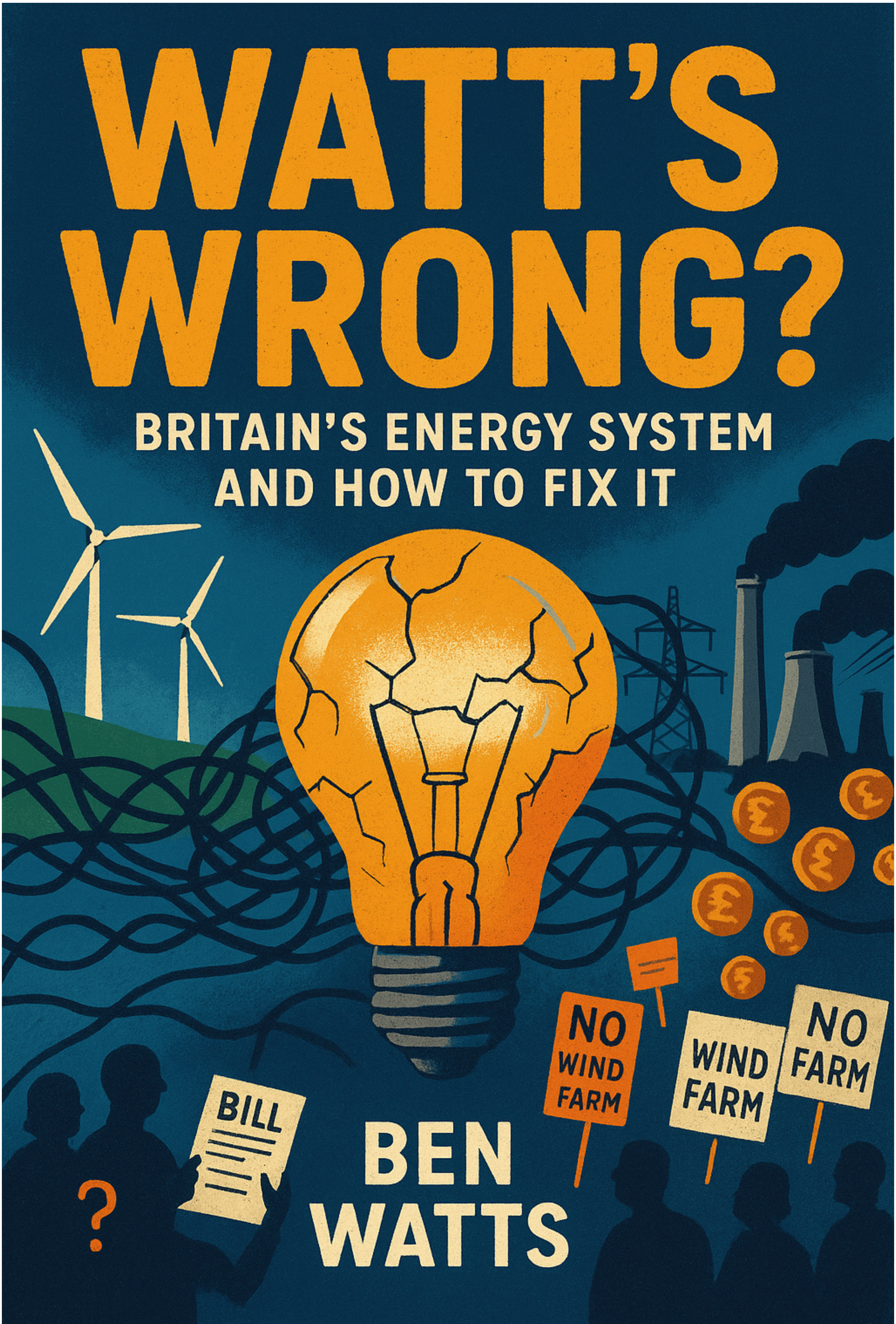
WATT'S WRONG?
BRITAIN'S ENERGY SYSTEM AND HOW TO FIX IT
BILL
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WIND FARM
NO FARM
BEN WATTS
Cover

# Watt's Wrong?

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**Language:** en

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# Chapter 1: Watt's Wrong with Britain's Energy?

## Welcome to Watt's Wrong?

Welcome to *Watt's Wrong?*, a comprehensive guide to understanding what's wrong with Britain's electricity and energy system. Whether you're new to energy policy or an expert in one area wanting to explore others, this book will give you the full picture of Britain's energy dysfunction.

## What This Book Covers

This book systematically covers Britain's energy system problems across 20 chapters:

1. **Introduction** - Welcome and overview
2. **Biomass** - The biomass energy problem
3. **Feed-in Tariffs and ROCs** - Renewable energy subsidies
4. **North-South and NIMBYs** - Geographic and political opposition to energy infrastructure
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19. **Glossary** - Commonly used acronyms

## How to Use This Book

### For Beginners

Start from the beginning and work through each chapter sequentially. Don't rush - take time to understand each concept before moving forward.

### For Intermediate Users

You can skip ahead to chapters that cover topics you're less familiar with, but I recommend at least skimming the earlier chapters to ensure you have the complete foundation.

### For Advanced Users

Use this book as a reference and focus on the advanced chapters. The earlier chapters can serve as a quick refresher when needed.

## What You'll Need

To get the most out of this book, you'll need:

- **Basic understanding** of how electricity works (we'll explain the rest)
- **Interest in policy** and how government decisions affect daily life
- **Curiosity** about why Britain's energy system seems so dysfunctional
- **Patience** - we're going deep into some complex topics

## Getting Help

If you encounter difficulties or have questions:

1. **Check the chapter summary** at the end of each chapter
2. **Review the previous chapters** - the answer might be there
3. **Use the online version** at [GitHub Pages link] for interactive reading
4. **Contribute improvements** by submitting pull requests to the repository

*Ready to begin? Let's dive in!*

# Chapter 2: Biomass

## Introduction

Biomass is the burning of wood or crops for energy. Mankind has relied on it since first burning firewood. With industrialisation in the 19th and 20th centuries, it got displaced by more abundant and energy dense fossil fuels like coal (and later oil and gas). In Britain today, the mostly used biomass is in wood fires stoves heating homes and at the massive Drax power station.

## What's good about biomass?

Before slating it, it's worth noting biomass technologies have a number of advantages:

- **Flexible storage**: biomass fuels such as wood pellets, biodiesel/ethanol can be stored in silos or big tanks just like fossil fuels, ready to be burnt when they're needed. Compared to electrified renewable technologies like wind and solar, they don't necessitate storing energy in batteries that use rare earth materials, and they're often not too much of a risk to the environment when they're stored. They can also be used for heat (e.g. a stove), transport (e.g. a biodiesel car/truck) or power generation (e.g. Drax).
- **Conversion**: you can often repurpose or convert existing fossil fuel appliances to run on biomass fuels. Drax power station previously burnt coal, diesel cars and trucks can be converted to run on vegetable oil derived biodiesel, coal fireplaces can be retrofitted with a wooden stove.
- **Consumer Adoption**: because they're tangible and similar to fossil fuels, they're often easier to persuade consumers to switch to. Biodiesel and bioethanol fuelled cars engender less range anxiety than EVs. Biomass boilers require less modification to home radiators than heat pumps.

## So what's the problem with Biomass?

In a nutshell, biomass isn't efficient. It's a very old technology, dating to cave people's first use of firewood, and we have to rely on some plant's growth cycle to capture stored energy. Plants aren't that efficient at storing the energy they photosynthesize from sunlight. To get any meaningful contribution to our energy needs from biomass requires large scale cultivation of crops and plants. And when we burn biomass fuels in power stations or stoves, we are lucky to usefully extract 30 or 40% of the energy the plants have captured. All together, this means to get any significant proportion of our energy from biomass requires converting massive tracts of land to growing large numbers of similar plants or crops. Such monocultures can't fail to have profound impacts on ecosystems affecting other wildlife, and competing with use of land for food production.

## How do you solve a problem like Drax?

Drax is massive. It is the largest power station the UK has ever had, with a capacity of 3,960 megawatts - enough to power over 6 million homes. It was built in 1974 in Yorkshire on the banks of the River Ouse, to burn coal sourced from the nearby Yorkshire coal fields. At the time, almost all Britain's power came from coal, and there were many other power stations like Drax. In the rivers like the Ouse, Trent, and Aire that empty into the River Humber, the area was nicknamed "megawatt valley" and accounted for over 40% of Britain's power generation at its peak. When Drax opened in 1974, it was the largest coal-fired power station in Europe and one of the biggest in the world - a symbol of Britain's industrial might and energy ambitions. At its peak, Drax was one of the largest carbon emitters in Europe, releasing over 20 million tonnes of $CO_2$ annually - more than many entire countries. While there are larger coal plants in Germany and Eastern Europe, Drax was certainly among the biggest emitters in Western Europe.

When the UK signed up to the EU Renewable Energy Directive in 2009, it committed to generate 15% of its energy from renewable sources by 2020. At the time, only around 3% of Britain's power was from renewables, and the challenge seemed daunting, especially as Britain's most established low carbon generation technology, nuclear power, couldn't be used toward the target. Now as it turned out, in 2020 Britain generated 24% of its power from wind and a further 4% from solar, because these technologies fell drastically in price and were deployed at scale around the country in a way that exceeded earlier expectations. So Britain never needed Drax to meet this target. Britain also left the EU in 2020-1, which certainly wasn't expected in 2009!

Successive governments and energy ministers have been terrified of losing Drax's generation capacity. In particular, the spectre of 1970s blackouts haunted Conservative administrations from 2010-2024, creating a political climate where keeping the lights on trumped all else. So when Drax's owners proposed converting initially two generating units in 2012, and then two more in 2016 and 2018, ministers decided to bend the rules for subsidising renewable technologies to include biomass. This wasn't entirely unprecedented—dedicated biomass power plants had been receiving Renewables Obligation Certificates since 2002, typically earning 1.5 ROCs per megawatt-hour of electricity generated. Examples included Steven's Croft Power Station in Scotland (44 MW, operational from 2008), which burns a mix of 60% waste from timber production, 20% coppiced wood, and 20% recycled fibre, and the Elean Power Station in Cambridgeshire (38 MW, operational from 2000), which burns straw, oilseed rape, and miscanthus. At current ROC values of £64.73 per certificate, 1.5 ROCs provide an additional £97 per MWh on top of the wholesale electricity price.

The first two Drax units (2012) received Renewables Obligation Certificates (ROCs), while the later units (2016-2018) received Contracts for Difference (CfDs) through a separate non-competitive arrangement called a "Final Investment Decision" (FiD) enabling contract, which unlike the transparent auctions for wind and solar wasn't a very open or competitive process.

Instead, it was more of a direct negotiation between Drax's private owners and government ministers and civil servants. The guaranteed prices Drax gets for its power are around £150-170/MWh today, and are guaranteed to increase each year in-line with inflation for 15 years after the conversion process, meaning between 2027 and 2033.

Given the quantity of wood pellets Drax needs to meet its annual energy requirement of around 20,000 GWh, it couldn't rely on British (or even European) sourced wood. So it turned to North America. The environmental and social impacts of this large-scale wood pellet industry have been extensively documented, including in a BBC documentary.

Despite the concerns with Biomass, the price paid for Drax's power is significantly more than other power generators:

**Conventional power plants** receive only the wholesale electricity price, currently around £50-80 per MWh depending on market conditions. **New wind projects** those under consideration today (for the upcoming AR6 subsidy round) are expected to get £110-150/MWh in today's prices.

## Wood stoves and pellet boilers - smoke and subsidies

As well as being used in the largest power station in the country, biomass is well established for heating homes and buildings. Wood fires are aesthetically pleasing, and stoves and biomass boilers can achieve 70-85% efficiency, comparing favourably with gas and oil boilers which typically achieve 85-95% efficiency. In many rural areas, routine tree surgery creates a ready supply of timber, making biomass an attractive local energy source. Wood stoves are resilient to blackouts too.

However, the growth of wood burning in urban areas, particularly during the 2022 energy crisis, has created significant air pollution problems. Wood stoves and open fires emit high levels of particulate matter (PM2.5 and PM10), nitrogen oxides, and other harmful pollutants that contribute to poor air quality and respiratory health issues. These are localised pollution problems, in contrast to the global nature of climate change. In response, the government has introduced regulations to phase out the sale of the most polluting fuels and stoves, with new restrictions on wet wood and coal sales coming into effect in recent years.

In Northern Ireland, subsidies for Biomass became particularly controversial when the Northern Ireland Audit Office revealed in 2016 that a subsidy to promote biomass use in smaller businesses (like farms) had been overly generous. Because the subsidy offered exceeded the cost of wood pellets, businesses had an incentive to burn as much biomass as possible. This experience has rightly made subsequent governments around the UK more critical

# Biofuels

Less topical of late, petrol and diesel are required to contain 5-10% of biofuel, typically derived from crops like corn, sugarcane, and palm oil. This creates a direct competition between fuel and food production, as agricultural land is converted from growing food to growing energy crops. The result is often large-scale monoculture plantations that replace diverse ecosystems, reduce biodiversity, and can drive up food prices in regions where these crops are grown. In some cases, the environmental impact of clearing forests for biofuel plantations has been so severe that the carbon emissions from land-use change exceed the carbon savings from using biofuels instead of fossil fuels. The cost of manufacturing biofuels significantly higher than fossil fuel derived petrol and diesel too, at least before taxes are added.

Perhaps worth mentioning some quantification of the inefficiency of said biofuels. Suppose oilseed rape is used as an input to the production of biofuel. Rapeseed yield can be up to 3,000kg/ha per harvest, i.e. 0.3kg/m$^2$; 1kg rapeseed contains about 0.5kg oil; with oil containing 38MJ/kg the energy gained is consequently 5.7MJ/m$^2$. This energy spread over one year (1 harvest per year) results in 5,700,000J /365/24/60/60 s = 0.180W/m$^2$ average power. Conversion to bio-diesel incurs certainly some additional losses. In contrast, the solar irradiation at sea level is about 1kW. With on average 4h/day and an efficiency of 20%, a 1m$^2$ solar panel would produce an about 10004/240.20 = 33W average power. Therefore, a factor of 184 more power can be harvested from solar panels than from growing rapeseed to produce biofuels. Consequently, biofuels from crops are indeed questionable in terms of efficiency.

# Chapter 3: Feed-in Tariffs and ROCs - How Subsidies Went Wrong

## Introduction

It’s often difficult for new technologies to get off the ground. Not only do you have to get the cost of manufacturing kit down, and the kit more reliable, but you also need a supply chain to distribute and a qualified workforce to install and maintain the equipment. This is particularly true if you want something installed en masse to millions of homes and businesses, but also a handful of larger sites like power stations.

## PV

Solar photovoltaic (or PV) technology is a watershed moment for making electricity. Unlike every other way of making electricity, it doesn’t rely on moving parts like spinning a generator. It therefore requires much less maintenance or frequent access. Given it’s relatively light, thin and flat, it can also be readily installed on existing building surfaces like roofs, and also be ground mounted. It also generates most electricity in the day time, when people are more likely to be awake, working and using electricity. Also, because it can be installed “behind the meter” of buildings, it offers the chance to bypass the charges of local energy grids, taxes and allow end users to generate some of their own power.

### Feed-in tariff

The UK isn’t blessed with the world’s sunniest climate, but despite this a well positioned kw of PV panels will generate an average of about 1kwh/day of power in winter and 4kwh/day in summer. A typical house without electric heating, a heat pump or an EV might use 3,000kwh of electricity in a year, and a typical roof can accommodate 3-5kw of PV panels. So on a net, year round basis, PV can make a typical UK house self-sufficient for electricity, although in reality they will have a daytime surplus in summer and maintain a heavy grid reliance in winter.

Seeing this potential, the (outgoing) Labour government in 2010 decided to launch a Feed-in Tariff, initially with a payment of 43.3p per kWh for every unit of solar electricity generated. Crucially, this payment is made even if the electricity is used onsite and never reaches the public grid. This was incredibly generous, at the time electricity from the grid typically cost just 8-12p per kWh. At the time, there were very few contractors able to install the equipment, and homeowners needed a strong incentive to consider the substantial financial investment. At the time in 2010, a typical installation could cost £12,000-15,000, so with the feed-in tariff offered the expected payback was around 8-10 years.

Given the Feed-in Tariff was guaranteed for 25 years in line with inflation, some of the oldest PV installations in the country are still turning their owners a tidy profit, indeed when uprated with inflation they are now earning around 71p per kWh, which for a typical 3kW installation represents an annual revenue of over £2,000, though degradation can eat into this significantly.

## Boom bust

In the years following the adoption of the Feed-in Tariff in 2010, the number of installations started to grow, little at first but gradually more and more as the cost of installations fell and homeowner confidence grew behind the earliest adopters. However, as the price of the installations fell, installation interest only went up more as the payback period fell. This left the government playing cat and mouse with the industry, as it started creating frequent deadlines when it would review and revise downward, as deemed appropriate, the level of feed-in-tariff subsidy. More and more installers entered the industry as well, operating at larger scale and at times with some sacrifice to the quality of workmanship. The pace of cuts to the feed-in tariff accelerated until March 2019, when the government announced an end to new entrants to the scheme, with the final closure taking effect in April 2019.

The boom peaked in 2011-2012 when over 200,000 solar PV systems were installed annually, with the industry employing around 25,000 people. By 2019, when the scheme closed, annual installations had fallen to fewer than 30,000, and the workforce had shrunk to approximately 5,000 - an 80% reduction in both installations and employment.

The closure of the Feed-in Tariff scheme created a massive bust in the industry, as the replacement support vehicle, called the Smart Export Guarantee, provides no support for generation unless it is exported to the grid. Consequently, a large number of installers went out of business. This was undesirable because:

**Aftercare**: Customers were unable to get aftercare for faults with installations. In particular, the Microgeneration Certification Scheme (MCS) - the industry body responsible for maintaining standards and providing consumer protection - failed to step in as many would have expected, leaving homeowners with faulty systems and no recourse. This reinforced scepticism among some consumers about the technology.

**Risk Premium**: Attracting more workers and investment into the PV sector in the future became harder because many were sceptical that government might again engineer boom-bust cycles, creating uncertainty about the long-term viability of renewable energy investments.

**Ripple Effects**: After installers went bust, homeowners with defective installations pursued the MCS Certification Body and in some cases bank/finance lenders. The outdated Section 75 consumer credit legislation, where lenders can be held responsible for the quality of home improvements they lend toward still makes financial institutions hesitant to lend for home retrofit.

### Inequality and Legacy

While the Feed-in Tariff scheme has now closed to new entrants, payments will continue until 2044 and its legacy lives on in several problematic ways:

**Wealth Inequality**: The scheme disproportionately benefited wealthier households who could afford the £12,000-15,000 upfront investment in the 2010s. This created a form of "solar aristocracy" where affluent homeowners received decades of premium payments while others missed out.

**Access Barriers**: The scheme was fundamentally unavailable to renters, flat-dwellers, and those without suitable roof space, creating a divide between property owners and those without access to suitable installation sites.

**Geographic Disparity**: Solar yields in Scotland are 20-30% lower than in southern England, meaning the scheme's benefits were geographically skewed toward wealthier, sunnier regions.

**Market Distortion**: The Feed-in Tariff was simple to understand and calculate paybacks, but its 25-year fixed duration takes no account of the declining value of solar generation during increasingly frequent periods of renewable energy abundance. This means early adopters continue receiving premium rates even when their electricity has minimal value to the grid.

**Financial Burden**: In common with other electricity levies (see Chapter 10: Electricity Levies - Hidden Costs Everywhere), the cost of Feed-in Tariffs was added to the electricity bills of all consumers. Those who consume more units of electricity contribute more, while users that buy less electricity from the grid (e.g. those with solar PV) pay less.

The FIT scheme closed to new applications in 2019, but payments to existing installations will continue until 2044, creating a long-term cost legacy that all electricity consumers must bear.

## Renewable Obligation Certificates (or ROCs)

Lesser known than the feed-in tariff these days, renewable obligation certificates were introduced as a way to increase the income received by early renewable projects plants connected to the grid. The scheme ran from 2002 to 2017, when it closed to new projects, though payments to existing installations continue until 2037. The main technology supported was wind power (both onshore and offshore), followed by biomass (including large-scale power stations like Drax) and hydroelectric projects.

In common with Contracts for Difference (CfD) support schemes, ROCs are only paid when generators are working and online, so the owner (rather than the taxpayer) is responsible for maintaining renewable generators in working order. This "performance-based" approach sounds sensible in theory - generators only get paid when they produce electricity.

The Renewables Obligation (RO) scheme supports only around 30% of Britain's renewable electricity generation. Despite this limited coverage, it still contributes approximately 10% to an average electricity bill, according to recent analysis.

The RO scheme was particularly generous to biomass projects like Drax and early offshore wind farms, which continue to receive premium payments. Early offshore wind projects under ROCs received around £140-150/MWh in 2012 terms. Adjusted for inflation, this translates to roughly £200-220/MWh today—significantly higher than current CfD prices of around £70-80/MWh for new offshore wind projects.

For these reasons, ROC projects still add about three times more to electricity bills than CfD projects. However, this comparison is somewhat misleading since many CfD projects haven't been built yet. As ROC projects reach the end of their support period, this imbalance will naturally rebalance.

A major flaw of the ROCs scheme is the asymmetry of the support. They prop-up, or increase the revenue of renewable generators above the wholesale market price. However, if the wholesale market price spikes (as it did in 2022), there is no method for clawing back or reducing the support. Instead, the renewable generators receive bonus profits. This was particularly evident during the 2022 energy crisis, when ROC generators like Drax and early offshore wind farms received both their guaranteed ROC payments AND the benefit of high wholesale prices - effectively double-dipping at consumers' expense.

In truth, ROCs are actually cheaper to consumers per MWh than FITs, but this can be misleading when looking at headline costs on electricity bills. According to recent analysis by Ben James, the Feed-in Tariff represents a smaller portion of electricity bills - approximately 2.4% of a typical annual electricity bill in 2025. However, ROC-subsidised renewable generators generate far more electricity in aggregate: in 2023-24 they generated around 78 TWh, compared to just 9 TWh from FIT generators. In terms of subsidy per MWh, ROCs provided around £50-120 per MWh (varying by technology and ROC banding), while FITs typically provided £140-190 per MWh (depending on technology and installation size). This means ROCs were actually more cost-effective per unit of electricity generated, but because they supported much larger volumes of generation overall, they appear more expensive on electricity bills.

These policy weaknesses contributed to the eventual replacement of ROCs with CfDs (see Chapter 14: CfD vs Marginal Pricing - Market Design Disasters). However, no reform of existing ROCs has been attempted, and during the 2022 energy crisis, the government even refused to levy the windfall tax on ROC generators, allowing them to keep their excess profits while other generators faced additional taxation.

Another weakness of the ROC scheme is the perverse incentive it creates when wholesale prices are low, which occurs during periods of excessive renewable generation - an increasingly frequent occurrence as Britain's wind and solar capacity grows. When wholesale prices fall below the level needed to cover ROC generators' costs, the grid operator must compensate them for the shortfall, effectively paying them not to generate electricity. This "curtailment compensation" means consumers pay twice: once for the ROC subsidy and again for the generator to stay offline.

ROC generators argue, with some justification, that this is a risk they shouldn't be liable for, as they were encouraged to build capacity under government policy. However, the cost of wind curtailment is growing rapidly on consumer bills, especially as the country fails to build enough transmission cable capacity fast enough (see Chapter 6: Transmission Constraints - Bottlenecks and Bottlenecks and Chapter 7: Scotland - The North-South Divide). This creates a situation where the ROC scheme not only subsidises generation when it's needed, but also pays generators to avoid generating when the system is oversupplied - a fundamental flaw in the market design.

## To renege, or not to renege?

The idea of reneging on ROC contracts has not been a mainstream policy position under consideration by either the previous Conservative or current Labour governments. Reneging on FIT payments hasn't been considered either, though given the direct impact this would have on millions of households and smaller businesses, one assumes it would be politically impossible.

However, reneging on renewable subsidies is definitely an idea considered by the Reform party, which has argued that some schemes are too generous and represent an unfair burden on consumers. It remains to be seen whether Reform will win an election, or whether these radical ideas might be adopted by other parties forming a future government.

For the time being, the credibility damage of reneging on subsidies, combined with the substantial legal obstacles built into these schemes, has prevented this from happening in the UK. Spain provides a cautionary tale: when the government attempted to cut renewable energy subsidies by €2.7 billion in 2013, it triggered over 52 international arbitration cases with compensation payments exceeding €1.6 billion, severely damaging investor confidence in future renewable projects. Unless a future UK government is prepared to accept similar risks, reneging on these contracts seems unlikely, except under two specific conditions:

1. A future government abandons Net Zero targets entirely—something Reform has indicated it might consider
2. The RPI inflation indexation continues to push legacy renewable power costs significantly higher than new-build renewable or fossil fuel projects. RPI is a widely discredited measure of inflation that consistently overestimates inflation.

As this cost gap widens and the ROC contracts become increasingly distant from current energy policy, it's not infeasible that a future government may be able to renege on some of these contracts with enough temporal and policy distance to avoid contagion risk to other energy infrastructure projects. But this will be a balancing act, and will result in significant legal challenge, as the system of contracts was set up precisely to make this difficult - the government needed to provide investors with confidence that their long-term investments in renewable energy infrastructure would be protected from political interference, ensuring private capital would flow into the sector. It could also easily knock investor confidence in unrelated sectors like water.

# Chapter 4: North, South and Nimbys

## Introduction

In Britain today, the total capacity of wind farms is about 30GW. If you look at a map of British wind farms, it's likely the first observations you'll have are:

- **The North Sea is dominant**: About 50% (15GW) of wind capacity is offshore, three-quarters (12GW) of which is in the North Sea.
- **Scotland is covered with windfarms**: About 30% (10GW) of wind capacity is onshore and in Scotland.

It's tempting to think this is a rational and logical distribution. After all:

- **The North Sea makes sense** It's much easier to build wind turbines offshore in the North Sea than elsewhere. It's incredibly shallow; it's only 15-30 metres deep 80-125 miles from the coast at Dogger Bank. North Sea oil and gas has been exploited for 60 years; it's well mapped and there are many ports on the east coast with the infrastructure and facilities to construct and maintain the infrastructure. It's also adjacent to major energy trading partners and power grids in Germany, Nordics (Denmark/Norway), the Netherlands/Belgium; whereas the west coast only borders Ireland.
- **Scotland is wild and windy** Scotland has 8 times fewer people per square mile than England (70 vs 1,100 people per square mile). Land costs are dramatically lower too - agricultural land in Scotland averages around £4,000 per acre compared to £10,000-15,000 per acre in much of England, with prime farmland in the South East reaching £20,000+ per acre.

However, politics is as influential as climate and economics. Understanding why this distribution exists requires examining both the historical development of Britain's energy system and the political decisions that have shaped it.

## The Historical Context

If you start studying or working in the British energy market today, there's little to formally distinguish the energy system in Scotland from the rest of England and Wales. It's part of the same wholesale market, retail consumers north and south of the border choose between the same suppliers. Regulation on competition is identical. Taxes are the same. And while the Scottish Government is devolved some powers in the energy space, which it has used to permit more onshore wind development in the planning system and offer more generous support for heat pumps and insulation over the years compared with Westminster administrations, this understanding misses key historical aspects.

History lessons can often be a bit boring, and many younger readers may be questioning why reading about what went on in the 1980s and 1990s might seem irrelevant. But we need to set the scene: Scotland and the Highlands in particular are absolutely front and center of the decarbonisation strategy that the UK is taking. The central challenge of our electricity system over the next 10-20 years is to deliver ever-increasing, affordable and reliable supplies of wind energy, managed intelligently and flexibly with modern technology from north to south. Understanding why this is such a challenge requires going back to how the system was originally designed, and what the institutional and political frictions are as well as those of physical geography.

In England, the electricity grid started as private (or municipal) undertakings in major cities in the late 19th century, with coal power stations built to serve nearby factories and housing. The first National Grid wasn't built until the 1920s/30s. Even then, it didn't extend north of central Scotland (Glasgow and Edinburgh). Electricity in the north of Scotland followed later, and focussed more at localised hydro schemes, where the region's unique geography and population density compared to the rest of the country created a radically different grid setup. However, after 1945 the electricity systems were largely separated and given different structures. In England, all the power stations (generators) were grouped together with the transmission grid, with separate regional electricity companies doing the local distribution and retail to end consumers. In Scotland, two vertically integrated companies were created to cover north and south Scotland, both spanning everything from generating power to retail. There was a small amount of capacity between Central Scotland and Northern England to move electricity north or south, but these links were not radically expanded over the decades even as electricity usage grew.

Fast forwarding to the privatisation of the 1990s, and the model adopted reflected the setup in England and Wales, rather than Scotland. Whereas in England there had long been a distinction between the transmission grid (which became National Grid) and siloed regional distribution grids, in Scotland such barriers were less distinct. In very rural areas, it didn't make sense to have distinct organisations strictly focussed at different voltage levels because the distances between settlements were so great and the population density so low that maintaining separate transmission and distribution networks would have been economically inefficient. Scotland was also more self-sufficient and contained, it wasn't as important to the national generation strategy. It would have been considered quite strange to try and transmit large amounts of electricity from the Highlands all the way to the south of England when there was so much coal generation capacity already located in the industrial heartlands of the Midlands and South.

## Forcing Retail Competition on Scotland

The vertically integrated Scottish electricity companies had powerful brands. Not only did they generate and transmit/distribute electricity, but in rural areas without gas supplies, storage heaters were supplied and maintained by the electricity companies with special tariffs and widespread use of remote controlled charging. The Scottish electricity companies also had powerful retail brands, with high street shops and a local (nationalist) identity. Even British Gas identifies itself as Scottish

Gas north of the border. Even when customers were allowed to choose a supplier in Scotland after 1998, far fewer chose to switch than in England. And companies with origins south of the border found it much harder to win customers in Scotland.

## Merging wholesale markets

For 15 years after initial privatisations, Scotland remained outside the wholesale market for England and Wales. It only fully joined in 2005, 15 years later than the rest of England and Wales. The Scottish market remained dominated by the two vertically integrated electricity companies and wholesale prices were regulated. In a market as small as Scotland, it was deemed there simply wasn't enough competition to rely on a free market to set prices, and there wasn't enough transmission capacity with England to be part of that much larger market.

Prices in Scotland remained higher, despite which Scotland never saw the same "dash for gas" that took hold south of the border, in part because without a liquid private market, it was more difficult for developers to privately finance such developments. Over time, it became clear the same impediment would limit the development of Scotland's increasingly abundant wind resources, which needed access to markets south of the border.

## NIMBYism and the Onshore Wind Ban

Since the first onshore wind farm in Britain was built in Delabole, Cornwall in 1991, some local residents have been reluctant to accept wind farms. Interestingly, much of the opposition to the Delabole project focused on noise abatement; today, visual disturbance tends to be the top concern, along with construction traffic and disruption.

Wind farms are relatively unique in Britain for bringing into conflict two quite different groups of stakeholders. On the one hand, you have the developers; typically working-age urbanites who are highly educated and strongly focused on national and international climate challenges and supply chains. On the other hand, you have local communities with a more diverse age range, including many retired and non-working groups, for most of whom their home represents their largest financial asset or pool of savings.

As Britain has a national grid with uniform pricing, there are no automatic bill savings for communities located close to wind farms. With the recent rejection of regional (and zonal) pricing; this looks set to remain the case for the large part; however there are ways for groups of energy users and generators to use the same energy supplier and primary substation in order to avoid some grid levies for electricity.

Given how complex the planning and engineering can be, if a developer or operator of a wind farm disturbs the day-to-day life of local communities, getting recourse or compensation through legal means against a large private company is likely to be too intimidating for most local communities, even if they can organize together.

The center right (i.e. the Conservative party) of British politics has long harboured a scepticism for wind and solar, and despite the need for state financial support has preferred nuclear energy. Following their return to office in 2010 and coupled with the rapid expansion of onshore wind farms in conservative leaning rural districts, the Government in 2015 effectively banned any new onshore wind in England (QUESTION: through what mechanism? For instance, a single objection can halt the planning process?). In Wales, Scotland and Northern Ireland the decision was taken by their respective Governments to continue with onshore wind. The decision in England was a mistake which was particularly profound because of the lack of mitigation for the consequences:

1. **Connect and manage** - Britain took the view that it was acceptable for wind developers to build projects in areas that were poorly served by the national and local distribution grids. This meant a lack of coordination between projects being built and the local grid being upgraded to accommodate them. When the two weren't in sync, the result was—and continues to be—that wind farms are compensated for being turned off (or down), which now costs £3-4 billion per year.

Had more wind farms been built in areas like Devon/Cornwall and the Pennines, there would have been fewer grid problems because the biggest constraints are north/south, especially across the Scottish border. Additionally, because demand would be closer to generation, there would also be smaller losses in transporting electricity long distances through cables. The current concentration of wind farms in Scotland and the North Sea creates a bottleneck where power has to flow south through limited transmission capacity, while England's southern regions remain heavily dependent on imported electricity, both from abroad and further north.

1. **Unequal jobs/benefits** - Much of rural England struggles for quality, year-round jobs. By forcing more of the onshore wind North of the Border, the Conservative Government robbed deprived parts of the Westcountry, Pennines, Northumbria, and other windy regions of England that could have benefited from wind farm development. This is particularly problematic because the windiest parts of England tend to be the poorest and most isolated—areas like Cornwall, the Pennines, Northumberland, and parts of Yorkshire. These regions are typically:
    - Further from major cities and economic hubs
    - Lacking high-quality arable farmland (often only suitable for sheep farming or marginal agriculture)
    - Struggling with depopulation and limited employment opportunities
    - In need of economic development and infrastructure investment

Wind farms could have provided these communities with construction jobs, ongoing maintenance work, and annual payments to landowners—often the only significant income some of these areas see. Instead, these benefits were concentrated in Scotland, leaving England's windy but economically deprived regions without this potential lifeline.

In contrast, many parts of rural Scotland have attracted large numbers of engineers—both working for the onshore wind developments and for the grid infrastructure that facilitates them. Having a year-round job with significant training and investment from a large employer is often difficult to find in rural areas, but can offer a much more stable quality of living to many rural people of working age. These skilled positions provide not just employment, but career development opportunities that are rare in isolated rural communities.

By keeping and indeed attracting new people of working age to an area, this sort of development also helps to preserve other parts of the social fabric such as keeping schools, shops, pubs, and medical facilities open. Rural depopulation is a vicious cycle—as young people leave for better opportunities elsewhere, local services close, making the area even less attractive to families and businesses. Wind farm development can break this cycle by providing stable, well-paid employment that allows people to stay in their communities and support local services. Energy related jobs also enable people to finance mortgages and buy homes in rural areas. Without stable employment, many rural communities become dominated by second homes, holiday lets, and retirees, with few young families able to put down roots. Wind farm development creates the economic foundation that allows working-age people to build lives in rural communities rather than being forced to move to cities for employment opportunities.

This creates a chicken and egg problem: because there are few working-age people in rural areas to advocate for economic development and renewable infrastructure, local politics becomes dominated by older, close to retirement and retired people. These residents typically have less focus on economic development—especially job market expansion—and more focus on preserving the asset value of their homes and maintaining the “character” of their communities. Older residents naturally focus more on the short-term disruption of construction rather than any longer term benefits. This political dynamic makes it even harder to attract the very development that could bring working-age people back, creating a self-reinforcing cycle of rural decline.

This represents a clear tragedy of the commons failure: while each local community rationally seeks to avoid hosting renewable energy infrastructure (to preserve views, property values, and local character), the collective result is a suboptimally low amount of renewable energy deployment nationally. Without national coordination and the ability to force through renewable infrastructure projects, Britain will continue to fall short of its climate targets and energy security needs, while individual communities remain trapped in cycles of economic decline and political opposition to the very development that could help them.

## Marriage of Mutual Convenience

Now fully part, at least financially of the GB power market, investment in power generation in Scotland has boomed in the last 20 years. The two major renewables support schemes (ROCs and CfDs) collect revenues a bit like taxes but instead as levies on electricity bills across Great Britain (England, Wales and Scotland). The legal guarantee of these subsidies or support is the key to unlocking private finance that then pays the substantial upfront cost of building the windfarms (and the associated grid infrastructure). Given the focus on wind energy within the renewables push, even back in 2010 it was obvious that Scotland was always going to punch above its weight in the national generation mix. After all, Scotland only has about 10% of the UK’s population. However, particularly with the onshore wind ban in England in 2015, this only accelerated Scotland’s role as Britain’s renewable energy powerhouse.

This has created a situation where Scotland receives substantial renewable energy investment financed by British electricity consumers, while the economic benefits - jobs, business rates, infrastructure investment, and community development - are concentrated in Scottish communities. The onshore wind ban in England has effectively made Scotland the primary beneficiary of Britain's renewable energy push.

What has emerged is an asymmetric relationship. Scottish renewables projects are financed through levies on electricity bills across Great Britain, meaning Scottish consumers do contribute to the costs - but with Scotland representing only about 10% of Britain's population, their contribution is proportionally much smaller than the benefits they receive. Scotland gets the lion's share of investment in new infrastructure, jobs, tax revenues, and substantial business rates from renewable energy projects. For example, Highland Council alone receives over £20 million annually in business rates from renewable energy projects, with some individual wind farms contributing £500,000-£1 million each year to local council coffers. With a population of just over 235,000 people, this represents around £85 per person annually in additional council revenue from renewable energy - a significant boost for one of Britain's most sparsely populated and economically challenged regions.

It's a bit like all British bill payers (including Scots) agreeing to a debt repayment surcharge on their electricity bills to concentrate energy infrastructure projects in Scotland. While Scottish consumers pay the same levies as everyone else, they represent only about 10% of the total contributions but receive a much larger share of the local economic benefits. The costs are spread across 67 million people, but the local economic benefits - the new infrastructure, the jobs, the business rates, the economic development - are concentrated in areas with just a fraction of that population.

However, the size and scale of the investment would likely not have been possible in a country the size of Scotland on its own. Having access to the capital markets of the City of London and sterling currency are equally essential to Scotland's renewable energy boom. Had Scotland (as it nearly did) voted for independence in 2014, or during a later schism post-Brexit, unpicking the long-term contracts and arrangements in the electricity infrastructure would have been one of many thorny issues that would have had to have been negotiated. The complex web of CfD contracts, transmission agreements, and cross-border electricity trading arrangements would have created a legal and financial nightmare for both sides.

In addition to pushing the investment north, this concentration also requires more infrastructure to bring the energy 500 miles south to where most of the demand is located. This in turn adds costs and complexity to the grid, increases transmission losses, and creates more political tension from NIMBY opposition to new pylons and transmission lines. The very communities that rejected local wind farms are now being asked to accept massive new transmission infrastructure to bring Scottish wind power to southern markets.

Transmission losses over such distances are significant - typically 2-3% per 100 miles for high-voltage AC transmission, meaning 10-15% of the energy generated in Scotland is lost before it reaches southern markets. Even with modern high-voltage DC transmission used on undersea bootstrap cables (which has lower losses of around 1-2% per 100 miles), the 500-mile journey from the Highlands to London still results in 5-10% energy losses. These losses represent not just wasted energy, but also increased costs that are ultimately borne by all British electricity consumers.

Such a dynamic was always going to happen to some extent between urban and rural areas - cities need energy but can't host large-scale renewable projects, while rural areas have the space and resources but limited local demand. However, the onshore wind ban in England has exacerbated this natural tension by forcing a significant portion of the development into Scotland rather than allowing for a more balanced distribution across Britain's rural areas.

This highlights a fundamental tension in Britain's energy system that was recently exposed by the rejected consideration of zonal electricity pricing. The proposal would have created different electricity prices in different regions based on local supply and demand, which would have made electricity cheaper in Scotland (where there's abundant wind generation) and more expensive in southern England (where there's high demand but limited local generation). The rejection of this proposal shows how politically difficult it is to address the geographic imbalances that the current subsidy system has created - where Scottish communities benefit from renewable energy development while English and Welsh consumers pay the bills, but any attempt to reflect these real costs and benefits in pricing is politically unpalatable.

## UK Diversification

When learning about investment portfolios, one of the first lessons you learn is to reduce risk by diversifying. Certain assets decline while others rise, smoothing out overall returns. There's a direct parallel with the distribution and location of wind farms around the UK.

While some areas are outright windier than others (Scotland vs. the South East), the real benefit comes from geographic diversification. Not just that, but often when it's windy in one part of the country, it's less windy elsewhere. Much of our weather consists of fronts emerging from the North Atlantic. Often these hit the northern part of Britain (e.g., Scotland) harder, occasionally the south. Sometimes these fronts hit the UK at a different angle, tracking from the south-west, west, or north-west. And because wind speeds tend to be strongest around the line of the weather front, there is almost always a timing lag between a weather front hitting one part of the UK and the other.

Some weather systems move from west to east, others from south-west to north-east, creating complex patterns where wind generation varies significantly across different regions at different times. This geographic and temporal variation means that a well-distributed portfolio of wind farms across Britain would provide much more stable and predictable generation than concentrating all capacity in just a few areas.

The current concentration of wind farms in Scotland and the North Sea creates a "single point of failure" problem. When weather conditions are unfavourable in those regions (which can happen for days or even weeks during certain seasons), Britain's renewable generation drops dramatically. A diversified portfolio would include more:

- **Coastal wind farms** in Cornwall, Devon, Wales and Western Scotland (exposed to Atlantic weather systems)

- **Upland wind farms** in the Pennines and Northumberland (benefiting from orographic effects - where wind is forced upward by hills and mountains, creating higher wind speeds and more consistent generation)
- **Southern and eastern wind farms** (catching different weather patterns, especially in the Channel)

This diversification would reduce the volatility of renewable generation, decrease the need for expensive backup generation, and improve Britain's overall energy security. The onshore wind ban in England has prevented this diversification, leaving Britain's renewable energy portfolio dangerously concentrated and vulnerable to regional weather variations.

## European Diversification

Even with a diversified UK portfolio of wind and solar assets, the UK remains a relatively small country with a relatively confined climate. Having access to trade electricity with the wider continent allows the UK to benefit from changes in weather patterns over a much larger area, exporting at times of surplus and importing surpluses elsewhere at times of scarcity back home. As noted in Chapter 16, Brexit has introduced extra friction to short-term electricity trading of the sort which is particularly helpful in balancing renewables. However, the construction of 5 new interconnectors since 2016 has thankfully still occurred despite these challenges.

## Fastforward to 2025

Taking its history into context, the challenges of making Scotland the center piece or mecca of our energy system today, as we are trying to make it, are enormous. Political history lessons can be boring and sometimes seem a bit irrelevant, but it's quite important to understand just how much of a challenge or strain we're putting on infrastructure and organisational arrangements that simply weren't set up for the top-heavy, wind generation-focused system in the north of Scotland that we are hoping to now get from our electricity system.

Until quite recently, the Highlands and Scotland were basically a backwater - or a sideshow that was never conceived of or properly integrated into Britain's main electricity and energy system. The grid was designed around serving the industrial heartlands of England, with Scotland's hydro schemes and later nuclear plants providing supplementary generation rather than being central to the national strategy. The idea that Scotland would become the powerhouse of Britain's renewable energy system would have seemed absurd to the engineers and planners who built the original grid infrastructure.

Getting electricity from the Highlands to Southern England is, a bit like the equivalent road/rail journey, a tortuous process from the perspective of both physical and institutional geography. It requires transmitting electricity through assets owned three different transmission companies (SSE, Scottish Power, and National Grid). Indeed, if the generation project is connected at lower voltage, it may also involve the entirely (separate) distribution part of SSE. That's a large number of stakeholders, each of which has to be separately managed and regulated. Each of these companies has different perspectives, cultures, and financial objectives. If an investment fails to work out, it's much harder to hold any particular organisation accountable. Indeed, it's arguably simpler to bring power from the near continent (France, Belgium, Netherlands) to the South East of England, and when you look at the flows this is exactly what happens much of the time.

This fragmentation raises the question of whether Britain might need to consider merging or reorganising its grid further - beyond the National Energy System Operator (NESO) that the government recently created. While the creation of NESO was a step toward better coordination, the fundamental problem of multiple transmission companies with different objectives and regulatory frameworks remains. A truly unified transmission system might be necessary to efficiently manage the north-south flows that Scotland's renewable energy boom requires.

## Unexplored Solutions

The extent of the transmission gap between the north of Scotland, the Central belt and the rest of England and Wales is finally being addressed. While the continued growth of renewables continues to put more strain and set higher standards or move the goal posts up, by the 2030s it's expected that many of the current issues will be in the past assuming that grid upgrades go ahead as planned and expected. Other accelerations such as the growth in grid scale battery storage and smart grid technology could also have a rapid impact on what remains quite an unsophisticated and unmanaged grid today.

That said there are a number of other levers which with correct coordination the respective parts of government could start to accelerate in a way that might receive political consent and mitigate or at least buy time for the parts of the system which are struggling to expand the transmission grid.

For example, the frequent surplus of electricity which Scotland faces today could be addressed by an acceleration or concentration of the growth of new demands for electricity there over the south of England. Ruling out zonal or nodal pricing removed an important market signal which could have achieved this automatically however there remain policy levers which could affect this over time:

1. **Data centres** - Despite higher land prices in the south of England, data centre developers overwhelmingly choose locations around London and the M4 corridor. While not every computing workload is suitable for northern locations, the planning system could actively encourage data centre projects further north by streamlining application processes and reducing bureaucratic complexity. A similar argument could be made for other electricity intensive forms of industry, including manufacturing.

2. **Air source heat pumps** - Scotland has historically provided more generous support for insulation and energy efficiency measures compared to England and Wales. Using Westminster funds, this support could be further extended to boost electricity demand in Scotland and reduce transmission constraints on the national grid.

3. **Electric vehicles** - EV incentives are currently identical across Scotland and the rest of Britain, with both offering £350 grants for home chargers and similar vehicle grants. This could be differentiated by exempting Scottish-registered vehicles from vehicle excise duty, or exempting Scottish EV chargers from VAT. These measures would accelerate EV adoption in Scotland and reduce transmission constraints caused by excess power generation in the north.

## Summary

The concentration of Britain's renewable energy development in Scotland, driven by the 2015 onshore wind ban in England, has created a complex web of economic, political, and technical challenges. While Scotland benefits from substantial investment and job creation, the costs are spread across all British electricity consumers, creating an asymmetric relationship that is difficult to address politically. The resulting transmission constraints, energy losses, and lack of geographic diversification leave Britain's energy system vulnerable and inefficient. Addressing these challenges will require both technical solutions and political courage to overcome the NIMBY opposition that created this situation in the first place.

# Chapter 5: Nuclear

## A tale of two countries

France and Britain's energy policies were remarkably similar until the 1970s. Both countries had nationalised their electricity industries after World War II, both relied heavily on coal for power generation, and both were developing civilian nuclear programs. But when the 1973 oil crisis hit, their responses couldn't have been more different. France launched the ambitious Messmer Plan - a massive state-driven program to shift almost entirely to nuclear power. Meanwhile, Britain's response was characteristically muddled.

What makes Britain's failure even more striking is that it started with a clear lead. The UK connected the world's first commercial nuclear power station, Calder Hall, to the grid in 1956; by the early 1960s it had a fleet of Magnox reactors in operation and was exporting nuclear expertise to countries like Italy and Japan.

France, by contrast, lagged the UK through the 1960s and only leapt ahead after decisively committing to both improving energy self-sufficiency and technical consolidation in the 1970s. The Messmer Plan—named after Prime Minister Pierre Messmer and launched in response to the 1973 oil crisis—was a bold national strategy that standardised on pressurised water reactors (PWRs) and created a comprehensive domestic supply chain. This single-minded focus on nuclear power would see France build 56 reactors in just 15 years, while Britain stuck with a sequence of bespoke designs (Magnox → Advanced Gas-cooled Reactor → the never-completed Fast Breeder → belated PWRs), each change resetting learning curves, complicating procurement, and delaying delivery.

The discovery of North Sea oil and gas in the late 1960s had already complicated Britain's energy planning. Should the country double down on nuclear power like France? Or rely on this new domestic fossil fuel bounty? The result was policy paralysis. While France built 56 nuclear reactors in just 15 years, Britain's nuclear program became mired in debates about reactor designs, locations, and costs. The contrast in outcomes is stark: today nuclear provides over 70% of France's electricity at some of the lowest prices in Europe, while Britain's aging nuclear fleet supplies just 15%, is owned by the French state supplier EDF and is mostly due for retirement.

That said, the French approach isn't without long term challenges of its own. Having built so many nuclear reactors so quickly, the French grid effectively became saturated with nuclear energy. To find markets, France had to expand interconnector cables with each of its 7 continental neighbours and Britain. When the saturation occurred in the 1980s and 1990s, France also had to stop building new nuclear reactors. The massive, geographically mobile workforce and domestic supply chain which had grown up around the nationwide attempt that built 56 nuclear reactors in 15 years started to disintegrate. Talented workers went elsewhere or retired. Intermediate suppliers ramped down production facilities. In the years between 2002 when Civaux was finished and 2024 when Flamanville C was finished France didn't open a single new nuclear reactor. This important point is often ignored in British discourse comparing energy policy on either side of the channel. However, with 14 nuclear reactors representing 14 GW of capacity expected to retire in the 2030s, 22 GW in the 2040s and 20 GW in the 2050s, France now faces a cliff edge. Life extensions to nuclear plants are commonplace and substantial extensions are expected, inevitable and unlikely controversial for safety. However, the technology which was supposed to epitomise stability and self-sufficiency in energy production had instead created a multi-generational boom-bust cycle.

Financially, the French approach is also laying the foundations for longer term challenges. The investment in nuclear energy assumed a 0% discount rate. Given the vast upfront and decommissioning costs of nuclear power, there is a huge financial burden on future generations of decommissioning and containing the nuclear waste. It's quite difficult to measure the lifetime (or lifecycle) cost of nuclear in terms that you can compare to gas or other energy technologies. However, according to the French energy regulator CRE's 2022 estimate, the lifetime levelised cost of electricity (LCOE) for French nuclear power is around 61 EUR/MWh in 2022 prices (equivalent to approximately 67 EUR/MWh in current prices after 3 years of inflation), while gas-fired electricity costs 40-80 EUR/MWh depending on gas prices and plant efficiency.

The main advantage of the French approach is stability. When wholesale energy prices spiked in 2022, France should at least in theory have been well-placed to ride out the period of high prices. The cost of nuclear power generation in the short-run is relatively low, nuclear fuel costs only about 5-7 EUR/MWh generated compared with a peak of 500-600EUR/MWh in 2022. The value of nuclear exports should have massively boosted France's balance of trade and the trading results of its state-owned electricity generator, EDF. And even if energy prices in France were allowed to rise, to respect the country's commitments to the EU single energy market, there would be considerable tax revenue from France's energy companies, most significantly EDF to offset the cost of any state support afforded to households and businesses.

However, EDF's financial position has deteriorated significantly in recent years. The company's debt ballooned to over €60 billion by 2022, driven by the costs of maintaining France's aging nuclear fleet and extensive repairs over the years. The French government was forced to fully renationalise EDF in 2022, buying out minority shareholders at a cost of €9.7 billion, reversing the privatisation of 15% of the company in 2005. The liability for decommissioning France's nuclear plants rests with EDF, though the French state has created dedicated funds to cover these costs. However, these provisions are widely regarded as insufficient, with the French Court of Auditors estimating that EDF's nuclear decommissioning and waste management liabilities could reach €74 billion - exceeding the company's total market value and highlighting the long-term financial burden that nuclear power places on the state.

Compounding these financial problems, France didn't see the expected windfall from nuclear exports in 2022 for a number of reasons:

**Nuclear Fault** - In 2022, France's nuclear fleet was operating at just 60% capacity due to widespread corrosion issues discovered in key reactor components. This forced the shutdown of 32 reactors for safety inspections and repairs, dramatically reducing France's nuclear output and export potential.

**Hydro Drought** - France's second-largest electricity source, hydroelectric power, was severely affected by drought conditions across Europe. Reservoir levels fell to historic lows, cutting hydro generation by 40% compared to normal years and forcing France to import electricity rather than export it. Heatwave conditions also restricted cooling water intake on some river sited nuclear plants for a while too.

The combination of these two crises meant that France, normally Europe's largest electricity exporter, became a net importer for the first time in decades. France imported 16 TWh of electricity in 2022 - equivalent to the annual consumption of 4 million households. This reversal from France's typical 50 TWh annual exports contributed significantly to Europe's energy shortage during the Ukraine crisis, pushing wholesale electricity prices to €400/MWh in August 2022 - ten times the pre-crisis average. For context, France's annual electricity consumption is around 450 TWh, in Britain it is 300 TWh. France's sudden need for gas-fired power from neighbouring countries like Britain, Italy and the Netherlands had a particularly marked effect on prices. This demand brought less efficient, peaking gas power stations into operation, which due to marginal pricing forced up the cost of power more generally in Europe.

## Current British nuclear programme

There are just 5 nuclear plants left online in Britain, each of which is expected to close shortly:

1. **Hartlepool** - Advanced Gas-cooled Reactor (AGR), 1,190 MW capacity, expected closure 2026
2. **Heysham 1** - AGR, 1,155 MW capacity, expected closure 2026
3. **Heysham 2** - AGR, 1,320 MW capacity, expected closure 2028
4. **Torness** - AGR, 1,360 MW capacity, expected closure 2028
5. **Sizewell B** - Pressurised Water Reactor (PWR), 1,198 MW capacity, expected closure 2035

All except Sizewell B are Advanced Gas-cooled Reactors built in the 1980s and early 1990s. Sizewell B is Britain's only Pressurised Water Reactor, built in the 1990s as a prototype for a wider PWR programme that never materialised. Together, these plants currently generate about 15% of Britain's electricity, down from a peak of around 25% in the 1990s.

## Hinkley Point

The vast new nuclear plant at Hinkley Point C (3,200 MW) has been under construction since the year 2017. When completed it will be the largest nuclear plant ever constructed in Britain. Hinkley Point C is an EPR reactor.

The construction has been a disaster. It was originally supposed to open in 2023, but is now not expected until 2030 at the earliest. Every year that its completion is delayed, the National Grid is without 3GW of low carbon electricity, which is invariant to weather conditions and reduces the need for gas generation and imports.

Not surprisingly, the cost of construction has also ballooned, from an original estimate of £16 billion to current projections of £32-35 billion. Thankfully for the British taxpayer and billpayer, because of the way the CfD contract is structured, EDF will be remunerated only when the power station generates electricity. However, the negotiation with EDF that took place before construction began guaranteed EDF a very high price for Hinkley's output; £128/MWh in 2025 prices, which will rise in line with inflation. This is slightly more expensive than the latest expected costs for offshore wind (about £116-117/MWh)

As noted above, this price is about double the average cost of EDF generating nuclear power in France and is higher than the current UK wholesale price, meaning it will be subsidised by billpayers. One could even argue that the delay is saving customers money; at least until power prices rise.

## More nuclear plants

A follow-on nuclear project at Sizewell C has been announced by the UK Government, replicating about 85% of the EPR design from Hinkley Point. As with Hinkley Point, by using an existing nuclear site, it is hoped that the local population will be more amenable to the project, recruiting staff with the right skills will be easier, and there will be an existing grid connection to use.

The financing model for Sizewell C is called RAB (Regulated Asset Base) and is the opposite of Hinkley Point; the taxpayer/billpayer will finance and take on the risk of construction. EDF was reluctant, especially after Hinkley Point to repeat the CfD arrangement. RAB (Regulated Asset Base) is the same as the water industry and some other privatised monopoly utilities.

If lessons are learnt from Hinkley Point, it's feasible that Sizewell C could end up being cheaper or at least that not much more expensive than Hinkley Point. Hinkley Point is the first in a generation nuclear project in Britain, and the first time an EPR reactor had been built in the UK. If some savings passed through to Sizewell C, the billpayers would benefit from the savings, unlike the CfD arrangement where savings would accrue to EDF.

However, underspend on nuclear plants is not the norm! And substantial increases in interest rates since 2012 (when they were close to zero), mean that with the best engineering advances, it's much more likely that, should things go wrong at Sizewell, billpayers will end up paying for any increases in the budget and suffer the consequences of any delays to the generation of power from it.

Bloomberg New Energy Finances has recently estimated the cost of Sizewell C's power in levelised cost terms (a sort of average NPV or net present value) at £286/MWh; which is extremely high. It's no surprise perhaps that EDF is choosing to ditch the EPR and build a lower price simpler reactor for the 6 new projects it intends to build in France by 2038. However, this begs the question whether the UK is wise to continue using the combination of EDF and the existing EPR design.

# Is nuclear reliable?

Traditionally, the strongest argument for nuclear power is its supposed reliability. Compared to the main low carbon alternatives (wind and solar), nuclear is "dispatchable", you can control if a nuclear reaction is to take place and the amount of power that's produced. Unless a drought prevents a nuclear plant getting cooling water, you're generally not affected by weather, and a nuclear plant is designed to run 80% of the time, with planned outages just for maintenance.

More recently, this reliability has come into serious doubt for two reasons:

## Construction Delays

Every nuclear plant built in Europe in the last 25 years has been severely delayed and over budget. France's Flamanville 3 (1,650 MW) was under construction from 2007 to 2024 - 12 years later than originally planned, with costs escalating from €3.3 billion to €19.1 billion (€11,600/MW). After finally opening in 2024, it was immediately shut down due to technical issues and operational problems. Finland's Olkiluoto 3 (1,600 MW) took 18 years to build (2005-2023) and cost €11 billion compared to the original €3 billion estimate (€6,900/MW). Britain's Hinkley Point C (3,200 MW) is currently projected at €37-41 billion versus an original €19 billion estimate (€11,600-13,000/MW). Hungary's Paks 2 project (2,400 MW) was originally planned for €12.5 billion but has been suspended due to escalating costs. The pattern is clear: nuclear construction in Europe averages 10-15 year delays and 3-6x cost overruns, with final costs of €7,000-13,000/MW. Note: In "How Big Things Get Done", author Bent Flyvbjerg highlights nuclear power plants as notoriously underperforming megaprojects due to cost overruns, findings which are mostly data driven.

An incomplete nuclear plant is useless. Not only do they not generate any power, but given the scale of investment involved, grid planners need to know with reasonable certainty when a nuclear-sized plant will be available. If it isn't, they must make provision for alternative firm capacity, as Britain is doing for Hinkley Point, which was supposed to be the largest power plant on our grid by 2023. The knock-on effects of nuclear delays ripple through the entire energy system - when a 3.2 GW nuclear plant is delayed, it affects grid planning, energy security, carbon targets, and consumer bills across the country. The absence of Hinkley Point C is particularly problematic because it would have generated over 3 GW of power in the South West, a region that already lacks adequate transmission capacity to import power from the North and East of England. A construction delay at a medium-sized onshore wind farm might cost a few hundred megawatts and be relatively easy to compensate for, but nuclear delays create system-wide planning challenges. In reality, we're fortunate that Britain has existing gas plants that can be kept in service rather than needing to build entirely new capacity to replace the delayed nuclear plant. However, it's worth noting that construction delays for wind (even offshore), battery storage, solar, and gas plants are much lower and more predictable than nuclear. This reliability in planning and delivery makes these technologies far more valuable to grid operators than nuclear power.

### Unscheduled Outages

The French nuclear outages in 2022 occurred when a common fault was identified that affected a large number of reactors. These were the Pressurised Water Reactor (PWR) type, specifically the 1300 MW and 1450 MW models, and 32 reactors were built between 1980 and 2000 with the same design flaw - stress corrosion cracking in the emergency cooling system piping.

French nuclear plants also suffer frequent strike-related outages, with EDF workers regularly walking out over pay disputes, pension reforms, and working conditions, further undermining the reliability that nuclear power is supposed to provide. While UK nuclear workers are unionised and have the legal right to strike, their track record of industrial action is relatively limited compared to France - though wildcat strikes at Sellafield and Heysham in 2009 showed the potential for disruption.

Were Britain to replicate the French model and build a large number of identical nuclear plants, it might achieve economies of scale and reduce nuclear costs closer to French levels of 60EUR/MWh, which are about half the cost of Hinkley Point. However, this approach would expose Britain to the same systemic risk that France experienced in 2022, where a single design flaw could simultaneously take out a significant portion of the entire nuclear fleet. The critical difference with nuclear power is that faults cannot be ignored or tolerated - unlike gas turbines or wind turbines, nuclear reactors must be immediately shut down when safety issues are discovered, regardless of the economic consequences.

## Small Modular - a potential way out

Small Modular Reactors (SMRs) have been touted as a potential solution to Britain's nuclear construction problems. Unlike traditional nuclear plants built on-site with bespoke designs, SMRs are designed to be manufactured in factories and assembled on-site, with proponents claiming this approach could reduce costs and construction times through standardisation. The government has already committed £210 million to the SMR design competition and a further £157 million to support Rolls-Royce's SMR programme, despite no SMRs yet being built commercially anywhere in the world.

Proponents suggest factory-built reactors could achieve levelised costs of electricity (LCOE) of around £60-80/MWh - significantly below Hinkley Point's £128/MWh - though these are theoretical estimates based on untested technology. The modular approach could potentially open up distributed deployment options that traditional nuclear cannot match, such as powering individual industrial complexes or data centres. Rolls-Royce brings submarine reactor experience to this market, and while they sold off their civilian nuclear business to Westinghouse in the early 2000s, they do have extensive civilian power generation expertise through their aero-derivative gas turbines, which are widely used in power plants worldwide.

While this is definitely one to watch, and if it works out could be a technology that Britain could export globally, the track record of nuclear construction in Europe suggests that theoretical advantages often fail to materialise in practice. However, given the downsides of centralised nuclear at Hinkley Point and elsewhere, modular reactors merit further attention and investment.

# Chapter 8: Regional Privatisation Model - How Fragmentation Hurts

## Pre-privatisation

Prior to privatisation in the 1990s, the electricity system in Britain comprised of:

– **Central Electricity Generating Board (CEGB)**: transmission grid and all power stations – **Regional Electricity Boards**: local distribution cables and retail (tariffs, billing etc) - there were 12 in total – **Scotland**: 2 vertically integrated power companies

The decision to privatise is well documented elsewhere. One of the main objectives was to create retail competition as a downward pressure on prices. However, there were a number of issues:

__ **Existing integration**: the regional grids were integrated with the local retail operations – **Barriers to entry**: enticing completely new entrants to a new market seemed unlikely

## Privatisation

So as a privatisation roadmap in 1990, the decision was taken to:

– Preserve separate network companies in each region. Though eventually these were allowed to merge with each other and share some management functions, the 12 (14 including Scotland) regions are still largely regulated separately. – Allow each of the regional companies over time to compete outside their existing area.

The world has changed a lot since 1990. Back then, having regional organisations made a lot more sense, but this is much less true today because of:

### Technology

In 1990, regional electricity companies were installing, maintaining and manually reading electricity meters, creating quarterly bills and taking cash/cheque payments. Aside from field engineers, many of their employees were clerical, working in regional call centres. They had no technology platforms (websites, apps) - systems that have largely fixed costs but can scale to any number of users. Marketing wasn't a priority, there was no need to attract/win over customers, there were a handful of tariffs. With no switching, the volume of customers joining or leaving the supplier was much smaller.

### Bureaucratisation

The cost of management and administration has soared. Executive pay at Distribution Network Operators (DNOs) has increased dramatically since 1990 - from around £50,000-80,000 for senior managers in the public sector Regional Electricity Boards to £500,000-£2 million for CEOs of today's DNOs. Even accounting for inflation (where £1 in 1990 is worth about £2.50 today), this represents a real increase of 2.5x to 16x in executive compensation. The broader cost of management, administration, and corporate overhead has grown from around 5-8% of total costs in 1990 to 15-20% today. This is because having a privatised structure creates more executive and management jobs at the government regulator (Ofgem), as well as an army of consultants and accountants that support the marathon price control process. Every few years, companies negotiate with regulators and are eventually told how much, as monopolies, they are allowed to charge customers. Having 14 regional areas means this process and cost is replicated 14 times.

### Outdated Remuneration

Under privatisation, network companies get a guaranteed return on capital for every pound of assets, be it pylons, substations or pipelines. Given this, the assumption is that left to their own devices, the network company will want to invest more than is strictly necessary, and that the regulator is therefore required to limit their expenditure, which they do within the price control.

To be fair, this process can work quite neatly when not much is changing. The budgeting process takes last year's figures as a starting point, and the main action each year is that some assets nearing the end of their working life get replaced, an inflation increase is applied, and companies get some productivity targets. This was broadly the world that existed up until the 2010s, but since then we've been radically departing from this stable model for the following reasons.

## Peak Gas

Gas currently reaches around 85-90% of British homes. Until recently, it was the standard assumption that new build homes and particularly houses would have a gas connection. The expected move to heat pumps means this is no longer the case, and as existing homes start the process of retrofitting heat pumps, over time fewer and fewer homes will have a gas connection. However, as this process isn't co-ordinated, gas network companies are in most places still going to have to maintain a similar mileage of network but with fewer customers, at least for the time being.

This creates a fundamental problem with the privatised network model. From the Government, consumer, and environment's perspective it makes sense over time to abandon the gas network. However, from the perspective of a privatised gas network company, the incentive is to maximise the returns from the assets they have for the longest potential period. At the moment, for example, they have a particularly strong incentive to replace any infrastructure (such as any remaining old steel pipes) with new plastic ones, as this will get from the regulator a guaranteed return on these new assets for 15-25 years.

The regional structure compounds this problem. With 8 regional gas networks, each facing similar challenges, there's no coordinated approach to managing the decline. Each company fights to maintain its customer base and asset value, even when the overall system would benefit from economies of scale. The result is likely to be higher costs for remaining customers and slower progress toward net-zero, as the privatised model prioritises shareholder returns over system efficiency.

Worse still, this legacy burden is likely to fall most acutely on poorer households that are slower to embrace heat pumps and other low-carbon technologies. As wealthier households transition away from gas, the remaining customers will face higher bills to maintain the same network infrastructure. This creates a regressive effect where the costs of the energy transition are borne disproportionately by those least able to afford them, while the benefits accrue to those who can afford to upgrade their heating systems first.

## Demand Electrification

The local electricity distribution cables for a typical residential home with gas heating were designed to support diversity demand from each house of around 1-2 kW. As the lifetime of cables and substations is around 40-50 years, the average age of kit out there was designed over 20-30 years ago. An EV charger of the size typically recommended uses 7 kW, which is 3-7 times more than the original diversity demand capacity. A heat pump in a typical home might use 2-3 kW in peak winter times in addition. If one or two homes in a street get these upgrades, the network can typically cope and gradually expand. But if there are concentrated pockets (e.g., where neighbours copy each other), then this can create problems for network companies.

This problem is also exacerbated by the use of single-phase (instead of three-phase) electricity supplies in the UK, because homes can only draw power from one phase of the distribution network, concentrating demand on individual cables rather than spreading it across three phases. If the houses in a street that have upgraded to heat pumps and EVs happen to share the same phase of the three phases supplied to the street, then the network company may have to undertake expensive cable upgrades even if only a minority of houses on the street have made these upgrades.

This creates a fundamental problem with the privatised model. Left to their own devices, network companies would want to rewire everything with expensive physical upgrades to handle the new demand. However, in reality there is a range of smart technologies - from dynamic load management and smart inverters to battery storage and demand response systems - that can avoid or at least delay many network upgrades. The regulatory price control process, designed to prevent over-investment, now acts as a barrier to the rapid expansion needed for net-zero.

The regional structure compounds this problem. While the government and Ofgem claim there is a coordinated approach through various strategies and investment frameworks, the reality is more fragmented. With 14 separate electricity distribution networks, each facing similar electrification challenges, coordination remains limited. Each company makes investment decisions based on local regulatory incentives rather than national energy transition needs. The result is likely to be slower electrification progress, higher costs from piecemeal upgrades, and a system that prioritises regulatory compliance over strategic network development.

## Debt

The privatised structure has also led to concerning trends in leverage and gearing across Britain's network companies. Electricity and gas distribution companies have increasingly loaded up on debt, with gearing ratios (debt to equity) rising from 20-30% pre-privatisation to 60-70% in the early 2010s to 80-90% today. This strategy was made possible by the prolonged period of low interest rates following the 2008 financial crisis, which made high leverage financially attractive. This mirrors the pattern seen in water companies, where high leverage was used to extract dividends and reduce tax bills, creating what became known as "financial engineering" rather than real operational efficiency. This shift has also changed the financial risk profile of Britain's energy infrastructure, making it more vulnerable to interest rate fluctuations and market volatility.

Since 2022, this high leverage has become a major problem. Rising interest rates have dramatically increased the cost of servicing this debt, with many companies now facing interest costs that are 2-3 times higher than they were just a few years ago. The regulator's response has been to allow these higher financing costs to be passed through to consumers, but this creates a vicious cycle where higher bills reduce demand, which increases the per-customer cost burden, leading to even higher bills.

## The Way Forward

The fundamental problem with Britain's regional privatisation model is that it was designed for a stable, predictable world that no longer exists. The energy transition requires rapid, coordinated change across the entire system, but the current structure creates perverse incentives that work against this goal.

Network companies are incentivised to maximise returns on existing assets rather than facilitate the transition to net-zero. The fragmented regional structure prevents coordinated strategic planning. High leverage makes companies vulnerable to interest rate shocks and creates pressure to pass costs through to consumers. And the regulatory framework, designed to prevent over-investment in a stable world, now acts as a barrier to the rapid expansion needed for decarbonisation.

One potential solution is to create a single national distribution system operator. This would deliver significant advantages over the current fragmented model, and would bring Britain in line with international best practice. While Britain has 14 distribution companies for a population of 67 million, France has just one main operator (Enedis) serving 95% of the country's 68 million people. Other European countries with similar populations, such as Spain and Italy, also have far fewer distribution companies than Britain. The UK's fragmentation is particularly striking given its relatively small geographic size and population.

**Elimination of False Competition**: The current 14 regional companies don't actually compete with each other - they operate as separate monopolies. A single national company would eliminate this artificial fragmentation while maintaining the benefits of private sector efficiency.

**Operational Efficiencies**: A single company could standardise systems, processes, and equipment across all regions, reducing costs and improving reliability. Staff and resources could be moved between regions as needed, both for normal operations and emergency response to storms or other disruptions.

**Regulatory Simplification**: Instead of 14 separate price control processes, there would be just one. This would eliminate the need for 14 sets of management teams, consultants, and accountants, dramatically reducing the bureaucratic overhead that has grown from 5-8% to 15-20% of total costs.

**Strategic Coordination**: A single company could develop truly national strategies for the energy transition, rather than 14 separate approaches that may conflict or duplicate effort. This would be particularly valuable for managing the electrification of heat and transport.

**Financial Benefits**: A larger, more diversified company would likely benefit from lower cost of capital and reduced financing costs, as investors would see lower risk from geographic and operational diversification.

**Innovation and Technology**: A single company could develop unified IT systems, smart grid technologies, and demand response markets that work consistently across the country, making it easier for innovative companies to participate. This is particularly important today, as the energy transition requires sophisticated digital technologies, smart meters, electric vehicle charging networks, and demand response systems that work seamlessly across the entire country. In the 1990s, when the regional model was designed, such technologies didn't exist - electricity distribution was largely a matter of maintaining physical infrastructure. Today's challenges require national coordination and standardization that the fragmented regional model cannot provide.

**The Ownership Problem**: The current 14 distribution companies are owned by a complex mix of shareholders, including British pension funds, foreign state-owned enterprises, and private equity funds. Some are owned by single foreign entities, while others have diverse shareholder bases. Any attempt to create a single national operator would require either:

- **Negotiated acquisition** of all 14 companies, which would be extremely expensive and fraught with disputes over valuation, particularly given the guaranteed returns these companies enjoy under the current regulatory regime
- **Compulsory purchase** through nationalisation, which would face legal challenges and political opposition, especially from foreign investors and their governments

**The Cost Challenge**: The combined market value of Britain's distribution companies runs into tens of billions of pounds. Any government attempting to acquire these assets would face enormous upfront costs, even if the long-term benefits of a single operator were clear. The political and financial risks of such a transaction would be substantial.

**Alternative Approaches**: Given these challenges, more incremental reforms might be more politically feasible. This could include greater coordination between existing companies, shared services agreements, or the creation of a national planning body that could direct investment priorities across all regions. However, these approaches would likely deliver only a fraction of the benefits that a truly unified system could provide.

The regional privatisation model that seemed sensible in 1990 has become a barrier to the changes needed in 2024 and beyond. But overcoming this barrier will require confronting the difficult political and financial realities of unwinding three decades of privatisation.

# Chapter 9: Smart Meters Optional - Why the Rollout Failed

The UK smart meter rollout is unparalleled in its failure, and what's most surprising is how few people know just how bad we are compared to similar countries. To put this in perspective, the smart meter rollout has cost taxpayers and billpayers over £13 billion - more than the London 2012 Olympics (£8.8 billion), approaching the cost of Hinkley Point C nuclear power station (£25-30 billion), and a significant fraction of the HS2 rail project (£100+ billion). Yet unlike these other major infrastructure projects, the smart meter rollout affects 20-30 million homes and businesses across the entire country, making it one of the most widespread government programmes ever attempted. This works out to an average cost of around £500-650 per home or business - a substantial sum that has been added to everyone's energy bills. Despite this massive scale and cost, regulatory and bureaucratic blunders mean we aren't getting the return on investment we should from it.

As of 2025, after 16 years and £13 billion, the UK has achieved just 67% completion - meaning one in three homes still lacks a smart meter. Even more concerning, of the 39 million smart meters installed, 3.9 million are not functioning in full smart mode due to connectivity issues or technical problems. (NOTE: please provide source for this assertion). This means the actual functional completion rate is even lower than the headline figure suggests.

One of the reasons why it has been so expensive is that it has gone on for such a long time. Indeed, it's gone on for so long that the original minister who agreed to the smart meter rollout back in 2009 was Ed Miliband - a reminder of just how many governments and energy ministers have presided over this project without managing to complete it. The extended timeline has allowed costs to escalate dramatically, with each delay and restart adding millions to the final bill. The irony is that Miliband is now back in the same job as Energy Secretary, having returned to the department where he launched this troubled project 16 years ago.

To understand the root of the problems, it's important to understand some of the mistakes made during the privatisation of our energy market, which are explained in further detail in Chapter 8. The smart meter rollout's failures are not isolated incidents but symptoms of deeper structural problems in how Britain's energy system was designed and regulated.

Back in 2009, the government decided on a complex ownership model for smart meters. It was felt that electricity suppliers (retailers) should own as much as possible of the relationship with energy customers. At the same time, it was decided that meter ownership should be outsourced to a separate group of competing private companies that could own and operate them as infrastructure assets. This was seen as preferable to the previous arrangement, where regional electricity companies had maintained and owned meters, or to the approach used in other countries like France, Germany, and the Netherlands, where meters continue to be owned and operated by the network companies. It was also felt that there were significant benefits to having smart meters for gas (as well as electricity), and given that many customers had “dual fuel” energy contracts with the same supplier for electricity and gas that by putting suppliers in charge, this would enable synergies between electricity and gas. This feeling was held strongly by energy companies with lots of gas customers, who felt it might make it more difficult and expensive to sell gas.

The theory was that this model, where electricity suppliers appoint meter companies to install meters on their behalf, would make it easier for customers to switch between suppliers in the competitive retail market. Suppliers could simply transfer the meter lease from one metering company to another when a customer changed providers.

1. Every electricity and gas supplier (there are x operating in the market today) have had to build and maintain their own departments, systems and platforms to procure install and maintain smart meters
2. Appointments have to be per customer, not per street.
3. Gas meters are often separate from electricity meters. Old gas meters don’t need an electricity supply, and so there is often not an electricity supply to connect a smart gas meter to.
4. Whenever a smart meter is installed and there is a wider problem with the electricity supply coming into the property, the metering company and supplier then have to negotiate with the electricity network anyway. It also removes accountability from a single company for the smart meter rollout.

However, there are broader problems too:

**Pandering to conspiracy theorists**

A niche group of energy consumers believe that smart meters have publicly unacknowledged downsides, such as affecting human health or facilitating some dystopian or Orwellian future. To placate such groups, the Government built in safeguards to allow energy consumers the right to opt out of smart meter installation. However, this opt-out provision has created additional complexity and cost, as suppliers must maintain separate systems for customers with traditional meters while also ensuring that the smart meter network can still function effectively. The irony is that these conspiracy theories, while unfounded, have actually contributed to the rollout’s failure by creating a system that’s more complex and expensive than it needed to be.

Moreover, until recently, suppliers were generally not allowed to offer cheaper tariffs specifically to smart meter customers, as this could be seen as discriminatory against those who have opted out or cannot have smart meters installed. This meant that one of the key benefits of smart meters - the ability to offer more sophisticated and potentially cheaper time-of-use tariffs - could not be used to incentivize adoption, further undermining the business case for the rollout. However, this has started to change with the emergence of EV, heat pump, and battery tariffs that do require smart meters, though these remain a small fraction of the market.

**Gas smart meters never made sense**

As a country, we’re moving away from gas. It makes little sense to make such a colossal investment in our gas system. Unlike electricity, where smart meters allow for more accurate measurement of when power is used and therefore enable time-of-use tariffs for the first time -

thus helping cut costs and accelerate the transition to renewables - it matters much less when gas is used. While gas demand peaks in the evening and morning (similar to electricity), there is so much storage capacity in the gas network (called "linepack") that there is no benefit to measuring half-hourly gas usage in the same way as electricity.

The practical challenges of gas smart metering are even more significant. Gas meters are often located in different places to electricity meters - typically in cellars, garages, or external meter boxes. A large part of the cost of smart metering for gas involves establishing communication links between the electricity meter and the gas meter, either through wireless connections or new cabling. If this isn't practical, then gas meters might still need to be read manually (either by the consumer or the energy company), which negates most of the benefits of smart metering.

When the EU mandated that all member states install smart meters, they specifically excluded gas meters for precisely these reasons. The UK, making this decision while it was still an EU member, decided to go much further and gold-plate the regulatory requirement. This was a classic case of regulatory overreach - taking a sensible EU requirement and making it unnecessarily complex and expensive.

Even if the lack of smart metering for gas had led to an accelerated move towards electricity for heating, this would have been environmentally beneficial, even though it would have been undesirable for energy companies that supply gas.

**Network connectivity** Smart meters send really tiny amounts of data, back to electricity companies, in substance it's a single number telling them how many kWh is used every half hour. Meters need something similar to an internet connection to send this information back. The most obvious way to do this would be over mobile phone networks, where the volume of data would be trivial compared to modern 5G smartphone browsing. The obvious fallback in areas lacking a phone signal from at least one of the mobile networks would probably be to drop into the home Wi-Fi connection, in the same way many of our other devices (Smart TV, Doorbell, Printer etc.) do. For the very few homes that lack both mobile connection and Wi-Fi (which would be tiny), then there are satellite and radio options which could work out.

What the Government instead decided to do was to split the country into two regions. First, Government divided the country between the North and South along a line roughly between Liverpool and Leeds. So all of Scotland and part of Northern England falls in a northern region, while the rest of England and Wales falls into a southern region. For the southern region, the Government handed an exclusive contract to O2 (Telefonica) to use their existing mobile network. For the Northern region, the Government handed an exclusive contract to Arqiva for a solution based on longer distance radio signals. The thinking was that this would suit the more rural topography of Scotland and Northern England, and the denser population further south. However, this approach has proven too broad-brush and problematic:

1. In the Northern region, Arqiva's radio solution doesn't work as well in urban areas. It's based on radio technology originally designed for use by the emergency services in rural areas by vehicles with big aerials, where there is a low density of devices. Urban electricity and gas meters are clustered together in basements or alleyways. And even in Scotland and the North of England, the majority of the population is urbanised. The decision to award an exclusive contract to Arqiva for these areas also prevents energy suppliers falling back to use O2, even though in most built-up areas, a mobile signal would be readily available.

2. In the Southern region, many rural areas originally lack an O2 signal, but did have coverage from Vodafone/EE/Three. The most remote places would probably have been better suited to Arqiva's technology. In any case, this led to many situations where smart meters either couldn't be installed or worked unreliably. This situation has in recent years with the merger of O2 with Vodafone, a separate fallover contract for smart meters with Vodafone and a Shared Rural Network programme where in the most rural areas, all network companies share infrastructure.

### Inhome Displays versus Mobile Apps

In 2009, when the smart meter rollout began, the iPhone was 2 years old and mobile apps were nowhere near as ubiquitous as today, especially with older and more vulnerable households e.g. pensioners. The decision was therefore taken to mandate energy suppliers provide customers with an in-home screen device (IHD) to present live and summary information from the smart meter.

This added significantly to the cost because they are a separate piece of hardware that needs to be user-friendly and have a power supply. To be diplomatic, the IHDs which energy suppliers eventually procured are of variable quality and ease of use to the average customer. If IHDs break, energy suppliers have to replace them which can be quite frequent in tenanted properties. IHDs also use energy (albeit small amounts), for negligible benefit to most consumers.

In 2025, the growth of smartphones, tablets and computers as well as the accessibility improvements which have happened to them makes the continued requirement for an in home display (IHD) verging on the absurd.

### A network rollout makes infinitely more sense

Connecting all the previous downsides, the overarching mistake Government made was not to consolidate smart meter rollout to electricity network companies. This was the approach taken in most other European countries, including Italy (99% completion), Sweden (95% completion), Finland (90% completion), France (85% completion), and Ireland (80% completion), where the rollout of smart meters is significantly more complete than the UK's current 67% completion rate. Even more damning, the UK's functional completion rate is even lower when accounting for the 3.9 million smart meters that aren't working properly. Had the Government taken a network rollout approach, we'd have made much better progress, at a lower cost, with greater reliability and a better consumer experience. As noted in Chapter 8, a single national network operator might implement such a technology rollout even better.

# Chapter 10: Electricity Levies - Hidden Costs Everywhere

In the UK, there's been considerable interest of late in high energy prices. While generally true, the reality is more mixed:

1. The standard cost of electricity per kWh is about 25p and is similar for business and residential consumers. This is expensive by international standards, especially for businesses, though not that expensive by European levels and for the residential sector.

2. The standard cost of gas per kWh is much lower, at about 7p. This is relatively cheap by international standards, particularly for residential consumers, though business gas prices are a bit higher because of extra environmental and carbon charges that they face.

There are quite a few reasons why British energy users have such mixed fortunes:

**Reliance on Gas for Electricity** The UK is particularly dependent on gas not just for heating, but also to generate electricity. Unlike France, Britain has much less nuclear power. Outside Scotland, Britain lacks the geography for much hydropower, at least compared to the Nordics, Alpine countries, Spain or Canada. And compared to Germany, Poland, US, China and India, Britain shifted entirely from coal power, which used to generate nearly all our electricity.

Gas produces about half the $CO_2$ emissions per unit of electricity generated (around 400g $CO_2$/kWh) compared to coal (around 800g $CO_2$/kWh). Even though the UK had well established gas fields in the North Sea, it was considered a premium fuel for heating and industry, and the CEGB (Central Electricity Generating Board) had limited gas-fired generation capacity before privatisation, preferring coal for electricity production. However, there were significant advances in gas turbine technology at power stations in the 1980s and 1990s, and it was cheaper and easier to build new gas-fired power stations. Combined Cycle Gas Turbine (CCGT) power stations became the preference for newly privatised energy companies, and between 1990 and 2010, around 30 major CCGT plants were built around the UK in a "dash for gas".

Investment in new nuclear plants basically stopped after the completion of Sizewell in the 1990s, which had been initiated before privatisation, but which dragged on and was massively over budget. Given the scale and long term risk of nuclear investment, coupled with cheap gas and wholesale power prices privatised utilities were unable and unwilling to invest in new nuclear plants, and the existing plants which were privatised eventually went bankrupt and were sold to the French state utility EDF.

The wholesale price mechanism used in Britain sets the price of electricity at the cost of the most expensive power generator in each half-hourly period. 98% of the time, this is a gas power station. And so wholesale electricity prices in Britain closely shadow gas prices, although there is considerable movement from day to day and hour to hour depending on the level of demand. This is because the most efficient gas power stations in Britain, like the newer CCGT plants, are around 55-60% efficient, while the least efficient gas power stations (often older, simpler gas turbines) are more like 30-35% efficient. This means that the cost of making a unit of electricity at the least efficient gas power stations is maybe double that at the most efficient ones. In turn, this means that the least efficient power stations operate very little, typically only firing up on very cold days midwinter and for the peak late-afternoon and evening periods when demand is highest and all available capacity is needed to keep the lights on. And when the least efficient plants do have to fire up, prices spike!

After 2010, there was a notable increase in wind energy investment, which now contributes a similar share % as gas. Private companies have also continued to build more interconnectors to European neighbours. There are now x interconnectors built, up from one pre-privatisation and in 2024 the UK imported about x% of its power through these cables. Despite both these trends, gas continues to drive the overall market and prices, even if it only accounts for about one-third of the power used.

Why does this matter for prices? Well gas is quite an expensive fuel. It creates half the carbon of coal, and is much cleaner to burn, meaning there is vastly less local air pollution. And power stations have to buy carbon permits, which operate like a tax on natural gas that domestic and many business users don't have to pay when they burn gas in boilers or cookers. These carbon permits add about x% (or £x/tonne) to the cost of the gas.

**Accounting tricks** Starting in 2010, when the coalition government got serious about the pace of expansion of renewable generation, they needed to finance a substantial expansion of Britain's wind, solar and biomass generation at a time of public expenditure restraint (austerity). The private companies developing these projects needed subsidies through ROCs (and later CfDs). Unlike longstanding government support such as agricultural subsidies, export guarantees or student loans, which are treated as public expenditure and inflate the size of the recorded deficit and national debt figures, renewable energy subsidies were structured to avoid this accounting treatment.

The key innovation was the Levy Control Framework (LCF), which allowed the government to commit to long-term subsidy payments without these liabilities appearing on the national balance sheet. ROCs and CfDs are essentially contracts between the government and private companies, but they're financed through levies on consumer bills rather than direct government spending. This means that while the government is legally committed to paying these subsidies for 15-20 years (in the case of CfDs), the total liability - which could run to tens of billions of pounds - doesn't count towards the official national debt figure.

This accounting treatment was crucial politically, as it allowed the coalition to claim it was reducing the deficit while simultaneously committing to massive long-term spending on renewable energy infrastructure. It's a classic example of "off-balance sheet" financing - the economic reality is that British consumers are paying for these subsidies through their electricity bills, but the government can claim it's not adding to the national debt.

Putting additional levies or charges onto energy bills to fund these costs was preferable to tax rises for political reasons. Given the levies are mandatory, they could be described as a stealth tax.

**Sharing the cost evenly** Given the decision to finance renewable subsidies off energy bills, the Government was then faced with the decision of which energy bills to target. At the time, only around 85% of households and a smaller 60% of businesses had a gas supply, while nearly 100% of homes and businesses have an electricity supply. The decision was taken to finance the bulk of subsidies and supports for renewables from levies and charges to electricity bills. It was felt that the burden of these charges would then be felt broadly in proportion to how much electricity they used. By raising the levies off a single fuel i.e. electricity rather than a mix of different fuels, it was felt that the administration would be simpler. As the levies would not be traditional excise duties like road fuel (petrol and diesel) the Government could also avoid presenting them as tax rises.

**Electricity levies discourage heat pumps** When they were first introduced, electricity levies weren't that significant. In 2012, the cost of electricity for households was around 12-14p/kWh and gas was around 5-6p/kWh, a ratio of roughly 2.5 to 1. However, over time, the levies have grown dramatically. Analysis by Ben James on the excellent Electricity bills shows how such levies have increased far more than expected:

**Generation Subsidies per household:**

- **Renewables Obligation**: More than doubled from £39.85 in 2015-16 to £108.18 in 2025 (FYTD)
- **Contracts for Difference (CfD)**: Exploded from just £0.13 in 2015-16 to £31.27 in 2025 (FYTD), though they briefly turned negative during the 2022-23 energy crisis when wholesale prices were high
- **Capacity Market**: Grew from £0.07 to £28.67 over the same period

**Social and Infrastructure Costs per household:**

- **ECO (Energy Company Obligation)**: More than doubled from £11.78 to £27.09
- **Smart Meter Charges**: Nearly tripled from £6.94 when it started in 2018-19 to £19.82 in 2025
- **Warm Home Discount**: Increased from £6.56 to £10.98

The total burden of these levies per household has grown from around £70 annually in 2015-16 to over £200 today, representing a nearly threefold increase in just a decade. About 30% of household electricity bills are now levies and VAT. This dramatic growth explains why electricity has become so expensive relative to gas, and why the current price ratio is now closer to 4:1 rather than the ratio of 2.5:1 of 2012.

At this level, electricity bill levies are a significant detractor from the effort to sell and install heat pumps (and in some cases EVs). A well installed heat pump is about 350% efficient, and a well installed gas boiler about 90% efficient. But a heat pump is typically 4 times more expensive to purchase (£8,000-12,000) than a gas boiler (£2,000-3,000).

If we didn't have levies on electricity bills, but had instead funded the costs through general taxation, and the cost of electricity were still just 2.5 times more expensive than gas (currently 7p), then heating homes with heat pumps would be around 35-40% cheaper, with a typical saving (assuming annual heating/hotwater use of 12,000 kWh) of £400-550/year, especially if homes ditched their gas connection and avoided £100-150 of standing charges.

Taking this argument further still, if we had instead put the cost of levies onto gas bills rather than general taxation, then the cost of electricity would be about 1.5 times more expensive than gas. At this level, then heating homes with heat pumps would be around 65% cheaper than gas, with a typical saving of £600-750/year. For homes with solar PV and/or a battery, then heat pump savings would be even greater, perhaps £1,000/year. With this sort of savings, many homeowners could have achieved a clear payback in 5-10 years, and heat pumps would quickly have been popular without Government support or major subsidies.

However, because the Government continued with imposing large levies on electricity bills, it has been far more difficult to persuade homeowners of the rationale to install heat pumps. This has meant:

1. The Government is now paying an upfront grant of £7,500 per property (as well as a VAT exemption worth another £2,000 on average). If heat pump installations hit 800,000 a year in 2028 as the Government hopes, these grants will cost £6bn a year. This is a massive figure, for context the total budget for all the primary schools in England is about £6-7bn.
2. Because heat pump installations rely on grant funding that's on an unsustainable path, installers aren't recruiting and training enough new installers. They're rightly nervous given how previous Governments have cut support for Feed in Tariffs (FiTs) and other energy efficiency grants like ECO.
3. Because of the lack of qualified installers, the Government is having to subsidise the training, by offering grants and funding for training programs, creating yet another taxpayer-funded intervention in what should be a self-sustaining market.
4. Only affluent households are installing heat pumps. This means the taxpayer is subsidising the better off to get expensive heating systems they could afford anyway, while poorer households continue to struggle with high electricity bills. Research shows that 70% of heat pump installations are in homes in the top 40% of income brackets, with the average household income of heat pump adopters being £65,000 - well above the UK median of £32,000.

**Taxing Gas** The obvious solution or remedy to the current mess is to move (or rebalance as it's commonly referred to), levies from electricity and onto competing fossil fuels. At the moment there are very few taxes on natural gas, especially that used in households. On the total retail price of 7p/kWh, levies account for just 0.5-1p/kWh, which is drastically less than electricity, especially as a percentage.

Given most energy companies that supply electricity also supply gas, it would be feasible to move many of the levies onto gas. But while this could plug much of the gap, and many energy users using a mix of electricity and gas might not notice much overall change in their bills, there would still be winners and losers. Levies or taxes might also need to be extended to LPG, heating oil and coal fuels to avoid a perverse incentive for energy users to shift from mains gas to one of these alternatives, all of which have higher carbon emissions and local air pollution. However, doing so would probably require the Government formally creating or increasing excise duties, which are taxes, and this would draw more potentially unwelcome political attention.

The basic rebalancing proposal has been around for a decade, and successive Governments have resisted the suggestion. At the core of its reluctance is the perception that any move which increases the price of natural gas would be considered regressive, and sharply increase the cost of the most basic need for heating in the winter months.

Of course, rebalancing from electricity to gas has a positive effect on both sides of the coin. It doesn't therefore take that much to significantly alter the economics of a home contemplating an investment in a heat pump.

**Impact of Electricity Levies on EVs** It's true that electricity levies also have some impact on discouraging the adoption of EVs. However, as explained in Chapter 16, petrol and diesel duties remain very significant compared to the minimal levies and taxes on natural gas. For homeowners with a driveway, there's ample incentive to charge at home, with overnight tariffs available as cheap as 6.5p/kWh for charging. The bigger challenge is the cost of VAT on public charging, which mainly affects those without driveways.

# Chapter 11: Price Cap - The Sticking Plaster Solution

Retail electricity prices were fully liberalised in the year 1999. In the period since privatisation in the year 1990, they had been regulated because there wasn't yet competition. From then until 2018, the market was in charge. However, in the years after 2010, higher energy bills became a more regular item on the political agenda. Eventually, the Labour party, then under the leadership of Ed Miliband (previously and once again energy secretary) pledged to introduce a price cap in the 2015 general election.

Though the Labour lost the 2015 election to the Conservatives, the price cap was a popular proposal and high energy issues didn't dissipate as an issue. In the following 3 years, average energy bills didn't rise for engaged consumers that actively compared and switched suppliers. However active residential customers were only about 40% of the market, or 10 million out of about 25 million homes. For the remaining 15 million (or 60% of homes) who weren't actively a tariff, prices were significantly higher. There are a number of conclusions Government could have made from this. Clearly, if you are hoping for retail competition to be the main lever to keep energy prices competitive, if a majority of households aren't active in the market, something is inadequate or missing. There were some efforts to boost the volume of switching, though the advent of price comparison sites since year x had dramatically cut the ???? SOMETHING is missing ????

Political concern therefore continued to grow. Eventually, in 2018 a price cap was introduced. Customers remain free to choose a tariff from different suppliers. However, if a customer at any point hasn't actively agreed a tariff, suppliers are obliged to enroll residential customers onto a default, price-capped tariff.

The price cap levels are published quarterly by the regulator. The methodology is extensively documented and is recommended for anyone trying to understand the composition of home energy bills. As of 2024-25, a typical home electricity bill of £869 breaks down as follows:

- **Wholesale costs** - £311 (36%) - The cost suppliers pay to buy electricity from generators on the wholesale market. This is the most volatile component and drove the massive bill increases during 2021-22. In reality in a free market, suppliers can choose how far forward to hedge or buy the wholesale energy they need to satisfy customer demand. However, for the purposes of the price cap the potentially overly simplistic assumption that suppliers will hedge 12 months in advance is made.

- **Network charges** - £209 (24%) - Covering the poles, wires and infrastructure that deliver electricity to your home. This includes transmission charges (TNUoS - £40), system balancing costs (BSUoS - £32), and distribution network costs (DUoS - £138).

- **Policy levies** - £226 (26%) - The biggest chunk of hidden costs, funding renewable energy subsidies and social programmes:
    - Renewables Obligation: £104 (supporting older wind/solar projects)
    - Contracts for Difference: £34 (supporting newer renewables)
    - Feed-in Tariffs: £23 (small-scale solar/wind payments)
    - Capacity Market: £21 (keeping backup power plants available)
    - ECO scheme: £27 (home insulation programmes)
    - Smart meter rollout: £18 (funding the national smart meter programme)
    - Warm Home Discount: £11 (supporting vulnerable customers)
- **Supplier costs & margin** - £110 (13%) - Covering customer service, billing, bad debt provisions and a modest profit margin for energy companies.
- **VAT** - £43 (5%) - Energy bills get a reduced VAT rate of 5%, rather than the standard 20%. Even this "discount" adds £43 to the typical annual bill.

Now because of the way the price-cap assumes forward hedging of about 12 months, when wholesale energy prices started rising very dramatically in 2021-2, suppliers found themselves in a difficult situation. This meant that suppliers were no longer able to offer competitive tariffs to active customers looking to switch in the market. However, under the price-cap regulation, suppliers continued to be required to offer a price-cap tariff to all customers at rates that weren't keeping pace with the spike in wholesale costs. For the first time since competition, it was no longer advantageous for householders to shop around for energy tariffs, but instead accept the default, price-cap tariff from their supplier. This advice was quickly disseminated by consumer groups, influencers like Martin Lewis and the media. Suppliers started withdrawing their fixed tariffs. Then around 30 suppliers went bust - including Bulb Energy, which required a £2.2 billion taxpayer bailout before being sold to Octopus Energy.

Credit is due to regulatory and industry the handling of the 30 defunct suppliers. In each case, customers were allocated to a new supplier with no interruption to their energy supply. However, the retail energy market ended up with far fewer competitors; ironically the price cap had inadvertently destroyed the very competition it was meant to encourage.

Eventually, by September 2022, with wholesale energy prices continuing to rise, the Government intervened much further in the energy market and started directly subsidising home energy bills. This decision was about the only lasting policy decision enacted by the short-lived Truss administration. Given the economically liberal image projected by Truss, the choice and extent of the subsidies proposed is somewhat ironic. Initial estimates suggested costs of £60-140 billion, but the actual cost turned out to be around £40 billion total - still roughly £1,400 per household. This included £21 billion for the Energy Price Guarantee itself (keeping bills at £2,500), £12 billion for the universal £400 household rebate, and £5.5 billion for business support.

However, the energy price guarantee, as it was known, was not a cap on the bills paid by households. Instead, it was a direct subsidy paid by Government to energy suppliers - essentially the state picking up the difference between wholesale costs and the £2,500 household target. This represented a complete abandonment of market pricing, with taxpayers subsidising energy consumption regardless of usage levels or household income. The irony was complete: a supposedly free-market Conservative government had nationalised household energy costs in all but name.

Remarkably, this £40 billion commitment was made without proper parliamentary scrutiny or Treasury costings. The EPG was announced on 8 September 2022 - the day before the Queen's death - which suspended parliamentary business for ten days of national mourning. When Parliament resumed, the mini-budget chaos dominated proceedings. The Energy Prices Bill wasn't even introduced until 12 October (over a month after the policy began), received just a few hours of debate, and was fast-tracked to Royal Assent within two weeks. No Office for Budget Responsibility forecast was sought, no cost-benefit analysis was conducted, and no proper parliamentary committee scrutiny occurred. The largest peacetime fiscal intervention in British history was implemented with less parliamentary oversight than a typical local planning application.

To put the magnitude of the Energy Price Guarantee into context, £40 billion is roughly equivalent to the entire annual education budget for England, or about half the annual defence budget. During Covid, the Government spent £69 billion on furlough support over two years. The EPG was a vast programme, handing a significant payment in kind to almost every household in the country.

However, the scheme was deeply regressive. Although the £400 household rebate was uniform, the Energy Price Guarantee itself was paid per unit of energy consumed, meaning the largest subsidies went to those with the biggest and worst insulated homes. While a typical household might have received £800-1,000 in EPG support, a wealthy family in a large, poorly insulated country house could easily have received £3,000-5,000 in taxpayer support. The owner of a 10-bedroom mansion with an annual energy bill that would have been £8,000 without the cap received roughly £5,500 in government subsidy - ten times more than a pensioner in a well-insulated flat. The policy essentially socialised the heating costs of the wealthy while providing minimal help to those who needed it most at a time that widespread inflation hit every aspect of household expenditure.

The scheme was also regressive across generations. To understand the scale of this inequality: the wealthiest 10% of UK households (predominantly older homeowners) hold 43% of all wealth, while the bottom 50% (disproportionately younger people) hold just 9%. The richest 1% possess more wealth than the bottom 50% combined. Meanwhile, older households received the biggest energy subsidies while paying minimal tax to fund them (particularly pensioners), while younger people - more likely to live in small flats or shared accommodation - received little direct benefit but will spend decades paying higher taxes to service the additional £40 billion of national debt. In effect, young renters in London bedsits subsidised the heating bills of older homeowners in large detached houses, then got handed the bill to pay it back over the next 30 years.

More worryingly from the perspective of basic economics, the energy price guarantee did nothing to solve the underlying problem causing the energy price shock that Europe faced. Following a severe restriction on the supply of gas from Russia, the logical policy response was to reduce demand for gas to force down the market price. These could have included:

1. **Public information campaigns** - informing the general public of the shortage of natural gas, the reasons for it, and the actions they could take, reducing heating and hotwater use, that could lead to an improvement.

2. **Maximum legal temperatures for heating** - France imposed 19°C limits in public buildings and encouraged the same in private homes, while Germany set 19°C for offices and 16°C for corridors and lobbies.

3. **Reduced working hours** - Moving to 3-4 day working weeks to cut commercial energy demand, or encouraging remote working to reduce both office heating and commuting. That said, remote working in winter in the UK, where most homes are heated with gas could feasibly have increased demand for gas.

4. **Temporary cohabitation incentives** - Tax breaks or payments encouraging families to move in with friends or relatives during extreme cold snaps, reducing the number of homes needing heating.

5. **Public building closures** - Closing non-essential public buildings (libraries, community centres) during peak demand periods and consolidating services.

6. **Industrial demand management** - Paying energy-intensive industries to reduce production during peak hours, rather than subsidising their consumption.

Instead, the UK chose to subsidise consumption rather than reduce it - the exact opposite of what basic economics would suggest during a supply shortage.

As it turned out, the energy price shock was over more quickly than initially expected. Wholesale gas prices began falling in early 2023 as European storage filled up, alternative LNG suppliers were found, and a mild winter reduced demand. By July 2023, the Government announced the end of the Energy Price Guarantee, reverting to the normal Ofgem price cap. The crisis that supposedly justified £40 billion of taxpayer spending had largely resolved itself through normal market mechanisms - exactly what would have happened faster and cheaper if demand had been reduced rather than subsidised.

The price cap, originally introduced as a temporary measure to protect vulnerable customers from supplier exploitation, has instead evolved into a permanent feature of the energy market. What began as a “sticking plaster” solution to a competition problem had become the foundation for the largest peacetime fiscal intervention in British history. Rather than fixing the underlying issues with Britain’s energy system, the price cap had simply made them more expensive for taxpayers to ignore.

More worryingly, the Energy Price Guarantee has created a dangerous precedent. Having bailed out energy consumers once, the electorate now expects the same treatment during any future price spike. Psychologically, voters believe it is the Government’s responsibility to ensure energy prices remain affordable, regardless of the cost to future taxpayers. This creates classic moral hazard - when people expect to be rescued from the consequences of their choices, they make riskier decisions.

The bailout has reduced incentives for both households and businesses to invest in energy resilience:

1. **Household energy efficiency** - Why spend £10,000 on insulation, heat pumps, or solar panels when the Government will subsidise your gas heating bills instead? The EPG removed the price signal that would drive investment in home energy independence.

2. **Industrial energy efficiency** - Why should factories invest in energy-saving equipment when they can expect taxpayer support during price crises? Heavy industry now has less incentive to reduce consumption or switch to alternative energy sources.

3. **Energy market resilience** - Why should suppliers hedge their wholesale purchases properly when they know the Government will intervene to prevent customer bankruptcies? The EPG has made the entire energy supply chain more fragile by removing market discipline.

The Energy Price Guarantee essentially nationalized energy price risk while keeping energy supply private - the worst of both worlds. Consumers get the illusion of market choice while taxpayers bear the cost of market failures. This moral hazard ensures that Britain will be even less prepared for the next energy shock, making future bailouts both more likely and more expensive.

# Chapter 12: EPCs - Energy Performance Certificates That Don’t Work

Energy Performance Certificates are supposed to inform users of the energy costs and environmental impact of buildings. There are separate certificates for residential homes and commercial premises. EPCs were introduced in the year 2007 source and are required whenever a building is offered for rent or sale.

For a variety of reasons, the EPC system as it exists at the moment is dysfunctional.

# Quality of Assessment

The current EPC can be undertaken by assessors with minimal training - typically just a few days of classroom instruction and some supervised assessments. The going rate for an EPC assessment is about £60-80, reflecting the low barriers to entry and the commoditized nature of the service. For most vendors and landlords, it is a tickbox exercise to satisfy legal requirements rather than a genuine attempt to understand or improve the property's energy performance.

The assessment process itself is heavily reliant on standardized assumptions rather than detailed analysis. Assessors typically spend 20-30 minutes in a property, taking basic measurements and checking for obvious features like double glazing, cavity wall insulation, and boiler types. Many factors that significantly affect energy performance - such as air tightness, thermal bridging, or the quality of installation - are either estimated from standard assumptions or completely ignored. It is a fact almost universally accepted that EPCs overestimate the heat loss of walls in most older houses, as the methodology assumes worst-case scenarios for thermal performance rather than accounting for the actual thermal mass and construction techniques used in traditional buildings. The result is that two identical properties can receive different EPC ratings depending on when they were assessed, who conducted the assessment, or even which version of the assessment software was used.

This variability undermines the credibility of EPCs as reliable indicators of energy performance. Personal experience bears this out - I've seen significant inconsistencies between EPCs on the same house over time, with insulation levels mysteriously falling between assessments despite no physical changes being made to the property. Even more concerning are the differences between houses clearly constructed at the same time on the same estate, where identical properties can receive different EPC ratings based purely on which assessor conducted the evaluation. Homeowners and buyers cannot trust that an EPC rating accurately reflects the actual energy efficiency of a property, making it difficult to make informed decisions about energy improvements or property purchases.

# Outdated Emissions Methodology

The current EPCs in use employ a methodology that was agreed in 2012. Since then, Britain's electricity system has undergone a dramatic transformation. Coal generation has been phased out entirely, while wind and solar now provide over 40% of our electricity. However, in the methodology used by current Energy Performance Certificates, the share of coal in electricity is still assumed to be around 30% and the emissions from electricity are calculated as 450-500 g/CO2/kWh, which implies the emissions from using a heat pump are almost as high (at around 130-150 g/CO2/kWh) as a gas boiler (around 210 g/CO2/kWh).

Given the actual carbon intensity of electricity in 2024 is more like 115 g/CO2/kWh, the emissions of a heat pump operating at 350% efficiency are now around 33 g/CO2/kWh, making them approximately 84% lower than a gas boiler.

# Missing Outputs

The outputs shown on an Energy Performance Certificate focus around the annual costs and energy usage. Although the calculation framework considers each of the following, they are not presented to the end user:

## Variations in energy prices

The cost to run a house in an energy performance certificate uses standardized energy prices set by the EPC methodology, which are updated periodically but not automatically with current market prices. Over the last 5-10 years there have been dramatic swings in energy costs, with electricity prices rising from around 14p/kWh in 2012 to 25p/kWh in 2024, and the 2022 energy crisis causing unprecedented volatility. During the energy crisis, wholesale gas prices peaked at over £400/MWh, causing household energy bills to double within months. However, EPC calculations continue to use the standardized prices from the methodology, meaning the running costs shown on certificates become increasingly disconnected from actual energy bills over time. This creates a misleading picture for homeowners and potential buyers, as the EPC running costs don't reflect the real financial impact of the property's energy performance.

## Heat Loss

The heat loss of a building is the amount of heat that it looses at a given temperature. It can be expressed either as a number of Watts per degree that the outside air temperature falls below 16°C or so, e.g. 100W/°C, or alternatively a design heat loss e.g. 5KW, which is the amount of heat needed to keep the house inside at a comfortable 21C when the outside temperature is at the minimum that can be reasonably expected, depending on where in the UK you are this is between -2C and 2C or so.

Knowing the heat loss of buildings had some value, but ultimately wasn't that important in an age when most buildings were heated with boilers. Most boilers are dramatically oversized for the heat loss of the building, which allows them to rapidly heat them on demand, which in turn allows the central heating to be turned on separately in the morning and evening on a day when all occupants go out during the daytime. To give you a feeling of typical oversizing, a typical gas combi-boiler might have an output of 25KW or so, even though the design heat loss of a typical house might be 5-10KW.

That said, the power rating of combi boilers is usually set to provide hot water at nearly full flow rate; for instance, a flow of 10l/min heated up from 10°C to 55°C, i.e. $\Delta T$ of 45°C, requires about 33kW. Consequently, the majority of home users are now accustomed to appliances with high peak power output which a heat pump is unlikely to match.

However, for heat pumps, and in particular those thinking of installing a heat pump, the design heat loss is incredibly important. It’s the single figure that indicates how large the heat pump you might want to install in the house is. It’s a pre-requisite for rough installation cost estimate.

# Chapter 13: RHI vs BUS - Heating Policy Confusion

NOTE: What do RHI and BUS stand for?

## The last 50 years - the rise and rise of the gas combi-boiler

For the last 50 years, Britain has benefited from easy access to natural gas. Nowadays 85-90% of homes are heated with natural gas, which replaced a number of inferior solutions, including:

1. Coal derived gas
2. Coal fires and back boilers - which are more hazardous and created vastly more localised pollution
3. Heating oil and storage heaters - which remains common in the most rural areas, but has been squeezed out of most suburbs and larger villages by the arrival of natural gas

Over the same period, the number of homes and buildings with proper central heating has grown from x% to x% (TODO: find dumers and source). Whereas previously, homes might have had a number of manually controlled fireplaces, and some rooms e.g. bedrooms and kitchen/bathrooms that went largely unheated. This has significant health benefits, especially for the vulnerable and elderly.

More recently, combi (combination) gas boilers have also enabled many homes to ditch having a separate hot water tank. By burning a lot of gas very quickly, much quicker than typically used for central heating, they enable homes to heat enough hot water to run showers and baths on-demand. Over the same period, homes have also abandoned loft tanks for fresh water, the combination of which has freed up significant storage space, which is of particular value in smaller properties and in parts of the country like London and the South East which have seen the most rapid growth in property prices.

The volume of gas boiler sales has also meant significant improvements in their efficiency, which in well installed properties can now push 90%.

## Turning tide post 2000

In the last 20-25 years, the previous infallible status of gas combi boilers has started to wane somewhat.

First, Britain's production of domestic North Sea gas peaked in the year 2000, when it covered almost all our annual gas demand, and has declined about 70% since then, meaning we now import about 50% of our gas annually. In the peak winter heating season, this figure can reach 70-80% and the majority of our seasonal imports come from far-flung LNG (Liquefied Natural Gas) markets like the US and Qatar. LNG gas is more expensive because it has to be liquefied at high pressure and transported across oceans in specifically designed tankers. Turning the gas into a high-pressure liquid requires masses of energy, meaning LNG is about 15-25% higher in carbon emissions than pipeline gas. This is especially true for US shale-derived gas, where there are extra carbon emissions associated with fracking the rock formations and processing the gas before liquefaction.

And LNG is also much less secure than UK gas, or gas imported under long-term pipeline contracts with our neighbour Norway, because LNG cargoes go the highest global bidder, which can include rapidly growing Asian markets, and are dependent on the political stability and goodwill of producers like the US and Qatar.

Starting in 2003 and escalating to the full-scale 2022 Ukraine invasion, Russia has become an increasingly less reliable and desirable pipeline gas supplier to continental Europe, where it was previously so dominant that countries like Germany had no LNG import facilities and many others relied exclusively on Russian pipeline gas. Over this period, Russia has threatened to cut off gas supplies at least 15 times, including major disputes in 2006, 2009, 2014, and 2019 that disrupted supplies to Eastern Europe and created political pressure on Western European countries. This pattern of using energy as a political weapon has put the UK competing with demand for both LNG cargoes and Norwegian pipeline gas, even though the UK itself has never directly bought much Russian gas.

## GDP versus short-term cost savings

It's worth going into a bit more discussion here about the difference between trying to find the cheapest and most convenient way of heating our homes and businesses and taking the long-term approach in terms of what's best for our economy, living standards and incomes.

In the short-term, for many of the last 20-25 years, importing increasing volumes of gas from abroad has been cheaper and easier than sourcing the same energy from alternative sources, like nuclear, wind or domestic shale. However, each time we install or replace a gas boiler, we commit ourselves for that boiler's lifetime, typically 10-15 years, to importing more foreign gas. And when we buy energy from abroad rather than making it ourselves, that money creates very few jobs in our own country, and raises very little in tax revenues for our Government. Instead, it helps other countries.

The balance of trade is rather neglected as a concept. Put simply, it shows the net surplus or deficit in how much the country as a whole spends. If you look at oil and gas over the last 25 years, then as a percentage of our overall income (or GDP), the cost of energy imports has risen dramatically, from being around £75 per person in 2000 when North Sea production was at its peak, to reaching £1,200-1,500 per person during the 2022 energy crisis. Even now, with prices having moderated, energy imports still represent about £600-900 per person annually - a significant drain on our economy that was partly avoidable.

Had we invested more in domestic energy sources like nuclear, wind and shale gas, then we might have paid more upfront for the energy, particularly the investment required. However, much of that investment would have stayed within the UK economy, we would have better infrastructure and assets, and during energy price shocks like 2022, our economy would have been more insulated. This is true even if domestic energy producers had been allowed to increase their prices, provided we had sensible profit (including if needed, windfall) taxes in place to collect and redistribute.

*For a detailed analysis of the UK's missed opportunity with shale gas development, including the economic benefits, environmental considerations, and political factors that led to its rejection, see* *Chapter 21: Shale Gas - A Missed Opportunity*.

# Chapter 14: CfD vs Marginal Pricing - Market Design Disasters

There is an urban myth that all British electricity is expensive because of the role of gas fired power.

**PPAs** Most commonly associated with renewable projects like wind and solar, a PPA contract is a bilateral, over the counter agreement that bypasses the wholesale electricity market and enables generators to sell their power at a longer term ??more?? fixed rate to an energy supplier or an industrial customer that uses lots of electricity. This agreement can be mutually beneficial because it can allow the energy consumer to fix their prices (potentially indexed by inflation) and for the generator to insulate themselves from any fluctuation in wholesale prices. This is particularly important for obtaining debt finance at reasonable rates, because without this sort of guarantee, the profits of renewable power generators can be incredibly volatile.

**CfDs** The Government CfD programme is designed to stabilise the cost of renewable electricity relative to the more volatile wholesale gas price. The way is does this is to effectively sell an insurance policy to the developers of renewable projects that tops-up, or knocks-off any difference between the wholesale price and a guaranteed strike price that they will end up receiving. The money to pay any top-ups, when the wholesale price is low come from a CfD levy on consumers, and any surplus in times of high prices goes back to consumers as a credit. This means that both from the perspective of the renewable generator and the end consumer, there is essentially a fixed price for the power that is generated under CfDs. So while the wholesale power market continues to exist, and operates as a market of last resort to enable fine-tuning of the electricity grid, there is much greater stability at an outer level. By the year 2030, over x% (TODO number and source) of Britain's power is expected to be generated under CfDs. The more power which is generated under CfD's the more stable power prices will become. The wholesale power price will remain important to generators and the grid for balancing the grid, but it will be increasingly irrelevant when it comes to determining consumer prices.

# Chapter 15: Flexibility, Balancing and Storage - The Grid's Hidden Challenges

## Why Timing Matters: The 9-5 Problem

If you ask a typical well-informed Brit when the electricity grid feels the most strain, chances are they'll respond with the old story about balancing the spike in kettle use that happens during must-watch TV events and especially knock-out Euros and World Cup England football matches. While it's a memorable story that explains the need for hydro pumped storage (and these days, batteries) on the grid quite poignantly, it's never really been true.

The reality is rather less charming. Much of the electricity spike comes from fridge compressors in pubs and homes as spectators grab cold drinks during the match. And yes, there's also a surge from water companies as everyone rushes to the toilet during half-time, forcing pumping stations to work overtime to refill cisterns. Neither of these explanations has quite the same romantic appeal as the tea-making story, so it's no wonder the kettle myth persists - it's much more British.

The bigger explanation as to why this isn't true however is that major England football matches, which in the age of Netflix are about the last remaining collective live TV event, represent the wrong kind of stress on the grid. These events create short-term demand spikes lasting perhaps 15-30 minutes - the kind that can be managed with quick-response storage like pumped hydro or batteries. The grid is never under much strain at 8-9pm on a summer evening, when the World Cup or Euros matches are typically held.

Instead, the real challenge comes from sustained high demand that stretches the entire generation system for hours on end. This happens between 4pm and 7pm on winter weekday evenings and during school term times - a completely different type of stress that requires the grid to operate near its maximum capacity for extended periods. There are a number of complementary reasons for this sustained high demand:

1. It gets dark from 3pm onwards, especially in mid-winter, further north and on overcast days. This drives a need for lighting both in buildings and on streets that doesn't exist to the same degree in the rest of the year. And while the development of LED lighting has dramatically cut the use of electricity in this space, lighting remains a significant contributor to UK electricity demand during winter months.

2. It's colder in winter, which created greater demands for heating.

3. Families begin the preparation of evening meals, especially those with younger children. Cooking appliances use lots of electricity, especially ovens!

4. The end of the school working day at 3-4pm and office working day at 5pm creates a particular spike in home heating demand as thermostats warm-up homes in preparation for people arriving home.

5. The mismatch of the end of the school working day (3-4pm) and office working day (5pm) creates an overlap period from 4 to 5:30pm when most offices are still open and using electricity for computers, lighting or machinery, but many households and especially those with children are at home and using appliances there e.g. for cooking. This coincidence, the use of electricity in both sets of locations at once, albeit only for a relatively short period of time, is what drives the need for a lot of the investment in our energy system and the costs we see on our bills.

## Two Types of Grid Stress

Understanding this distinction is crucial for energy policy. There are fundamentally two different types of stress on the electricity grid:

**Short-term spikes** (like football matches) last 15-30 minutes and can be managed with: - Quick-response storage (batteries, pumped hydro) - Demand-side response (asking consumers to reduce usage briefly) - Fast-start gas plants

**Sustained peak demand** (winter evenings) lasts 2-3 hours and requires: - Significant generation capacity to be available and running - Multiple backup systems to be on standby - The entire grid infrastructure to operate near maximum capacity

The winter peak is far more challenging because it requires sustained operation of the entire generation fleet at high levels, not just quick-response backup systems. This is why the grid needs so much investment in generation capacity, transmission lines, and distribution networks - not because of occasional TV events, but because of the predictable, sustained demand patterns of modern life.

There are laudable attempts by suppliers to discourage use of electricity in peak periods. Smart tariffs reward customers for this and this is possible because the suppliers can avoid more expensive wholesale energy prices in the peak hours, when the least efficient power stations and batteries are needed to meet demand, as well as punitive charges from the electricity networks. Over time, automation and remote control of home batteries, heat pumps and EVs is likely to extend this sort of demand response much further and without any conscious behaviour from end users. Indeed, given the spike in electricity demand over the 4-7pm period is often only 5-8 GW, it would only take around 2-3 million homes installing a standard 3kW battery to completely eliminate this peak. That said, as we use more power and especially power from renewables, the goal posts may shift higher further into the future.

It begs the question of whether a more root-and-branch review of how we structure our working day might be called for. The norms we have - such as the 9-5 working day for adults and 13 weeks of school holidays per year - are a legacy of Victorian industrial practices, for example when children were needed to gather summer harvest crops. Recent evidence has called into question the productivity of knowledge-focused work in particular, with research suggesting that an 8-hour working day may not be optimal for cognitive tasks. Closing offices earlier would significantly reduce electricity demand during peak periods, allow working parents to more easily collect children from school, and bring substantive improvements to mental health and road safety (fewer journeys completed in the dark).

Another aspect of why our current working day adds so much to energy bills is that we only really put significant pressure on the energy system for a relatively short period of time. So the fixed cost of maintaining an energy system capable of meeting these peak demands is spread over a relatively limited number of hours and days. The main winter season lasts from early November (just after the clocks go back) to late February. During this period, there is much less pressure on the grid on weekend evenings (which account for 2 out of 7 days). There is also significantly less pressure on Friday evenings, as people are more likely to head out straight from the office, eat later, or dine out. This pattern is further interrupted by the Christmas fortnight and, to some extent, the February half-term week, which also sometimes falls in a different week around the country. And from the start of March, even if the weather isn't much warmer, the lighter evenings are enough to cut the use of much lighting. Putting all this together, there are only really around 70 potential evenings - Monday to Thursdays between November and February. And if the weather is particularly mild and windy, which with climate change it often is, this can further reduce the strain on the grid as heating demand is lower and there is abundant wind generation on the grid. In many winters, we might realistically only face 20 evenings when we put much strain on the grid.

However, adopting a model where we require dynamic behaviour change in response to strains on the grid has risks. It is likely to be inherently disruptive, like the overnight routine changes faced by many families during COVID. The alternative - blackouts - are vastly more disruptive, so it would always be worth even very drastic action to avoid this eventuality. But even with automated solutions like smart batteries and EVs, there's still a strong case for a more joined-up approach that considers broader social, education, and health policy. The 9-5 working day and school hours that create our peak energy demand aren't just energy policy issues - they affect family life, mental health, road safety, and educational outcomes. A coordinated approach that addresses these multiple benefits could be more effective than relying solely on technological fixes. Moreover, making an overall and permanent change - such as shifting typical working hours earlier - would be more predictable for both the energy system and for families, rather than requiring constant adaptation to grid conditions.

## The Technical Challenge: Grid Flexibility

Britain's electricity grid faces a fundamental challenge that has grown dramatically in recent years: the need for flexibility to balance supply and demand in real-time. As we've increased our reliance on intermittent renewable sources like wind and solar, the traditional model of matching generation to demand has become increasingly complex and expensive. We're also moving more of our heating from fossil fuels to electricity (mostly heat pumps), meaning in winter especially, our demand for electricity might start to grow dramatically (to date it hasn't).

## The Balancing Challenge

Unlike fossil fuels, electricity cannot be stored easily, at not without other technologies and investment in big hydro dams and batteries. Grids are inflexible, supply and demand must be balanced second-by-second. The grid can only tolerate energy imbalances of about 1% - roughly 400-500MW in Britain's system - before automatic load-shedding kicks in to prevent cascading blackouts. When this balancing fails, the consequences can be severe: Iberia's grid collapse in April 2025, triggered by a combination of unexpected demand spikes and insufficient backup generation, left millions without power and demonstrated how quickly a modern electricity system can fail when the balance between supply and demand breaks down.

This balancing act has become significantly more challenging as our energy mix has shifted from predictable fossil fuel plants to variable renewable sources.

### The Scale of the Problem

In 2024, wind and solar now provide over 40% of Britain's electricity, up from less than 10% in 2010. This transformation has created new challenges:

- **Wind variability**: Wind output can vary from near-zero to full capacity within hours
- **Solar intermittency**: Solar generation drops to zero every evening and is reduced on cloudy days (and winter!)
- **Demand patterns**: Peak demand still occurs on winter evenings when renewable generation is typically low

The result is a system that requires far more sophisticated balancing mechanisms than the simple "turn up the gas" approach that worked when fossil fuels dominated.

## Current Balancing Mechanisms

Britain's electricity system uses several mechanisms to maintain balance:

### 1. The Balancing Mechanism

National Grid ESO operates the Balancing Mechanism, where generators and demand-side response providers can offer to increase or decrease output to help balance the system. This operates in real-time, with offers typically made 1-4 hours ahead.

### 2. Frequency Response Services

These services respond automatically to frequency changes on the grid: - **Primary Response**: Automatic response within 10 seconds - **Secondary Response**: Automatic response within 30

seconds
- **High Frequency Response**: For when generation exceeds demand

### 3. Reserve Services

- **Short-term Operating Reserve (STOR)**: Gas and diesel plants that can start within 20 minutes. In the recent past, there have also been special reserve contracts for coal plants approaching retirement, though these have now all lapsed.
- **Dynamic Containment**: Fast-acting batteries and other technologies responding within 1 second

## The Cost of Flexibility

The increasing need for flexibility has created a significant new cost category in the electricity system. In 2023, balancing costs reached over £2 billion annually, up from around £200 million a decade ago. These costs are passed through to consumers via network charges.

### Why Costs Are Rising

1. **Reduced inertia**: Traditional thermal plants provide system inertia naturally. As these close, we need to pay for synthetic inertia from batteries and other technologies such as grid-forming inverters.
2. **More volatile prices**: With intermittent renewables, electricity prices can swing from negative (when wind is high and demand low) to over £1,000/MWh (when demand is high and wind is low).
3. **Backup capacity**: We still need enough dispatchable capacity to meet demand when renewables aren't available, but this capacity earns less revenue when renewables are generating.

## Storage Technologies

### Battery Storage

Battery storage has emerged as a key technology for providing flexibility, though adoption varies significantly across markets. The cost of battery storage has fallen dramatically, from over £1,000/kWh in 2010 to under £200/kWh in 2024, making it increasingly competitive with traditional energy storage. With a lifetime of 6,000-8,000 cycles, and a finance (cost of capital) cost of 7.5%, a battery charging and discharging every day (called cycling) can typically achieve a payback if it can charge at 8-12 pence/kWh less than it can discharge, over a lifetime of 16-22 years. This calculation accounts for 10-15% of the energy to be lost during the charging and discharging process (called a round-trip efficiency of around 85-90%) - the rest is lost as heat. This 8-12 pence/kWh spread (£80-120/MWh) is roughly the same as the cost of generating power for a few hours every evening from a medium efficiency gas power plant.

## Battery Storage Deployment: Britain vs. Europe vs. US

### United States: The Battery Leader

The US leads global battery storage deployment, particularly in California and Texas. California's aggressive renewable targets and high electricity prices have created strong economics for battery storage, with over 6 GW installed by 2024. Texas has become the second-largest market, driven by its deregulated electricity market and extreme weather events that create high price volatility. The US benefits from federal tax credits and state-level incentives, making battery projects highly attractive to investors.

### Europe: Catching Up

European battery deployment has been slower, constrained by regulatory barriers and fragmented markets. Germany leads European deployment, driven by high electricity prices and strong renewable integration needs. Britain has been catching up rapidly, with over 2 GW of battery storage deployed by 2024, supported by capacity market mechanisms and frequency response services. However, European projects face higher costs due to more complex permitting and grid connection processes compared to the US.

### Britain: Unique Challenges and Opportunities

Britain's battery market has unique characteristics. The country's high electricity prices and significant renewable capacity create strong arbitrage opportunities, but high interest rates and complex grid connection processes have slowed deployment compared to the US. Britain's capacity market provides revenue certainty, but the lack of long-duration storage incentives has focused investment on shorter-duration applications. With continued cost reductions and market reforms, Britain could see accelerated battery deployment, particularly for grid-scale applications.

## Types of Battery Storage

- **Grid-scale batteries**: Large installations installed by utilities and connected directly to the power grid. These installations are increasingly common, particularly alongside conventional power generators (like wind and solar farms), to share the existing grid connection.
- **Behind-the-meter storage**: Household and commercial batteries can be installed where power is already being consumed. When combined with onsite solar PV, such storage allows a

site to extend the self-sufficiency potential of the PV by charging during the daytime and using the electricity stored in the evening and nighttime, a process which typically makes significant additional bill savings through significant grid levy savings on electricity.

- **Electric vehicles**: Mobile storage that can in-theory provide vehicle-to-grid services. To date, this is still a technology in its infancy and the mass adoption of it isn't expected for some years yet due to regulatory and technical issues. Almost all existing car chargers (and most cars) are not able to do this, so we're some way off it having an impact.

## The Case for Low-Hanging Fruit

Rather than pursuing the most ambitious battery storage projects, there's a strong argument for focusing on the low-hanging fruit - investments that offer lower risk and more stable returns. These include behind-the-meter storage combined with solar PV, where the economics are more predictable and the returns more certain. A household with solar panels and a battery can avoid grid charges and time-of-use pricing, creating a guaranteed return that doesn't depend on volatile wholesale electricity markets. Similarly, commercial and industrial sites can use batteries to reduce peak demand charges, which are often the largest component of their electricity bills. These applications provide steady, predictable returns that are less exposed to market volatility than grid-scale storage projects that rely entirely on wholesale price arbitrage. By focusing on these lower-risk applications first, the industry can build experience, reduce costs, and create a foundation for more ambitious grid-scale projects as technology matures and markets develop.

### Pumped Hydro Storage

Britain has four major pumped hydro facilities in Snowdonia (Wales) and Scotland. These each hold enough energy when fully loaded (charged) to run at full tilt for 5-7 hours:

- Dinorwig (1,728 MW -> 5.3 hours, 9.1 GWh)
- Ffestiniog (360 MW -> 5.6 hours, 2.0 GWh)
- Cruachan (440 MW -> 7.3 hours, 3.2 GWh)
- Foyers (300 MW -> 6.7 hours, 2.0 GWh)

A major new pumped storage project, Coire Glas near Loch Ness, has been approved and could add 1,500 MW with 30 GWh of storage capacity, with nearly double the energy storage of all existing British facilities combined it should hopefully be able to run for 20 hours at full capacity. Coire Glas could rival some of Europe's largest pumped storage schemes like Grand Maison in the French Alps.

# Chapter 16: Exercise Duty & Road Pricing - Transport Energy Policy

## A Personal Introduction

I wasn't a typical student, even by Cambridge standards. Back in 2009, I co-founded a non-partisan student think-tank called the Wilberforce Society with a Wordpress blog on which I'd penned a controversial article advocating road pricing. When the Government of the day floated ideas in this area, my article was found by a number of journalists who approached me for comment. They were somewhat disappointed to hear I was a mere undergrad. As an economics student, road pricing made intrinsic sense to me and continues to do so. However, to most people it's deeply controversial.

## The Economics of Fuel Duty

Petrol and diesel duties are about 58p per litre, or roughly 40% of the total price when you throw in 20% VAT. For the Government, this makes them an incredibly important tax, raising over £25 billion annually, or about 3% of total tax revenues. Indeed, they raise more than corporation tax on small businesses, inheritance tax, and capital gains tax combined - making fuel duty one of the government's most reliable and substantial revenue streams.

What makes fuel duties particularly attractive to the Treasury is how easy they are to collect. Unlike income tax or VAT which require millions of individual transactions and returns, fuel duties are collected from just a handful of major oil companies and import terminals. The tax is levied at the wholesale level before it reaches consumers, meaning collection doesn't directly involve individual voters or require complex enforcement. This makes it both politically convenient and administratively efficient - a perfect cash cow for any government.

From a policy perspective, fuel duty also has some merit as a proxy for road usage and environmental impact. All things considered, the tax per litre is not a bad approximation for the number of miles vehicles travel, the size of the vehicle, and the level of its emissions. Larger, heavier vehicles consume more fuel per mile, so they pay more tax. More fuel-efficient vehicles pay less. And the more you drive, the more fuel you buy and the more tax you pay. While not perfect - it doesn't account for congestion, road wear, or the specific location of journeys - it's a reasonable first-order approximation that has served Britain's transport policy for decades.

## The Limitations of Fuel Duty

The main social problem (externality in technical speak) that petrol/diesel tax doesn't address well are the more urban problems of congestion and localised air pollution. A diesel car or delivery truck driving around the countryside poses no risk to those with lung problems and asthma - the same car idling outside a suburban school gate does. Fuel duty treats all fuel consumption equally regardless of where it happens, but the social costs vary dramatically by location and timing. This creates a fundamental mismatch between the tax and the actual harm caused.

This shortcoming is why cities like London, Manchester and others have sought to introduce extra charges - especially on higher emitting vehicles. The London Congestion Charge, Ultra Low Emission Zone (ULEZ), and similar schemes in other cities are attempts to address the specific urban externalities that fuel duty cannot capture. These local charges target the vehicles that cause the most harm in the most sensitive locations, creating a more targeted approach to managing urban transport problems.

While the efforts of these cities are laudable, the lack of a coordinated national approach creates the risk of a race to the bottom where dirtier vehicles are recycled or relocated to more provincial towns and cities. As London and other major cities implement stricter emissions standards, older, higher-emitting vehicles don't simply disappear - they often end up being sold to buyers in smaller towns or rural areas where such restrictions don't exist. This can create a perverse outcome where urban air quality improves at the expense of air quality in areas that may have fewer resources to address the health impacts of poor air quality.

## What Fuel Duty Actually Costs Per Mile

To put fuel duty in perspective, let's work out what it actually costs per mile to drive. A typical VW Golf with a 1.5-litre petrol engine might achieve around 35 miles per gallon (mpg) in real-world driving conditions. With fuel duty at 58p per litre and 4.55 litres per gallon, that works out to about £2.64 in fuel duty per gallon. At 35 mpg, this means fuel duty costs approximately 7.5p per mile driven. This gives us a baseline understanding of what drivers currently pay for road usage through fuel duty - a figure that will become increasingly important as we consider alternatives.

For a typical driver covering around 8,000 miles per year, this works out to about £600 annually in fuel duty. When you add VAT at 20% on the total fuel cost, the total tax burden rises to around £720 per year. This is a significant sum that drivers have become accustomed to paying, and it represents the revenue that any alternative road pricing system would need to replace if fuel duty were to be abolished or significantly reduced.

This contrasts sharply with Vehicle Excise Duty (VED), which is a flat annual tax based on vehicle emissions rather than usage. For a typical petrol car, VED might be around £180 per year - just 25% of what the same driver pays in fuel duty. This highlights the fundamental difference between the two taxes: VED is a fixed cost that doesn't vary with how much you drive, while fuel duty is a variable cost that directly reflects road usage. It's this usage-based nature that makes fuel duty such an effective proxy for road usage, but also makes it vulnerable to changes in driving patterns and vehicle technology.

To put this 7.5p per mile fuel duty in context, it's worth comparing it to other motoring costs. The total cost of motoring (including fuel, insurance, maintenance, depreciation, and other running costs) typically ranges from 30p to 60p per mile depending on the vehicle. So fuel duty represents about 12-25% of the total cost of driving. However, many of these 30-60p costs are invisible or annualised from the perspective of the end user - depreciation happens gradually, insurance is paid annually, and there's an opportunity cost of having cash tied up in a vehicle rather than invested elsewhere or paying down debts or a mortgage off early. By comparison, a typical bus journey costs around 15-25p per mile, while rail travel varies dramatically from 10p per mile for long-distance advance tickets to over 50p per mile for peak-time commuter journeys. This shows that fuel duty, while significant, is just one component of transport costs, and any replacement system needs to consider the broader financial impact on households.

## The Electric Vehicle Challenge

This being said, petrol and diesel taxes face significant headwinds. Politically, fuel taxes haven't kept up with inflation since 2010, following intense lobbying and campaigning, under Governments of all parties. And while the total mileage driven has stayed quite steady since 2010 (though there have been shifts from cars and commuting toward delivery vans, especially since COVID and the rise of remote working), the biggest challenge going forward is the growth of electric vehicles. These now account for about 3% of the total vehicle fleet, and 2% of total mileage. But they account for 16% of new vehicle sales, and the Government's own target is for this to reach 100% by the year 2035.

The tax implications of this transition are stark. A typical electric vehicle might use around 0.3 kWh of electricity per mile driven. At a rapid charging station costing 80p per kWh, this works out to 24p per mile - of which the government collects 4p in VAT (20%). At home on an overnight tariff of 7p per kWh, the same journey costs just 2.1p per mile, with VAT of only 0.11p (5%). Compare this to the 7.5p per mile fuel duty that petrol drivers pay, and you can see the problem: even at expensive public charging, EV drivers are paying less than half the tax per mile, while home charging reduces their tax contribution to less than 2% of what petrol drivers pay. This creates a fundamental inequity that will only grow as more drivers switch to electric vehicles.

This VAT disparity creates a particularly perverse social outcome. Better-off households with driveways can charge their EVs at home on the 5% VAT rate, while less well-off drivers and renters who can't persuade their landlords to install chargers are forced to use expensive rapid charging stations at 20% VAT. The result is that wealthier EV owners pay both lower prices and lower tax rates, while poorer EV owners face higher costs and higher tax rates. This is exactly the kind of regressive policy outcome that the energy transition was supposed to avoid, and it highlights why simply relying on electricity taxation to fund roads creates both revenue problems and social equity issues.

## The Problem with Electricity Levies for Road Funding

The broader problem with trying to fund roads through electricity levies is that electricity bills already carry significant policy costs - including the Renewables Obligation, Contracts for Difference, and Capacity Market charges that support the energy transition. While these could arguably be considered taxes, they serve specific policy purposes. Trying to raise additional revenue for roads by increasing electricity levies would create perverse incentives that work against other government objectives. Higher electricity prices would disincentivise the adoption of electric heating and heat pumps, which are crucial for decarbonising buildings. They would also make electric vehicles less attractive relative to petrol cars, undermining the very transition that's creating the need for alternative road funding in the first place. This illustrates why road funding needs to be separated from energy policy - the two objectives can conflict with each other.

As discussed in Chapter 10 in this book, there are arguably already too many charges on electricity bills compared to natural gas. Electricity carries the burden of funding renewable energy, grid infrastructure, and energy efficiency schemes, while gas - which remains the dominant heating fuel and a major source of carbon emissions - faces relatively few policy levies. Adding road funding to electricity bills in a bid to replace lost petrol and diesel taxes would only exacerbate this imbalance, making electricity even more expensive relative to gas and further disincentivising the switch from gas boilers to heat pumps. This creates a perverse situation where the cleaner energy source (electricity) becomes more expensive than the dirtier one (gas), working directly against decarbonisation goals.

## The Case for Road Pricing

Road pricing, by contrast, is the logical solution that addresses all these problems. Modern vehicles - both electric and petrol - almost universally come equipped with GPS and inbuilt SIM cards, making distance-based charging technically straightforward. With just a handful of major car manufacturers, collecting tax revenues from them could almost be as straightforward as collecting petrol and diesel taxes is from today's oil and gas producers. Integration with insurance companies could create additional benefits, as insurers could offer discounts for safer driving patterns and lower mileage, potentially offsetting some of the road pricing costs for responsible drivers. Perhaps most politically appealing is the opportunity to charge foreign-registered vehicles that use British roads. With around 2 billion miles driven annually by foreign vehicles on British roads, road pricing at 7p per mile could raise around £140 million annually from drivers who currently contribute nothing to road maintenance. Indeed, there's a strong case for charging foreign drivers more than British drivers - after all, they don't pay UK income tax, council tax, or other contributions to public services, so asking them to pay a premium for road usage could be seen as fair. A higher rate for foreign vehicles, perhaps 10-15p per mile, could significantly increase this revenue stream while remaining politically popular. While this is a useful additional revenue stream, it's clear that the main funding would need to come from British drivers - the foreign vehicle revenue is just the cherry on top of a system that treats all road users equally regardless of their vehicle type or charging options.

## The Time is Now

For various reasons, the stars are now aligning for road pricing in a way they weren't back in 2009 when I wrote that controversial blog post. The technical barriers have largely disappeared with the ubiquity of GPS and connected vehicles. The fiscal imperative has become urgent as electric vehicles erode fuel duty revenue. And the political landscape has shifted, with growing recognition that the current system creates inequities between different types of drivers and different charging options. What once seemed like an economist's pipe dream is now becoming a practical necessity.

# Chapter 17: Brexit Friction - How Leaving the EU Made Energy Harder

## The GB Model and European Integration

When I started working in energy markets, a common term in use was the GB model. This was the informal term given to the way that the EU had adopted the British privatisation model as a template for frictionless trade across European markets. At the core of the single market for energy was the notion of harmonised regulations, standardised trading mechanisms, and seamless cross-border electricity and gas flows that treated the entire continent as one integrated market.

This trajectory only gained momentum as the growth in renewables took hold in different European markets. Wind and solar are intermittent, and enabling previously siloed national electricity markets to trade the inevitable surpluses and shortages which happen over time is of clear mutual benefit. This was perhaps most obvious to Britain (and Ireland), which account for around 40% of Europe's wind resources, but which are separated by sea from the continent. However, prior to 2011, Britain's international electricity connections were limited to just two cables: the 1986 IFA cable linking England with France, and the 2001 Moyle interconnector linking Northern Ireland with Scotland.

Being within the EU single market for electricity meant that Britain could trade power with Europe almost as easily as trading within the country itself. From 2014, Britain joined a clever system called "implicit day-ahead coupling" - essentially a computer algorithm that would automatically work out the best way to buy and sell electricity across multiple countries at once, moving power to wherever it was needed most and could fetch the best price. There was no need for energy companies to separately bid for space on the cables - it all happened seamlessly behind the scenes.

The day-ahead market is by far the most important electricity trading venue - it's where the bulk of power is bought and sold for delivery the following day, and it's the most "liquid" market (meaning there are lots of buyers and sellers, making it easy to trade large volumes without moving prices dramatically). This was becoming increasingly crucial for Britain as wind power expanded, because wind generation is unpredictable and varies significantly from day to day. Having access to Europe's deep, liquid day-ahead markets meant British wind farms could easily sell their surplus power when the wind was blowing hard, and Britain could readily import power when the wind dropped.

Building cables across the seabed is significantly more expensive than over land, typically costing 3-5 times more per kilometre. Despite this cost premium, the economic benefits of cross-border electricity trading have been substantial, allowing Britain to export surplus wind power to

Europe during periods of high generation and import nuclear and hydroelectric power from France and Norway during periods of low wind.

## Britain's Interconnector Expansion

Following BritNed in 2011, Britain embarked on a major expansion of its interconnector network. To the continent, the Nemo cable to Belgium came online in 2019, ElecLink through the Channel Tunnel to France in 2021, IFA2 cable to France in 2021, and the North Sea Link to Norway in 2021. Britain also expanded its connections with Ireland: the Moyle interconnector linking Northern Ireland to Scotland had been operational since 2001, followed by the East-West interconnector connecting Ireland to Wales in 2012, and the Greenlink interconnector from Ireland to Wales which began operations in 2025. Several more interconnectors are planned or under construction including additional links to Denmark, Germany, and further Ireland-Britain connections.

While these interconnectors were mutually beneficial to both Britain and the continent, they were typically more valuable to Britain than to its European neighbours. Continental countries already had extensive networks of relatively cheap overland interconnectors linking them together - France could trade with Germany, Belgium, the Netherlands, Spain, and Switzerland through land-based cables. Britain, as an island nation, was far more isolated and dependent on these expensive subsea links for access to European markets.

Recognizing this asymmetry, Britain's energy regulator Ofgem had to design a special subsidy mechanism called the "cap and floor" regime to guarantee interconnector developers a minimum revenue stream. This was essential to make the expensive subsea projects financially viable. Crucially, these subsidies were predicated on the assumption that the interconnectors would have frictionless, automatic access to European electricity markets through the implicit day-ahead coupling mechanism - particularly important given Britain's rapidly expanding but intermittent wind generation that needed reliable export opportunities when production was high.

## The Brexit Shock

Brexit threw this into doubt. Having access to the frictionless "implicit day-ahead coupling" required the UK to be subject to EU energy market regulations and the jurisdiction of European institutions. When Britain left the EU on 31 December 2020, it automatically lost access to this seamless trading mechanism.

From 1 January 2021, Britain's interconnectors reverted to the old system of "explicit" capacity auctions - energy companies now had to separately bid for space on the cables before they could trade electricity. This added complexity, cost, and uncertainty to cross-border trading. Instead of a single, automated process that optimized flows across multiple countries simultaneously, British traders now faced a two-step process: first win capacity in an auction, then trade electricity in separate national markets that no longer cleared together.

The impact was immediate and significant. Trading became more expensive and less efficient. The sophisticated algorithms that had automatically balanced supply and demand across borders were replaced by a more cumbersome system that required separate decisions about capacity allocation and energy trading. For Britain's wind farms, this meant losing the seamless access to European markets that had been crucial for managing the intermittency of renewable generation.

This was precisely the kind of friction that the cap and floor subsidies had never been designed to handle - the entire regulatory framework had assumed continued participation in EU market mechanisms that Brexit had now made impossible.

It's worth noting that this outcome wasn't inevitable. During the Brexit negotiations, there were options for a "softer Brexit" that could have maintained Britain's participation in EU energy market regulations while leaving other areas of EU law and regulation. Countries like Norway participate in parts of the EU's internal energy market without full EU membership. However, the UK government chose a harder Brexit approach that prioritized regulatory sovereignty across all sectors over maintaining sectoral integration in areas like energy where the benefits of continued cooperation were particularly clear. This political choice meant that billions of pounds of interconnector infrastructure, subsidized by British consumers through the cap and floor regime, would now operate under less efficient trading arrangements than originally envisaged.

## The Financial Fallout

Despite the complexities introduced by Brexit, the volume of electricity traded between Great Britain and continental Europe has continued to grow significantly. In 2020, electricity imports via interconnectors were approximately 22,391 GWh, supplying about 6.6% of the UK's gross electricity supply. By 2023, this figure had increased to 33,212 GWh, with interconnectors supplying around 10.4% of the UK's electricity.

The UK's interconnector capacity has expanded significantly, reaching 8.4 GW by January 2023. This growth is driven by increased interconnector capacity and the integration of renewable energy, particularly wind power. Much of this growth can be attributed to interconnector projects that were planned or agreed upon before the Brexit vote in 2016 and the hard Brexit agreement in 2020. These projects were part of long-term strategies to enhance energy security and integrate renewable energy sources, particularly wind power, into the UK's energy mix. As a result, the physical infrastructure and capacity expansions continued to progress despite the political and regulatory uncertainties introduced by Brexit.

However, the financial implications for British taxpayers were significant. The cap and floor regime guarantees interconnector developers a minimum revenue - the "floor" - if their trading revenues fall below a certain threshold. By making cross-border electricity trading more expensive and cumbersome, Brexit would likely reduce both the frequency and efficiency of trading on these cables. Less frequent trading means lower revenues for interconnector owners, increasing the probability that their earnings would fall below the guaranteed floor levels. When this happens, British consumers are contractually obligated to top up the difference through higher energy bills. The irony was stark: Brexit had reduced the commercial value of infrastructure that British taxpayers were legally bound to subsidize, potentially making those subsidies more expensive precisely because the infrastructure had become less useful to the British energy system.

These financial burdens are in addition to the higher electricity costs and loss of export revenues that have resulted from the increased friction in trade. The combined effect is a lose-lose situation for the UK energy sector: higher costs for consumers and taxpayers, reduced competitiveness for British energy exports, and diminished returns on significant infrastructure investments. This underscores the complex and far-reaching economic consequences of Brexit on Britain's energy landscape.

In recent times, there have been renewed hopes for better harmonization between Britain and the EU in the energy sector. As the realities of Brexit's impact on energy trade become clearer, there is growing recognition of the mutual benefits that closer regulatory alignment could bring. Discussions have emerged around the possibility of Britain moving closer to the EU's regulatory orbit, particularly in areas like energy market integration and renewable energy cooperation. Such alignment could help reduce trade friction, enhance energy security, and support the transition to a low-carbon economy. While political challenges remain, the potential economic and environmental benefits provide a compelling case for exploring pathways to closer cooperation.

There is also a very compelling case for developing a shared offshore grid in the North Sea, connecting the UK with other countries that have major offshore wind installations. Such a grid could optimize the distribution of renewable energy across borders, balancing supply and demand more effectively and reducing the need for backup fossil fuel generation. By pooling resources and infrastructure, participating countries could achieve greater energy security, lower costs, and accelerate the transition to a low-carbon energy system. The North Sea's vast wind resources present a unique opportunity for regional cooperation, and a shared grid could serve as a model for future collaborative energy projects.

## Carbon Market Divergence

Another significant development was the decoupling of the UK from the EU carbon market. Prior to Brexit, the UK was part of the EU Emissions Trading System (EU ETS), which is a cornerstone of the EU's policy to combat climate change by reducing greenhouse gas emissions. The EU ETS works on the 'cap and trade' principle, setting a cap on the total amount of certain greenhouse gases that can be emitted by installations covered by the system. After Brexit, the UK established its own UK Emissions Trading Scheme (UK ETS) in 2021, which is similar in design but operates independently of the EU ETS.

This decoupling has implications for both markets. For the UK, it means having the flexibility to set its own carbon pricing and emissions targets, potentially allowing for more ambitious climate policies. However, it also means losing the benefits of a larger, more liquid market that can provide more stable carbon pricing and greater opportunities for trading. For the EU, the loss of the UK as a participant in the EU ETS reduces the overall size and liquidity of the market, which could impact the effectiveness of the system in driving down emissions across Europe. The decoupling highlights the broader theme of Brexit: the trade-off between regulatory independence and the benefits of integrated markets.

While the UK ETS provides flexibility, it also poses significant risks. One major concern is the potential for a carbon border adjustment mechanism (CBAM) to be imposed by the EU on UK goods. If the UK maintains lower carbon prices than the EU, it could lead to competitive imbalances, where UK industries benefit from lower costs at the expense of higher emissions. To prevent carbon leakage and ensure a level playing field, the EU has proposed a CBAM that would impose tariffs on imports from countries with less stringent carbon pricing. This could affect a wide range of UK exports, increasing costs for British businesses and potentially leading to trade disputes. The risk of a CBAM underscores the challenges of maintaining regulatory independence while ensuring compatibility with major trading partners.

Since Brexit, the UK's carbon prices have consistently been lower than those in the EU. In 2023, UK carbon prices were approximately 28% lower than those in the EU, with the UK price at £35 per tonne of $CO_2$ equivalent. By 2025, UK carbon prices were around £45 per tonne, compared to the EU's €73 (approximately £62) per tonne.

This disparity has significant economic implications. The lower carbon prices have led to revenue shortfalls, with the UK raising over £1 billion less over a six-month period in 2023 compared to 2022 levels. If this trend continues, the Treasury could lose up to £3 billion annually. Additionally, the EU's CBAM, set to be fully implemented in 2026, could impose up to £800 million in additional costs on UK exporters by 2030.

To address these challenges, there have been discussions about linking the UK ETS with the EU ETS. Such a linkage could harmonize carbon prices, prevent competitive distortions, and reduce costs for both UK and EU consumers. In May 2025, the UK and EU agreed to work towards linking their respective Emissions Trading Systems.

For British exporters, facing a CBAM on exports to the EU in addition to higher energy costs than many EU countries would be an extra trade barrier they would prefer to avoid. The combination of these factors could make UK goods less competitive in European markets, potentially leading to reduced market share and profitability for British businesses. This highlights the importance of addressing carbon pricing disparities and energy cost challenges to maintain the competitiveness of UK exports in the EU.

## Carbon Price Impacts on Electricity Costs

Carbon prices play a crucial role in determining the cost of gas-fired electricity generation. In both Britain and Belgium/Netherlands/Ireland, gas power stations can be identical in almost every respect—similar efficiencies, fuel costs, and technologies—except for the carbon price. This single difference can have a profound impact on the competitiveness of electricity generation. A lower carbon price in the UK can make its gas-fired electricity cheaper to produce, giving it a competitive edge in the market. Conversely, a higher carbon price in the EU can make electricity from similar stations more expensive, affecting where power is generated and traded. This highlights the critical role of carbon pricing in shaping energy markets and influencing cross-border electricity flows.

An artificially low carbon price in the UK can lead to unintended consequences. By making gas-fired electricity generation cheaper in the UK, it can shift emissions from gas power stations to

Britain, as power generation becomes more economically attractive domestically. However, when this electricity is exported to the continent, it incurs higher transmission losses, reducing overall efficiency. This not only undermines the environmental benefits of lower carbon pricing but also highlights the complexity of balancing economic and environmental objectives in cross-border energy trade. It can also drive up the cost of electricity relative to gas within the UK, which hinders the incentive for decarbonisation.

## Solutions and Pathways Forward

To address the challenges outlined in this chapter, closer harmonization with the EU on carbon prices and electricity trading presents a clear and viable solution. Even without a comprehensive re-entry into the EU single market, aligning the UK's carbon pricing with the EU ETS could mitigate the risk of the Eu's CBAM and enhance the competitiveness of UK exports. Harmonizing carbon prices would also help stabilize the market, reduce revenue shortfalls, and prevent competitive imbalances.

In terms of electricity trading, re-establishing closer ties with the EU's energy market mechanisms could reduce trade friction, improve efficiency, and lower costs for consumers. This could involve negotiating agreements that allow for more seamless cross-border electricity flows and participation in EU market coupling initiatives. Such steps would not only enhance energy security but also support the transition to a low-carbon economy by facilitating the integration of renewable energy sources.

Ultimately, these solutions highlight the importance of strategic cooperation and alignment with the EU to address the economic and environmental challenges posed by Brexit. By pursuing closer harmonization, the UK can leverage the benefits of integrated markets while maintaining its regulatory independence.

Recent developments have shown positive signs in this direction, suggesting that there is room for optimism. Both the UK and the EU have expressed interest in exploring pathways for closer cooperation on energy issues. Discussions about linking the UK ETS with the EU ETS and re-establishing energy market connections indicate a willingness to find common ground. These positive noises suggest that, despite the challenges of the past few years, there is potential for a more collaborative and integrated approach to energy policy moving forward. By building on these positive developments, the UK and the EU can work together to address shared challenges and seize opportunities for mutual benefit.

# Chapter 18: Interest Rates

I learnt early in my career that the single most important figure in short term electricity markets is the gas price. In long-term electricity markets, the equivalent metric is the interest rate.

Starting my career in 2011 and despite having studied economics I have to admit that I didn't realise until really quite recently how profound the effect of near zero interest rates was over the 2010 decade. And while many people have learnt the hard way how it's unravelling the rise in interest rates post 2021 has changed the world of property, business and vehicle finance, It couldn't have happened at a more prescient and disruptive time for the Energy transition.

In Economics, you learn that the interest rate is the connection or the price between now and the future. High interest rates mean that investors require a greater return on the capital in order to be better off than simply putting the money in a bank account or low risk investment like government bonds. All things equal, higher interest rates make it more attractive to put off any sort of capital or upfront investment like insulating a building, replacing a vehicle, installing a battery.

## Fossil versus Low Carbon

The biggest Divide between fossil fuels and the appliances we used them in and low carbon technologies brackets including renewables is the amount of extra upfront investment you need if you want to pursue the low carbon option. This paradigm holds true in all different levels and sectors of the energy system:

### Gas Power versus Nuclear/Wind

The upfront cost of a state-of-the-art CCGT power station is around £800-£1,200 per kW. The equivalent figure for a nuclear plant like Hinkley Point is £6,000-£8,000 per kW. For an offshore wind farm it's around £3,000-£4,000 per kW. However, when it comes to the running costs or marginal costs of these technologies, the pattern reverses. Wind farms don't require fuel. Nuclear fuel is usually under £10 per megawatt hour of power generated. Gas power even at today's relatively low prices costs upwards of £60-£80 per megawatt hour, given CCGTs are at best 55% efficient and power stations face carbon taxes as well.

### Energy Networks

Separate from the cost of generating electricity, there are profound differences in the cost of the network and infrastructure needed to support a renewables oriented grid. Wind and Solar are less dense in terms of their footprint on the ground than traditional large scale power stations. They also tend to be much further from natural centres of demand in big cities, partly because land prices are higher around cities and partly because the windiest places tend to be quite remote isolated and either high up offshore or coastal. An access factor in the UK is the role of NIMBYs in deterring many renewable projects from less isolated parts of England.

Either way, renewables end up needing more miles of electricity cables, pylons and substations to run the grid than would be needed from traditional fossil fuels. And the cost of building this infrastructure is very capital intensive. According to analysis from the Energy Bills website, the contribution of energy network costs in household energy bills has increased from around 20% in 2015 to 25% in 2025, making it one of the biggest drivers in energy bill increases. This represents a significant shift from operational costs (fuel) to capital costs (infrastructure).

### Gas Boiler versus Heat Pump

The gas boiler is cheap to manufacture and easy to install, particularly for replacement jobs. For a typical home, a replacement gas boiler might cost £2,500 and in a typical year might result in a gas bill of £1,250. Retrofitting a heat pump might cost upwards of £12,000 without government grants and might result in annual electricity costs of £750, or potentially lower if the house also has a battery and/or solar PV installed.

### ICE versus EVs

The most expensive component in an EV is the battery, costing upwards of £8,000-£12,000 toward the typical cost of a family-sized car. In a traditional petrol car, the equivalent is a simple fuel tank which costs around £200-£400 and holds 10 times as much energy. The cost of driving a mile in a typical petrol car - let's say a 1.5 litre VW Golf achieving 45mpg with petrol at £1.50 per litre - is around 15 pence per mile. For an identical size EV, the cost of driving that mile on cheap overnight electricity taken from the grid (at around 8p/kWh) would be more like 2 pence per mile.

## Compounding - the effect on gearing

The effect of higher interest rates has another knock-on effect through the impact it has on the balance sheet of utilities and other investments in the energy sector. Debt is cheaper than equity, or shareholder money, and borrowing money from a bank enables energy investments to be done at a lower cost. However, the banks or other lenders that provide such finance have limits in terms of how much they think it is safe and reasonable to lend. And when interest rates are higher, the cost of servicing debts is also higher, meaning that a project cannot sensibly borrow as much without running the risk of running out of money and not being able to reliably service debts. This creates a knock-on effect where projects have to stump up more shareholder or equity money, which being more expensive further drives up the cost of capital on investments in the energy sector and results in higher costs to consumers or less investment taking place. You can see this dynamic playing out very clearly in the annual CFD auctions for offshore wind, which have increased from £73 per MWh in 2022 to around £103 per MWh in 2024.

## Compounding - when the cause is supply side inflation

Inflation can have different causes. In 2022, the shock was largely one that started in energy and commodities. At the same time, the hangover effects of Covid furlough schemes meant a simultaneous shock took place in labour markets. For renewable projects that are capital intensive and require large amounts of both specialist labour and materials that require lots of energy such as steel and concrete, there was a perfect storm for cost inflation.

This meant that renewable projects have had to deal with cost increases from two simultaneous drivers: the cost of engineering and the cost of financing that engineering over the lifetime of the project.

## It's the real interest rate that actually matters

One common misunderstanding with interest rates is to ignore the impact of inflation. If interest rates are 6% (called nominal rates), but inflation is running at 5%, then in real-terms, interest rates are only 1%. Viewed through this lens, real interest rates across the 2010-21 period were not just low, but for much of the period negative, particularly following the monetary and quantitative interventions following the financial crash, eurozone crisis, Brexit vote and pandemic.

This perspective shines a different perspective on the consequential 2021-2 period, when the reopening post-pandemic hit a massive inflationary shock. In the UK, interest rates set by the Bank of England didn't peak until August 2023 at 5.25%, by which point inflation was 6.7%. Even if 5.25% sounded like a high interest rate in nominal terms by the standards of the last few decades, it was actually -1.45% in real terms.

Since 2022, inflation has gradually slowed from its peak of over 11% in 2022, but remained stubbornly above the traditional 2% target, averaging around 4-5% through 2023-24. Despite this slowdown, the Bank of England has been extremely cautious about cutting interest rates, with only modest cuts by early 2025, leaving rates at 5.25%. This means that real interest rates have been positive and significant (around 1-2%) for over two years now - a dramatic shift from the negative real rates that prevailed for most of the previous decade.

This is particularly damaging for infrastructure investments like offshore wind and nuclear, because the upfront construction costs are financed at nominal interest rates, while the long-term returns are inflation-indexed. When real rates are high, this mismatch squeezes the economics of big capital projects, making them much harder to finance and build.

## The becalming of Offshore Wind

The current state of the offshore wind industry provides a helpful metaphor for the effects of the last few years. The prolonged period of ultra-low interest rates and rising climate change concerns led to unparalleled investment in offshore wind between 2010 and 2020. There were massive improvements in the supply chain and efficiency of building offshore turbines. The size of turbines increased from around 3 MW to over 15 MW, which increased yields and reduced the number of foundations required.

Even going into the initial energy crisis of 2022, offshore wind maintained momentum. The spike in fossil fuel prices left offshore wind looking incredibly attractive, and some of the cost rises had not fully worked their way through the system yet. Interest rates had not yet peaked in real terms because inflation was high, but the market hadn't realised quite how long interest rates would need to stay at elevated levels in a bid to control the persistent inflation that had crept into the system.

New offshore wind farms bid for long-term, fixed-price contracts to sell their electricity before they start construction; the fixed price they receive is inflation-indexed and guaranteed by bill-payers under the Contract for Difference (CfD) scheme. Arguably, the high watermark for optimism in offshore wind was the CfD AR4 auction in July 2022, when 7 offshore wind farms totalling 7 GW agreed to an equivalent long-term price of £52/MWh (£37.35/MWh in 2012 prices). This price was astonishingly low; at the time, wholesale gas prices were around £200/MWh. There was a widespread optimism that the early investment in offshore wind had paid off, and that Britain was on the verge of a new era of cheap, clean energy.

Since 2022, things have gone into dramatic reverse. A number of offshore wind farms under development have been abandoned, including several that had qualified and won long-term CfD contracts. Getting to this stage is a massive investment in itself, costing £50-100 million and involving a team of 50-100 people including engineers, lawyers, environmental consultants, and project managers over 5-8 years of development work. In 2023, the CfD AR5 auction failed to attract any winning bids from new offshore wind farms - the first time this had ever happened, despite offering a maximum price of £44/MWh in 2012 prices (equivalent to around £62/MWh in 2023 prices, up 19% from the AR4 auction). In 2024, under the new Labour Government, the maximum price offered to offshore wind farms was hiked by another 40% from 2023 (£103/MWh in 2024 prices), and 3 wind farms won contracts. However, one of them, the 1.5 GW Hornsea 3 project, then pulled out only 8 months later, citing cost concerns despite the significantly higher price on offer. Another CfD auction (AR7) is expected in September 2025, however, major developers including Ørsted have indicated they may not participate unless prices increase further, highlighting the ongoing challenges facing the sector. Ørsted's own troubles - including a rights issue to raise €4 billion, political controversy over its US projects, and a share price that has fallen from over €1000 in 2021 to under €200 in 2024 - illustrate the broader financial pressures affecting the offshore wind industry.

## The Case for Low-Hanging Insulation Fruit

In this environment of higher interest rates, there's a compelling argument for focusing on the low-hanging fruit - energy investments that offer lower risk and more stable returns. Rather than pursuing ambitious capital-intensive projects like new offshore wind farms or nuclear plants, policymakers and investors should prioritise technologies and measures that deliver quicker paybacks with less financial risk.

Insulation and energy efficiency improvements represent the most obvious example. While retrofitting homes with proper insulation requires upfront investment, the payback periods are relatively short and the returns are often attractive even in a high interest rate environment. While insulation savings do depend on energy prices (higher prices mean faster paybacks), the relationship is straightforward and predictable - unlike renewable energy projects that depend on volatile electricity markets and complex wholesale pricing mechanisms, energy efficiency measures deliver direct, proportional savings on energy bills. Importantly, insulation is fuel-agnostic: whether a home is currently heated by gas, oil, electricity, or will transition to heat pumps or other renewable technologies in the future, the insulation investment continues to deliver savings. This makes insulation a particularly attractive investment in an uncertain energy transition landscape.

The appeal of insulation goes beyond just financial returns - it's also remarkably simple to understand and explain. Any intelligent homeowner can grasp the basic logic: less heat escaping in winter means less energy needed to maintain comfort, which translates directly into lower energy bills. The variables are straightforward: upfront cost, annual energy savings, and simple arithmetic to calculate payback period. Compare this to the complexity of renewable energy investments, which depend on wholesale electricity markets, grid connection costs, policy support mechanisms, and technological risk. Insulation offers the rare combination of good economics and intuitive appeal.

Perhaps even more importantly, insulation creates a virtuous cycle that unlocks cheaper heat pump installations. A well-insulated home requires a smaller capacity heat pump, which costs significantly less upfront. For example, a poorly insulated Victorian terrace might need a 10kW heat pump costing £10,000-£12,000, while the same house after insulation might only need a 7kW unit costing £7,000-£9,000. The savings are enhanced because smaller heat pumps can operate at lower flow temperatures (45-50°C rather than 55-65°C), which improves their efficiency. Heat pump efficiency (Coefficient of Performance or COP) typically improves from around 2.8-3.2 at high temperatures to 3.5-4.0 at lower temperatures - meaning 15-25% less electricity consumption for the same heating output. This cascading benefit means insulation doesn't just reduce energy demand, it makes the remaining demand cheaper to meet with clean technologies.

Even if a homeowner can't afford a heat pump immediately, or faces planning restrictions or space constraints, insulation investment makes the property "heat pump ready" for the future. When the time comes to replace the gas boiler, the smaller heat pump requirement, existing radiator compatibility (or smaller radiator upgrades needed), and lower flow temperature requirements make the transition much more straightforward and affordable. This future-proofing aspect adds significant value to insulation investments, particularly in an era where heat pump adoption is accelerating but installation costs remain a barrier for many households.

## Insulation Measures: Costs and Paybacks

Based on Energy Saving Trust data and industry analysis, here's how the main insulation measures compare (assuming gas prices of around 6-8p/kWh, typical of 2024 UK energy costs). The scale of opportunity is substantial - with around 28 million homes in the UK, millions could still benefit from these improvements:

**Cavity Wall Insulation:** - **Cost**: £500-£1,500 for blown mineral wool or polystyrene beads (most common retrofit method) - **Annual Savings**: £150-£300 - **Payback Period**: 3-7 years -

**ROI**: 14-33% annually (excellent return) - **Best For**: Homes built after 1930 with unfilled cavities - **Potential Scale**: ~8-10 million homes still have unfilled cavities - **Retrofit Method**: Small holes drilled in mortar joints, insulation blown in using compressed air, holes patched - typically 1-2 day installation with minimal disruption - **Note**: Blown mineral wool is the most popular retrofit approach due to its cost-effectiveness, complete cavity fill, and fire resistance

**Solid Wall Insulation (External):** - **Cost**: £8,000-£15,000 for a typical semi-detached house - **Annual Savings**: £400-£600 - **Payback Period**: 15-25 years - **ROI**: 3-5% annually (moderate return) - **Best For**: Older homes without cavity walls - **Potential Scale**: ~7-8 million homes with solid walls (mostly pre-1930)

**Floor Insulation:** - **Cost**: £300-£1,000 for a typical house - **Annual Savings**: £50-£100 - **Payback Period**: 5-10 years - **ROI**: 10-20% annually (good return) - **Best For**: Homes with suspended floors over unheated spaces - **Potential Scale**: ~15-20 million homes with uninsulated floors

**Double Glazing:** - **Cost**: £300-£800 per window - **Annual Savings**: £100-£200 (for entire house) - **Payback Period**: 15-25 years - **ROI**: 4-7% annually (moderate return) - **Best For**: Homes with single-glazed windows - **Potential Scale**: ~3-5 million homes still have single glazing

**Triple Glazing:** - **Cost**: £600-£1,200 per window - **Annual Savings**: £150-£250 (for entire house) - **Payback Period**: 20-30 years - **ROI**: 3-4% annually (low return) - **Best For**: New builds or major renovations - **Potential Scale**: ~20+ million homes could upgrade from double to triple glazing

# Chapter 19: Shale Gas - A Missed Opportunity

## Introduction

Shale gas is one of those energy topics that gets people really worked up. As someone who cares deeply about climate change, I understand why - the idea of more fossil fuels makes environmentalists nervous. But when shale gas was being debated in Britain, I heard a lot of misleading arguments on both sides. Some claimed it would solve all our energy problems and make gas dirt cheap. Others insisted it would poison our water and cause earthquakes. The reality, as so often happens with energy policy, was somewhere in between.

What's particularly frustrating about Britain's shale gas story is that it never really got a fair hearing. The debate was so polarised that reasonable discussion became impossible. And in the end, we threw away a potential source of domestic energy that could have made us more secure and wealthier, without really understanding what we were giving up.

## Comparing North Sea and Shale Gas Resources

Before we discuss why shale gas mattered, it's worth understanding what Britain had to choose from in terms of domestic energy resources. The choice wasn't just between shale gas and imports - it was between different types of domestic production.

The North Sea has been Britain's energy lifeline for nearly 50 years, but it's rapidly running dry. Since oil and gas production began in the 1970s, the UK sector has produced somewhere in the region of 45 billion barrels of oil equivalent. Production peaked around 2000 at 4.4 million barrels per day, making Britain a significant energy exporter. In the 1990s, the UK was over 100% self-sufficient in oil and gas - we produced more than we consumed and exported the surplus.

That golden age didn't last. Production has declined relentlessly since 2000, falling from 4.4 million barrels per day to around 1 million barrels per day by 2024 - a drop of roughly 77%. Britain became a net energy importer in 2004, and our self-sufficiency has collapsed. For gas specifically, we went from 99% self-sufficiency in 1998 to just 43% by 2017, and it's fallen further since. We now import over half our gas, and that figure is rising every year as North Sea production declines.

Here's the remarkable thing: Britain's gas consumption has actually fallen by about 37% since 2000, driven by improved energy efficiency, warmer winters, and the shift to renewables for electricity generation. We're using much less gas than we did at the turn of the century. Yet despite this massive reduction in demand, we've still become heavily dependent on imports because domestic production fell even faster - collapsing by around 64% over the same period. This is the scale of the North Sea decline: even with consumption falling dramatically, we can't keep up with the loss of domestic supply.

The North Sea's remaining reserves tell an interesting story. As of 2024-25, the UK sector contains approximately 7.5 billion barrels of oil equivalent (BOE) in remaining recoverable reserves. But here's the crucial detail that often gets overlooked: the split between oil and gas matters enormously for Britain's energy transition.

Based on Norwegian North Sea data (which provides the best proxy for UK reserves composition), the remaining offshore reserves are roughly 60% oil and 40% gas. For the UK's 7.5 billion BOE, this translates to approximately: - 4.5 billion barrels of oil - 3.0 billion BOE of gas (equivalent to about 5,300 TWh, or roughly 7 years of current UK gas demand)

But here's the crucial point: those "7 years of gas" won't actually be extracted over 7 years. North Sea gas fields have natural decline rates of around 9% per year, and mature fields are already past their peak production. UK gas production has fallen from about 108 billion cubic metres (bcm) per year in 2000 to roughly 35-39 bcm/year in 2023. Without massive new investment - which the government is actively discouraging by banning new exploration licenses - production will continue declining.

In practice, these reserves will likely be extracted over 15-25 years, with production falling continuously throughout that period. By 2030, North Sea gas production could be down to 25-30 bcm/year. By 2040, it could be 15-20 bcm/year or lower. The reserves don't run out suddenly; they dwindle away over decades as fields deplete and fewer new fields come online to replace them. This means Britain will be importing an ever-increasing share of its gas needs - currently around 50%, but potentially 70-80% or more by the 2030s.

Now compare this to Britain's prospective shale gas reserves. The British Geological Survey's 2013 assessment estimated the Bowland-Hodder formation alone contained gas in place equivalent to about 380,000 TWh, with recoverable reserves potentially ranging from 38,000-76,000 TWh using conservative recovery rates of 10-20%. To put this in perspective, that's equivalent to 50-100 years of Britain's current annual gas consumption of approximately 750 TWh.

Think about what this means: Britain's shale gas potential in the Bowland-Hodder formation alone was roughly 7-14 times larger than the remaining North Sea gas reserves. But here's a crucial caveat: we don't actually know for certain what the full composition of Britain's shale resources would have been. The Bowland formation was assessed primarily for gas potential, but the Weald Basin in the south showed signs of oil-bearing shale (the Kimmeridge Clay formation). Without proper exploration, we never definitively established whether Britain's shale resources were predominantly gas, predominantly oil, or some mix of both.

What we can say is that the most extensively studied formation - Bowland-Hodder - appeared to be gas-rich rather than oil-rich, which from an energy transition perspective would have been more valuable than oil. But this is one of the frustrating aspects of Britain's shale story: we banned it before we really understood what we had.

## Why the oil-gas split matters

For Britain's energy future, gas is fundamentally more valuable than oil - not because gas is inherently better, but because of how we use energy and how electrification changes everything. Understanding this requires looking at both carbon emissions and the transition to electric vehicles.

First, the basic carbon math: natural gas emits approximately 29% less $CO_2$ than oil per unit of energy when burned. For heating oil specifically, gas produces about 202g $CO_2$/kWh compared to oil's 284g $CO_2$/kWh. But the real difference emerges when you consider what we use these fuels for.

We import virtually all our transport fuel anyway (petrol and diesel), so North Sea oil mainly helps our balance of payments but doesn't directly improve our energy security for the things that matter most: heating homes and generating electricity. And here's where the oil-gas split becomes crucial for the transition to clean energy.

Consider electric vehicles. A typical petrol car emits around 350g $CO_2$ per mile over its lifetime (including manufacturing and fuel production). An electric vehicle emits around 200g $CO_2$ per mile over its lifetime - a roughly 43% reduction. But these figures mask something important: the EV's emissions depend entirely on how its electricity is generated.

In the UK, gas-fired power stations provide around 35-40% of our electricity generation. These modern Combined Cycle Gas Turbine (CCGT) plants produce electricity at roughly 350-400g $CO_2$/kWh. The current UK grid average is around 150-180g $CO_2$/kWh when you blend gas with renewables, nuclear, and other sources. An EV charging from this grid uses about 0.2-0.25 kWh per mile, resulting in operational emissions of 30-45g $CO_2$/mile - far lower than a petrol car's 180-200g $CO_2$/mile from fuel combustion alone.

This is why domestic gas matters for the transition to EVs. Even when the electricity comes partly from gas, electrification delivers massive emissions reductions. A petrol car burning oil-based fuel at 40mpg produces direct emissions around 190g $CO_2$/mile. An EV charged from gas-fired electricity (at the worst case 400g $CO_2$/kWh) still only produces about 80-100g $CO_2$/mile - a 50-60% reduction.

The mathematics are similar for heat pumps. A gas boiler at 90% efficiency uses gas at roughly 202g $CO_2$/kWh of heat delivered (224g ÷ 0.9). A heat pump at 350% efficiency uses electricity at 150g $CO_2$/kWh (grid average), delivering heat at just 43g $CO_2$/kWh - a reduction of about 79%. Even if that electricity came entirely from gas generation at 400g $CO_2$/kWh, the heat pump would still deliver heat at 114g $CO_2$/kWh - a 44% improvement over a gas boiler.

This is why gas reserves are more valuable than oil reserves for Britain's energy transition: gas enables electrification that dramatically reduces emissions, while oil locks us into high-carbon transport. Domestic gas provides the flexible, dispatchable power generation that makes renewable electricity viable - keeping the lights on when the wind drops and the sun doesn't shine. This in turn makes EVs, heat pumps, and other electric technologies practical and low-carbon.

Of course, even with a 100% renewable grid, EVs still have embedded carbon from manufacturing - roughly 8-12 tonnes of $CO_2$ for battery production, plus emissions from steel, aluminum, and component manufacturing. But over a vehicle's 150,000-mile lifetime, this manufacturing burden (equivalent to about 50-80g $CO_2$/mile) is far smaller than the 180-200g $CO_2$/mile from burning petrol.

The North Sea's 60% oil, 40% gas split is therefore worse for the energy transition than if it were reversed. We need gas to enable electrification; we're stuck with oil that perpetuates high-carbon transport. Britain's shale resources appeared to be predominantly gas, not oil - making them far more valuable for achieving our climate goals while maintaining energy security.

The North Sea's remaining reserves are declining fast - production has fallen from around 108 billion cubic metres per year in 2000 to about 35 bcm/year in 2023. At current production rates and with new field developments, the remaining 5,300 TWh of North Sea gas might last 15-20 years. But production will continue declining as fields deplete, meaning we'll be importing an ever-larger share of our gas needs.

Shale gas, on the other hand, could have provided 38,000-76,000 TWh of recoverable gas - potentially equivalent to 50-100 years of Britain's current gas consumption, though obviously production would have ramped up gradually and wouldn't have met 100% of demand. More importantly, it appeared to be predominantly gas rather than oil, directly addressing our most critical energy security vulnerability.

## The security of supply problem

Britain's approach to energy security reveals a fundamental misunderstanding of risk. We maintain large strategic reserves of the energy we care less about, while having virtually no storage capacity for the energy we depend on most.

Consider the numbers: Britain holds strategic oil stocks equivalent to 90 days of net imports - a requirement under International Energy Agency and EU agreements. This means that if oil imports were completely cut off tomorrow, we'd have roughly three months of supply to work with. Add in the fuel sitting in vehicle tanks across the country (roughly 1.5-2 billion litres, equivalent to another 6-8 days of consumption), and Britain has a reasonable buffer against oil supply disruptions.

But here's the thing: oil supply disruptions, while inconvenient, wouldn't be catastrophic for most Britons. Petrol prices would spike, driving would become expensive, and we'd face economic disruption. But our homes would stay warm, our lights would stay on, and most people could survive by reducing car journeys, working from home, or using public transport.

Now compare this to our gas storage capacity: approximately 3.2 billion cubic metres, equivalent to just 7.5 days of peak winter demand. During the winter of 2023/24, our entire gas storage capacity provided only 7% of total winter demand. The rest had to come from continuous imports via pipelines from Norway and LNG shipments from Qatar and the United States.

Think about what this means in practice. If Britain lost access to gas imports during a cold snap in January, we'd have about a week before storage ran dry. Within days, 85% of British homes would lose heating. Gas-fired power stations, which provide around 40% of our electricity and the critical backup for when wind and solar aren't producing, would shut down. Hospitals, schools, offices, and factories would go cold. Unlike oil, where there are alternatives and workarounds, there's no quick substitute for gas in heating and power generation.

The disparity becomes even more striking when you compare Britain to other European countries. The EU collectively maintains gas storage equivalent to around 20% of annual demand - meaning countries like Germany, France, and Italy have storage capacity equivalent to 60-90+ days of consumption. Britain has one of the lowest gas storage capacities in Europe, despite being one of the most dependent on gas for heating.

This vulnerability isn't theoretical. Britain's largest gas storage facility, Rough, was closed in 2017, cutting our storage capacity by more than half. It reopened in 2022, but its operator, Centrica, has warned it may close again without government support. If Rough closes permanently, Britain's gas storage would fall to just a few days of peak winter demand.

So Britain's energy security picture looks like this:

- **Oil**: 90 days strategic storage + 6-8 days in vehicle tanks = ~96-98 days total
- **Gas**: 7.5 days storage at peak winter demand (12.9 days average demand)

We have comfortable reserves of oil, which we mainly import for transport anyway and where alternatives exist. But we have barely a week's supply of gas, which heats most homes, provides backup power, and has no realistic short-term alternatives at scale.

This is the context that makes the shale gas ban so baffling. Britain sat on potential gas reserves equivalent to 50-100 years of consumption - resources that could have dramatically improved our energy security - and chose instead to remain dependent on continuous imports with virtually no storage buffer. We prioritised maintaining large reserves of the less critical fuel while accepting extreme vulnerability in the fuel that matters most.

And it's not just about storage capacity. Domestic gas production provides inherent security - you can't have your supply cut off by foreign governments, pipeline sabotage, or shipping disruptions. Even if we'd only developed enough shale gas to meet 20-30% of demand, it would have provided a crucial security buffer during supply crises.

The February 2022 spike in gas prices after Russia's invasion of Ukraine showed exactly how vulnerable Britain is. With minimal storage and heavy import dependence, UK gas prices shot up faster than almost anywhere else in Europe. Households saw energy bills double or triple. The government spent tens of billions subsidising energy costs. All because we had no domestic production cushion and no storage capacity to weather the storm.

## Why shale gas mattered

Britain has been importing more and more gas over the years. We used to produce most of what we needed from the North Sea, but that's been declining since around 2000. These days, about half our gas comes from abroad - mostly from Norway via pipeline, but also from the US and Qatar as liquefied natural gas (LNG).

The irony is painful: we banned shale gas development while sitting on gas reserves potentially 7-14 times larger than what remains in the North Sea. Instead of developing these domestic resources, we're importing American shale gas that's been liquefied, shipped 4,000 miles across the Atlantic, and regasified - adding significant emissions and cost at every step.

When you buy energy from abroad, you're not just spending money - you're also missing out on all the economic benefits that would come from producing it at home. Every pound spent on imported gas is a pound that doesn't create British jobs, doesn't generate British tax revenue, and doesn't build British infrastructure.

Had we developed our shale gas resources, we would have created jobs in the regions where the gas was found. These aren't just drilling jobs either - there's a whole supply chain of engineers, truck drivers, equipment manufacturers, and service companies that would have benefited. The salaries in oil and gas are typically £65,000-75,000 a year, roughly double the national average. That means each worker pays significantly more in taxes than the average British worker.

The tax benefits are even more dramatic. Oil and gas companies pay some of the highest taxes in the economy - around 65-75% of their profits go to the Treasury, compared to 25% for most businesses. For every pound spent on gas produced in Britain, about 21-27p goes back to the government in taxes. For imported LNG, it's more like 5p (just the VAT). With our energy imports running at £25-35 billion a year, that's a lot of potential tax revenue we're missing out on.

## The great price myth

One of the most common arguments for shale gas was that it would make gas much cheaper. "Look at America!" people would say. "Gas is dirt cheap there now!" But this argument missed some crucial differences between Britain and the US.

The US shale boom happened because America had massive reserves of shale gas that were globally significant. When the US started producing shale gas in huge quantities, it changed the global gas market. Britain, by contrast, has much smaller shale gas reserves. Even if we'd produced every drop of our technically recoverable shale gas, it wouldn't have moved global gas prices one bit.

More importantly, Britain is part of a global gas market. If we'd produced shale gas here, it would have been sold at the same price as gas from Norway, Qatar, or anywhere else. The companies producing it would have wanted to maximise their profits, not give us a discount. The only way to force them to sell it cheaper would have been to create some kind of special British gas market, which would have been incompatible with our trading arrangements and probably illegal under various international agreements.

So shale gas wouldn't have made gas cheaper in Britain. But it would have meant that more of the money we spend on gas stayed in Britain rather than going abroad.

## The environmental case

Here's where things get interesting. Despite what many environmentalists assumed, shale gas might actually have been better for the environment than the alternatives we're using today.

Most of our imported gas comes as LNG from the US and Qatar. Getting gas from the ground in the US, turning it into a liquid, shipping it across the ocean, and turning it back into gas creates a lot of emissions. The total lifecycle emissions for US shale LNG are around 295-310 grams of $CO_2$ per kWh. Even Qatari LNG, which is slightly cleaner, comes in at 285-302 grams.

British shale gas, by contrast, would have eliminated all those transport emissions. The total lifecycle emissions would likely have been around 251-268 grams of $CO_2$ per kWh - a 15-20% reduction compared to imported LNG.

This is the kind of environmental analysis that rarely gets discussed in the heat of the shale gas debate. But it's crucial: if your goal is to reduce emissions, then replacing high-carbon imports with lower-carbon domestic production makes sense.

NOTE: what about other environmental concerns: water consumption, pollution etc?

The environmental benefits of gas go beyond just direct emissions comparisons. Natural gas is fundamentally a transition fuel - much cleaner than oil or coal, but still a fossil fuel that we'll eventually need to phase out. However, this transition role is crucial for enabling the clean energy technologies that will replace it. With gas fired power providing about one-third of the current total on the grid, heat pumps (at 350% efficiency) reduce the use of emissions and gas by about 90% compared to a condensing gas boiler that's 90% efficient. An EV that travels 5km per kWh reduces total emissions by about 90% compared to a petrol car achieving 40mpg. In both cases, electrification also shifts emissions away from homes and people to power stations, where we might one day be able to capture and store them.

This is why my support for shale gas is quite different from support for shale oil. While gas and oil deposits often occur together, finds that are skewed towards gas rather than oil are potentially much more interesting from an environmental and economic perspective. Gas can play this crucial transition role in enabling cleaner electricity and heating.

Britain's shale gas potential was particularly interesting because the geological formations suggested gas-rich rather than oil-rich deposits. This meant we could have developed a domestic energy source that would have supported the transition to cleaner technologies, rather than simply extending our dependence on high-carbon transport fuels.

## Why Britain said no

So if shale gas wouldn't have made gas cheaper but would have created jobs, generated tax revenue, and actually reduced emissions, why did Britain reject it?

The answer is politics, pure and simple. The largest shale gas reserves in Britain were found in politically inconvenient places. The Bowland-Hodder formation stretches from Lancashire through Yorkshire to Staffordshire. The Weald Basin covers parts of Surrey, Sussex, Hampshire, and Kent.

Lancashire alone contained four marginal constituencies where the Conservative majority was less than 1.5% in the 2019 election. These weren't constituencies where the government could afford to lose votes. Meanwhile, the Weald Basin covers affluent Surrey constituencies like Surrey Heath and Woking, which are home to wealthy donors and politically connected individuals who can make their feelings known in ways that matter to politicians.

The opposition took different forms in different places. In Lancashire, there was genuine grassroots concern about the environmental impact. In Surrey, there was more organised, well-funded opposition from affluent residents who didn't want drilling anywhere near their expensive homes.

Had the shale reserves been located in different parts of the country - perhaps in rural areas with fewer marginal seats - the politics might have been very different. But they weren't, and so the government chose to protect the electoral interests of a few key constituencies over the economic interests of the country as a whole.

This is a classic example of how energy policy gets made in Britain. What should be a decision based on energy security, economics, and environmental impact becomes a calculation about electoral maths and political pressure.

## What we lost

The economic impact of Britain's shale gas ban is hard to quantify precisely, but it's substantial. We lost the chance to create thousands of jobs in regions that could really use them. We lost billions in potential tax revenue. We became more dependent on foreign gas suppliers, which means we're more vulnerable to global energy price shocks.

More importantly, we lost the chance to build up domestic energy expertise and infrastructure. The skills and equipment needed for shale gas development could have formed the foundation for other energy industries. The gas processing and distribution networks could have supported other energy technologies.

We also lost credibility as a place to invest in energy projects. If Britain can't develop its own energy resources because of political opposition, why should companies invest in other energy projects here? This kind of policy uncertainty makes it harder to attract the investment we need for wind, solar, and other energy technologies.

## The bigger lesson

Britain's shale gas experience reveals something important about how we make energy policy decisions. Too often, we let short-term political considerations override long-term national interests. We let local opposition from vocal minorities prevent developments that would benefit the country as a whole.

This isn't to say that local concerns don't matter. They do. But there needs to be a better way to balance local interests with national needs. Perhaps we need better ways to compensate communities that host energy infrastructure. Perhaps we need better processes for weighing environmental risks against economic benefits.

As Britain faces similar challenges with nuclear power, offshore wind, transmission lines, and other energy infrastructure, the lessons from shale gas become even more relevant. We can't afford to let every energy project get bogged down in local politics. We need to find ways to make energy policy decisions that serve the national interest while respecting local concerns.

The shale gas story also shows how important it is to base energy policy on evidence rather than emotion. The environmental case against shale gas was often based on fears rather than facts. The economic case was often oversold by its supporters. We need better, more honest discussions about the real costs and benefits of different energy options.

Britain's energy future depends on making better decisions about how to balance environmental protection, economic development, and energy security. If we can't get this basic calculation right for shale gas, how are we going to make the much more complex decisions about nuclear power, renewable energy, and carbon capture that lie ahead?

The shale gas opportunity is gone. But the need for better energy policy decision-making remains. Let's hope we learn the right lessons from this missed opportunity.

# Chapter 20: Power Versus Other Sectors - Energy’s Place in the Economy

## Power Generation versus other emissions

This book is focused largely on energy and specifically electricity. Electricity is expected to be the dominant energy of the future, and is expected to supplant the use of fossil and biomass fuels in most use cases of the 21st century economy. So considering our evolving generation mix is particularly important both and into the future, as the volume of electricity we consume is expected to grow.

That said, in the context of the wider challenge to decarbonise and stop climate change, it’s important to see the wider context of how progress in power generation compares to uses of energy.

Countries sign up to climate targets in a number of areas:

**Emissions targets** There are targets on overall country emissions, such as those agreed at the UN sponsored Conference of Parties (or CoP talks), including the Paris, Copenhagen and Kyoto agreements. These targets are typically in reference to a base emission year (typically 1990), with different consideration for developing countries including rapidly growing China, India etc.

Carbon emissions trading schemes like the EU (and now UK) fit within these targets. They can cover a broad range of sectoral emissions, including aviation, heavy industry and although not yet typically included, potentially agriculture in the future.

As such, these schemes allow for tradeoffs in emission reductions to occur between sectors like power generation and agriculture, rather than being specific or imposing constraints on a specific sector to play a minimum role. Economists like this arrangement because it allows for flexibility and market forces to guide where investment gets the most efficient payback with respect to the emissions avoided. So, if emissions reductions are much cheaper and easier in let’s say power generation compared to aviation (which still relies almost 100% on aviation kerosene as a fuel), then this allows for the aviation sector to buy carbon permits off the power generation sector, which can use these to build more wind and solar farms.

**Renewable Electricity Targets** In addition to broader carbon targets, there have been specific renewable electricity targets imposed either at state/provincial level (e.g. California), national (e.g. UK) or international (e.g. EU) level. These target only the power generation sector, and can exclude the contribution of older renewables like hydro and low carbon (but not technically renewable) nuclear power.

The EU renewable electricity obligations are particularly strict and binding because they are binding individually on each member state and don't allow trading of obligations between each other. So a member state like France, which has >x% of (TODO: number and source) power generation from nuclear power, is nonetheless obliged to achieve over x% of generation from new renewable technologies like wind and solar. While some wind and solar projects are merited in France, the French grid is relatively saturated by its nuclear generation, and in many instances in summer, the French grid operator is effectively curtailing (or turning down) nuclear generation purely to accommodate solar PV (and wind) generation on the grid, which are needed in sufficient quantities across the year to meet France's EU renewables target of x% from renewables by the year x (TODO: number and source). In actual fact, this whole exercise is rather pointless, because the emissions from solar and wind are similar to those from the French nuclear plant, especially at the margin when the nuclear plant might well be turned on anyway.

The short answer is that, while it's safe, turning down nuclear generation for France is pretty pointless, in most cases the only way to do it involves blowing large amounts of steam into the atmosphere to dissipate the heat generated by the reactor. France might just as well curtail its solar generation, but for the obligation the EU imposes on it to generate a certain fraction of its electricity specifically from renewable generation. There is almost no additional marginal emissions of carbon from the nuclear generation.

Another inefficiency of national targets is the inability of EU member states to outsource renewable generation to other countries. For example, there is x GW of solar PV capacity in Germany, but only x GW in Spain and x GW in Italy (TODO: number and source). This is despite both Spain and Italy being significantly sunnier than Germany. Had Germany found a way to invest in solar PV generation across Spain, it could have invested in assets that yielded x kWh of carbon free electricity a year, compared to a maximum of about x kWh per year in Southern Germany. EU emissions as a whole could have been reduced at lesser overall cost or expense to EU households and businesses. However, national priorities continue to take precedence over broader EU objectives.

## UK Emission Targets

The UK is actually doing quite well on each of the shorter term emission targets it has signed up to:

**Kyoto Protocol** - The 1997 international treaty where developed countries committed to reducing greenhouse gas emissions. The UK exceeded its Kyoto target of 12.5% reduction below 1990 levels by 2012, achieving a 23% reduction. **Status: Exceeded target.**

**EU 2020 Targets** - While the UK has left the EU, it was previously bound by the EU's 2020 climate and energy package, which included a 20% reduction in greenhouse gas emissions, 20% renewable energy share, and 20% improvement in energy efficiency compared to 1990 levels. **Status: Net emissions target (43% reduction), exceeded renewable target (42% share), exceeded efficiency target (24-26% improvement).**

**Paris Agreement** - The international climate accord signed in 2015, where the UK committed to limiting global temperature rise to well below 2°C above pre-industrial levels, with efforts to limit it to 1.5°C. The UK's Nationally Determined Contribution (NDC) pledges a 68% reduction in emissions by 2030 compared to 1990 levels. **Status: On track for 2030 target, with approximately 53-55% reduction achieved by 2024 (provisional).**

**Clean Power 2030** - The UK government's commitment to decarbonise the electricity system by 2030, ensuring 95% of electricity comes from low-carbon sources. This includes phasing out unabated gas-fired power generation and expanding renewable energy capacity. The target under the Conservative administration had been set to 2035; on coming into office Labour accelerated this to 2030. **Status: Target date 2030, current progress shows approximately 58-60% low-carbon electricity in 2024.**

**Gas Boiler Phaseout** - The UK government has set different targets for new builds and existing homes. **New builds** will be banned from installing gas boilers from 2025, while **existing homes** will face a complete ban on new gas boiler sales from 2035. This phased approach recognises the greater difficulty of retrofitting existing properties compared to building new homes with low-carbon heating systems from the start.

**Petrol/Diesel Vehicle Phaseout** - The UK has committed to ending the sale of new petrol and diesel cars and vans by 2030, with hybrid vehicles allowed until 2035. This target was originally set by the Conservative government in 2020 and has been maintained by Labour, aiming to accelerate the transition to electric vehicles.

**Net-Zero 2050** - This is by far the biggest, most ambitious and most long-term target, encompassing all the others as intermediate stepping stones. The legally binding target under the Climate Change Act 2008 (amended 2019) requires achieving net-zero greenhouse gas emissions across the entire UK economy by 2050. This covers all sectors including power, transport, buildings, industry, and agriculture. The intermediate targets we've already hit and in some cases exceeded significantly are in effect the low-hanging fruit. Much of what remains are the hardest sectors to decarbonise: transport, buildings, and heavy industry, where emissions are deeply embedded in infrastructure, consumer behavior, and fundamental production processes. **Status: Long-term target, progress being monitored by the independent Climate Change Committee.**

When you dig into the composition of existing progress on the intermediate targets, there's considerable variation between sectors:

**Power Generation** - Has seen the most radical decline in emissions, falling by 73% since 1990 due to coal phase-out and renewable expansion. As recently as 2012 it was still at a staggering 40% of power generation. Coal power produces about 800g/KWh of $CO_2$, making it about the worst way from a climate perspective of generating power; gas generation in contrast produces around 400g/KWh of $CO_2$. Coal was effectively eliminated from regular generation in 2024. Today's generation mix shows wind and gas as joint first/second (each around 30-35%), followed by nuclear (15%), imports (10-15%), and solar (5-10%). Power consumption in 2024 was also around 15% lower than 1990, reflecting energy efficiency improvements like LED lighting and general appliances.

**Transport** - Has seen the least progress on emissions reduction, with only a 3% decline since 1990. Electrification remains minimal: electric vehicles accounted for just 2% of the UK car fleet in 2024, and electric trucks and buses are virtually non-existent. This is despite significant efficiency improvements in internal combustion engines - modern petrol, diesel and aviation engines are 20-30% more efficient than their 1990s counterparts. However, these efficiency gains have been largely offset by continued growth in transport volumes - passenger car traffic increased by 25% between 1990 and 2019, while flight passenger numbers more than doubled. The sector's emissions have been stubbornly resistant to policy interventions, with road transport still responsible for around 90% of transport emissions and aviation for most of the rest.

**Buildings** - Have seen moderate progress with emissions falling by around 25% since 1990, though this masks significant variation between domestic and commercial properties. Domestic buildings have achieved the most improvement through better insulation, more efficient boilers, and the gradual phase-out of coal and oil heating. However, progress has been uneven - while new builds are well insulated, the UK's ageing housing stock remains a major challenge. Around 85-90% of homes are heated with natural gas, with gas boilers remaining the dominant heating system and heat pumps accounting for less than 1% of domestic heating systems despite generous government subsidies. Commercial buildings have in some ways fared better, with many already using air conditioning (HVAC) systems for heating and cooling which have automatically benefited from the improvements in power generation. However, many older commercial buildings remain poorly insulated by international standards, and the prevalence of renting creates little incentive for landlords to invest in energy efficiency upgrades. The policy inconsistency is striking - domestic buildings face no carbon pricing on their gas consumption, while large commercial buildings are subject to the Climate Change Levy, creating a perverse incentive to keep gas boilers in homes while commercial properties face pressure to electrify.

**Industry** - Has seen significant progress with emissions falling by around 45% since 1990, though this masks dramatic variation between sectors and the reality of offshoring. Heavy industry like steel, cement and chemicals has achieved improvement through process efficiency gains, fuel switching from coal to gas, and the closure of some of the most carbon-intensive facilities. However, much of this apparent progress reflects the offshoring of carbon-intensive production to countries with lower environmental standards - Britain's steel, cement and chemical production has declined significantly since 1990, while imports from high-emission countries have increased. The sector's emissions have been more responsive to policy interventions than transport or buildings, but this is partly because carbon pricing and efficiency standards made it cheaper to import than produce domestically. The high cost of deep decarbonisation technologies like hydrogen and carbon capture remains a significant barrier, while offshoring continues to shift emissions rather than eliminate them.

**Agriculture** - Has seen modest progress with emissions falling by around 15% since 1990, though this masks significant changes in both production methods and consumption patterns. The sector has achieved improvements through better fertiliser management, reduced methane emissions from livestock, and some efficiency gains in crop production. However, progress has been uneven - while some farmers have adopted more sustainable practices, others continue with intensive methods that maximise yields at the expense of environmental impact. The most significant change has been in dietary habits, with per capita meat consumption declining by around 15% since 1990, particularly red meat, which has the highest carbon footprint. However, this reduction has been partially offset by population growth and increased consumption of dairy products. Much of the apparent progress reflects the offshoring of food production to countries with lower environmental standards, with UK food self-sufficiency declining from around 75% in 1990 to under 60% today. The sector's emissions have been relatively resistant to policy interventions, with the post-Brexit Environmental Land Management scheme replacing the EU's Common Agricultural Policy but still struggling to balance food production with environmental goals. The continued tax breaks on red diesel for agricultural machinery actively encourage high-emission practices, while the high cost of transitioning to regenerative farming practices and the lack of carbon pricing on agricultural emissions remain significant barriers to faster decarbonisation.

**Waste** - Has seen significant progress with emissions falling by around 60% since 1990, though this masks important distinctions between different types of emissions and broader environmental benefits. The sector has achieved dramatic reductions in methane emissions from landfill through improved gas capture systems and the gradual phase-out of organic waste disposal. Methane is the same chemical molecule as natural gas; when released unburnt into the atmosphere it is a different greenhouse gas to CO2, but with 25 times more global warming potential over a 100-year period. However, progress outside methane has been more mixed. The UK's recycling rates have improved from around 5% in 1990 to over 45% today, reducing the need for virgin materials and their associated emissions. However, much of this apparent progress reflects the offshoring of waste processing to countries with lower environmental standards, particularly for plastics and electronics. The sector's emissions have been more responsive to policy interventions than transport or buildings, with landfill taxes and recycling targets driving meaningful change. However, the high cost of advanced waste treatment technologies and the continued export of difficult-to-recycle materials remain significant barriers to achieving truly sustainable waste management.

## Decarbonisation of power generation is broader

The stark variation in progress between sectors reveals a fundamental challenge for the UK's net-zero ambitions. While some sectors like power generation have achieved dramatic emissions reductions, others like transport and buildings remain stubbornly resistant to policy interventions. This uneven progress suggests that the UK has exhausted most of the "low-hanging fruit" - the relatively easy emissions reductions from fuel switching, efficiency improvements, and technological upgrades.

In the contemporary narrative, there is a perception that the power generation sector in Britain in particular has failed to decarbonise at an affordable cost. While there are many mistakes documented in this book which explain how the decarbonisation of power generation has undertaken could have been cheaper, we need to acknowledge:

1. Power generation started in a relatively poor position. Unlike countries with significant hydro (Nordics) and nuclear (France) generation, Britain was highly dependent on coal generation. As a result, it has gone through two transitions over 30 years:
    - First, moving from coal to gas (1990s-2000s)
    - Second, moving from gas toward wind, solar and greater imports (2010s-2020s)

2. The investments in power generation e.g. synergising new technologies like wind and solar, are foundations upon which much of the upcoming decarbonisation of buildings, transport, industry will be built. The challenge for the power generation sector is also much broader given the dependency on electrification of decarbonisation to other sectors like transport, buildings and industry. UK electricity demand could double, from about 300TWh/year to 600 TWh/year by 2050.
3. If buildings, transport and industry had decarbonised faster over the last 30 years, the power sector would have struggled to meet the increased electricity demand with clean generation. The explosive growth of data centres and AI computing is creating unprecedented electricity demand that was never anticipated in early decarbonisation plans, potentially derailing progress on power sector emissions. UK data centres already consume around 15 TWh annually - equivalent to 5% of total electricity demand - and this could triple by 2030 as AI applications scale up, adding another 30 TWh of demand that wasn't factored into net-zero planning.
4. The shift toward gas for power generation coincided with the decline of domestic reserves in the North Sea and closure of UK coal pits. Even with Clean Power 2030, unless there is a rapid acceleration of Building decarbonisation in particular, we will remain very exposed to LNG imports especially in the winter months. That said, given that coal supplies were frequently disrupted by industrial action in the 1970s/80s, this instability isn't that novel to the UK.

# Perfection versus pragmatism

## Going coal free

Considerable media attention was given as, one-by-one over the last 15 years, coal plants were decommissioned across Britain. These moments were significant for the workforce and local communities, marking the end of decades of industrial heritage.

### Non-Carbon Emissions

In some instances, coal plants were retired earlier than expected primarily due to local air pollution concerns rather than climate change. Cockenzie near Edinburgh closed in 2013 after failing LCPD compliance on sulphur dioxide and nitrogen oxide emissions, while Kingsnorth in Kent (30 miles from London) was mothballed in 2012 rather than invest in expensive emissions control equipment. The health impacts of coal pollution are severe and well-documented. A 2016 EU study found coal plants in Britain contributed to around 1,600 premature deaths annually, with communities within 30 miles of power stations showing significantly higher rates of respiratory diseases, heart conditions, and certain cancers.

### Carbon Free Hours

Similarly, in the energy sphere, there was for much of the last 5-10 years a fixation on the number of coal-free running hours on the national grid. As coal plants retired, these periods extended dramatically, so that by the time the last few coal plants remained at Radcliffe on Soar and West Burton, coal generation was only used during the coldest weeks of winter when demand peaked and renewable generation was low. At various points, these coal power plants in their final were also operated under emergency reserve contracts by National Grid rather than selling their output on the open market.

## Lost Opportunity - given our lack of gas storage

More generally, what matters is the total volume of carbon emissions from all generation sources combined. While there's something discrete and tangible about whether coal power stations remain on the grid, the broader question is whether Britain has truly moved beyond fossil fuel dependency.

In the coming 5-10 years, legitimate concerns exist about the power grid's capacity to meet peak energy demands, particularly as heat pump adoption accelerates. While these risks are often amplified by climate sceptics seeking to discredit renewable technologies, dismissing them entirely would be unwise. The reality lies somewhere between alarmist rhetoric and complacent optimism.

One of the UK's biggest energy weaknesses is its lack of gas storage. The UK has only around 1.5 TWh of gas storage, enough for about 4-5 days of supply. Given the proximity of the North Sea, gas storage was never seen as a priority. In countries with longer traditions of importing gas, such as Germany, there is around 24 TWh of gas storage, which can meet 80-90 days of peak winter demand.

This vulnerability is compounded by a fundamental characteristic of British winter weather: air temperature is negatively correlated with wind speed. British winters typically oscillate between two weather modes: low-pressure systems bringing mild, wet, windy conditions from the Atlantic, or high-pressure systems bringing cold, dry weather from the east. The former is excellent for wind generation and reduces electric heating demand, especially with heat pumps that are 250% efficient at 10°C but only 200% efficient at 0°C. The latter is poor for wind generation (though cold air is denser and can improve wind turbine performance slightly) and dramatically increases electric heating demand.

This creates a fundamentally different energy system dynamic. Traditionally, gas demand for heating was roughly linear with outdoor temperature - gas boilers consumed proportionally more fuel as temperatures dropped. But in a decarbonised heating system, the relationship becomes exponential. When temperatures fall below freezing, heat pump efficiency plummets while demand soars, requiring massive amounts of electricity generation. Since this electricity must come from gas-fired backup plants during Dunkelflaute events, the gas demand curve becomes much steeper and more volatile than the old linear relationship.

The result is a perfect storm: the weather conditions that maximise heating demand (cold, still) simultaneously minimise renewable generation (no wind), while the conditions that maximise renewable generation (mild, windy) minimise heating demand.

Even as UK gas consumption declines with home decarbonisation, switching between these weather modes could create significant swings in gas demand for power generation. While the absolute volatility of gas demand will certainly fall as fewer homes use gas directly for heating, in relative terms it could actually increase. With a smaller overall gas market, the same absolute demand swing represents a larger percentage change, making the system more sensitive to weather variations and supply disruptions. This volatility exposes the fundamental weakness of relying on gas as the primary backup for renewables.

Given this challenge, it could have made sense to maintain some coal power stations as strategic reserves. Unlike gas power plants, coal can be stored in dense form adjacent to power stations without the massive investment required for underground gas storage infrastructure. A week or two's supply of coal would have been sufficient to manage many 1-in-5 or 1-in-10 year cold snaps, or to handle unexpected disruptions like sabotage of undersea cables or LNG terminals. Such strategic reserves would have provided a crucial buffer against the volatility of the decarbonised energy system while requiring minimal ongoing investment.

The human cost of energy system failures during extreme weather events should be weighed against the environmental damage from short-term coal generation. Prolonged blackouts in winter, particularly for vulnerable populations, could result in significant health consequences and economic disruption. Decarbonisation policy needs to balance these competing concerns.

The economics of maintaining such reserves are not trivial - the UK already spends £21 per household annually on the Capacity Market to keep backup power plants available. However, the cost of maintaining mothballed coal plants as strategic reserves would likely be significantly lower than building new gas storage infrastructure, particularly when accounting for the value of energy security during extreme events.

## Hybrid compromises

Until power grids are 100% renewable, all heat pumps and electric vehicles connected to the grid will effectively run on a mixture of fossil fuel-generated power and renewables. The exact split depends on when they're used and what weather conditions prevail at that moment. A heat pump running on a cold, still winter evening might be powered 80% by gas and 20% by renewables, while the same heat pump on a windy spring afternoon might run 90% on renewables.

On average for a heat pump, a recent study by academics working for Octopus Energy estimated the current reduction in gas usage being around 90%. That figure accorded with rough hypothetical calculations I did on my own home (about 85%); and the saving figure will trend up to reach 100% as the rest of the grid decarbonises. For the UK's energy security as a net importer of gas this is a big improvement; and heating buildings accounts for around 40% of our current use of natural gas.

The principal deterrent to heat pump installation is often the upfront capital cost, particularly in older buildings with poor insulation or limited space for the larger radiators and hot water cylinders that heat pumps require. Heat pumps work most efficiently at lower flow temperatures (typically 35-45°C) compared to gas boilers (60-80°C), which means they need significantly more radiator surface area to deliver the same heat output. This usually requires either upgrading to larger radiators or installing underfloor heating systems, which provide even greater surface area but are expensive and disruptive to retrofit. Current regulations for government grants demand systems capable of heating homes to comfortable temperatures even on the coldest winter days - typically when outdoor temperatures reach -1°C in the south of England to -3°C in northern Scotland. For such challenging properties, hybrid heat pump systems could offer a practical compromise.

Similar to plug-in hybrid cars that switch between battery power and petrol, hybrid heat pump systems could meet 80-90% of a building's heating needs with electricity, using gas or oil only as backup during extreme cold when heat pumps become inefficient and the power grid is strained. For rural properties, this backup could also include wood-burning stoves or open fires, which many homeowners install anyway for aesthetic or practical reasons. Such secondary heating systems provide crucial resilience during power cuts, which are becoming more frequent and severe due to climate change and increasingly extreme weather events. By taking the strain off heat pumps at lower temperatures, this secondary heating also boosts the average efficiency of the heat pump system overall, since heat pumps operate most efficiently when not pushed to their performance limits. This hybrid approach would reduce both the upfront cost of retrofitting and the broader grid infrastructure costs needed to support full electrification, while also boosting consumer confidence by addressing the fear - however well-founded - that heat pumps might not work in all conditions. This inertia was and still is an important decision factor, similar to range anxiety with EVs.

Another hybrid approach keeps the existing combi-boiler for hot water while adding air-to-air heat pumps for space heating and cooling. This gives homeowners unlimited hot water on demand without sacrificing floor space to a water cylinder. The air-to-air system - essentially reversible air conditioning - provides both heating in winter and cooling in summer, making it particularly attractive for urban properties like small flats and terraced houses that often overheat during warm weather.

Regrettably, the Government hasn't yet considered either of these hybrid options, though it is considering air-to-air heat pumps for properties with an electric cylinder or way of heating water.

**The perfection trap** This obsession with achieving perfect, 100% renewable electricity before electrifying other sectors creates a dangerous delay. Britain could have made much faster progress on transport and building decarbonisation by accepting that electrification would initially be partially fossil-fuel powered, rather than waiting for the perfect renewable grid. The result is that sectors that could have been electrifying for the past decade are still waiting for the power sector to achieve perfection, while emissions from transport and buildings continue largely unabated.

## Conclusion: The Perfectionism Paradox

The UK's decarbonisation journey reveals a fundamental tension between two approaches to climate action. On one side stands the perfectionist approach: waiting for complete renewable energy systems before electrifying other sectors, insisting on 100% clean solutions, and rejecting any technology that doesn't achieve zero emissions. On the other side stands pragmatism: accepting incremental progress, embracing hybrid systems, and recognising that partial decarbonisation today often achieves more than perfect decarbonisation tomorrow.

The evidence from Britain's energy transition is clear. The power sector has achieved a 73% emissions reduction since 1990, largely through the "dash for gas" and renewable expansion. Yet transport emissions have fallen by only 3%, and building emissions by just 25%. This stark contrast reflects not technological limitations, but policy choices that prioritized perfect solutions over practical progress.

The perfectionist approach has created several perverse outcomes. By eliminating coal entirely rather than maintaining strategic reserves, Britain has increased its vulnerability to gas supply disruptions during extreme weather events. By insisting on full heat pump adoption rather than hybrid systems, the government has slowed building decarbonisation and increased costs for homeowners. By waiting for perfect renewable grids before electrifying transport, Britain has delayed the transition to electric vehicles.

The pragmatic alternative recognises that decarbonisation is a journey, not a destination. Hybrid heat pump systems that achieve 60-70% emissions reductions are better than no heat pumps at all. Strategic coal reserves that provide energy security during extreme events are better than blackouts that endanger vulnerable populations. Partial electrification that begins immediately is better than perfect electrification that never starts.

This is not an argument for abandoning climate ambitions or accepting continued fossil fuel dependence. Rather, it's a recognition that the path to net-zero requires balancing environmental goals with practical constraints, economic realities, and human welfare considerations. The UK's current approach of eliminating coal entirely while building massive offshore wind capacity has created a system that's both more expensive and less resilient than necessary.

The lesson for policymakers is clear: perfect should not be the enemy of good. Britain's energy system would benefit from embracing hybrid approaches, maintaining strategic reserves, and accepting that decarbonisation happens in stages. The goal should be maximum emissions reduction at minimum cost and disruption, not ideological purity at any price.

As the UK faces the challenge of doubling electricity demand by 2050 while maintaining energy security, the choice between perfectionism and pragmatism becomes increasingly urgent. The perfectionist approach risks creating an energy system that's both expensive and fragile, while the pragmatic approach offers a path to rapid, cost-effective decarbonisation that builds resilience rather than vulnerability.

The question is not whether Britain should decarbonise - that's already decided. The question is how to do it in a way that maximises environmental benefits while minimizing economic and social costs. The answer lies not in waiting for perfect solutions, but in embracing the messy, incremental reality of energy transitions. Britain's energy future depends on choosing pragmatism over perfectionism, and progress over purity.

# Chapter 21: Glossary

## Acronyms

**CBAM - Carbon Border Adjustment Mechanism**

**CCGT - Combined Cycle Gas Turbine**

**CEGB - Central Electricity Generating Board**

**CfD - Contracts for Difference**

**kWh - Kilo Watt hour**

**LCOE - Levelised Cost of Electricity**

**ROC - Renewable Obligation Certificates**