Economic Consulting Associates

Insight

Just why are Britain's industrial energy prices so high?

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Neither gas nor net zero obligations adequately explain difference from European peers

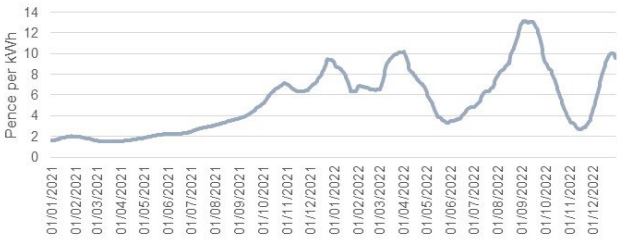
Back last autumn, in its periodic comparison of international energy price statistics, the UK Government created headlines by publishing comparisons that showed that in 2023 the country had the highest industrial energy prices in the OECD. Europe's exposure to fossil fuel price volatility as a substantial net importer is well documented. However, even when compared to its immediate European neighbours, Britain's average price of 25.4p/kWh far outstripped the 15.6p/kWh in Germany, 17.6p/kWh in France, 13.3p/kWh in Spain, and 18.3p/kWh in Italy. As part of its response to these findings, the Prime Minister has announced further exemptions for Energy Intensive Industries (EIIs) from network charges to help improve their international competitiveness. Nevertheless, it is acknowledged this won't bridge the full gap.

A slew of analysis followed last autumn's finding as to the reasons for the UK's particularly high costs, falling broadly into the politicised camps of either blaming gas in one corner, or net zero in the other. However, by letting politics dominate the debate, have we let the real reasons go relatively unexplored? To try and disentangle the arguments, let's review core components, covering wholesale energy costs, policy costs, and network costs to see where the greatest differentials between Great Britain and its EU comparators lie.[1]

It's gas, isn't it?

Few argue that the energy price crisis which peaked through 2022 was heavily influenced by the preceding tensions and then war in Ukraine and the disruption to gas supplies that ensued (dragging prices for substitute fuels up in its wake). Between early 2021 and early 2022 gas prices rose more than five-fold and remained high and volatile through to the end of the year (see Figure 1). Britain is relatively gas dependent, generating 35% of its electricity from the fuel in 2023, as compared to 16% in Germany, 6% in France, and 23% in Spain. Italy, however, has an even higher share from gas (45% in 2023).

Figure 1 30-day rolling average System Average Price (2021-2022)



Source: National Grid. Accessed 2025. Gas Transmission Data.

If gas saw the greatest price rise, and Britain is relatively gas dependent, then isn't it pretty cut and dried that gas is the key culprit? Not so fast. The European electricity grid and market is extensively interconnected, allowing for easy arbitrage across borders whenever there is spare capacity to do so. Price differentials therefore occur to the extent congestion in such interconnection fragments the market leaving cheaper generation stuck behind a

[1] The UK's power market is split between that of Great Britain and that of Northern Ireland which forms part of the Single Electricity Market (SEM) of the island of Ireland. Given the small impact of Northern Irish data on overall UK figures, where statistics are published for the UK as a whole no attempt has been made to disaggregate.

constraint and unable to export. Wherever this isn't the case, the most expensive generation needed to meet demand – in this case gas – sets the wholesale spot market price in both jurisdictions.[2]

So, to what extent is gas the marginal price setter across Europe? This question was asked by Zakeri and Staffell (2022) who estimated gas set prices in Great Britain 98% of the time, as compared to 82% in Italy, 65% in Spain, 24% in Germany, and just 7% in France. The authors do correctly note, however, that pricing for the key alternative in much of Europe, hydro power, is set based on the value of stored water. That value is itself set with reference to the counterfactual price setter, which in the absence of transmission congestion will in most cases be gas. Accounting for this and based on the same data, gas may directly or indirectly be the marginal price setter for 97% of the time in Spain and 96% of the time in Italy – very similar results to the UK.

Even in France, the finding that nuclear is the price setting generator for over 80% of hours is of questionable relevance given the technology's low variable cost of generation does not correlate to day-ahead market prices significantly differentiated from that of the interconnected countries, indicating similar bidding strategy considerations are taking place. This is corroborated by the European Commission's 2024 report on energy prices and costs that found for several countries, including Germany, Italy and France, the natural gas price alone provided a better forecast of monthly electricity prices than consideration of several additional explanatory variables, such as the fuel mix.

More easily, we can sanity check the relative impact of such gas dependency simply by looking at wholesale prices. Here, in support of their finding, Zakeri and Staffell quote the UK's average Day Ahead price for 2021 of €272/MWh as compared to between €88 and €136/MWh elsewhere in Europe. This is a huge difference but also one that appears to be an error. ENTSO-E and Ember Energy data show the UK having similar average wholesale prices to its European peers throughout 2021-2023. The average day-ahead wholesale price in the UK across 2022-2023 was €174/MWh; similar to Germany at €165/MWh, France at €186/MWh, and Italy at €216/MWh. Only Spain showed a notably lower average price of €128/MWh, driven by its temporary cap on the price that could be offered by gas-fired generators to the wholesale power market, as well as its superior LNG import capacity.

So, while GB's relative gas dependency may have seen some periods of higher marginal prices during a few hours when interconnection with the rest of Europe was congested, this did not translate to higher average costs over the course of a year and therefore cannot account for the retail price differentials observed.

The key issue seems to be either the translation of wholesale into retail prices, or differences in procurement practices that impact wholesale price pass-through, rather than wholesale prices themselves. That means either the addition of levies, tax, network tariffs and supplier margins, or differences in hedging strategies/obligations.

If not gas, then surely it is renewables?

Levies associated with renewable energy are added to retail bills, after wholesale purchases, hence providing an obvious point of investigation for why the UK may have a higher retail to wholesale price ratio than elsewhere. This becomes the driver for the argument that renewables are the cause.

For renewable generation, excluding large-scale hydro, the UK is not special, with similar overall contributions to those seen in Germany and Spain (Figure 2). But the country could be paying more for the same result for a variety of reasons. Looking first at direct subsidies, government figures show net payments to cover the ROC, CfD and feed-in tariff schemes amounted to £7.9 billion in the financial year for 2022/23 and £10.4 billion in 2023/24 (the large majority, £6.4 billion and £6.8 billion respectively being ROC payments).

The nature of the ROC scheme itself and lack of hedging to wholesale price rises leaves UK prices particularly vulnerable. CfDs do provide a price hedge and in effect go a long way to delinking renewable energy costs from the variable price of gas in the manner that has been widely called for (while retaining the useful link to a reference price for incentivising efficient trading and maintenance scheduling). This is evidenced in their relatively small contribution to 2022/23 renewables levies although the net payment could have been lower still had some generators not been able to delay their

[2] This may occur either directly through pay-as-clear exchanges, or indirectly via the pricing strategy of market participants entering bilateral contracts.

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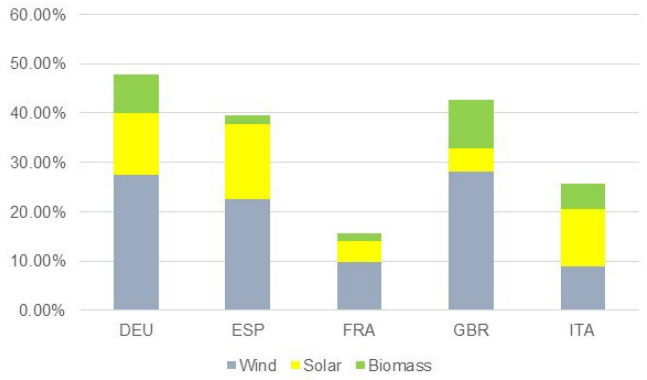
commencement and avail the windfall of high wholesale prices. ROCs are a legacy scheme and their impact will gradually disappear from the market. However, some ROC contracts still have many years to run and as so, without any amendment, will continue to add costs even in periods of high wholesale pricing.[3] A transition to fixed price certificates is expected from 2027; imposing a hedge alongside the changes would help protect consumers in future periods of high gas prices.

Figure 2 Share of core non-hydro renewables in electricity generation for 2023



Source: International Energy Agency. Accessed 2025. Electricity data for Europe

Renewable support schemes are varied in design and ensuring like-for-like comparison between countries is difficult. However, quoted budgets for Germany's Erneuerbare-Energien-Gesetz (EEG) and Spain's RECORE (which both seek to assess the net costs of direct subsidy support schemes for renewable energy) indicate 2022 costs of €6.4 billion and €4.0 billion respectively. Divided by non-hydro renewable energy generation in each country (as this is typically not eligible for subsidy), this amounts to an additional cost per MWh of £60/MWh in Great Britain, €32/MWh (£27/MWh) in Germany, and €38/MWh (£32/MWh) in Spain. It is noticeable how the structure of support in Germany, where tariffs were either fixed or hedged against wholesale prices, meant a much sharper drop in support levels from the prior year (from €22.6 billion in 2021) than in the UK (where ROC costs were also £6.4 billion in 2021/22), or in Spain (€5.8 billion in 2021).

Since 1 July 2022 Germany has gone a step further and moved all costs associated with the EEG from electricity bills to general taxation. Originally undertaken as part of its response to the energy price crisis this approach has not been reversed and follows similar changes in the Netherlands. France, Italy, and Spain similarly enacted emergency measures including a temporary removal of certain taxes. Calls to follow the German approach in the UK have been made and this is a clear area where approaches diverge in a manner that harms the UK's competitiveness. However, this of course represents a reallocation of costs to taxpayers instead of electricity consumers, rather than a reduction in the costs themselves.

Nevertheless, even with such changes the difference in renewable policy costs per kWh sold fails to explain the much larger gap between wholesale and retail prices paid in the UK. Indeed, EII have long had substantial exemption from them. The exemption amounted to 85% of associated costs in 2022-2023 and was increased to 100% from 2024.

What about the other renewables-driven components of an electricity bill?

Wholesale energy and renewable subsidies together only constitute around 60% of retail costs in the UK (although the share of wholesale will have been higher in 2022 in particular). Other key cost components come from network charges – both for use of the network infrastructure and balancing use of system charges – and, to a lesser extent, capacity market costs. The composition and cost base for each of these is influenced by the integration of higher volumes of renewable energy and this has led to claims they provide indirect subsidies to support renewable integration which then pushes up costs.

Eurostat monitor the components of electricity bills including network costs. The most recent year that included submissions from the UK was 2019. For all non-household consumers the average network cost at this time for the UK was reported as €c2.5/kWh as compared to €c3.3/kWh in Germany, €c1.8/kWh in Spain, €c2.5/kWh in France, and €c2.4/kWh in Italy. Ie, the UK was very much aligned with the average. Ofgem data for households does indicate average network costs GB-wide rose approximately 70% between 2019 and 2023. Similar is true in Eurostat data for Spain (83%), but much less so for Germany (29%), Italy (20%), and France (16%).

[3] It is noted the proposed transition to fixed price certificates from 2027 will not address this issue as no hedge is provided against wholesale prices.

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The need to facilitate transmission of renewable energy is a key driver for network expansion, while commodity price increases for raw materials saw infrastructure costs escalate alongside energy prices. These drivers should impact all the comparator countries although geographical differences can play a role (for example the UK has particular issues with north to south transmission). However, much of this additional cost is charged back to the renewable generators through locational transmission use of system charges for generators that seek to reflect the long run costs of expanding capacity within the relevant zone. This part of the cost is therefore already incorporated in wholesale/CfD prices.

Assuming industries saw a similar 70% increase in network costs to that observed for households then applied to 2019 Eurostat data this may have added in the region of 1.7p/kWh to retail prices by 2023. This is a substantial amount but relatively small in comparison to the difference in overall industrial electricity prices.

More important are the exemptions provided from network costs to particular industries. A majority of network charges are ”residual”, ie costs that need to be recovered but which cannot be attributed to specific network users. These costs are incurred for a variety of reasons including the need to meet reliability standards as well as imperfect foresight and limitations of lumpy investment. Ramsey Pricing principles, which seeks to minimise the impacts of price distortions and thereby maximise economic efficiency, suggest they should be recovered from the least elastic demand. Industrial electricity consumption is relatively elastic and therefore this provides an argument in favour of such exemptions that have been in place for each of Germany, France, Spain and Italy since before the price crisis. In 2023 no such exemption was in place for the UK and this will have been a significant contributor to the price differentials observed. This discrepancy was first addressed in April 2024 when a similar 60% exemption from network fees (including BUoS) was introduced for EIIs. Today’s announcement pushes that up to 90% - moving beyond the level that could be justified via Ramsey Pricing.

Bridging the gap

Exemptions from network fees and, to a lesser extent, renewable policy costs together therefore explain a significant portion of the difference in industrial energy prices reported for 2023; at an approximate estimate in the region of 4 to 5p/kWh. The gap to the four comparator countries for 2023 was, however, between 7p/kWh and 12p/kWh.

The remaining gap appears to require country-specific explanations. Gas price regulation in Spain helped dampen wholesale prices through the crisis period. In Italy, industrial retail prices for the full period January 2021 to December 2023 averaged very similar to the UK (15.6p/kWh as compared to 15.5p/kWh) but peaked in 2022 rather than 2023 possibly due to different norms on hedging strategies.

For France the wholesale price as recorded on power exchanges provides a distorted picture of the cost of wholesale power procurement. Legacy nuclear generation is sold under a regulated tariff, the Accès Régulé à l'Électricité Nucléaire Historique (ANRH) which has been priced at €42/MWh in nominal terms since 2012. EDF have highlighted the price if insufficient to cover even ongoing life extension capital as well as operational and maintenance costs of the existing nuclear fleet, and it is set to expire in 2025. For now, however, it allows a large share of France’s generation to be made available to suppliers far below wholesale prices. Domestic and some small commercial tariffs are regulated, ensuring this saving is passed through to consumers. No such protections are in place for larger consumers but this should still have enabled substantial hedging of retail prices.

Lastly Germany provides possibly the most curious case. Despite day-ahead market prices similar to the other countries reviewed here, the “energy and supply” cost component reported to Eurostat was substantially lower than for peers through 2020-2022 – particularly for the largest industrial users. The most recent reported years of 2023-2024 do indicate that advantage has been lost and hedging for lignite plants against the EPEX spot is common which should smooth prices over time at the cost of a small premium. However, a substantial overall advantage seems to have been retained over Spain and Italy (and presumably the UK) at least when reviewing the period as a whole. It would seem improbable that the other inputs to the energy and supply cost component – energy balancing and supplier margin costs – could vary sufficiently to account for the difference, leaving scope for further exploration.

What does all this mean for the UK?

The increased exemptions to renewable energy and network charges announced since 2023 will bring treatment of industrial consumers onto a more level

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playing field with its European peers, although the raising of the network exemption to 90% will distort price signals and load costs on other consumers. Proposals to shift renewable levies to general taxation could help provide similar respite for smaller commercial and domestic consumers. Such exemptions represent the most accessible policy options available in the short-term.

To some extent the 2023 results may also be a quirk of timing vis-à-vis norms for company hedging strategies and/or reflect the legacy of past ROC obligations. Both effects would be expected to gradually dissipate. But what about the longer term? Some clear findings are present:

- Diversification of fuel supply away from dependency on imported gas is a priority. Although Britain's dependence isn't unique in Europe, it contributes to higher prices across the continent. Exposure to wholesale prices set by marginal cost of gas should incentivise such diversification.

- However, price volatility, particularly of the extreme nature observed during 2022, is near impossible to forecast and therefore difficult to finance a capex-intensive alternative against. Hedging, embedded in policy (eg France's regulated purchase price for nuclear generation, or CfDs) as well as driven by the market, is therefore a clearly vital to tool to protect against such periods. The absence of demand for long-term contracting by retailers due to a reluctance by most end consumers to fix tariffs in the long-term, means a requirement for policy instruments is likely to persist even where renewable energy or nuclear could be expected to lower costs.

- Greater interconnection drives greater price convergence, which in the short run can actually increase or retain exposure to gas setting the marginal price even if dependency in GB were to decline. However, if combined with hedging instruments such interconnection remains desirable where price spreads justify as it reduces the overall costs of generation across both interconnected countries. Policy questions should then focus on the allocation of any producer or consumer surplus derived.

- The is scope for reinforcing hedging through amendments to renewables policies. CfDs may be strengthened through tightening of rules on delayed commencements (which have allowed operators to avail high wholesale prices before switching to a CfD as these prices fall). The structure of the ROC support mechanism is a greater risk and consideration of how some form of hedging may be introduced could form part of the decision on the move to fixed price certificates from 2027.

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