Future Energy Associates

Warm This Winter Tariff Watch

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Executive summary

State of the market

- The energy market is regaining competitiveness with major suppliers offering multiple fixed tariffs, responding to a sustained drop in wholesale prices. Single fuel and bundled tariffs are notably becoming more competitive.

Fixed Tariffs Watch:

- Current forecasts suggest that any one-year fixed tariff is worth fixing to at any rate at or below the following rates with an exit fee of no less than £80 for a dual fuel tariff:
  - Standing Charges: Electric 51 p/day, Gas 30 p/day
  - Unit Rates: Electric 26 p/kWh, Gas 6.3 p/kWh.
- The Fixed Tariff Ranking Table showcases a range of fixed energy tariffs from various suppliers, each with distinct features. It finds that there are 3 fixed tariffs worth considering:
  - OVO Energy's 1 Year Fixed + Boiler Cover (Jan 2024) offers a 9% reduction compared to the January Price Cap, so it is recommended if Boiler Cover is valued. It's available to the whole market but requires additional products to be purchased.
  - Home Energy's Home FIXED December 2023 v1a provides a 6% saving, but to get the best value from this, you would then need to possibly switch back to the Standard Variable Tariff in April..
  - So Energy's So Mint One Year- Green 12-month fix provides a 5% saving, a good option for those with high electrical consumption

Tariff Analysis

- From the fourth quarter of 2023 to the first quarter of 2024, the energy market saw slight changes in both fixed and variable tariffs. For fixed tariffs, there was a slight decrease in the overall annual cost, declining from £1,894 to £1,874 for the average household. This reduction was driven by falls in both gas and electricity unit rates. Specifically, the average cost of electricity under fixed tariffs remained the same at £961, while the average cost of gas saw a more noticeable decrease, from £934 to £913 for the average household.
- In contrast, variable tariffs presented a different trend during the same period. The overall average cost for variable tariffs increased from £1,817 to £1,921. This rise was reflected in both components of the tariff: the average cost of electricity under variable tariffs went up from £925 to £969, and the average cost of gas increased from £892 to £951.
- For variable tariffs as of January 2024, Standard Credit (CAC) users typically incur an average annual cost of £2,065.62 for combined gas and electricity. In comparison, customers opting for Direct Debit (DDM) experience a marginally lower combined annual expense of £1,921.15. Meanwhile, Prepayment (PRE) customers, who have historically faced higher charges, now encounter an annual cost of £1,942.92 for their energy needs.

Network Costs

- Total network costs have risen by 50% from winter 2021/22 to 2024 Q1. In that same time, network costs without supplier of last resort (SOLR) costs have increased by 42.52%. SOLR costs are those faced by suppliers who have taken on customers from the many smaller suppliers that have gone out of business in recent months and are paid for by the bill payer. For 2024 Q1 SOLR costs £19 per year.

- A dynamic approach to calculating line losses in energy transmission could lead to more equitable billing and efficient resource allocation.
- Ofgem is urged to provide clearer methodologies and machine-readable data formats to enhance transparency in cost calculations for electricity networks costs.
- Ofgem should provide greater transparency in determining how gas network costs are separated between standing and unit rate costs.
- Since April 2023 the balancing element of network costs (BSuoS) has been levied completely on households, a change that moved costs away from energy generators.
- A big cost element of BSUoS costs is for network constraints for wind farms in the North of the UK. These result from a failure for transmission network upgrades to keep up with deployment of low carbon technology, meaning customers are paying now for a historic lack of planning and investment.
- Profitability and Investment of DNOs: Distribution Network Operators have high operating margins (42.5% in 2023), but there are indications of underinvestment in the grid, affecting new connections and project handling.
- Infrastructure Development Post-Privatisation: Investment in electricity and gas networks has lagged behind the nationalised period, leading to higher costs and slower network upgrades.

Network Performance Monitoring:

- In an analysis aimed at monitoring DNOs efficiency at supplier households, Manweb has been identified as an outlier as it is characterised by high standing charges despite its average urban/rural supply point split.
- Distribution Network Operators have generally been under-spending against their allowances (2015-2022), with longer term improvements to networks typically being the area of underspend. Underspend is split between customers and DNOs, so there is a question about whether the regulator is doing enough to ensure the right amount and type of investments are being made.

Table of contents

Introduction

Background into the retail market:

In August 2022, wholesale energy prices reached a peak, resulting in costs that were approximately ten times higher than those in the summer of 2019 [1]. This surge was attributed to a myriad of interconnected factors, including the Russia-Ukraine conflict and the consequential decision by Western European and UK governments to cease their reliance on Russian gas supplies, coupled with French nuclear reactors going offline, which in turn heightened their gas consumption.

Both gas and electricity prices are intrinsically linked; gas still contributes significantly to electricity generation in Great Britain, and often sets the marginal price in pay-as-clear wholesale markets.

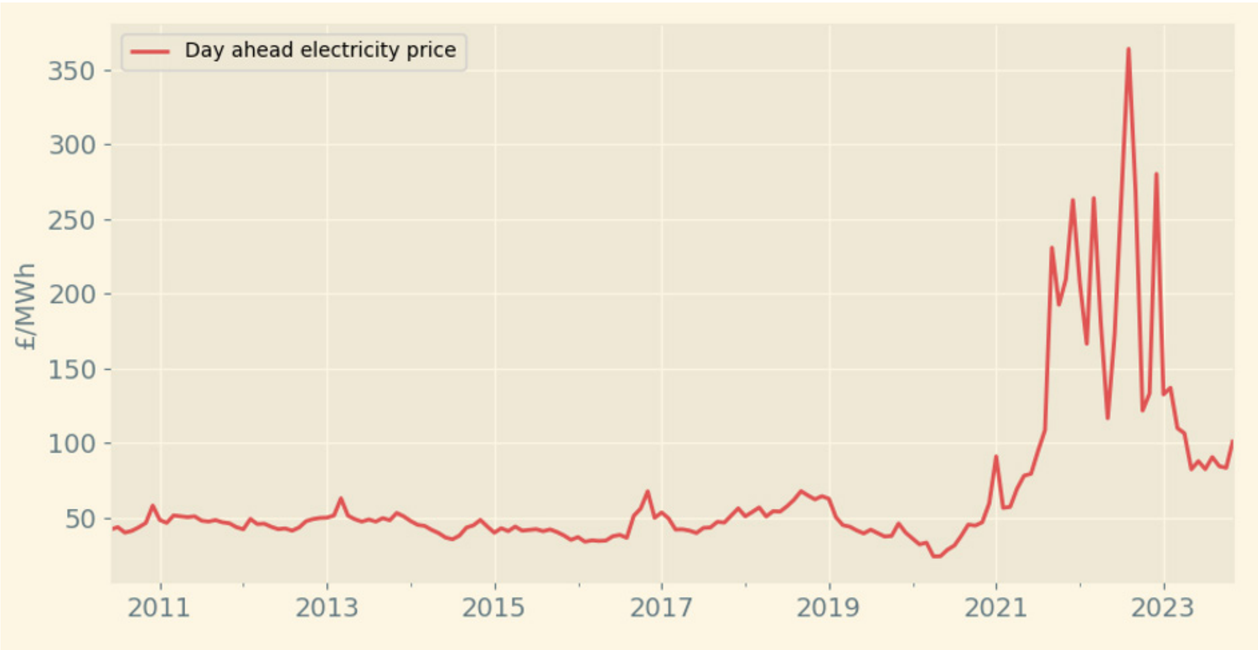


Figure 1: Electricity wholesale prices.

Rising wholesale prices, the prices at which suppliers purchase energy from the grid, inevitably translated into increased retail prices for consumers, albeit with a time lag. Consequently, the winter of 2022-23 saw retail energy prices peak, requiring the government to intervene and cap average direct debit dual fuel tariff prices at £2,500. However, when combined with underinvestment in energy efficiency measures over recent years, which results in higher energy consumption, the government support was insufficient for many. The result was that millions of people spent the winter in cold damp homes [2]. In 2023, the Department for Energy Security and Net Zero (DESNZ) projected that, based on its limited definition of fuel poverty, 14.4% of households would experience fuel poverty in England, a rise from 13.1% in 2021[3]. Prices for consumers remain high. While an environment with stability and low risk for energy suppliers is desirable, this must be balanced with fair and transparent prices for consumers.

Since peaking in August 2022, both electricity and gas wholesale prices have seen a decline of over 50%. This shift has begun to be felt in the retail energy market, with the Ofgem price cap decreasing for the third consecutive quarter as of October 1st. The January price cap has seen a subsequent increase, but forecasts suggest further decreases are to come. Although this is certainly good news for households, the levels of energy bills remain around double what they were in winter 2020/21. The reintroduction of a competitive retail energy market presents its own set of challenges. Households now face the difficult task of navigating numerous suppliers and tariffs to find the best fit for their needs.

The outlook for domestic prices in 2024 is looking significantly more positive than previously had expected. Various global and regional factors, such as the Israel-Hamas conflict, LNG production issues in Australia, and pipeline disruptions, have failed to significantly impact energy prices for the UK market. Instead, the mild winter and higher-than-expected European gas storage levels have caused wholesale prices to decline significantly which is being reflected in forecasted price caps for Q2 onwards (Q2-24 £1,660, Q3-24 £1,590.36). However, forecasts of energy prices remain subject to significant uncertainty and the eventual price cap values could deviate significantly from current predictions.

Objective, Purpose, and Scope of the Report:

This report, commissioned by the 'Warm This Winter' campaign, delves into the UK's retail energy market, assessing how retail energy prices have responded to significant changes in the wholesale energy sector. The data used for this report is accurate as of January 12th, 2023 and is sourced from Future Energy Associates' retail tariff database, which encompasses all tariffs across England, Scotland, and Wales.

Our primary goal is to investigate how retail energy prices have adjusted to decreasing wholesale prices. In doing so, we'll evaluate the roles of the UK Government, the energy regulator Ofgem, and energy suppliers in this transition. Specifically, we aim to ascertain whether these entities are ensuring households reap the benefits of falling wholesale prices and to pinpoint any areas necessitating further action or refinement.

The second edition of the 'Tariff Watch' series focuses in more depth on Network Costs.

Market and Policy Overview

The current state of the market:

Since April 2023, the domestic retail energy market has seen a resurgence, allowing suppliers to offer competitive tariffs that are profitable for their business while also expanding their customer base. A notable indicator of this trend is the increase in the number of fixed tariffs available to households, which has seen a consistent growth quarter-on-quarter.

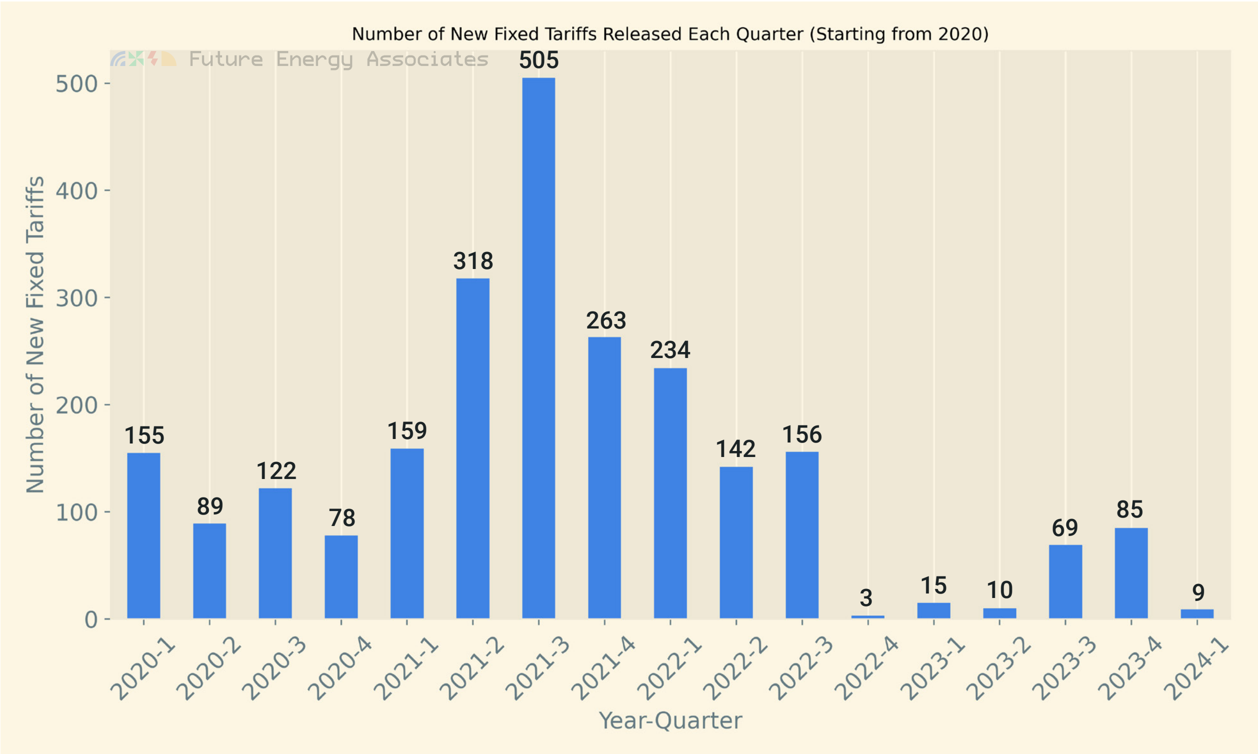


Figure 2: Number of Domestic Energy Suppliers (Data sourced from Future Energy Associates Tariffscanner Database)

While the expansion in choice is indicative of a recovering market, it's important to note that among the fixed tariffs available, only a small fraction were likely to result in cost savings for households over the duration of the contract. The majority of these tariffs primarily benefited the suppliers, catering to households that prioritise price stability over cost savings. These findings suggest that while the increased number of fixed tariffs provides more options to consumers, their potential to offer financial benefits to households is limited. However, this landscape is expected to shift with the planned reintroduction of acquisition tariffs and the elimination of the market stabilisation charge on March 30th, actions that could lead to more advantageous conditions for households.

A move towards bundled and EV tariffs?

In the last quarter, the energy market has seen a significant increase in competition, especially regarding bundled tariffs. Bundled tariffs refer to tariffs where multiple services or products (i.e. Boiler Care, Boiler Insurance, Mobile data) are combined into a single package, often at a discounted rate compared to purchasing each service individually. Industry leaders such as British Gas, OVO Energy, and Utility Warehouse have considerably broadened their tariff plans, fostering a more competitive environment. These providers have designed their bundled tariffs to cater to a wide range of customers, incorporating a variety of incentives and pricing strategies to differentiate themselves in a saturated market.

Alongside the expansion in bundled tariffs, the market for electric vehicle (EV) tariffs has also become increasingly competitive. EDF Energy, in particular, has positioned itself as a prominent player in this space by introducing competitively priced tariffs tailored for EV owners. An integral part of their strategy has been the strategic partnership with Pod Point, a leading provider of electric vehicle charging infrastructure.

In contrast to those benefiting from more competitive electric vehicle tariffs, Economy 7 households are increasingly at a disadvantage. This gap is well exemplified by EDF Energy's current tariff structures: the GoElectric Overnight tariff, aimed at EV owners, offers an average nighttime electricity unit rate of just 8.00 pence per kWh across all DNO regions. In stark contrast, the Standard Variable tariff, serving as an Economy 7 equivalent, imposes a significantly higher night-time unit rate of 16.63 pence per kWh. This disparity not only highlights EDF's strategic focus on EV users but also exacerbates the challenges faced by Economy 7 users who rely on lower night rates. Such a significant hike in nighttime tariffs from December 2023 to January 2024 by EDF disproportionately affects these consumers.

Price Analysis

The Price Cap is enforced by Ofgem, the energy regulator for Great Britain, and sets the maximum amount that energy suppliers can charge households for their standard variable ("default") tariffs. Crucially this means that fixed tariffs are not regulated by the Ofgem price cap. The price cap applies to unit rates and standing charge, however is typically expressed as an annual value. This average consumption value was reduced to 2,700 kWh/year of electricity and 11,500 kWh/year of gas [4] as of 1st October 2023. For example, the current January price cap is set at £1,928 per year for dual fuel tariffs, paying by direct debit, and consumes the 'typical medium' amount of energy, as defined by Ofgem under the new consumption values.
It is also worth stressing that households that consume more energy than this will have annual costs which exceed the price cap.
In this report, we consider domestic tariffs, and all the annual costs reflect the energy usage of a typical medium household as specified above - and using the new Ofgem typical consumption values. For households on Economy 7 tariffs, we assume the same energy consumption level, with 42% of electricity usage occurring during night rate hours. These tariffs apply specifically to electricity and have different unit rates during the day and at night. The night rates are cheaper to encourage off peak electricity use, when overall electricity demand is lower. Therefore, the day rates can exceed the price cap as long as these are balanced out by lower night rates.

Increased Prices: Moving Towards the End of the Energy Cost Crisis

Throughout 2023, households experienced a significant decrease in energy prices across both variable and fixed tariffs, leading to a reversal of the previous upward trend. However, this trend saw a slight deviation with variable tariffs experiencing a modest increase and fixed tariffs continuing to fall slightly as the price cap rose again in January 2024. This shift is especially significant as it occurred during a period of typically high energy consumption and in the absence of the same level of support packages that were available in the previous winter.

Figure 3 highlights this trend, illustrating a steady decline in retail energy rates over the past year, with a nuanced shift in the final quarter. For variable tariffs, electricity prices saw an overall decrease of approximately 10.6% from £1,084.91 in January 2023 to £969.33 in January 2024. However, there was a slight increase in these rates from October 2023 to January 2024. Similarly, gas prices under variable tariffs decreased notably by about 25.9% from £1,287.34 in January 2023 to £951.82 in January 2024.

In contrast, fixed tariffs followed a more consistent downward trajectory. Starting at an average combined cost of £4,215.47 in Q1 2023, they saw a substantial reduction, dropping to an average of £1,874.03 in Q1 2024, a decrease of approximately 55.5% over the year. Specifically, the average electricity cost under fixed tariffs decreased from £1,497.23 to £961.43, and gas costs reduced from £2,730.75 to £912.60, with both continuing to decline slightly from October 2023 to January 2024.

From the fourth quarter of 2023 to the first quarter of 2024, the energy market saw slight changes in both fixed and variable tariffs. For fixed tariffs, there was a slight decrease in the overall annual cost, declining from £1,894 to £1,874. This reduction was driven by falls in both gas and electricity unit rates. Specifically, the average cost of electricity under fixed tariffs remained relatively stable, changing marginally from £961 to £960, while the average cost of gas saw a more noticeable decrease, from £934 to £913.

In contrast, variable tariffs presented a different trend during the same period. The overall average cost for variable tariffs increased from £1,817 to £1,921. This rise was reflected in both components of the tariff: the average cost of electricity under variable tariffs went up from £925 to £969, and the average cost of gas increased from £892 to £951.

Despite these reductions, it's important to recognise that retail energy prices remain at historically high levels. As colder months approach, households face the challenge of navigating these costs, particularly in the absence of the extensive support packages seen in the previous winter. This situation highlights the ongoing importance of energy efficiency and budgeting in household financial planning.

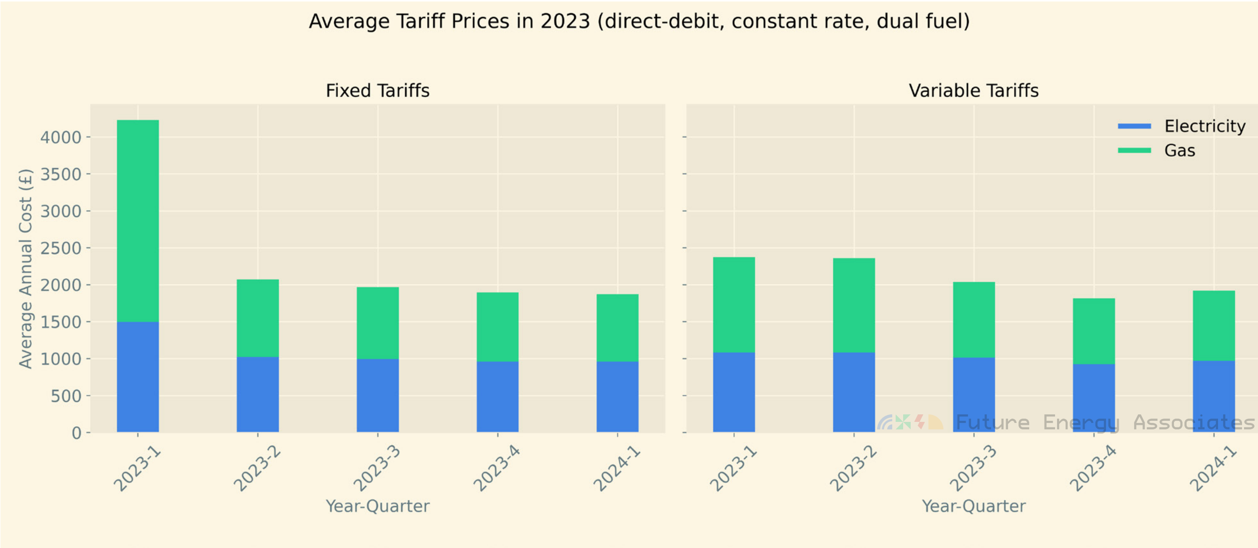


Figure 3: Average annual cost for fixed/variable a medium-use household on from 2023 Q1 onwards

Payment methods continue to have an impact on consumer energy costs, shaping their financial planning and annual budgets. As of early January 2024, the tariff data reveals distinct differences between fixed and variable tariffs for each payment method. For fixed tariffs, customers using Standard Credit (CAC) have a combined annual average of £2,015.83 for gas and electricity, while those opting for Direct Debit (DDM) benefit from a lower combined average of £1,898.20 annually (a 6.2% uplift). Prepayment (PRE) customers see their combined annual average at £1,911.62. In contrast, under variable tariffs, Standard Credit (CAC) users encounter a higher combined annual cost of £2,065.62. Direct Debit (DDM) customers enjoy a slightly lower average of £1,921.15, and Prepayment (PRE) users face an annual cost of £1,942.92. These figures illustrate the continued premium for Standard Credit users and the narrowing cost disparity for those on Prepayment plans, across both fixed and variable tariffs. This cost disparity between prepayment and direct debit payment method will be brought to zero on the allowed Ofgem Price Cap from April 2024.

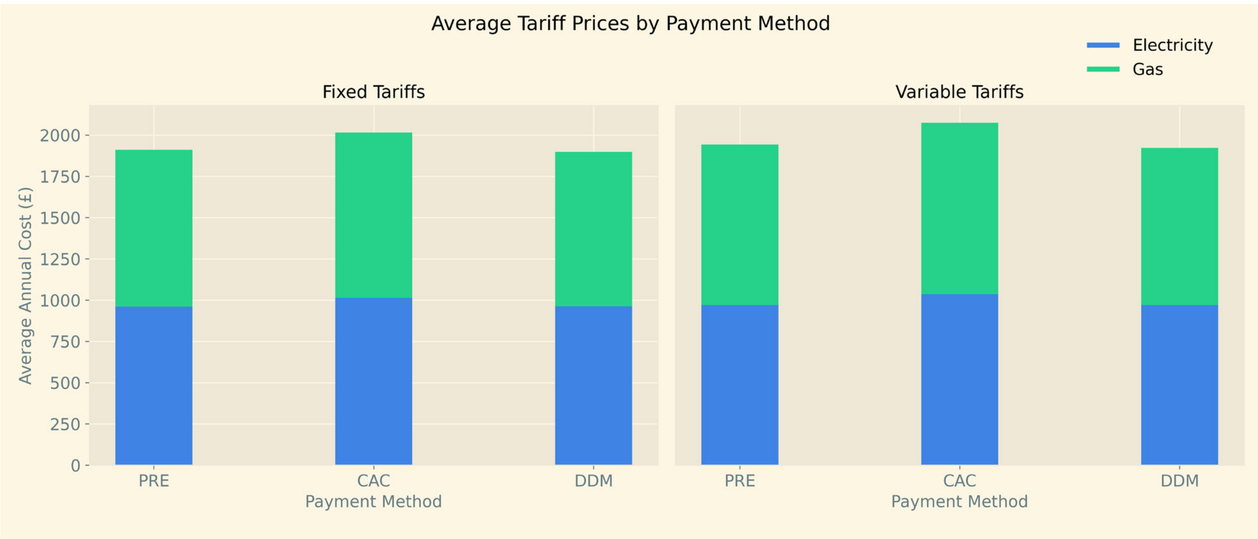


Figure 4: Mean tariff prices, split by payment type, for a medium use household.

Price variation by region

Electricity is distributed at a local level by distribution network operators (DNOs). Gas is distributed across eight different regional areas, but is accounted for by Ofgem across these same DNO areas. There are 14 geographical areas run by different DNOs which are referred to as DNO regions, and these can be seen in figure 3. Differences in the way power needs to be distributed within these regions, for example because of the length of connections to properties, as well as differences in the way DNOs operate, leads to differences in costs passed onto suppliers. In addition, electrical losses vary by region because of the makeup of the network, meaning more power has to be bought by the supplier for the same amount of energy end-use.

Figure 5: A breakdown of the different DNO regions. Data from [5].

Overall

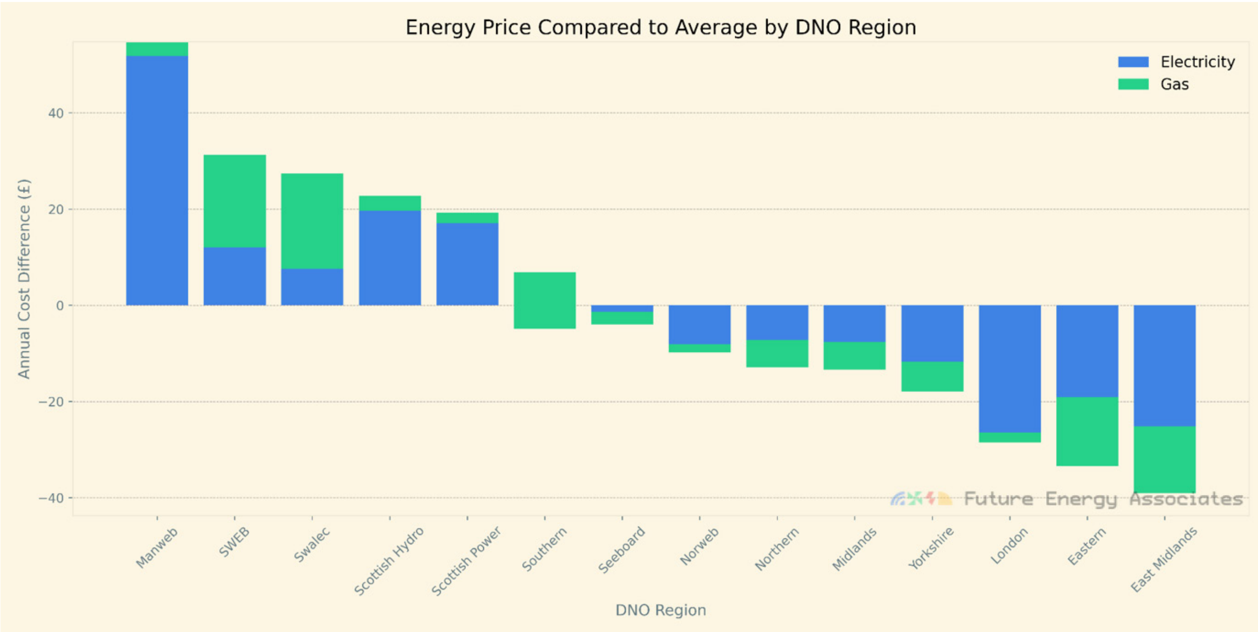


Figure 6: Annual cost for a medium use dual fuel household, varied by DNO.

Overall, the average price of energy continues to exhibit significant regional variations. According to the latest data, these disparities are mainly driven by variations in electrical costs, particularly the electrical standing charge. For instance, households in the Manweb region (covering Merseyside, Cheshire, and North Wales) encounter an average electrical standing charge of 62.75p/day, which is 57.3% higher than that in London, where it's 39.90p/day. This difference translates to an annual disparity of approximately £83.50. The variation in household gas prices is less marked, with the annual cost differing by around £29.7 (3%) between the least expensive region (East Midlands) and the most expensive (SWEB) for gas.

Electricity

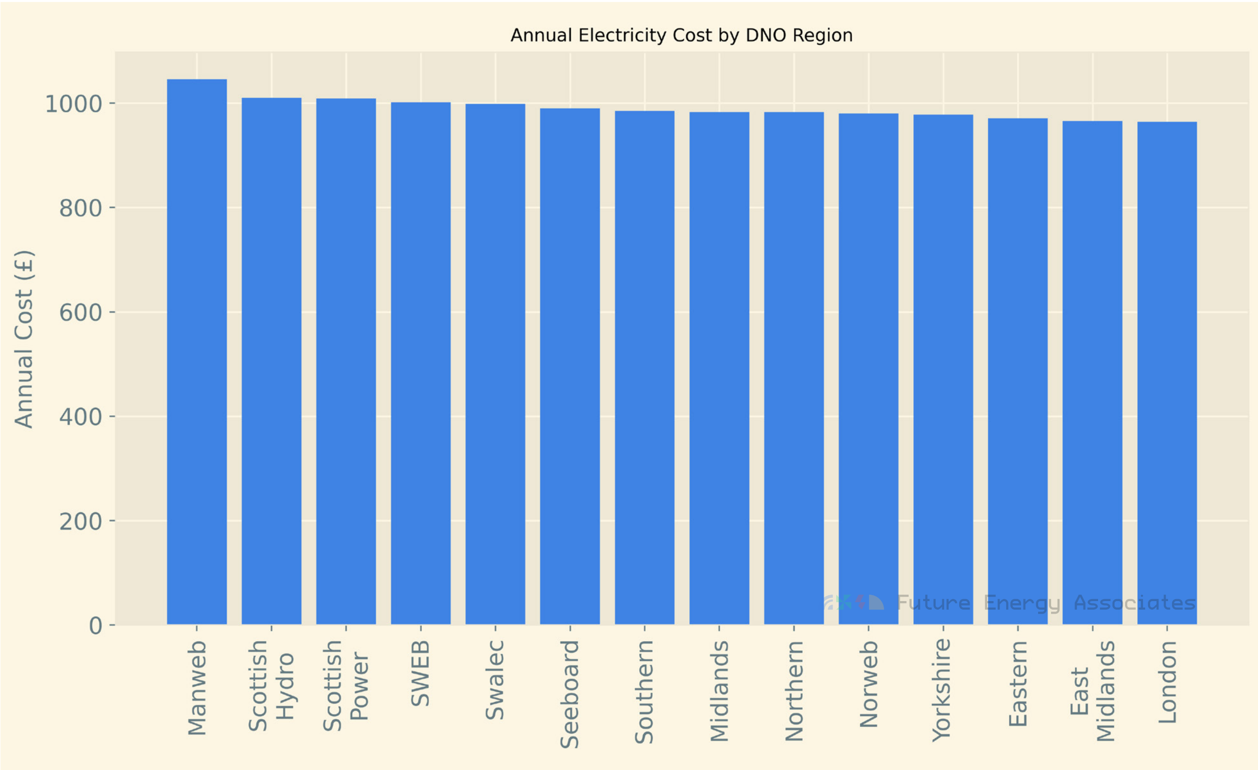
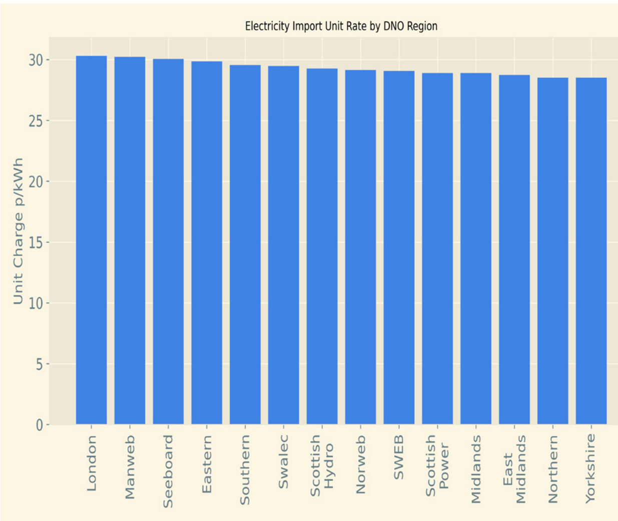


Figure 7: Annual average electricity costs by DNO region, for a medium-use household.



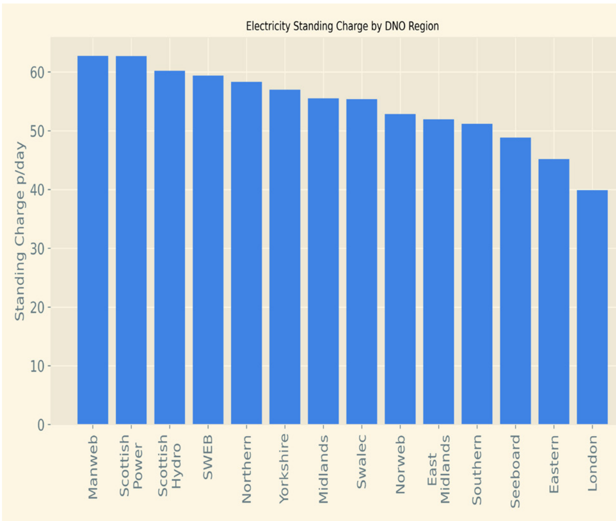


Figure 8: Electricity Prices: **Left:** Variation in electrical unit rate by DNO region. Note that in the case of Economy 7 tariffs these figures only take into consideration the day rates. **Right:** Variation in standing charge by region.

Home Energy (Home SVT January 2023 v1)

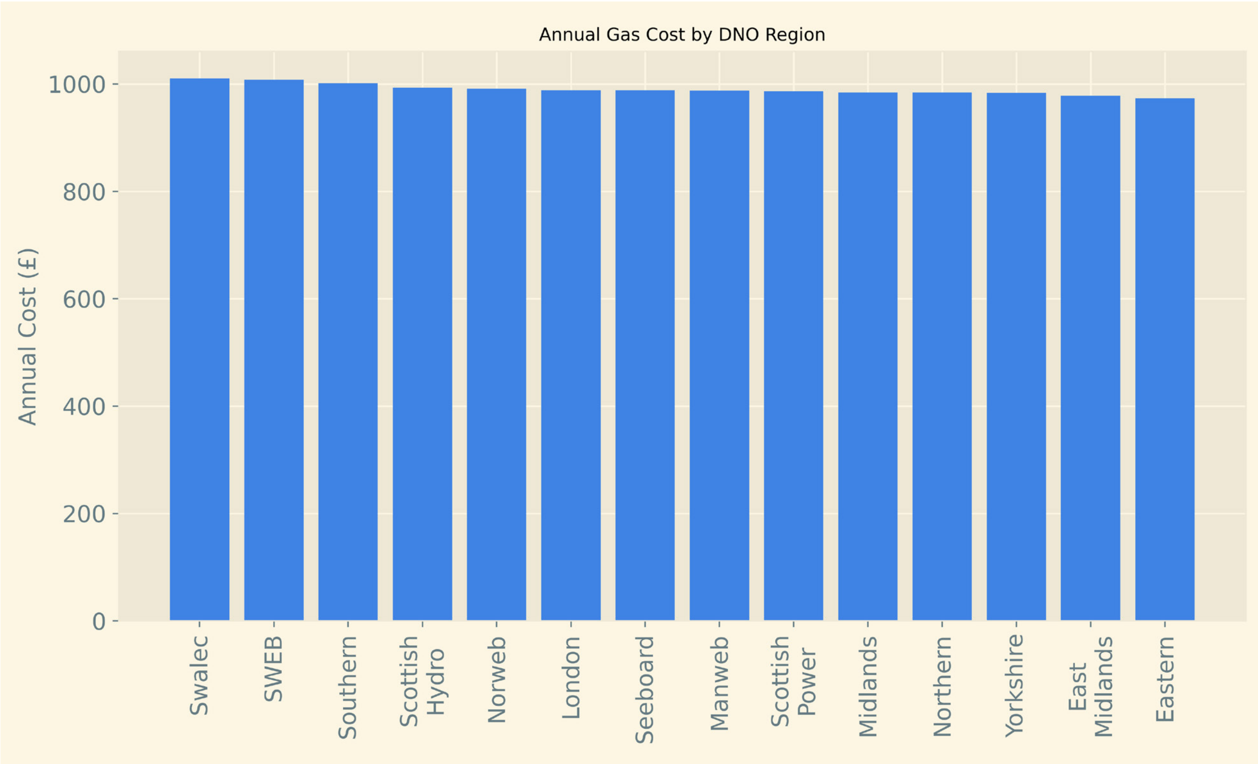
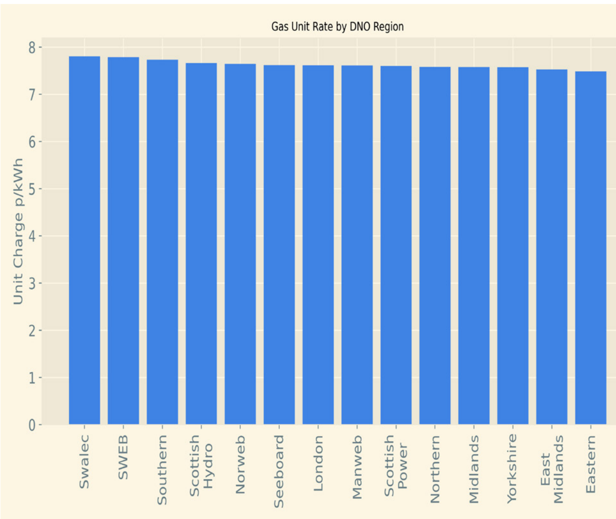


Figure 9: Annual Gas cost per DNO region for average consumption households



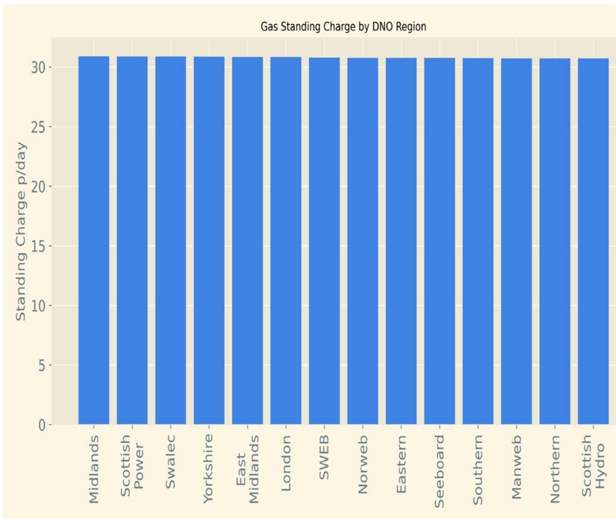


Figure 10: Left: Standing charge. **Right:** unit rate variation

Tariff Tracker

In this section, we explore the most cost-effective energy tariffs for average consumption households using standard meters and paying by direct debit. Against the backdrop of fluctuating price caps, we examine the market's cheapest fixed and variable tariffs. We will compare these against the current price cap and the forecasted reductions for later in the year. Our analysis aims to identify valuable deals for households and provide guidance on when to consider fixing tariffs. We also define what rates constitute a 'good' fixed tariff deal, helping households navigate the complex energy market efficiently.

What are the cheapest tariffs on the market?

In this section, we consider what the cheapest tariff on the market is for households with average consumption, with a standard meter, and paying by direct debit. We recommend selecting any fixed tariff at or below the January price cap should be selected.

Cheapest Variable Tariffs

- Electricity: Fuse Energy (Fuse Saver)
- Gas: Home Energy (Home SVT October 2023 v1)

Cheapest Fixed Tariffs

- OVO Energy - 1 Year Fixed + Boiler Cover 14 December 2023 Change to 1 Year Fixed + Boiler Cover 4 January 2023
- Home Energy - Home FIXED December 2023 v1a (Does not require Bundling)

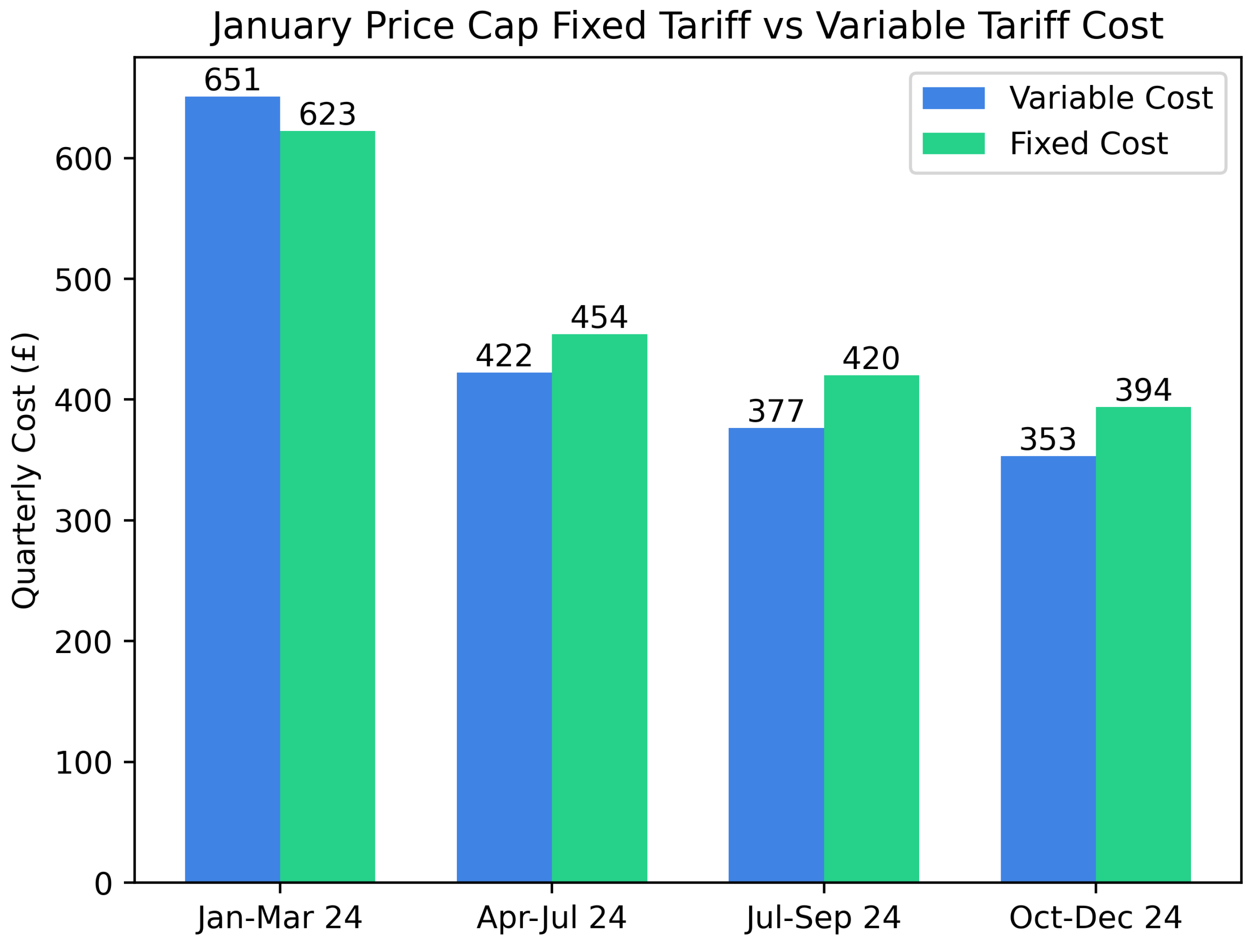
When should households consider fixing their tariff?

Households should select a fixed tariff at any **rate at or below the following rates** with an exit fee of no less than £80 for a dual fuel tariff.

- Standing Charges: Electric 51 p/day, Gas 30 p/day
- Unit Rates: Electric 26 p/kWh, Gas 6.3 p/kWh

Tariff Watch recommendation: The data suggests that households **should switch to the Home Energy - Home FIXED December 2023 v1a** and then switch onto either the **cheapest possible variable tariff combination** in April (annual cost of £1775 or £27 in savings) or onto a cheaper fixed tariff. However if a household was willing to bundle different utilities the **Utility Warehouse Fixed Saver 11 or the OVO Energy - 1 Year Fixed + Boiler Cover 14 December 2023 Change to 1 Year Fixed + Boiler Cover 4 January 2023** could also be an option, but it requires signing up to two additional services for which separate price comparisons would need to be made. For households considering the switch to the now 'Fixed' Octopus Agile tariff please refer to this previous analysis run by FEA.

The graph below shows the savings of switching to the **Home Energy - Home FIXED December 2023 v1a tariff compared to being on a variable tariff that is at the forecasted Ofgem Price Cap**. The annual savings would be £4.37 with the estimated cost of being on the Ofgem Price Cap estimated to total to be £1808 and the fixed cost being £1804.



Source: SERL Monthly Consumption Values, Cornwall Insights Price forecasts

Figure 11: Year ahead forecasts: Fixed Tariff Cost vs Price Cap Forecasts

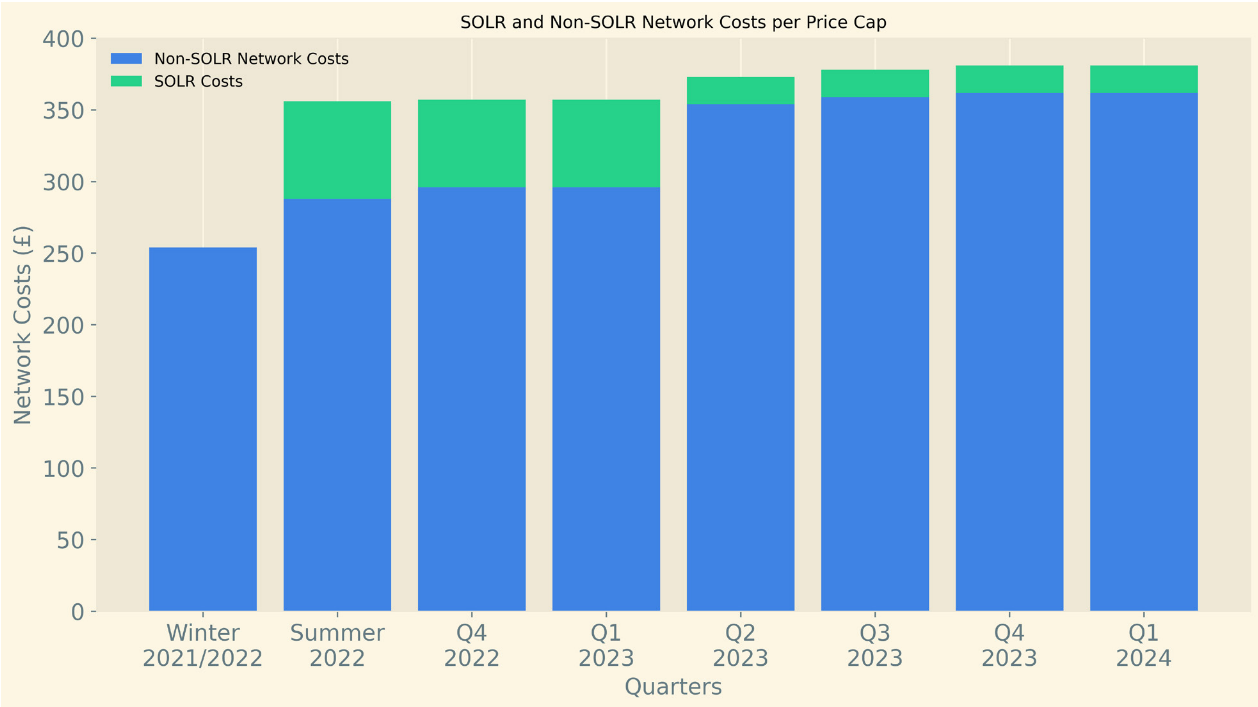
Fixed Tariff Ranking Table

Supplier & tariff		Unit Rate and Standing Charge	Exit Fees	Average annual cost compared with January Price Cap	Is this recommended	Who can get it?
OVO Energy - 1 Year Fixed + Boiler Cover 8 January 2024	E	28.12 p/kwh 39.37 p/day	150	9% Less	Yes, but only if you value their Boiler Cover offering	Whole market, but requires additional products
	G	6.94 p/kwh 15.57 p/day				
Home Energy - Home FIXED December 2023 v1a	E	26.91 p/kwh 51.61 p/day	0	6% Less	Yes, but they are not part of the Warm Home Discount scheme	Whole market
	G	6.78 p/kwh 29.98 p/day				
British Gas - Home Move Exclusive Jan25 v5	E	27.16 p/kwh 50.35 p/day	150	6% Less	No	Only new homeowners
	G	6.88 p/kwh 26.6 p/day				
Utility Warehouse - UW Fixed Saver 11	E	29.01 p/kwh 41.4 p/day	150	6% Less	No	Whole market, but requires additional products
	G	7.32 p/kwh 17.66 p/day				
So Energy So Mint One Year- Green 12-month fix	E	26.91 p/kwh 51.61 p/day	150	5% Less	Good electric rates, so only recommended for those you have electric heating	New customers only
	G	6.78 p/kwh 29.98 p/day				
E.ON Next Fixed 12m v6 12-month fix	E	27.04 p/kwh 53.35 p/day	150	4% Less	No	Whole market
	G	7.05 p/kwh 29.6 p/day				
EDF Essentials 1Yr Jan25v2 one-year fix	E	27.88 p/kwh 53.34 p/day	150	4% Less	No	Whole market
	G	6.9 p/kwh 29.98 p/day				
British Gas Fixed Jan 25 v9 The Fixed One v33 12-month fix	E	27.90 p/kwh 51.72 p/day	150	4% Less	No	Whole market
	G	7.05 p/kwh 27.97 p/day				

Deep Dive: Network Costs

Network expenses are designed to offset the charges that providers incur for the use of gas and electricity transmission and distribution networks. The electricity network consists fundamentally of two primary sectors: the transmission and the distribution networks.

Price Cap Overview



Network costs saw a 50% rise, moving from £254 in the winter of 2021/22 to £356 in the summer of 2022, and later climbing to £381 for the Q4 2023 and Q1 2024 caps.

From 2021 onwards caps encompassed an extra fee to compensate for the 'Supplier of Last Resort' levy expenses. These are incurred by providers who have acquired customers from smaller suppliers that have recently failed. In the summer of 2022, this component of the network costs amounted to £68, and for the Q4 2022 and Q1 2023 caps, it was £61, decreasing to £19 for the Q2, Q3, Q4 2023 and Q1 2024 caps[1]. These costs are added to the standing charge of domestic electricity customers' bills as network costs and added to the unit costs of domestic gas bills.

Transmission Network: The Motorway of Energy

The transmission network operates like the motorways or highways in our road system. Just as motorways connect major cities and facilitate fast, high-volume traffic over long distances, the transmission network is designed for the high-capacity, long-distance transport of energy. In the case of electricity, this involves high-voltage lines capable of moving large amounts of power from generating stations to substations across the country. Similarly, for gas, this network comprises high-pressure pipelines transporting gas from production sites to regional distribution points. The transmission network is the backbone of our energy system, ensuring that large quantities of energy can travel vast distances efficiently, much like motorways allow for efficient long-distance travel.

[1] https://researchbriefings.files.parliament.uk/documents/CBP-9491/CBP-9491.pdf

Distribution Network: The Local Roads of Energy

On the other side, the distribution network resembles the local roads and streets that branch off from the motorway, reaching into towns and neighbourhoods. In energy terms, this network takes over from the transmission system, operating at lower pressures for gas and lower voltages for electricity. It's responsible for the 'last mile' of energy delivery, ensuring that electricity and gas are safely and reliably supplied to individual homes and businesses. The distribution network includes local infrastructure such as transformers (for electricity) and regulators (for gas) that adjust the energy flow to levels suitable for domestic use. Just as local roads are crucial for connecting residents to the broader road network, the distribution network is essential for connecting consumers to the national energy grid.

The Interplay and Costs

Both the transmission and distribution networks are vital for a fully functioning energy system, each playing a distinct yet interconnected role. Understanding this distinction is key to comprehending the complexities of network costs and how they impact energy prices for households. This report focuses on electricity costs only, gas network costs will be the subject of future Tariff Watch reports.

Electricity Network Costs

TNUoS Costs

The Transmission Network Use of System (TNUoS) tariffs, established by the Electricity System Operator (ESO), are directed at both energy suppliers and producers. These tariffs serve a dual purpose: they contribute to the expenses associated with the operation and maintenance of the transmission network in various locales, and they ensure that the revenue requirements of transmission owners, both on land and at sea, are fulfilled.

The TNUoS tariffs incorporate a geographical component that modifies charges in accordance with the electric power flow—increasing the tariffs when demand escalates and additional network investment is required, and reducing them when demand falls. These rates reflect the overall generation and consumption within the network, as well as the electrical characteristics of the grid connections.

Traditionally, TNUoS charges are levied based on peak demand (p/kW), calculated using the Triad system—these are instances of highest electricity demand observed from November through February, generally occurring between 4 and 6 pm.
With the advent of Transmission reforms, a significant shift has occurred, with approximately 90% of the charges transitioning from reliance on an entity's Triad usage to a fixed-rate structure. The details are as follows:

- Half-Hourly Metered Supplies are now charged at a fixed rate (£/Kw/day), determined by bands that correspond to an organisation's Available Supply Capacity (ASC). With incremental charges for higher ASCs, entities can potentially lower their TNUoS costs by managing their ASC to fall within a lower band.

- Half-Hourly Unmetered Supplies are subject to a new consumption-based tariff, priced at p/kWh.

- Non-Half-Hourly Supplies are charged based on consumption as well, but specifically during the hours of 4-7 pm, also at a rate of p/kWh.

This restructuring of charges aims to more accurately align tariffs with the actual use and demands on the transmission network. The cost model also considers the investment required for different transmission assets, such as cables and overhead lines, and the expenses vary by region. These costs are based on current replacement values, not the original costs, meaning they don't always match the actual investment for a specific connection.

However, these locational charges don't fully cover the revenue transmission owners are allowed. Therefore, non-locational "residual" charges are added to make sure the right amount of revenue is recovered. For demand, these are banded charges, and for generation, an adjustment tariff balances the revenue from producers and consumers. Since April 2023, demand tariffs have been split by location and consumption type, with additional banded charges for different levels of usage.

For transparency and clarity on TNUoS tariffs, it's imperative for Ofgem to provide a detailed cost breakdown. The following table showcases the types of charges Ofgem reports. Yet, a more detailed, machine-readable data format like CSV or XML is needed, beyond the current references to National Grid's website. This change would aid stakeholders in analysing data more efficiently and effectively. By providing data in a directly usable format, Ofgem would greatly facilitate a deeper understanding and utilisation of TNUoS tariffs.

Cost Name	Cost Description	Cost Amount
Non-Locational demand residual banded charge (domestic)	Non-Locational demand residual banded charge (domestic) measured £/Site/Day	0.119
TNUoS non-half hourly demand tariff	Cost for supplying the required demand. Measured as p / kWh at GSP	0.279

Analysis of TNUoS Costs

- Non-Locational demand residual banded charge (domestic): This charge, at 0.119 £/Site/Day, is applied evenly across all domestic sites regardless of their location. It's designed to collect a portion of the transmission owners' revenue requirement that's not covered by locational charges. Considering this charge is non-locational, it's a way to ensure that all domestic users contribute to the fixed costs of maintaining the transmission network and for consumers to pay out of standing charge.

- TNUoS NHH demand tariff: The average value of 0.279 p/kWh across all DNO regions, based on the charges provided, represents the cost of using the transmission network to supply electricity to non-half-hourly metered sites. This rate factors in the cost of infrastructure investment and the need to ensure network reliability and capacity for future demands. For consumers this is paid out of their unit rates.

Recommendation for Ofgem

For each of these costs, Ofgem should provide a detailed methodology explaining how these tariffs are calculated. This should include:

- Detailed Breakdown: A clear description of all the components that make up the tariffs, such as the cost of new investments, maintenance of existing assets, and administrative expenses.

- Formula Transparency: A transparent formula for how the TNUoS NHH demand tariff is aggregated from different demand tariffs, considering the locational and non-locational elements, including the specific variables and coefficients used.

- Machine-Readable Data: The provision of all underlying data and tariffs in a machine-readable format like CSV or XML, along with an explanatory document that maps each data point to the corresponding component in the cost model.

- Aggregation and Determination: A clear explanation of the aggregation process for determining the final tariffs, outlining how individual costs are combined and weighted.

By addressing these points, Ofgem would enhance the transparency and accountability of the TNUoS charging mechanism. It would enable stakeholders to understand the derivation of their charges, assess the fairness of the tariff structure, and plan accordingly for their energy consumption or generation. Such transparency is crucial for trust in the regulatory framework and for informed decision-making by all market participants.

These costs are multiplied by demand and losses to and distributed accordingly to form the total TNUoS costs.

DUoS Costs

The Distribution Network Operator (DNO) sets the Distribution Use of System (DUoS) tariffs for energy suppliers. These tariffs are integral for covering the costs associated with the distribution network, including the maintenance and expansion required to meet changing demands.

DUoS tariffs are composed of various charges, each serving a specific purpose:

1. Consumption Charges (p/kWh): These charges are based on the electricity consumption of an organisation, with rates varying according to the time of use. This is segmented into Red, Amber, and Green time bands, reflecting peak, medium, and low demand periods, respectively.

2. Standing Charges (p/MPAN/day): A fixed daily charge applied per Meter Point Administration Number (MPAN), covering the fixed costs of electricity distribution.

3. Capacity Charges (p/kVA/day): These are levied based on the assigned Available Supply Capacity (ASC) of an organisation, with higher capacities incurring greater charges.

4. Reactive Power Charges (p/kVArh/day): Applied for the reactive power used by an organisation, which is essential for maintaining voltage levels within the distribution network.

5. Supplier of Last Resort (SOLR) Costs: Including the SOLR Fixed charge (p/MPAN/day) and the Excess SOLR Fixed charge (p/MPAN/day), these are specific charges aimed at covering the costs incurred when a supplier fails and another supplier takes over their customers.

6. Eligible Bad Debt Fixed Charge Adder (p/MPAN/day): An additional charge to cover the costs associated with uncollectible debts.

Analysis of DUoS Costs

The DUoS charges are designed to reflect the actual costs of distributing electricity. The time-of-use rates (Red, Amber, Green) provide a method for recovering costs for consumption at peak times. The capacity charges, which will increasingly consider Available Supply Capacity, ensure that organisations with higher demands contribute more towards the infrastructure required to support these demands. However, the introduction of charges like the SOLR and Bad Debt adders introduces complexity and may affect the predictability of costs for organisations.

Performance management of DNO costs and outcomes

DNO performance is monitored through the RIIO2 process. RIIO stands for 'Revenue = Incentives + Innovation + Outputs'. Outputs are measured for metrics in the following areas[2]:

- Reliability: We expect companies to improve network reliability and reduce the number and duration of power interruptions.
- Connections: Companies will provide a better service for customers wanting to connect to the network.
- Customer Service: We incentivise companies to deliver good customer service and listen to stakeholders.
- Social Obligations: Companies will do more to help vulnerable customers, particularly during power interruptions.
- Environmental: Companies must reduce their carbon emissions and other environmental impacts.
- Safety: Companies are funded to ensure the network remains safe and meets Health and Safety Executive standards.

For each of the defined outputs there can be associated incentives, for example:

- Interruptions Incentive Scheme
- Time to Connect Incentive
- Stakeholder Engagement and Consumer Vulnerability Incentive
- Totex Incentive Mechanism

Uncertainty in Forecasting Requirements

A critical aspect of setting budgets for DNOs and subsequently the rates they charge is forecasting demand for network upgrades and other services. Overestimation can mean that DNOs under-spend and receive some benefit under the totex incentive mechanism (TIM). TIM splits the benefit of any under spend between customers and the DNO, where around 50% of any underspend is shared between the DNO and consumers. TIM also applies to overspend i.e. additional costs are shared 50/50 between consumers and the DNO. The split of overspend and underspend is reviewed by Ofgem and a higher degree of sharing (in the DNOs favour) may be attributed where Ofgem has a higher degree of the certainty of cost forecasts and where the forecasts are independently verified[3,4]. The rate per DNO is shown in the tables below. There is a need for transparency in how these forecasts are made and the level of scrutiny the regulator has over this process.

[2] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/energy-network-indicators
[3] https://www.spenergynetworks.co.uk/userfiles/file/RIIO-T2_Annex_33_-_Sharing_Factor.pdf
[4] https://www.ssen-transmission.co.uk/globalassets/documents/a-network-for-net-zero/about-the-energy-industry-and-our-role/111regulatory-framework_final-draft.pdf

Table 1 below summarises the cumulative allowance and expenditure for DNOs between 2015-16 and 2021-22. This shows most DNOs underspend in the period, meaning £527 million of the £933 million goes to DNOs. Over the period this equates to approximately £4.73 per household per year of which £2.67 goes to the DNO. The picture varies from year to year, with the latest year for which data is available 2021-22, seeing a slight overspend in total. UK Power Networks, National Grid Electricity Distribution and Electricity North West are the operators who have generally had underspend over the whole period and in 2021-22.

DNO Operator (sharing rate)	DNO Region	Allowance	Expenditure	Difference	
		£m	£m	£m	%
Electricity North West (58%)	North West	2,085	1,917	-168	-8%
Northern Power Grid (56%)	North East	1,472	1,515	43	3%
	Yorkshire	1,953	1,921	-32	-2%
National Grid Electricity Distribution (70%)	Midlands	2,318	2,329	11	0%
	East Midlands	2,346	2,312	-34	-1%
	South Wales	1,228	1,163	-65	-5%
	South West	1,890	1,831	-59	-3%
UK Power Networks (53%)	London	2,007	1,741	-267	-13%
	South East	1,941	1,657	-284	-15%
	East Anglia	2,889	2,622	-268	-9%
Northern Power Grid (56%)	North East	1,472	1,515	43	3%
	Yorkshire	1,953	1,921	-32	-2%
Scottish and Southern Electricity Networks (56%)	North Scotland	1,492	1,519	26	2%
	Southern	2,635	2,670	34	1%
Total	**GB**	**27,957**	**27,023**	**-933**	**-3%**

Table 1: DNO allowance and expenditure cumulative 2015-16 to 2021-22[5]

[5] https://www.ofgem.gov.uk/sites/default/files/2023-03/RIIO-ED1%20Network%20Performance%20Summary%202021-22.pdf

Looking in more detail at areas of overspend and underspend, it appears that underspend has generally been in longer term investment in networks i.e. network reinforcement and replacing equipment. Conversely overspend has generally been in shorter term operational activities.

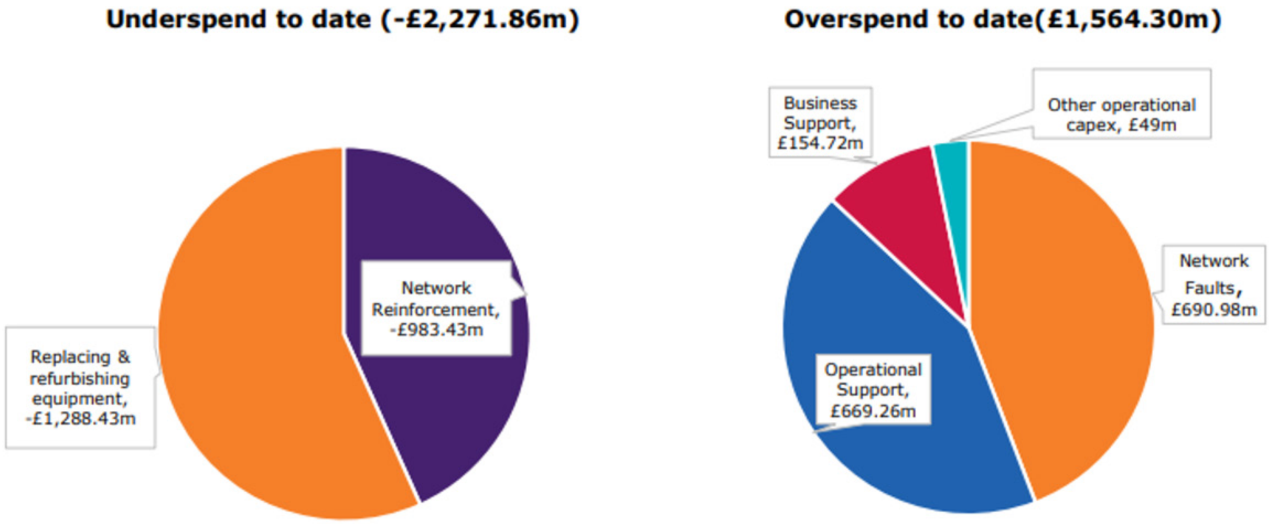


Figure 12: Detail of under-spend and over-spend by DNOs in the period cumulative 2015-16 to 2021-222[2]

DESNZ has recently outlined the required investment requirements necessary for the UK energy network to support a net-zero future. As highlighted by Arthur Downing, to achieve our targets for a Net Zero future with a Low Demand scenario we would need £5,612m in CAPEX, an amount only previously matched with a nationalised energy system (figure 13). Given that some DNOs are consistently underspending, there remain questions about whether Ofgem have the right performance measures in place to ensure customers' needs are met and whether they are incentivised correctly to meet our long term needs.

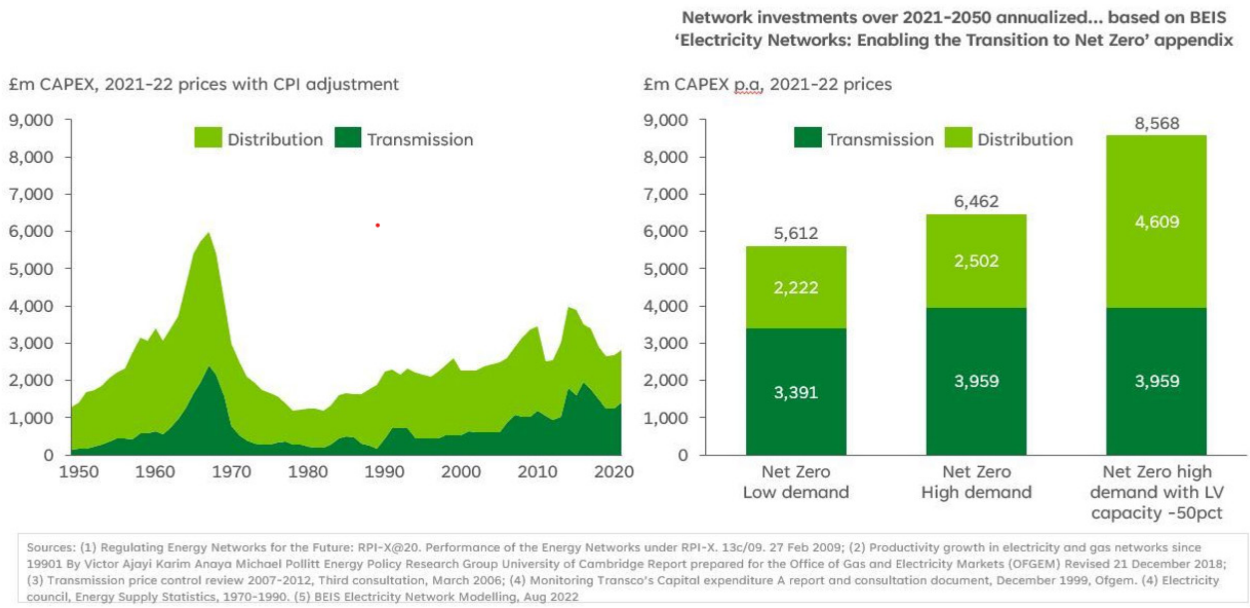


Figure 13: Historical CAPEX expenditure on electricity networks - source[6].

[6] https://www.linkedin.com/pulse/endowments-energy-sector-productivity-uk-since-1948-arthur-downing-doptc%3FtrackingId=2VlwZqT2Mcuad8qEEi Pxhw%253D%253D/?trackingId=2VlwZqT2Mcuad8qEEiPxhw%3D%3D

Failure of Ofgem in DUoS Cost Translation

A significant issue with the current DUoS structure is the lack of clarity in how the costs submitted by Distribution Network Operators (DNOs) translate into the tariffs set by Ofgem. This process is not transparent, and stakeholders find it challenging to understand the correlation between DNO costs and the cost specified by Ofgem in the network cost annexes.

Currently, stakeholders must navigate through various PDFs and PowerPoints on individual DNO websites to piece together this information. This method is not only time-consuming but also inefficient, leading to difficulties in comprehending how the final DUoS tariffs are derived. Such a fragmented approach hinders stakeholders' ability to effectively analyse and plan for these costs. The costs provided by Ofgem are set out below:

Cost Name	Cost Description
DUoS fixed charge	Cost for supply an MPAN (p /day)
DUoS Unit Charge (p/ kWh supplied)	Cost for supplying the required demand. Measured as p / kWh at GSP for RAG Band for weekend/ weekday at on or off-peak

Recommendations for Ofgem

1. Clear Translation Formulas: Ofgem should provide explicit formulas that demonstrate how DNO-submitted costs are translated into the final Ofgem tariffs. This would enhance stakeholders' understanding of the tariff-setting process.
2. Centralised Data Repository: All relevant data and documentation should be made available on Ofgem's website in a centralised and easily accessible format. This approach would eliminate the need for stakeholders to search through multiple sources.
3. Machine-Readable Data Formats: Ofgem should ensure that all data related to DUoS charges is available in a machine-readable format (e.g. CSV). This would facilitate easier analysis and understanding of the tariffs.

By following these recommendations, Ofgem can ensure that the DUoS charges remain clear, fair, and justifiable, thereby maintaining trust in the regulatory framework and aiding organisations in their planning and operations.

BSUoS Costs

The Balancing Use of Systems costs are those associated with the activities of the National Grid ESO (electricity system operator) in balancing electricity supply with demand on a continuous basis. This covers a number of different activities (cost in 2022/23[7]):

- Balancing Mechanism (BM) (£1,536m): When there is a variance between scheduled energy generation and actual demand, the Balancing Mechanism activates to maintain grid stability. It allows for the immediate adjustment of electricity supply or demand by contracting with market participants, such as generators or consumers, to either increase or decrease their output. This continuous fine-tuning ensures that the grid operates within acceptable frequency and voltage limits, preventing disruptions and ensuring a reliable and secure electricity supply for consumers across the UK.
- Ancillary Services (£1,383m): This covers a range of services, including frequency response, demand flexibility service, reactive power and reserve services. These cover a range of purposes that are contracted separately from BM activities.
- ESO Internal Allowances (£384m): Internal costs (allowed revenue) are calculated in the Price Control Financial Model (PCFM) process as determined by the current RIIO-2 price control period.
- Energy Trading Costs (£1,231m): These are costs for trading done with generators outside of the balancing mechanism e.g. forward trading via bilateral agreements (typically between a day ahead and one hour ahead)[8].

BSUoS is a charge per MWh at both a fixed rate and a rate that varies in each half hour of the day. Previously the charge was levied on both generators and final demand (suppliers), but as of April 2023 the charge is only levied on final demand[9]. The rationale for this is to remove distortions in the market for generation that come from applying the levy to generation. Whilst this does increase the cost to the end customer for the BSUoS element (~£7 for the average consumer in 2025), Ofgem's analysis estimates a positive impact on wholesale cost which offsets some of this[10] .

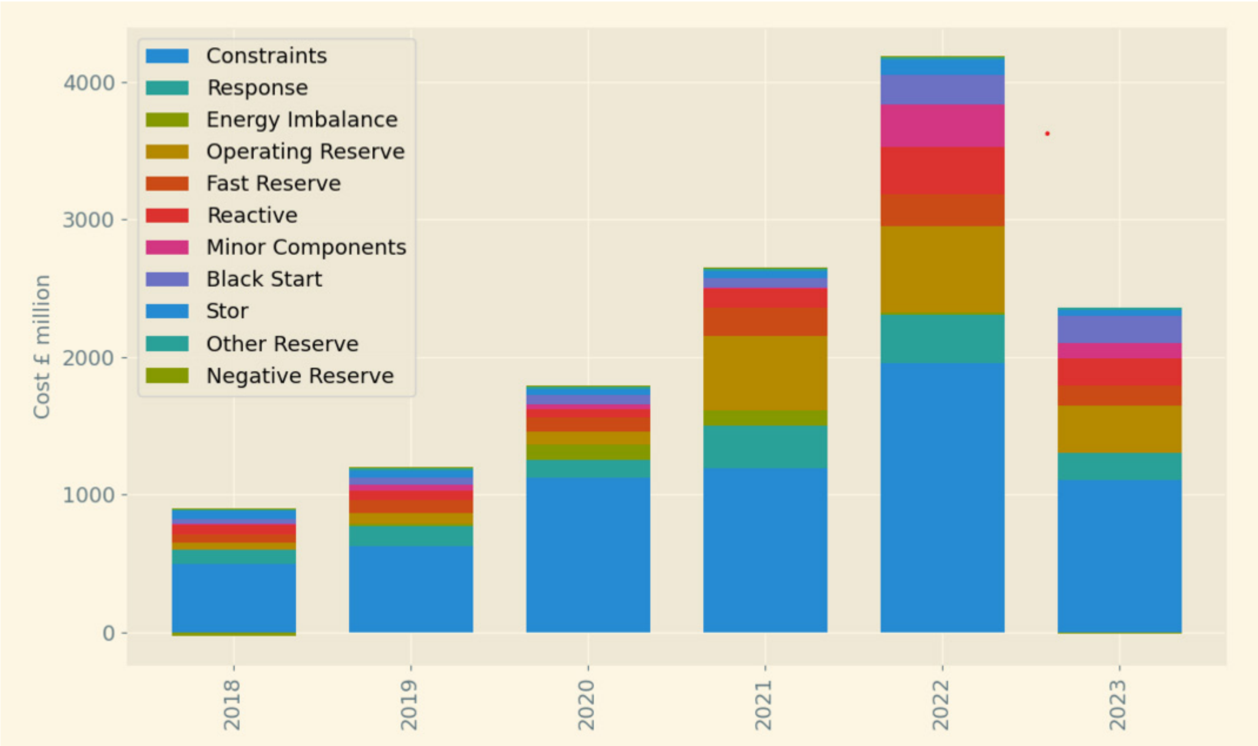


Figure 14: Makeup of balancing costs 2018 to present

Constraint payments make up by far the largest single cost element of National Grid's balancing costs. These payments are those made to generators to alter (reduce) their output to manage bottlenecks in the network at specific locations. This can be any kind of generator, but is often wind farms in the north of the UK that are required to turn off when there's not enough capacity on the transmission network. Generally constraint payments have been increasing over time. In 2022 these constraint payments totalled £2 billion. A secondary effect of the constraints being managed like this is that when wind farm operators are asked to turn down, National Grid will in a lot of cases require additional generators to turn on through the balancing mechanism. This will generally be gas generators that have a higher marginal cost, therefore increasing balancing costs again and increasing emissions.

[7] https://www.nationalgrideso.com/document/299026/download
[8] https://www.nationalgrideso.com/industry-information/balancing-services/trading#Trading-Instruments
[9] https://www.ofgem.gov.uk/publications/cmp308-removal-bsuos-charges-generation
[10] https://www.ofgem.gov.uk/sites/default/files/2022-04/CMP308%20Decision_0.pdf

The cost of constraints is partly a result of the market design in the UK, and could potentially be solved by for example a change to location based pricing. Ultimately though constraints exist in the first place because investment in the network has fallen behind the rate needed to keep up with demand for low carbon technologies .

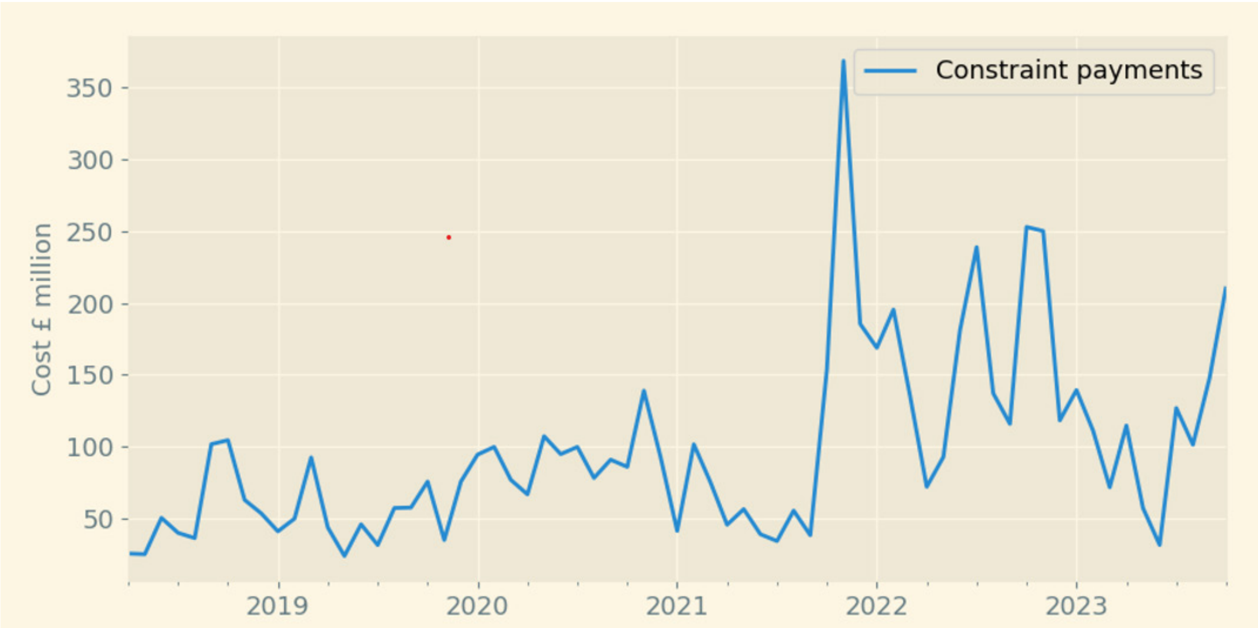


Figure 15: Change in constraint payments by month

Line Losses

Current State of Line Losses Calculation

Line losses, a key element in measuring energy transmission efficiency, denote the amount of energy lost while transmitting electricity between the demand point and the central point in a Distribution Network Operator's (DNO) network. Currently, these losses are calculated using a static model, assigning a uniform line loss factor to each site within a specific area, such as a neighbourhood. Although this factor remains relatively constant, it often fails to accurately represent the effect of line losses at a half-hourly level.

Furthermore, the traditional assumption underpinning line losses is based on a transmission model that involves electricity flowing from a generator, through the DNO's network, into a transmission network, and then back to the DNO's network before reaching the final consumer. This model was more applicable in times of centralised electricity generation with fewer, large-scale power plants. However, the modern energy landscape in Great Britain has evolved into a more decentralised system, characterised by numerous generation sources dispersed across the regions. This shift is critical to understand because it challenges the traditional assumption of line loss calculation. In many cases, electricity generation and consumption occur within the same Grid Supply Point (GSP) area, reducing the extent of electrical losses that would otherwise occur in a more centralised system.

[11] https://www.regen.co.uk/wp-content/uploads/Regen-Insight-Managing-Constraint-Costs.pdf

How are line losses accounted for in household bills

Ofgem provides the loss factors that are used to adjust for the electricity that is lost as it is transmitted across the network. These loss factors are applied to the amount of electricity that suppliers put into the network to ensure that they are appropriately charged for both the energy supplied and the losses incurred in transporting that energy to consumers.

In essence, if a region has a loss factor of 110%, this implies that for every 100 units of electricity put into the network, the supplier is charged as if they supplied 110 units, to account for the estimated 10% loss during transmission and distribution. This approach ensures that suppliers contribute towards the costs of losses in proportion to their use of the network. These line losses are applied to TNUoS NHH demand tariff to create the unit rate component of TNUoS costs and are applied to the capped BSuoS values to create the BSuoS cost component of the network costs.

Is a dynamic approach needed?

The current approach to calculating line losses could be substantially improved by adopting a dynamic framework. In the United States, for example, line losses are calculated at the transmission network level, taking into account factors like thermal conditions, which can significantly affect line loss rates. Such a dynamic approach would offer a more precise and responsive way of assessing line losses, ultimately leading to more accurate billing and resource allocation.

Additionally, across different DNO regions, there are variations in line losses, yet the structure for calculating these losses remains consistent. By adopting a more nuanced model, these regional differences could be more accurately reflected, leading to fairer and more efficient energy distribution.

Potential for Greater Accuracy and Savings

Adapting the line loss calculations to include temporal dynamism could enhance the accuracy of these charges. For instance, large energy consumers like supermarkets with refrigeration needs, which typically consume most of their power during midday, could see more accurate billing, especially in regions like Cornwall where energy usage patterns might differ significantly from the national average.

Recommendations

Given these considerations, there is a case for Ofgem to reform its methodology for calculating line losses. Moving towards a dynamic, geographically sensitive framework would not only bring about more equitable billing for consumers but also encourage a more efficient and responsive energy network. Such a reform is aligned with the broader goals of energy efficiency and sustainability, especially critical as the UK progresses towards its net-zero objectives. This approach would acknowledge the varied and changing nature of energy consumption and transmission across different regions, paving the way for a more accurate, fair, and sustainable energy system.

Relationship between network costs and population sparsity

Differences in electricity network

Using the ONS Rural Urban Classifications from 2011, we can classify each small area (Lower Super Output Area) into urban or town and rural and see how many electricity and gas meters in each DNO region fall into the respective classifications. Chart XX shows the proportion of meters in each region that falls in different urban-rural areas.

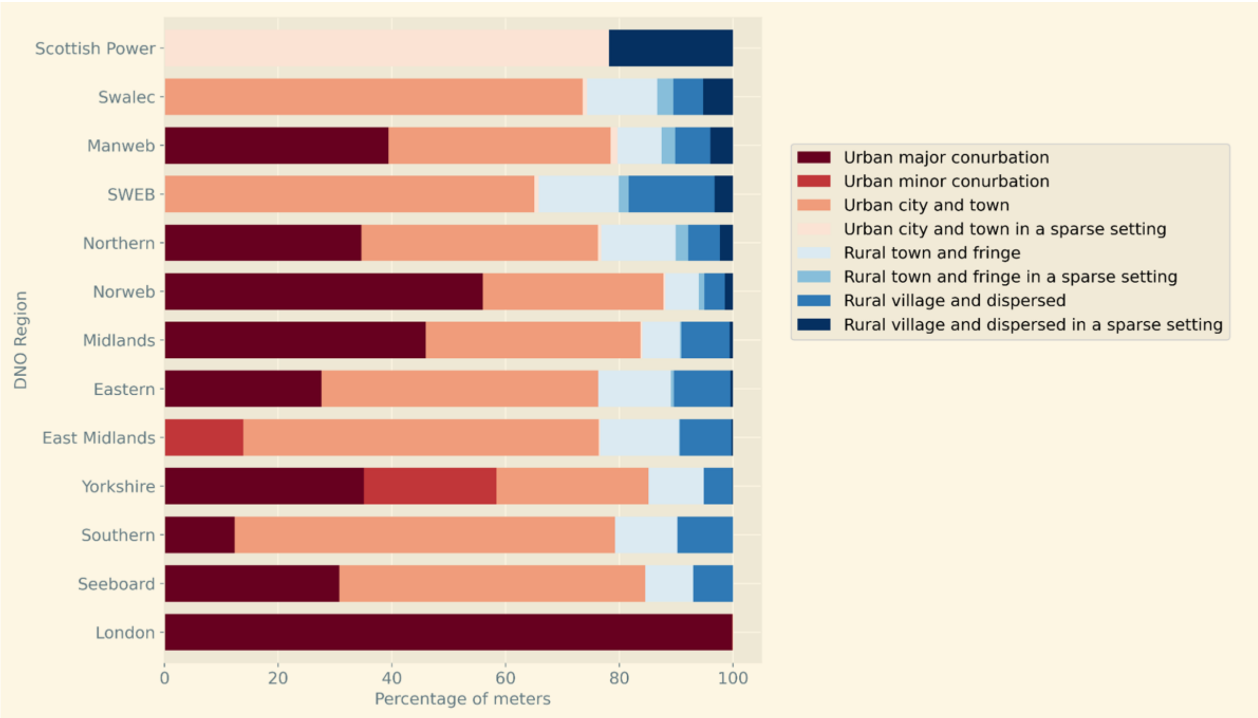


Figure 16: Breakdown of meters in different rural and urban areas

Figure 16 below shows a simplified breakdown separating urban areas from Town and Rural and comparing it to the standing charge for each DNO region. Whilst there is a relationship between the two as expected there are clear outliers, notably Eastern and Manweb. Whilst they have similar proportions of electricity meter points in town and rural areas (~22%) they have very different standing charges with Manwebs being almost 20 pence greater per day.

Figure 17: Breakdown of meters in rural and urban areas against standing charge

Profits and Ownership of Electrical Transmission and DNO

Transmission

Financial Overview:

- Dividend Payments: Over the past decade (ending March 2023), National Grid plc has consistently rewarded its shareholders, paying out an average of £1.6 billion in dividends annually. This translates to a staggering total of nearly £28 billion in dividends since privatisation.
- Investment vs. Dividend Payouts: The company's approach to financial management is reflected in its investment and dividend strategy. For every £1 National Grid UK Electricity Transmission (NGET) has invested over the past decade (gross capex), 40p has been returned to shareholders as dividends, totaling nearly £4.1 billion in dividends from the UK transmission business alone.
- Revenue to Shareholder Returns: Approximately 13% of NGET's revenue, derived mainly from customer bills, has been directed towards shareholder dividends.
- Profit Allocation: The dividend payouts by NGET represent 62.3% of the segment's post-tax profits.
- Future Commitments and Comparisons: National Grid plc has pledged to invest up to £9 billion in its UK electricity transmission business in the five years leading to 2026. However, if the company continues its past trend of dividend payouts, nearly the same amount (£7.8 billion) could be paid in dividends as its maximum potential investment in UK transmission over this period.

Ownership Structure

Corporate Identity:

- **Global Operations:** National Grid plc operates internationally, with approximately equal operations split between the UK and the United States.

Shareholder Distribution:

- **Global Shareholders:** As a publicly listed company, its shareholders are globally distributed. The significant shareholders include major US asset management firms and international investment authorities.
- **Major Shareholders:** The top five shareholders, including BlackRock, Capital Group, and Vanguard, collectively control nearly a quarter of all shares.

Shareholder Name	Ownership of Shares Outstanding
BlackRock	10%
Capital Group	5%
Vanguard	%4
Abu Dhabi Investment Authority	%3
Lazard	%2
State Street	%2

Distribution

Financial Overview and Profitability

- **Exceptional Profit Margins:** The Distribution Network Operators (DNOs) have consistently demonstrated high profit margins, ranking as one of the most profitable sectors in the UK in 2023, with a margin of 42.5%. See top performing industries by profit margin from IBIS below.
- **Investment vs. Revenue:** Despite being capital-intensive industries, the profit margins of DNOs indicate a substantial portion of their revenue is directed towards profits, suggesting a need for scrutiny regarding their investment in infrastructure and maintenance.

Industry	Profit Margin 2023
Electricity Distribution in the UK	45.7%
Venture Capital in the UK	43.3%
Gas Distribution in the UK	%39.3
Private Equity in the UK	%35.6
Banks in the UK	%35.2
Legal Activities in the UK	%34.3
Search Engines in the UK	%34.0
Open-Ended Investment Company Activities in the UK	%33.6

Table 2: DNO Profit Margin (IBIS 2023)

Challenges and Investment

- Structural Underinvestment: There is an ongoing concern about underinvestment in the grid, evidenced by long wait times for new connections and inadequate capacity to handle electricity generated by new projects.
- Cost Implications for Consumers: The high profit margins of DNOs suggest that a significant portion of consumer bills is contributing to these profits rather than being reinvested into the grid, potentially impacting the affordability and reliability of electricity supply.

Ownership Structure

- Complex Ownership: The ownership of DNOs is varied, with some being part of multinational corporations and others being owned by private entities or individuals, including figures such as Warren Buffett and Li Ka-Shing.
- Implications of Ownership: This varied ownership landscape raises questions about the alignment of DNO operations with public interest, particularly in the context of the need for substantial investment in grid infrastructure for the transition to a decarbonized energy system.

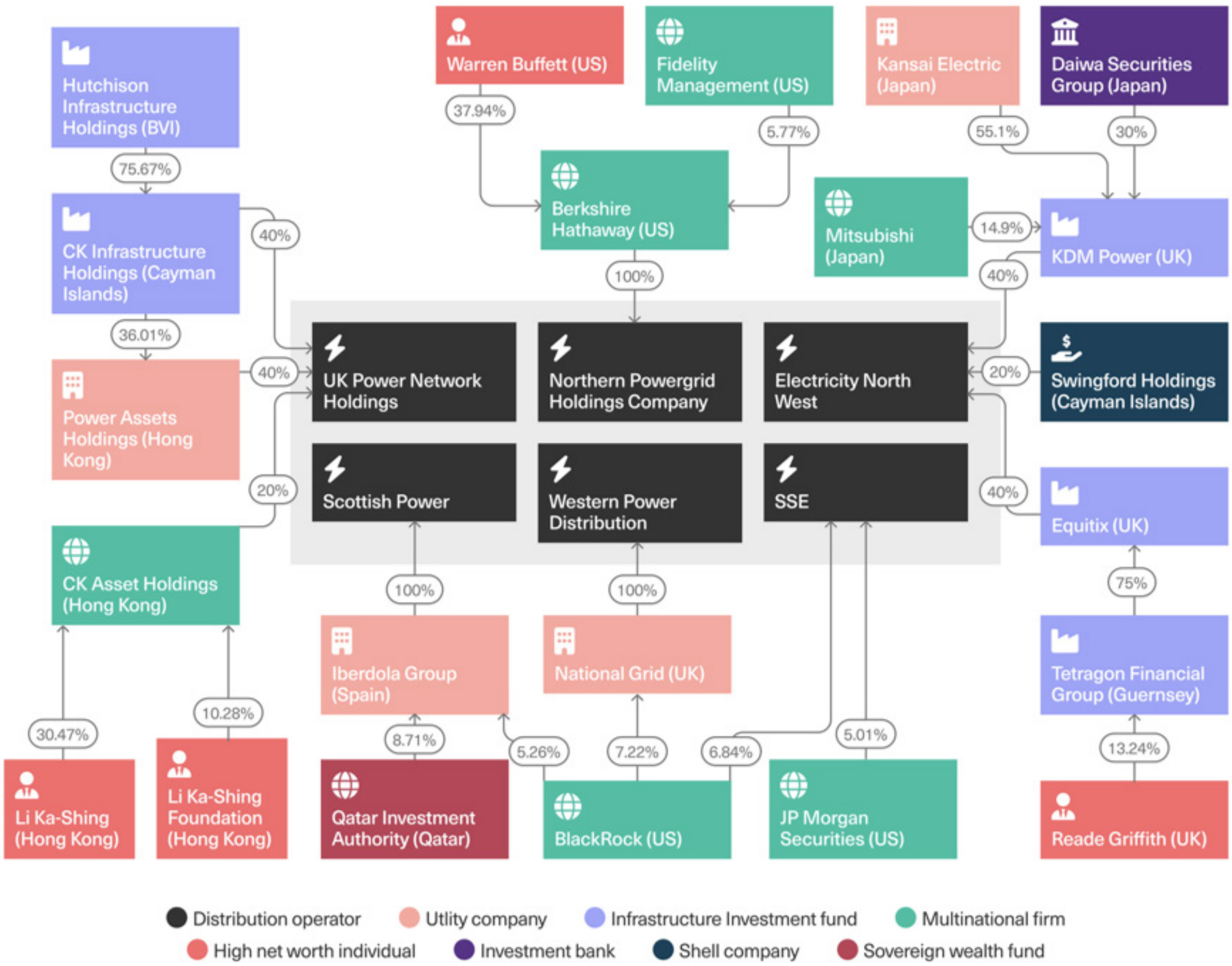


Figure 18: Ownership of DNO operators in the UK - taken from common-wealth Study[13].

[12] IBISWorld (2023). Industries with the Highest Profit Margin in the UK in 2022. IBISWorld. Accessed: https://www.ibisworld.com/united-kingdom/industry-trends/industries-highest-profit-margin/, 23 December 2023.
[13] https://www.common-wealth.org/publications/grid-is-good-the-case-for-public-ownership-of-transmission-and-distribution

Can a privatised energy network deliver on our net-zero needs

Since the privatisation of energy networks in the UK, there has been a noticeable shift in the investment in electricity and gas transmission and distribution networks. This shift becomes more apparent when contrasted with the period of nationalisation. The pace of building and upgrading these networks has slowed significantly, and the associated costs have risen substantially. Even when adjusted for CPI, in our privatised system it is now 8x more expensive to upgrade the gas network and 19x more expensive to upgrade the electricity network .

In the electricity network, a slowdown in investment has led to delays and increased expenses in network development. As pointed out by Arthur Downing, in order to meet our objectives for a Net Zero future under a Low Demand scenario, we would require a CAPEX investment of £5,612 million, a level of funding that has only been equaled in the past during periods when our energy system was under national ownership.

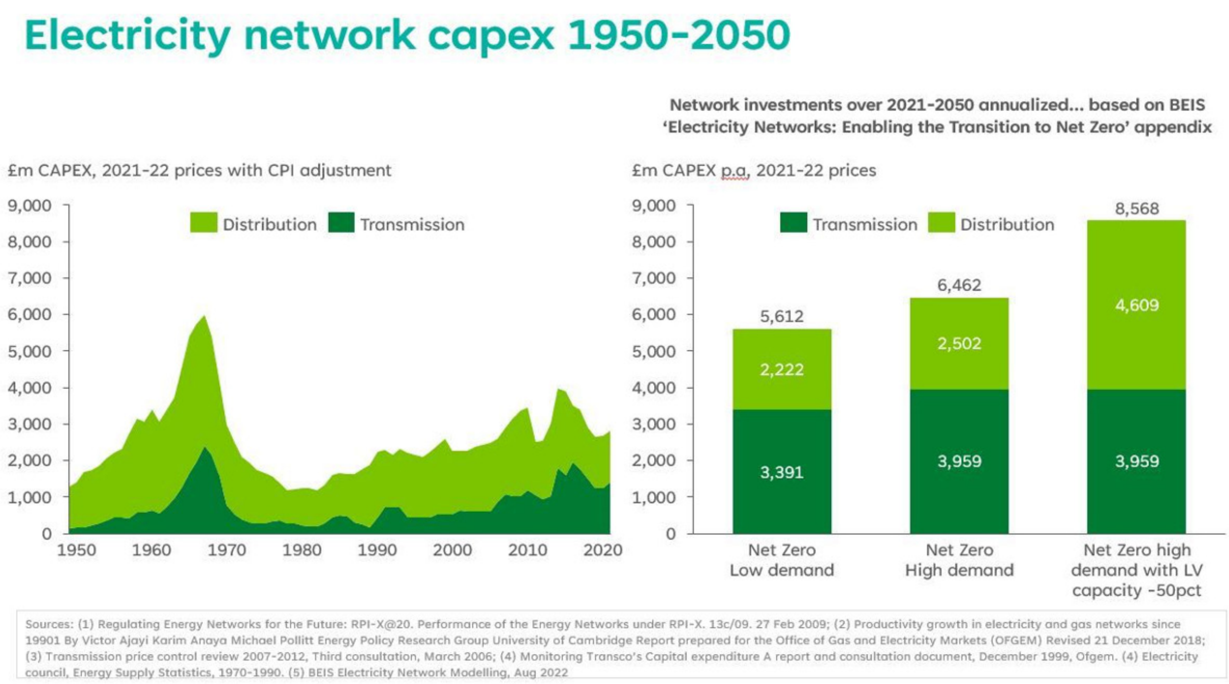


Figure 19: Historical CAPEX expenditure on electricity networks

[14] https://www.linkedin.com/pulse/endowments-energy-sector-productivity-uk-since-1948-arthur-downing-doptc%3FtrackingId=2VlwZqT2Mcuad8qEEiPxhw%253D%253D/?trackingId=2VlwZqT2Mcuad8qEEiPxhw%3D%3D

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[INFL] Carole Nakhle, "Energy prices and inflation: Politics trump the economics" https://www gisreportsonline.com/r/energy-prices/

Appendices

Appendix 1: Data Analysis details and Assumptions

- Months were assumed to consist of 30 days and 1/12th of a year.
- Years were assumed to be 365 days.
- For the price analysis section, fixed and variable tariffs were combined. There were no new fixed tariffs in April, so it was difficult to compare fixed tariffs over time.
- Only domestic import tariffs were considered.
- Due to discrepancies with how prices are calculated, tariff information from the Supplier "Utilita" was disregarded.
- For tariffs with a dual fuel discount, half the discount was applied to each of the annual costs of gas and electricity.
- Average GB prices are taken from a dataset that is separated into tariffs that have electricity rates and tariffs that have gas rates. This was then grouped by the supplier name, name of the tariff, whether it is fixed or variable, whether it is dual or single fuel, and the payment type. Any tariff which is unique for any of these categories is considered as separate. The average annual prices were then found from these data points. The number of customers on any given tariff is not considered in this data analysis.
- For the DNO region analysis, the separated electricity and gas data was grouped by supplier, tariff name, whether it is fixed or variable, whether it is dual or single fuel, and the DNO region.

Appendix 2:

DUOS Costs:

The document lists a variety of charges associated with the use of the distribution system for Eastern Power Networks, effective from April 1, 2025. Here are the different types of charges mentioned:

1. Import Charges:

- Super Red unit charge (p/kWh)
- Fixed charge (p/day)
- Capacity charge (p/kVA/day)
- Exceeded capacity charge (p/kVA/day)

2. Export Charges:

- Super Red unit charge (p/kWh)
- Fixed charge (p/day)
- Capacity charge (p/kVA/day)
- Exceeded capacity charge (p/kVA/day)

3. Site Specific Preserved Charges:

- Red/black unit charge (p/kWh)
- Amber/yellow unit charge (p/kWh)
- Green unit charge (p/kWh)
- Fixed charge (p/MPAN/day)
- Capacity charge (p/kVA/day)
- Exceeded capacity charge (p/kVA/day)
- Reactive power charge (p/kVArh)

4. Supplier of Last Resort Charges: