their gas-fired power stations at Connah's Quay and Rye House.

Two power station owners to get more than £12m for three hours of electricity | Energy industry | The Guardian

The cost of paying the inflated cost was in excess of £12 Million, something that the Government deemed worth paying to ensure the lights stayed on and domestic heating boilers and cooker hobs remained alight.

Given there has been no effort to increase gas storage in the interim, the UK remains vulnerable to supply shortages especially on cold, dark, winer days, and so, a repeat of events like those that happened in January are likely, the costs of which will be borne by the taxpayer, billpayer or both.

**PART 2: How is a domestic UK energy bill structured?**

Domestic UK energy bills are governed by the Energy Price Cap, administered and updated by OfGEM every quarter. This determines the upper limit of what a supplier can charge an "average customer" for their energy use.

The price cap is intended to protect customers on a standard variable tariff (default tariff) by being charged a price reflective of the cost of energy. Customer bills vary around that average price, depending on the amount of energy the consumer uses.

The price cap determines a Daily Standing Charge for each of gas and electricity. This price cap covers both the commodity price and the "Additional charges" for running the system.

The figures shown below for Q2 and Q3 2025 are the **GB average**, but within the average are 14 regional variations

Get energy price cap standing charges and unit rates by region | Ofgem

| | Energy Price Cap | Q2 2025 | Q3 2025 | % change |
|---|---|---|---|---|
| Electricity | **pence per kWh** | **27.03** | **25.73** | **-4.81%** |
| | **pence daily standing charge** | **53.80** | **51.37** | **-4.52%** |
| | *Additional charges* | *26.77* | *25.64* | **-4.22%** |
| | % price contribution | 50.2% | 50.1% | |
| Gas | **pence per kWh** | **6.99** | **6.33** | **-9.44%** |
| | **pence daily standing charge** | **32.67** | **29.82** | **-8.72%** |
| | *Additional charges* | *25.68* | *23.49* | **-8.53%** |
| | % price contribution | 21.4% | 21.2% | |

Table 1: UK energy price cap Q2 and Q3 2025 comparison

Table 1 above shows the price cap period for 1st July to 30th September 2025 and how these prices changed from the previous quarter.

Prices for both electricity and gas fell from one quarter to the next. This delta is show in red on the right column

| | Energy Price Cap | Q2 2025 | Q3 2025 | % change |
|---|---|---|---|---|
| Electricity v Gas | pence per kWh | 3.9x | 4.1x | **5.13%** |
| price comparison | pence daily standing charge | 1.6x | 1.7x | **6.25%** |
| Pence per kWh | Electricity | 2.0x | 2.0x | **0.00%** |
| vs standing charge | Gas | 4.7x | 4.7x | **0.00%** |
| | pence per kWh | 34.02 | 32.06 | |
| Aggregate of Gas | pence daily standing charge | 86.47 | 81.19 | |
| plus Electricity | Total additional charges | 52.45 | 49.13 | |
| | Price % | 39.3% | 39.5% | |

Table 2: 2025 Q2 and Q3 UK price cap analysis

The figures in blue show the pricing relationship in each quarter of gas and electricity on a pence per kWh basis. This demonstrates that over the current and previous quarters, **electricity is about 4 times the price of gas**.

The price of gas declined faster than the price of electricity during the periods and therefore electricity by comparison has become relatively more expensive than gas quarter on quarter.

The figures in green show a consistent relationship between the commodity price (pence per kWh) and the Daily Standing Change.

The commodity price (pence per kWh) is the approximate price a supplier pays to purchase the commodity. Suppliers have different hedging strategies and procurement policies, but this price is the same for all UK suppliers.

This difference between the commodity price and the Daily Standing Charge represents the other costs recovered through UK consumer bills. Whilst the commodity price is reflective of international prices, the standing charge methodology is country specific.

**Whether a particular cost is recovered through energy bills or another form of general taxation is a country specific political decision and why energy prices are a politically charged topic.**

The purple numbers show combined wholesale commodity prices were c.40% of the total bill in Q2 and Q3 2025. Ofgem quote a breakdown of other charges below (although this analysis is from an older period when wholesale costs were 45%);

- 45% wholesale costs
- 20% network costs
- 15% operating, debt and industry costs
- 11% policy costs (levies to support low carbon generation, energy efficiency and vulnerable customers), which are broken down into their component parts in the next section
- 5% VAT
- 4% assumed suppliers (profit) margin
- 1% other costs.

*Domestic energy prices - House of Commons Library

The price relationship between gas and electricity is important. Whilst we still use gas to make electricity, it is logical the price of the input ingredients is relative (cheaper) to the price of the output product.

It is the regularity that gas is setting the electricity price that is creating a problem. If the UK wants to reduce electricity costs, solutions could be either reduce the number of periods gas sets the price or have a method of physical intervention when the input price reaches a threshold considered too high.

**What are the Policy Costs that appear on bills and what do they cover?**

The "green levies" include renewable subsidies, energy efficiency schemes, and social programs (like helping vulnerable customers).

Policy costs, are additional costs for consumers because of Government policies, made up £198 or 11% of the Q2 2025 cap. Ofgem has excluded the costs of Contracts for Difference from policy costs in recent cap breakdowns. This support scheme reduced the caps from Q4 2022 to Q2 2023 as it repaid money back to suppliers overall (a function of whether actual market prices are above or below the index price in the CfD).

- **Renewables Obligation (RO)**: supports large-scale renewable electricity generation.

- **Feed-in Tariff (FiT)**: supports small-scale renewable generation (solar panels, etc) installed by households and businesses.

- **Contracts for Difference (CfD)**: supports large-scale low-carbon generation (such as offshore wind, nuclear) under newer arrangements.

- **Energy Company Obligation (ECO)**: requires energy suppliers to fund energy-efficiency improvements (insulation, heating upgrades) in households, especially vulnerable/low-income ones.

- **Warm Home Discount (WHD)**: gives a bill discount for eligible vulnerable households (paid for via a levy).

- **Assistance for Areas with High Electricity Distribution Costs**: a smaller levy paying for higher distribution costs in remote/low-density areas (e.g., parts of Scotland).

- **Green Gas Levy**: funds the Green Gas Support Scheme (biomethane injection) via gas bills.

- **Network Charging Compensation Scheme:** Funds the reduction in network charges for energy intensive industries

Of these policies, approximately half is the Renewables Obligation, which added about £89 of the £198. The second largest is the ECO scheme, which contributed about £59.

The Contracts for Difference contribution can vary widely depending on the wholesale price of electricity. This fell from just under £21 per customer in the winter 2021/22 cap to nearly zero in the summer 2022 cap and was negative in the following three quarterly caps. This was because higher wholesale electricity prices meant few generators were due top-up payments under this scheme in summer 2022 and they were expected to make payments back to electricity supplier from Q4 2022. This highlights why a project with a lower CfD strike price is a better deal than one with a high price and how these feed into consumer bills.

**The impact of VAT**

Although VAT is charged on commercial energy bills at 20%, most domestic supplies which have low usage – less than 145 kWh of gas or less than 33 kWh of electricity - are only charged at 5%.

[VAT rates on different goods and services - GOV.UK]

The discount is meant to address affordability concerns. All electricity users benefit from this discount, and it is not means tested.

Consequently, VAT is a relatively small component of a consumer bill and whilst a reduction in the headline rate will be welcome, especially for those who are charged at the higher rate currently, the scale of rewiring our power networks and re-purposing our Energy System away from its current reliance on gas supplies are on a scale that far outweighs the savings made by scrapping VAT. Removing VAT will therefore have a near term impact in arresting inflation but for all the aforementioned reasons, the long-term trend is still for bills to rise.

**Network and infrastructure costs**

After the actual wholesale costs element of UK domestic bills, the cost of operating and maintaining the network is the second largest factor accounting for 20% of the total charge.

The UK has decided against a zonal pricing system in favour of reforming the existing national system. Small regional variations in domestic energy prices already exist and significant variation in transmission costs ("TNUoS") exist for generation projects.

A disproportionate population split towards the Southeast and a grid that was designed for a fossil fuel system with historic coal and gas generation projects located close to demand, is the backdrop to OfGEM launching a consultation on national system reform.

The ambitious renewables build-out programme consistent with Clean Power 2030 means an acceptance that generation projects will be located in regions away from the cities and industrial clusters that use the power they generate.

The scale of the network upgrade investment and the cost of balancing the system until the upgrade is complete are significant and will have to paid for by either the existing mechanics in consumer bills or through taxation.

Investment in the Transmission infrastructure enabled more areas to be connected and incrementally over decades, the grid physically began to appear as we have today with the cost of electricity "balanced" across the country, in the same way the physical electrical characteristics are also shared.

The grid has successfully evolved from local to national and then from transitioned from coal to gas as production from the North Sea and other parts of the UK Continental Shelf (e.g. East Irish Sea) ramped up and the UK converted to gas for domestic heating, cooking and some of its power supplies.

The challenge today is the incorporation of an increasing share of renewables generation from wind and solar, much of which is generated a long way from point of use and therefore requires additional transmission investment, a situation that is not unique to the UK and is increasingly being shared around the world.

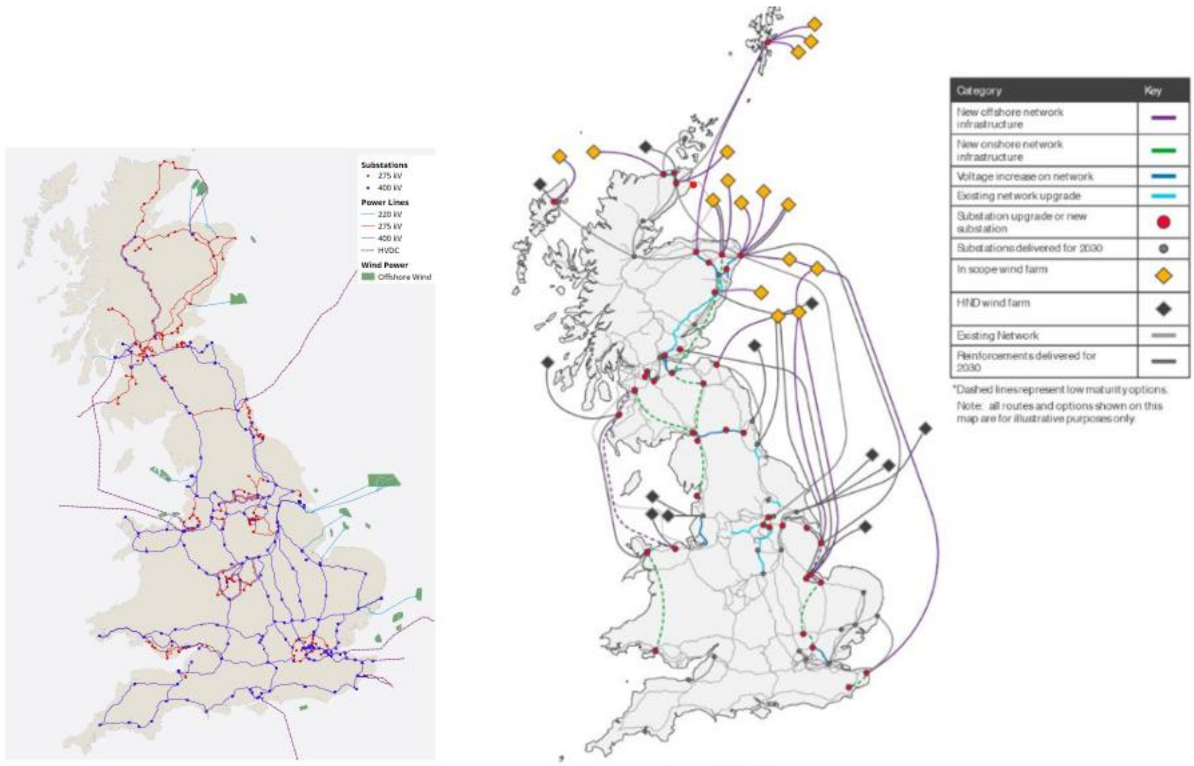
Renewables generation is intermittent by its very nature (i.e the sun doesn't always shine and the wind doesn't always blow), and has very different characteristics to conventional fossil fuel-based systems. Renewables lack the ability to provide "mechanical inertia"; are unable to release or absorb fluctuations in energy to stabilise the grid at the right frequency, something that relies on other systems with a fast frequency response, battery storage and continued investment in transmission infrastructure.

Not having sufficient inertia across the system can leave electricity transmission vulnerable when the systems are stressed by imbalance, trip out occurs and there is a need for a fast ramp up from baseload as demonstrated by recent events in Iberia. This is not a problem in itself, the solutions exist to manage the imbalances, but grid investment must keep pace with the continued development of renewables.

Operating at a frequency of 50HZ, mainland Britain's high voltage electricity power network is known as the National Grid and it connects power stations and substations across England, Scotland and Wales (but not Northern Ireland). The Grid consists of a series of 400kV, 275kV and 132kV power lines (Fig.1), the hubs for which are largely dictated by the locations of the original coal-fired power stations that were invariably linked to coal mining areas (examples of which include Longannet, Cockenzie, West Bridgford, Drax and Ratcliffe-upon-Stour), gas-fired power stations (e.g. St Fergus), nuclear power stations (e.g. Dounreay and Torness) and hydro-electric generators.

Onshore and some offshore wind sites have been added to the network in the past decade, but the aspiration is that more will be forthcoming to take the UK from its current 14.7GW to 50GW of generating capacity by 2030.

The costs of rewiring Britain on such a scale will need to be borne by the bill payer, unless it can be borne by another budget (e.g. defence spending) and the taxpayer.




Source: National Energy System Operator

*Figure 4: Maps of the current National Grid network of existing electricity sub-stations and power cables and the new design following the re-wiring to accommodate new clean power sources.*

**Impact of a fractured market**

The UK energy sector is no longer characterised by large monopolistic or integrated energy companies. The market is regulated into generation, transmission and supply, with each business or part of the system under pressure to deliver independent shareholder returns.

Regulation encouraged a proliferation of smaller and thinly capitalised suppliers to provide competition into the market. These new businesses didn't maintain their own fleet of generating assets on their balance sheets, but sourced commodity needs and obligations in the wholesale market

This was feasible due to the UK pursuing a very "fractionated" system, however, each "fraction" needs a return on investment. In a highly fractionated system, there is no place for balancing business risks through offsetting physical supply and demand.

The reasons above explain why UK electricity price are what they are. An assertion that UK electricity is expensive is demands a comparison with benchmarks in time or with other Countries. However, the structure of our electricity market is unique to the UK and other Countries account for investment and costs through other methods.

**Hedging & supplier failures**

During the 2021–2022 price spike, many smaller suppliers went bust because they hadn't hedged against rising wholesale prices. The cost of other suppliers taking on these customers is socialised across all bills adding extra charges.

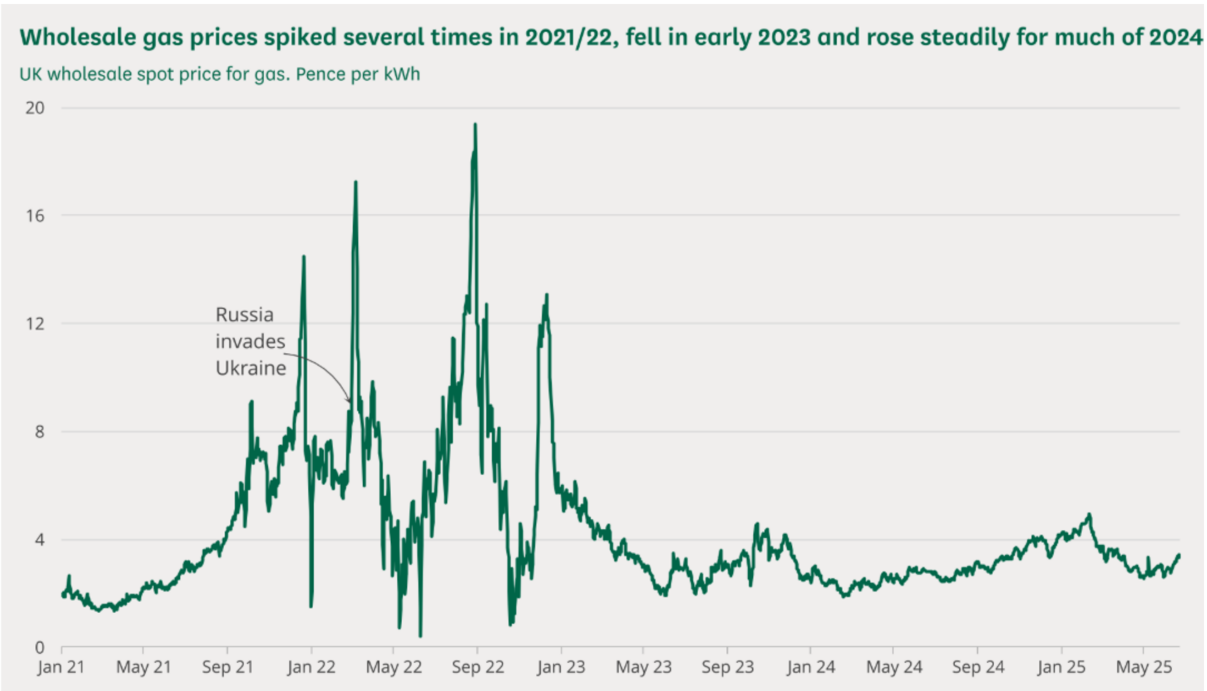



Figure 5: UK gas prices during the Russian invasion of Ukraine

[CBP-9491.pdf]

In the years prior to the wholesale gas price spikes, UK Government and OfGEM had a policy of encouraging competition in the retail supply market through having a large number of suppliers.

There were low barriers to entry and suppliers were able to launch a route to market with commodity procured through the wholesale market. This led to the newest suppliers successfully building a customer base based on lower prices.

These new suppliers didn't have the same expensive cost structures of traditional utilities and didn't have capital intensive generation divisions that provided some or all of the power in the wholesale market.

The model was a success in the sense customer choice was significantly widen from a small number of large suppliers and their business model helped acquire a cross section of price sensitive consumers who shopped around for the cheapest deals.

Many of these thinly capitalised suppliers did not have sophisticated hedging strategies, which worked against them when wholesale power prices spiked upwards and which lead to the biggest administration of Bulb Energy.

Energy firm Bulb set to go into administration - BBC News

Bulb Energy went into administration in November 2021 and was run by the Government through the regulator OfGEM. This was because the regulator was unable to find another supplier willing to take on the customers on acceptable terms.

This "supplier of last resort" regime was previously seen as a backstop, unlikely to be used because the market would function and another supplier would assimilate the customers.

However, those customers would not come across with any associated hedging and in a market of volatile energy prices, other supplier baulked at taking this risk. Offers were made, but the conditionality of Government financial support was unpalatable.

Bulb Energy remains in administration, and the most recent Administrators report was published in June 2025 to Companies House. The business has continued to operate, selling off smaller parcels of customers when market conditions allow.

application-pdf

In response to the supplier failures during the energy price spike, OfGEM has imposed new capital adequacy requirements on suppliers, despite the market still being volatile market under pressure from thin margins. These tests include;

1. A minimum capital buffer of £115 per dual fuel customer. Not having this capital buffer could prohibit the business taking on new customers.

2. Dividend restrictions until capital buffers are in place. Paying dividends could result in enforcement action
3. Ring-fencing of funds. Suppliers typically went into administration when their annual renewables obligation payment fell due. These funds must now be segregated on the balance sheet or risk a license sanction.

The issue remains topical through the summer of 2025 with Centrica advocating that Octopus Energy presented a systemic risk, acquiring new customers whilst still not yet meeting regulatory requirements;

Centrica calls for ban on Octopus taking on new customers

Suppliers are potentially raising new capital, not to meet cashflow needs of their operating business, but in acknowledgement of new market regulatory criteria that moves away from the pre-energy crisis objective of encouraging competition and consumer choice. Raising genuinely new equity capital will require supply businesses to convince investors in the profitability forecasts and therefore stability of the UK electricity market at a time when the profit and stability are not obvious features.

**PART 3: Critical Infrastructure and Defence Spending**

At the 2025 NATO Summit in The Hague, NATO members committed to a new benchmark: spending **5% of GDP annually** on defence and security-related spending by 2035. Previously, NATO members had a target to spend at least **2 % of GDP** on defence (a target set in 2014), which was a threshold few members reached. Whilst this new target is political, rather than legally binding, it does signal a major escalation in commitment, reflecting growing security concerns.

The new 5 % target has two categories; 3.5 % of GDP on "**core defence**"—troops, major equipment, operations and maintenance and 1.5 % of GDP on broader "**defence- and security-related**". The definition of this second category is broader and includes; cybersecurity, infrastructure resilience, critical logistics and the defence industry.

If the UK were minded to remove the significant, but necessary, grid upgrade works from consumer bills, it would need to be funded through general taxation. However, defining these costs as part of the "infrastructure resilience" definition above, would enable these being Defence Spend and meeting the NATO target.

With similar logic, there have been recent industry calls for new gas permitting, linked to existing infrastructure, which can increase domestic supplies and reduce our reliance on the international markets as argued for recently in a separate paper from Aberdeen University.

Government urged to back strategic oil and gas measures | News | The University of Aberdeen

The August 2025 price cap announcement is a reminder of how exposed the UK is to global energy prices. Whether this exposure is increasing or decreasing is now a function of the wind blowing, the sun shining and the international gas price.

If lower electricity bills are the objective, then the **structure of bills** needs to be reconsidered. Placing the costs of both the network upgrade and the network balancing onto bills at the same time is problematic. The Energy Transition is something consumers must retain enthusiasm for and be able afford for both climate and security of supply considerations.

Over a longer timeframe, the investment in the network will reduce curtailment and balancing costs. This is how we reduce the **number of periods** where gas prices set the electricity price, given there will be more capacity on the electricity grid. One solution to this shorter-term problem is the removal of the Network costs approved on the 1st of July onwards from consumer bills and funded through general taxation.

The network upgrade costs would still need funded, but once the system balancing costs begin to decline due to network investment, the cost of network investment could return to consumer bills. This **phased approach** would protect the most vulnerable consumers from the short-term price increases of the grid investment requirements but still maintain support for the Energy Transition.

This investment in network capacity and resilience should also be considered through the lens of security of supply and defence spending. The UK is committed to increasing defence spending to 2.5% of GDP in 2025, rising to 5.0% of GDP by 2035. National and International Energy infrastructure have always been a closely aligned with defence. Investing in a stronger electricity network within the UK and connections to neighbouring markets could be part of this solution.

Of further consideration should be the UK investment into strategic gas storage solutions. Gas will continue to be necessary on the electricity system when the wind doesn't blow and the sun doesn't shine.

Gas will continue to set the price of electricity for many years, but it is only problematic in the periods where gas prices are perceived as too high. Therefore, logical objectives should be (i) limit the number of periods this is happening through investment in renewable generation and grid infrastructure (already happening) (ii) license and operate **new UK domestic gas fields** to maintain a target storage requirement and produce only when required due to the higher global prices. This investment could act to dampen the effects of gas prices in the most expensive periods but would need to operate on a new licensing regime.

Investment in UK gas assets is currently lacking confidence as highlighted in the recent position paper from Aberdeen University;

The-case-for-introducing-strategic-infrastructure-led-permits-to-replace-traditional-offshore-licensing.pdf

The Investment landscape makes gas storage a logical investment class for Great British Energy (GBE). These assets of wider strategic value, used to keep the lights on at times of highest gas price, but investment is in decline. Widening the investment mandate for GBEto include investment in Gas Storage would help provide a more stable energy system through the transition. Investment in this niche asset class would also help industries and employees navigate the transition.

The operation of a gas field in this way is not a particularly new idea; the Morecambe gas fields development back in 1980's was to provide peak UK demand for gas in the winter when the sole licensee and operator of the field was Hydrocarbons GB Limited and is now owned by Spirit Energy.

The energy system transition doesn't just need renewable generation alone. It needs grid investment, it needs gas storage as a fall back and it will take time. These recommendations make for low regrets options that the UK Government should urgently consider.

**Conclusions and Recommendations**

So, we recommend the following actions are taken:

- **Rebalance cost recovery:** UK electricity bills are already among the highest in the world, and placing the full cost of necessary network upgrades onto consumers would make them even less affordable. These infrastructure improvements should instead be funded through general taxation until they are completed. Once the upgrades are in place and congestion-related curtailment is reduced, there will be sufficient headroom to transfer these costs back onto consumer bills. Whilst network upgrade costs should be moved from consumer bills to general taxation, with a phased return once balancing costs decline.

- **Energy security as defence:** investment and gas storage are critical infrastructure for electrification, but also strategically important assets for the security of supply. The point has arrived for making these part of the Defence budget and using this expenditure so, we should treat parts of grid investment as national security expenditure, aligning with the UK's commitment to increase defence spending to 5% of GDP by 2035 to meet our NATO targets.

- **Strategic gas licensing and storage:** Develop a new licensing regime for domestic gas fields and invest in storage to dampen price spikes during high-demand periods, which would incentivise production when global markets are high and injection and storage when prices are low

- **Maintain public support:** Ensure affordability during the transition and undertake a campaign to inform the public about the scale of the transformation needed to avoid undermining consumer confidence in decarbonisation goals.

**Authors**

- **Matthew Porter** ~ is a seasoned renewable infrastructure and investment professional with over 25 years of experience spanning both the public and private sectors. He was a founding member of the UK Green Investment Bank in 2013 and later joined Macquarie Group, where he spent nearly eight years working across its Green Investment Group and as Head of Investment Management for Corio Generation, an offshore wind platform. Matt has served as a Board director for numerous UK offshore wind projects through development, construction, and operational phases. In 2025, he founded NextLife Energy, an investment vehicle focused on operational onshore wind opportunities.

- **Professor John Underhill** ~ is the University Director for Energy Transition at Aberdeen University. He has had a distinguished academic career based at Edinburgh, Heriot-Watt and Aberdeen Universities. While at Heriot-Watt, he helped establish the Lyell Centre for Earth and Marine Science and Technology and was University Chief Scientist. His research focuses on the role of geoscience in the energy transition and use of technologies, methods, and data to deliver low-carbon net zero goals. He has led the GeoNetZero Centre of Doctoral Training, a £22M academic-industry pan-UK partnership comprising 12 Universities and 8 companies and chaired the National Energy Skills Accelerator (NESA), where he helped secure £1M from the Scottish Government’s Just Transition Fund to up- and re-skill workers for careers in renewable energy. John populates the UK Subsurface Task Force and was on the Scottish Science Advisory Council (SSAC), the leading independent advisory board for Scottish Government.