CORNWALL INSIGHT

CREATING CLARITY

Insight paper

Addressing the cost of electrification

Decarbonising heat for energy intensive sectors

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About the Confederation of Paper Industries

The Confederation of Paper Industries (CPI) is the leading organisation working on behalf of the UK's Paper-based Industries.

CPI represents the supply chain for paper; comprising paper and board manufacturers and converters, corrugated packaging producers, makers of soft tissue papers and collectors of paper for recycling.

About Cornwall Insight

Getting to grips with the intricacies embedded in energy and water markets can be a daunting task. There is a wealth of information online to help you keep up-to-date with the latest developments, but finding what you are looking for and understanding the impact for your business can be tough. That's where Cornwall Insight comes in, providing independent and objective expertise. You can ensure your business stays ahead of the game by taking advantage of our energy market training, publications, consultancy and market research services.

Content

Addressing the cost of electrification

1. Executive Summary

This report outlines the challenges that energy intensive industries (EIIs) face in decarbonising their heat supply, (currently dominated by natural gas) by switching to grid supplied electricity. The paper has been sponsored by the Confederation for Paper Industries (CPI) and therefore has a particular focus. However, many of the challenges highlighted here may be applied to – and may reflect the experiences of – other energy intensive industrial sectors.

The domestic economy has relied on a reliable and affordable natural gas supply to heat homes and power processes for many years, including increased use for electricity generation. Since 2005, GB has been a net gas importer, relying on supplies including output from the UK Continental Shelf (UKCS), pipeline imports from Norway, cargoes of Liquefied Natural Gas (LNG), and links to gas networks in mainland Europe. While this diversity of supply was expected to help avoid supply constraints, the global post COVID-19 lockdown recovery, together with geopolitical concerns over supplies from Russia, has changed this assumption and resulted in calls for a new energy policy.

Additionally, unabated natural gas consumption is not compatible with the long-term goals of net zero due to the carbon intensity of the fuel, and businesses are now facing a policy drive to stop using natural gas and are assessing options for decarbonising their heat. However, many businesses are struggling with a lack of commercially viable alternatives, even in the face of high gas prices. Hydrogen remains at best a number of years away from being widely commercially viable and electrically-powered heating – which will decarbonise as the carbon intensity of grid electricity decreases – faces considerable cost challenges, not least because of a link between the cost of gas and the cost of electricity. Figure 1 provides more details.

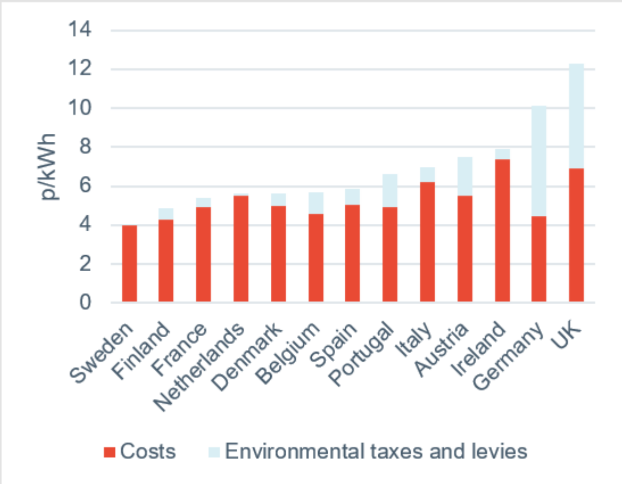
Our analysis indicates that switching heat generation from natural gas to electricity is not currently a commercially viable option for industry, because the cost of grid supplied electricity is much higher than the comparative cost of natural gas. For internationally traded energy intensive goods, UK-based sites cannot stay competitive if they face higher energy costs than those faced by competitors outside the UK – where there may not face the same drive to immediately begin the phase out of natural gas for heat production.

This paper explores these issues and outlines a number of policy options to address the price discrepancy between gas and electricity, so that switching to electricity from gas could become a commercially viable proposition.

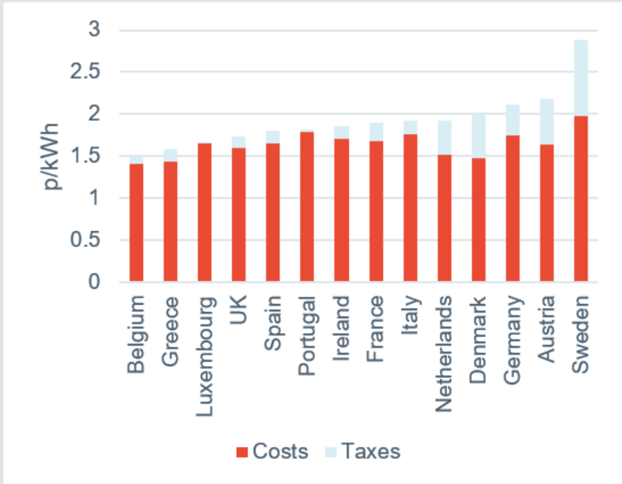
Figure 1: Summary of the key challenges in decarbonising industrial heat

Great Britain has some of the highest delivered electricity prices in Europe for large consumers. By contrast, gas prices are in line with other major economies. The electricity cost disparity is largely due to the allocation of non-commodity costs as well as the carbon price floor which increases the cost of fossil carbon based generation, currently the GB marginal source of electricity.

Delivered electricity costs - very large consumers (H2 2020)



Delivered gas prices for large consumers (H2 2020)



Source: BEIS

Please note that these charts show prices before the current energy price crisis, but the overall international price differentials remain valid.

Assuming direct electrical boilers are used to replace heat from gas boilers, then – given that delivered electricity prices are around six to seven times current delivered gas prices – a huge reduction in the cost of electricity is required if operating costs are to stay the same.

Looking at heat pumps as a potential alternative, then the best coefficients of performance are presently around 4. This means gas prices need to be over a quarter of the price of electricity for heat pumps to be viable (excluding upfront capex and technical differences). However, heat pumps are not suitable for many industrial processes and heat demand profiles, where the heat requirement is for high-temperature steam.

It follows that both options are a long way from being economically viable at the current time, without policy support or market change.

In Cornwall Insight's earlier sister paper "*Who pays for net zero?*", the authors argued for the reallocation of policy costs from the electricity bill into either the gas bill or wider taxation. For households, this could support the decision to electrify heat from the perspective of ongoing fuel and operation costs.

The situation is more nuanced for EIIs, as some companies already receive a significant exemption from some of the main policy costs and taxes across electricity and gas – thereby meaning that any reduction in these costs will have significantly less impact on the business case to electrify heat – though we note that GB based installations face considerable higher network costs than their overseas competitors in Europe and elsewhere, and these are not discounted.

> “Recent research by Ofgem and BEIS acknowledges that the UK has the most expensive electricity in the major manufacturing economies

Those exemptions which are in place are only partial and limited in the number of sectors judged as eligible. Eligibility is not consistent even within sectors due to the imposition of cost impact thresholds based on fiscal data drawn from full company accounts, rather than a specific installation.

Further, given that investment decisions are taken on a basis of 25 years or more, and EII exemptions are not bankable over this period due to potential policy change, such exemptions cannot support investment alone.

Therefore, wider options need to be considered in order to remove the current economic disparity between the costs of gas and electrified heating. This paper outlines some non-exclusive options that can support large industrial users in choosing to decarbonise heat via electrification.

1.1 Summary

The commercial reality is that individual governments cannot set policy in isolation because businesses, especially energy intensive industries exposed to competition from areas with lower costs, can only transition to a low carbon fuel source when the commercial case to do so is appropriate and internationally competitive. The current market, regulatory and policy environment provides little incentive or commercial opportunity for large and energy intensive businesses to fundamentally alter their main sources of heat generation.

This paper presents a non-exhaustive range of potential policy and regulatory considerations, each with their own merits and challenges. These are summarised in Figure 2 overleaf.

1.2 Conclusions

Current GB energy retail energy prices make it uneconomic for energy intensive businesses to transition from natural gas to supply their activities with lower carbon electricity, due to the much higher costs of retail electricity compared to retail natural gas. These higher costs would make UK manufacturing unattractive and could open these sectors to imports from international sites with lower manufacturing costs, resulting in a loss of jobs and economic activity (a process referred to as “carbon leakage”).

Figure 2: Merits and challenges of each of the options summarised in this paper

Option	Merits	Challenges
Market-based solution –Corporate Power Purchase Agreement	Established market models Relatively straightforward to deliver under current market environment Supports ESG goals of buyer and can directly support construction of low carbon assets	Typically, no discount to market price because the delivered electricity price is near identical in tariff composition as the non-commodity costs must be added when the power passes through the grid
Network charge reforms	Deliverable via regulatory and code governance change – no legislative amendments needed Reductions in cost would more align delivered prices with international comparators	Lower costs for industry result in reallocated costs to other types of user, including SMEs and households Cuts across Ofgem's Targeted Charging Review (TCR), which is broadly applying higher costs to large users. May impact cost-reflectivity or appropriate residual allocation
Reduced or removed subsidy costs for low-carbon generators from the electricity bill	Provides marginal support to the decision to electrify heating (as part of a package of measures) Costs reallocated to gas can act as a double incentive to decarbonise heat but only if the cost of electricity is sufficiently reduced to be a realistic alternative	Requires legislative and/ or policy change to implement Lower costs for industry mean higher costs for all other electricity consumers
Amending the delivered gas price (policy levies or carbon taxation)	Removes or reduces the disparity between electricity and gas prices Makes delivered costs more reflective of the carbon intensity of fuels	Requires detailed policy reform to implement, likely linked to the carbon intensity of different types of fuels
Policy instrument (heat CfD or similar)	Provides financial support to opt for low-carbon heating options Provides investor certainty and clarity on project revenues	Requires new legislation and funding mechanism Lengthy to implement A number of uncertainties on scheme comparators including pricing benchmarks, pass-through costs, and scheme design

While none of the options discussed in this paper present a panacea to support businesses in making decisions to decarbonise their heating needs, they do present a range of options which can be explored, likely in combination, to develop a realistic opportunity to decarbonise industry.

To reach net zero by 2050 (and the challenging interim targets), it is clear that the pace and level of change need to accelerate sharply, and this needs to be driven by government policy encouraging the take-up of low-carbon alternatives and discouraging the use of fossil fuels.

Operationally, the electricity grid of the future is also likely to be very different to that of today with significant levels of intermittency, and potential explicit procurement of services such as inertia and reactive power/ voltage support. There may be further value in energy intensive users providing a large and stable load or demand-side response services in response to grid needs. In this context, we also note the existing role of gas-fired onsite electricity generation on many industrial sites which, if curtailed, could both add to the overall grid demand and reduce flexibility in the supply system, adding to existing and growing pressures on electricity networks.

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Decarbonisation policies that drive energy costs higher in the UK than elsewhere make manufacturing less internationally competitive

2. Introduction by the Confederation of Paper Industries

As part of the national strategy to transform UK emissions of climate change linked gases to deliver net zero by 2050 (with challenging interim targets in 2030 and 2035 driving early action), policymakers are looking at decarbonisation strategies across the whole of the economy. Amongst the sectors most affected by these proposed changes are the so-called Foundation Industries – installations providing 75% of the materials that underpin manufacturing and construction supply chains, and where product shortages quickly translate into widespread economic problems.

These sectors (including chemicals, cement, ceramics, glass, metals and paper) are characterised by the energy intensive nature of their manufacturing processes and jointly they emit around 10% of total UK emissions of carbon dioxide, consume 12% of non-domestic electricity and 8% of non-domestic gas. With sites being mostly located in less affluent areas, they already directly support 210,000 jobs, deliver £29 billion in value to the UK economy each year and their potential to help the levelling up agenda is recognised by Government. Indeed, Post-Brexit a number of policies are seeking to support these sites, securing jobs and attracting new investment to help deliver a re-balanced economy.

With energy being one of the top three costs for energy intensive installations, decarbonisation polices that drive these costs higher in the UK than elsewhere inevitably make these sites less internationally competitive. Furthermore, driving up costs will cascade through whole supply chains. With such sites being capital intensive, a progressive loss of competitiveness means losing out on new investment and eventually closure. If replacement plant is outside the UK, then domestic manufacturing is replaced by imports. Rather than delivering real carbon savings, closure of domestic manufacturing means that emissions are simply moved to other countries – almost all with less ambitious climate change polices than the UK. If UK carbon accounting was adjusted to include imported manufactured goods, much of the reported progress in emissions reduction proves to be illusionary.

A major part of the Government strategy is to support the decarbonisation of energy intensive sites by technological innovation and changing the energy sources used by industry to reduce their carbon intensity. The Committee on Climate Change (evidence for the 6th Carbon budget) has examined these issues in some detail and identified a number of different approaches that could be taken including electrification, bio-gas, hydrogen, biomass, resource and energy efficiency.

This report looks at electrification – the option to switch from natural gas to grid supplied electricity, on the assumption that the electricity provided by the grid is progressively decarbonising as the proportion of low carbon generation continues to increase. BEIS confirmed in October 2021 its intention that the grid be zero-carbon by 2035 [1].

1 https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035

Assuming grid supplied electricity continues to decarbonise, then at some stage it saves carbon by replacing industrial use of gas with electricity – firstly in gas boilers, but also potentially also replacing heat and power from onsite gas-fired Combined Heat & Power plant.

The proposal to substantially increase the use of grid-supplied electricity by industry comes with a number of technical challenges, such as the added total electrical demand, grid reinforcement needs, supply issues, new equipment and the loss of flexible industrial operation in balancing the grid. These issues are considered in a second discussion paper (in partnership with Fichtner Consulting Engineers) while this paper (in partnership with Cornwall Insight) is focused on one specific question – can industry afford the operating costs of swapping from gas to grid supplied power and stay competitive?

Recent research by Ofgem and BEIS acknowledges that the UK has the most expensive electricity in the major manufacturing economies, with costs for UK sites consistently higher than in nations manufacturing goods to import to the UK [2]. While recent wholesale market supply issues have caused real problems and price spikes, in the long-term UK gas prices have been internationally competitive; meaning that the current use of expensive grid-supplied electricity to generate heat is minimal.

High electricity costs largely arise from non-commodity costs charged to customers, such as network, distribution, system management, green levies and taxation. While Government has acknowledged this issue – and indeed developed a number of schemes that partially offset these costs for some installations – the coverage of the compensation schemes only addresses part of these additional costs while the schemes are patchy in coverage.

Support schemes are also time-limited, and periodic reapplication is required – meaning a mismatch between the length of the support schemes and the length of the prospective investment. This means that investment decisions cannot bank on the support being in place for the long-term.

Historic high costs for grid supplied electricity have resulted in a number of industrial sectors (with both an electrical and heat requirement (such as paper, chemicals and food & drink) investing heavily in on-site Combined Heat & Power plant. Indeed, for a number of sectors, regulatory guidance (the technical BREF documents that underpin the legally required site operating permits) remains that on-site CHP should be the default position. With the long-term use of such gas-fired plant now also being questioned, this paper also highlights the issues this will raise over the economic use of UK plant that comprises a significant regulatory driven investment for a number of companies.

2 https://www.ofgem.gov.uk/sites/default/files/2021-07/Final%20report-%20Research%20into%20GB%20electricity%20prices%20for%20EnergyIntensive%20Industries.pdf

3. Context

3.1 Energy Intensive Industry

Specific energy intensive installations may be eligible for partial exemptions from some of the costs levied on GB retail energy bills, in order to protect their competitiveness against global producers. Eligibility rules for each scheme differ, with periodic reapplication, meaning that the impact is uneven and cannot be counted by different sites when competing for investment decisions.

In this paper, we have partnered with the Confederation of Paper Industries, using the UK paper manufacturing industry as a representative example of an EII to discuss some of the issues arising for the potential electrification of GB industry and high domestic electricity prices..

3.2 The paper industry

The Confederation of Paper Industries (CPI) represents the UK paper industry, including paper and board manufacturing, packing providers, tissue manufacturers, and collection and recycling of paper. By 2021, the sector had cut carbon emissions by 72% compared to 1990 levels, ahead of the target for the wider economy. The 86 members of the CPI have turnover of £12.1bn/year and employ 62,000 people. BEIS's *Digest of UK Energy Statistics 2020* (DUKES 2020) reports that the industry consumed approximately 21.3TWh of energy in 2019, mostly in the forms of electricity (1.6TWh), natural gas (8.7TWh) and bioenergy (3.5TWh).

Papermaking sites (needing both heat and power) make extensive use of on-site Combined Heat and Power (CHP) plant to reduce some of the costs of energy use. DUKES 2020 reports 23 assets, with over 2.1GW of electrical and 6.7GW of heat production capacity within the sector. According to industry data, these generated 1.6TWh of power for use by the sector, and 0.4TWh for export, using primarily gas and biomass to fire these assets.

Parts of the paper industry have been partially exempted from certain energy costs due to its status as an EII. This reflects the fact that the industry has been deemed electrically intensive, and at risk of offshoring without this support. The status has been designated as per the European Commission's Guidelines on State Aid, with the designation maintained by the UK government post-Brexit. However, it should be noted that the exemption is not complete and sector-wide, and also that exemptions are time-limited and must be periodically renewed – reducing the extent to which they can be fully costed into investment decisions and limiting value in attracting new investment.

Eligible installations are exempted from 85% of the costs of certain policy levies, for the proportion of the electricity used in producing the applicable product. The relevant levies are the costs of the Contract for Difference (CfD), the Feed-in Tariff (FiT) and Renewables Obligation (RO). These currently add around £40/MWh to the retail electricity bill, and the exemption therefore saves the industry around £34/MWh. Support is also provided to a limited number of EII sites to obviate the cost impact of the UK Emissions Trading Scheme and Carbon Price Support mechanism, although this scheme is currently under review with current support lasting only until March 2022, though BEIS is actively considering a follow-on scheme.

In addition to this, the industry benefits from a sector-wide umbrella Climate Change Agreement (CCA), which exempts it from much of the costs of the Climate Change Levy (CCL). The rates, and exemptions, from the CCL are set out in Figure 3. BEIS's current plan is to increase the gas levy to match the electricity levy by 2025 as part of plans to decarbonise the economy by disincentivising use of the fuel. BEIS recently extended the CCA regime by two years, to last until 2025.

Figure 3: CCL rates and CCA exemptions

Fuel	Year	CCL rate (£/MWh)	CCA exemption (%)	Exempt rate (£/WMh)
Electricity	2021	7.75	92	0.62
	2022	7.75	92	0.62
	2023	7.75	92	0.62
Gas	2021	4.65	83	0.7905
	2022	5.68	86	0.7952
	2023	6.72	88	0.8064

Source: BEIS - Current rates, Proposed future rates

The structure of industry charges and policy levies, as well as further exemptions from the CCL, mean that electricity and heat generated onsite is largely exempt from network costs and levies as it is not transported across the public networks or submitted into central industry systems. As presented in Section 4, these costs make up around half of the typical retail electricity bill for large users without exemptions. This highlights the value of onsite generation, for example from CHP engines (which around two-thirds of paper industry sites operate).

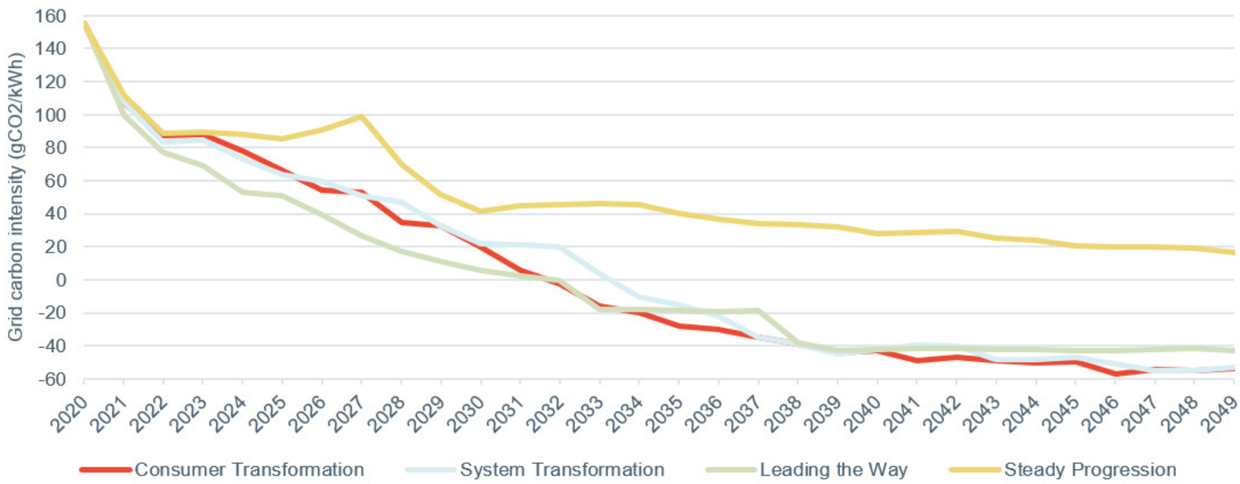
3.3 Towards net zero and the role of electrification

The CPI set its direction to net zero with its October 2020 publication of the *2050 Decarbonisation Roadmap*, in partnership with the Paper Industry Technical Association and the government. This document sets out the intention of the sector to transition to an 80% reduction in emissions, with the plan being updated to chart a way to net zero emissions in February 2022.

The carbon intensity of GB electricity has fallen by 55% between 2008 (535gCO2/kWh) and 2018 (245gCO2/kWh)[3], and National Grid Electricity System Operator (ESO) forecasts emissions continuing to fall. Zero carbon electricity is expected to be possible for limited periods from 2025, with average grid electricity carbon emissions falling to zero by the early 2030s under most of its scenarios in its *Future Energy Scenarios* (FES) modelling. Emissions then become negative as the sector uses bio-energy and direct air carbon capture and storage (BECCS and DACS respectively). Figure 4 shows the ESO's forecasts for grid carbon intensity over time.

BEIS has also set an ambition for the decarbonisation of the entire GB electricity system by 2035, at the latest.

Figure 4: Historic and forecast GB electricity carbon intensity



Source: National Grid ESO

3 According to the Committee on Climate Change's *Sixth Carbon Budget* documents

This makes electrification of many sectors of the economy, including paper, a key route to de-carbonising the GB economy. The challenge is that – like many other northern European countries – GB has a much higher cost of electricity than of gas, even for energy intensive industries which pay lower electricity prices than domestic and other consumers. This dis-incentivises the switch to the lower-carbon fuel and may render the whole business case for doing so uneconomic, creating a significant hurdle between today's gas-led world and the low carbon future.

3.4 The Sixth Carbon Budget

The Committee on Climate Change (CCC) is an independent body with a responsibility to support the government in delivering its Carbon Budgets. It published its recommendations for the Sixth Carbon budget – which will run 2033-37 – in December 2020, with government legislating to set the Budget in April 2021.

This includes a target to reduce UK-wide emissions by 78% from 1990 levels, and – for the first time – includes aviation and shipping emissions. Key elements of the budget include decarbonising heat production and transport, both of which are forecast to provide relatively large carbon emission reductions in return for early investments. However, decarbonising industry is more expensive at this point, as much of the "low-hanging fruit" of lower cost energy efficiency and technology switching has already been delivered.

CCC noted that the levelised costs of offshore wind generation have fallen from ~£150/MWh to £45/MWh over the last ten years, below the cost of gas generation. This cost is anticipated to continue falling – at a slower rate – over the years to 2050, resulting in final costs in the range £25-40/MWh (although this level of cost-reduction is not certain). This implies that an industrial user who is able to sign a direct Corporate Power Purchase Agreement (CPPA) with a wind generator may be able to benefit from a cost of electricity somewhat lower than the current paradigm

However, this wholesale cost of energy makes up only part of the final delivered energy bill, as presented in Section 4. Furthermore, even the ambitious lower end of the range, the wholesale power price is higher than the retail cost of gas[4], making the cost of providing heating energy through direct electrical heating potentially higher – though technologies such as heat pumps[5] may reduce this, as we discuss in Section 5.

4 Abnormal wholesale gas and power price spikes and volatility in the second half of 2021, during the writing of this paper, are assumed not to continue and become a feature of the market; but rather the long-term price differential between gas and grid supplied electricity is retained.

5 Heat pumps do not generate heat, but instead concentrate it from the environment. Depending on the temperature needed, and ambient temperatures in the environment, efficiencies can range from 200% to 400-500%. Current heat pumps operate in the range of 0-80 degrees, lower than the heat ranges commonly used by EII sites.

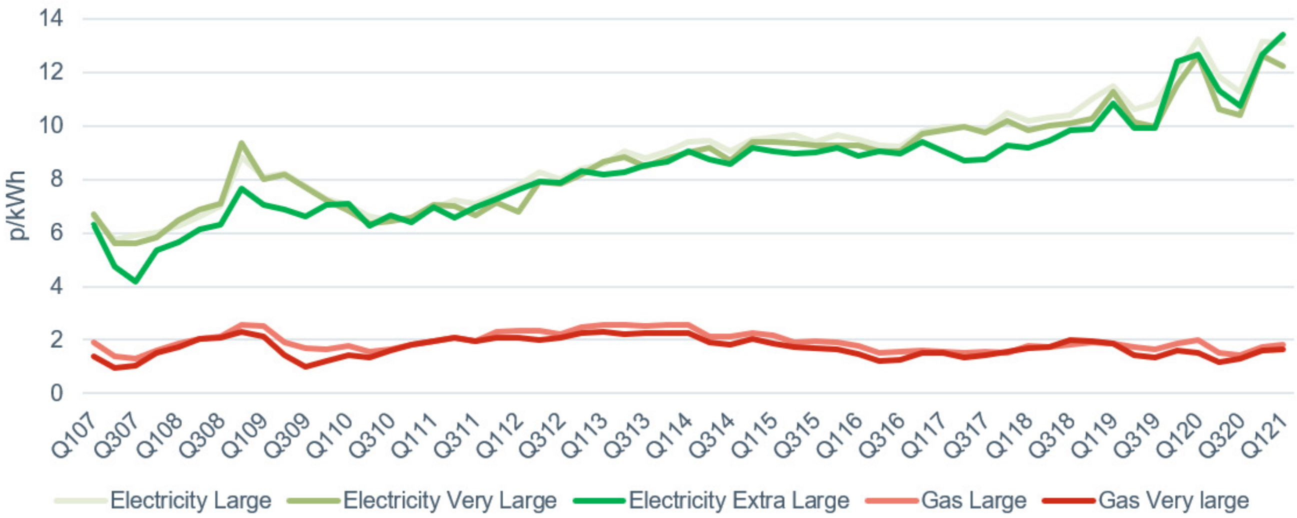
4. Current electricity and gas cost-stack

4.1 Introduction

Figure 5 outlines the delivered energy costs for large, very large, and (in the case of electricity only) extra large consumers of gas and electricity *as defined by BEIS*[6], excluding the additional costs of the Climate Change Levy (CCL) and Value Added Tax (VAT). For electricity, these are consumers that use over 20GWh per annum, and for gas those that consume 27.8GWh or more each year. The delivered costs of electricity (left hand axis) have generally risen from around 5p/kWh in 2007 to around 12p/kWh in Q1 2021. Meanwhile, gas costs have fluctuated significantly between 0.97p/kWh and 2.59p/kWh, but have not followed a discernible trend[7].

Examining costs in aggregate over the last decade, the trend appears to be a general increase in delivered prices. However, the key takeaway is that, per kWh, the cost of electricity is substantially higher than the cost of gas by a factor of between six to seven times.

Figure 5: Delivered costs for large, very large and extra-large electricity and gas consumers



Source: BEIS

These trends are driven by a number of factors, including the fluctuating prices of the wholesale commodity price, the changing cost of the networks to deliver power and gas, and (generally rising) policy costs. These are explored in more detail below:

- Energy – the costs of the power or gas being bought on the wholesale market (inclusive of any upstream network and policy costs). This cost – particularly for gas prices – is heavily impacted by global demand, weather conditions, and global geo-political shifts
  - As well as a critical heating fuel, gas remains the marginal electricity production fuel, and therefore retains significant impact on the cost of wholesale electricity
- Networks – the costs of using the transmission and distribution systems to transport the energy to the end consumer
- Policy costs – costs associated with supporting wider policy ambitions, (such as subsidy for low-carbon generation), peak system security, and energy or carbon-related taxes

6 Electricity: Extra large (>150GWh/year), Very Large (70-150GWh/year), Large (20-69.999GWh/year); Gas: Very large (277.8-1,111.1GWh/year), Large (27.8-277.8GWh/year)

7 This trend is expected to continue, once prices have normalised from the unprecedented high levels being experienced at time of publication in Autumn 2021

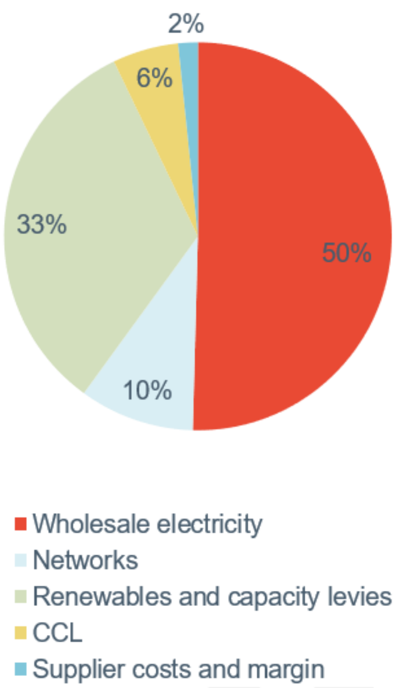
- Supplier costs – the costs for the supplier to serve the customer, inclusion of some overhead costs, and assumed margin. There may also be a brokerage cost depending on whether the consumer used a third party intermediary (TPI) to change supplier
- VAT – value added tax

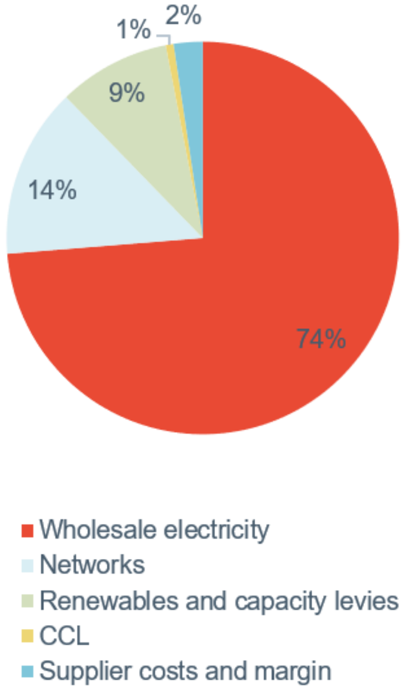
The level of each of these components, and their significance on the energy bill, depends on the energy being considered and the size of the consumer in question. We will explore example cost make-up for electricity and gas for a representative large energy user in the following section.

4.2 Retail breakdown of electricity and gas

Electricity costs are characterised by a significant non-commodity element of the bill. These include network charges and policy costs to support the deployment of renewable technologies and to meet peak demand. Large users face the smallest non-commodity element on the bill of all electricity consumers, as their network costs are proportionally lower than for other users. However, as seen in Figure 6, these non-commodity costs still account for almost 50% of the electricity bill. Certain energy intensive installations can receive partial exemptions from the costs associated with several policy and tax schemes, thereby lowering their overall costs of electricity. Figure 7 outlines the breakdown of the energy bill for the same user with EII exemptions and a CCA in place. The value of these exemptions is considerable – the consumer in Figure 6 pays 46% more per unit of energy consumed than the user in Figure 7, as we explore further in Section 5.

Figures 6 and 7: Representative large user electricity breakdown – without EII exemptions (left) and with EII exemptions (right)

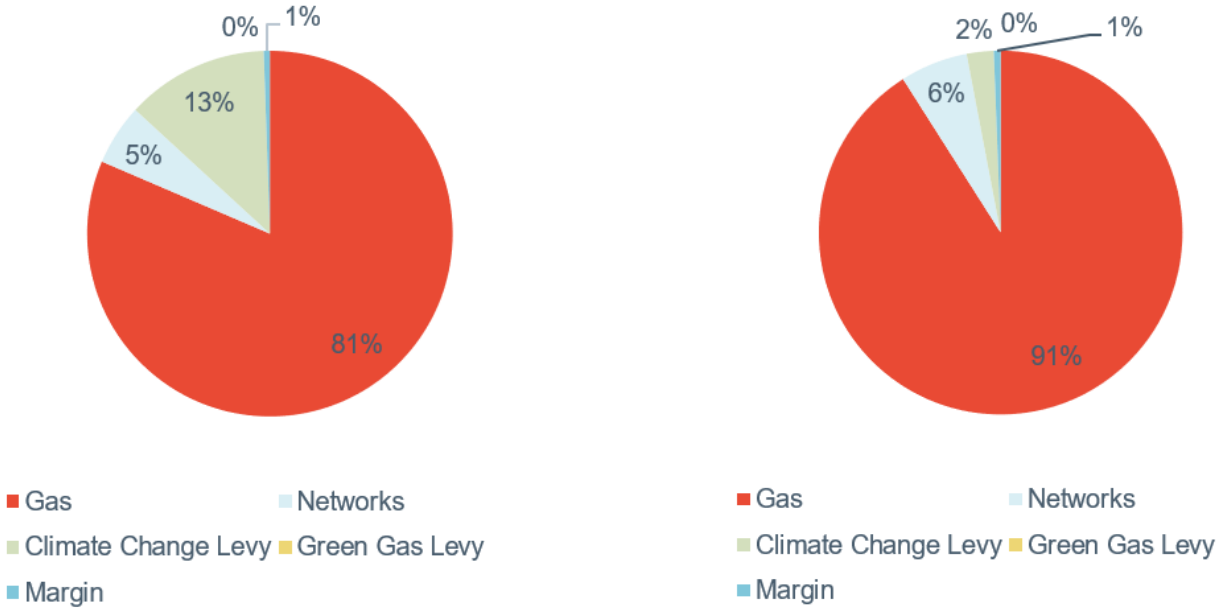




Source: Cornwall Insight analysis and assessments, a notional EHV-connected site, costs exclude VAT

The breakdown of the gas bill is comparatively more straightforward, with a much greater proportion of wholesale energy costs (see Figures 8 and 9). This means that the discount for being an EII is also much lower, only applying to the CCL component of the gas bill. The total costs for the user without a CCA are 16% higher than for a user with a CCA – a much smaller proportion than observed in electricity.

Figures 8 and 9: Representative large user gas breakdown – without a CCA (left) and with a CCA (right)

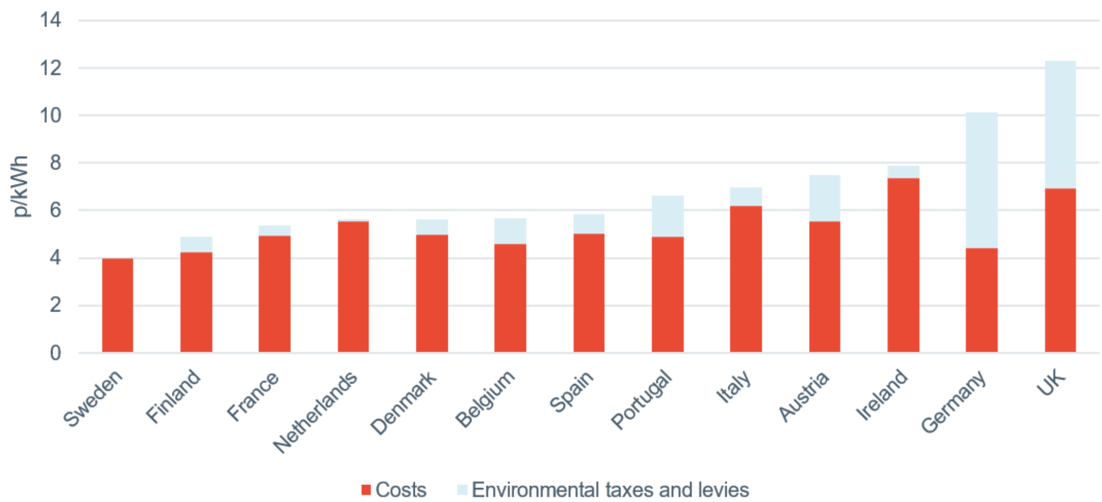


Source: Cornwall Insight analysis and assessments, a notional site with an AQ of 29.3GWh, costs exclude VAT

4.3 International comparison

The breakdowns explored in the previous section highlight the range of additional costs present in the electricity bill in the form of policy costs and taxes. The UK wholesale power price is also inflated by the impacts of the Carbon Price Support (CPS) mechanism[8] and transmission-connected generator network charges. The result, as can be seen in Figure 10, are some of the highest electricity prices in Europe for very large users.

Figure 10: European electricity prices for very-large users – July to Dec 2020



Source: BEIS

In comparison, the UK's gas prices are historically some of the lowest in Europe, ranking fourth lowest in the comparison outlined in Figure 11[9].

8 *Carbon price support* is a tax on electricity producers who use fossil fuels. The price is designed to ensure a minimum price of carbon emissions from power generation, in concert with the Emissions Trading Scheme. Current rates (to 31 March 2023) are 0.331p/kWH for natural gas. This price is paid by carbon emitting generators and inflates wholesale power prices. As gas remains the marginal fuel, this typically raises wholesale power prices across the entire market, including power from renewables.

9 Prices are expected to return to these levels, following Autumn-Winter 2021's unprecedented high market prices, though it is not yet clear over what timeline this will happen and prices may be elevated for a considerable period.

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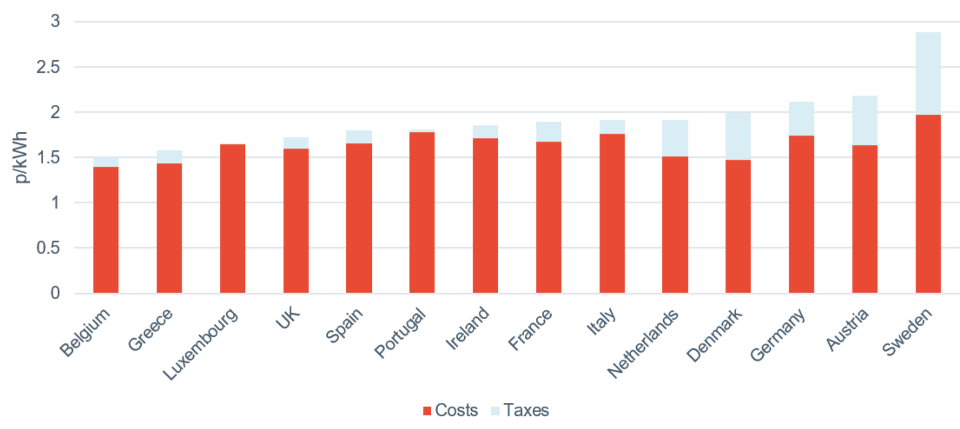
In order to decarbonise the wider economy, transition from fossil fuels to green electricity for transport and heating will be an important factor.

Figure 11: European gas prices for large users – July to Dec 2020



Source: BEIS

4.4 Heat generation

Due to the inherent differences in price of the input fuels – explicitly, as stated previously, retail electricity prices being at least six-seven times the cost of retail gas – the commercial dynamics for heat production via these two fuels are very different. Given these current cost conditions, an electrically-fired heat source therefore needs to be at least six to seven times as efficient as the gas equivalent, and potentially even more efficient if the consumer is not classed as an EII or eligible for Climate Change Agreements. The default electrified boiler replacement option would be typically 99% efficient, versus 81% for a gas boiler – far below the requirement.

The other potential replacement heat source is a heat pump. According to BEIS data on the domestic Renewable Heat Incentive (RHI)[10], the average seasonal performance factor (SPF) of new and legacy air source heat pumps (ASHPs) is 3.2 and ground source heat pumps (GSHPs) is 3.5[11].

These performance factors, while relatively high, are not sufficient to overcome the cost differential and incentivise large non-domestic users to decarbonise heat generation.

Furthermore, while the provision of heating and cooling to commercial and domestic sites can be easily substituted for the relatively low temperature heat output by heat pumps, many industrial processes principally require high-grade heat.

This cannot be supplied by current technologies, making heat pumps unsuitable for many industrial applications - including for most purposes in the paper industry, which require steam heat.

10 Data for May 2021 (note that only SPFs from the domestic scheme are available, with comparative data for the non-domestic scheme unavailable)

11 The SPF looks at the Co-Efficient of Performance (CoP) across the year, weighted to consider the forecast demand on heat from the heat pump across the year and average temperatures (and therefore changing CoP) across the year.

5. Potential and sign-posted change

5.1 Rebalancing policy costs

The current and historic paradigm for the recovery of policy costs for the renewable transition is for them to be allocated principally to the electricity bill for a number of years after such new assets are commissioned. There are historical reasons for this: cost rises over the last two decades have primarily resulted from the subsidy of renewable electricity generation, and the rising electricity unit costs driven by these charges have provided an incentive to consumers to reduce their electricity consumption, driving investment in energy efficiency measures. We also note that legacy schemes, such as RO and FiT (which closed to new generation in 2017 and 2019 respectively) continue to contribute to bills and will do so well into the 2030s.

However, given the success of this approach in supporting a low carbon, renewable electricity supply, there have been several signals that government is considering transitioning away from this model. In order to decarbonise the wider economy, transition from fossil fuels to green electricity for transport and heating will be an important factor.

The addition of policy costs to the retail electricity bill, driving up the cost of consuming electricity relative to other fuels, may therefore no longer be in the interests of promoting decarbonisation.

There has been speculation in the press and across the energy industry since before the 2016 General Election that the government is considering re-balancing the recovery of renewable electricity generation policy costs away from the electricity bill. The first formal indication of this potential move came in November 2019 when HM Treasury *announced* its Net Zero Review.

An *interim report* was published in December 2020 confirming the government's intention to complete a review of how the transition to net zero will be funded, and where the costs should fall. The *final report*, published in October 2021, examines the fiscal implications of the net zero transition and highlights key areas where solutions will be required, but does not provide the clarity which some had hoped for in terms of policy changes such as re-allocation of legacy and future subsidy costs, though future consultation on this topic is promised.

December 2020 saw the publication of the government's *Energy White Paper*, which announced that it would "publish a call for evidence by April 2021 to begin a strategic dialogue between government, consumers and industry on affordability and fairness", and noted that, "This will allow us to take decisions on how energy costs can be allocated in a way which is fair and incentivises cost-effective decarbonisation." It additionally identified the issue of "how the costs of decarbonising energy are apportioned between gas and electricity bills" as a key one for incentivising or disincentivising consumer behaviour. This call for evidence has not yet been published.

5.2 Impact on the relative attractiveness of fuels

In this section we present figures analysing the potential change in electricity and gas retail prices (relative to each other), these being based on options for the reform of policy cost recovery.
We note that, given the EII exemptions from which parts of industry benefits and which exempt some producers from 85% of the costs of policy levies on the electricity bill, the impact of reducing levies on bills would be limited for some installations. The risk of levies on the gas bill increasing, however, is greater – assuming that similar exemptions are not introduced for the gas bill, which remains a possibility. We would also expect that any GB policy changes would also need to consider competitive implications if other countries do not take a similar approach, as is likely in the EU where gas continues to be regarded as a transitional fuel to net zero.

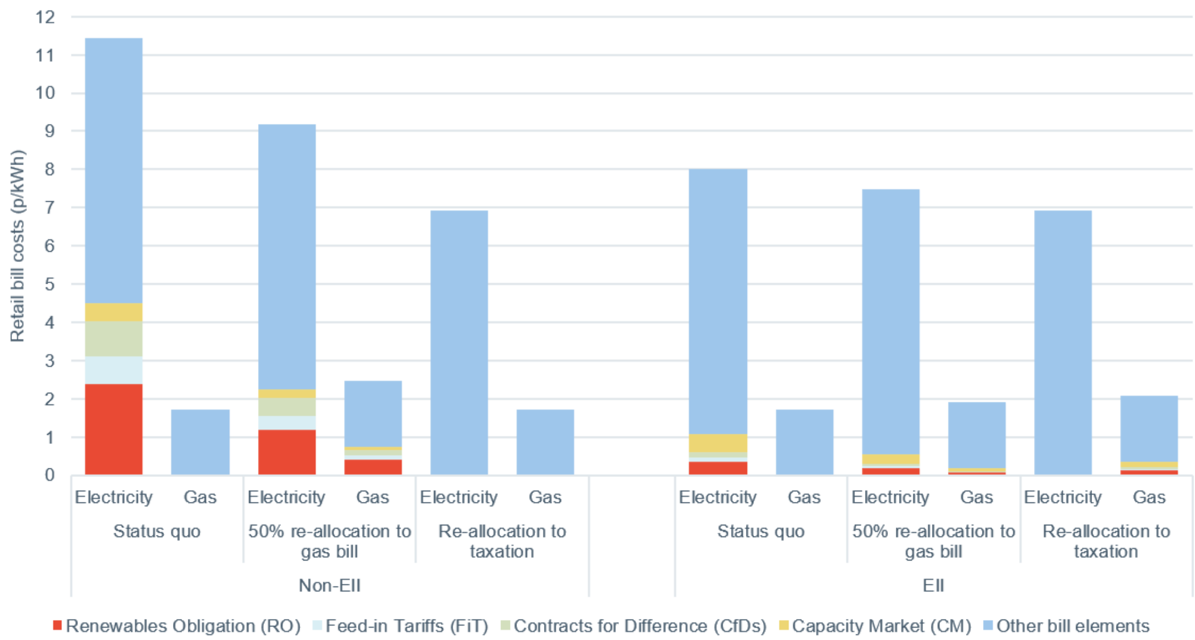
5.2.1 Reallocation impacts

Figure 12 presents the relative costs of electricity and gas, under several scenarios:

- The status quo, where policy costs are allocated to the electricity bill in full
    - We have considered the costs of the RO, FiT, CfD and CM in this analysis
- A re-allocation of half of the monetary value of policy costs to the gas bill
- A complete re-allocation of policy costs from the energy bill to the public purse

A second set of scenarios replicates these, assuming that the user benefits from an existing EII exemption under both the electricity and gas retail bills

Figure 12: Relative costs of electricity and gas under various reform options, 2020-21



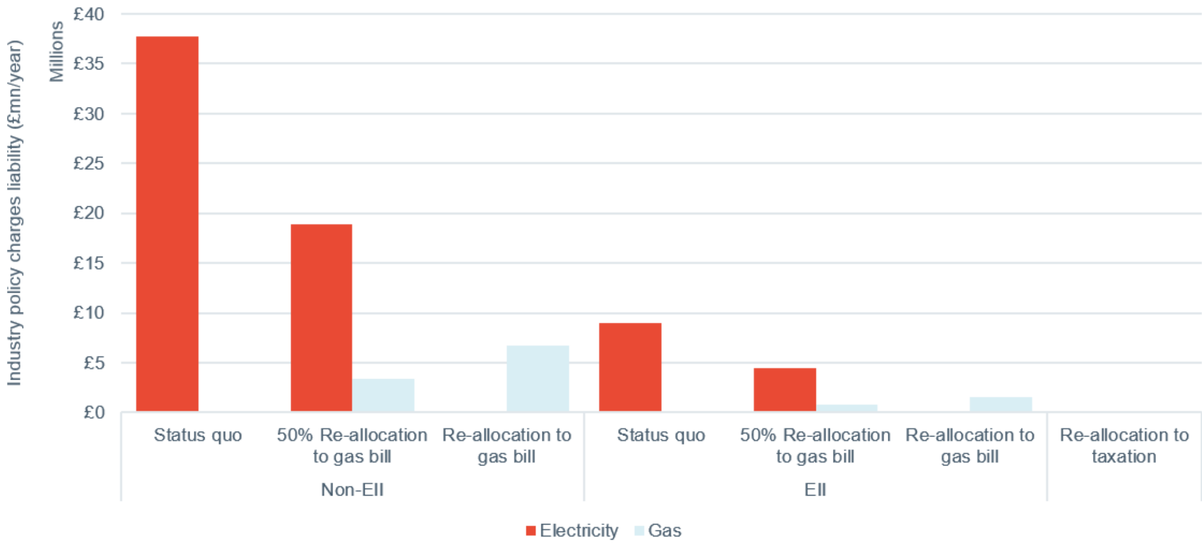
Source: Cornwall Insight, from BEIS data

These scenarios see the cost of electricity falling, by between 2.26p/kWh (20%) and 4.51p/kWh (39%), with the cost of gas rising in some scenarios by up to 1.49p/kWh (86%). The ongoing wholesale energy price crisis does not affect these numbers, which do not include the wholesale costs.

5.2.2 Impact on annual costs

Under the current status quo, we project (using BEIS figures for energy volumes consumed) that the GB paper industry would be paying around £37.72mn/year for policy levies if it were paying the full amount, or £9.01mn assuming that all energy is covered under EII exemptions. This is shown in Figure 13. Under no re-allocation scenario does total exposure to policy levies rise from the status quo. This is due in large part to the industry's existing heavy reliance on electricity.

Figure 13: Total policy costs for the paper industry, under various scenarios, assuming electricity consumption from the public networks of 8.36GWh/year and gas consumption 4.52GWh/year

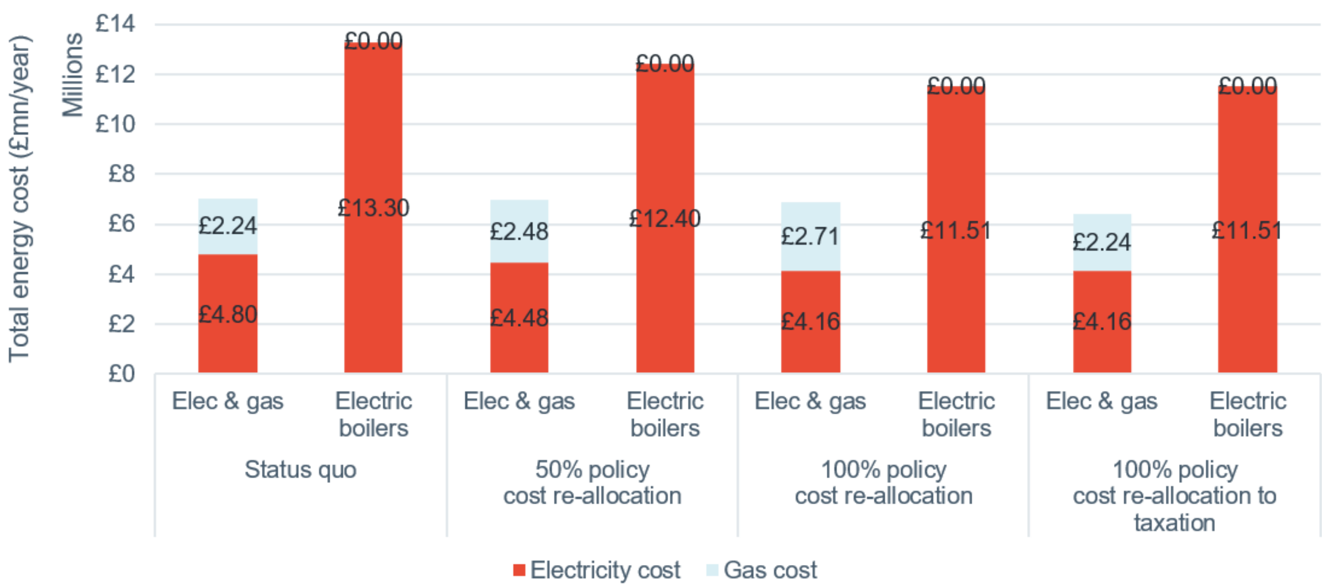


Source: Cornwall Insight, from BEIS data

5.2.3 Example site – No CHP

For the purpose of this analysis, CPI has provided data of a representative consumption site within the organisation, which has the following characteristics. The site is a papermill in the industry's medium-large category which operates 24/7 for 355 days of the year. It does not have a CHP engine, operating solely on grid electricity and natural gas as its energy sources. Its demand profile is relatively constant, varying by perhaps ±15%, though with occasional peaks for start-up of around +50-60% of daily average usage. The mill requires process heat, for paper-drying, which is currently supplied by steam and by direct-heating from natural gas burners. The mill consumes around 60GWh/year of power, as well as 130GWh of gas to meet a heat requirement of 105GWh. Figure 14 sets out the mill's assumed total cost of energy under various scenarios, assuming that the mill has an CCA and EEI exemption.

Figure 14: Total energy cost for example papermill, under various scenarios, 2021-22 (£mn/year)



Source: Cornwall Insight

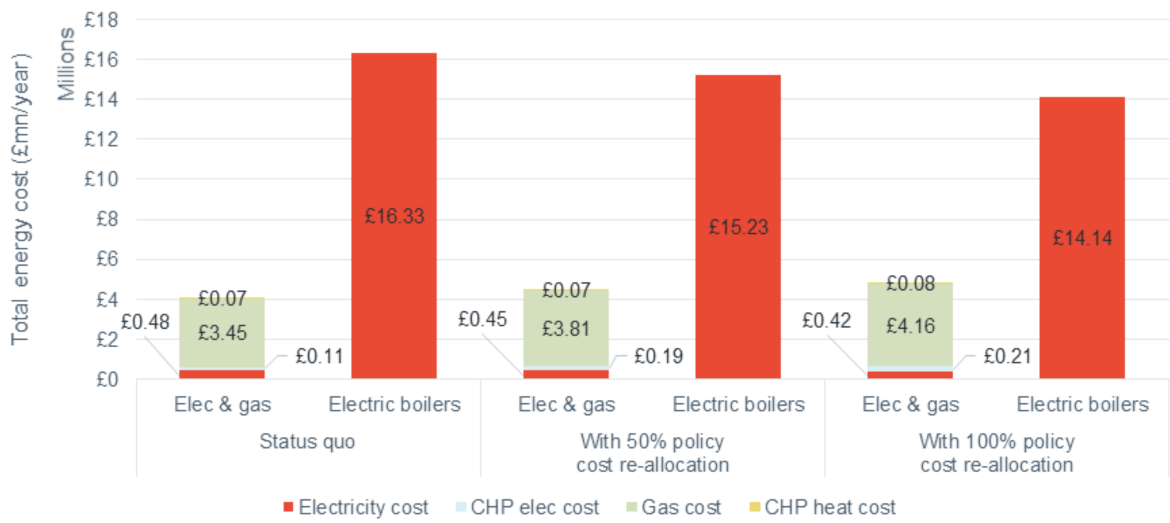
Under the status quo, the mill would spend around £7mn/year on its total energy (electricity and gas) needs. This figure remains roughly constant under our scenarios, which see 50% or 100% of electricity policy costs re-allocated to the gas bill: falling about £100,000/year under the 50% scenario and £200,000 under the 100% policy cost re-allocation scenario.

If the mill were to fully electrify, there would be considerable additional annual energy costs to bear, in addition to the capital costs of the new equipment. Moving to high-efficiency electric boilers[12] would cut the total energy import of the mill from 190GWh/year to around 166GWh/year. However, costs would increase from £7mn/year to around £13.3mn/year. Even when the re-allocation of policy costs is considered, costs would still rise, to around £12.4mn/year under a 50% re-allocation of policy costs and £11.5mn/year under a 100% re-allocation.

5.3 Example site – CHP

Our second example is of a similar papermill with an onsite CHP engine to produce heat and power, and which operates with efficiencies of 54% and 34% respectively (total 88%). Its electricity demand is the same as the previous example, but around 90% is generated onsite via the CHP. Heat demand at this site is higher, and is met partially by CHP heat (17%), but primarily by gas boilers (83%). This site also benefits from CCA and EII exemptions from policy costs.

Figure 15: Total energy cost for example papermill, under various scenarios, 2021-22 (£mn/year)



Source: Cornwall Insight

As Figure 15 shows, this mill faces an even greater increase in costs from electrification – its energy costs under current operation are a little over £4.1mn/year[13], rising to £4.5mn/year under a 50% re-allocation of costs to the gas bill and to £4.9mn/year under a 100% re-allocation. Under a fully electrified future, where it can no longer operate its CHP engine, costs would rise dramatically under all scenarios.

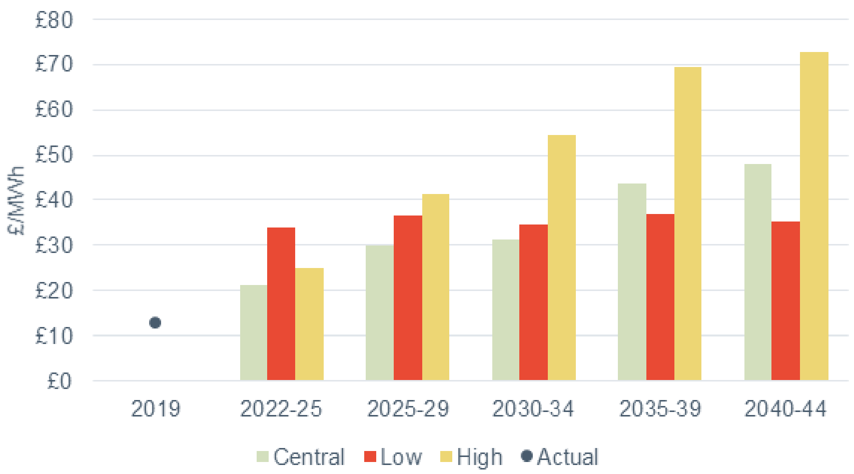
12 Typical electric boiler efficiency is 99%, compared to around 81% for industrial condensing gas boilers.

13 Note that this does not include carbon emissions under the UK ETS, which (depending on CHP size and efficiency, and exemption status) may add around £1.6mn/year to costs. Nonetheless, this still leaves it paying less for energy than under other paradigms.

5.4 Flexibility

The rising share of intermittent renewable generation on the national networks is having an increasingly large effect on wholesale power prices. Wind and solar generators have very low or zero marginal generation costs per MWh. Therefore, when the wind is blowing and/or the sun shining, wind and solar generators will produce large amounts of power and cause wholesale prices to fall. When these resources are not available, wholesale power prices will tend to rise as dispatchable generation will try to capture its fixed costs over shorter times. This is illustrated in Figure 16, which shows the standard deviation of wholesale power prices expected over the next 25 years as an indication of potential market volatility. This highlights the increasing value of being able to consume power flexibly, where the customer is exposed to the underlying wholesale price.

Figure 16: Standard deviation of Day Ahead wholesale power prices, 2019-2044



Source: Cornwall Insight

The paper industry, like many industries, has a generally flat power consumption profile with little opportunity to flex its consumption. The industry has started to implement some flexibility solutions where processes allow this, for example in material preparation.

As volatility in the wholesale markets increases, the value of consuming power more flexibly, to avoid high prices and maximise consumption at times of low prices, will increase. This may support the development of behind-the-meter batteries and other storage technologies, including heat storage, in order to manage cost exposure. It is unlikely, however, that storage technologies will be able to deliver overriding energy cost savings at the level necessary to compensate for significantly higher cost of heating by electricity compared to the natural gas cost paradigm, as explained in Section 5.2 above.

5.5 Combined Heat and Power plant

As indicated in Section 3.2, the paper industry is one among several to have developed a considerable natural gas-fired CHP fleet, using natural gas efficiently to produce local heat and power. While requiring major capital investment, CHP has helped the industry to manage costs, as well as increasing the useful energy output of burning fuel, reducing carbon emissions, and has been supported by policy as recently as 2020.

These long-lived assets provide an economic benefit to host sites, providing savings on the cost of fuel for heat and power. They are also flexible in terms of the power which they produce, providing benefits to the wider electricity system. On-site CHP will reduce the import of power from the local network to the industrial site, particularly at peak times for the network, reducing potential network reinforcement costs. The CHP fleet collectively also exports around 20% of the power generated to the public networks, further helping to manage the requirements of the network for reinforcement. CPI members operate around 240MWe of gas-fired and 100MWe of biomass-fired CHP engines, which typically reduce the import demand of plant by around 300MWe and export around 40Mwe to the local system.

> There is an opportunity to revise network charging to potentially reduce electricity costs for large users in GB.

However, given the pressure to decarbonise the economy and the government's aim for a decarbonised electricity system by 2035, it is to be expected that there will be a regulatory/ policy push to end operation of natural gas-fired CHP assets over the next 15-20 years. Shifting policy costs from the electricity bill to the gas bill, as discussed in Section 5.2 above, could also have considerable impact on the economics of this type of generation and may make assets no longer economic to operate. Section 5.3 examines the high cost energy impact on CHP sites if such sites were required to switch to grid supplied electricity. Also considering the support that these assets provide to the electricity networks, these changes should be carefully considered before reform is decided on. The timing of these decision will be important, particularly with regards to the emergence of alternative technologies and expansion of low-carbon gas markets which could potentially provide alternative fuels for the existing fleet.

The sector has also developed a fleet of biomass CHP, largely supported by subsidy payments under the RO. While emissions from biomass generation are net zero compliant, the current assumption is that this fleet will become uneconomic to operate when RO subsidy ends after each station's 20-year accreditation period, due to the relatively higher cost of biomass fuel compared to the alternatives. This may compound the issues arising from the retirement of natural gas-fired CHP engines and again is a key topic for policy and regulatory consideration as we move towards a net zero power system.

6. Options for reform

This section of the report explores potential solutions to resolve the key capital cost and ongoing fuel cost issues. These are summarised in Figure 17:

Figure 17: Summary of explored options for reform

Option	Ease of Implementation	Support to net zero	Price impacts	Overall
Market-based solution – e.g. CPPA	Established market models	Directly procures from low carbon generation	Secures energy price but no discount due to addition of network and policy costs	A route for meeting ESG and fixing price, but doesn't deliver lower costs
Network charge reforms	Requires a restructure to cost allocation for largest consumers	Supports decisions to electrify, but not wider carbonisation	Reduces the most significant component of the bill bar energy costs for EIIs	Provides a sizeable price discount and supports electrification
Reduced or removed subsidy costs	Requires legislative and/ or policy change	Provides marginal support to decision to electrify, but does not fully bridge economic gap	Existing EII discount means little further benefit for some installations	Provides a small price discount, doing little to support electrification
Amending the delivered gas price	Requires legislative and/ or policy change	Rebalances the cost of fuels depending on carbon intensity	Strong input fuel cost signal but could impact international competitiveness	Drives carbonisation via amendments to counterfactual fuel costs
Policy instrument (heat CfD or similar)	Requires new legislation and funding mechanism	Provides financial support to opt for low-carbon heating options	Financial incentive supports businesses	Direct support to businesses incentivising low-carbon heat

Source: Cornwall Insight

While each of these ideas alone would not be sufficient to provide a route to decarbonisation for UK EII, in reality a number of these measures working in combination could provide a potential solution.

A market-based option can use established models such as Corporate Power Purchase Agreements (CPPAs) to directly procure power from renewable assets for supply to end consumers. However, this is unlikely to drive any price benefit against the values achievable in the wider market and is typically used to support ESG commitments and/or to support a long-term fixed price for power consumption. Government could assess the merits of alternative structures which support market-based solutions, within the context of a wider review of non-commodity costs. However, this may disagree with its stated "no free riding" principles, which suggest that all network users should pay a share of costs.

Over the long-term, there is an opportunity to revise network charging to potentially reduce electricity costs for large users in GB by up to 14% on average. These costs are significantly higher than those seen in other countries (8% in the Netherlands and less than 4% in Germany and France). However, lowering network costs for industrial users is not a focus of Ofgem's current charging reforms and this could require substantial re-working of network changes, which have already recently been subjected to far-reaching change from regulatory workstreams. It would also re-balance network costs onto other users, which are also trying to decarbonise.

As explored further in Section 5, reductions to low carbon subsidy costs are unlikely to drive a significant signal to decarbonise, as some EIIs already receive a substantial reduction on these costs. Any reallocation to the gas bill would act as a supporting driver, rather than fundamentally change the business case.

Finally, a new policy instrument, such as a heat CfD (Contract for Difference) or similar, could provide the financial incentive to support EIIs in making the decision to electrify or decarbonise their heat, however the funding for this mechanism would likely need to be recovered by other parts of the market or the public purse.

Each of these options is explored in further detail below.

6.1 Market-based solutions

Large consumers of energy can approach generators/ developers to contract directly with a renewable generator, using a supplier as an intermediary to manage the flows on the electricity system. The concept is now well-established in GB and international electricity markets, with a number of high-profile deals being agreed, including Amazon's investments in Scottish wind[14], and Northumbrian Water's[15] and Nestle's[16] CPPAs with Ørsted. Inside the sector, deals include Kimberley-Clark's CPPA with Octopus Renewables to take the power from the 50MW Cumberhead onshore wind farm, enabling construction of that site and providing low-carbon power to cover around 80% of Kimberley-Clark's consumption.

Where generators are located adjacent or in close proximity to consumers, it is possible to transfer power over private networks and avoid the final consumption levies (network charges and policy costs) which make up much of the delivered retail price. However, more usually, electricity is transported over the public network and the CPPA arrangement will only affect the wholesale energy portion of the bill, with consumers exposed to other costs at the applicable levels.

Typically, such a deal will agree a price or price benchmark for a number of years (typically 5-15 years) and therefore provides price certainty for both the generator and the consumer, as well as supporting the low-carbon credentials of the consumer. However, such a deal is dependent on both parties agreeing on a price and duration, and often requires parties to be of a certain scale and creditworthiness to support its brokerage, particularly over longer tenures and where new-build renewable generation is involved.

In the present market environment, the benefits to large energy consumers include supporting their green credentials and fixed price certainty. These deals are not necessarily struck with the expectation that they will lead to a discounted price relative to the prevailing market, particularly given that the non-wholesale elements of the bill are not reduced by the arrangement. As renewable technology costs continue to fall, and the technologies continue to be deployed (supported by pledges such as the government's target of 40GW of offshore wind by 2030), the prices agreed through CPPA should fall, as should market prices during periods of high wind output. Therefore, these arrangements typically drive no comparative cost benefit to the end consumer in terms of wholesale prices.

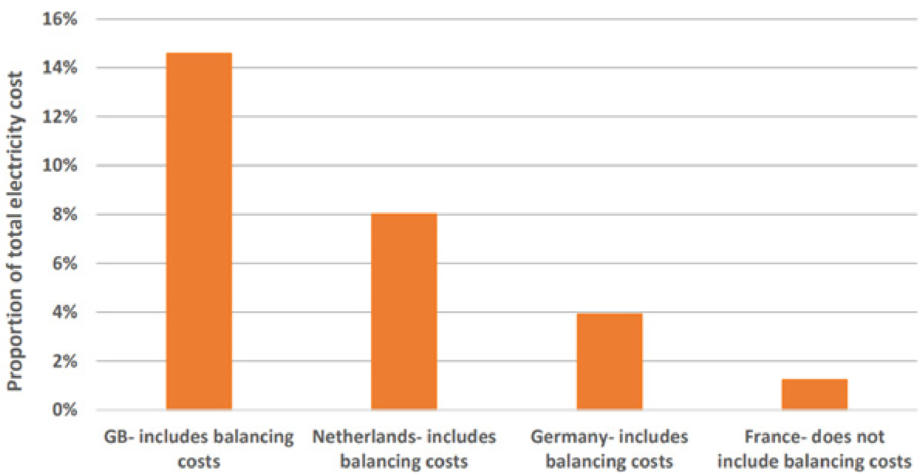
As long as non-commodity electricity costs remain such a substantial cost element, even for EIIs, this will remain a barrier for sectors and technologies looking to electrify in GB. To provide a substantial drive to support EII sites in electrifying, the pass-through of non-commodity costs under CPPAs would need to be reviewed.

14 https://www.insider.co.uk/news/amazon-makes-major-investment-third-23944824
15 Northumbrian Water Case study (orsted.com)
16 Ørsted and Nestlé sign 15-year offshore wind power purchase agreement (orsted.com)

6.2 Network cost reforms

A recent Ofgem study[17] found that some European countries (France, Germany and the Netherlands) offer discounts on network costs for EIIs that meet eligibility criteria on electricity consumption and off-peak grid utilisation. This allows eligible EIIs to lower their network costs by up to 90% in some cases. The rationale for these discounts focuses on the value of EIIs' baseload demand to the grid. Network costs in GB equate to 14% of the delivered electricity bill for large consumers, compared to 8% in the Netherlands and less than 4% in Germany and France, as evidenced in Figure 18.

Figure 18: Estimated network costs as a proportion of total electricity cost (2020, 100-500GWh annual



Source: Ofgem

Large energy consumers in GB inherently face much lower network charges than small users because, as they are connected at higher voltages, they are not required to pay for the lower voltage networks. Despite this, consumers in the EU are clearly paying much less than their GB equivalents. This is (and will be) further exacerbated by the outcome of Ofgem's Targeted Charging Review (TCR), which will increase the network charges levied on large energy consumers by reducing the charges to which generators are exposed.

The TCR also has levied many of these costs back on to large users in the form of large fixed charges (residual costs) that can no longer be avoided through flexibility, e.g. the historic practice of Triad avoidance. The analysis supporting the TCR final decision *Distributional Impact of Reforms to Residual Charges*[18] estimated that TNUoS recovery from transmission and extra high voltage (EHV) connected customers would increase from 7% to 11%. It also estimated that larger high voltage (HV) connected customers would face a higher distribution bill as a result of the changes.

To support international competitiveness, Government may wish to consider reducing rather than increasing network costs for some of the largest consumers in GB. This could tie in with the wider flexibility and demand-side response (DSR) agenda through, for example, a higher proportion of time of use pricing or critical peak pricing to support businesses in deciding to avoid consumption at times of peak network usage. Alternatives could include a reduction in the allocation of the residual[19] allotted to the largest users, lowering the assumed use over peak periods, or introducing some form of blanket electricity discount or rebate. Put simply, when seeking to encourage sites to electrify, policy changes that increase the cost of electricity are counterproductive.

17 https://www.ofgem.gov.uk/sites/default/files/2021-07/Final%20report-%20Research%20into%20GB%20electricity%20prices%20for%20EnergyIntensive%20Industries.pdf

18 https://www.ofgem.gov.uk/publications/targeted-charging-review-decision-and-impact-assessment

19 The residual was introduced by Ofgem's TCR and applies the sunk costs of the network on a p/day basis depending on the maximum import capacity of the user type. For flexible users, this has acted to (generally) increase the costs they pay for network charges.

“

A heat CfD could fix the value of heat compared to the costs of low-carbon fuels used to produce that heat

6.3 Transitioning costs

As presented in Section 5.1, the current policy approach from the Government to reducing the costs of electrification is to reallocate policy costs away from the electricity bill. This has limited benefit for some EIIs, which are already exempt from most (85%) of these costs. These units, if decarbonising by electrifying heat production, will in general experience a considerable increase in costs due to the higher wholesale cost of the fuel over the existing cost of gas.

This is likely to feed through into higher prices for energy intensive products, which may allow less decarbonised competitors overseas to take market share from the electrified papermills which are experiencing greater costs of production (“carbon leakage”). Some consumers have targets and requirements for decarbonisation throughout their supply chains, however, most do not and will opt for the cheapest supplier.

6.4 Amending the delivered gas price

An alternative means of supporting the transition to electrification and low carbon heat generation could involve applying some form of tax or additional cost burden to the delivered gas bill. This could be in addition to or aligned with any policy cost reallocation from the electricity bill to the gas bill, and likely linked to a reflection of the carbon intensity of the fuel. Such a move would incentivise the transition from gas-fired to electrically powered heating in a shorter timeframe, depending on the cost impact and method of implementation.

The electricity generation mix in GB has been rapidly decarbonised over the last 15 years, hitting a new low of 181gCO2/kWh in 2020[20]. This has been supported by a range of support mechanisms such as the RO, FiT and CfD, and some precursor schemes. In comparison, gas carbon intensity sits at 184gCO2e per kWh consumed, according to the *Greenhouse Gas Reporting Conversion Factors 2020*[21]. As highlighted, while both fuels have approximately the equivalent carbon intensity, gas prices are less than one quarter the price of electricity, while the electricity mix is forecast to continue decarbonising.

Policy makers should be conscious of any impact on international competitiveness through such a transition, recognising that GB already has high electricity bills at the international scale and increasing gas bills may have sectoral or carbon leakage impacts. While transitioning policy costs from electricity to gas may leave the average user in a similar net position, this may not be a case across the economy and the pace of change, as well as the direction, will have an impact on the ability of industry to make capital investments to align to the new cost model.

20 https://www.nationalgrideso.com/news/record-breaking-2020-becomes-greenest-year-britains-electricity

21 https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020

6.5 Future policy considerations

As illustrated by the experience of the domestic sector, the status quo alone will not support the drive to Net Zero. Given the scale of the challenge presented by the Net Zero challenge, the necessary speed of decarbonisation required to reach the target, and the fundamental shift required in both the technologies which businesses use and the way in which they use them, policy makers will likely need to consider all of the tools available to them to support the transition. If the policy intention is to preserve EII manufacturing in the UK, while delivering Net Zero, then cost issues must be addressed.

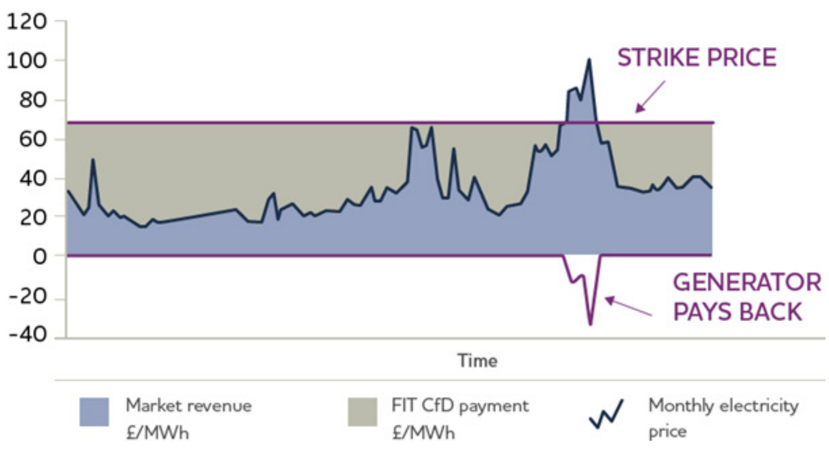
There are potentially a range of cost-effective policy mechanisms which could support the decarbonisation of significant volumes of heat consumption in EII sectors, representing a substantial decarbonisation option for governments looking to accelerate the low carbon agenda. We have identified two policy options to address the pricing issues for EIIs in GB. The first, introduction of a “heat CfD” would look to defray some of the costs of decarbonised heat with a subsidy, while the second, a carbon border tax, would introduce a tariff on alternative imports from beyond the UK, managing the competitiveness issued created by the costs of decarbonisation of heat.

However, individual polices need to be developed in a wider context that takes account of the wider policy dynamic. As an example, many energy intensive industries deliver high levels of domestic recycling as part of the circular economy. More than 80% of paper manufactured in the UK is from recycled fibre recycled at gas-fired mills, while imported paper is predominantly virgin fibre from mills powered by zero carbon biomass residues. This puts two sets of priorities in opposition, with decarbonisation being placed against circular economy priorities.

6.5.1 Heat CfD

An example of a policy implement which could be introduced to support the transition to low carbon heat is a “heat CfD”. The CfD has supported investment in low-carbon technologies at lowest-cost in a technology-neutral manner, supporting over 10GW of built or under-construction renewable generation capacity, with AR4, the fourth auction exercise (allocation round) for support, expected to increase this by as much as 12GW of further capacity. Existing power CfDs see an auction to set “strike prices” for power produced by new-build renewable generation. Generators are topped up to this price when wholesale prices are lower and pay back if the wholesale price rises above the strike price, as illustrated in Figure 19.

Figure 19: CfD diagram



Source: EMR Settlement Company

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This is an alternative approach to the various implementations of EII exemption to carbon levies

A heat CfD could fix the value of heat compared to the costs of low-carbon fuels used to produce that heat, ensuring that investors were able to recover the capital costs and operational of equipment used to produce it. Heat CfD auctions could allocate support to the most economic projects, providing the long-term income stability necessary to fund investment in capital equipment to provide low-carbon heat, whether that be from electricity, biomasses and biogas, or another source.

A similar implement has been proposed in Germany, where companies in the steel, cement, line and ammonia industries may be able to access Carbon Contracts for Difference. These contracts would provide funding based on the difference between the CO2 emission costs of production without decarbonisation, based on ETS prices and the costs of implementing decarbonised steel production, expressed in terms of a hypothetically higher ETS price as agreed in the CfD. This mechanism is intended to allow investment in reducing carbon emissions with certainty on avoided costs over the long-term.

However, it must be noted that heat provision is an inherently local requirement, which brings additional risks to the subsidisation of heat production which are not present in electricity markets. In particular, the cessation of a demand for heat within a given location or region is always possible, where a key industrial heat consumer ceases or reduces operations. Which party – the government/ CfD counterparty or the plant operator – bears this stranded asset risk will be important to both protecting consumers and ensuring that schemes are investable. There may be a requirement for a "Heat Offtaker of Last Resort" to protect investors in the case of heat demand cessation, and establishing a route through this issue will be key to confidence.

Cornwall Insight and WSP *investigated the potential* for CfDs to support Carbon Capture, Usage and Storage (CCUS) power generation in a report for BEIS in 2019. The report investigated several models, which included baseload, hybrid/flexibility, and flexible with capacity element. Many of the conclusions of that paper could be usefully applied to the heat market. In particular:

- While power CfDs have concentrated on maximising output, with payments per MWh of generation, a heat CfD would, like a CCUS CfD, need to focus on flexibility and meeting demand efficiently rather than simply paying for the maximisation of heat output, whether useful or not
- In the absence of a market reference price for the subsidised service, a proxy would be needed
- Some elements such as fuel costs may need to sit outside the CfD structure as pass-through expenses, which may need to be incorporated into the strike price
- The design of the scheme would need to evolve over time; probably including an evolution from a baseload model with a heavy front-weighting to a more long-term operational model, as investors grow more comfortable with technologies
- Early heat CfDs may need to be negotiated rather than auctioned, to ensure investor confidence, with the power market having set an example here in the negotiation for a specific CfD for new nuclear plant Hinkley C

As this option would not be likely to be cost-neutral, a new levy or carbon tax, or a new imposition on general taxation, would have to be emplaced to support the decarbonisation of heat.

6.5.2 Carbon Border tax

Various governments, including the EU and more recently the UK, have expressed interest in implementing a carbon border tax. These proposed taxes seek to minimise carbon leakage. This is an alternative approach to the various implementations of EII exemption to carbon levies, namely making imports more expensive, rather than making local manufacturing lower cost.

The EU example, which is to be implemented in 2026, is the Carbon Border Adjustment Mechanism (CBAM). The levy will apply initially to five sectors: iron and steel, cement, fertiliser, aluminium and electricity generation with potential expansion to be considered in 2026. The system will function by requiring importers to track and report the emissions embedded in the goods which they bring into the EU, paying a financial adjustment to cover this carbon impact based on the value of the EU ETS (prices for the ETS are shown in Figure 20. We note that prices in the UK ETS and EU ETS were aligned over the first months of the scheme, but more recently have diverged due to higher UK prices.

Figure 20: CfD diagram 100-500GWh annual

Source: ICAP Carbon Action and Ember Climate (£1 = €1.19)

Tied to the introduction of the CBAM is the withdrawal of free carbon allowances for the sectors covered, over the period 2026-35, with the cost of the CBAM increasing as free allowances for the EU ETS are gradually withdrawn over the introductory period. Importers from regions where a carbon price is already paid can also deduct this amount from the amount paid.

Around €10bn/year (£8.5bn/year) is expected to be recovered by the tax, depending on the market price of carbon, which will be allocated in part to the EU's budget and in part to national governments to finance climate policies.

There is a potential downside for consumers, who may experience higher prices as a result of the introduction of the price mechanism and removal of free allowances. Furthermore, negotiation of the impact on international trade agreements would be extensive and potential impact on the efficacy of a carbon border tax, with complex calculations required to maintain the competitive position of EU exports in the absence of free allocations.

The Environmental Audit Committee announced in September 2021 that it has launched an enquiry into CBAMs. This is investigating matters including the risks of carbon leakage, the potential to introduce a unilateral CBAM, which products and sectors should be incorporated into this, how a CBAM might impact on international obligations including trade, whether there should be a special regard for developing economies or SMEs, and what practical and administrative challenges in designing and implementing a CBAM.

Of course, a CBAM only addresses the specific issue of costing carbon and does not in isolation address other issues (previously discussed in this report) that result in high cost grid supplied electricity for UK consumers.

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