WHEN TRUST MATTERS

ENERGY TRANSITION OUTLOOK UK 2024

A national forecast to 2050

Final turbine installed at Viking Wind Farm. Image: © SSE Renewables.

FOREWORD

2023 saw extreme weather events devastate communities around the world, with new records set for global temperatures and carbon emissions. Public discourse, however, was dominated by geopolitical tensions, conflict, and short-term economic challenges. Scaling the energy transition to meet net-zero targets seems further down today's agenda.

At COP 28, countries agreed on the need to "transition away from fossil fuels in energy systems" for the first time, providing hope that meaningful action would decisively mobilize the world into action. Unfortunately, the deal doesn't compel countries to act, and no timescales are specified.

The UK's early ambition and action to champion the energy transition has allowed the nation to make good progress. That progress now seems to be stalling, and, as we detail in this UK Energy Transition Outlook (UK ETO), the country will not meet its 'net zero by 2050 target' unless the government increases policy support to a low-carbon future. This forecast, now in its second edition, is based on our independent model and accounts for the UK energy system's physical, political, technological, and economic links to Europe and the rest of the world.

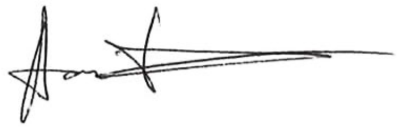
Over the next three decades, the UK will undergo a strong shift from fossil fuels to electricity as an energy carrier. But the scale of the shift is now lower than we forecast in our first UK ETO report, issued in 2022. As a result, oil and gas will still account for 35% of the UK's primary energy supply mix in 2050. Moreover, the outlook for hydrogen now seems a lot less certain in the absence of a clear, UK-wide strategy on the demand and supply of this crucial decarbonization fuel. One bright spot this year is that the future of UK CCS looks more robust due to heightened government support and an expected increasing carbon price.

London Underground (the tube) launched its 'Mind the Gap' safety campaign more than 50 years ago, and that call to action has become second nature for my fellow Londoners. I think we need to elevate the message to 'Mind the Gap to Net zero'. The gap in question is between the Nationally Determined Contributions (NDCs) of many nations, including the UK, and the 2050 net-zero ambitions they are pursuing through their current emission-reduction plans. There is a gap in the number of gigawatts needed and the number of renewable projects being built. There is a gap between what supply chains can deliver and what nations need. There is an ever-increasing skills gap. But fundamentally, there is a gap between targets and the policy needed to drive industry to scale.

To bridge the gap we need to keep focused on the positives: the UK has the largest offshore wind market in the world – established through a combination of North Sea oil and gas expertise coupled with strong government policy support. The nation is seeing a greater number of solar projects constructed, industrial scale energy storage plants and year-on-year sales growth of EVs. We also need to focus on the key challenges. The national power grid needs significant scaling to make it more responsive to better manage supply and demand, and pipeline infrastructure needs to be tested and upgraded to ensure the safe transmission of blended hydrogen to communities and businesses around the UK. Home insulation is a key enabler of decarbonization and must be policy priority.

Like all balanced systems, if you want less of something you must start with more of something else. Green electricity is key to the energy transition, the competitiveness of the UK's future economy, and the wellbeing of our households.

With oil and gas representing 80% of today's energy system, a dramatic ramp up of renewable power and grid capacity is needed. Without this, change will not be realized. Alignment between authorities, energy companies and society is needed to bridge the gap and to achieve legally-binding net zero commitments. We will move forward, faster, together.



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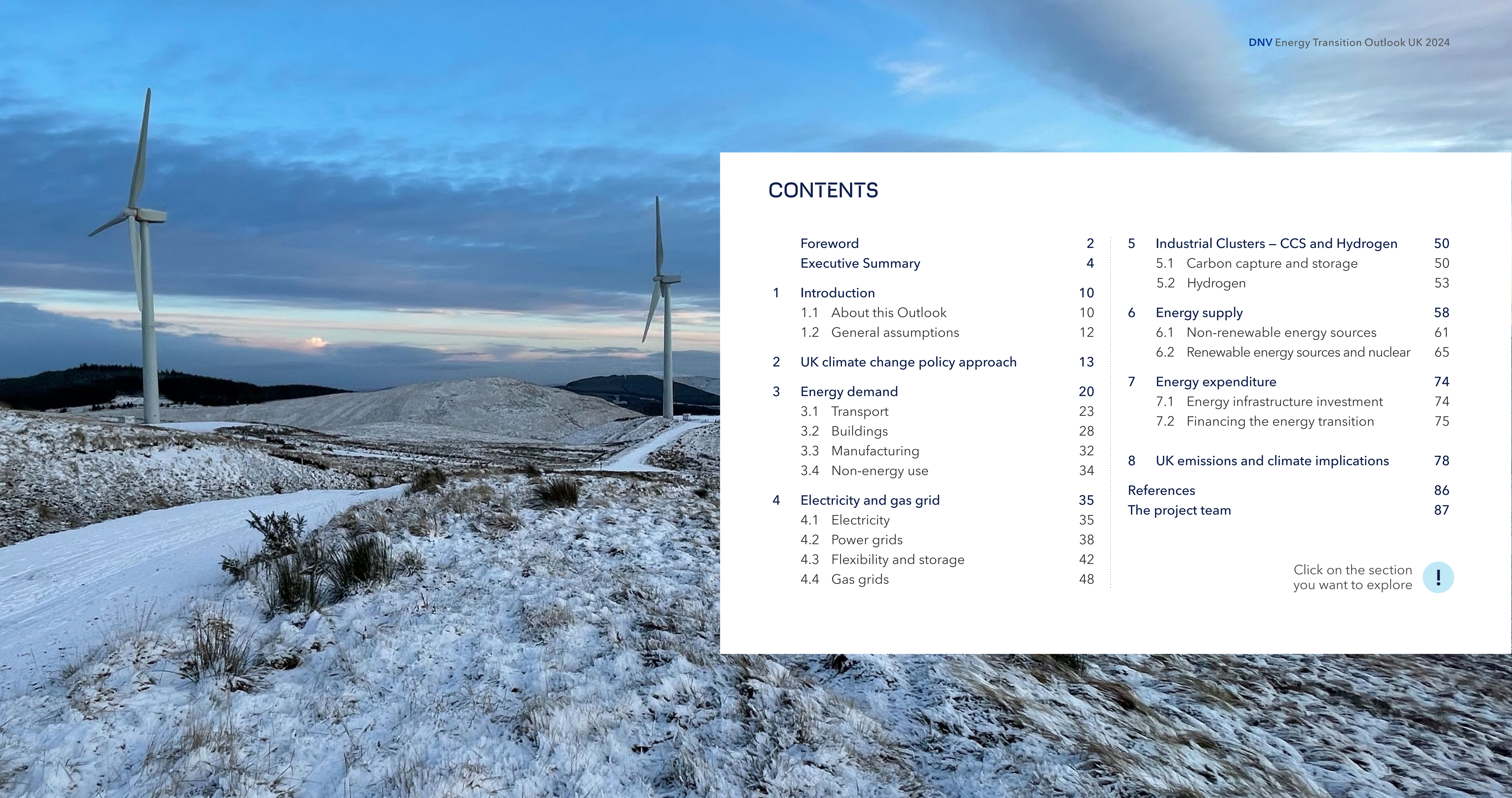

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EXECUTIVE SUMMARY

HIGHLIGHTS:

1. **Not on track** – The UK looks set to miss both its 'Net Zero by 2050' target and its decarbonization commitments for 2030
2. **Affordable** – Decarbonization comes with a green dividend for UK households, with average energy spend dropping 40% in the next 30 years
3. **Partial decarbonization** – Low carbon sources to rise from 20% of UK primary energy today to 65% by 2050, but still 35% will be fossil fuels
4. **Falling demand** – Energy demand will fall by a quarter by 2050 largely due to system efficiency gains from increased electrification
5. **Green electricity** – Demand for electricity increases by +130%, with three quarters of power generation from renewable sources by 2050

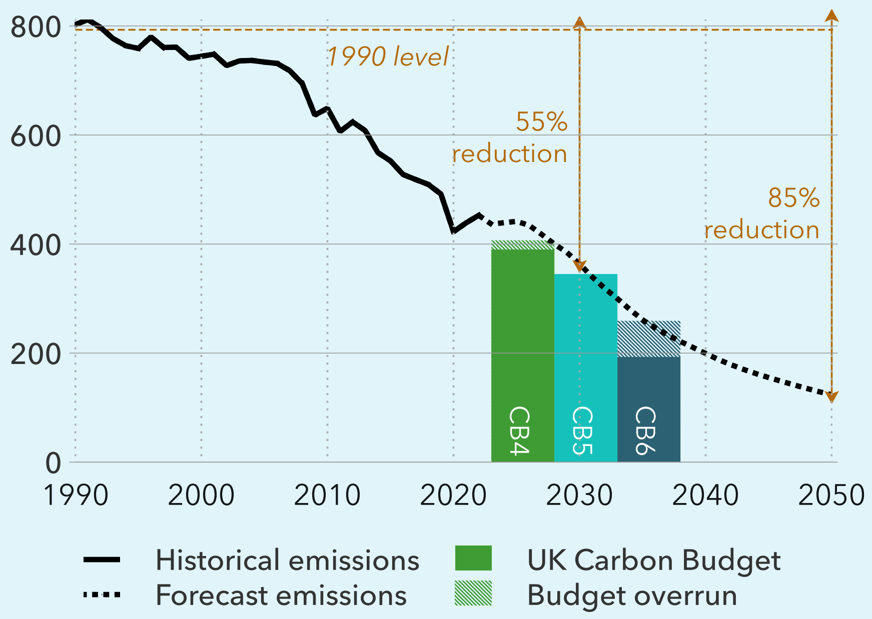
1 **We forecast that the UK is not on track to meet either its legally-binding 'Net Zero by 2050' target or its commitments for 2030 under the Paris Agreement (Figure 1).**

Our forecast shows that the UK's annual emissions will amount to some 125 $MtCO_2e$ in 2050. That implies a significant 85% reduction relative to 1990 levels, but not the 100% reduction by 2050 which the UK legislated for in 2019.

FIGURE 1

UK total greenhouse gas emissions

Units: $MtCO_2$/yr



Similarly, the UK will also not meet its Nationally Determined Commitment (NDC) of reducing emissions by 68% by 2030 compared with 1990; we expect an emissions reduction of around 55% by then relative to 1990 levels. In terms of the UK carbon budgets, we forecast that we will get close to meeting carbon budgets up to 2032 but then exceed carbon budget 6 (2033-37) by 37%.

The transport and buildings sectors are the major remaining contributors to the total annual emissions in 2050. In transport, a sizeable proportion of vehicles, particularly commercial ones, will continue to be fossil-fuelled, and aviation will continue to emit significantly due to the slow penetration of low-carbon fuels such as synthetic e-fuels and hydrogen by 2050.

Natural gas will still comprise over 50% of final energy demand for buildings in 2050, primarily for space heating. There is clearly an opportunity for government to act more forcefully on the decarbonization of domestic heating.

2 **The decarbonization of the UK economy is affordable and will, by 2050, reduce average household energy expenditure by nearly 40% relative to 2021 levels (Figure 2).**

A substantial green prize awaits the UK economy in the form of a cleaner, more efficient, and less expensive energy system.

We forecast annual energy infrastructure CAPEX spend to increase from an annual average of GBP 26bn in previous decades to around GBP 38bn per year over the next 30 years. While this is a significant increase in absolute terms, the share of GDP devoted to energy CAPEX expenditure remains relatively stable at just above 1% of GDP across the 2000-2050 period.

Over 50% of the energy system investment for the next 30 years will be CAPEX for the addition of new power generation capacity, primarily renewables, and grid infrastructure comprising both reinforcement and build-out of new infrastructure to meet the increased annual electricity demand.

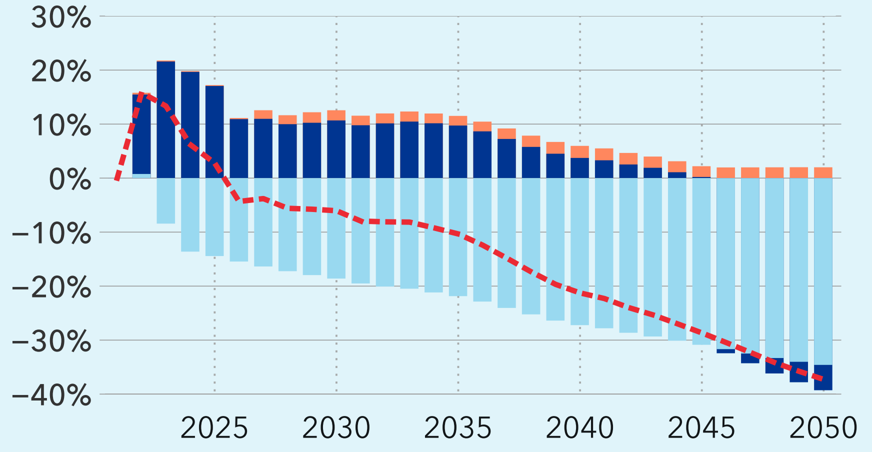
Approximately 12% of investment will be associated with improving energy efficiency of the UK housing stock.

Excluding the costs of house insulation improvements, our forecast shows that total household energy costs are expected to drop below 2021 levels by 2026 and then gradually reduce further to nearly 40% below 2021 levels by 2050. The decline in household energy expenditure is driven by increased electrification of both household heating and passenger transport, leading to an overall reduction in energy demand.

FIGURE 2

Variation in UK household expenditure on energy, compared to 2021

Units: Difference to 2021 (%)



Home heating will remain dominated by natural gas

By 2050, only about one third of homes will have heat pumps, but over half of the homes will still use natural gas for heating. Heat pumps are the prime option to decarbonize home heating, but large-scale uptake in the UK is hampered by costs and insulation requirements:

For heat pumps we forecast that the levelized cost of home heating will remain higher than heating with gas boilers for the next 5–10 years, even with current government support packages for heat pump installation. The main reason for this is the high electricity price relative to gas in the current energy market, where the electricity price is around a factor of four higher than gas per kWh.

In addition, there is the more structural limitation to heat pump installation potential linked to the insulation status of the UK housing stock. Today, based on recorded Energy Performance Certificate ratings, it is estimated that only approximately 50% of the UK housing stock is suitable for heat pumps. This will gradually change over time as insulation is retrofitted and new housing stock with better insulation standards is added, but in the medium term this will limit the percentage of households that can consider a heat pump for replacement of a boiler.

The only alternative pathway for decarbonization of home heating at scale would be to replace natural gas with hydrogen in the network. However, we forecast that hydrogen for heating will remain expensive up to mid-century, even with hydrogen production costs reducing to \$2.5/kgH_2 by 2050, which would still result in hydrogen prices being double the price of natural gas per kWh. Furthermore, there are concerns about the availability of sufficient green hydrogen to heat a large part of the UK housing stock.

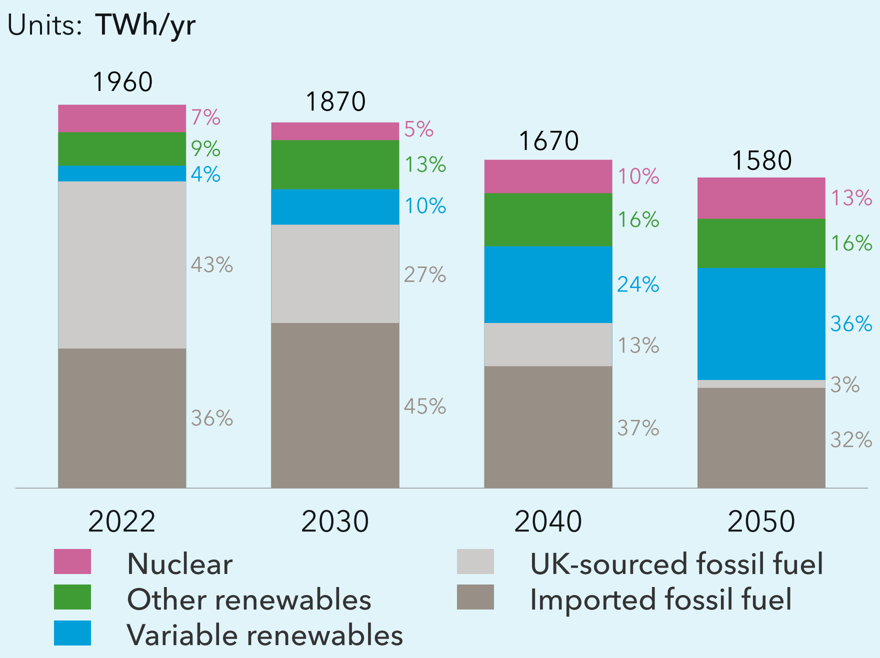
As a result of the above factors, we forecast that, at least for the next 5–10 years, the majority of UK homeowners will replace their boiler at the end of its lifetime simply with a new boiler. Heat pump installations will overtake boiler replacements only around 2040. Short of a major policy shift by the UK government, this will lock in the domestic heating system to natural gas with nearly 60% of homes still burning natural gas for heating by 2050. ■

3 **UK's primary energy supply will shift from fossil fuels to low-carbon sources, with the latter rising from 20% of primary energy today to 65% by 2050 (Figure 3).**

Today, close to 80% of all UK primary energy comes from fossil fuels, of which just over 50% is produced in the UK and the remainder imported. Renewables supply 13% and the remaining 7% is covered by nuclear energy. Even with the expected build-out of renewables, this heavy reliance on fossil fuels will remain for the next decade, only reducing to 70% by 2031.

FIGURE 3

UK primary energy supply by source



Percentages are rounded and might not add up to 100%
Historical data source: IEA WEB (2023)

By 2050, this picture will change significantly with low-carbon supply sources meeting nearly 65% of the UK energy needs. More than half of that will be via variable renewables (wind and solar) and the remainder split between bioenergy and nuclear.

However, we forecast that despite this strong shift, a third of the UK primary energy supply will still be fossil fuels by mid-century, dominated by their remaining unabated use in household heating and aviation.

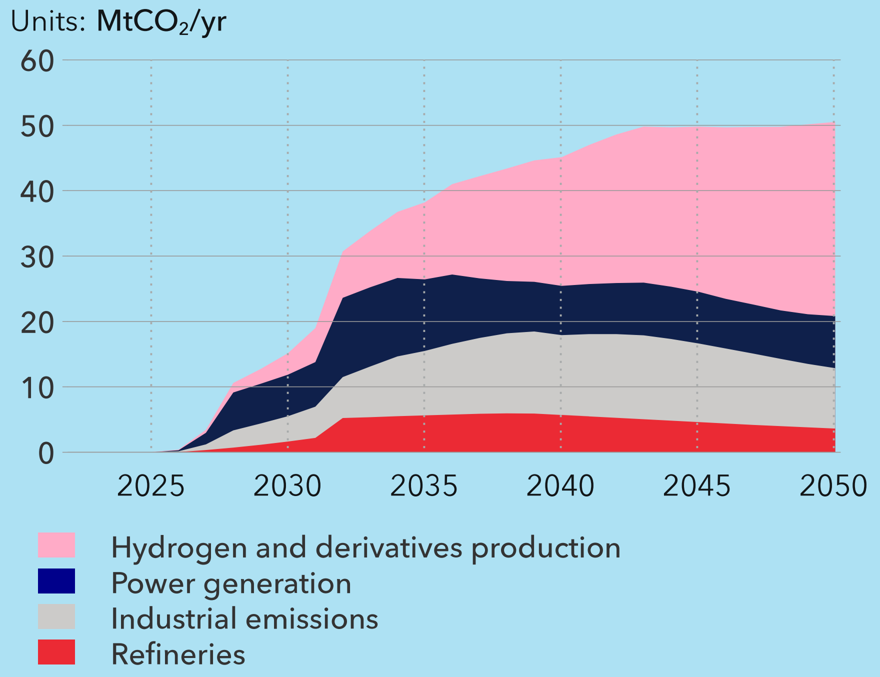
The future for Carbon Capture and Storage (CCS) is looking more promising

CCS is benefiting in the short term from the announced GBP 20bn Government support and over the long term will be driven by the expected increase in the carbon price.

Based on our latest estimates, carbon prices for Europe (including UK) will increase significantly between today ($75/t) and 2050 ($250/t). Current views indicate the carbon price could reach $150/t in 2030 and $200/t in 2035. This would mean that the cost of emitting CO_2 would start to exceed the cost of capturing CO_2 for most applications in the 2030-35 period, incentivizing installation of CCS for industrial use, power generation and H_2 production.

FIGURE 4

UK carbon capture and storage capacity



As part of our forecast we have assessed the current planned/supported Track 1 CCS projects which would already result in 11 $MtCO_2$/year CCS capacity in 2030 and 19 $MtCO_2$/year by 2035. However, as a result of the increasing carbon price, we forecast that the trend will actually be higher, reaching 40 Mt/yr in 2035.

This ramp up of CCS capacity will require the availability of sufficient transportation, injection and storage capacity, but in our view that should not be a major constraint in that time frame, considering the large potential for CO_2 storage in UK Continental Shelf. ■

4 UK final energy demand will no longer grow in lock-step with GDP and population growth; in fact, energy demand will fall by a quarter by 2050 due mainly to electrification (Figure 5).

An electrified energy system is more efficient than a fossil-fuelled energy system. Hence, the predicted shift towards electricity as the key future energy carrier will de-couple UK energy demand growth from economic growth.

Today, three quarters of all energy is supplied to customers via two fossil fuel carriers: natural gas –

mainly for the buildings and manufacturing sectors – and oil, mainly for the transport sector. Only 17% of UK energy is delivered to customers in the form of electricity.

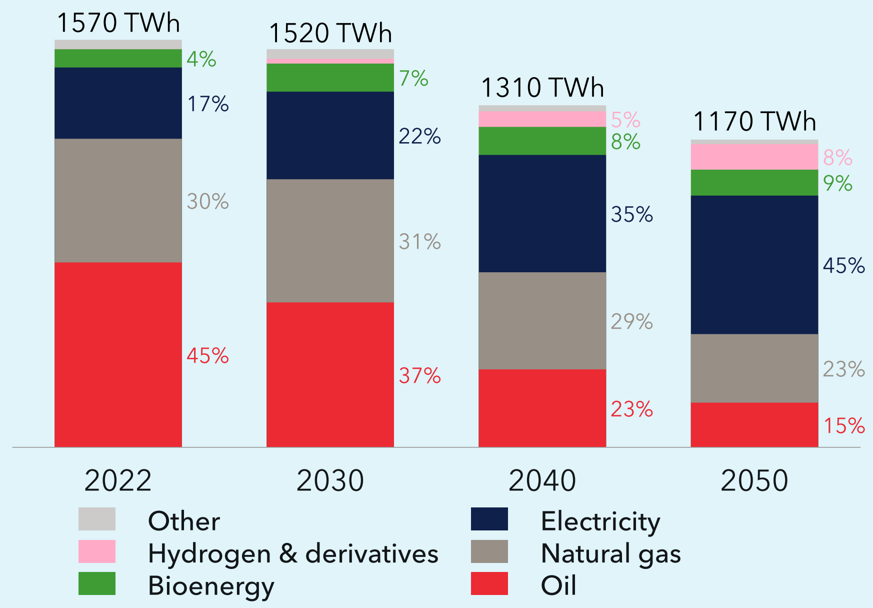
By 2050, electricity will deliver close to half of UK final energy demand, mainly because of electrification of road transport and heating of a third of UK households.

With electrification and other efficiency improvements, the energy intensity of GDP will fall. Not only will large losses to heat in thermal generation be avoided, but the electrification of end-uses will drive very meaningful energy savings.

FIGURE 5

UK final energy demand by carrier

Units: TWh/yr



Historical data source: IEA WEB (2023), DUKES (2023)

5 Electricity demand in the UK will increase by a factor of 2.3 by 2050 compared to today (Figure 6).

Electricity generation in the UK will increase from 315 TWh/yr today to 700 TWh/yr in 2050. At present, the biggest share (40%) of power generation output in the UK originates from unabated gas-fired power plants. As a result of decarbonization incentives and the declining costs for renewable electricity generation, this share is expected to gradually decline to 3% by 2050, by which time all remaining gas-fired units will primarily use hydrogen as fuel. In contrast, power generation from variable renewable resources will grow dramatically from 90 TWh/yr today to 560 TWh/yr in 2050.

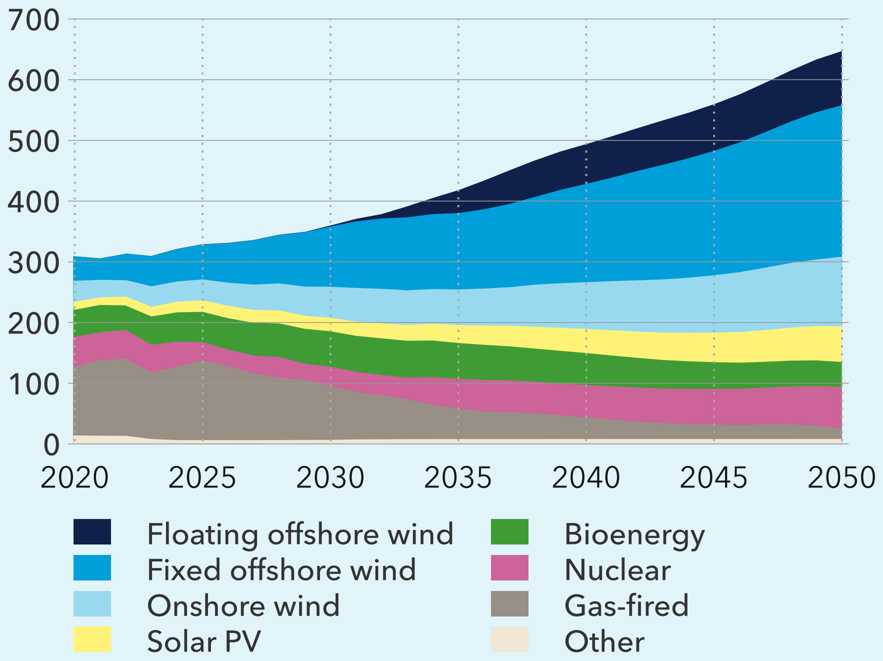
The increase in electricity demand will require the addition of approximately 140 GW of new generation capacity over the next 30 years, with most of these additions (90%) being new wind and solar farms. There is also the need for some new gas/biomass-fired units and nuclear capacity to provide dispatchable power and base load.

In parallel, there will also be a continued need to strengthen and expand the grid to connect all the new power sources and carry the additional power loads. Most of the growth in UK wind will be in locations at some distance from the major demand centres (e.g. Scottish renewables feeding the rest of the UK), requiring significant investment in the UK transmission grid. Considerable investment in energy storage will also be needed, along with demand-response capabilities.

FIGURE 6

UK grid-connected electricity generation by power station type

Units: TWh/yr



6 **Electricity generation will shift fundamentally away from fossil fuels to variable renewable energy sources (VRES) which will be supplying three quarters of total electricity in 2050 compared to only a quarter today (Figure 7).**

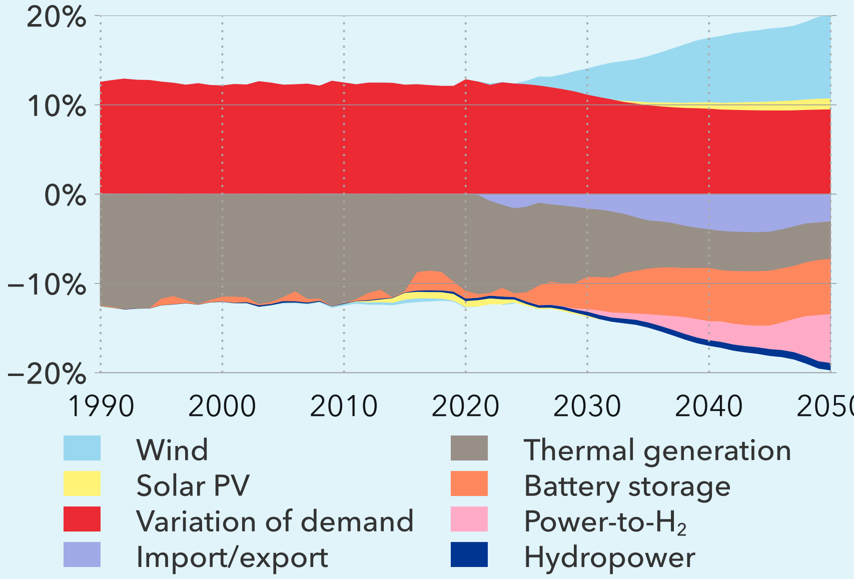
The significant VRES penetration in electricity generation will cause a major increase in supply variability around the average hourly grid throughput compared to today (Figure 7).

Today's electricity system is subject to a 12% annual variability primarily due to variability in demand (40 GW ±5 GW). This variability is mitigated through an equivalent 12% flexibility mainly provided through dispatchable gas-fired generation which can be ramped up and down quickly to match demand fluctuations.

FIGURE 7

Sources of annual variability and providers of flexibility in the UK power system

Units: % of average demand



Annual cumulative hourly deviation from the average annual demand, relative to average annual demand.Positive numbers show sources of variability. Negative numbers show reduction in variability by flexibility options.

By 2050, the electricity system will nearly see a doubling in variability up to 20% caused by the increased penetration of variable renewables in the supply mix (90 GW ±20 GW). This will require a commensurate doubling of flexibility response within the overall electricity system. The majority of this flexibility (85%) would be provided roughly in equal measure by three key systems within the UK electricity system: 190 GWh of utility-scale battery storage, 20 GW of dispatchable thermal generation and some of the 35 GW total electrolysis capacity to convert electricity to hydrogen during periods of excess wind and solar generation.

The remainder of the necessary flexibility (15%) is provided by interconnectors with other power grids in Europe – both in terms of exporting/storing excess supply during times of high VRES generation or supplying back-up power during supply shortages.

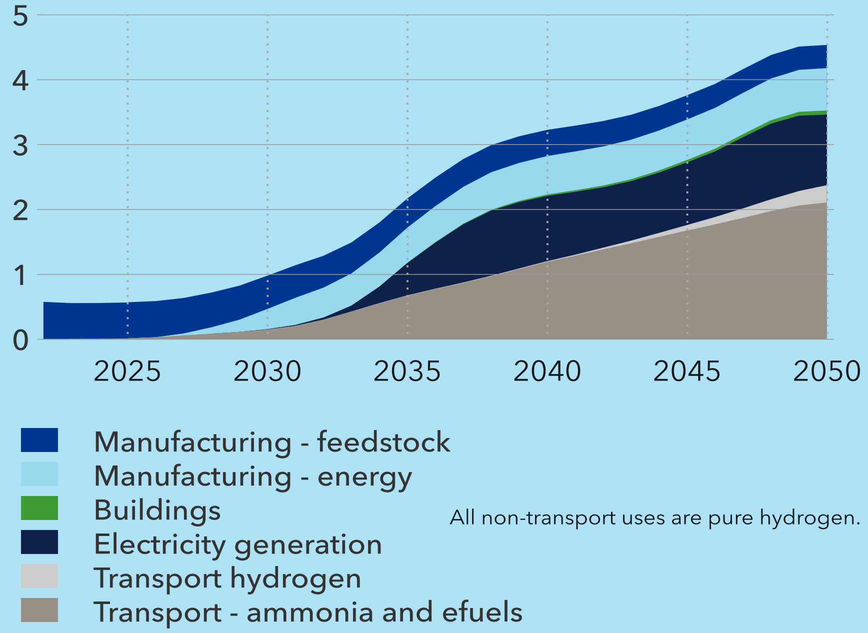
The development of the UK hydrogen market needs significant support

We forecast hydrogen production to reach 1 Mtonnes/yr in 2030, of which only 60% will be low carbon. This would be equivalent to ~5 GW of low carbon hydrogen production by 2030 versus the government target of 10 GW. This forecast is in line with the current expectations around timelines and capacities for the selected hydrogen projects in the industrial clusters, assuming they will receive further government support to ensure the projects reach Final Investment Decision (FID) in the next few years.

FIGURE 8

UK demand for hydrogen and its derivatives by sector

Units: MtH_2/yr



Hydrogen production will then grow to 4.6 Mtonnes by 2050, equivalent to 10% of final energy demand in the UK.

Half of the hydrogen and its derivatives will be used for transport, 25% in industry and 25% for dispatchable low-carbon power generation. Our forecast shows that the main driver for long term hydrogen demand is the increasing need for hydrogen derivatives in the transport sector to meet national and international fuel directives – especially for maritime, which has ambitious decarbonization targets and whose emissions will also be included in the EU Emissions Trading Scheme. Without a clear business model or market support mechanism, high production costs would make H_2 generally uncompetitive for industrial use and domestic heating even by 2050.

By 2050, we predict a 50/50 split between blue hydrogen (produced from natural gas through reformers with CCS) and green (electrolytic) hydrogen.

With use of hydrogen mainly limited to industrial clusters and power generation, it is expected that hydrogen will mainly be produced/consumed within the clusters. This may limit the need for a potential national hydrogen transmission system to balance demand and supply between clusters and transmission of electrolytic hydrogen from renewable generation sites. ■

RECOMMENDATIONS

We believe that the UK can meet its 2050 net zero target, but this will require clear early policy decisions to overcome the inherent system inertia and ensure that the transition is accelerated.

Large-scale electrification using renewable electricity sits at the heart of the UK energy transition. The UK's early ambition and action to champion the energy transition did result in a strong start for greening the electricity supply through progressive policies around Contracts For Difference frameworks and competitive strike-prices. This has resulted in a strong build-out of wind and solar capacity, reaching an impressive total of 45 GW today (45% of the total installed UK generation capacity).

That progress now seems to be stalling, with the disappointing latest wind allocation round results, uncertainty around decarbonizing home heating and the role of hydrogen in the UK. Consequently, as our findings show, on its current trajectory the UK will not meet its 'net zero by 2050' target unless the government increases policy support to a low-carbon future.

Based on our findings, we would recommend that the following specific issues are addressed urgently to close the gap to net zero:

- Firstly, to succeed on the electricity supply side, it is imperative that we deliver the necessary step-change to treble the historical electricity investment levels to ensure the grid will be the enabler, not a blocker to the energy transition.

  To meet the investment challenge, the way our networks are planned, built and operated needs to adopt a fundamentally different approach. Critically, policy makers and regulators need to accept that the levels of risk associated with delivering this step-change will be different from risks that previously were deemed acceptable.

- Secondly, there needs to be a focus on reducing the energy demand side with a strong push on energy efficiency measures, including electrification of home heating and road transport, and other demand-side measures to reduce energy consumption. The government needs to actively engage with industrial clusters on emissions reduction and with society at large on energy efficiency/electrification, waste reduction, lifestyle changes, travel reduction and modal shifts in transport. Our model accounts for behavioural changes only to a limited extent but we see this as a key element of the transition story.

- Combining the supply and demand side of the equation, the UK needs a more integrated systems approach across all key energy vectors, so we can define and implement the optimum decarbonized energy system for the UK as a whole. Currently we see competition between industrial clusters for allocation of hydrogen and CCS capacity, consumer choice mainly driving the domestic heating decarbonization and general uncertainty about the future of gas. The new National Energy System Operator (NESO) needs to play a pivotal part in this key system definition.

- Our forecast clearly shows that the current electricity pricing model is not providing sufficient incentive for consumers to transition from gas to electricity for domestic heating. Today the consumer electricity price is 4x the price of natural gas per kWh, caused by a combination of factors: the marginal wholesale electricity pricing model (where prices are generally set by gas-fired power plants), significant environmental levies and indirectly because fossil fuel electricity generation is subject to carbon taxes. It is important to re-design the future electricity/gas markets to ensure fair competition between all available fuel sources. These new energy markets should reflect for each source the actual capture price, the true impact of carbon costs, and an equal distribution of any charges associated with the energy transition.

- For the hard-to-abate sectors, the UK needs to develop a clear business plan for the hydrogen market, based on a good understanding of what will be driving hydrogen demand in the UK, and determine where it is essential or economical to incentivize hydrogen production capacity. This should cover the role of hydrogen for the future maritime/e-fuels market, specific industrial applications and as a key back-up option for use of excess renewable energy.

1 INTRODUCTION

1.1 About this Outlook

This report, the *UK Energy Transition Outlook* (UK ETO), describes the energy future of the UK through to 2050. The analysis, the model framework behind it, the methodology, the assumptions, and hence also the results lean heavily on DNV's global forecast, *Energy Transition Outlook 2023* (DNV, 2023a). The UK model is also part of the same global Energy Transition Outlook (ETO) model, where the UK is modelled as a separate region interacting with other regions of the world.

This is necessary, because the UK energy system is not standalone and is connected to the European and global energy systems physically (e.g. via pipelines and grids); politically (carbon prices and other policies); technologically (learning rates, technology costs, technical solutions, etc.); and, economically (cost of materials, market prices, etc.). The DNV model takes this into account by modelling the UK as a stand-alone region linked to the other regions in Europe and globally, and looks at global, regional, and domestic supply and demand balances integrating it into one single model.

Unlike most energy forecasters, DNV does not develop scenarios. Not because we know what the future will be like, but because not all futures are equally likely, and DNV sees a lot of merit in giving a best estimate. Hence, our analysis produces a single 'best-estimate' forecast of the energy future for the UK, where we also discuss uncertainties and sensitivities. This forecast accounts for expected developments in policies, technologies, and associated costs, as well as some behavioural changes. The forecast also provides a basis for assessing whether the UK is likely to meet its energy and climate-related targets.

Our approach

Our model simulates the interactions over time of the consumers of energy (transport, buildings, manufacturing, and so on) and all sources of supply. It encompasses demand and supply of energy globally, and the use and exchange of energy between and within 10 world regions.

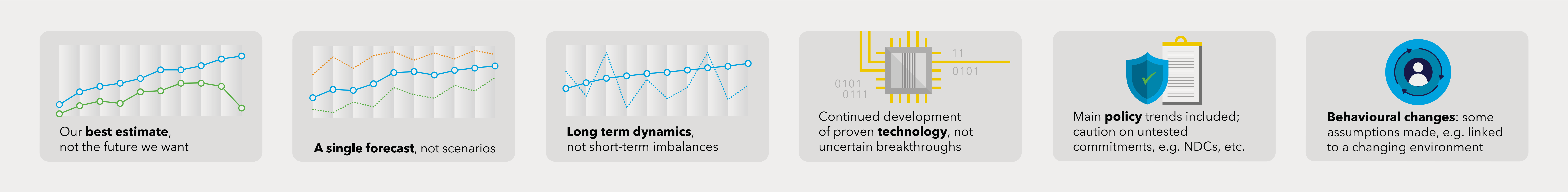
To tailor the model for this project, we added the UK as a standalone region by splitting region Europe into two regions: 'UK' and 'Europe-without-UK'. In this way, we derive separate forecast results for the UK, along with the other 10 world regions.

The analysis covers the period 1990–2050, with changes unfolding on a multi-year scale that in some cases is fine-tuned to reflect hourly dynamics. We continually update the structure of our model and the input data. In this report, we do not repeat all the details on methodology and assumptions from the ETO 2023 report but refer to that open report for further details.

Figure 1.1 overleaf presents our model framework. The arrows in the diagram show information flows, starting with population and GDP per person, while physical flows are in the opposite direction. Policy influences all aspects of the energy system. Energy-efficiency improvements in extraction, conversion, and end use are cornerstones of the energy transition.

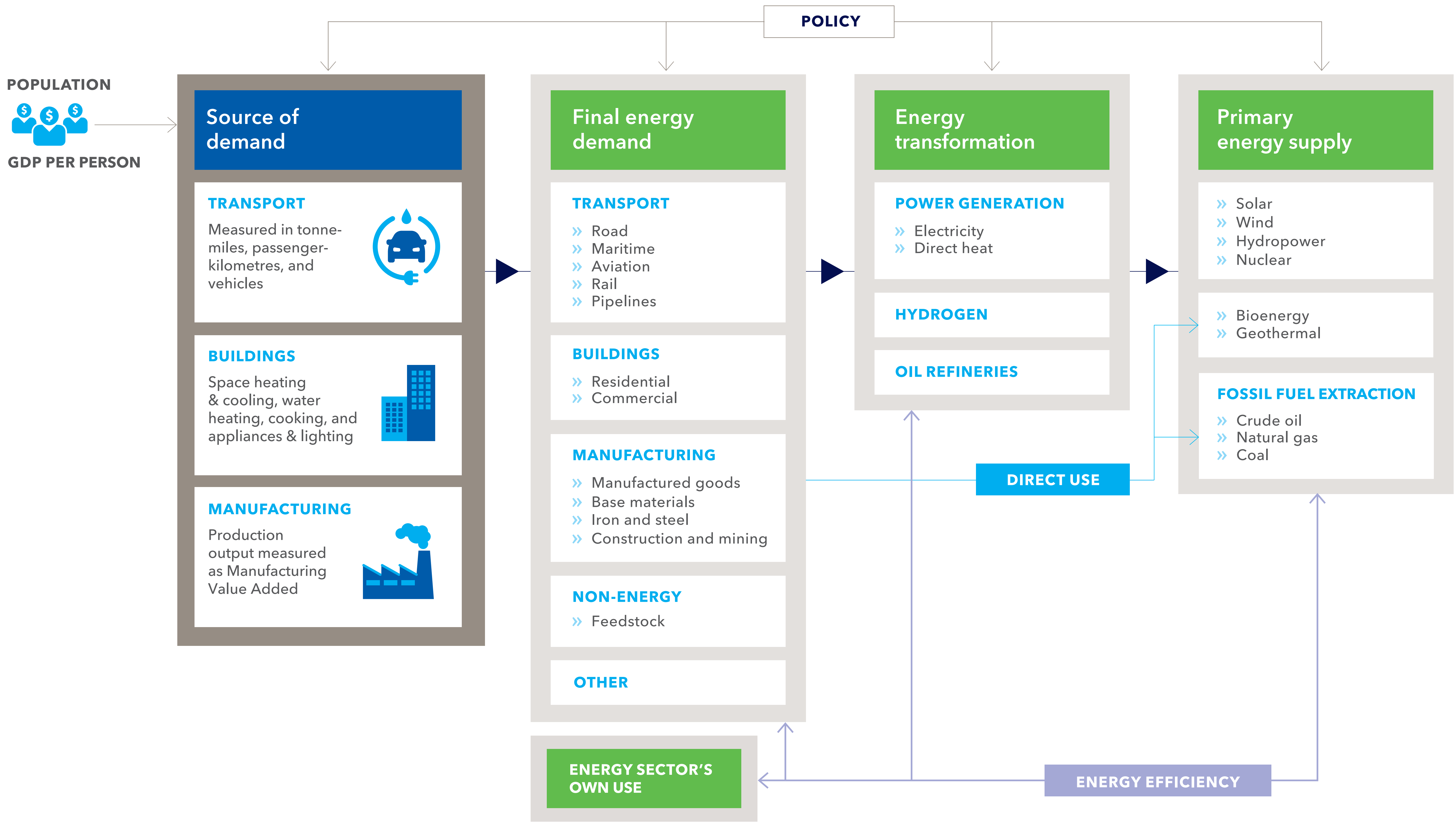
We use policy and behavioural effects, either explicitly (e.g. the effect of increased recycling on plastics demand) or implicitly (e.g. the impact of expected electricity prices on electrification of heating). We estimate sectoral energy demand in two stages. First, we estimate the energy services provided, such as passenger-kilometres of transport, tonnes of manufacturing, or useful heat for water heating. Then we use parameters on energy efficiency and energy-mix dynamics to forecast the final energy demand by sector and by energy carrier.

Our main priorities when designing the ETO model were to include three key characteristics of the energy system: interconnectedness, inertia, and non-linearity. Whereas many energy models are



econometric and assume equilibrium conditions, our model does not. Instead, it simulates the consequences of its assumed goals, parameters, and interrelationships. The model explicitly reflects the delays in reaching a desired state and, consequently, can forecast the path and speed of energy transitions. Our model does not assume optimality or rationality as a prerequisite. It recognizes that the energy system evolves because of many individual decisions based on limited information, rather than one decision-maker that would minimize total cost of the system. Consequently, our forecast is not necessarily the cheapest or most efficient future but a path-dependent and imperfect future.

Our modelling approach, as well as the calibration of modelling input values, becomes increasingly sensitive when we model a country compared with a region or globally. This is especially prevalent when we consider exogenous or outside assumptions such as policies or factors that are specific to the country which have a significant effect in forcing the model to select solutions that are not necessarily the cheapest option. Such factors could be energy security, job creation, or global climate commitments. These key policy assumptions are discussed in Section 2.



1.2 General assumptions

Key input assumptions in the ETO model are in the areas of population, economic development, technology development, and policy.

Population
We use the research and results from the UK Office for National Statistics. According to its January 2022 release of its 2020-based interim forecast (ONS, 2022), the UK population is forecast to grow from 67.5 million people today to reach 72.8 million in 2050.

Economic development
GDP per capita is a measure of the standard of living in a country and is a major driver of energy consumption in our model. Our future GDP per capita numbers are based on IMF's World Economic Outlook (IMF, 2022) until 2027 and on OECD's Long-Term Projections (OECD, 2021) after that.

At infrequent intervals, extraordinary events result in notably different GDP and productivity changes. The 2020 COVID-19 outbreak caused such a change, with negative growth figures as a result. The GDP change for the UK is therefore −9.0% in 2020, +7.2% in 2021, and +3.5% in 2022, thereafter returning to the growth rates given by the DNV GDP model.

For the UK, 2021 GDP was GBP 2,300 billion, while in 2050 it is expected to be at GBP 3,300 billion. This implies a compound annual growth rate (CAGR) of 1.3% per year. Productivity increases from GBP 34,000 to GBP 46,000 per person in the same period in constant British pounds.

Technology development
DNV bases its forecast on the continued development of proven technologies in terms of costs and technical feasibility, not on uncertain breakthroughs. However, during the period covered by this Outlook, the technologies we currently consider most promising might shift due to changes in levels of support, and varying cost reductions. Other technologies may achieve a breakthrough, such that they become cost competitive.

With technology learning curves, the cost of a technology typically decreases by a constant fraction with every doubling of installed capacity. This cost learning rate (CLR) dynamic occurs because ongoing market deployment brings greater experience, expertise, and industrial efficiencies, as well as further R&D. Technology learning is global, and it is the global capacity that is used in learning-rate calculations.

Learning rates cannot easily be established for technologies with low uptake and which are still in their early stages of development. In such cases, calculations rely instead on insights from similar, more mature technologies. Examples of this include carbon capture and storage (CCS) other than that used in enhanced oil recovery, and next-generation electrolysis. Solar photovoltaic (PV), batteries, and wind turbines are proven technologies with significant grounds for establishing learning rates with more confidence. Further down the experience spectrum are oil and gas extraction technologies where unit production costs and accumulated production levels are high and easy to establish. However, hydrocarbons face pressures from the structural decline in oil demand in tandem with rising extraction costs and carbon prices.

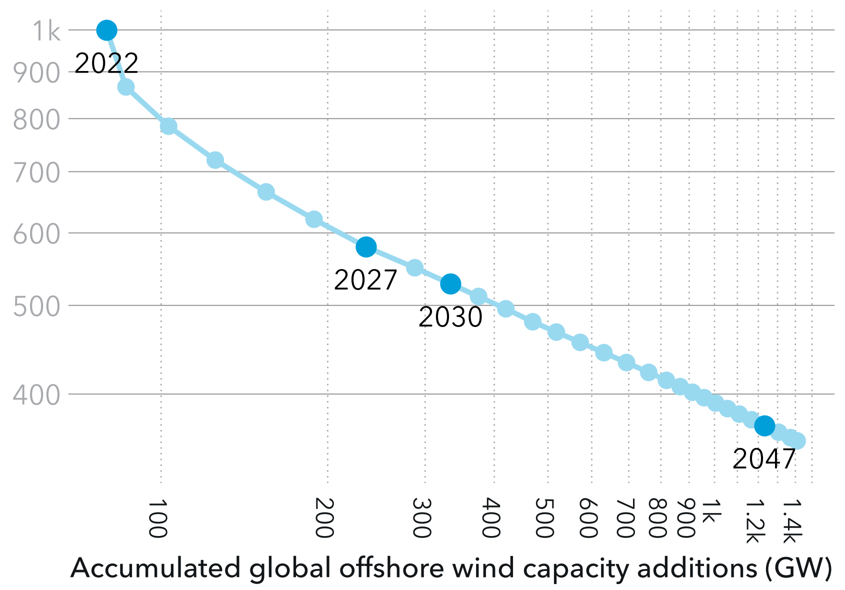
For all technologies, it is necessary to separate out the cost of the core technology (e.g. PV panels) from supporting technologies (e.g. control systems and installation kits). Typically, the latter have a lower learning rate. For PV, core technologies have a CLR of 26%, while balance of supply has only 9%. For some technologies, like batteries, the core technology is almost all there is, and so the highest learning rate dominates. For other technologies, like unconventional gas hydraulic fracturing, other cost components dominate.

Core technology learning rates that we have used through to 2050 in our forecast include 19% for batteries, 16% for wind, and 26% for solar PV but falling to 17% later in the forecast period. Oil and gas development has a learning rate of 10% to 20%, but the annual cost reduction is minor because it can take decades for the cumulative installed capacity to double.

FIGURE 1.1

UK bottom-fixed offshore wind turbine cost

Units: GBP/kW

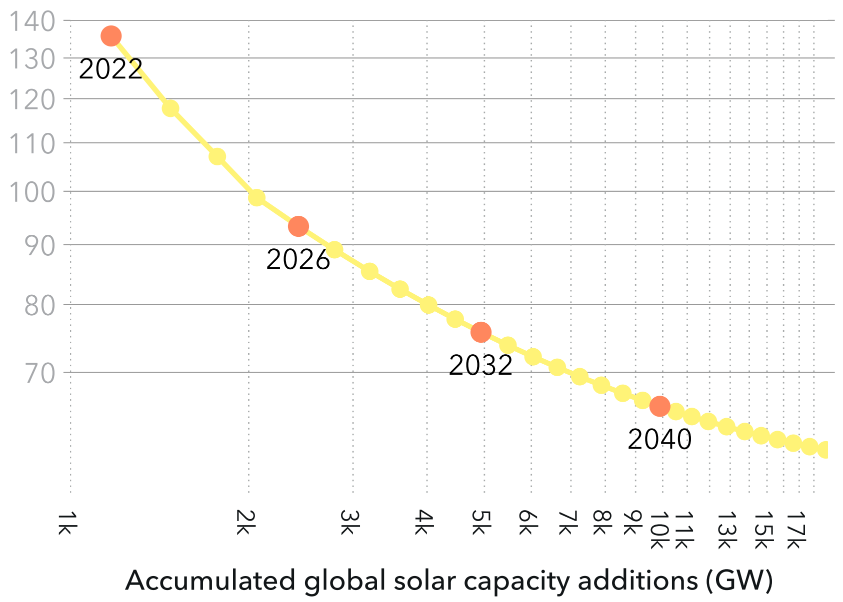


Each labelled year represents approximately one doubling of global capacity.
1 GBP = 1.30 USD

FIGURE 1.2

UK solar panel cost

Units: GBP/kW



Each labelled year represents approximately one doubling of global capacity.
1 GBP = 1.30 USD

2 UK CLIMATE CHANGE POLICY

Since 1990, the UK has made good progress in cutting GHG emissions by 49% while GDP has expanded by around 80%. To meet its legally binding net-zero target by 2050 will, however, require a step-change in decarbonization levels across the entire economy, and particularly in the harder-to-abate sectors – buildings, transport, and manufacturing.

This chapter summarizes the UK's legislation and policies to deliver on its climate change commitments. Our forecast is published amid multiple uncertainties that are likely to impact the UK energy transition, namely high inflation, high interest rates, energy price volatility, a cost-of-living crisis and increased global competition in the green energy race. Even more reason, in our view, to formulate and implement policies that will accelerate a transition towards a more secure, efficient, and affordable energy system that promises to deliver a substantial green prize to hard-pressed UK consumers.

The reality is that these factors have resulted in the UK Government softening some of its green policies in its September 2023 announcement on net zero while still committing to deliver on its climate-change commitments (Gov.UK, 2023a). With general elections looming in the UK in 2024, we expect further short-term policy announcements. However, our Outlook is designed to focus on long-term trends, and we have assumed there will be no change in the overall UK Government ambition to deliver on net zero by 2050.

UK climate-change commitments

The Climate Change Act 2008 underpins the UK's approach to reducing its GHG emissions to mitigate the impact of climate change. The Act sets out the 2050 emissions target and provides interim targets expressed in five-yearly carbon budgets which are established based on advice from the Climate Change Committee (CCC) – an independent statutory body set up under the Climate Change Act.

The original target within the Climate Change Act was to reduce the 2050 GHG emissions by 80% compared to 1990 levels. The CCC recommended levels of emissions reduction for five carbon budgets – spanning the years 2008 to 2032 – based on this original target.

In June 2019, the UK legislated to reach net zero by 2050, thereby amending the original target within the Climate Change Act 2008. The net-zero target implies deep decarbonization of economic sectors, with any residual emissions in 2050 being offset by greenhouse gas removals (GGRs). Such deep decarbonization is a major challenge and is reflected in the CCC's recommendations on the sixth carbon budget

(CB6), for the period 2033 to 2037. This first carbon budget set under the net-zero target calls for a step-change in climate policy.

In June 2021, the UK government set in law the sixth carbon budget which commits the UK to reduce its GHG emissions by around 78% by 2035 compared to 1990 levels.

Under the Paris Agreement, the UK also committed to a 68% reduction in GHG emissions by 2030 on 1990 levels in its Nationally Determined Contribution (NDC) submitted in December 2020. This target is, however, non-binding.

Status of UK emissions

Greenhouse gas emissions have fallen 49% while the economy has grown by around 80% over the period 1990 to 2022. This corresponds to a 70% reduction in GDP emissions intensity from 0.58 $kgCO_2$ per US dollar of real GDP to 0.17 $kgCO_2$/USD real GDP, with GDP measured in 2022 terms for comparison. Per capita emissions in 2022 averaged around 6.5 tCO_2, 55% less than in 1990 (14.4 tCO_2).

The significant fall in emissions and decoupling from GDP growth can be primarily attributed to the change in fuel mix for electricity generation with the shift from coal to gas and, recently, to renewables.

Changes in electricity generation mix has resulted in a reduction of 70% in emissions, as shown in Figure 2.2. Additionally, the decline in energy-intensive industries coupled with increased process and energy efficiencies contributed to a two-thirds reduction in emissions from the industry sector. The transport and buildings sectors have seen much smaller changes in emissions over the 30-year period.

UK carbon budgets

To date, the UK has met its first three carbon budgets CB1 (2008–2012), CB2 (2013–2017) and CB3 (2018–2022). Subsequent carbon budgets would require significant reduction in emissions with the five-yearly average emissions going from around 433 $MtCO_2e$ per annum for CB3 to around 190 $MtCO_2e$ per annum for CB6 (2033–3037) representing a reduction of 56%, as shown in Table 2.1.

Such a reduction would need extensive decarbonization across all economic sectors, with CB6 requiring a step-change in emissions reduction. To achieve this level of emissions reduction means that the roadmaps for addressing the harder-to-abate sectors including buildings, transport, and manufacturing need to be clearly defined within the next years.

FIGURE 2.1

UK emissions and GDP change 1990-2022

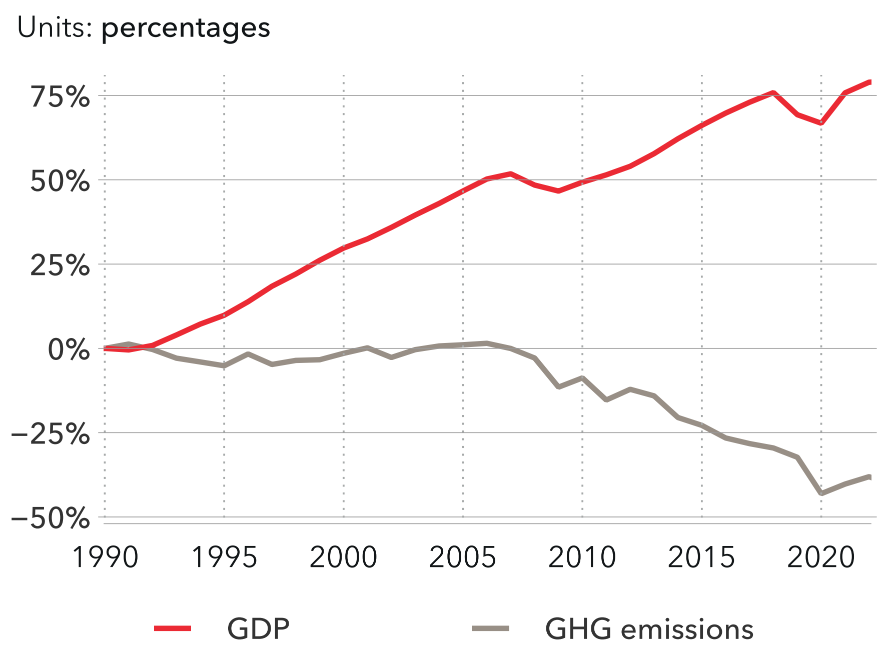


FIGURE 2.2

UK GHG emissions by sector 1990-2022

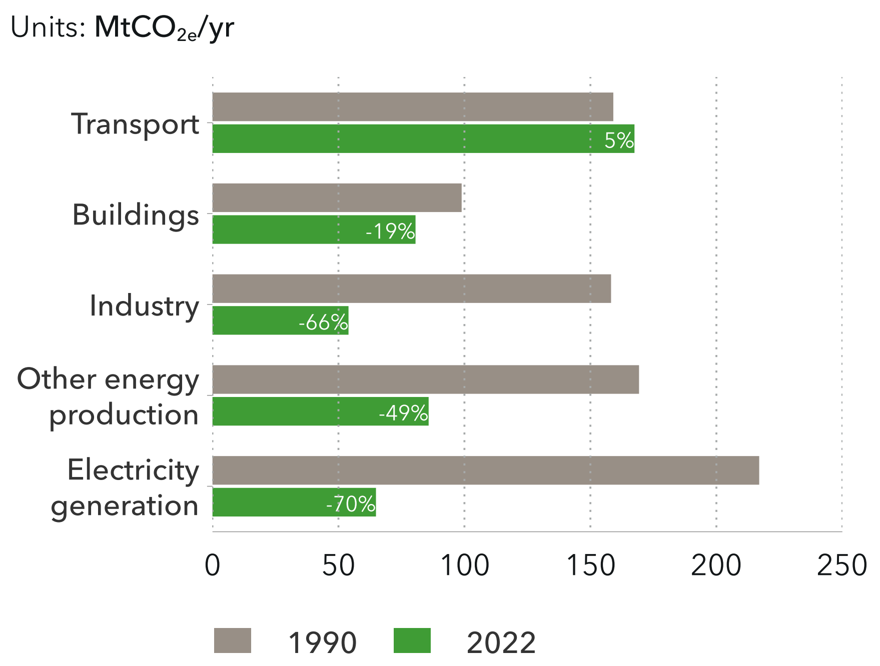


TABLE 2.1

Carbon budgets past, present, and future

	Period	Budget ($MtCO_2e$)	Outturn ($MtCO_2e$)	5-yearly average ($MtCO_2e$)
CB1	2008-2012	3,018	2,996	599
CB2	2013-2017	2,782	2,554	511
CB3	2018-2022	2,544	2,315	463
CB4	2023-2027	1,950	-	390
CB5	2028-2032	1,725	-	345
CB6	2033-2037	965	-	193

* Estimated figure based on an assumed 2% reduction in emissions for 2022 compared to 2019 (pre-Covid emission levels)
** 5-yearly averages for CB1, CB2 & CB3 based on outturn figures

How the UK electricity mix is changing

The UK has an ambition to decarbonize its electricity generation by 2035 subject to security of supply. This reflects the recommendation in the CCC's sixth carbon budget, which under its 'Balanced Net Zero Pathway' assumes a reduction in the carbon intensity of generation from around 220 gCO_2/kWh in 2019 to around 10 gCO_2/kWh in 2035 and 2 gCO_2/kWh in 2050.

Over the period 1990–2022, the UK has significantly decarbonized its electricity generation, moving from primarily fossil-fuel generation in 1990 to over 55% of low-carbon generation in 2022, as illustrated in Figure 2.3.

The key features of the on-grid generation evolution over the period 1990–2022, and the next steps required to deliver a decarbonized generation mix, are:

– Significant phase-out of coal and oil-fired generation from 222 TWh in 1990 to around 8 TWh in 2022, a 97% reduction in fossil-fuel generation. Over that period, the carbon intensity of the on-grid generation fell from around 730 gCO_2/kWh to around 200 gCO_2/kWh.

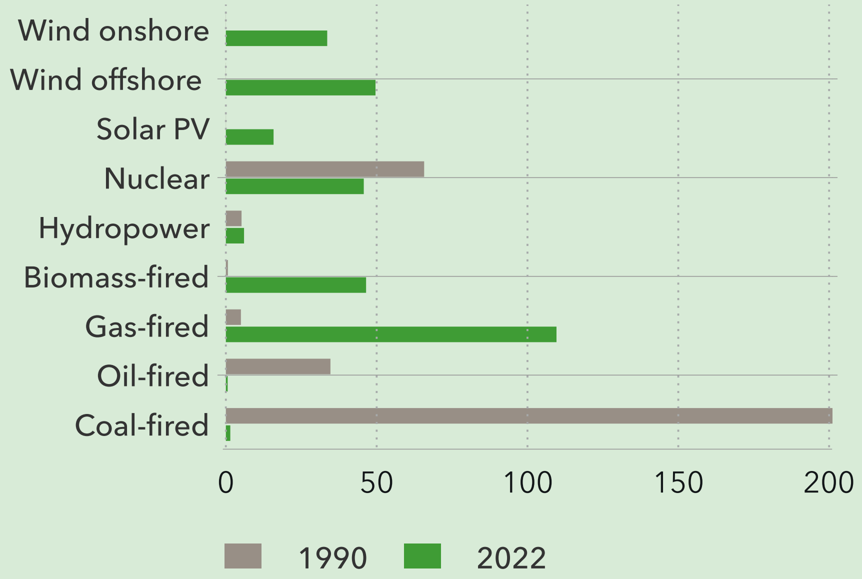
– Increase in gas-fired generation from 5 TWh in 1990 to 137TWh in 2022. For the UK to decarbonize its electricity generation, all gas-fired plants post-2035 should be abated with use of carbon capture and storage (CCS) or should use hydrogen. The economics of both CCS and hydrogen are dependent on business models which are yet to be finalized by BEIS.

– Wind and solar accounted for around 26% of electricity generation in 2022. The UK is targeting a substantial acceleration of the deployment of renewables with a target of 50 GW of offshore wind by 2030 and around 70 GW of solar by 2035.

FIGURE 2.3

UK on-grid electricity generation 1990-2022

Units: TWh/yr



Delivering a Net Zero electricity mix by 2035 will require a multi-stakeholder approach to address the physical and supply constraints across the electricity value chain.

This implies a step-up in build-out rates for both offshore wind and solar. For offshore wind, the implied build-out rate in the UK government target is around 4 GW/yr up to 2030 from around 1.5 GW/yr over the period 2017–2019 (excluding the COVID-impacted years). For solar, the build-out rate has been around 0.5 GW/yr over recent years and would need to ramp up to a similar 4 GW/yr up to 2035.

– Electricity generation from biomass (including Energy from Waste, EfW) has also increased significantly over the period 1990–2022. This includes biomass from organic waste and residues from agriculture and livestock production, wood from forests, energy crops and aquatic biomass. There is currently no specific government target for electricity generation from biomass although the CCC in its sixth carbon budget indicated that around 0.7 million to 1.4 million hectares of land could be dedicated to energy crop production in the UK. ■

Carbon Budget Delivery Plan
To deliver on its legally binding carbon budgets CB4, CB5 and CB6, the UK published a Carbon Budget Delivery Plan (CBDP) in March 2023. The CBDP provides details of the anticipated emissions reductions (where quantified) to 2037 of the proposals and policies put forward by the government.

Most of the proposals and policies are included in strategy and policy documents that the government has published over the last two years (see Box 1). Key points from some of the documents are provided below.

Ten Point Plan for a Green Industrial Revolution – November 2020
The 'Ten Point Plan' sets outs ambitions to deliver green growth for the UK with specific targets for accelerating the development of offshore wind and low-carbon hydrogen, delivering new nuclear projects, shifting to zero-emission vehicles, and aiming for energy-efficient and low-carbon buildings. Some elements of the plan were updated and extended by the British Energy Security Strategy (BESS) (UK Government 2022) issued following Russia's invasion of Ukraine, to reduce the level of UK dependence on oil and gas from Russia.

Energy White Paper: Powering our Net Zero Future – December 2020
This confirmed the commitments made in the Ten Point Plan and pledged to:

- Commit to progress planning for a new nuclear power station to the point of Final Investment Decision (FID) before the end of this parliament.
- Consult on the changes to the Gas Act 1986 to enable decarbonization of gas networks by allowing a greater proportion of biomethane and hydrogen in them.
- Establish a new UK Emissions Trading System. This has been launched.
- Consult on whether it is appropriate to end gas grid connections to new homes being built from 2025. The prospective gas boiler ban is yet to be officially confirmed within the Future Homes Standard guidance.
- Require all rented non-domestic buildings to be Energy Performance Certificate (EPC) Band B by 2030. A separate change to the Domestic Minimum Energy Efficiency Standard (MEES) is currently progressing through parliament and would require EPC C for new domestic rented properties by 2025, and for all rented properties by 2028. *In its September 2023 announcement on net zero, the government has scrapped the latter two requirements.*

BEIS Net Zero Strategy – October 2021
Outlines the plans for reducing emissions from each sector of the UK's economy to meet the legally binding carbon budgets (CB4 to CB6). The Net Zero Strategy provides an indicative pathway to meeting the sixth carbon budget.

The policies within the strategy document build on those in the Ten Point Plan, the Energy White Paper, and on sector-specific strategies including the *North Sea Transition Deal, Industrial Decarbonisation Strategy, Transport Decarbonisation Plan, Hydrogen Strategy and the Heat and Buildings Strategy.*

Some of the key energy-related policies within the *Net Zero Strategy* document include:

- A fully decarbonized electricity system by 2035 subject to security of supply;
- Electrification of oil and gas installations and addressing venting and flaring;
- Decarbonization of industry through resource and energy efficiency, fuel-switching, and deploying carbon capture, utilization and storage (CCUS);
- All new heating appliances in homes and workplaces to be low-carbon by 2035.

British Energy Security Strategy (BESS) – April 2022
This sets out how the UK will accelerate home-grown power for greater energy independence. The strategy was published in response to Russia's invasion of Ukraine and the rise in energy prices. BESS increased the targets for low-carbon power generation compared to previous targets set out in the Net Zero Strategy. In particular, there was an increase in ambition in relation to nuclear, renewables, and hydrogen, as well as support for domestic production of natural gas.

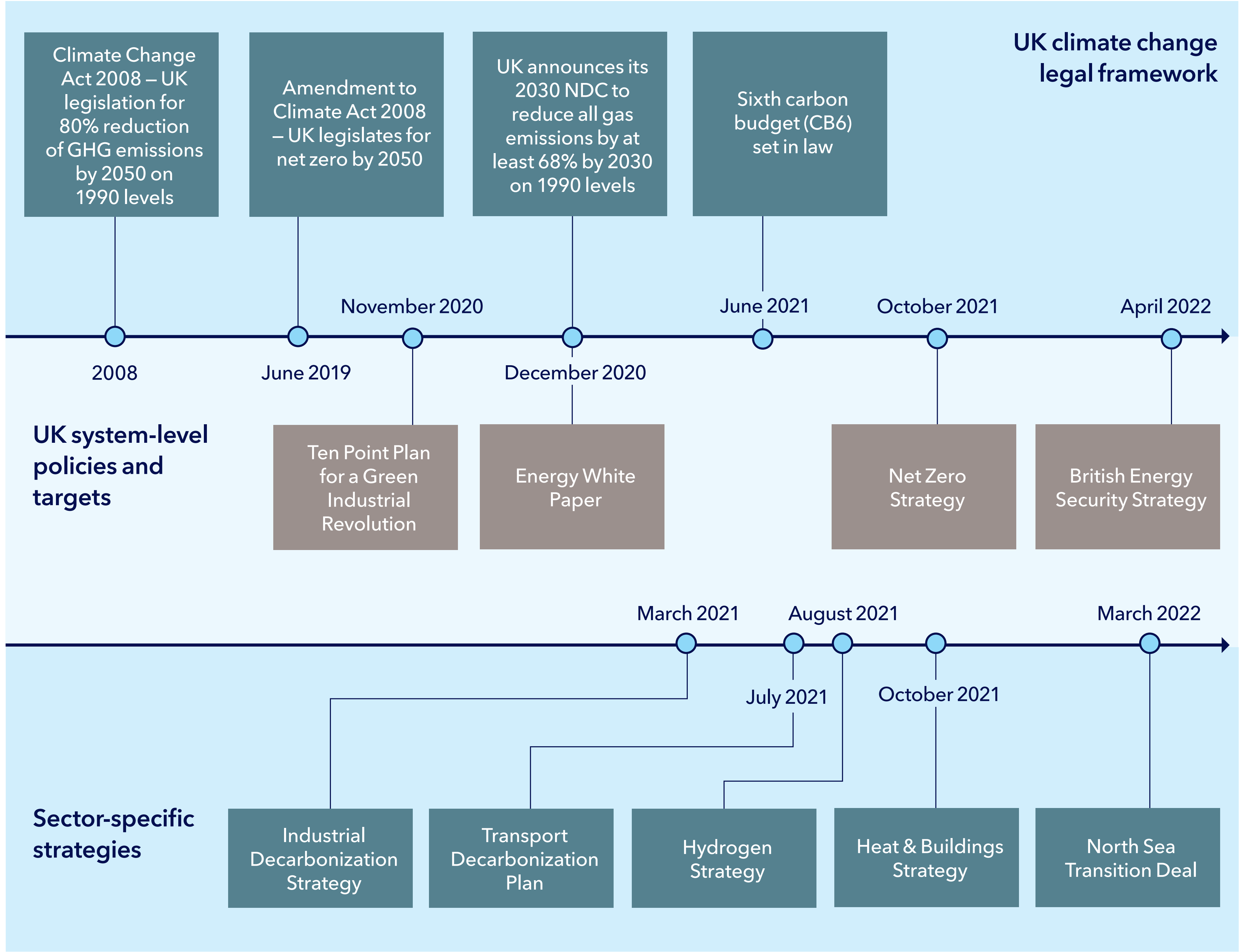


Table 2.2 summarizes some key non-binding policies and targets from these strategy documents. The policies and targets depend in many cases on the development of business models and on further incentives for uptake of technologies and scaling of supply chains.

TABLE 2.2

Key non-binding decarbonization policies and targets from UK strategy documents

	UK policy ambitions and targets
Offshore wind	50 GW including up to 5 GW floating wind by 2030. 11 GW of installed offshore wind capacity in 2021 with build-out rate of around 1 GW/yr over last five years. Target implies a ramp-up in build-out rate of around 4 GW/yr over the next 8 years.
Onshore wind	There is currently a total of 15 GW of installed onshore wind capacity. Despite a September 2023 amendment, stricter planning consent in England implies that it is difficult to get planning permissions for any new onshore wind farms.
Solar	Ambition for a 5-fold increase in rooftop and ground-mounted solar up to 70 GW by 2035. There currently is 15 GW of installed solar capacity in the UK.
Nuclear	Ambition for one large-scale nuclear plant to reach Final Investment Decision (FID) by 2024 with two projects to FID in next Parliament. By 2050, UK aims to have 24 GW of installed nuclear capacity. In 2022, UK had 8 GW of nuclear capacity with five of the six plants going offline over the next 10 years and one plant under construction.
Hydrogen production	Aim of 10 GW of low-carbon hydrogen production capacity by 2030 with at least 50% from electrolytic hydrogen. By 2025, the ambition is to have up to 1 GW of electrolytic hydrogen in construction or operational. UK also plans to develop new business models for hydrogen storage and infrastructure by 2025.
CCUS	Ambition to deliver four carbon capture, utilization and storage (CCUS) clusters capturing 20–30 $MtCO_2$ per year across the economy by 2030, including 6 $MtCO_2$ of industrial emissions. Business models for CCUS are yet to be finalized.
Heat pumps and gas boilers	Target of 600,000 heat-pump installations by 2028 coupled with an ambition that by 2035, no new gas boilers will be sold. By 2050, the aim is that all heating systems are compatible with net zero. The government introduced the Boiler Upgrade Scheme which provides GBP 450 million of grant funding over three years from 2022 to 2025 to support the decarbonization of heat in buildings. Installation of heat pumps has averaged 30,000 over the past three years. There are currently 280,000 such installations in the UK, placing the country at the bottom of the European heat-pump league (Figure 2.4) (New Scientist, 2022).
Road transport	A ban on sales of new petrol and diesel cars and vans by 2035. Aim to end sale of all new, non-zero emission road vehicles by 2040, including motorcycles, buses, and HGVs (subject to consultation).
Aviation	Ambition is for UK aviation to meet net zero by 2040 (subject to consultation) and UK shipping by 2050. For aviation, UK aims to develop a UK sustainable aviation fuel (SAF) mandate to enable delivery of 10% SAF by 2030.
Rail	Ambition for all diesel-only trains to be removed from the network by 2040 and achieve a net-zero rail network by 2050.

Implementing UK policy in our UK Energy Transition Outlook

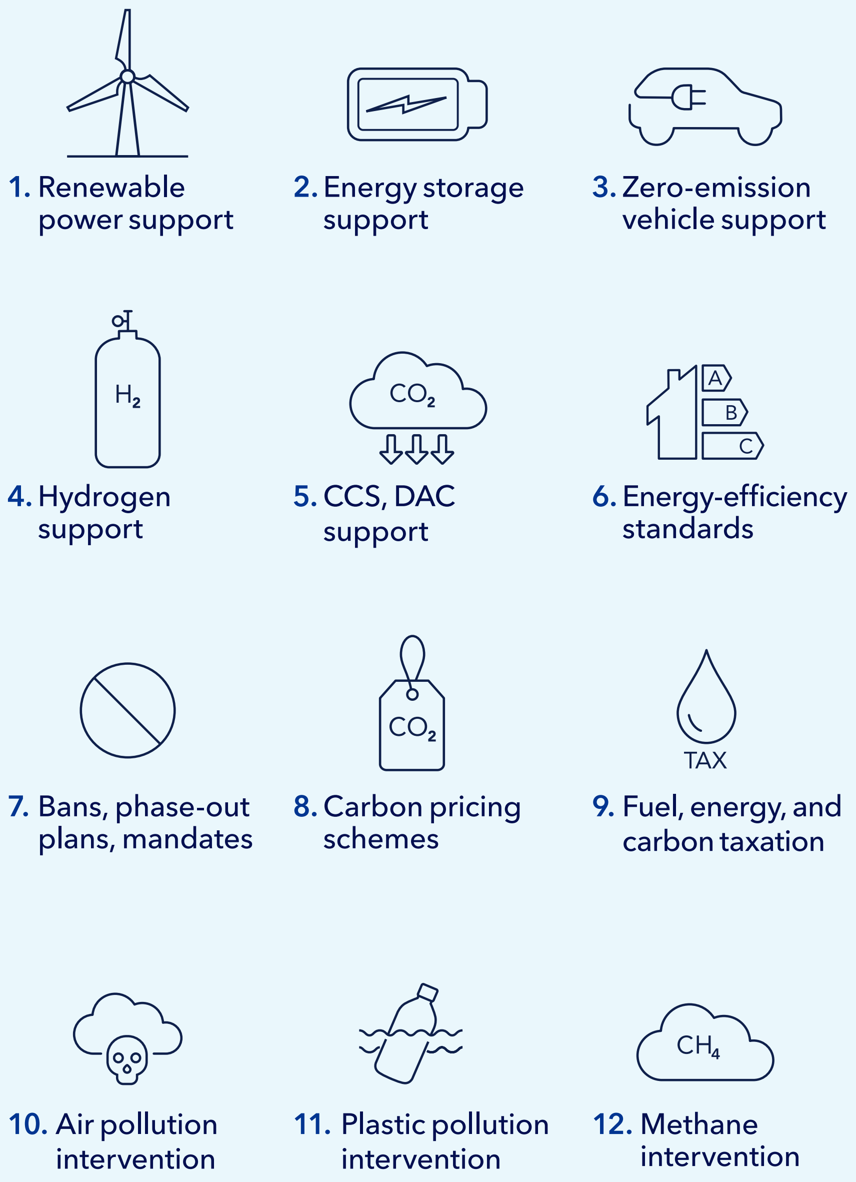
Our model is informed by the policies and targets set out in the UK Government strategy documents. We have also factored in our own assessments of the state of play in economic sectors based on our global energy sector knowledge, our technical and commercial expertise, and discussions with a broad range of stakeholders.

Our model includes assumptions on population, GDP, technology costs, learning rates, performance and carbon price, among many others. Based on the input assumptions and built-in cost competition (and cost learning), the model forecasts the uptake and development of various energy-related technologies in different sectors. As such, our ETO UK forecast does not necessarily assume that all the current government targets and ambitions will be met.

From our main ETO report (DNV, 2023a) we have a comprehensive list of the policy factors influencing the forecast. The same policy factors are incorporated in this analysis with the following adjustments for the UK:

FIGURE 2.4

Policy factors included in our Outlook



Zero-emission vehicle support
- Electric vehicles (EVs) will receive government support to accelerate their market share towards a ban on new internal combustion engine (ICE) cars in 2030 and phase-out of hybrid vehicles by 2035.
- The support schemes for EVs in the commercial vehicle segment will be in place, until they reach 90% of new commercial vehicle sales in 2040.
- The support scheme for hydrogen in the commercial vehicle category will help uptake of fuel cell electric vehicles (FCEVs) based on hydrogen from the early 2030s as production of hydrogen becomes viable, to reach a final new sales share of 10% in the commercial vehicle segment by 2050.

Hydrogen
- Financial support will be provided to implement carbon capture at existing hydrogen production facilities for ammonia production and refining.
- Blue and green hydrogen production projects will receive support to reduce the cost of hydrogen and enable uptake of hydrogen as an energy carrier, starting with industrial clusters and blending into the gas network.
- All new boilers will be hydrogen-ready from 2030.
- Hydrogen blending into the gas network will start before hydrogen reaches cost parity with gas.

Carbon capture and storage
- Support for blue hydrogen uptake will enable about a quarter of all CCS uptake by 2050.
- Other CCS development will be commercially driven, incentivized by the carbon price, subject to capacity-building constraints.

Carbon price
- The UK's carbon price will be in line with the EU ETS price, reaching GBP 77/tCO_2 in 2030 and GBP 104/tCO_2 in 2050.

Fuel tax
- Petrol tax increases at a quarter of the carbon-price growth rate.
- Electricity tax rates are halved for industrial consumers by 2050 and reduced by two thirds for residential consumers by 2040.
- Hydrogen for residential use will be taxed at the same rate as natural gas.

Power capacity limitations
- Future power plant capacity at various stages of planning and construction is reflected in the model, with an increasing probability of being realized with the project completion status.
- Beyond the Sizewell-C and Hinkley Point-C large-scale nuclear power plants, government will finance the construction of small modular reactors at a rate of 2 GW per decade, coming online after 2030.
- Existing coal-fired power generation capacity is retired by 2024.

Current challenges to delivering on government net-zero ambition

There is intensifying debate around the pathway to net zero. Although the government is committed to deliver net zero by 2050, it has recently rolled back on some of its previous ambitions, stating that it is now taking a 'more pragmatic, proportionate, and realistic approach to meeting net zero'. This highlights several key challenges – policy, pace of change, systems thinking, and societal engagement – in transitioning the UK energy system.

Policy

Policy clarity, policy consistency, and policy certainty are important to provide a stable environment for investment by companies and financial investors. There have been inconsistencies in the UK Government approach over the years. For example, the September 2023 roll-back on energy-efficiency measures, and the five-year delay on the ban of sales of new Internal Combustion Engine (ICE) cars, are detrimental to providing a stable investment environment and have damaged industry confidence. Well-developed policies supported by the majority of interested parties can set the pathway for the rapid transition that we need.

Ramping up the pace of energy system transformation will require long-term policy consistency and extensive societal engagement.

Pace of change

We are still taking an incremental approach to the energy transition rather than the transformative approach required if we are going to deliver on net zero by 2050. The government needs to be prepared to step in to provide more support to the low-carbon technologies that will shape the future UK energy system. This includes financial support and reforming the planning and permitting system which is a cause of major bottlenecks.

Systems thinking

The energy system is highly interconnected and changes in one element will trigger intended and unintended feedback in others. For effective implementation of policy initiatives, there needs to be better joined-up thinking; in other words, 'systems thinking'. For all the targets and the initiatives that the government has put forward, there needs to be a clear plan of action that considers all the stakeholders required to successfully deliver the target or initiative. That includes in most cases a materials supply chain that is resourced and resilient, a skilled workforce to coordinate and install the technologies, a customer base that is primed and ready to provide the demand, and access to financing.

Societal engagement

Public engagement should be at the heart of the net-zero strategy. There should be a massive campaign of education as well as broad engagement with society at large to communicate the net-zero strategy and its implications and how the government plans to make it a just transition by supporting low-income households. For example, if we take the Climate Change Committee scenarios, over 40% of the measures to deliver on net zero require public support, whether on energy efficiency, lifestyle changes, or on modal shifts and reduction in transport. Establishing independent bodies that can provide trusted advice to people is key for the communication campaign. ■

3 ENERGY DEMAND

Looking forward, UK demand for products and services will continue to expand through to mid-century but final energy demand will move in the opposite direction, declining by a quarter between 2022 and 2050. Driving the decline in energy demand is the acceleration of energy efficiencies from widespread electrification in transport, manufacturing, and heating in buildings. We will see accelerating rates of adoption of electric road vehicles (EVs) and heat pumps for space heating in buildings. The mix of energy carriers will shift dramatically, with a two-thirds decrease in use of fossil fuels and an almost doubling in use of electricity between now and 2050. Hydrogen and its derivatives will start to make an impact after 2030, increasing to provide 8% of final energy demand by 2050.

This chapter describes the demand for energy carriers within the transport, buildings, and manufacturing sectors, and for non-energy applications such as industrial feedstocks. Final energy demand represents energy delivered to consumers, including non-energy use, but excluding the energy sector's own use and the energy lost in transformation processes such as in power stations.

Energy demand tends to grow in lockstep with population growth and improvements in standards of living (as captured by GDP per capita), although that growth is reduced by improvements in energy efficiency. The UK's population is expected to increase slowly but continuously to be 8% higher in 2050 than in 2022 – an annual average growth rate of 0.3%. The UK economy is expected to grow at a much faster rate, with GDP per capita in 2050 being 34% higher than in 2022 – an average annual growth rate of 1%.

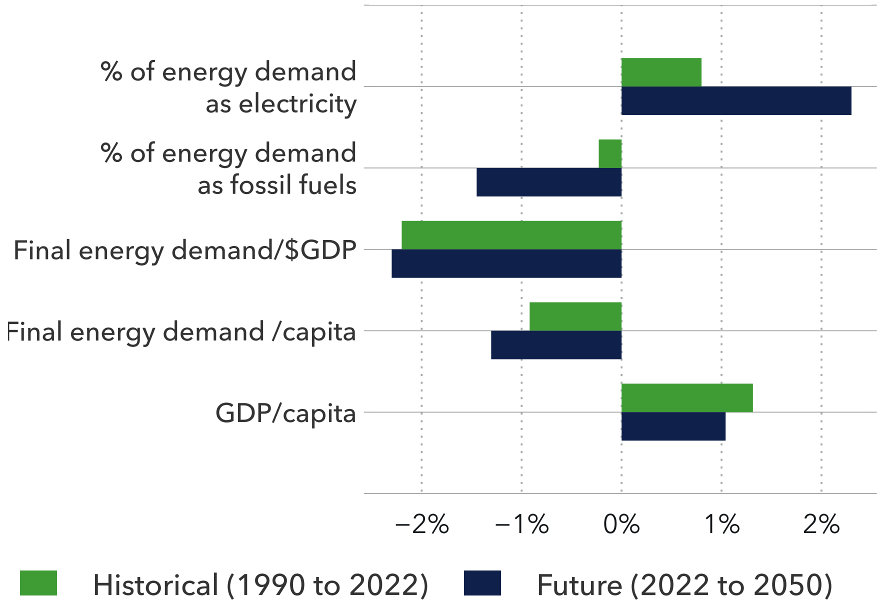
In the absence of any efficiency improvements, the combined effects of growth in population and income per capita would normally drive an increase in energy demand. However, an accelerated improvement in energy efficiency, primarily driven by widespread electrification, more than compensates for the growth in demand for energy services. The overall trend is for a slight increase in final energy demand up to 2026 and then a gradual decrease up to 2050. Total final energy demand in 2050 is a quarter lower than today.

An overview of trends in key indicators for energy demand is shown in Figure 3.1. There is an increase in the rates of change in three key indicators in the period 2022–2050, compared with 1990–2022, indicating an acceleration of the energy transition up to 2050. The percentage of all final energy as electricity increases three times faster than previously; the percentage of final energy as fossil fuels decreases six times faster than previously; and final energy per capita decreases 40% faster than previously. The overall picture for the future is an acceleration of the beneficial changes that reduce energy demand and fossil-fuel use which began during 1990–2022. This will lead to deep transformation in energy demand and energy carriers, and carry on the decoupling of energy demand from GDP.

FIGURE 3.1

Rates of change in key energy demand indicators, past and future

Units: Average annual rate of change (%)



Final energy demand by sector

Looking at final energy demand in the three main demand sectors, of the 397 TWh decrease in final energy demand between 2022 and 2050, transport accounts for the majority (71%) of that reduction, followed by buildings (13%), manufacturing (12%), and other/non-energy (4%). Transport's huge 283 TWh (36%) reduction in annual demand is driven by a rapid electrification of road transport, achieved through the mass uptake of passenger and commercial electric vehicles (EVs). The 51 TWh (16%) reduction in buildings energy demand is driven largely by electrification of heating (principally the replacement of gas boilers by heat pumps) along with building energy performance improvements.

In manufacturing, a more stable pattern of energy demand is forecasted, since industrial heat, where most manufacturing energy demand originates, is 'hard-to-electrify'; however, a 49 TWh (19%) decrease is achieved.

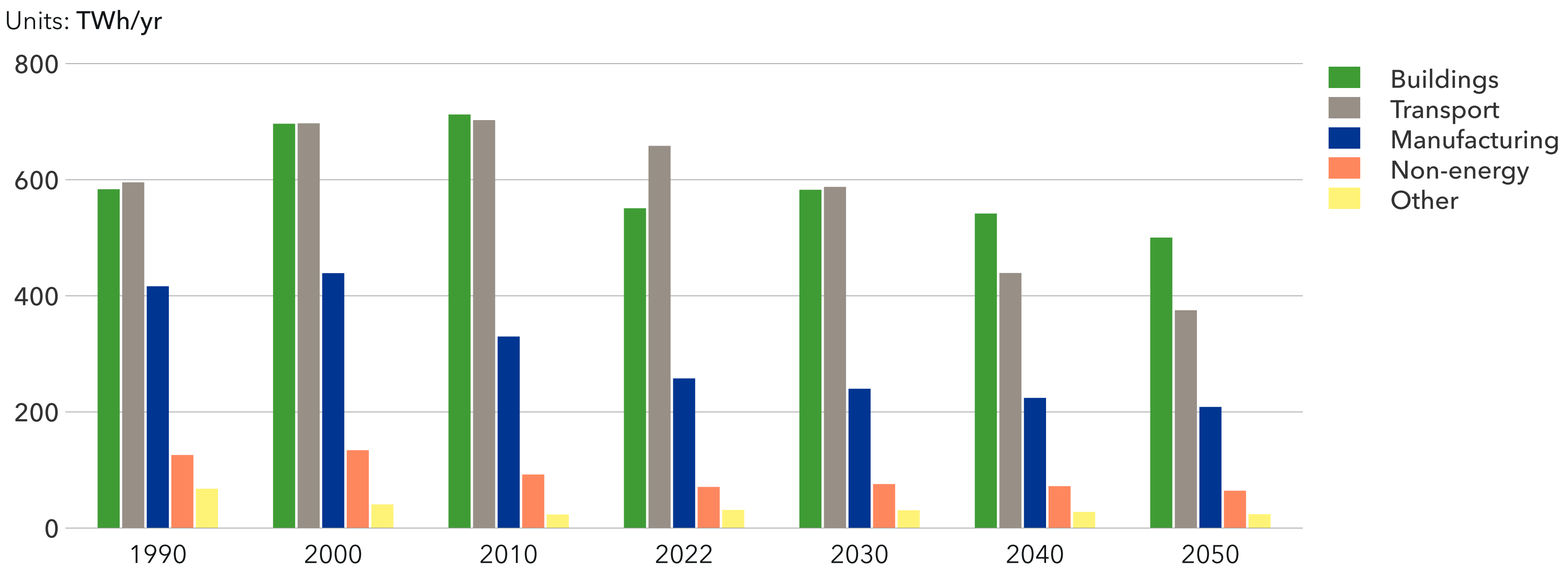
Figure 3.2 shows annual final energy demand by sector. It is notable that while buildings and transport have been consistently the two largest demand sectors and approximately equal from 1990 to 2022, after 2030 transport demand decreases much faster than for buildings. This is indicative of the more challenging nature of demand reduction in buildings compared to transport. Deployment of EVs is relatively straightforward compared to deployment of heat pumps and building energy efficiency, which requires improving buildings that vary in age, construction materials, and ownership type.

Final energy mix

Today, fossil fuels still supply three-quarters of the UK's final energy demand. However, our forecast is for an increasingly fast transition away from fossil fuels and towards electrification after 2030. Figure 3.3 shows this transition. By 2050 there is a complete phase-out of coal and fossil fuels' share of the total is halved. Natural gas persists as the most economically viable energy carrier in various sectors, and so its 43% decline between 2022 and 2050 is slower than that of oil (at 77%). Electricity demand, on the other hand, increases by 93% from 2022 to 2050, making it the largest energy carrier with a 45% share of the total in mid-century – driven by mass electrification in transport and buildings. Biomass use also grows steadily, increasing by 46% and providing 8% of final energy in 2050. Hydrogen and derivatives (including ammonia, hydrogen and e-fuels) grow quickly from negligible amounts in 2022 to 92 TWh/yr in 2050, representing 8% of total demand. Although this is a relatively small amount, these fuels are vital for those sectoral end uses that are hard-to-electrify. Oil still meets 16% of total demand in 2050, largely in transport and non-energy demand.

FIGURE 3.2

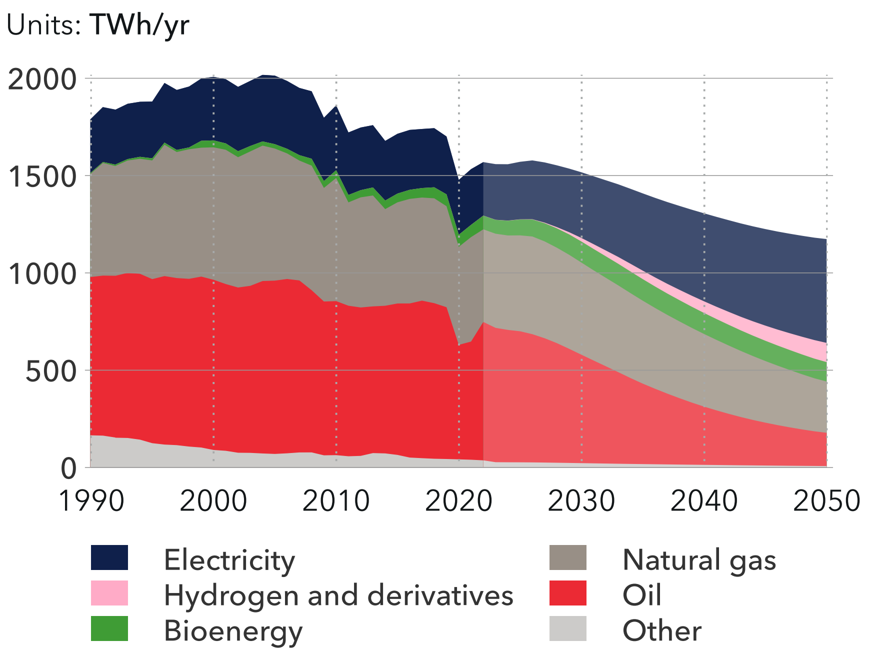
Final energy demand by sector



Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 3.3

Final energy demand by carrier



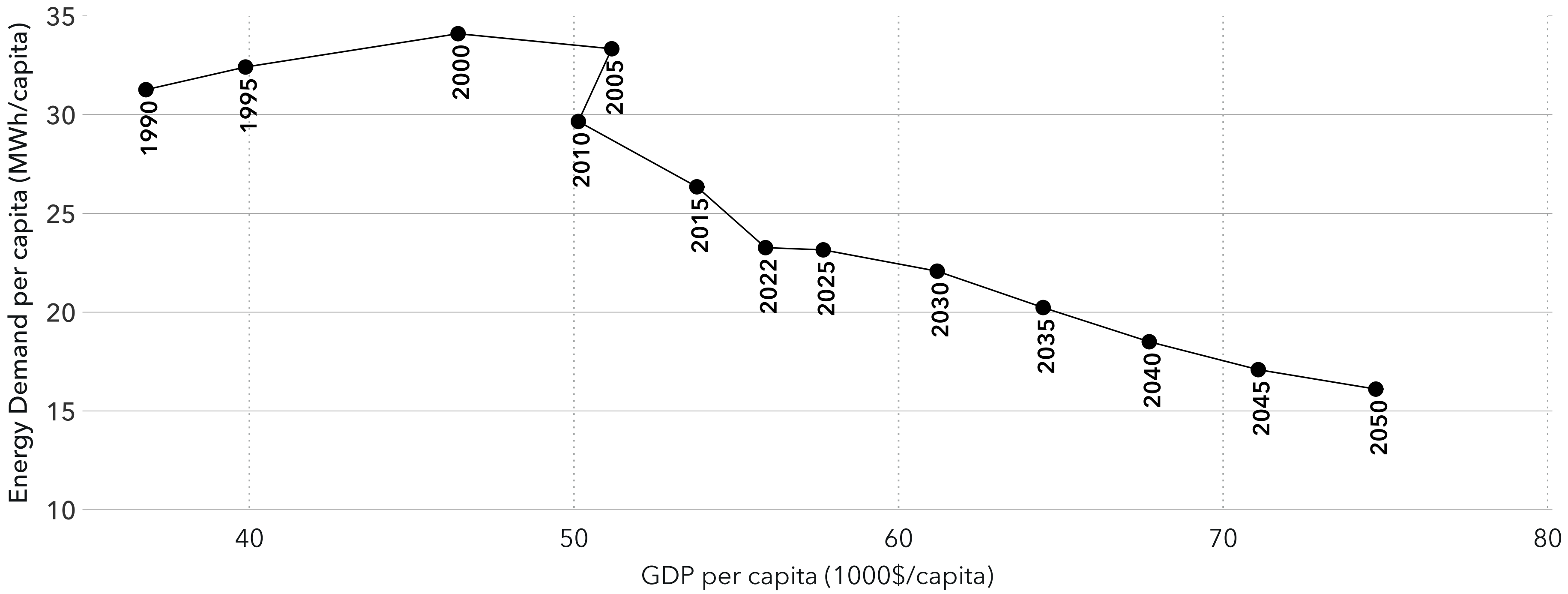
Historical data source: IEA WEB (2023), DUKES (2023)

Energy efficiency

Energy efficiency is usually the most cost-effective means of reducing energy demand and should be top of the list when authorities and companies consider emission mitigation options. Efficiency can be improved through a variety of measures, including electrification (due to improved conversion efficiency), improving insulation in buildings and their operation to reduce energy waste; improving the provision of public transport options; and improving the efficiency of freight logistics. The total potential for demand savings from energy efficiency is limited by many factors, including the need to transform legacy infra-structure, a wide variability in the how energy using equipment is purchased and used, and the funda-mental properties of energy conversion. A broad indication of how the energy efficiency of products and services has been changing is shown in Figure 3.4. Final energy demand per capita and income per capita move in the same direction from 1990 to 2010. After that, there is a decoupling between the two. Between 2010 and 2022, despite a 12% increase in GDP per capita, there is a 17% reduction in energy demand per capita. Projections to 2050 show further steady decoupling in every year, indicating continual overall energy-efficiency improvements across the economy.

FIGURE 3.4

Energy intensity of GDP



Stagecoach electric bus operating a park and ride bus service in Cambridge, England.

3.1 Transport energy demand

Transport accounted for 42% of the UK's energy demand in 2022. Between 1990 and 2022, transport energy demand peaked in 2007, with demand in 2022 about an eighth (13%) lower than the 2007 peak. We forecast that because of significant improvements in energy efficiency, particularly in the road transport subsector, transport energy demand will decline by 36% between 2022 and 2050. These numbers include the UK's estimated share in international aviation and shipping.

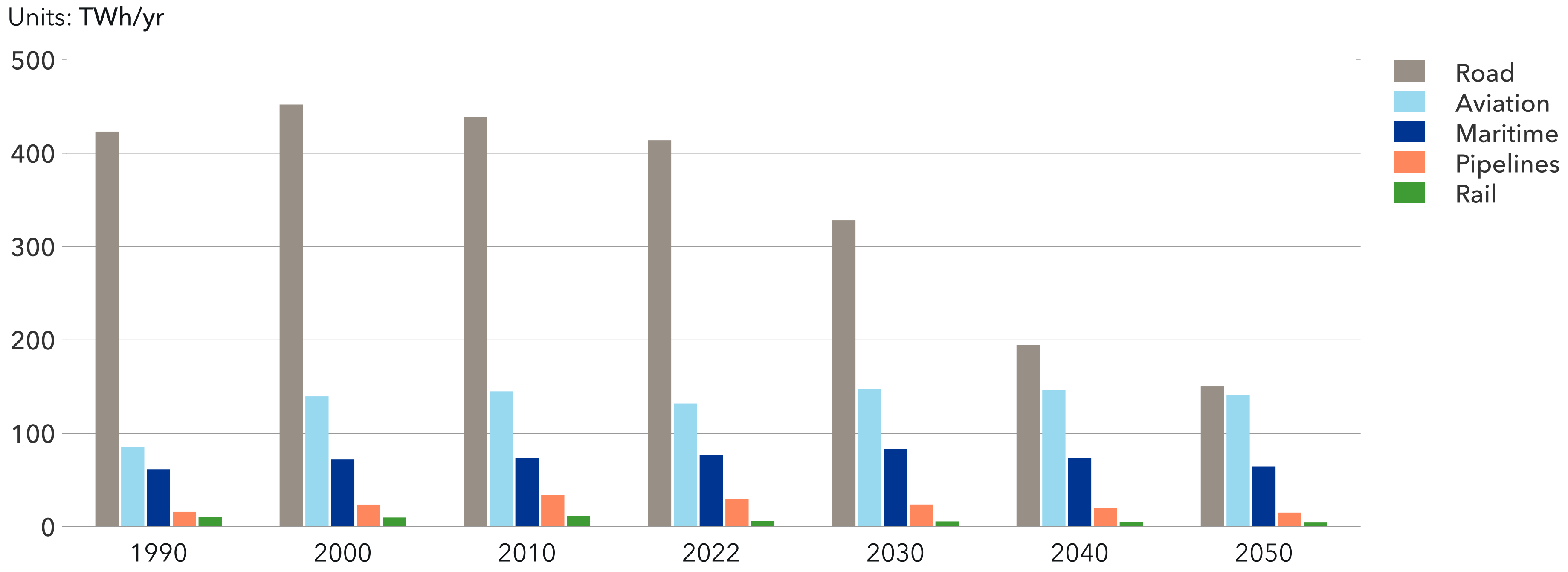
There are five transport subsectors: road, aviation, maritime, rail, and pipelines. Road, aviation, and maritime combined currently account for 94% of transport energy demand and thus are our key focus areas in this section. Figure 3.5 shows that between 2022 and 2050, aviation demand is fairly constant, and so the rapid decrease in road transport energy demand means that by 2050 demand in road and aviation are fairly close in size.

In terms of energy carriers for transport, today's mix is completely dominated by oil and natural gas, which together make up 96% of final transport energy demand. Going forward, this dominance will disappear but they will still constitute 32% of transport energy demand in 2050. The phase-out of oil in transport is difficult partly due to its particular suitability for powering vehicles and the current dominance of oil-fuelled vehicles in the UK fleet of vehicles on the road. Oil in its various forms has a highly beneficial combination of volumetric and gravimetric energy density that provides more energy per kilogram compared to other non-electricity carriers in transport. It is also stable, easily transportable, and does not have to be produced from feedstocks but comes 'ready-made'.

Despite the benefits of the incumbent dominant fuel, market changes mean that the period 2022 to 2050 will see a revolution in energy carriers for transport. Figure 3.6 shows future changes in transport carriers. Oil use declines 80% between 2022 and 2050, and natural gas use by 46%. The largest change will be a 17-fold increase in electricity between 2022 and 2050, to end up representing 36% of transport demand by 2050. Biomass use doubles, representing 14% of transport demand by 2050. From negligible amounts in 2022, hydrogen and its derivatives will grow to be 19% of demand (as ammonia (6%), e-fuels (8%), and hydrogen (5%); this this will require rapid development of new infrastructure and supply chains to produce and distribute these fuels and since they cannot replace oil in a like-for-like way in most vehicles there will need to be associated changes to or replacement of vehicles.

FIGURE 3.5

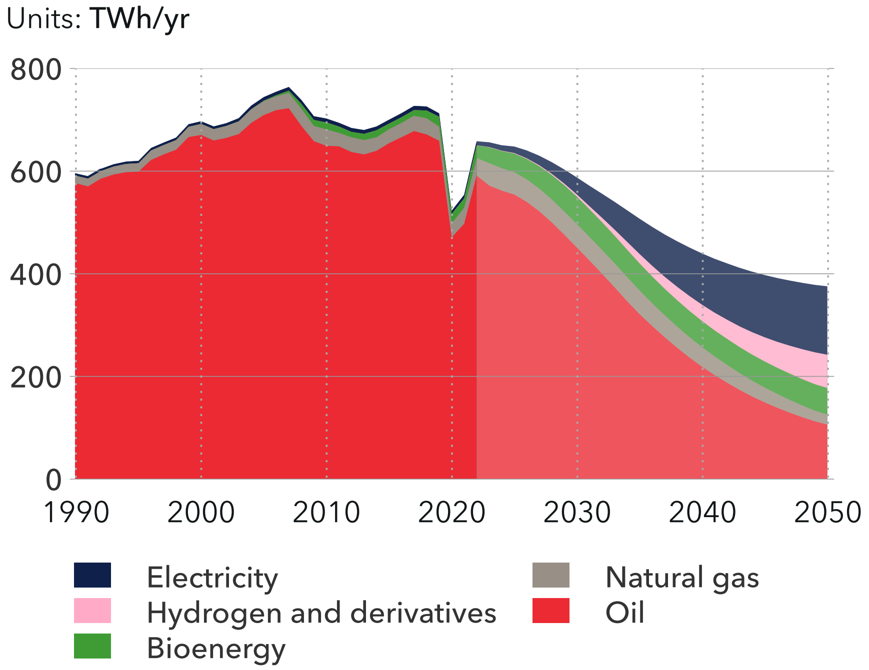
Transport energy demand by subsector



Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 3.6

Transport energy demand by carrier



Historical data source: IEA WEB (2023), DUKES (2023)

3.1.1 Road transport

Road transport includes two subsectors – passenger road vehicles (all vehicles with between three and eight passenger seats, including most taxis), and commercial vehicles (all other vehicles, including light duty vehicles, heavy duty vehicles, public service vehicles). Two key factors drive energy demand for road transport: total vehicle-km (vkm) travelled and the average energy intensity of vkm travelled. Average fleet energy intensity is determined by the mix of vehicles on the road and their energy efficiency, how they are driven, and how far different types of vehicles are driven each year.

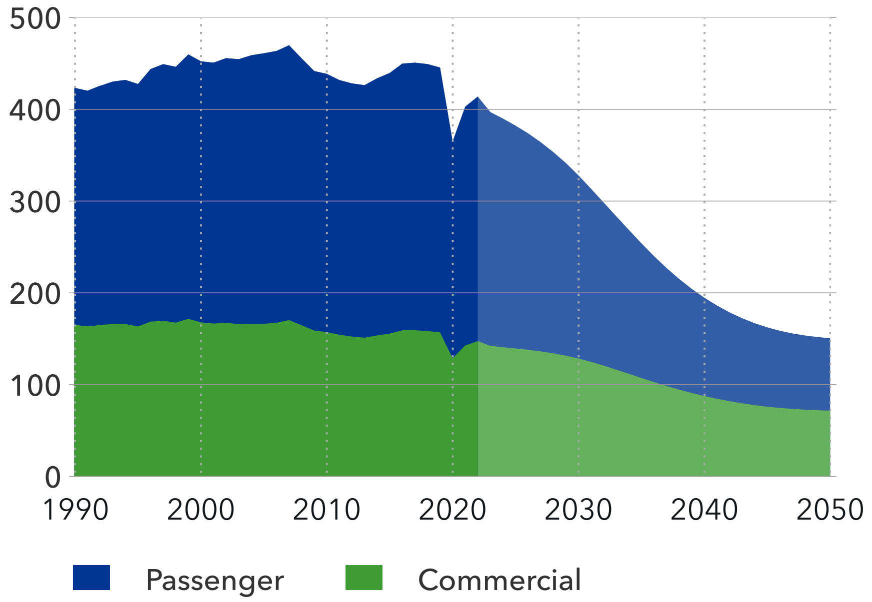
Travel demand for road transport is expected to increase steadily from now to 2050 (DfT, 2022). The Department for Transport (DfT) defines eight scenarios for the future of road transport. All show increasing annual miles travelled, with the growth between 2015 and 2050 ranging from 5% (behavioural change scenario) to 56% (technology scenario), and 29% in the core scenario. In the ETO, road miles increase at a similar rate to the DfT's core scenario, rising by 22% between 2015 and 2050.

Figure 3.7 shows that total energy demand for road transport will decline steeply after 2022, by 52% for commercial road travel, 70% for passenger, and by 64% overall. Passenger transport currently represents two-thirds of energy demand, but this share will fall to just over half by 2050 due to faster electrification of cars than commercial vehicles. Energy demand in passenger and commercial subsectors become approximately equal by 2050.

FIGURE 3.7

Road transport energy demand by subsector

Units: TWh/yr



Historical data source: IEA WEB (2023), DUKES (2023)

Vehicle sales

Today, internal combustion engine vehicles (ICEVs) dominate passenger new vehicle sales, holding an 80% market share. There are several reasons for the slower than expected market transformation in new vehicles, despite EVs typically consuming less than a third of the energy of ICEVs per km and costing less to maintain (Consumer Reports, 2020). Firstly, buyers often focus on purchase price when making vehicle choices and EVs are still more expensive to buy than ICEVs – the so-called 'up-front cost barrier' – although on a total cost of ownership basis both passenger and commercial EVs are already close to or even cheaper than their ICEV equivalents. Secondly, the UK's EV charging network is not growing as fast as the rate of EV ownership, and the strain on the existing charging network has been growing. *The Public Charge Point Regulations 2023* of November 2023 (Gov.UK, 2023b) should ensure consistent and positive experiences for people using public charging points. For example, all motorway service stations are now expected to have at least six high-speed EV public chargers, compared to only 23% of the UK's 119 motorway service stations today (What Car?, 2023). Thirdly, supply-chain constraints are another hurdle, with lead times for EV purchases longer than for ICEVs.

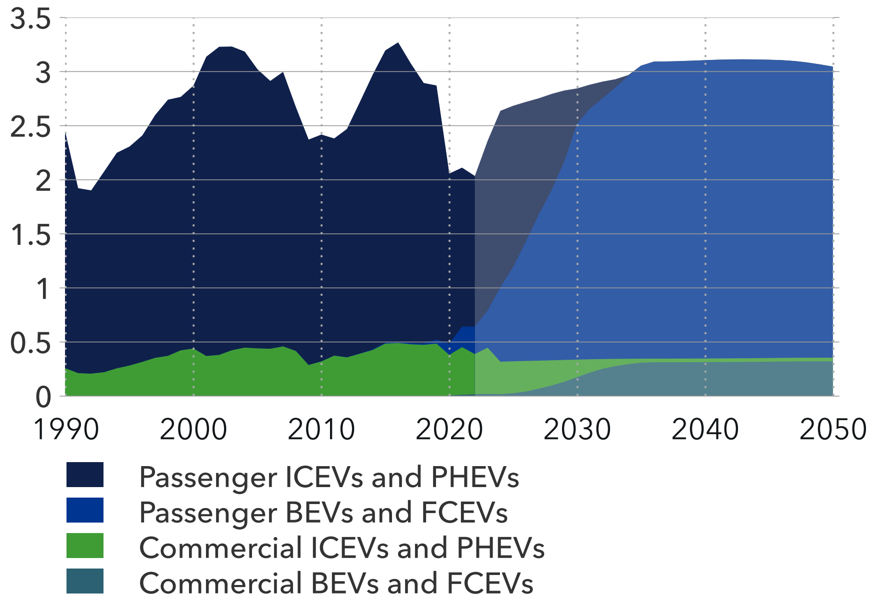
Since the previous ETO update, the government delayed the deadline for the phase-out of new ICEVs from 2030 to 2035. The change was greeted with disappointment by the vehicle industry, who have been preparing for imminent market transformation. In the short term, this regulatory change will slow the phase-out of ICEVs as new car sales. In our 2022 ETO, sales of ICEVs declined to 42% of total annual sales by 2025, whereas we now see that share at 65% in 2025 (62% of passenger and 92% of commercial sales). Despite this delay, the outlook is still for a rapid phase-out of the purchase of ICEVs after 2030 as up-front EV costs continue to decline, charging infra-structure becomes more reliable and available, and the TCO advantages become clearer to consumers.

Figure 3.8 shows the share of ICEVs in new vehicle sales declining to 15% by 2030 and to 1% by 2035. Commercial vehicle sales are much slower to with 47% as ICEVs in 2030, and 10% after 2040. Approximately 98% of all vehicle sales will be battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs) or fuel cell electric vehicles (FCEVs) by 2040. Thus, in the long term the government's change in the year of phasing out ICEVs makes little practical difference, given manufacturers' commitments and the falling cost of EVs.

FIGURE 3.8

Road transport vehicle sales by vehicle type

Units: million vehicles/yr



Historical data source: Marklines (2023), IEA EV Outlook (2023), EV Volumes (2023)

Leading the charge: EVs in the UK

In 2023, the UK electric vehicle (EV) market experienced sustained momentum in vehicle electrification. The average quarterly sales of plug-in hybrid and battery electric vehicles in the passenger segment for 2023 were circa 20% higher than the quarterly average vehicle sales in 2022. Notably, sales in the bus segment in the first half of 2023 matched those throughout the entire previous year.

Despite the inflationary environment and the shift in the UK Government's stance on the ban of zero-emission vehicles from 2035 instead of 2030, the growth in plug-in vehicle sales suggests that the market remains driven by customer demand and by the commitment of the commercial segment to reduce carbon emissions. For the automotive industry in the UK, the direction is clear, and manufacturers are scaling up and adapting facilities to rapidly transition to battery-electric vehicles (BEVs). This transition is supported by recent announcements of additional investments by the automotive original equipment manufacturers (OEMs), with new investment commitments totalling up to GBP 2 billion for EV production by a leading OEM.

To accommodate the increase in the EV demand and ensure reliable domestic supply chain of key components and raw materials, such as battery cells, the UK government has announced investments of over 2 billion GBP in new capital and R&D funding to support the development and manufacturing of zero-emission vehicles, their batteries, and the supply chain until 2030 as part of the UK Battery Strategy. Additionally, the Tata Group has committed investments totaling GBP 4 billion, for the establishment of a 40 GWh battery gigafactory in Somerset, UK. From DNV's work supporting investors in the sector, we observe a growing interest in battery manufacturing across Europe, where the continued development of innovative battery technology, the scale of facilities, and low-carbon production processes are becoming increasingly important.

With an ever-growing portion of the vehicle fleet transitioning to EVs, the demand for and deployment of charging infrastructure has increased significantly. This growth has contributed to reduced concerns around the range of EVs. Not only has the number of EV charging stations increased, but DNV has observed that the technology of the charging infrastructure has matured. Newer stations feature scalable and modular construction, leading to improved uptime and, consequently, the reliability of the overall charging infrastructure across the country

The improvements in charging infrastructure have been largely enabled by developments in battery technology, such as 800V architecture, higher energy densities, and faster charging capabilities. These advancements allow EVs to absorb more energy from the chargers, further enhancing the efficiency and reducing time associated with the charging process. Despite the improvements in charging speed, DNV expects most charging to take place at home due to the higher cost associated with public charging stations.

For heavy-duty vehicles and ferries, the power range extends to megawatts (MW), with ferries capable of charging at 10 MW.

From a strategic perspective, EVs play a crucial role in the energy transition. They are poised to significantly reduce transport costs, GHG emissions, and air pollution, while simultaneously improving grid reliability. The fact that GHG emissions from EVs are three to four times lower than internal combustion engine vehicles (ICEVs), depending on the use-case, contributes to these positive outcomes. The flexibility inherent in EVs also facilitates their seamless integration, as well as that of renewables, into the broader energy system. These advantages stem from substantial investment directed toward EVs and charging infrastructure, and cater to the growth of the holistic sustainable transport ecosystem. ■

Vehicle fleet

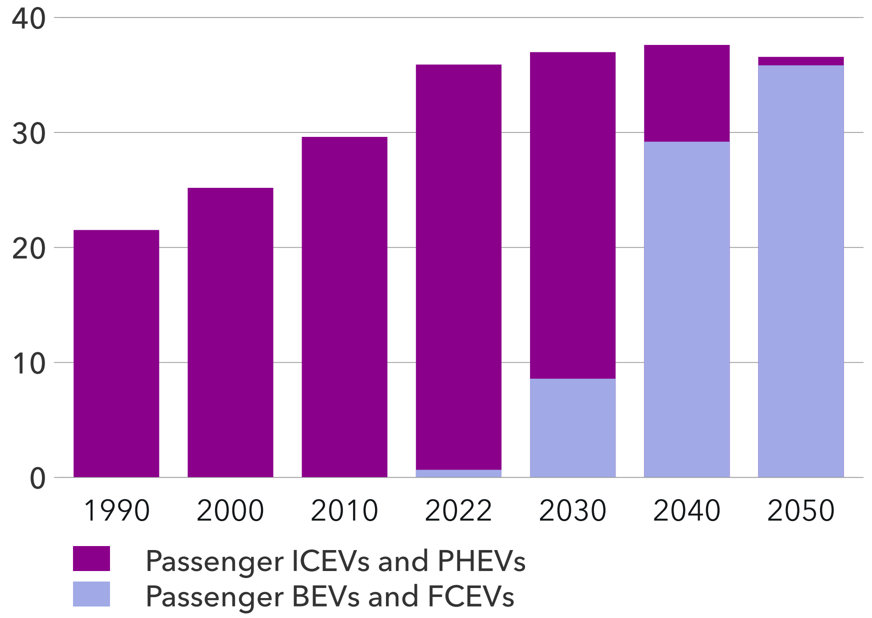
While the number of vehicles per capita increased considerably between 1990 and 2022 – by 43% for passenger and 46% for commercial – we expect this trend to change going forward. The total number of vehicles will remain fairly stable after 2022, with 37 million passenger vehicles and 6 million commercial vehicles on the road. Several innovations can improve the efficiency with which vehicles are used and reduce the number of vehicles that need to be in use, such as car sharing, ridesharing, improving freight logistics, and modal shifts from private to public or active travel. Today, ICEVs make up 98% of existing UK vehicle stocks. The changes in types of vehicles being sold, shown in Figure 3.8, will take some time to significantly affect the mix of vehicles on the roads. The rate of fleet transformation is dependent on the number of vehicles replaced each year, which is not expected to change significantly. ICEVs remain the majority of passenger cars in the passenger road fleet until 2034 (Figure 3.9) and the majority of the commercial road fleet (Figure 3.10) until 2040.

> The total number of vehicles will remain fairly stable after 2022, with 37 million passenger vehicles and 6 million commercial vehicles.

FIGURE 3.9

Road transport passenger vehicle stock by vehicle type

Units: million vehicles

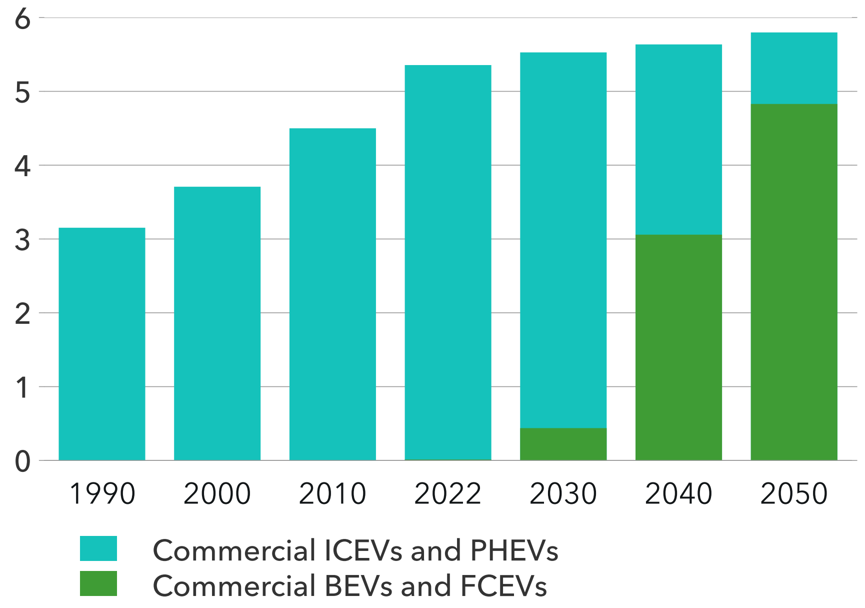


Historical data sources: Marklines (2022), IEA EV Outlook (2022), EV Volumes (2022)

FIGURE 3.10

Road transport commercial vehicle stock by vehicle type

Units: million vehicles



Historical data sources: Marklines (2022), IEA EV Outlook (2022), EV Volumes (2022)

3.1.2 Aviation

Demand for air travel in the UK has risen strongly in recent decades and is expected to continue growing – although there has been some dampening of demand for business travel since the COVID-19 pandemic with a shift towards virtual meetings and events. Trends for increasing leisure travel, on the other hand, are expected to remain unchanged. Passenger flights per capita increased from 0.8 to 1.8 between 1990 and 2022, with a further doubling of per capita airline journeys expected by 2050.

Aviation energy demand in the UK peaked in 2006/2007 at 160 TWh/yr and since then, despite increases in passenger journeys, energy demand has remained around 145 TWh/yr and is projected to stay at this level up to 2050. This levelling of energy demand has been achieved by continual improvements in aviation energy efficiency. The aircraft and airline industries have been driving this through interventions including increasing load factors, lightweighting aircraft, improving the efficiency of propulsion, and improving aircraft aerodynamics. In future, electrification of a share of the fleet covering short-haul flights will also contribute to energy-efficiency improvements.

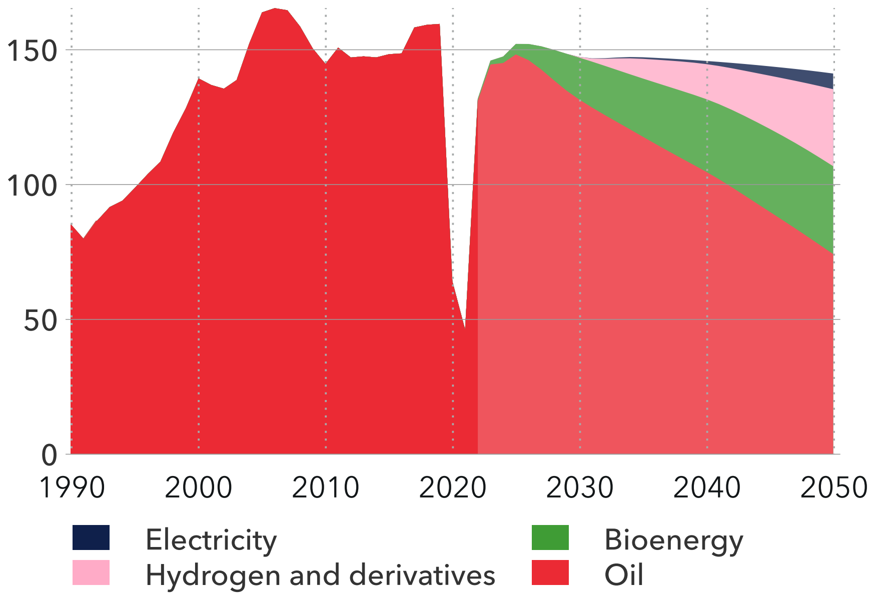
Figure 3.11 shows developments in the energy mix for aviation. Until now, all the energy demand for aviation has been met by oil-based fuels. Over the next three decades, the share of petroleum-based aviation fuel is expected to decline to 53% of the energy mix by 2050. Electric aircraft will be limited to short-haul domestic and international flights.

For medium to long-haul flights, decarbonization progress is achieved with the introduction first of bioenergy (the world's first transatlantic flight running on biofuels happened in November 2023 (Virgin Atlantic, 2023)), then synthetic e-fuels (such as e-kerosene), electricity growing after 2030, and hydrogen being introduced in the early 2040s. There is still significant uncertainty around which fuels will dominate aviation energy in future, as the available alternatives are currently fairly evenly poised in terms of cost and availability. Our Outlook shows that by 2050 non-oil energy carriers will provide the following share of carriers: biofuel blends (23%), synthetic e-fuels (15%), hydrogen (5%), and electricity (4%).

FIGURE 3.11

Aviation energy demand by carrier

Units: TWh/yr



Historical data source: IEA WEB (2023), DUKES (2023)

3.1.3 Maritime

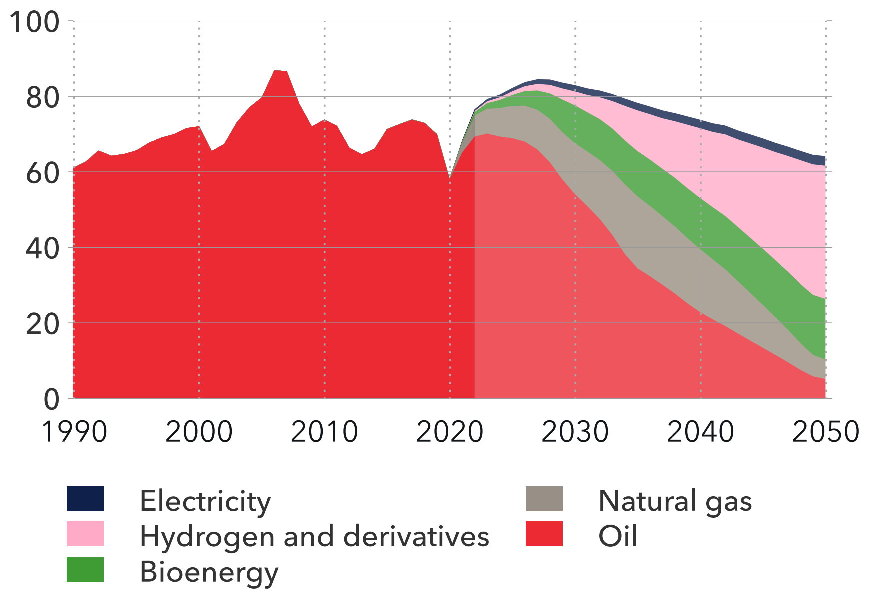
Maritime is the most energy-efficient mode of transporting freight, especially over long distances, in terms of energy used per tonne-mile. It represented 12% of UK transport energy demand in 2022. Maritime energy demand comes from vessels on the UK's inland waterways and on international routes, and demand from international ships bunkering in UK ports. In 2021, 85% of maritime energy demand went into international marine bunkers. Maritime energy demand is expected to peak by 2030 (at 10% above today's level) and decline slowly afterwards due to energy-efficiency improvements. By 2050, we expect UK maritime energy demand to be 15% less than today.

Energy efficiency is reliant on improvements to vessels such as adding wind-assisted propulsion and increasing ship utilization rates. Fuel switching also contributes to energy efficiency. Short-sea shipping and local ferries could use a combination of electric shore power with electric propulsion. The introduction of new fuels has already started, with the use of biofuels and natural gas. Use of electricity and e-fuels will start growing in the mid-2020s, with ammonia starting to be adopted by 2030. The maritime energy mix will be a lot more varied by 2050 (Figure 3.12) and consist of 36% ammonia, 25% bioenergy, 19% synthetic e-fuels, and the remaining share made up of oil, natural gas, and electricity.

FIGURE 3.12

Maritime energy demand by carrier

Units: TWh/yr



Historical data source: IEA WEB (2023)

The maritime energy mix will be a lot more varied by 2050, dominated by 36% ammonia, 25% bioenergy and 19% synthetic e-fuels.

3.2 Buildings energy demand

Buildings account for about 35% of UK final energy demand, consuming 550 TWh/yr, making it the second biggest end-use sector after transport. Across all UK buildings, residential buildings accounted for 68% of total building demand in 2022, and this will fall slightly to 63% by 2050. Total buildings energy demand peaked in 2004.

Almost half of buildings energy demand is used for heating. Drivers of energy demand in buildings include energy efficiency, floor area, heating technology and fuel, the energy behaviour of building users, energy-using equipment, and type of building. Similar to transport, rising population and income levels are likely to drive up demand for energy services in buildings in the future, which would normally lead to increasing energy demand. However, the expected increase in energy demand will be counteracted by improving efficiencies in buildings, appliances, and heating, and in the longer-term by a reduction in heating degree days due to increased global warming.

Overall, the trend since 1990 has been for the energy intensity of buildings to decrease, in terms of total energy demand per square meter of building. This indicates an overall improvement in the energy efficiency of buildings. Despite a 30% increase in residential buildings floor area between 1990 and 2022, energy demand decreased by 14%, and there was a similar efficiency improvement in commercial buildings. Our forecast sees this beneficial trend continuing up to 2050 at about the same pace, with a 30% decrease in the energy intensity of all buildings between now and 2050. In terms of the energy mix, we are going to see a notable transition towards electrification of heating in buildings, leading to a 44% increase in buildings electricity demand between now and 2050, growing its share of the energy mix from 32% now to 51% in 2050. At the same time, natural gas's share of buildings energy demand will decline from 56% today to 45% in 2050. Other carriers – oil, biomass, direct heat – represent only 13% of the total energy demand today, falling to 5% in 2050 (Figure 3.13).

Despite much discussion around hydrogen replacing natural gas in buildings, we currently do not foresee this happening on a large scale. It will provide just 2.2 TWh/yr by mid-century, blended into the gas grid. This limited uptake is primarily due to the substantial price difference, where we foresee that, even in 2050, hydrogen will be twice as expensive as natural gas. Therefore, until further clarity (expected only in 2026) is provided by the government on hydrogen for heating as well as on plans for the required infra-structure build-out, our cost and efficiency-based model gives very little hydrogen use in buildings.

Buildings energy demand by end use

We model buildings energy demand broken down into five end uses: space heating, water heating, appliances and lighting, cooking, and space cooling. Today, space heating, water heating, and appliances and lighting make up 95% of energy demand in buildings, and so these are our focus for this section.

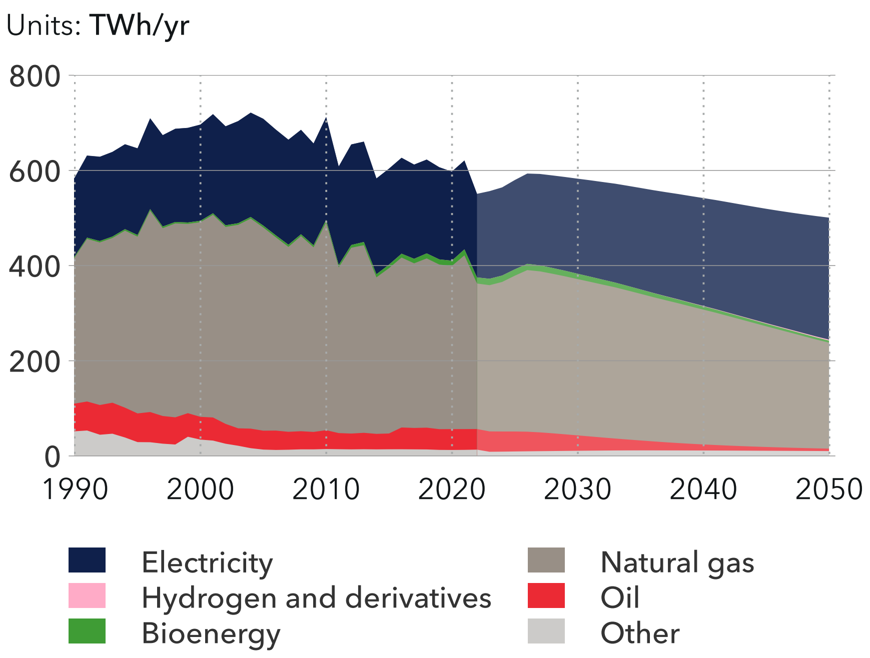
The lion's share of buildings energy demand is for space heating, which is about half of the total today but due to decline to a third of the total by 2050 (Figure 3.14). Energy demand for space and water heating was relatively stable between 1990 and 2022, while demand for appliances and lighting increased by 20%. Appliances and lighting continue their incrementally increasing trend in future, although at a slower pace, increasing by 23% by 2050 compared to 2022, while space and water heating demand will decline by 37% and 12%, respectively.

3.2.1 Space heating

Space heating technologies are currently dominated by natural gas boilers, which provide heating for 84% of UK households. Going forward, however, we are set to witness a strong trend in electrification of space heat, predominately with heat pumps. Heat pump uptake in buildings will only really take off, however, after 2030, heating 20% of homes by 2040

FIGURE 3.13

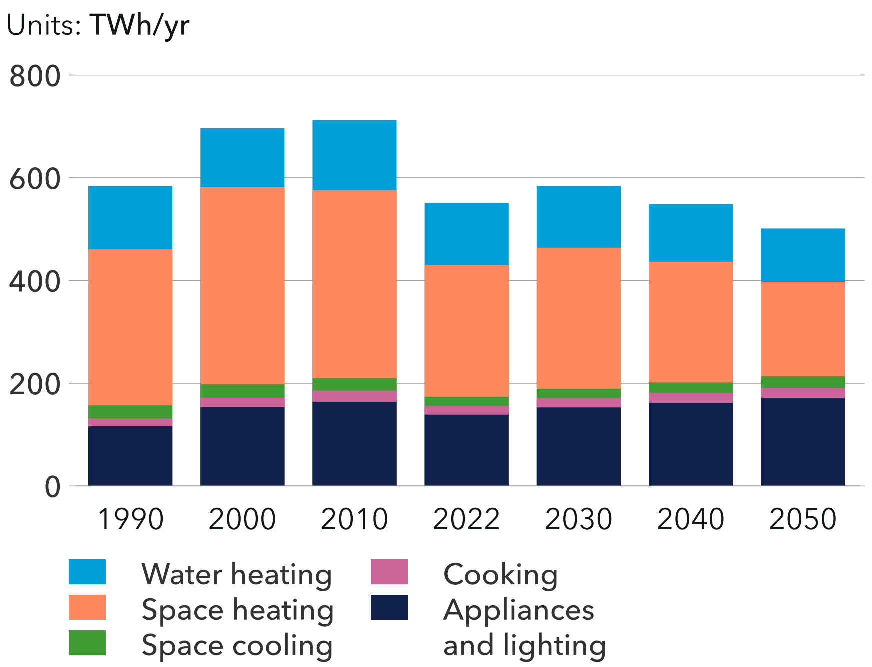
Buildings energy demand by carrier



Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 3.14

Buildings energy demand by end use



Historical data source: IEA WEB (2023), DUKES (2023)

and 38% by 2050 (Figure 3.15). System inertia limits the speed of roll-out of heat pumps in the UK, as further detailed in the pop-out box. In future, we expect an increasing share of new boilers being installed to be 'hydrogen-ready', as the technology exists and is not expected to cost much more than regular gas boilers. To what extent this hydrogen readiness will be used is highly uncertain. There remains a very high cost penalty for switching from natural gas to hydrogen as a fuel, and whether there will be sufficient dedicated supply of hydrogen at the scale needed for expanding its use in building heating is uncertain at this time.

Space heating energy demand was suppressed somewhat during and shortly after the electricity and natural gas energy price hike in 2022, due to the war in Ukraine. In the near term, we expect demand for space heating to rebound from 258 TWh to 284 TWh in 2026. After that, we expect it to decline slowly towards 187 TWh by 2050 thanks to a combination of electrification, better equipment efficiency, and improved building efficiency.

Figure 3.16 shows that today, 92% of final energy demand for space heating is provided by fossil fuels (almost all as natural gas, oil, and coal), while electricity holds a very small (3%) share of the total. By 2050 the dominance of fossil fuels will be less pronounced but still in place. Fossil fuels' share of energy demand for space heating in 2050 will decline to just below 80%, while electricity will increase to 14% of heating energy. Note that due to the much higher efficiency of heat pumps (in the order of 300%), electricity will serve to heat a much larger (35%) share of homes. The rest of the energy mix will be as direct heat (5% by 2050) and very small amounts of biomass and hydrogen (approximately 1% each by 2050).

3.22 Water heating

Energy demand for water heating remained fairly stable from 1990 to 2022, with demand being 121 TWh today. We expect it to decline by 15% between 2022 and 2050 thanks to more efficient water heaters and electrification of water heating. With regards to the energy mix for water heating, the overall picture is similar to space heating in that the share of energy as fossil fuels today, predominately natural gas, will decrease and give way to increasing amounts of electricity for which the share will increase three-fold. The share of final energy demand as fossil fuels will fall from 89% today to 65% by 2050, while electricity's share will increase from 6% to 28%, with bioenergy (6%) and hydrogen (1%) making up the remainder.

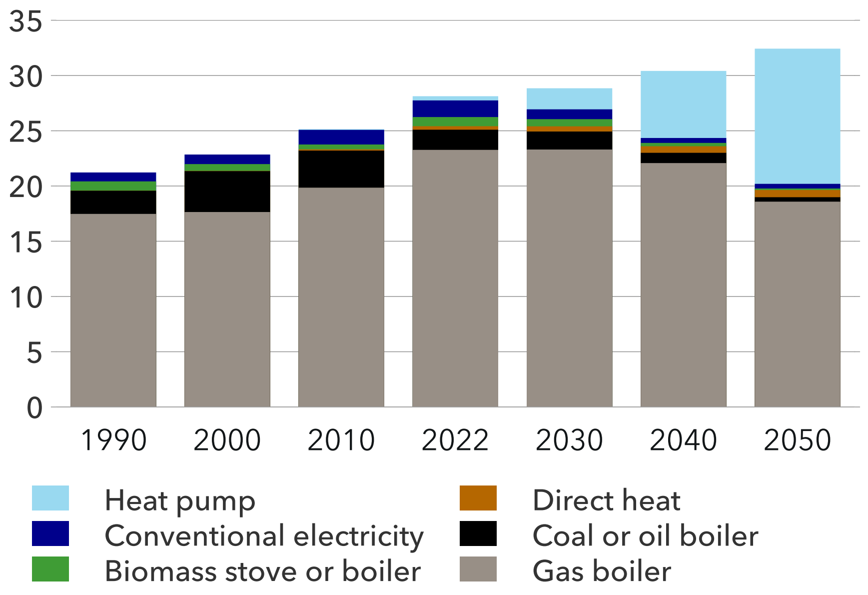
3.2.3 Appliances and lighting

The appliances and lighting segment encompasses all electrical devices not used for heating or cooking – from lamps to computers, refrigeration units, ventilation fans, and clothes dryers. Historical evidence suggests that in general, as GDP per capita increases, demand for use of appliances and lighting also increases across the economy. Between 1990 and 2022, residential demand for appliances and lighting grew by 5% and commercial demand grew by 40% - in line with the growth in buildings floor area in residential (29%) and commercial (68%) buildings during this time. Both residential and commercial energy demand for appliances and lighting peaked around 2005 and decreased up to 2022, largely due to improvements in the energy efficiency of end-use equipment. However, we forecast that these energy demand reductions will be overcome in future by stronger increases in the demand for electric appliances. We expect about a quarter increase in energy demand for appliances and lighting between now and 2050.

FIGURE 3.15

Households space heating technologies

Units: Millions of households

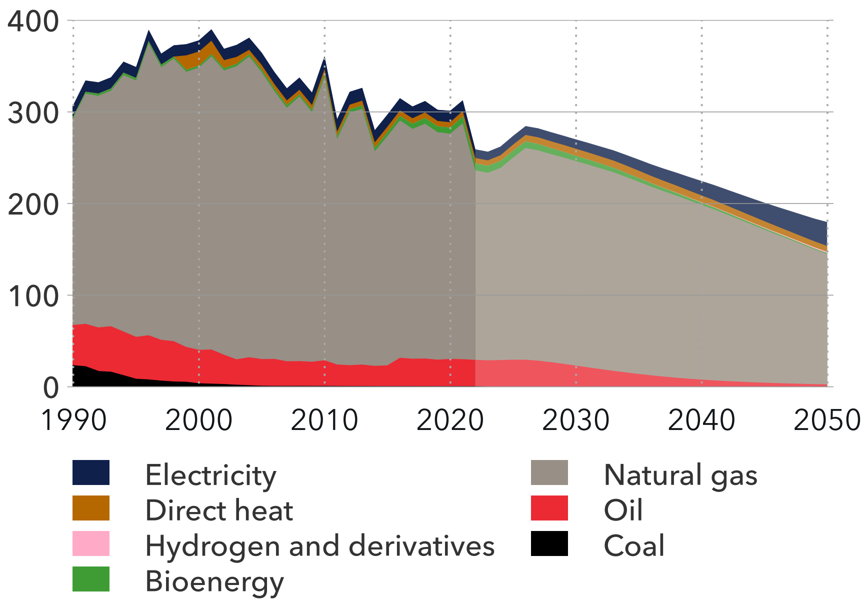


Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 3.16

Buildings space heating energy demand by carrier

Units: TWh/yr

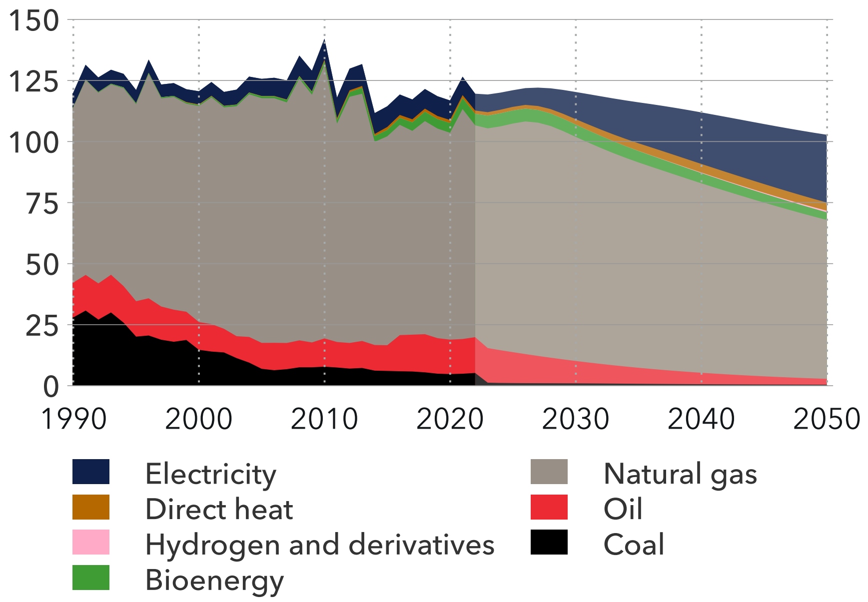


Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 3.17

Buildings water heating energy demand by carrier

Units: TWh/yr



Historical data source: IEA WEB (2023), DUKES (2023)

Decarbonizing buildings heating and system inertia

Decarbonizing energy use in buildings is one of the most significant challenges facing the delivery of net zero in the UK. Today, 85% of the UK housing stock, representing over 24 million homes, is heated by natural gas boilers. This accounts for 17% of UK CO_2 emissions, approximately 77 $MtCO_2e$.

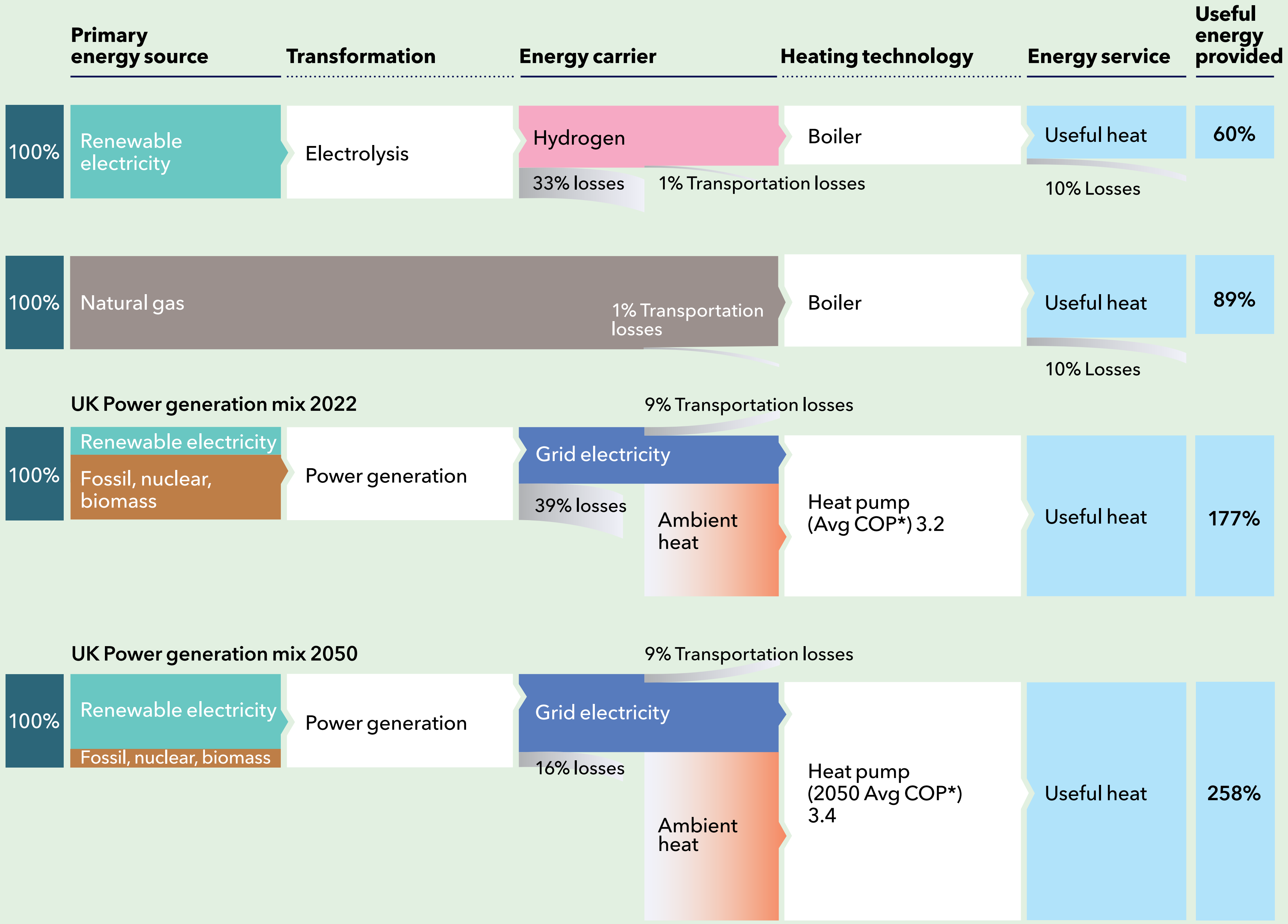
The first challenge to address in domestic heat is to reduce demand. Improving levels of insulation in UK housing is critical to both reducing demand and protecting those living in fuel poverty. However, of the UK's current housing stock, around half has an efficiency rating of EPC D or worse. The government has set a target to upgrade existing houses to EPC bands B and C by 2035, and for all newbuilds from 2025 to meet higher efficiency standards according to a new Standard Assessment Procedure (BRE, 2023).

The second challenge relates to the decision on which heating technology to use to replace natural gas boilers. Realistically, there are two options for deployment at scale, hydrogen boilers or heat pumps, though district heating solutions may also be used in certain places. Heat pumps have the advantage of high levels of efficiency compared with a gas boiler. A typical Coefficient of Performance (CoP) for a heat pump is higher than 3, meaning that for every 1kW of electricity used, over 3 kW of heat can be produced. The equivalent hydrogen boiler would only have a CoP of about 1.

The infographic on the opposite page compares the efficiency of different space heating technologies while taking into account various efficiencies, conversions, and losses over the value chain. As can be seen, for every 100 units of primary energy supplied, a heating system based on a future green hydrogen grid can deliver roughly 60 units of useful energy to the end user. In comparison, a heating system relying on much more efficient heat pumps can raise the useful energy delivered to 177 units, considering the UK's current power generation mix. By 2050, with the significantly larger share of more efficient renewables in the power generation mix and with a slightly higher average coefficient of performance for heat pumps, useful space heating energy delivered could be raised further, up to 259 units, which is over four times higher than a green hydrogen-based system.

However, efficiency is not the only factor that consumers focus on; they are also concerned about upfront costs, running costs, levels of disruption and changes to their lifestyle. Currently, the capital costs for a heat pump are three to four times more than the cost of an equivalent gas boiler. To make a heat pump work effectively in homes, an EPC rating of C or higher is needed, requiring additional investment ▸▸

UK SPACE HEATING



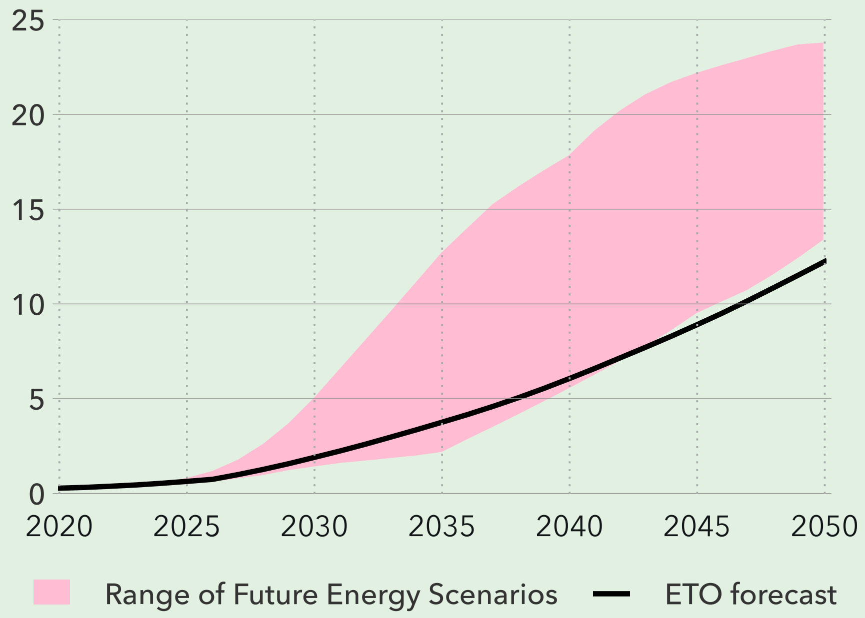
*COP = Coefficient of performance

in insulation. A heat pump may also require larger radiators and changes to pipework to account for the lower flow temperatures it achieves.

In terms of heat pump uptake, system inertia is likely to constrain the rate of uptake. In our forecast, only about 12 million (or 38% of) households will be heated by heat pumps by 2050. In terms of annual uptake, with a forecast of about 300,000 installations in 2028, we expect to fall short of the government target of 600,000 installations in that year, which we only expect to be reached about 10 years from now.

UK heat pump uptake

Units: Million households



Our forecast gives results which are more conservative than other major scenarios in the UK energy industry. For example, the figure below compares cumulative heat pump uptake in the ETO versus the range of Future Energy Scenarios (FES) 2023. FES are published annually by the National Grid Electricity System Operator (NG ESO) and are widely used as a basis for UK's energy infrastructure planning. FES consist of three Net-Zero-compliant scenarios and a non-Net Zero scenario (Falling Short). The graph shows that in our forecast heat pump uptake is slower than all Future Energy Scenarios. Even the 'conservative' ETO cumulative uptake graph shown above entails an exponential rise in annual sales of heat pumps from only about 60,000 per year today to over 250,000 in 5 years' time.

In the UK, natural gas is nearly 30% cheaper than the European average, while electricity prices are similarly high. Currently, use of natural gas for home heating does not incur a carbon tax. This effectively subsidizes natural gas versus low-carbon energy vectors, and gives further competitive advantage to gas boilers versus heat pumps. On top of that, based on data from DESNZ on household insulation (DESNZ, 2023a), currently only about half of the UK housing stock is well-insulated enough to be suitable for fitting a heat pump. The efficiency of heat pumps drops notably in poorly insulated homes, making them impractical and/or uneconomical in such cases.

Furthermore, electricity grid constraints and delays involved in the expansion of grid infrastructure are other hurdles to achieving the rising pace of heat pump uptake typically foreseen in Net Zero scenarios.

When considering running costs, the cost of electricity per kWh in the UK is currently four or five times as much as for natural gas, negating the efficiency savings of a heat pump – at least for now. In the longer term, a higher penetration of renewables will see electricity prices reduce. The cost of hydrogen will probably be more than the cost of natural gas, but that is not yet clear, and we await clarity on the hydrogen production business models to help understand the price point.

Gas boilers typically last around 15 years, and today we are still adding around 1.7 million gas boilers every year, which will remain in the system for another 15 years unless targeted and costly government intervention programmes are introduced. This introduces new inertia in the system, which will inevitably slow the energy transition in the medium term.

As things stand today, full decarbonization of buildings heating via heat pumps seems extremely unlikely to happen by 2050. If that target is to be reached, as shown in our Common Planning Pathway project report (DNV, 2023b), hydrogen will need to play a role in providing heat for a share of households.

The other challenge is the scale and speed of conversion. Currently, the government prefers a consumer-led transition, with homeowners choosing which solution to use to decarbonize their heating. However, recent experience with government schemes to promote heat decarbonization has not been encouraging. The 2012 Green Deal was scrapped in 2015 with just 15,000 loans having been taken out (versus the 14 million by 2020 originally targeted), and the Green Homes Grant was scrapped early with less than 2% of the GBP 1.5 billion earmarked for the scheme having been allocated in 2020–21. The current Boiler Upgrade Scheme, launched in 2022, is also showing low levels of uptake. DNV believes that a consumer-led transition is unlikely to achieve the speed of conversion necessary to decarbonize domestic heating and will cause significant transition planning problems for both the electricity and gas network operators.

At the same time, stronger policy support for heat pumps (e.g. incentivizing electricity over natural gas use via reallocation of taxes, including the carbon tax), and clear direction on hydrogen for heating are needed. Importantly, these need to be accompanied by much stronger action on insulation retrofitting of existing poorly insulated buildings which, besides enabling faster uptake of heat pumps, reduces heating energy demand via improved building stock efficiency. As the saying goes, the greenest energy is the energy we don't use. ■

3.3 Manufacturing energy demand

Our analysis of the UK manufacturing sector includes all the industries that extract and process raw materials and/or convert raw materials (and/or parts) into products; we exclude fossil fuel extraction and refineries, which are accounted for separately as energy sector own use. There is historical evidence that the industrial sector evolves as the standard of living – as measured by GDP per capita – increases. As society becomes more affluent, a country transitions from being an agrarian (primary) economy through to being an industrial (secondary) one, and finally, to a service-based (tertiary) economy, whereupon the industrial sector declines. In our analysis, we have mapped the different sectors of the economy from historical records and then extrapolated those trends into the future.

Manufacturing currently accounts for 18% of UK GDP compared with 40% in 1980 (Statista, 2022), and we expect this share to remain the same in future. Manufacturing energy demand decreased by 38% from 1990 to 2022 due to a combination of economic deindustrialization, improvements in the energy efficiency of industrial processes, and electrification. Energy demand was highest in 2000, at 440 TWh/yr, and has been decreasing ever since. There will be a further 17% decrease in total energy demand between 2022 to 2050, and manufacturing energy demand in mid-century will be less than half of what it was at its peak. The rate of reduction in energy demand will be slower in future compared to the last few decades. This indicates that most of the major structural and manufacturing technology changes that were possible have already been implemented, and that further changes will be more focused on fuel switching and electrification. By 2050, the manufacturing sector will represent a slightly greater share of total UK energy demand than it does now, going from 15% to 17%, due to other sectors decreasing their energy demand faster.

3.3.1 Manufacturing subsectors

We divide manufacturing into seven subsectors.

Manufactured goods: the production of general consumer goods, food and tobacco, electronics, appliances, machinery, textiles, leather, vehicles and other transport equipment. This subsector accounts for the largest share (45%) of total energy demand. The main reduction in manufacturing energy demand also comes from this subsector, which will require 17% less energy in 2050 (96 TWh/yr) compared with today (115 TWh/yr), thanks to efficiency improvements. In this subsector, temperature ranges are low enough in some of the industries (e.g. food or textile production), which enables at least a partial switch to highly efficient heat pumps for industrial heat.

Base materials: the production of non-metallic minerals except cement and non-ferrous materials such as aluminium, and wood and its products including paper, pulp, and print. This is the second largest subsector in terms of energy demand, with a 20% share in total manufacturing energy use today. Energy demand in this subsector is expected to remain relatively stable, with a small decrease from 46 TWh/yr today to 42 TWh/yr by 2050, with its share of total manufacturing energy staying at 20% in mid-century.

Iron and steel: production of about seven million tonnes of steel annually, contributing around GBP 2.4bn to the UK economy per year. Owing to high overhead costs and a lack of competitiveness in the international market, the UK steel industry has been in decline over recent decades. However, the government is committed to keeping this 'vital' industry alive through, for instance, a public procurement policy (House of Commons, 2021) and recent investment in greener steelmaking at Port Talbot (Gov.UK, 2023c). Iron and steel production, which currently consumes around 30 TWh/yr, is expected to reduce its demand by 55% to 14 TWh/yr by 2050.

Construction and mining: construction of roads, buildings, and other infrastructure, and mining of minerals. This subsector contributes around GBP 151bn per year to the UK economy with most of that being produced by the construction industry. Despite a growing economy and therefore an expected increase in activity in this subsector, we expect its energy demand to almost halve from 20 TWh/yr today to 11 TWh/yr by 2050. About 82% of energy demand in this subsector is used to produce heat (e.g. to produce asphalt), with the remainder split equally between running onsite vehicles and other machines. There is scope for improving the

energy efficiency of onsite vehicles and machines through increased electrification of industrial vehicles and machinery. Industrial heat is more likely to be decarbonized in the long term with hydrogen (when it becomes more affordable in the 2030s or 2040s).

Plastics: production of various polymer types such as polyethylene (PE), polypropylene (PP), polystyrene (PS), polyvinylchloride (PVC) and polyethylene terephthalate (PET). Plastics is a large manufacturing subsector, being one the UK's top 10 exports, with annual sales of GBP 25bn (British Plastics Federation, 2022). The UK produces 1.7 MT/yr of plastics raw materials, about half as much as it consumes, making it heavily reliant on imports of raw materials (British Plastics Federation, 2022). Going forward, we expect demand for virgin plastics to increase by about 20% by the mid-2030s in line with economic growth, at which point we foresee a peak and thereafter a 10% decline towards 2050. This reversal in trend will happen because of higher plastics recycling rates (both plastics-to-plastics and plastics-to-feedstock) and a reduction in the use of plastics due to environmental concerns. In line with this, plastics energy demand, at 20 TWh/yr today, will increase to 24 TWh/yr by the mid-2030s and then fall again to 19 TWh/yr by 2050.

Other petrochemicals: production of methanol, ammonia, (if used as feedstock[1]) and a wide range of other chemicals such as lubricants, paint, and so on.

1. Otherwise, energy demand for the production of methanol and ammonia used as energy carriers are counted under energy sector own use in our model.

This subsector's energy demand will increase from its level of 21 TWh/yr today, to 26 TWh/yr by 2040, then fall to 22 TWh/yr by 2050. Note that besides the required energy, plastics and petrochemicals production also entails significant non-energy fuel demand for feedstock, which is discussed in the next section.

Cement: six manufacturers in the UK produce around nine million tonnes of cement a year, which covers most of the domestic demand in the UK and contributes about GBP 1bn per year to the UK economy (WCA, 2023). Cement is the smallest manufacturing subsector in terms of energy demand. Its demand is only 4 TWh/yr today and will remain relatively stable towards 2050, with only marginal efficiency improvements expected in this mature industry. The cement industry is hard-to-electrify due to the high temperatures required for clinker formation. The industry is expected to continue being dominated by fossil-fuel use, though with increasing use of CCS for emissions abatement, particularly since the chemical calcination process in clinker formation is responsible for approximately 60% of carbon dioxide emissions (Nikolakopoulos et al., 2024). This would occur irrespective of low-carbon fuel utilization.

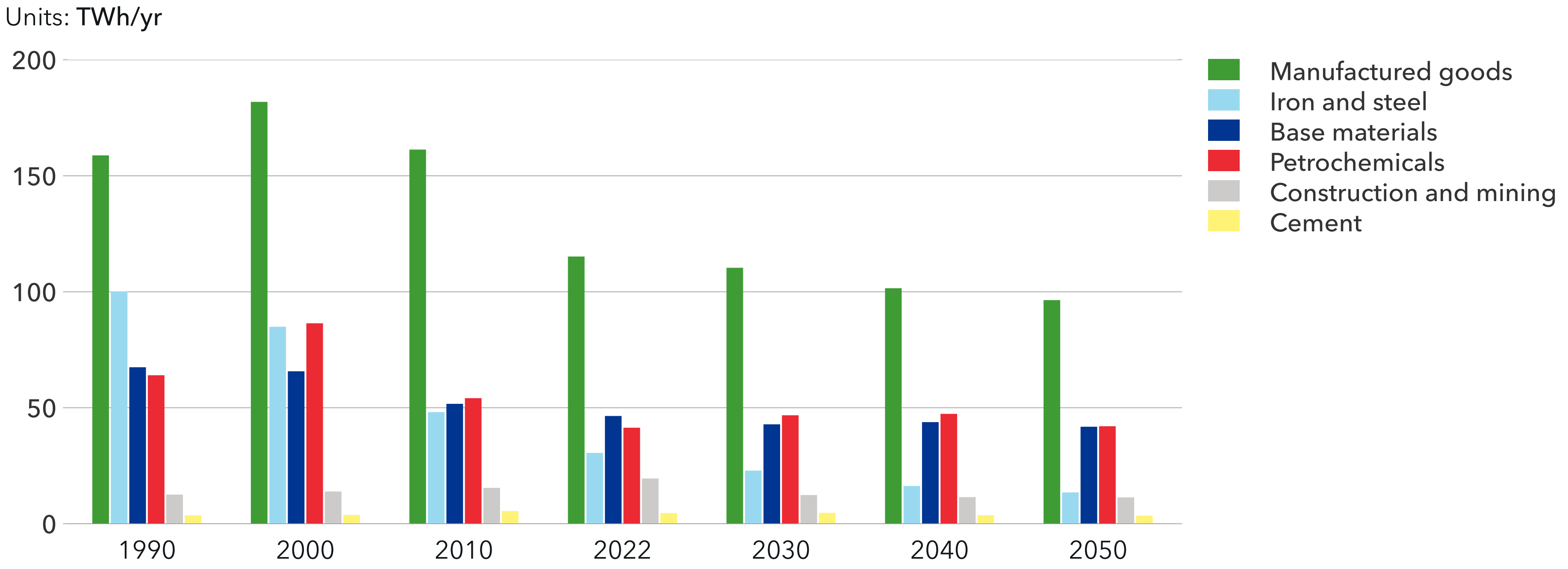
Figure 3.18 shows energy demand in all the manufacturing subsectors, in comparison. The manufactured goods subsector has been the largest energy user since 1990 and it will continue to remain so to 2050. Energy demand for iron and steel, which was the second highest subsector in 1990, will become the fifth largest by 2050. Energy demand for base materials and petrochemicals remains about the same level as today.

3.3.2 Manufacturing energy mix

Developments in the manufacturing sector's energy mix are dependent on technology suitability, energy resource availability, and policy. The share of energy carriers in manufacturing has been changing rapidly since 1990. Use of fossil fuels nearly halved between 1990 and 2022, making up 57% of final energy today compared to 74% in 1990. Today, natural gas, coal, and oil supply 36%, 11%, and 9% of the energy mix, respectively, while electricity provides 34%.

At this stage there is still substantial room for further electrification. In Norway, for example, twice as large a share of industrial energy is currently provided by electricity. Therefore, electrification provides the biggest opportunity for efficiency improvement and decarbonization for end uses such as machinery, industrial vehicles, and low to medium-heat industrial processes. In our forecast, electricity will grow from 86 TWh/yr today to 135 TWh/yr in 2050. The main increase in industrial electricity consumption is electrification of some low-heat processes; use of electric arc furnaces for iron ore reduction; and an increased role for electrolysis in ammonia production. The continuing mechanization and automation to

FIGURE 3.18
Manufacturing energy demand by subsector



Historical data source: IEA WEB (2023), DUKES (2023)

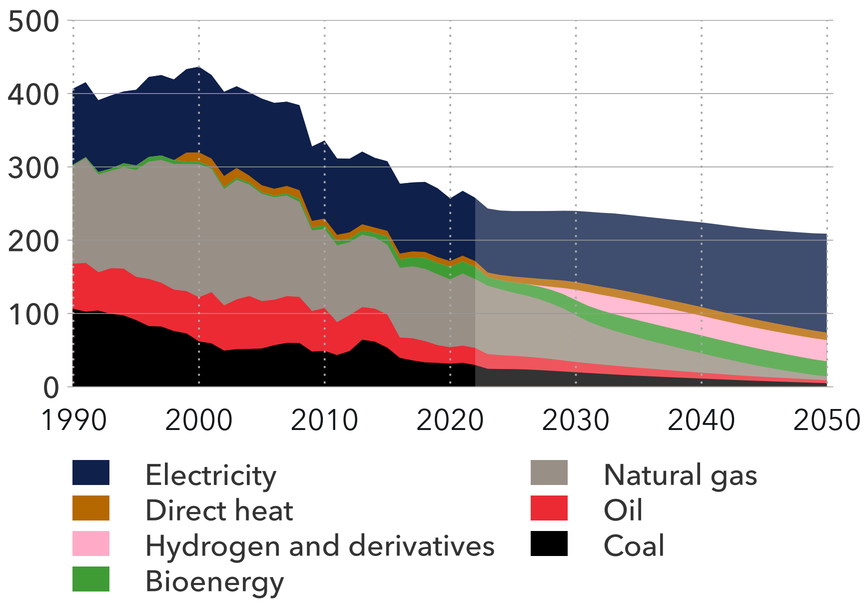
replace manual labour will also contribute to a rise in electricity demand.

As shown in Figure 3.19, the key development to be expected from now up to 2050 in manufacturing energy demand will be the gradual phasing out of most fossil fuel use. By 2050, the majority (65%) of final energy will be supplied as electricity, followed by hydrogen and derivatives at 14%, biomass at 10%, direct heat at 5%, and the remaining 7% provided by fossil fuels. From the 2030s, we expect hydrogen to increasingly replace fossil fuels for higher-heat processes. The use of hydrogen at 14% of the energy mix by 2050 is slightly higher than our forecast for the share of hydrogen in the manufacturing energy mix for Europe as a whole, and more than twice as large as in our overall global forecast (DNV, 2023). The anticipated future electrification of some industrial processes and conversion of others to hydrogen, most of which are unique to each industry and sometimes even to each industrial plant, poses a large technological challenge for the manufacturing sector in the coming decades.

FIGURE 3.19

Manufacturing energy demand by carrier

Units: TWh/yr

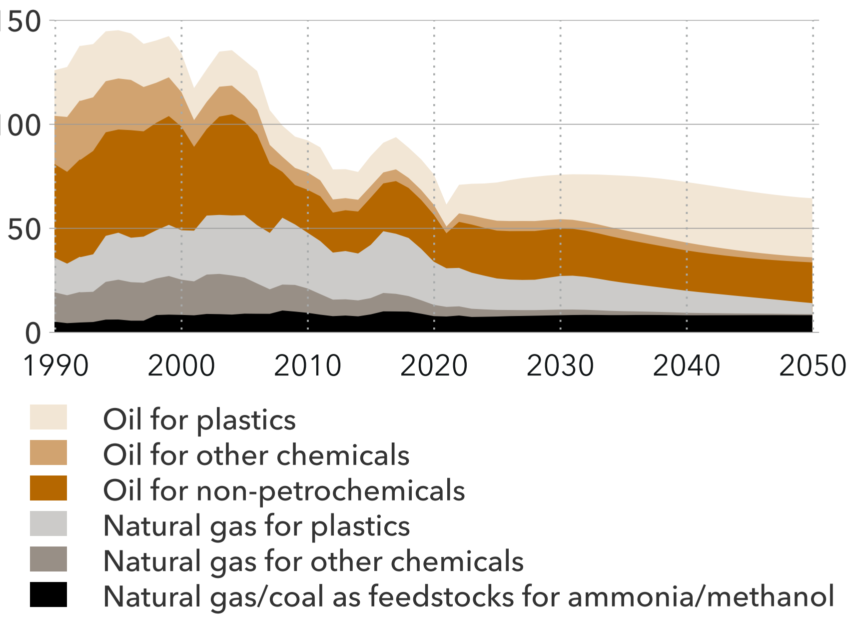


Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 3.20

Non-energy demand by end-use and carrier

Units: TWh/yr



Historical data source: IEA WEB (2023), DUKES (2023)

3.4 Non-energy use

Non-energy use reflects consumption of fossil fuels (oil and natural gas) as industrial feedstock for producing products such as plastics, paints, and ammonia (which is currently used primarily to make fertilizer). The products being manufactured include ammonia as feedstock, methanol as feed-stock, non-petrochemical products (such as bitumen/asphalt and lubricants), other chemicals, and plastics.

Demand is highest for manufacturing plastics (45%), followed by non-petrochemical products (31%) and other chemicals (12%), with ammonia and methanol as feedstocks accounting for the remaining 12%. Today, oil constitutes 51% and natural gas 47% of energy demand for non-energy uses. We expect the share of oil to slightly increase by 2050, to 70%, due to an increase in oil used for plastics and a decrease in the use of natural gas for other chemicals. Total demand will decline only slightly (8%) from now until 2050.

4 ELECTRICITY AND GAS GRID

Electrification is the main engine of the energy transition. Electricity demand in the UK will more than double by 2050. It will be greening at the same time and, through green hydrogen, penetrating hitherto hard-to-electrify sectors. All electricity supply will originate from low-carbon sources in the early 2040s. This will require major investment in power generation facilities and associated expansion and strengthening of the UK power grid. However, with reducing demand for gas we will see in parallel a significant reduction (-54%) in the utilization of the UK natural gas grid.

4.1 Electricity

Electricity demand

As Figure 4.1 shows, total UK electricity consumption (including from off-grid renewables) will increase by a factor of 2.3 from 310 TWh/yr in 2022 to 700 TWh/yr in 2050. This growth is seen across all sectors.

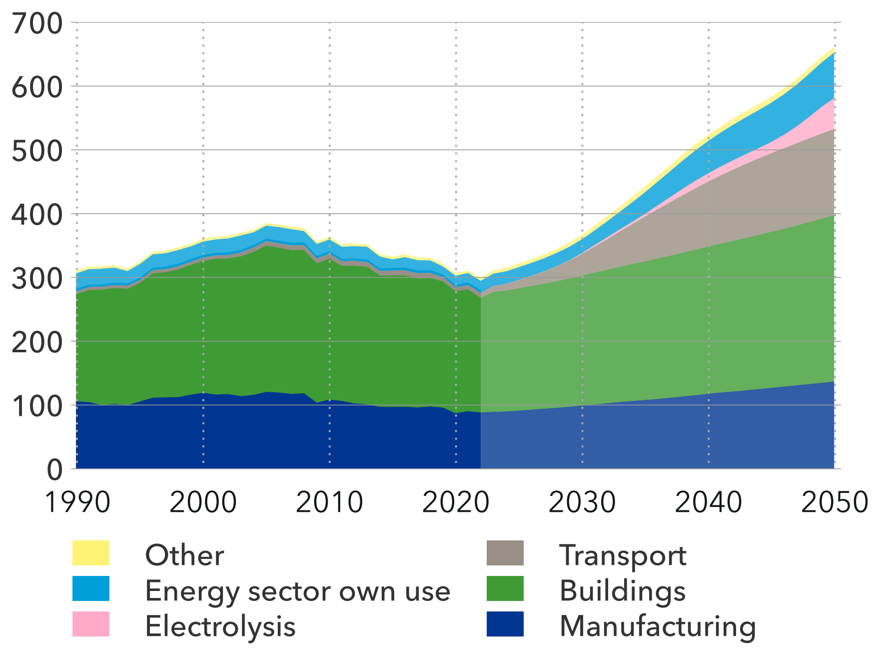
The largest increase will be in transport, where electricity demand will increase from 7 TWh in 2022 to 135 TWh in 2050. We will see electrification of all transport subsectors and their market segments, but first and foremost in road vehicles, with 120 TWh consumed annually by 36 million passenger EVs and 5 million commercial EVs in 2050. In the aviation sector, we expect electric short-haul flights to consume 6 TWh/yr in mid-century.

Total electricity use in buildings will increase from 190 TWh/yr in 2022 to 260 TWh/yr in 2050. This is mainly

FIGURE 4.1

UK electricity demand by sector

Units: TWh/yr



Historical data source: IEA WEB (2023), DUKES (2023)

driven by the increased uptake of heat pumps as a cost-competitive alternative to gas space heating from the early 2030s on, resulting in a significant market share for heat pumps by 2050 (one third of all households). Meanwhile, the appliances and lighting segment will grow in line with building expansion and increasingly tech-heavy lifestyles.

As hydrogen and e-fuels start to replace fuel from the late 2030s in manufacturing, electricity generation, and marine transport, electricity consumption from electrolysis plants will grow significantly, reaching 50 TWh in 2040 and 95 TWh in 2050.

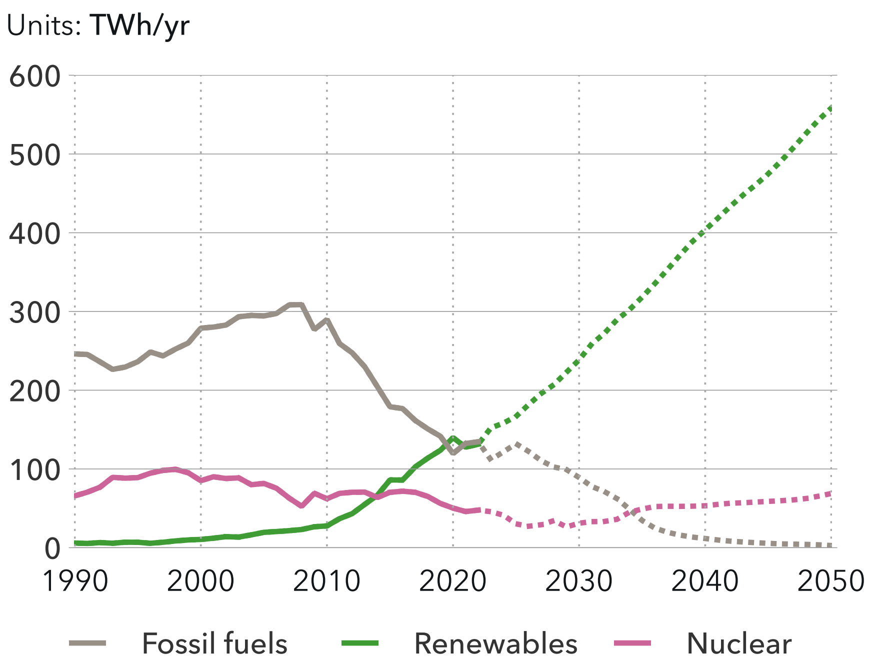
We will also see an increase in electricity demand in the manufacturing segment as the industry will be incentivized to decarbonize through higher carbon prices. Most electricity in the manufacturing sector is used either for industrial heat or to run machines, motors, and appliances. The energy system's own use of electricity will increase for the same reason as general industry, but there will also be an increase in electricity demand linked to blue hydrogen and ammonia production and Carbon Capture, Utilization and Storage (CCUS) facilities. Own use in the manufacturing and energy sectors will together see electricity demand nearly double from 110 TWh in 2022 to 210 TWh in 2050.

Electricity supply

Most of the additional UK electricity generation that will be required to meet the increasing demand will be from renewable sources. Figure 4.2 shows the development of electricity generation by fuel source. Currently, the total UK electricity supply mix is 42% renewables (including biomass), 43% fossil fuels, and 15% nuclear, but this will shift significantly by 2050 to 87% renewables, 3% hydrogen-fired (blue or green), and 10% nuclear. Figure 4.3 shows the UK electricity generation trend by specific power station type. Today, the biggest share (40%) of power generation output in the UK comes from gas-fired power plants. As a result of decarbonization incentives and the declining costs for renewable electricity generation, this share is expected to gradually decline to less than 5% by 2050. Gas-fired power plants in the UK will see initial CCUS uptake starting in the late 2020s, driven by the rising carbon price and supported by the BEIS Dispatchable Power CCUS Business Model[1].

FIGURE 4.2

UK grid-connected electricity generation by fuel source



Historical data source: GlobalData (2023), IEA WEB (2023)

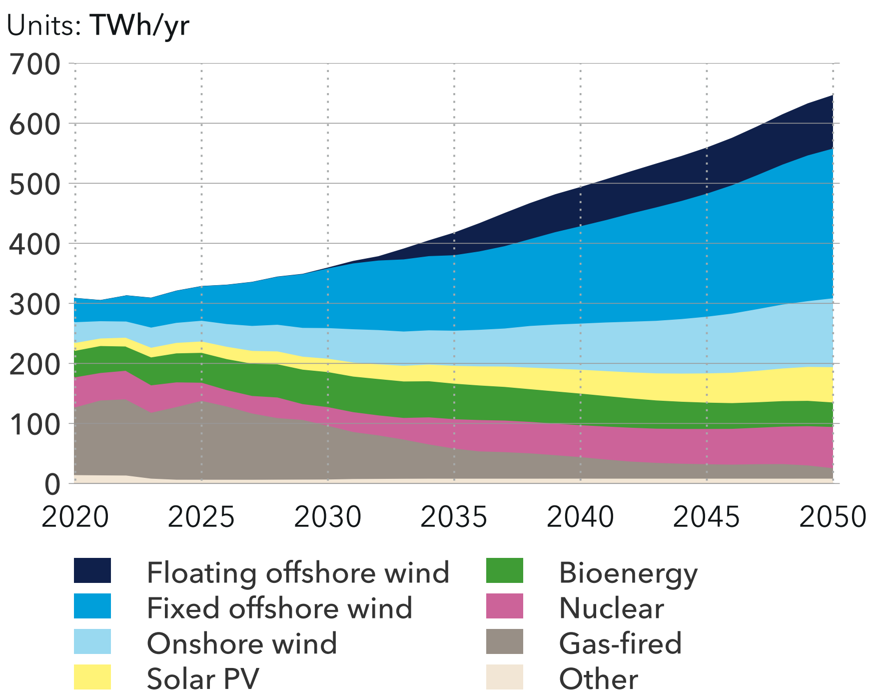
This uptake steadily increases until the mid-2040s, when most gas-fired power stations will have CCUS installed or use hydrogen as a fuel.

Biomass currently provides 13% of total UK electricity generation, including compressed wood-pellet-fired power plants, waste-to-energy plants, and biomethane. Biomass-fired plants will keep a substantial share (6% in 2050) of UK power generation capacity.

Gas-fired and biomass-powered power stations will be increasingly important to provide dispatchable power for flexibility and backup in power systems when variable renewable energy sources (VRES) are at reduced output. As a result, even with higher levelized costs than VRES, a minimum share of fired plants will be essential in future years.

FIGURE 4.3

UK grid-connected electricity generation by power station type



In 2022, VRES generated 27% of the UK's electricity. As decarbonization pressure grows and the costs of solar PV, wind generation, and battery storage continue to fall, VRES will take an ever-greater share of the electricity mix. We expect VRES to provide nearly half of UK electricity generation by 2030; and by 2050, 80% of the UK's grid-connected electricity will be generated from variable renewables.

In the UK, wind will be the dominant VRES electricity source, generating 70 TWh/yr in 2022, but increasing to 450 TWh/yr by 2050. Currently, wind generation

We expect VRES to provide nearly half of UK electricity generation by 2030; and by 2050, 80% of the UK's grid-connected electricity will be generated from variable renewables.

1. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1068426/Dispatchable_Power_Agreement_Business_Model_Summary_and_Consultation__April_2022_.pdf

is roughly evenly divided between onshore and offshore, but offshore wind will gain a larger share in future years, showing 9% average annual growth from now to mid-century. This is a result of there being higher wind speeds offshore, and less constraints on hub heights and site locations. In 2050, 70% of grid-connected electricity supply will be wind-based, with that share split as follows: 25% onshore wind, 55% bottom-fixed offshore wind, and 20% floating offshore wind.

Even with its cyclical daily production, solar PV already has similar levelized costs to onshore wind. Hence, its share in the power supply in the UK will also steadily increase from 5% today to 9% in 2050.

Nuclear generation plays a role in the UK in providing low-carbon base load electricity supply. The actual development of installed capacity of nuclear generation has historically been driven more by policy than cost. Hence, our forecast reflects the ongoing decommissioning programme for certain plants and confirmed capacity additions at Hinkley Point C (2029) and Sizewell C (2033/35). We also expect some uptake of Small Modular Reactor (SMR) technology, provided the technology will be fully proven by 2030, which is expected to help solve some of the existing hurdles for nuclear, such as high cost, safety, and public opinion. The combined effect of all the above will be that nuclear will provide 10% of the total electricity supply in 2050.

Power generation capacity development

Table 4.1 summarizes the expected total installed generation capacity today and at the end of each decade. Note that off-grid renewables would be standalone facilities dedicated to hydrogen production via electrolysis

Gas-fired power plant capacity will increase until the late 2030s, but then gradually reduce as older plants coming off-line are no longer replaced. We also see their capacity factor reducing from around 40% today to below 10% in 2050, reflecting their increasing role to provide dispatchable backup power during low production periods of wind and solar.

Biomass will show a continued small increase in capacity over time, reaching 10 GW in 2050 – also providing part of the necessary dispatchable power.

Offshore wind capacity will significantly increase from around 14 GW today to 90 GW in 2050 (including 10 GW of off-grid capacity for hydrogen production). This will increasingly include floating offshore wind facilities, which will be 24% of total offshore wind capacity by 2050.

Onshore wind installed capacity will increase more than three-fold to 52 GW in 2050.

It is expected that capacity factors for all types of VRES, but especially wind, will increase between now and 2050, reflecting expected improvements in turbine and panel design, larger units, and better efficiency through operations, resulting in increased output from the installed units. For offshore wind farms, capacity factors are expected to exceed 50% by 2040 (from around 45% today). Onshore wind farms will achieve capacity factors close to 40% by 2050.

Solar capacities will increase more than three-fold to 54 GW by 2050. For solar panels, we only expect a small further improvement in capacity factor compared with today, achieving 13% by 2050.

As discussed previously in this section, nuclear capacity changes reflect the expected ongoing decommissioning programme and confirmed additional units coming online, and beyond 2035 includes an uptake of SMR units – resulting in a total capacity of 11 GW by 2050 to provide some measure of firm base load.

TABLE 4.1
Installed power generation capacity

Power generation type	Installed capacity (GW)				
	2022	2030	2035	2040	2050
Grid-connected					
Gas-fired	36	42	36	30	20
Biomass	8	10	10	9	9
Fixed offshore wind	14	29	33	41	60
Floating offshore wind	0	1	11	15	21
Onshore wind	15	24	25	32	48
Solar	16	23	30	39	56
Nuclear	6	4	6	7	10
Others	7	6	6	6	6
Off-grid (hydrogen production)					
Offshore wind	0	1	3	7	9
Onshore wind	0	0	0	1	2
Solar	0	0	0	0	0
Total	**102**	**139**	**160**	**188**	**241**

4.2 Power grids

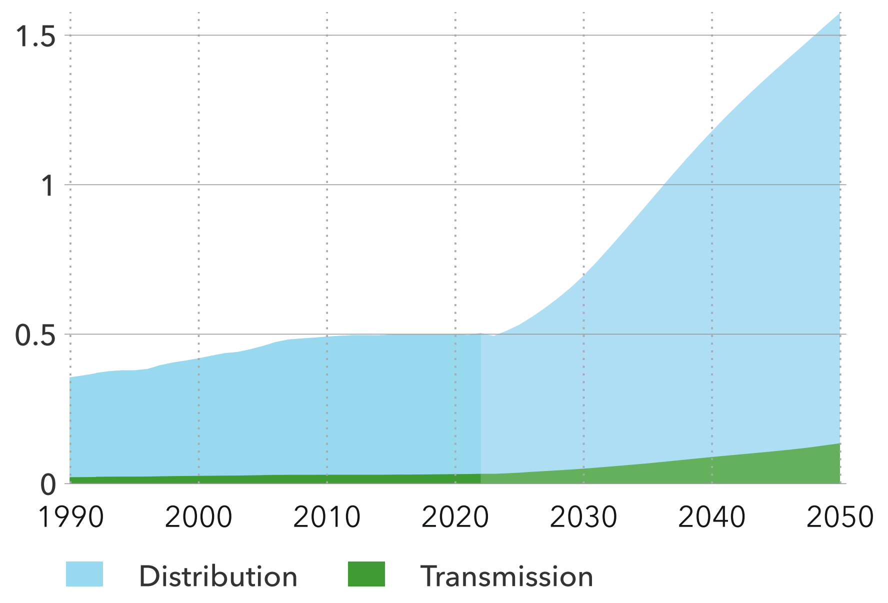
Physical infrastructure

With electricity demand growth averaging 3%/yr between 2021 and 2050, more grid connections will be needed. As Figure 4.4 shows, the UK electricity transmission network will increase from just over 34,000 circuit-kilometres in 2022 to 140,000 by 2050. Although it could be argued that distributed renewables remove the need for centralized electricity systems, most of the growth in UK wind will be in locations some distance from the major demand centres (e.g. Scotland's renewables feeding the rest of the UK), requiring continued investment in transmission grid expansion and strengthening.

FIGURE 4.4

UK transmission and distribution grid lengths

Units: Million circuit-km



Historical data source: GlobalData (2023)

While electricity demand grows by 3%/yr, peak power demand grows at a slightly higher 3.5%/yr, which has a direct impact on the growth of the physical grid infrastructure that needs to be able to handle the higher power and ensuing congestion. This is one of the reasons why the transmission grid will expand more rapidly than the rate of electricity demand growth.

We project the more widespread use of high-voltage direct current (HVDC) lines in the transmission grid in the future. HVDC lines currently make up only 1% of the transmission grid in terms of circuit-kilometres. This will increase to 10–15% by 2050. But, in terms of power capacity, they will have a share of 30% in the transmission grid by 2050.

Distribution lines will almost triple from 470,000 to about 1.4 million circuit-kilometres between 2021 and 2050. As the percentage of VRES grows significantly, integration of renewables and grid modernization will have to work together to achieve the reliable grids needed for UK society. Modernization of the grid will involve reinforcement or upgrading of transmission and distribution systems; investment in international interconnections; implementing decentralized energy data and information processes; installing advanced grid features (smart meters, sensors, remote controls); changing processes and business models; establishing more flexible energy markets; undergoing regulatory review; and modernizing system operations.

Challenges in UK power grid expansion and resilience

Based on government targets, the UK power system is to be fully decarbonized by 2035, meaning that subject to security of supply, the UK will be fully powered by green electricity.

Planning for the achievement of this ambitious target presents the collective of UK power grids (transmission and distribution) with perhaps its biggest challenges yet. The following three are among the most important:

Timely delivery of network capacity
Large volumes of variable renewable generation capacity connecting into the system require unparalleled investment to expand and reinforce the electricity transmission system. However, there is uncertainty around precisely how much will be needed, where, and when. This inhibits networks' ability to plan and secure regulatory funding for investment, which in turn creates further uncertainty with developers and investors. Even where investment requirements have been clearly discovered, the scale and pace are unprecedented and at risk due to staffing and skills gaps, stretched global supply chains for essential materials, lack of timely network access, and the parallel need for facilitative information and operational technology (IT and OT) investments.

Different parts of this puzzle are being considered in a suite of reform programmes around network connections, network planning, and network design. Ofgem's introduction of the ASTI (accelerated strategic transmission investment) regime in autumn 2023 should speed up the delivery of major power grid projects, but its efficacy remains to be seen. There is currently no centralized plan for the collective decommissioning of gas networks and transition to hydrogen.

Summer 2024 will see the introduction of the National Energy System Operator (NESO) and Regional Energy Strategic Planners tasked with optimizing infrastructure for molecules and electrons, at national and regional level. The governance framework and detailed decision-making methodologies for the NESO and affiliated entities are in development and have the potential to make or break the role of networks in realizing the UK's decarbonization commitments.

The role of hydrogen in maintaining grid resilience
In today's power system, variability is primarily dictated by power demand. In 2050, variability will be far greater and driven not only by demand but also by variable renewable energy sources: most power will be generated through wind and solar, with nuclear still providing base load, and with dispatchable power and interconnectors supplying the remainder of demand.

The resilience of the grid, i.e. its ability to accommodate large sudden load swings and 'Dunkelflaute'[5] periods, will be critically reliant on dispatchable generation. As we strive towards Net Zero 2050, an increasingly significant part of this dispatchable power will need to come from hydrogen-fired peaking plants. This requires urgent planning of, and significant investment in, hydrogen production, transport, and storage infrastructure – as well as supporting infrastructure for CCUS and water - to ensure hydrogen can play the part it needs to. Investment in ramping up the role of hydrogen must be carefully planned and delivered alongside a gradual easing off of natural gas and an increasingly electrified energy system – to ensure an economic, safe, and secure transition. The newly created NESO will have a key role in planning and overseeing this process.

Complexity of system operation
The increase in variable power supply and demand, as well as the growth and change in network users and technologies, create increasingly complex bi-directional power flows, stability issues, and different demand patterns. To manage these complexities, the energy system needs to operate faster and smarter, prompting the urgent need for investment in IT and OT to enable digitalization of network assets and system operation.

Electricity and gas networks will need to be self-healing and resilient to respond to an increasing variety of circumstances (e.g. bi-directional power flows, unplanned outages, severe climate events, cybersecurity events) in real-time. This will require autonomous and complex analysis of information to be presented to control room operators, so they are able to take the right actions. Network assets and low-carbon assets will need to be capable of collecting, sharing, and processing data to both inform and execute commands, leveraging international communication protocols. This means a full-scale upgrade of our energy networks for the latest Supervisory Control And Data Acquisition, (SCADA) systems with advanced control capabilities, digital asset instrumentation, advanced metering infrastructure (AMI), smart sensors and monitors.

A full-scale system upgrade requires network-wide planning and coordination within individual networks (to synchronize with capacity investments), between transmission and distribution systems, and again between electricity and gas grids. This full-system approach is essential to deliver system-wide resilience and restoration capability while ensuring it is delivered in time and economically. Software compatibility, standards for data exchange, and interoperability are critical requirements, and skills and supply-chain limitations are the primary showstoppers in the short to medium term. ■

Investment in transmission and distribution infrastructure

Grid investments in the UK have been relatively stable over the last two decades at an average of GBP 3bn per year. However, as shown in Figure 4.5, rapid grid expansion will result in an increase to an average of GBP 9bn/yr grid investment over the period 2030–2050. The continued growth in grid investment is driven by actions from grid operators accelerating renewables integration, grid modernization to improve resilience and reliability, and digital transformation.

Some 15% of grid investment today goes into digital infrastructure to address the complexity of a more decentralized power system, to manage more complicated electrical systems resulting from VRES, and to support decision-making in asset management and operations. Investment in digital tools will expand to enable collection of data and information from the grid and feed these to core processes. These tools include:

– Advanced analytical algorithms enhanced with machine learning to translate data from various sources into validated information about market processes, asset conditions, and decision-support functions;

– IT infrastructure to store and manage data for authorization and data quality;

– Standardized and secure data-communication infrastructure to transfer market and field data, enabling connectivity and interoperability; and

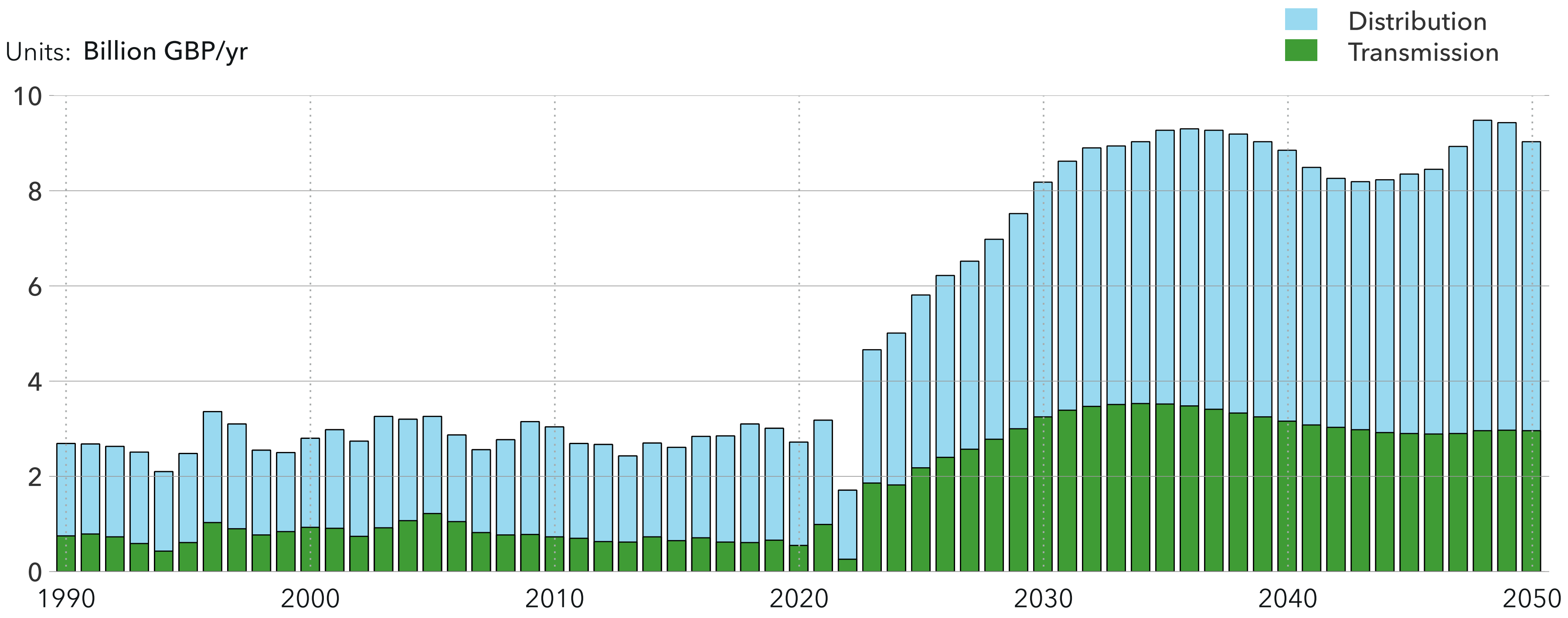
– Sensor arrays, collecting asset data to be utilized by a digitally enabled workforce.

This digital ecosystem enables the operation of equipment closer to physical limits, and for optimizing maintenance and replacement plans, as well as integrating distributed energy resources.

By allocating total cost of grid development and operation to the total electricity consumption, the grid charges in end-users' electricity bills can be estimated. Average UK grid charges have been relatively stable over the last two decades; we forecast this number to increase by nearly 50% because of the significant grid investments required over that period. Even so, grid charges will remain a relatively small percentage (±5%) of household energy bills.

FIGURE 4.5

UK annual grid investment cost



Grid investments in the UK have been relatively stable over the last two decades at an average of GBP 3bn per year. However, as shown in Figure 4.5, rapid grid expansion will result in an increase to an average of GBP 9bn/yr grid investment over the period 2030 – 2050.

Digitalization of the energy system

Decarbonizing and electrifying the UK's energy system requires increased interaction and cooperation between all energy stakeholders. Digitalization is a key enabler for a pathway towards net zero in an affordable way against a backdrop of volatility, unpredictability, and complexity.

In the UK's first Energy Digitalisation Strategy published in 2021, the Government set out how only a digitalized energy system can withstand the millions of new energy flows every second from low-carbon technologies connecting to the grid over the years ahead.

A significant number of use cases – many now being realized in the form of actual projects – are emerging across the UK energy sector.

The National Grid electricity system operator (ESO) is leading on the Virtual Energy System ecosystem of connected digital twins for Great Britain. This project will enable data sharing to drive innovation and deliver optimal whole-system decision-making. A contributing use case for the Virtual Energy System is CrowdFlex, which is exploring consumer behaviour to understand how domestic flexibility can support the coordination of energy consumption, generation, and grid management. The project is now looking to understand consumer demand and domestic flexibility to demonstrate the benefits of the Virtual Energy System and will build interconnected models of consumer demand and flexibility.

Within the onshore gas sector, National Gas and DNV have been working within a project consortium to establish the feasibility of using hydrogen, building the ambitious FutureGrid hydrogen test facility at DNV's site in Cumbria, UK. The FutureGrid facility has been designed to include hundreds of sensors to capture real-time data on the operation of the test system. This is passed via the cloud to the digital twin which uses simulation and machine learning to support decision-making. This allows the operators to see the impact of their decisions before they are implemented on the physical system and helps them to make more robust asset management decisions and predictions on future scenarios as well as conducting risk analysis before physical implementation. Once the feasibility of the FutureGrid digital twin is established, it should be possible to connect it to other energy sector digital twins and manage the entire system via the Virtual Energy System.

Understanding the potential economic impact in terms of market uptake, consumer demand, and future infrastructure investment in energy-related initiatives, such as power generation and distribution, requires establishing trust in data and specifically data that is derived from source.

Data needs to be adequate, standardized, and interoperable across the energy sector; Ofgem was the first regulator in Europe to set out its regulatory approach and intent to use the Common Information Model (CIM) IEC standards as the expected data standard in Ofgem's energy network data-related licence requirements, and for it to be used more broadly for data exchanges in the energy industry. It is expected that the use of the IEC CIM standard will become a requirement for all relevant data exchanges across connected systems, driving standardization and interoperability and setting the foundation for a wider adoption across the energy system. Discussions are also underway to ascertain practical ways in which Great Britain's gas networks will implement CIM.

For the gas industry, concerns around asset data and the quality of information held about operational assets more specifically will need to be addressed. This is particularly important as the gas networks strive to become smarter to meet future operational needs and alternative forms of low-carbon gases are introduced. For example. use cases that involve uprating specific gas pipeline assets to ensure compatibility with future energy carriers such as hydrogen already exist. They involve understanding the data held on as-built and operational components in order to use specific engineering judgement. However, there are gaps in records that are labour-intensive to fill and require a human-in-the-loop approach to build up data and resolve. ■

Illustration of National Gas Network Innovation Competition (NIC) FutureGrid Phase 1 Project where DNV is the primary partner responsible for design, building and operating the test facility for the research project. Spadedadam, Cumbria, UK.

4.3 Flexibility and storage

Variability and flexibility
With a nearly five-fold increase in UK VRES capacity over the next 30 years, the hourly variability around the average electricity throughput for the grid will increase significantly. This is illustrated in Figure 4.6. The positive axis shows the annual hourly electricity throughput variability trend up to 2050. This variability is calculated by summing up the absolute hourly deviations from the annual average. The negative axis displays the associated trend in required flexibility from various sources to manage this variability.

In 2022, the variability around the average hourly 35 GW consumption is around 12% (± 4.2 GW) mainly created by the variability in final consumption from the key demand sectors – transport, buildings, and manufacturing – after demand response. The necessary 12% flexibility on the supply side is currently mainly provided by gas-fired generation. Even VRES, particularly solar, contribute to the reduction in the variability in 2021 as the generation pattern of solar is generally in sync with the demand pattern. This overlap helps to reduce the additional flexibility need by shaving off the residual electricity demand after solar generation in peak hours.

This final consumption variability percentage will remain relatively constant going forward. However, Figure 4.6 clearly shows how the increase of VRES generation capacity will create an additional 8–9% throughput variability by 2050. This increase is due to electricity generation swings linked to wind and solar input variations, as the output of solar and wind at certain hours become so large that instead of reducing the need for additional flexibility, they create large swings that flexibility providers must respond to. In 2050, the expected total variability around the 88 GW average hourly grid throughput will be 20% (± 18 GW), which will require a significant increase in flexibility response within the overall electricity system.

The page overleaf illustrates the differences in demand and supply variability between today and 2047 by showing their hourly variations during a typical summer and winter week in those years.

The largest part of the required system flexibility (33%) in 2050 will be provided by utility-scale battery storage with capacity growing up to 190 GWh, mainly covering flexibility for shorter duration demand and supply fluctuations. This is discussed in more detail in the next subsection.

Approximately 20% of the required system flexibility in 2050 will still be provided by thermal generation technologies, where existing plants will increasingly operate alongside renewables, and hence the premium on the flexibility of these sources will increase. Flexibility in this context means shorter start-up times and higher ramp rates. Equally important will be the ability of thermal plants to run economically at predominantly low load factors when the bulk of power is provided cheaply by VRES.

Converting VRES to other energy carriers, such as hydrogen, is a key option that will provide flexibility during periods of high wind/solar generation. We predict that by 2050, 50 TWh/yr of generated on-grid electricity will be used to produce hydrogen, which can be sent to storage when renewables supply exceeds demand, providing another 27% of the required system flexibility in 2050.

Interconnectors with other power grids in Europe would provide 15% of the required flexibility – both in terms of exporting excess supply to the continent during times of high VRES generation or supplying backup power to the UK during supply shortages.

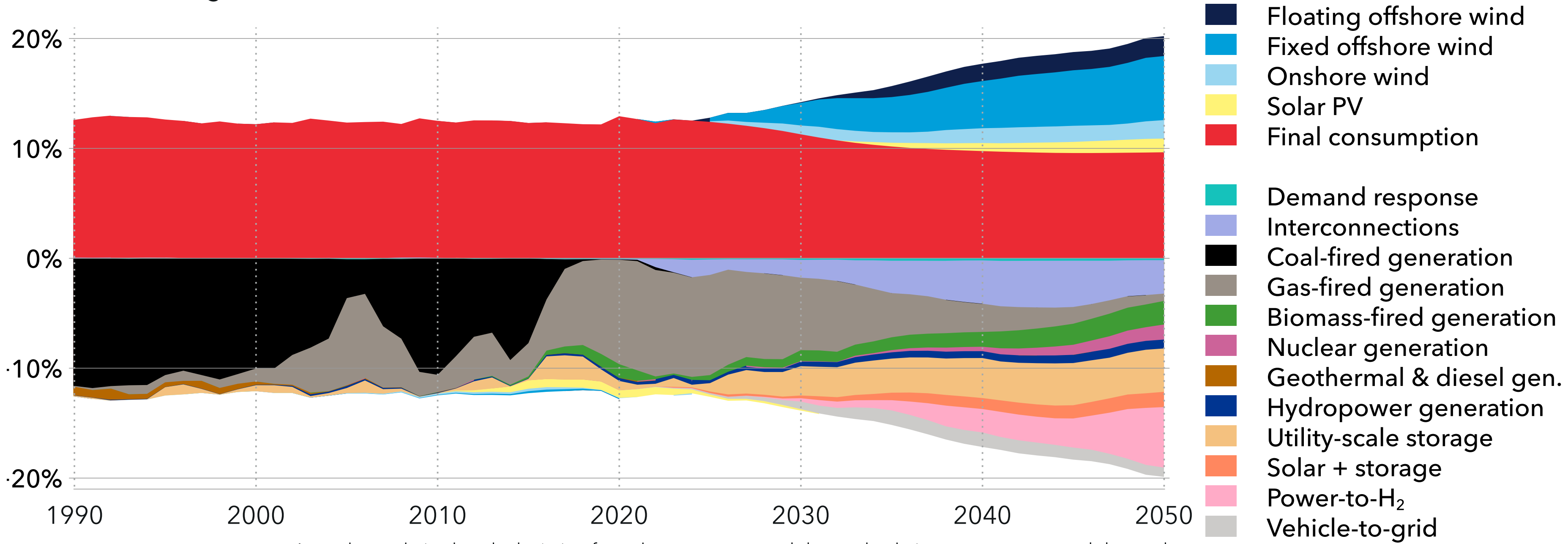
Adapting for flexibility requires physical changes investment in automation and analytics. Better prediction of renewable power generation levels and demand response will assist with reacting to excess renewables and shifting electricity usage from peak periods to times of lower demand.

In addition, new market designs will be needed that incentivize the flexible operation of thermal plants. From a system perspective, implementation of smart grid features will enable better management of energy flows. There is also a rising active consumer (sometimes referred to as 'prosumer') phenomenon: new technologies and market mechanisms will allow ever more consumers to provide flexibility in the form of demand response, vehicle-to-grid (V2G), and behind-the-meter (BTM) storage.

FIGURE 4.6

Sources of hourly variability over the year and providers of flexibility in the UK power system

Units: % of average demand

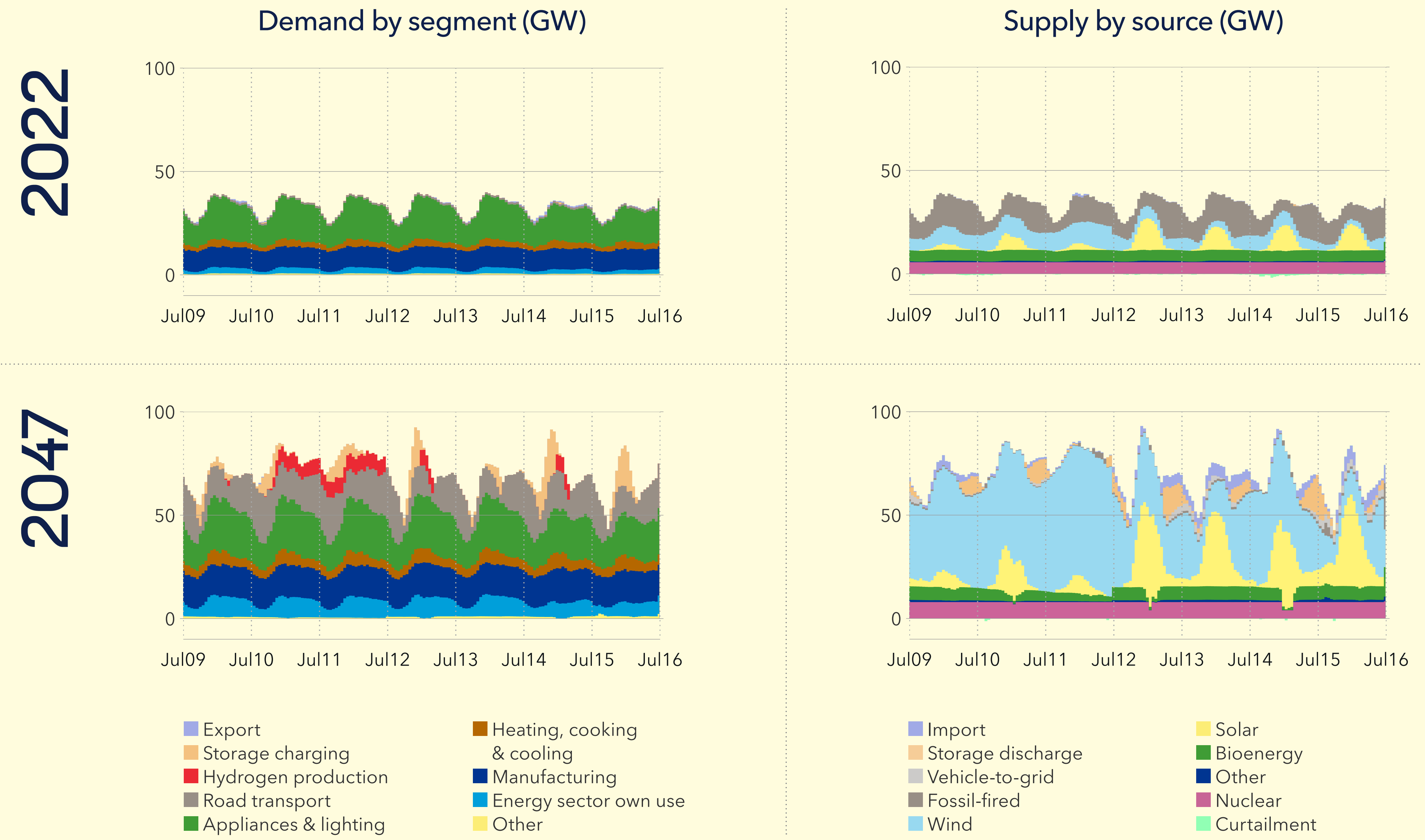


Annual cumulative hourly deviation from the average annual demand, relative to average annual demand. Positive numbers show sources of variability. Negative numbers show reduction in variability by flexibility options.

POWER SUPPLY AND DEMAND FOR A TYPICAL SUMMER WEEK

In a typical summer week in 2022, appliances and lighting with a daily fluctuating profile are the largest demand category and total demand peaks around 45 GW. On the supply side, nuclear and biomass provide the base load, with solar available during daylight hours supplemented by wind. The residual load is supplied by fossil-fired flexible generation.

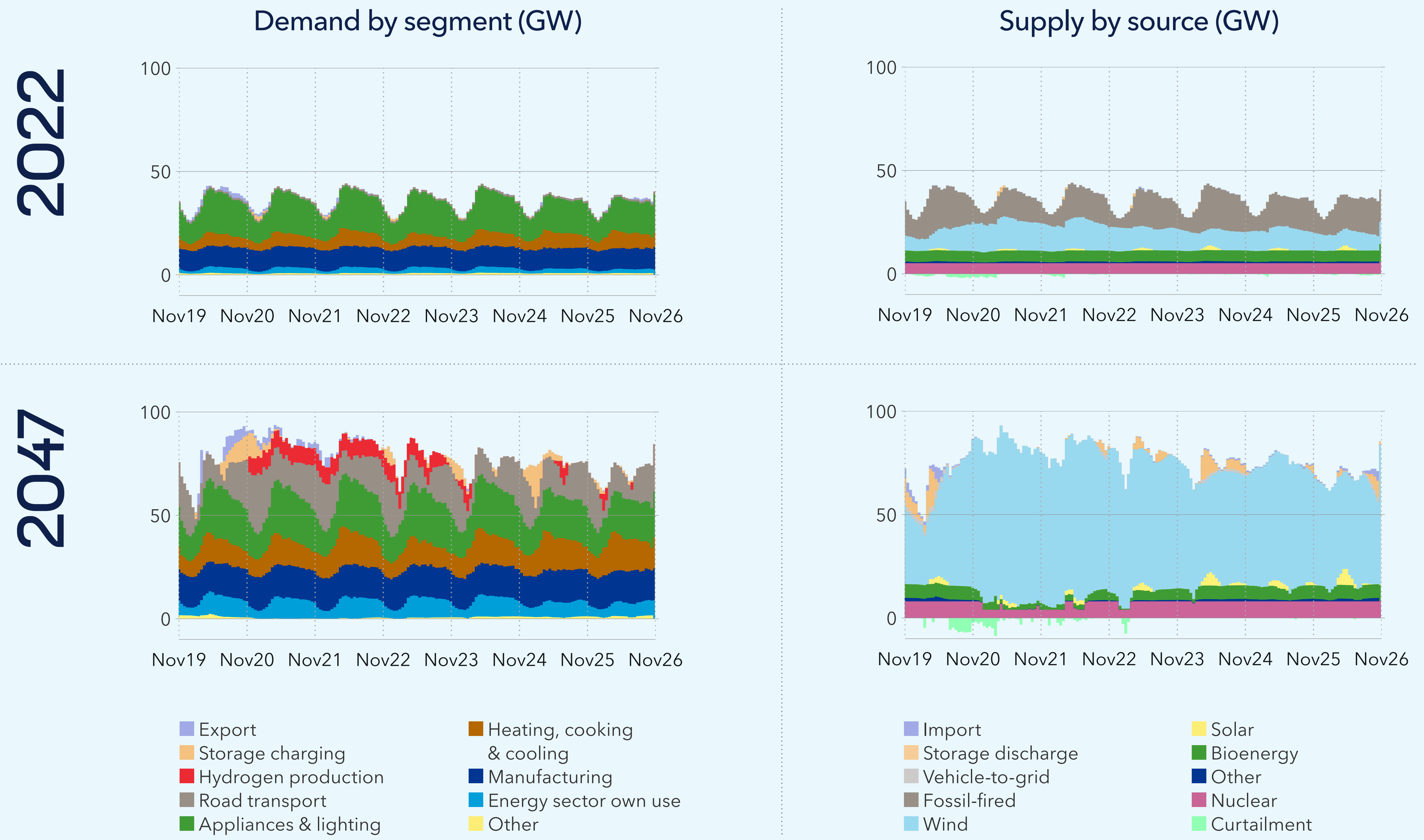
By 2047, a typical summer week will look very different. Firstly, average electricity demand/supply is significantly higher than today, peaking at close to 100 GW during daytime hours. On the supply side, solar generates significant daily peaks. During these peak solar hours, with large contributions from wind, some of the surplus will be used to charge battery storage and to run electrolysers to produce hydrogen. Conversely, during periods of low wind and solar, supply can be complemented by discharging battery storage. While nuclear continues to provide base load, fossil-fired generation will be almost negligible.



POWER SUPPLY AND DEMAND FOR A TYPICAL WINTER WEEK

In a typical winter week in 2022, electricity demand increases marginally compared with summer weeks to cover additional lighting and heating demand. On the supply side, the main difference is reduced contributions from solar, requiring more fossil-fired generation to make up this shortfall.

A winter week in 2047 will see an increase in average demand compared with summer. However, the variability in supply caused by solar will be significantly lower. Most of the power will be generated through wind, with nuclear still providing base load, and flexible dispatch provided mostly by biomass-fired generation. Even with increased winter demand, there will be periods with excess wind-generation capacity which can be used to charge storage, produce hydrogen, or export energy to the continent.



Storage

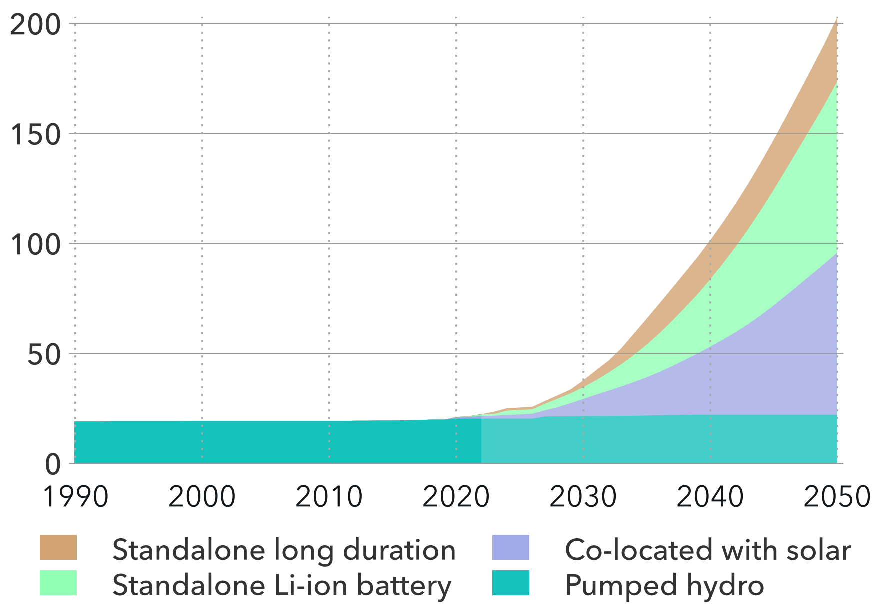
Short-term energy storage capacity in today's UK power system is predominantly provided by pumped hydro (Figure 4.7). Limited by geography, pumped hydro is a mature technology, and will only marginally increase in either power or energy capacity over the next three decades.

In contrast, utility-scale battery storage facilities have grown rapidly in the UK over the past few years to provide approximately a third of the power storage capacity available to the grid today. This growth is expected to continue through to 2050, reaching 180 GWh of energy storage capacity by then.

FIGURE 4.7

UK utility-scale electricity storage capacity

Units: GWh



Does not include behind-the-meter storage. Long duration storage includes 8–24 hours storage such as flow batteries, compressed air, liquid air, liquid CO_2 and gravity-based solutions. Historical data source: GlobalData (2023), US DOE (2023).

In addition, batteries in EVs are expected to play a significant role in the energy storage capacity of the UK through load management and V2G technology. It is worth outlining the scale of the contribution that EVs will make in power storage. Smart meters, smart grids, and regulatory changes will incentivize car owners to use V2G solutions. We assume that from 2035, 10% of the entire EV fleet's batteries will be available to provide flexibility at any time through V2G. By mid-century, V2G systems in the UK will provide 25% of the total throughput from battery storage, equivalent to 6 TWh/yr.

The significant uptake in energy storage deployments within the power system is driven by the increasing share of VRES, and overall electrification of the energy system. With these changes to the electricity system, storage is needed for ensuring grid stability as large thermal generators are removed, and for balancing supply and demand throughout the day. Li-ion batteries dominate current UK storage projects (95%). Costs for Li-ion batteries have long been declining, but supply-chain shortages, amplified during and after the pandemic, have seen battery costs increase in 2022 and some volatility remained in 2023. Nevertheless, we are optimistic about the cost trajectory, anticipating costs for utility-scale Li-ion battery systems to dip below USD 200/kWh by 2030, further reducing to approximately USD 130/kWh by 2050.

At present, the charge/discharge duration of the UK battery-storage fleet is a little over one hour. As storage capacity increases, the trend is for business models to shift from frequency-response management as a primary application, where one-hour duration or less is appropriate, to price arbitrage and energy capacity provision. With this shift, and as the costs of batteries continues to fall, the duration of battery-storage facilities is expected to increase gradually, up to a fleet average of 3.4 hours in 2050. As this trend for longer-duration batteries continues, alternative chemistries and technologies with 8–24 hours storage will have increasing value: for example, flow batteries, compressed air, liquid air, liquid CO_2, or gravity-based storage technologies. These alternative, long-duration storage solutions look set to enter the market at scale in the second half of the 2030s.

In addition to storage to provide the flexibility to address day-to-day supply variabilities, there is the issue of storage to address longer duration seasonal variations. Some of the challenges around this type of storage for a net-zero future are discussed overleaf.

Creyke Beck gas power plant and 49.99 MW battery storage facility. Cottingham, UK

Reflections on long duration storage

Designing energy storage
Energy storage is vital for energy security; it is needed to deliver energy during times of peak demand and periods of low energy production.
To be effective, storage needs to be designed and operated based on three key parameters: capacity and operation; efficiency and emissions; and reliability. These parameters need to be optimized to supply peak demand (hourly, daily, weekly), seasonal demand, and periods of low-energy production from variable renewables and non-weather dependent energy sources (fossil fuels with CCS, nuclear power, etc.). For peak demand, there needs to be agreement on whether these are defined as 1-in-20 year or 1-in-50 year events as this will significantly affect the key parameters.

Energy storage capacity and operation describe the quantity of energy stored and how the system responds to periods of significant withdrawal.
The most important measures are:

- Maximum quantity of stored energy
- Maximum energy withdrawal rate
- Duration of maximum withdrawal rate
- Start-up response time
- Geographic coverage

A comparison of the energy withdrawal rate against capacity for a range of different energy storage systems is shown to the right.

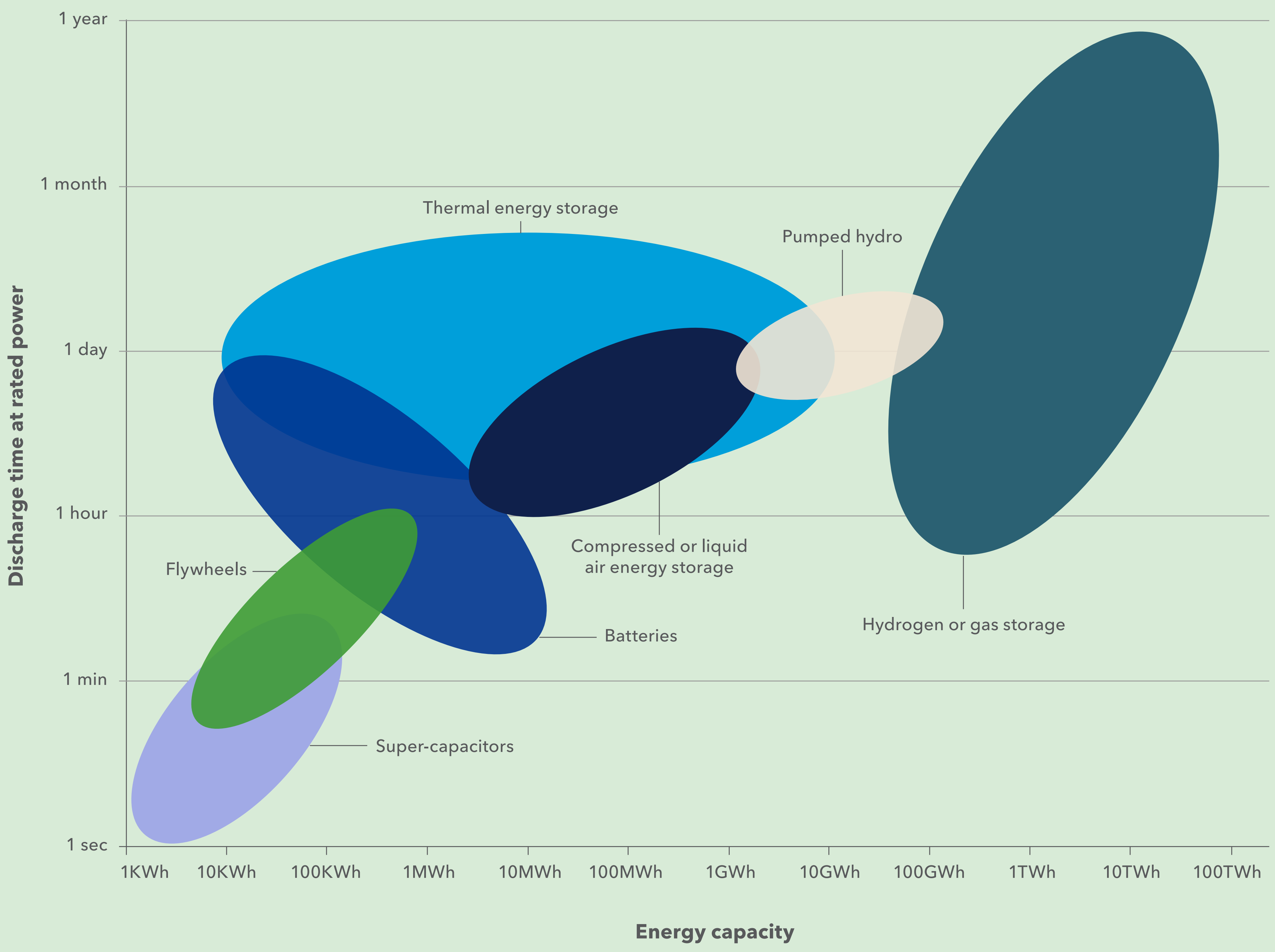
Energy storage efficiency and emissions need to be optimized to ensure that the energy storage system is cost-effective and efficient. Important considerations include:

- Cost of storage assets, including low-load factor dispatchable plant and the economics of industrial demand response mechanisms
- Energy losses through a cycle of injection and withdrawal from storage
- Energy density of storage and land requirements
- Emissions from energy production and/or use of stored energy

Energy storage reliability is a measure of the confidence that energy can be withdrawn from storage when it is needed. Typical factors that need to be considered are:

- Whether the energy is from domestic sources or imported; if the latter, is there a dependence on infrastructure such as interconnectors, import terminals and geo-political events?
- Sensitivity of the storage system to regional long-duration weather patterns (events that impact on the whole of northern Europe such as low wind generation) ▸▸

Comparison of the energy withdrawal rate against capacity for a range of different energy storage systems



- Sensitivity of the energy storage system to the failure of the largest storage asset
- Time required to replenish storage stocks in preparation for the next intra-seasonal peak
- Degree of reliance on the largest energy source (single points of failure)

How the gas networks handle peak demand

The security of supply from the UK gas networks is 99.999% – they are designed to supply gas during low probability events that result in exceptionally high peak demands. These rare but plausible peak demands usually result from extreme cold weather conditions. The demand for the 1-in-50 demand day is about 11% greater than the average peak demand day. It is therefore important to understand the types and duration of extreme weather events that could occur in the future when we are primarily dependent on variable renewable energy for both electricity and hydrogen supplies.

Low renewable power events in the UK

Periods of low energy generation are associated with periods of low or high wind speeds where offshore wind turbines do not operate. Low wind speed events cut-in at wind speeds below 4 metres per second (m/s) and high wind speed events have a cut-out limit of 25 m/s. Researchers at the University of Oxford report that in the UK low wind speeds are responsible for most low generation events. Across the UK's offshore wind farm locations, low wind speed events occurred on average 7% of the time in the 18-year period between 2000 and 2017 as compared to the incidence of high-speed events of 0.3%. Low wind speed events were therefore responsible for 96% of all low generation events. Persistent low energy production for periods longer than a week were observed over the 18-year study period and there was relatively high correlation in wind production between closely neighbouring countries; this means, for example, that there may be limited opportunities to rely on electricity import/export between the UK and Ireland during extended periods of low wind generation.

Geological hydrogen storage development

Due to the credible likelihood of low renewable power events in the UK, large-scale storage of energy will be necessary to deliver the energy transition. Geological storage options are at the terawatt (TW) scale and are relatively low cost and low energy to operate – in the case of salt caverns, they are also well-understood existing technology. There are two options:

- Salt caverns, which are voids generated by slowly dissolving salt deposits using water
- Repurposing existing porous rock hydrocarbon fields or virgin saline aquifer units

Salt caverns offer the most technologically ready, large-scale geological storage option for low-carbon hydrogen and this is the technology of choice for many refinery operators. These sites have demonstrated that industrial grade hydrogen can be stored safely, respond quickly to meet within-day demand fluctuations, and provide long-term storage. The limitations for salt caverns within the UK, however, are the location of suitable salt deposits in relation to producers and end-users; the time taken to develop at scale; the potential size of the caverns that could be developed; and the brine disposal requirements.

Depleted hydrocarbon fields could offer much larger storage volumes than salt caverns – for example, the Rough field in the North Sea could store up to 9 TWh of natural gas. However, it is not possible to generalize about the suitability of depleted hydrocarbon fields because the geology of each site is unique and risks need to be considered on a case-by-case basis. The main consideration will be the potential need for large volumes of cushion hydrogen, purification of produced hydrogen, possible microbial activity, and the impacts of these on cost. Due to the scale and complexity of depleted fields, the response times would be limited, with the fields unable to quickly provide hydrogen to meet a rise in demand (unlike salt caverns, which can respond quickly). These types of assets would therefore be more suited to seasonal demands for hydrogen or for security of supply in high-demand periods. ■

4.4 Gas grids

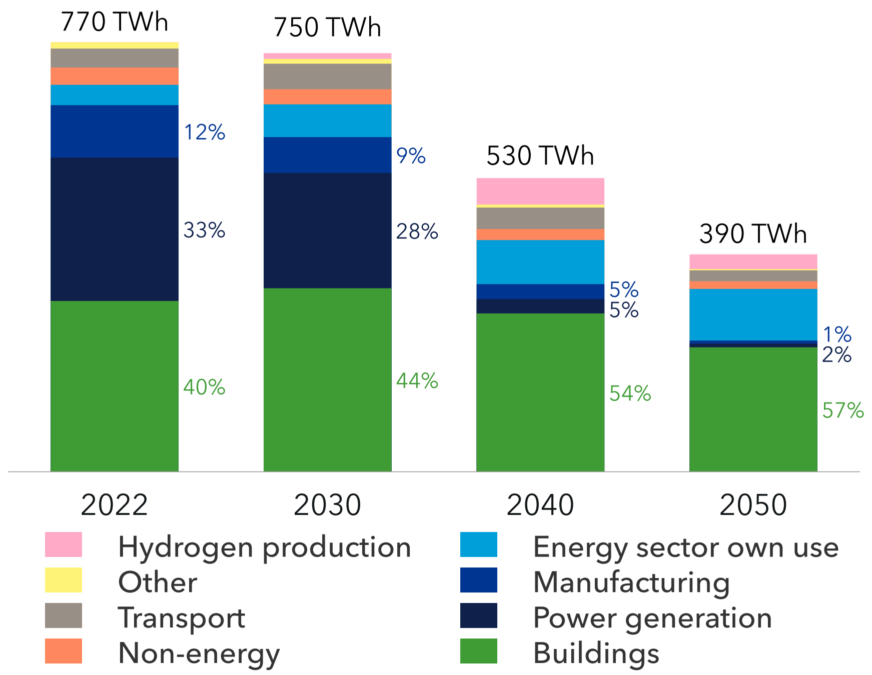
The gas networks in the UK today deliver close to 800 TWh/yr of natural gas to consumers. Figure 4.8 shows that the overall gas supplied via these networks will reduce from 770 TWh/yr now to 390 TWh/yr in 2050, mainly because of the electrification of the UK energy system.

Today, nearly half the gas is used in buildings for space/water heating and cooking and nearly a third is consumed by power stations. The buildings demand will reduce in absolute terms from 300 TWh in 2022 to 220 TWh in 2050 mainly because of increased use of heat pumps for heating and improved insulation in homes. This still accounts for nearly 60% of total gas use in 2050. With the increased use of renewables for power generation, natural gas use for power generation reduces significantly and by 2050, only a fraction of gas-fired units will use natural gas as fuel.

FIGURE 4.8

UK gas consumption

Units: TWh/yr



Decarbonization of the natural gas still used in 2050 is achieved in the power generation and manufacturing sectors through use of CCS facilities, ensuring that the majority of these emissions are captured in 2050.

However, it will not be possible to capture any emissions associated with natural gas end use in buildings. Hence, this will be one of the key ontributors to the remaining CO_2 emissions in 2050. Our forecast shows that only a very small amount of hydrogen will be blended into the gas supply used in the buildings sector to reduce emissions.

One of the potential pathways to decarbonise the domestic heating at scale and at speed is to convert the existing natural gas network infrastructure to hydrogen. However, before this can be considered, several key decisions need to be made around feasibility, safety and economic viability of this option.

To transform the network to hydrogen, and recognize the needs of the various consumers, it is important to understand the roles of the transmission and distribution systems, as their hydrogen pathways and timescales will be slightly different.

The National Transmission System (NTS) is the infrastructure that transports natural gas away from the import terminals (such as St Fergus, Bacton, Grain LNG, South Hook, Easington, and Dragon LNG) to industry, power generators, and domestic consumers. The most efficient way to move gas to consumers is at high pressure and in large diameter pipelines, using compressors at strategic locations to maintain the flows. The NTS currently transports over 97% of the natural gas that flows through the gas distribution networks, the remaining 3% of gas is biomethane which is injected directly into the distribution networks.

The Gas Distribution Networks (GDNs) provide the infrastructure that moves high-pressure gas from the NTS and delivers it to customers. Since 2002, the Iron Mains Risk Reduction Programme (IMRRP) has been delivering the modernization of the Great Britain gas distribution network. GDNs have already replaced 60,000 km of iron pipelines with polyethylene, which is fully capable of safely carrying hydrogen. There are 4 GDNs in Great Britain:

- SGN supplies all of Scotland and South East and South England;
- Northern Gas Networks supplies Northern and North East England;
- Cadent supplies East Anglia, East Midlands, West Midlands, North London and North West England;
- Wales & West Utilities supplies Wales South, Wales North and South West England.

The gas transmission and distribution networks have all been involved in extensive research programmes to evaluate the suitability of their networks for hydrogen usage. Research programmes have covered hydrogen blending and 100% hydrogen in transmission and distribution pipework. All these programmes will provide evidence to inform a government decision on heat policy in 2026, which will include the use of hydrogen in domestic heating.

Although significant progress is being made in hydrogen research, many elements of the end-to-end hydrogen value chain (e.g. hydrogen production and storage) are not currently the responsibility of the regulated gas networks but are critical to its achievement. This must be secured in a nationally co-ordinated manner. During the period to 2026, it will be essential for policy decisions and investments to be made to enable dedicated hydrogen production and storage facilities to be available in the 2026–2030 time frame, and for a clear domestic heat policy to be determined. Some of the key issues around re-purposing the network are discussed in the fact box overleaf.

Utilization of the current natural gas infrastructure will nearly halve by 2050 based on our forecast.

Pipeline repurposing for hydrogen

The implementation of the UK hydrogen economy will need the development of hydrogen transport infrastructure to link producers with users, facilitate imports and exports, and allow system flexibility and demand management. This role is currently filled by the existing pipeline networks for the distribution and transmission of natural gas. Although it is possible to construct new dedicated hydrogen pipeline networks, the most economically advantageous method of establishing the hydrogen transportation capability is the repurposing of the existing natural gas pipeline transmission and distribution networks. The repurposing is likely to begin with transporting blends of hydrogen and natural gas, leading eventually to transportation of 100% hydrogen once sufficient production is available.

Distribution networks

A strategic policy decision was made in December 2023 that the UK Government would support hydrogen blending into the Great Britain (GB, i.e. England, Wales, and Scotland) gas distribution pipeline networks. This decision is still subject to review of safety evidence and finalization of an economic assessment. It was informed by a consultation to assess whether blending could support the early development of the hydrogen economy. A key consideration is whether to amend the Gas Safety (Management) Regulations 1996 (GS(M)R) which currently limit the hydrogen content in natural gas to ≤0.1%. The earliest date expected for commercial scale blending would be 2025–26. Whether this will be extended in the future to 100% hydrogen use will depend on the policy decision on 'hydrogen for heat' in 2026 based on the evidence gained in the 100% hydrogen trials in Fife (Scotland) and Europe.

The GB gas distribution networks are undertaking studies and trials investigating the potential for blending hydrogen into the current pipeline networks. The studies are gathering evidence to demonstrate that the pipeline networks can safely be used for 20% hydrogen blends. The main distribution study is HyDeploy, which has already performed two trials of 20% hydrogen blends, one in a private network at Keele University in the English Midlands and the other in a public network in Winlaton, North East England. The current phase of HyDeploy is assessing the integrity and functionality implications of blending 20% hydrogen into all the distribution network pressure tiers up to local transmission system (LTS) pressure of 70 barg. This evidence will be provided to the government to support a decision to amend the GS(M)R.

High pressure networks – the National Transmission System

The development of transport capability for blended and 100% hydrogen in the high-pressure National Transmission System (NTS) will be mainly driven by the expected outlook for hydrogen production and use within the industrial clusters and will thus be independent of the hydrogen-for-heat decision.

The feasibility and blending into the NTS is being studied by National Gas's FutureGrid programme, which has constructed a large-scale trial facility from existing pipe and equipment for testing blends and ultimately 100% hydrogen. The National Gas HyNTS programme also includes an extensive suite of laboratory testing to determine the behaviour of materials and studies to examine the impact of hydrogen on other pipeline operations such as corrosion protection, inspection, and repair. National Gas's Project Union initiative plans to repurpose existing gas transmission assets to create a 100% hydrogen transmission network by the early 2030s. The project awarded pre-FEED (front-end engineering and design) contracts for the initial pipeline conversion studies in 2023.

Technical challenges of repurposing

The studies will need to resolve several technical challenges before large-scale pipeline repurposing is implemented. The first challenge is that the age of the GB networks means that the detailed data required to evaluate the feasibility of repurposing individual pipelines can be difficult to source for both the pipe/welds and network equipment. The

networks are using advanced data management techniques such as data mining to address this issue. A key challenge when repurposing the higher-pressure tier pipelines is the accelerated fatigue due to pressure cycling in hydrogen compared to natural gas. This can limit the opportunity for using line pack for gas storage in a hydrogen system and, as the UK has limited gas storage, will need to be addressed at a system level. An additional challenge for the high-pressure networks is the compatibility of the current compressor fleet with hydrogen blends and 100% hydrogen. Although the compressor vendors are expanding the hydrogen compatibility envelope of new and current designs, it is probable that some compressor replacement or modification will be required for operation of a hydrogen network. ■

5 INDUSTRIAL CLUSTERS – CCS AND HYDROGEN

The industrial clusters will drive forward the carbon capture and storage (CCS) and hydrogen markets in the UK, unlocking investment, securing jobs and decarbonizing hard to electrify sectors. We forecast, however, that especially for low carbon hydrogen production development, the pace of implementation is not keeping up with ambition, and more needs to be done to ensure the UK leads the way in the face of global competition.

5.1 Carbon capture and storage

UK market context

CCS is a key element of UK strategy to transition to net zero by 2050. The UK's ambition is to capture and store 20–30 $MtCO_2$ per year by 2030, including 6 Mt/yr of industrial CO_2 emissions, increasing to 9 Mt/yr by 2035. There is an ambition for at least 5 $MtCO_2$ per annum of engineered GHG removals (GGRs) by 2030. To support these ambitions, the UK has committed to deploy carbon capture, utilization and storage (CCUS) in two industrial clusters by the mid-2020s, and a further two by 2030.

In October 2021, the UK selected the HyNet cluster in North West England and North Wales, and the East Coast Cluster in Teesside and Humber as 'Track 1' clusters, those suited to deployment in the mid-2020s. Heads of terms have been agreed for ENI's HyNet CO_2 Transport and Storage network, with the East Coast Cluster's heads of terms agreed in December 2023. Final investment decisions (FIDs) on these Transport and Storage projects are expected in the second half of 2024. In July 2023, the UK selected the Viking CCS in the south Humber region and Project Acorn in Scotland as 'Track 2' clusters, those suited to deployment by 2030.

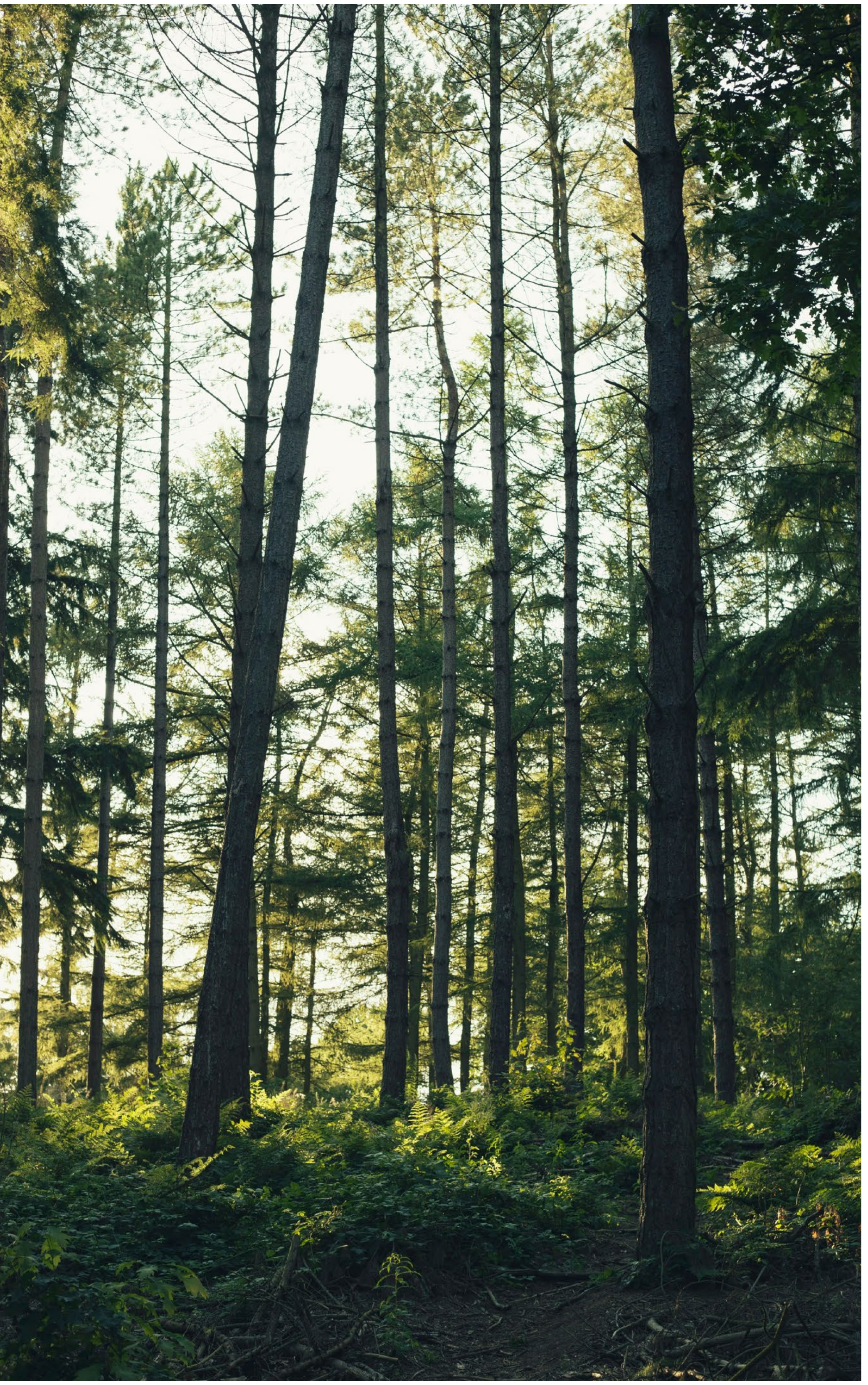
The major industrial clusters and their emissions from large point sources are shown in Figure 5.1.

The industrial cluster criteria were updated for 'Track 2' clusters to include a requirement for import of CO_2 into the clusters by ship. The favourable geology of the UK means there is a significant CO_2 storage potential compared to other countries in Europe. There are an estimated 78 billion tonnes of theoretical CO_2 storage in the UK Continental Shelf (Bentham, 2014) across the different storage options (depleted oil and gas fields or aquifers),

FIGURE 5.1

Major UK industrial cluster annual emissions accounted for in the UK Emissions Trading Scheme.

Source: NAEI 2019 data

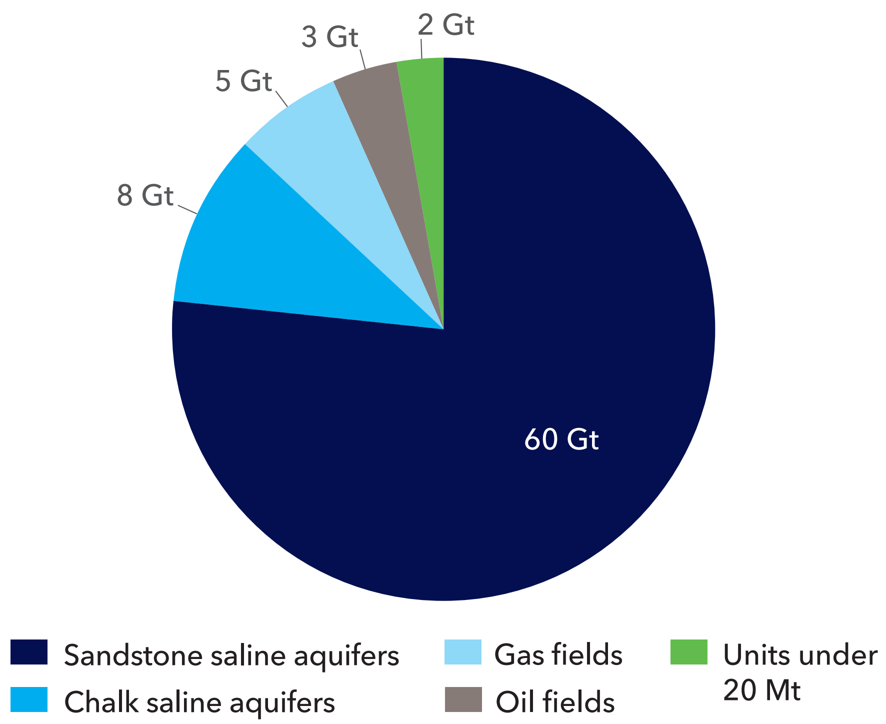


see Figure 5.2. If a lucrative carbon market appears, along with legislative obstacles being resolved and bilateral agreements being in place, the UK could become a net importer of CO_2 from the EU.

The 'Track 1' and 'Track 2' clusters were selected based on their ability to deploy CO_2 transport and storage networks in line with the government's timelines for its CO_2 and hydrogen ambitions. Hence, the development of CO_2 storage sites (saline aquifers or depleted oil and gas fields) is a critical aspect of all the selected industrial clusters. Recently the North Sea Transition Authority (NSTA) announced the award of 21 carbon storage licences, with successful applicants coming from 12 different companies,

FIGURE 5.2

UK CO_2 storage capacity by store type



taking the total to 27 storage licences. The award of additional licences is a positive step towards the UK ensuring that it has sufficient storage capacity and injection rates to account for an increasing capture project pipeline. However, the Carbon Capture and Storage Association (CCSA), having surveyed its membership, suggested that further development of almost half these storage sites is unlikely without clarity on future support and funding (CCSA, 2023).

The UK government announced in 2023 that it would provide a total GBP20 Bn support for CCS projects in the operational phase. As part of Phase 2 of Track 1 cluster sequencing, the UK Government shortlisted eight projects in March 2023 for negotiations on OPEX support. These included power CCUS, industrial carbon capture (ICC), waste-to-energy and CCUS-enabled hydrogen projects, and they have proceeded to the due diligence stage for funding support. This shortlist does not imply availability of funding for any or all the projects but is purely the outcome of the government's assessment against the Track 1 Phase 2 criteria. The timing for a decision on funding for the selected projects is not yet clear, but FIDs for these projects are unlikely to be taken until Q3 2024 at the earliest; hence, project start-ups before 2027 would appear unlikely.

An application process for Track 1 expansion projects for the HyNet cluster (those capture projects seeking to fill additional storage capacity and network capacity) was launched in December 2023 with due diligence and negotiations expected for Q3 2024. Applications for Track 1 expansion projects for the East Coast Cluster are expected in 2024. These projects are expected to be operational by end of December 2030 at the latest. In addition, in 2024 the Track 2 clusters (Acorn and Viking) are to define and submit plans for their initial projects targeting deployment from 2028–29. The Track 1 project expansion and Track 2 processes could select projects that can contribute towards the UK Government's policy ambition of delivering at least 5 $MtCO_2$/yr of engineered removals by 2030, potentially needing to rise to approximately 50 $MtCO_2$/yr by 2035.

New business models associated with Power Bioenergy with Carbon Capture and Storage (Power BECCS) and Greenhouse Gas Removals (GGRs) were issued in December 2023 and are expected to be approved by Parliament in 2024. Clear and defined business models are needed for GGR and Power BECCS to incentivize uptake of the technologies and development of the projects. GGRs can play an important role in offsetting CO_2 emissions, particularly in hard-to-abate areas such as aviation and manufacturing. The Net Zero Strategy, the UK Climate Change Committee, the IEA and the IPCC all agree that we need engineered GGRs if we are to meet the ambition of limiting average global warming to below 1.5°C

The overall vision of the UK Government is that CCUS will go through three phases: first, achieving the ambition of capturing 20–30 $MtCO_2$/yr by 2030; second, a transition involving the emergence of a competitive commercial market; third, a self-sustaining CCUS market becoming a reality.

Our CCS forecast

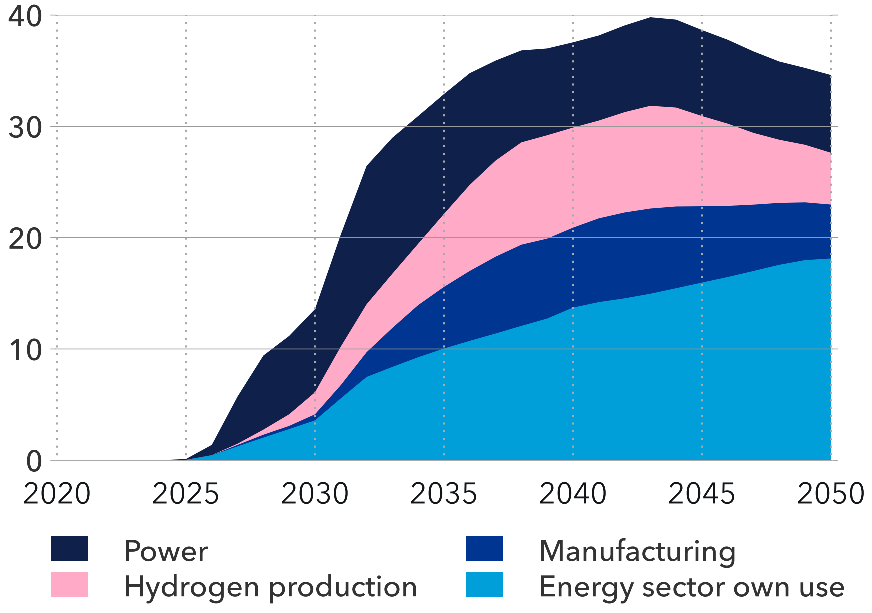
Our forecast indicates that UK carbon capture rates will reach 14 $MtCO_2$/yr by 2030, in line with our assessment of the current selected track 1 projects, but short of the UK target of 20-30 Mt by that year. However, beyond 2030 we see a steep increase in capture rates reaching 33 MtCO2/yr by 2035 and peaking at 40 $MtCO_2$/yr in the mid 2040s.

Initially the majority of carbon capture will be associated with power generation and manufacturing, focusing on the current large emitters. However, as production of hydrogen and its derivatives ramps up, this segment will be the key driver for carbon capture needs (60% of total by 2050).

FIGURE 5.3

UK CO_2 emissions captured

Units: $MtCO_2$/yr



The availability of sufficient transportation, injection and storage capacity is critical to meet these values, but in our view that should not be a major constraint in that time frame, considering the large potential for CO_2 storage in UKCS and the existing offshore infrastructure available for re-use.

Based on our latest estimates, carbon prices for Europe (including UK) will increase significantly between today (75 USD/t) and 2050 (250 USD/t). Current estimates indicate the carbon price will reach 150 USD/t in 2030 and 200 USD/t in 2035. This would mean that the cost of emitting CO_2 would start to exceed the cost of capturing CO_2 for most applications in the 2030–35 period, incentivizing installation of CCS for industrial use, power generation, and H_2 production without the need for government support.

Confidence in the longer-term (post-2030) outlook for CCS in the UK has risen due to the announcements of the selected Track 1 projects and Track 2 clusters, in addition to the opening of the applications for the Track 1 project expansion process for the HyNet cluster. However, key reasons for missing the 2030 targets are the current lack of clarity around the Power BECCS and GGR business models; slow er-than-expected development of the Track 1 clusters (and associated projects), as these have yet to take FID; and the expectation that only in the early 2030s will carbon prices start to approach the cost of CCS, so that uptake accelerates and deployment at scale begins. Finalizing and approval by Parliament of the Power BECCS and GGR business

models, and the initial clusters and projects passing through FID, are all essential to provide industry and investors with clarity on economic models of financial support and the confidence that an initial wave of projects will be developed that can unlock the pipeline of CCS projects and the flow of capital into the market.

5.2 Hydrogen

Hydrogen UK market context
The UK Government, through the British Energy Security Strategy, has an ambition for 10 GW of low-carbon hydrogen production capacity to be in place by 2030, with at least half of this coming from electrolytic hydrogen.

The market and value chains for hydrogen as an energy carrier are in their infancy, even though the potential has been debated for decades. Hydrogen markets today are mainly captive, with production taking place at or close to key industrial consumers.

The development of blue hydrogen will be a key enabler of the increase in the production of low-carbon hydrogen. The business models for blue (CCS-enabled hydrogen) will ensure that there are incentives for it to replace current grey hydrogen production for use in refineries, fertilizer production, and petrochemicals, where the CO_2 transport and storage network is available locally. Presently, the larger-scale hydrogen production projects in the UK are implementing blue or CCS-enabled H_2 technology, either newbuild or by retrofitting CCS to existing grey hydrogen production. New CCS-enabled hydrogen production at the industrial clusters will develop further to meet growing demand in the hard-to-electrify sectors. There are three CCS-enabled hydrogen production projects within the Track 1 project list with a total combined predicted H_2 production of 1.6 GW/yr by the beginning of 2028.

The first electrolytic (green) hydrogen allocation round (HAR1) provides both Net Zero Hydrogen Fund CAPEX support and Hydrogen Production Business Model revenue for support when operational. 17 projects have been invited to negotiations, of which 11 with a combined capacity of 125 MW were selected in December 2023 and are expected to be operational from 2025. The 11 have agreed a weighted average strike price of 241 GBP/MWh (9.49 GBP/kgH_2). A second electrolytic hydrogen allocation round (HAR2) was announced in December 2023 with projects agreeing an offer from the UK Government either in late 2024 or early 2025 and being operational between Q2 2026 and Q1 2029. HAR2 is expected to support significantly greater H_2 production capacity (up to 875 MW) compared to HAR1.

In Q3 2024, the UK Government intends to open up an application for allocating Hydrogen Transport and Storage Business Models, with successful projects to be announced in Q4 2025. Initial criteria were published in December 2023, with an operational date between 2028 and 2032 for the hydrogen transport network interfaced with one large-scale hydrogen storage facility. The predicted locations for the first phases of the transport and storage networks will be aligned to the CCS industrial clusters due to availability of large-scale low-carbon hydrogen production, future demand for hydrogen from industry, and the geological suitability of salt caverns for hydrogen storage.

In December 2023, the UK Government set its strategic policy decision to support the blending of up to 20% hydrogen by volume into the GB gas distribution networks, subject to future safety assessment impacts on the feasibility and economic cases. There remains uncertainty on the outcome of an overall decision on both blending and 100% hydrogen in the gas networks; but if the decision is positive, the UK Government predicts H_2 demand of up to 60 TWh by 2035 for heating buildings (DESNZ, 2023b).

In the UK, we can expect to see hydrogen supply growing outwards from industrial clusters in the next decade. There are little to no open commodity markets for hydrogen, except for hydrogen deriva-tives such as ammonia and methanol.

Hydrogen type and use

Many different hydrogen value chains will develop towards 2050. Hydrogen can be produced using several different methods with varying efficiencies and environmental impacts, and is typically classified under the names of colours, depending on the method and feedstock used.

A summary of the broad 'colours' of hydrogen, including feedstock and production technology is given in Table 5.1

UK industry has used large quantities of hydrogen for well over 100 years, as a chemical feedstock, in fertilizer production, and in refineries. Industry is familiar with its properties, and has developed the capability to produce, transport, and store hydrogen at scale. Nevertheless, the present use of hydrogen as an energy carrier in the UK is low, and it is in this expanded application where it faces several deployment challenges.

Hydrogen is a versatile energy vector. It can be produced from coal, natural gas, grid electricity, or dedicated renewables. It can be stored, transported, and used in its pure form, blended with natural gas, or converted to derivatives. In addition, it will be consumed across a range of industries and applications including maritime shipping, heat production, domestic heat, road transport, and aviation.

Hydrogen's properties give it great potential in the energy transition, but there are challenges to overcome for its widespread rollout. One key challenge is often the energy required to implement a hydrogen solution. The separation or extraction process for hydrogen production requires energy, and the energy content of the output hydrogen is always less than that of the input fuel plus the energy required for the hydrogen process. In other words, producing and converting hydrogen can involve large energy losses. Hydrogen production from steam reformation typically has a 75% efficiency (Higher Heating Value), whilst electrolysis today has an efficiency of around 80% (Higher Heating Value). Both production technologies claim that efficiency improvements are possible with scale-up. The value of hydrogen in pure form to users or to society at large must therefore be sufficient to justify the energy losses in its production, distribution, and use.

Aviation and shipping stand out in the ETO model as the two sectors that will make significant use of low-carbon, hydrogen-derived fuels (ammonia, methanol, and e-kerosene). What they have in common is that they are disconnected from the grid and require large amounts of energy, meaning electrification or pure hydrogen are not feasible alternatives to the fossil-based precursors that producing these fuels currently rely on. The energy densities of both pure hydrogen and batteries are also too low to be used widely in these industries. Where these sectors differ from each another is the weight and space available for fuel storage, with weight particularly critical in aviation.

- **Aviation** – Hydrogen-based synthetic fuels such as synthetic kerosene are likely to be used in long-haul aviation. We expect pure hydrogen to see some use for short and medium-haul flights, but do not forecast significant uptake before the 2040s.
- **Shipping** – There is no relevant battery-electric option for decarbonizing deep-sea shipping, with synthetic fuels, ammonia, hydrogen and biofuels being the most realistic low-carbon alternatives. These high-cost fuels, which can be implemented in hybrid configurations with diesel and gas-fuelled propulsion, will see significant uptake in the 2030s.

We currently predict a very low uptake of hydrogen in the road transportation subsector and its use of hydrogen to decarbonize heavy vehicles such as large trucks. The heavy vehicles market segment is also disconnected from the grid and does require large amounts of energy, so would be a candidate for increasing demand of pure hydrogen. However, the application of EVs to decarbonize this segment is predicted to dominate due to its lower costs. ■

TABLE 5.1
Selected hydrogen 'colours' by feedstock and production technology

	Colour name	Feedstock	Production technology
Produced using electricity	Green	Renewable electricity and water	Electrolysis
Produced using fossil fuels	Grey	Natural Gas	Methane reforming
	Blue	Natural Gas	Methane reforming with carbon capture and storage (CCS)
	Turquoise	Natural Gas	Pyrolysis

Hydrogen forecast results

As shown in figure 5.4 we forecast hydrogen production to reach 1 Mtonnes/yr in 2030, of which only 60% will be low carbon. This forecast is in line with the current expectations around timelines and capacities for the selected hydrogen projects in the industrial clusters, assuming they will receive further government support to ensure the projects reach Final Investment Decision (FID) in the next few years. Hydrogen production will then grow to 4.6 Mtonnes by 2050, equivalent to 10% of final energy demand in the UK. Of the 4.6 MtH_2 of annual demand in 2050 more than 50% goes into various transport fuels, 22% on electricity generation, 14% into industrial heat, 8% into traditional refining and fertilizer production, with only 2% for domestic heating application as a blend.

We forecast that nearly a quarter of hydrogen demand in 2050 will be for electricity generation, mainly linked to the high penetration of variable renewables in the electricity supply mix. Production of hydrogen will then be driven by availability of excess cheap renewable electricity during periods of high wind and solar generation, providing low-carbon fuel for dispatchable power generation units.

The primary explanation for such a low uptake of hydrogen overall in our current ETO model relates to two issues. One is the lack of certainty over a policy commitment from the government on the use of hydrogen heating in homes, with a decision not expected before 2026. The other issue is the current high cost of hydrogen compared with the incumbent source of home heating, natural gas. As a result, our model currently forecasts that 44% of UK homes will still be burning natural gas with only a small proportion of blended hydrogen in 2050. This is one of the major reasons that the UK fails to meet its net-zero goal. Hence, the outcome of the model should act as a call to action for government to speed up clarification of its position on the application of hydrogen in home heating, and to ensure that it can be deployed in an economical manner that meets the goal of a just transition for domestic consumers.

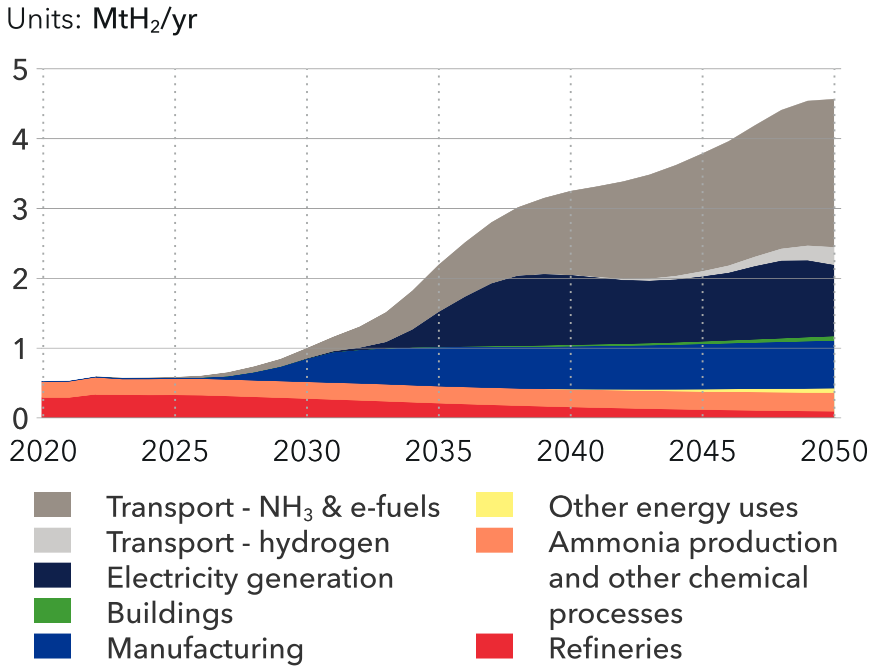
Figure 5.5 shows our current forecast for the split of the various hydrogen production sources in 2050.

Hydrogen in the UK is currently almost exclusively produced from natural gas without CCUS. Production at scale starts to ramp up in the late 2020s, with CCS-enabled (blue) hydrogen production beginning in the industrial clusters where it displaces existing grey hydrogen production initially. Grid-connected electrolysis of hydrogen at scale grows from 2035 onwards, but even by 2050 has yet to displace blue hydrogen as the main production pathway for hydrogen. In 2050, production is dominated by blue hydrogen (50%), followed by grid-connected electrolysis (30%), with dedicated wind producing 17%. The remainder includes a 1% contribution from nuclear-derived electrolysis.

The UK's production input capacity shown in Figure 5.6 follows a similar growth trend as hydrogen production. Each project will have differing technology efficiencies and capacity factors, meaning that a direct comparison between overall hydrogen input capacity and production is challenging. However, our forecast indicates that the UK will not meet its ambition of producing 10 GW of low-carbon hydrogen by 2030. In 2030, only around 5 GW will be produced, rising to around 16 GW in 2035 and 48 GW in 2050. Blue hydrogen is predicted to contribute a significant majority of the input capacity in 2030, with green hydrogen technologies providing less than 1 GW of low-carbon hydrogen capacity.

FIGURE 5.4

UK demand for hydrogen and its derivatives by sector



All non-transport uses are pure hydrogen.

FIGURE 5.5

UK hydrogen production by production route

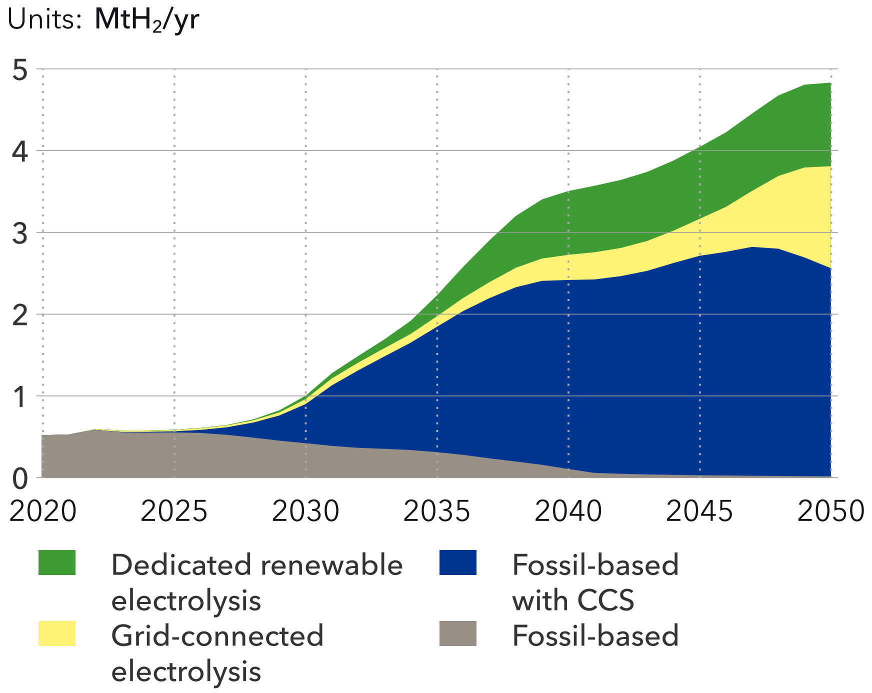
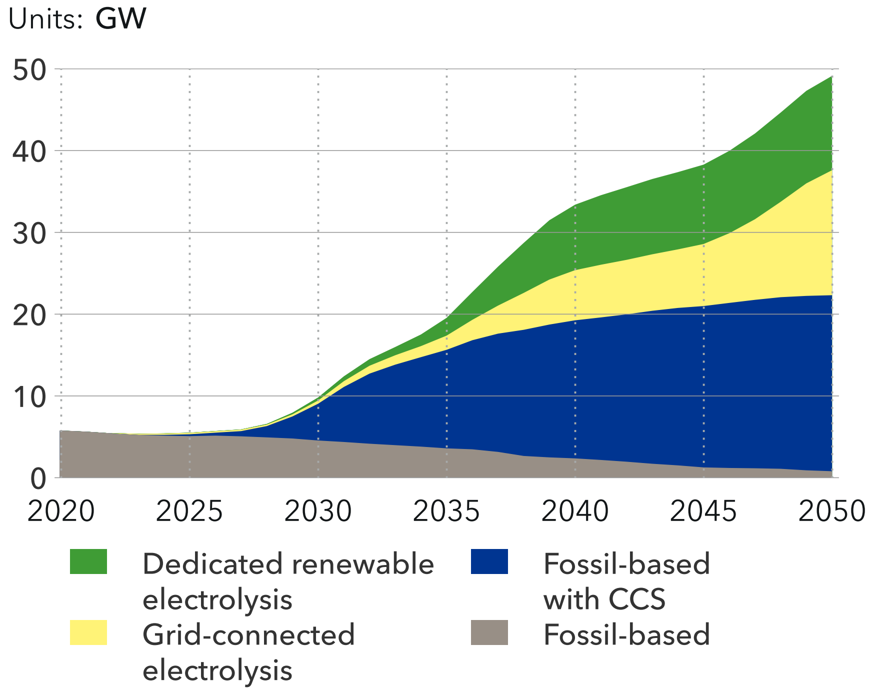


FIGURE 5.6

UK production capacity by production route



Blue hydrogen – building confidence in carbon emission intensity

Blue hydrogen only represents a serious low-greenhouse gas energy route if it can be shown to have low emissions. Confidence in the emissions intensity of blue hydrogen is critical, and getting into the details along the whole hydrogen value chain is important. The emissions need to be identified, measured, and accepted globally, but establishing that confidence is challenging. Key points are:

- There are broad ranges of emission intensities at each stage of the value chain. This is due to the different application of technologies, the length and nature of the methane supply chain, and the route that the methane feedstock takes to the hydrogen production unit.
- The reported data has high levels of uncertainty due to inconsistent and missing reporting of emissions and to a lack of operational experience in hydrogen production and carbon capture technology.
- The methods for calculating operational value chain emissions intensity are relatively straightforward, and once key factors are defined then outputs can be presented transparently and consistently.

Therefore, two things are required to improve the confidence in reporting of blue hydrogen emissions:

1) Much better and consistent reporting of emissions intensities for each part of the value chain. This requires a broad range of sectors to agree on:

   a. A standard for consistent reporting of emissions intensities for the upstream and midstream sectors. This could include a means for accurately quantifying emissions associated with natural gas production and include Scope 3 emissions from contracted services.

   b. Third party verification of the reported figures consistent with the certification already conducted by many companies for their reported greenhouse gas (GHG) emissions.

2) Clear reporting of the methane supply route specific to the hydrogen produced.

   a. Where the methane comes from a range of sources, a consistent means for aggregating the emissions intensities is required so that the relative performance of different blue hydrogen sources can be evaluated. This could be in the form of upper and lower ranges and/or a median figure.

   b. However, to do this will require regular review and update of the supply-chain route and associated emissions. This may be achieved through industry-level databases assuming that the input data is consistently measured and reported.

Incentives for transparent reporting could be driven by:

- **Contractual requirement by blue hydrogen producers.** As a condition of supply, reported data will need to meet the required standard. This may impact the cost of blue hydrogen feedstock and make the output less competitive, a challenge the sector already faces.
- **Governmental regulation.** Regulations around GHG emissions are becoming increasingly tight. As hydrogen demand increases for transportation and heating, planned national infrastructure will create a ready market that will require blue hydrogen sources. Regulators will respond to societal expectations that the hydrogen used has increasingly low GHG emissions associated with it.

The focus could be either on reporting or reducing the emissions associated with the blue hydrogen value chain. DNV sees one as driving the other – better reporting will lead to lower emissions, particularly if the reporting starts to impact the ▸▸

marketability of methane feedstock and attracts increasing carbon taxes. The technology and operational controls needed to reduce value-chain emissions exist; the pressure to apply them and make a return on that investment is what will deliver improved performance.

Thresholds for low, medium and high emissions associated with hydrogen production

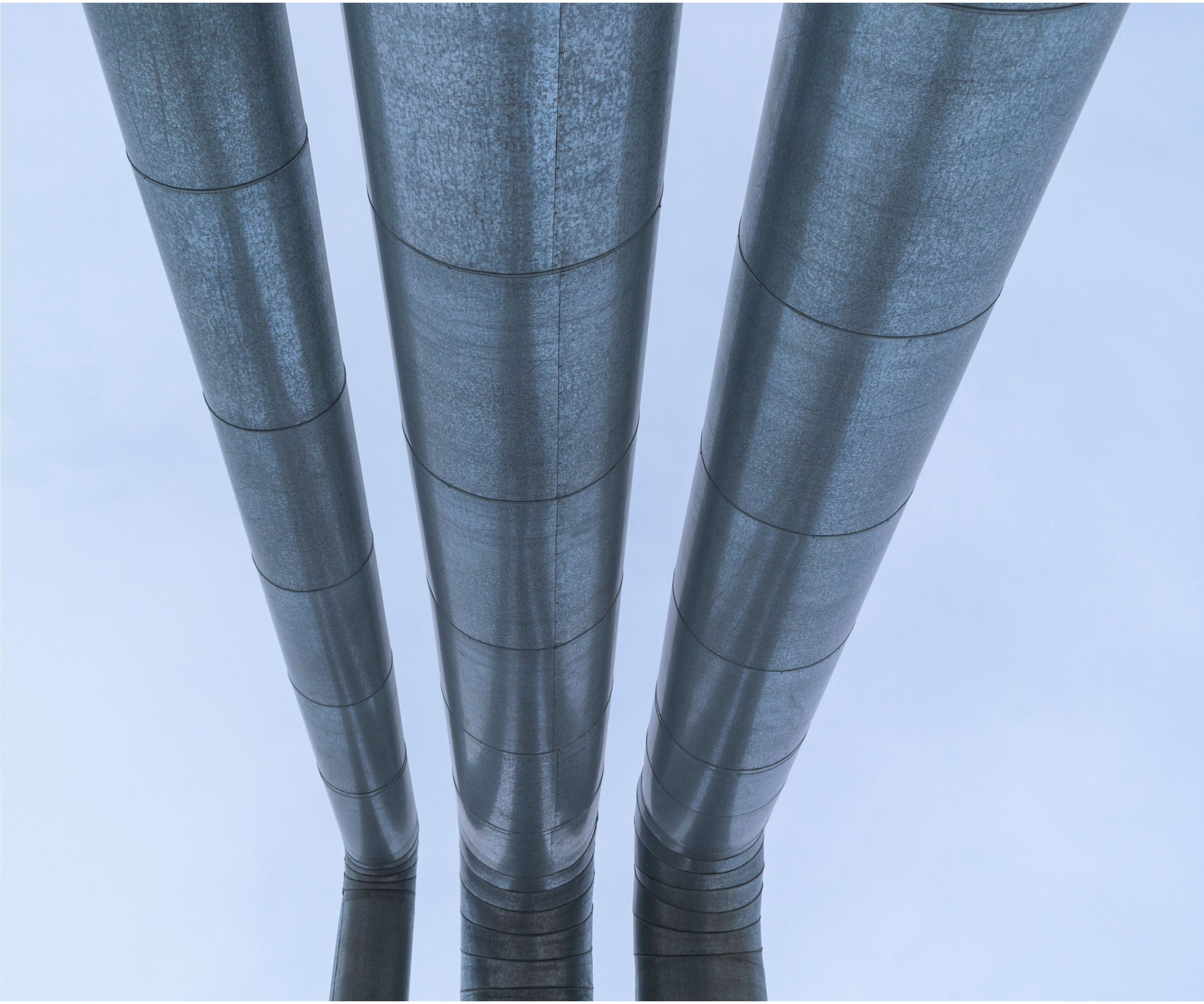
The World Business Council for Sustainable Development (WBCSD) recommends the thresholds shown in the table below (on a full lifecycle basis)

The reduced-carbon hydrogen threshold is only relevant as a stepping-stone to achieving lower-carbon hydrogen for existing higher-intensity production installations. The EU taxonomy sets the greenhouse gas emissions threshold for hydrogen production at 3 tCO_2eq/tH_2 on a lifecycle basis. This corresponds to the low-carbon threshold as defined by WBCSD.

Evaluation of possible emissions along the value chain

Production of blue hydrogen is strongly dependent on emissions throughout the supply chain, including whether the natural gas is transported by pipeline or as liquefied natural gas. Low-carbon and even ultralow-carbon hydrogen production is possible but will require case-by-case assessment. A study by DNV suggested that it is only at the low end of the emissions range – where upstream, midstream and production approaches are all delivering minimum GHG emissions – that the value chain comfortably meets the 50 gCO_2e/MJH_2 criteria for reduced-carbon blue hydrogen. All other tighter emissions thresholds require particular combinations of technologies and supply-chain options to be able to meet the criteria. This indicates that the specific supply-chain arrangements are key to demonstrating whether blue hydrogen production is sufficiently low-carbon. ■

Category	Maximum allowed emissions	Units	Maximum allowed emissions	Units
Reduced-carbon hydrogen	6	$kgCO_2e/kgH_2$	≈ 50	gCO_2e/MJH_2 (net)
Low-carbon hydrogen	3	$kgCO_2e/kgH_2$	≈ 25	gCO_2e/MJH_2 (net)
Ultralow-carbon hydrogen	1	$kgCO_2e/kgH_2$	≈ 8	gCO_2e/MJH_2 (net)



6 ENERGY SUPPLY

We expect UK primary energy consumption to continue falling from about 1,960 TWh/yr in 2022 to 1,600 TWh/yr by 2050. The primary energy mix will undergo dramatic change, with the rapid replacement of fossil fuels by renewable energy sources. We foresee the combined share of renewables and nuclear growing from 20% today to 65% by 2050. The most spectacular transition will be the steep rise in wind power, growing over 7-fold from 70 TWh/yr today to 500 TWh/yr by mid-century. Solar is expected to increase nearly 5-fold from 15 TWh/yr today to 70 TWh/yr by 2050.

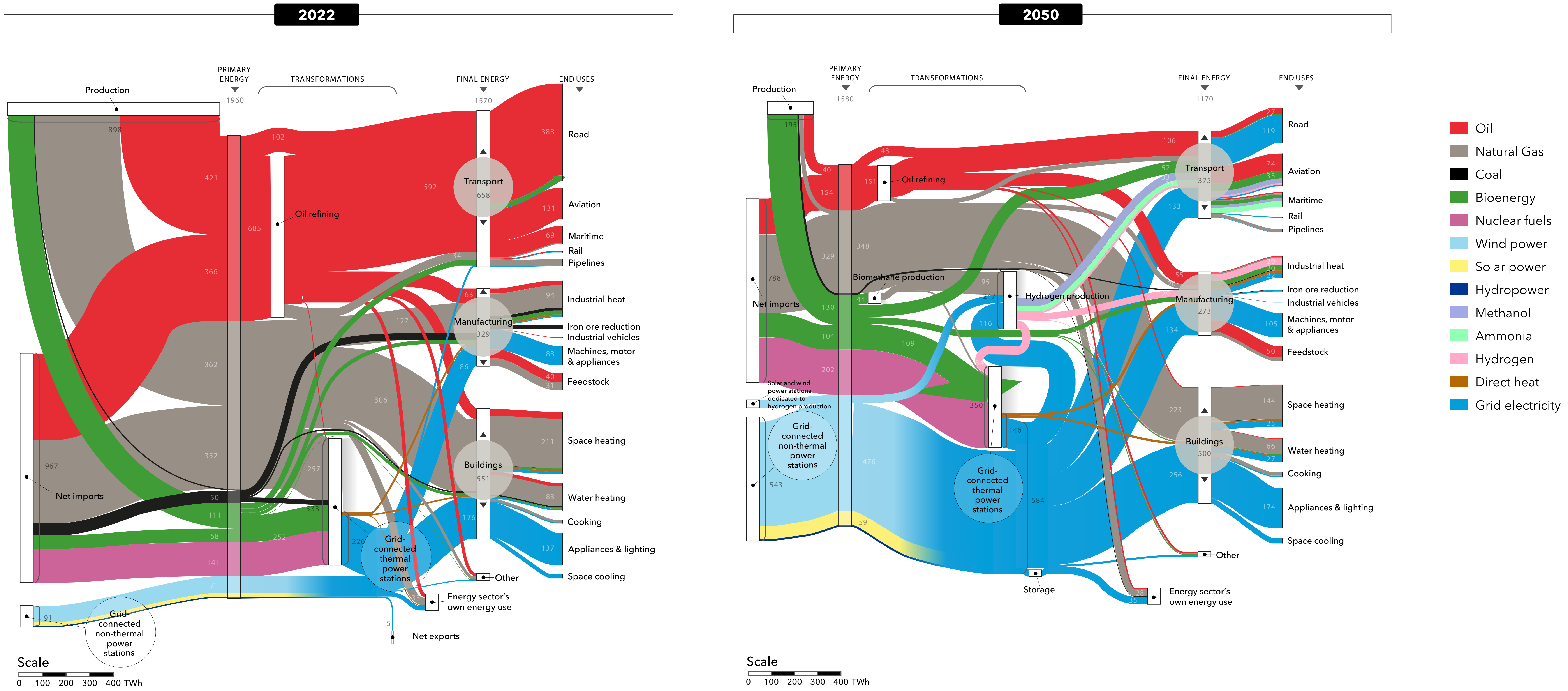
Primary energy consumption refers to the direct use of energy that has not been subjected to any conversion or transformation process. Considerable losses occur in the energy system, mainly when energy is converted from one form to another – such as heat losses in a power plant converting coal to electricity – and during energy transmission. Primary energy consumption is therefore considerably higher than final energy consumption (as reported in Chapter 3). In 2022, for instance, final energy demand in the UK was 1,570 TWh/yr, but primary energy consumption was 25% higher, at around 1,960 TWh. This 25% represents all the losses during the conversion, transmission, and distribution of energy.

Figure 6.1 displays historical and projected UK primary energy consumption, which peaked around 2,800 TWh/yr at the start of this century and has since steadily declined by some 30%. In line with the decline in final energy demand (as outlined in Chapter 3), we expect primary energy consumption to continue falling from around 1,960 TWh/yr in 2022 to 1,600 TWh/yr by 2050.

The UK primary energy mix has thus far been dominated by fossil fuels. The mix has changed since 1990, with the most prominent shift being the almost complete phase-out of coal, which now represents only 3% of primary energy consumption. In this transition, coal has given way mainly to cleaner natural gas, with the share of gas growing from 23% in 1990 to 36% today. Bioenergy has risen sharply, from almost nothing in 1990 to provide about 8.5% of primary energy today. Going forward, the overall primary energy mix will undergo dramatic change, with fossil fuels rapidly being replaced by renewable energy sources. The most spectacular transition will of course be the steep rise in wind power along with a steep decline in oil and gas. The key drivers of the non-linear rise in wind power will be plunging costs and the pressing need for decarbonization and energy security.

Scotland's largest offshore wind farm now fully operational.
Image: © Seagreen Wind Energy Ltd.

COMPARISON OF ENERGY FLOWS: 2022 AND 2050



The combined share of fossil fuels in primary energy is currently about 80%. Of this, the larger share (about 65% of total primary energy) is UK-sourced fossil fuels and the rest (about 15% of total primary energy) consists of imported fossil fuels. The share of fossil fuels will rapidly decline towards a third of total primary energy by mid-century. While overall fossil-fuel consumption is set to decline significantly, reliance on imports as share of total fossil-fuel consumption will increase to about 20% by 2050 (Figure 6.2).

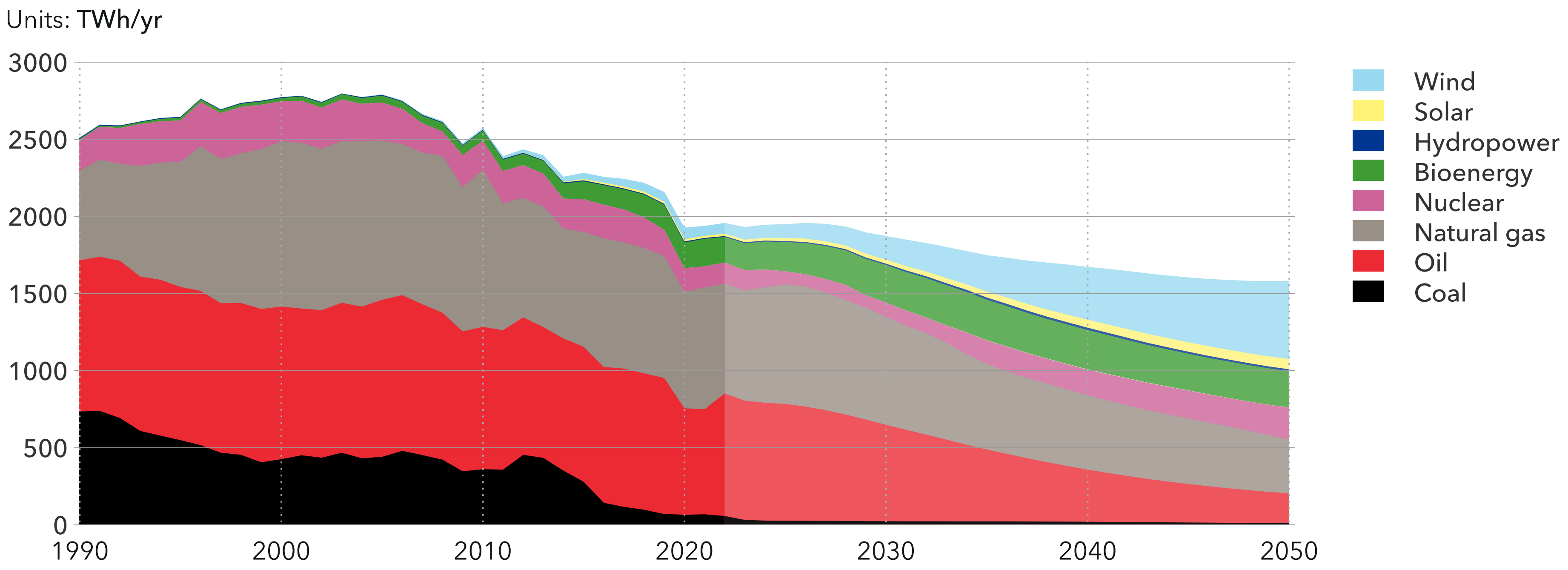
We foresee the combined share of renewables and nuclear grow from 20% today to 65% by 2050. Today, the dominant player among renewables is bioenergy. Going forward, however, wind will take over as the key player in the renewables sector, growing nearly 7-fold from 70 TWh/yr today to 500 TWh/yr by mid-century, covering one third of the primary energy mix by that time. Solar is expected to grow 5-fold from 15 TWh/yr today to 70 TWh/yr by 2050, representing 4% of the primary energy mix in mid-century.

Bioenergy is set to grow 40% from 170 TWh/yr today to over 230 TWh/yr by 2050. Given existing government ambitions and energy security concerns, nuclear is also expected to grow from 140 TWh/yr today to 210 TWh/yr by mid-century, almost doubling its share in the energy mix from 7% to 13%.

Bio-gas storage tanks in a wastewater treatment plant in Billingham, UK.

FIGURE 6.1

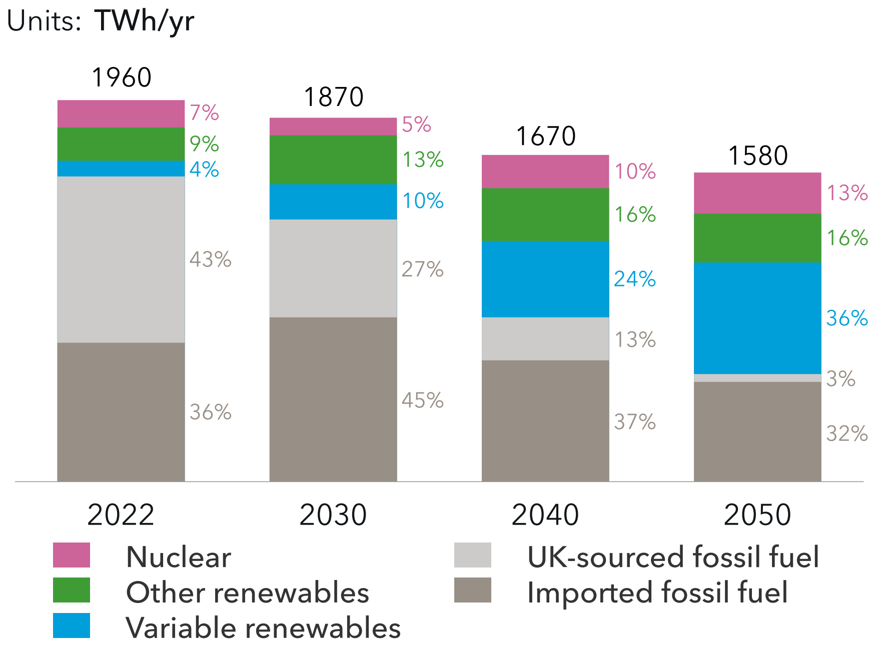
UK primary energy consumption by source



Historical data source: IEA WEB (2023)

FIGURE 6.2

UK primary energy supply by source



Percentages are rounded and might not add up to 100%
Historical data source: IEA WEB (2023)

Today, the dominant player among renewables is bioenergy. Going forward, however, wind will take over as the key player in the renewables sector.

6.1 Non-renewable energy sources

The combined share of fossil fuels in the primary energy mix is set to decline slowly from 80% today to 72% in 2030, after which the transition will accelerate further towards a combined share of 35% by mid-century. In the following sections, we look at each of the three main fossil fuels individually.

The UK Continental Shelf is a mature oil and gas production basin which, at the end of 2022, still had proven reserves of 2.3 billion barrels of oil equivalent (Bboe) of oil and natural gas. In addition, there is a potential 2.4 Bboe (P90 estimate) for 'prospective resources', those yet to be found.

Currently there are many oil and gas projects in concept or front-end engineering design (FEED) stage and working towards Final Investment Decision. Around 30 projects are looking to start up within the next five years, and recoverable reserves for these are estimated to be in the region of 2 Bboe over the life of the fields. Should these all proceed, with typical CAPEX of GBP 100 million to GBP 5 billion per project, then CAPEX spending for upstream oil and gas developments could still reach GBP 18 billion over the next five years.

As well as a continued overall decline in domestic oil and gas production, the industry will be significantly decarbonizing its production methods, primarily through electrification of its power sources, linked particularly to offshore wind. The new licensing round will have emissions reduction from production as a key focus area, both combustion-related emissions and fugitive methane emissions from flaring and venting. Emissions from the sector are expected to continue to drop as a result.

Many existing reservoirs, pipelines, and installations will also be repurposed for use as stores and transport options for CO_2 storage and hydrogen production from offshore wind farms. Decommissioning of several facilities will therefore be placed on hold, and some platforms and pipelines will see life extension programmes to support a new decarbonization role.

Britain's Energy Security Strategy, launched in April 2022 as a reaction to the events in Ukraine and the need to build a more resilient UK energy system, did call for increased oil and gas production. The 33rd offshore licensing round, closed in January 2023, offered some 900 blocks or part-blocks.

As well as a continued overall decline in domestic oil and gas production, the industry will be significantly decarbonizing its production methods, primarily through electrification of its power sources, linked particularly to offshore wind.

Image: © Seajacks.

UK Offshore Oil and Gas – Still a key contributor to UK Energy supply

The UK remains a key producer of oil. The new project pipeline is somewhat stalled as fiscal instability, mainly driven by the EPL (Energy Profits Levy), is concerning any potential investors seeking a predictable return on investment (ROI). There have been some Final Investment Decisions taken in 2023 with the Rosebank field West of Shetland the most notable.

The 33rd UK Offshore Licensing Round awards are being announced. The first two tranches have yielded 51 new licences from 115 applications covering a third of the 930 blocks on offer. The bulk of these licenses are close to operating assets to maximize efficiency. Significant blocks were awarded West of Shetland for an expected gas play. The licensing process is intended to become an annual event in future.

Looking at emissions reductions, the industry remains on track to meet the 2025 and 2027 targets, but off-track to meet the 2030 target. As over 70% of emissions are from power generation, platform electrification is important to success but is expensive and challenging. New projects are required to be 'electrification ready' but it is unclear when the electricity supply will be available, and where it will come from. With some 180 fields expected to be decommissioned by 2030, the expensive build-out of an offshore electricity grid will need careful cost-benefit analysis and appears to be many years away from implementation. ■

6.1.1 Natural gas

UK production of natural gas peaked in 2000 at almost 130 billion cubic metres per year (Bn m^3/yr) before steadily declining by two thirds to 43 Bn m^3/yr last year (DESNZ, 2023), and we expect it will continue to decline steeply to 2 Bn m^3/yr by 2050. As Figure 6.3 shows, the UK's gas was supplied predominantly locally up until the beginning of this century. Since then, local production has been insufficient to meet domestic demand, making the UK a net importer of natural gas, importing slightly over 45% of its natural gas consumption (equal to 37 Bn m^3) in 2022 (DESNZ, 2023). As local production declines, it is expected that the UK will continue to be a net importer.

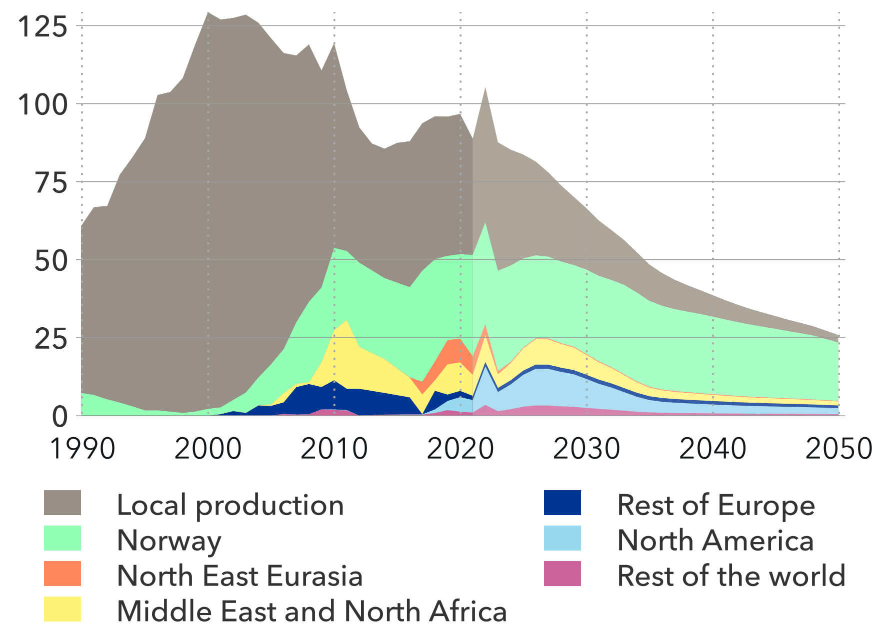
In 2022, the UK saw an interesting shift in natural gas trade flows with imports hitting a record high, up a significant 10% year-on-year (DUKES, 2023). There have been notable efforts toward the diversification of import sources following the war in Ukraine, with the UK importing from a record 13 countries last year. Norway is the single largest exporter of gas via pipeline to the UK, accounting for 55% of overall UK gas imports in 2022, down from over 60% in 2021. LNG imports from the US tripled in 2022, now accounting for 50% of total LNG imports, followed by Qatar at 30%, and Peru at under 10%. Having two of Europe's largest regasification terminals (e.g. at Milford Haven, Pembrokeshire), the UK is currently also acting as a hub for LNG, importing it from other regions, regasifying it, and pumping it to continental Europe. This role has grown increasingly important since the war in Ukraine with UK exports of gas to Europe hitting a record high last year. For example, exports to Belgium grew 9-fold in 2022.

Contributing towards decarbonization of natural gas, and with reducing cost of biomethane relative to natural gas, the share of biomethane in the UK's methane supply is expected to rise from nearly zero today to over 5% by mid-century. Furthermore, we expect the share of natural gas production emissions captured via CCS to grow from near zero today to 100% of emissions by the mid-2030s, as the carbon price exceeds the cost of CCS in natural gas processing.

FIGURE 6.3

UK natural gas supply by source

Units: Bn m^3/yr



In 2022, natural gas accounted for 36% of overall primary energy supply in the UK. In that year, natural gas demand suffered a 7% decline primarily due to the energy crisis and the ensuing consumer price pressures. In the short term, we expect to see a bounce-back to previous levels of demand by 2025. In the longer term, the UK's overall natural gas demand is expected to halve from 770 TWh/yr today to 390 TWh/yr by 2050. As Figure 6.4 shows, natural gas is primarily used to meet the energy needs of buildings heat. Demand for this end use peaked in 2004 at 440 TWh/yr and has since been generally declining (DUKES, 2023). We expect that it will continue to decrease due to increasing electrification of heat to reach about 220 TWh/yr by 2050, 28% less than today. However, with relatively quick phase-out of natural gas in other end uses (e.g. power stations) against its persistence in buildings heat, we expect the share of buildings heat in overall natural gas demand to increase from 40% now to nearly 60% by mid-century.

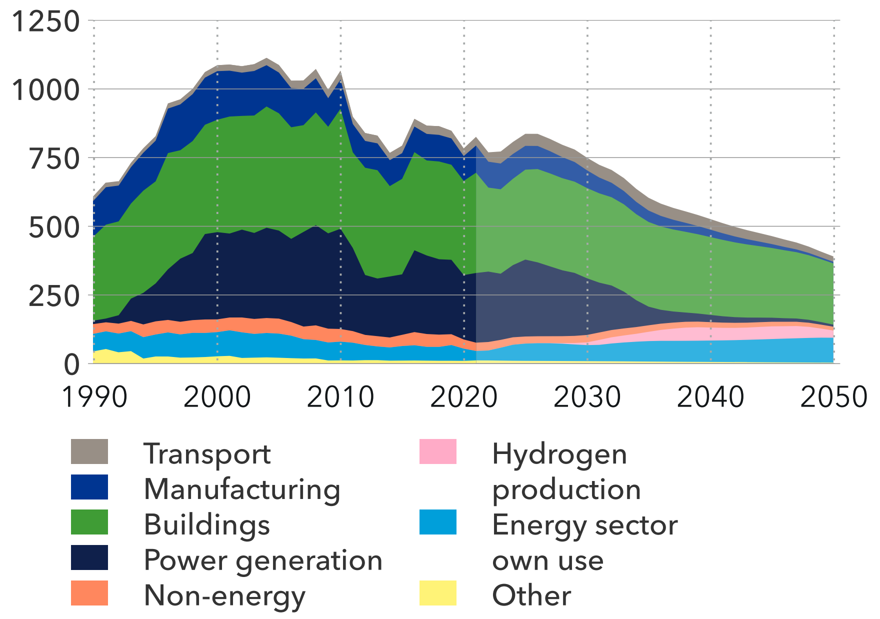
Power stations are the second-largest users of natural gas in the UK, accounting for a third of total natural gas demand. With the phase-out of natural gas, however, this will decline to nearly zero by 2050. All other sectors combined account for less than 30% of natural gas demand today. Natural gas consumption will decline in other sectors as well, though their combined share in demand will increase given the much steeper decline in gas demand for power generation. However, natural gas use in the production of hydrogen and derivatives is expected to grow from almost nothing today to 45 TWh/yr in 2045, accounting by then for almost a third of remaining natural gas demand.

Natural gas use in the production of hydrogen and derivatives is expected to grow from almost nothing today to 45 TWh/yr in 2045, accounting by then for almost a third of remaining natural gas demand.

FIGURE 6.4

UK natural gas demand by sector

Units: TWh/yr



Historical data source: IEA WEB (2023)

6.1.2 Oil

UK oil production, largely offshore, has seen substantial swings in recent decades, but has been generally in decline since the start of the century, when it peaked at 2.5 million barrels per day (Mb/d) (Figure 6.5). In 2022, it hit a fresh record low of 0.7 Mb/d, down by about 30% from pre-pandemic levels and by more than 70% from record levels at the beginning of this century. Oil production will decrease further by mid-century as existing fields approach end of life. Rising global competition in supply in a contracting market over the coming decades is likely to make it less appealing for the industry to invest in upstream oil production over the long term. The UK has been a net importer of oil since 2004 and remains so today with net imports of around 330,000 b/d. In percentage terms, oil imports have increased in recent years. The US has now become the main source of the UK's crude oil imports, accounting for 36% in 2022, closely followed by Norway at 33% (DESNZ, 2023c). With the rapid decline in oil demand for road transport, we expect oil imports to decline towards 180,000 b/d by mid-century. In terms of demand, UK crude oil consumption peaked around 2.0 Mb/d in the late 1990s. Nowadays, the amount of crude oil consumed has halved to around 1.0 Mb/d (annual average).

In 2022, oil accounted for 41% of overall primary energy, largely driven by the transport sector (DUKES, 2023). Figure 6.5 illustrates our prediction of a two-thirds decline to 0.25 Mb/d in domestic oil demand by mid-century. The key underlying development here is the almost complete phase-out of combustion engine vehicles. This is faster than the global transition, where we predict nearly a 40% decline in oil demand by 2050, but at a similar pace as the transition in the rest of Europe.

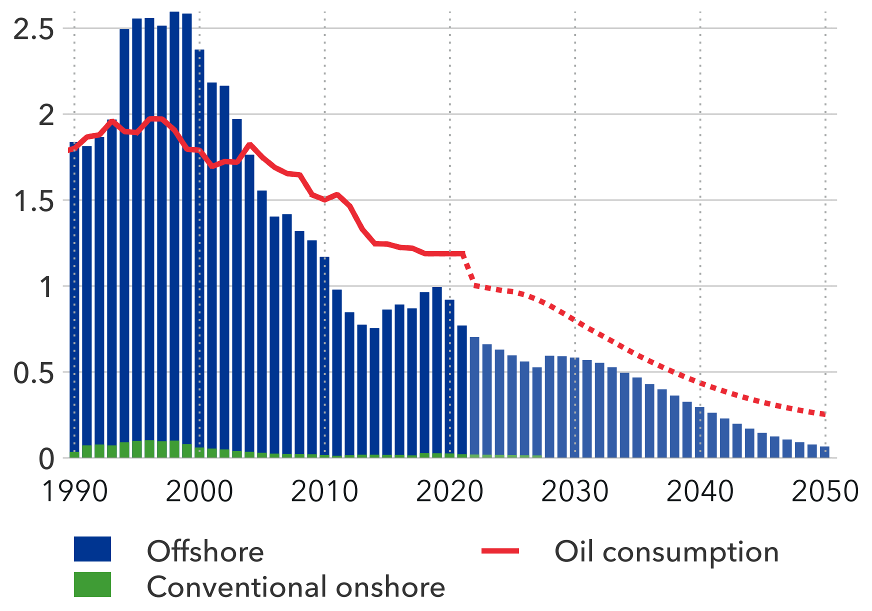
Figure 6.6 shows in detail UK oil demand by sector, with transport having a share of more than 80% and the remainder being split between non-energy, manufacturing, and buildings. In 2022, the road transport subsector accounts for just above half of total oil demand, aviation about 20%, and maritime about 10%. The share of oil consumption in the transport sector has climbed from less than half in 1980 to over 80% in 2022 while demand has decreased across all other sectors in absolute terms. Oil demand for transport was just above one million barrels per day on average in 2022. We forecast that this will decrease 72% by 2050.

Passenger vehicles will experience the most widespread transition to electric mobility going forward, and their share in oil demand is expected to drop by an order of magnitude by 2050. Oil demand will persist in the commercial vehicle segment in mid-century, though it will decline from about 240,000 b/d today to 40,000 b/d in 2050. As a hard-to-electrify sector, aviation will replace road transport as the single largest consumer of oil products, more than doubling its share from around 20% today to 42% by mid-century. Still, absolute demand in aviation will decrease 45% during the same period, giving way to some extent to bio-based and synthetic sustainable aviation fuels.

Aviation will replace road transport as the single largest consumer of oil, more than doubling its share by 2050.

FIGURE 6.5
UK crude oil demand and production

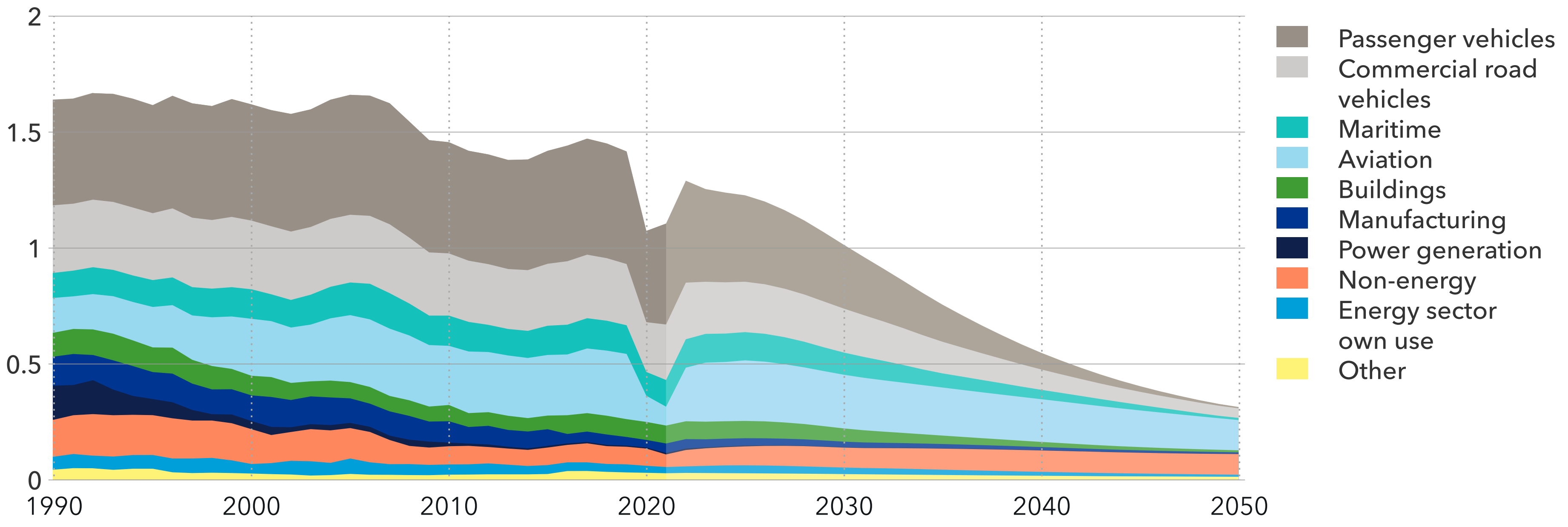
Units: Mb/d



Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 6.6
UK oil demand by sector

Units: Mb/d



Historical data source: IEA WEB (2023), DUKES (2023)

6.1.3 Coal

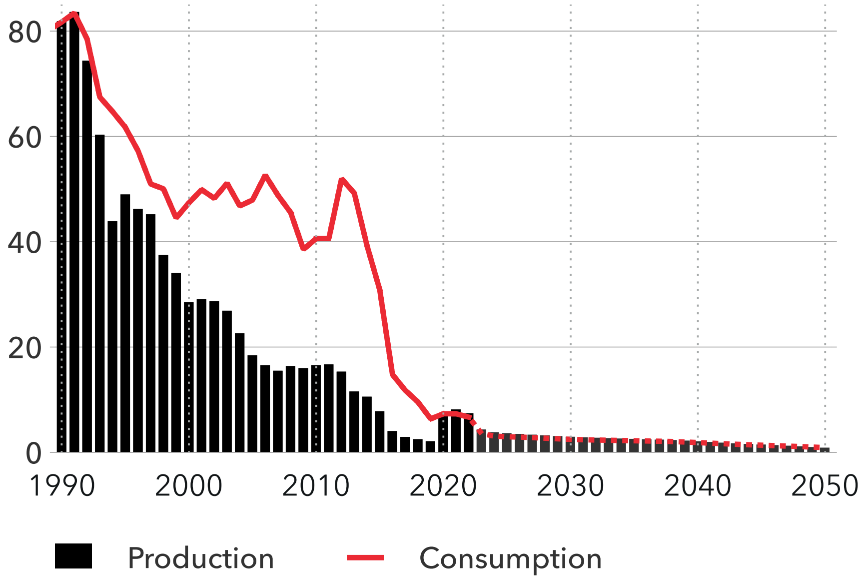
UK coal consumption has declined steeply from 47 Mt/yr in 2000 to less than 7 Mt/yr in 2022, representing a new record low as the UK pivots away from coal use (DESNZ, 2023c). With demand outweighing local production, the UK has historically been a net importer of coal. At present, though, given the very low demand, net import is close to zero. The reduction in demand has been enabled by wider availability of natural gas as a cleaner fuel for power generation and industrial heat. The UK now has only two operational coal plants remaining.

Twenty years ago, roughly 80% of coal was used in power plants, 15% in manufacturing, and less than 5% in buildings. This has radically changed as coal has gradually been phased out of power generation, and it is expected that coal use for electricity will cease completely by Q4 2024 (DESNZ, 2023c). Currently, more than half of coal in the UK is used for manufacturing, with the iron and steel industry being the main user. Coal is well on its way to be fully phased out by 2050, falling to nearly zero even by 2040.

FIGURE 6.7

UK coal demand and production

Units: Mt/yr

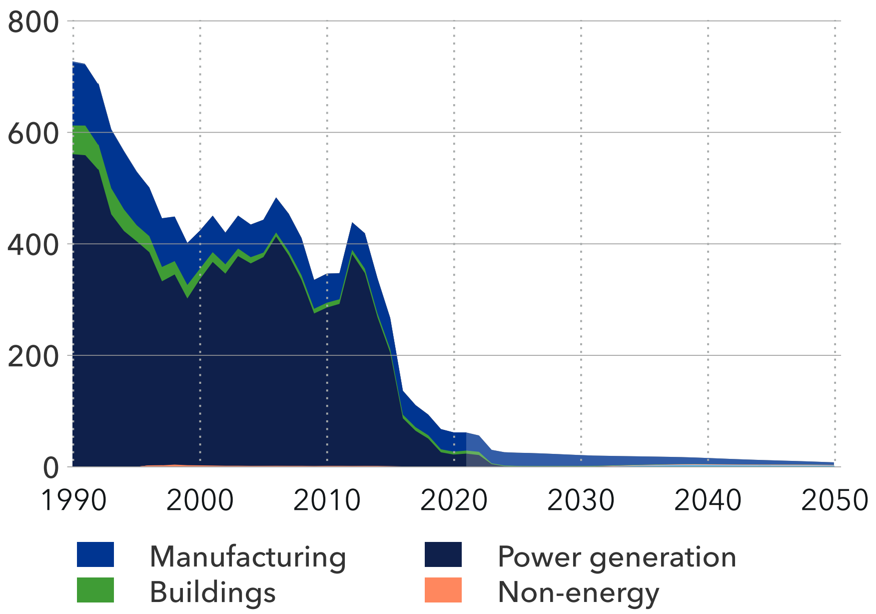


Historical data source: IEA WEB (2023), DUKES (2023)

FIGURE 6.8

UK coal demand by sector

Units: TWh/yr



Historical data source: IEA WEB (2023)

6.2 Renewable energy sources and nuclear

While renewables and nuclear together supply only a fifth of primary energy today, they are set to have a 28% combined share by 2030 and nearly 65% by mid-century. While bioenergy and nuclear are today the two main non-fossil sources of energy, wind will rapidly overtake them to become the lead renewable energy source, supplying a third of primary energy by 2050, more than the combined share of bioenergy and nuclear at that time. In the following subsections, we cover each renewable source separately.

6.2.1 Wind

The UK wind industry has grown steadily since its first utility-scale installation in 1991. Total installed capacity was 29 GW by the end of 2022, split nearly equally between onshore and offshore. About 80% of new capacity and about 60% of total onshore wind capacity is in Scotland, where there is a more favourable wind resource (BEIS, 2022). Favourable wind conditions and relatively shallow waters make the North Sea advantageous for offshore wind developments.

We expect total wind capacity to grow more than 5-fold from 29 GW now to 140 GW in mid-century (Figure 6.10). With opposition to onshore wind developments expected to continue, we predict that growth in UK wind capacity will be mostly offshore, constituting two-thirds of installed capacity in 2050. By then, we forecast that wind will power 70% of on-grid electricity generation: 52% via offshore wind turbines (both bottom-fixed and floating) and 18% via onshore turbines.

Cost reductions will be the most important driver for growth and will occur in all three key types of wind power. The most dramatic cost reductions will be seen in floating offshore wind, where we expect levelized cost of electricity to fall by a factor of five up to mid-century. Cost reductions in the more mature onshore and bottom-fixed technologies will be less pronounced; about 40% to 50% cheaper by 2050.

A major factor in cost reductions so far has been the effect of increasing turbine size and hub height. However, we expect this trend to slowly reach saturation as increases in turbine size will no longer directly result in significant reductions in the levelized cost of electricity. Instead, cost reductions will be driven by elements such as production optimization. But to capture these opportunities, the industry needs to shift from new product development to product improvement and optimization of manufacturing processes. In fact, there is now an increasing number of voices advocating for a slowdown in the size "arms race" between wind turbine OEMs, as this is leading to increasing pressures on them both technically and financially. Finally, given the location of offshore oil and gas production platforms and their decarbonization mandates discussed earlier, deploying floating offshore wind turbines close to them will be an increasingly attractive solution for meeting platform power demand as costs plummet.

FIGURE 6.9

Map of UK wind capacity 2021

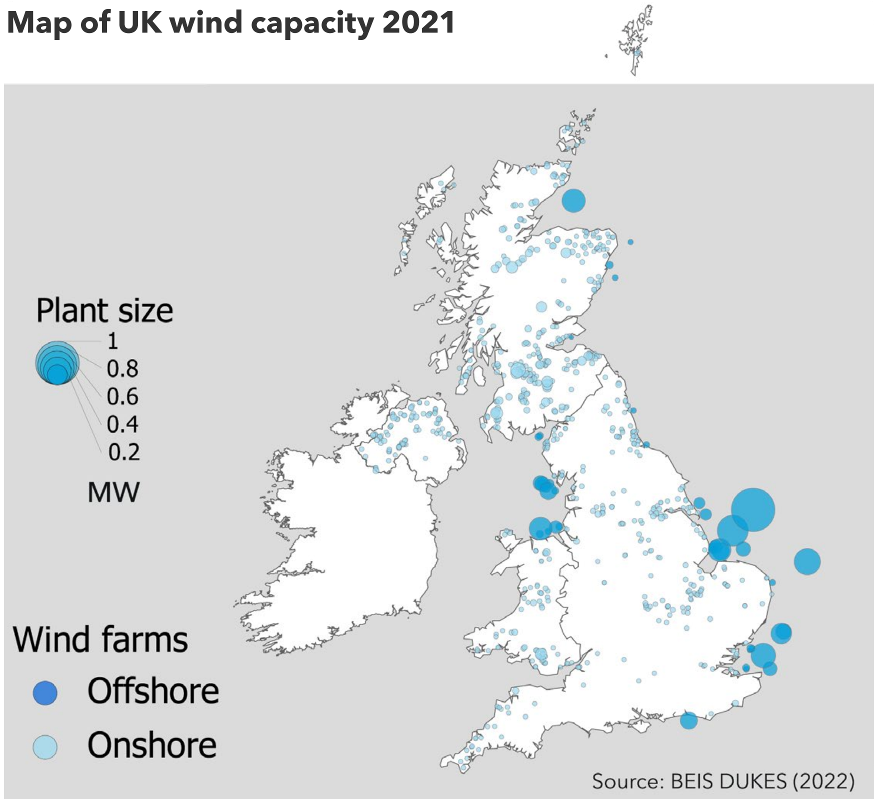
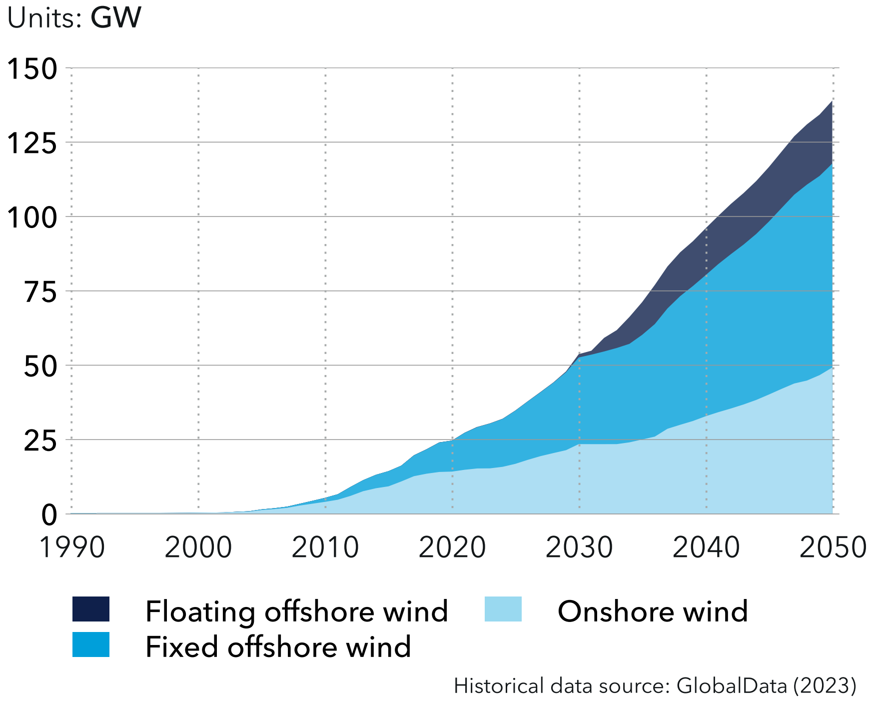


FIGURE 6.10

UK wind installed wind capacity by power station type



Seagreen May 2023. Image: © Seagreen Wind Energy Ltd.

Onshore wind: can repowering, extended lifetimes, and hybrid projects accelerate the UK pathway to net zero?

Onshore wind in the UK is a mature and proven technology. With 15 MW of capacity installed at the end of 2023 (RenewableUK, 2023), there are many multi-megawatt projects now reaching 30 years of operation with consistent high availability and financial performance. In the UK, onshore wind is on average the cheapest form of electricity generation. In recent years, hiatuses in deployment, and particularly in England, have not so much been due to financial viability but to restrictions in permitting. For example, England has seen a de facto planning ban on new onshore wind development since 2015, and prior to this a blanket restriction on the overall height of the turbines stifled potential generation. The recent Contracts for Difference (CfD) auction AR5 with a strike price of GBP 53/MWh, resulted in 24 onshore wind contracts awarded with a total rated capacity of 1.5 GW, with all but one contract in Scotland. The project pipeline supported by CfD is anear ready to build.

For onshore wind, grid bottlenecks and wait times for connection are limiting speed of deployment. 200 wind projects with a total capacity of 21 GW are currently queued and waiting for a grid connection, 16 GW of which have agreements with the Electricity System Operator to connect by 2030 (NGESO, 2023). This is the largest number of projects for any single country in Europe (DNV, 2023). This demand gives a strong signal that the number of potential onshore wind projects is not per se a constraint to growth.

DNV is of the view that existing wind farms will either be life-extended or repowered and that full decom-missioning and removal will be uncommon. In the next five to ten years, much of the projected increase in capacity will be through this route, as greenfield developments continue to experience planning and permitting hurdles. In the longer term, greenfield sites will gradually take over from existing repowered wind farms to meet the 50 GW capacity projected in our model by 2050.

Repowering

The average age of UK onshore wind turbines is around 10 years, and the average turbine rated capacity is 1.8 MW (RenewableUK, 2023).
If the existing fleet were to be repowered with contemporary 4 or 5 MW turbines with extended permits, then over 35GW of generating capacity could be achieved with a rolling replacement programme without extensive new greenfield developments. Advances in turbine control, design, and materials mean that loading can be managed more sophisticatedly whilst maximizing energy output and staying within existing wind farm boundaries. Such 'power boosts' are technically feasible but require relaxation in aspects of planning to allow higher turbine heights and continued removal of grid bottlenecks. A recent demonstration of repowering potential is the Hagshaw Hill Wind Farm in Scotland, owned and operated by ScottishPower: 14 turbines are replacing the original 24 turbines installed in 1995. The fewer but larger and more efficient turbines mean that the repowered wind farm will produce five times more power (Iberdrola, 2023).

Positive social impacts of repowering are also now apparent. Wind farms that have been established for 20 years or more in rural communities can be a significant contributor to the local economy providing employment and accessing local services; this is sustained through repowering.

Lifetime extension

A factor contributing to lower cost of energy for onshore wind in recent years has been longer lifetime assumptions. Typically, a UK wind farm financial model will assume an economic life of more than 30 years. This assumption is up from 20–25 years generally assumed at financial close of most of the current installed fleet. Longer lifetime gives favourable reduction in cost of energy and also lowers the overall carbon intensity (RenewableUK, 2022) with arguably more than 50% more production for only a marginal increase in raw materials.

A recent example is Ventient Energy who in December 2023 announced that they have secured approval to original planning consents to operate six 20-year-old wind farms with a total capacity of 200MW, for a further 10 years extending their overall lifetime from 25 to 35 years (Ventient Energy, 2023).

Hybrid projects

An emerging trend is to optimize existing onshore wind assets by co-location or hybridization with solar and battery storage or even hydrogen production, sharing land space and grid infrastructure. The potential advantages of such hybrid projects are:

- Avoidance of delays and costs of new grid connection
- Flexibility and reliability of delivery of electricity/ energy
- Minimization of impact of grid constraints and forced curtailment
- Ease of permitting; utilizing land already set aside for power generation.

Offshore wind roll-out stalled but recoverable

Stall is a phenomenon that occurs when a wind turbine's blade pitch angle is pushed past the limit of maximum power and efficiency. Once the blade moves past this 'tipping point', the flow of air around it detaches and the wind turbine rapidly loses power. This is analogous to the tipping point observed in UK offshore wind project economics over the past few years. The upward cost pressures have increased due to supply-chain inflation and interest rate hikes whilesubsidy prices have consistently fallen. Project profitability has been pushed past the tipping point where it is no longer feasible to move them into construction. This has resulted in a noticeable slowdown, or stall, of the offshore wind roll-out in the UK and Europe, evidenced by the 20% decrease in forecasted installation over the next five years for the region (according to 4C Offshore market research).

Allocation round 4 (AR4) in June 2022 was a landmark moment in the UK offshore wind industry with 5 offshore wind projects securing 7GW of offtake agreements under the UK government's contracts for difference (CfD) support scheme, representing the most capacity ever supported in a single round at the lowest price for any technology on record. However, 18 months later we see only one project in the offshore construction phase (Moray West), with two projects just squeezing through Final Investment Decision (FID), and the remaining two, totalling 2.5GW, at risk of having their CfD terminated due to not meeting their contractual milestone obligations (i.e. not taking FID). To add to this, the UK government ignored calls from industry to raise the administrative strike prices for 2023's AR5 in response to increased costs for developers. The unaffordable price offered by the government resulted in no bidders in AR5 despite their being 5GW of eligible offshore wind looking for a route to market. Moving into 2024, adding the 9GW of projects that have progressed through the planning system since AR5, the UK is in a position where it has 14GW of offshore wind projects stuck between planning consent approved and FID, searching for a feasible route to market.

Key project milestones in a UK offshore wind farm's route to starting construction. In 2014 the UK will have 14GW of projects competing in the route to market stage, where it normally has 4–7 GW.

AR6 in 2024 will need to play a big part in righting the ship and bringing the UK offshore wind project sequencing back on track. In response to the blockage of projects at the FID stage and lobbying from developers, the government has pushed the administrative strike price for AR6 up by 66% for fixed offshore wind and 52% for floating offshore wind compared to the unfeasible AR5 strike prices. This has been welcomed by developers, indicating that we should see projects bidding into the allocation round in 2024. A key parameter to be announced in March 2024 is the budget for the fixed offshore wind pot. The budget determines how much capacity can be awarded for the resulting clearing price. The bigger the budget, the more projects we will see securing a feasible route to market, enabling a surge in FIDs in 2024/25 and construction starts in 2025/26. The subsequent allocation rounds (AR7, AR8, AR9, etc.) will also need to have healthy strike prices and large budgets to push the backlog of projects through the system and into the water by 2030.

To reach the government's 2030 target of 50 GW installed capacity, the UK needs to be installing 5 GW per annum over the next 7 years. This is more than double the maximum installation rate observed to date. Given the delays described above, we forecast the rate of installation to fall to 1 GW/yr in 2024. But provided that the CfD allocation round strike prices and budgets remain supportive of project pipeline, this should rise to 2.5–3 GW/yr by the end of the decade. This would bring the UK to 30 GW installed capacity by 2030 – off target by a large margin but still in a good position considering the scale of the task. ■

Monopiles arrive for marshalling at Invergordon in the Cromarty Firth, Scotland, during the summer of 2023. These have been deployed onto the 882 MW Moray West project expected to deliver first power in May 2024. In a period of turbulent times for the UK wind industry, Moray West is the only Allocation Round 4 project to have reached financial close through non-recourse project financing, securing GBP 2 billion pounds, and is the first wind farm in the UK to have most of its offtake secured though corporate power purchase agreements. Photo: © Ocean Winds

Floating Wind

Floating wind is moving from the demonstration to commercialization phase around the world and the UK is at the forefront of this transition, with a large chunk of utility-scale projects now under serious development. However, the ambitious 5 GW floating wind target for 2030 set by the UK Government looks unlikely to be met (DNV predicts around 1 GW), primarily due to the availability of grid connection and expected development timelines of projects already announced.

Capacity is building from a handful of demonstrators and mini-arrays (of less than 10 turbines) in operation or in advanced stages of development today. Although some of these will have been hit by the recent acute mismatch between the revenue support (contracts for difference, CfDs) cap and rising supply-chain costs in the fixed offshore space, most of the floating wind project pipeline may have escaped the worst of the squeeze due to its early development phase.

Commercial-scale floating wind in the form of ScotWind projects totalling around 20 GW is now focused on delivery, with some challenges (particularly in relation to delivering at scale) still to overcome. In the last year, 13 more projects (totalling over 5 GW) have been awarded seabed rights under the Innovation and Targeted Oil & Gas (INTOG) scheme, with aggressive timescales decoupled from grid availability and CfD award for some of those as a result of the power being consumed by offshore rigs. In 2025, the Crown Estate will award further seabed rights under leasing Round 5 (Celtic Seas), which seems likely to be fiercely competitive and will see 4.5 GW of floating wind capacity allocated in the South West.

To enable this pipeline to be realized and costs to be drastically cut, technical challenges surrounding matters like turbine main component replacement, dynamic cable reliability, platform concept diversity and rapid turbine technology advancement will have to be addressed. In parallel, as well as obtaining timely grid connection, other practical aspects present at least as much of a challenge to potential projects. Prominent amongst these are supply-chain bottlenecks, including the need for upgrades to ports to enable assembly and storage of floating platforms at scale as well as providing a base for the necessary marine operations. Some progress in this regard has been promised in the form of Floating Offshore Wind Manufacturing Investment Scheme (FLOWMIS) and Scottish National Investment Bank support schemes, but much more is still to be done.

These constraints explain why DNV has not directly translated significant planned capacity into corresponding expected pipeline growth for this year's report. However, compared to previous years, DNV observes stronger signs that convergence is taking place amongst platform types selected for projects. We may therefore expect more rapid maturation of associated technologies and supply chains in the medium to long term, enabling an installed capacity in excess of 21 GW in the UK by 2050. ■

SSE Renewables and its partner TotalEnergies have announced all 144 turbines in the 1.1 GW Seagreen Offshore Wind Farm are fully operational. Image: © Seagreen Wind Energy Ltd.

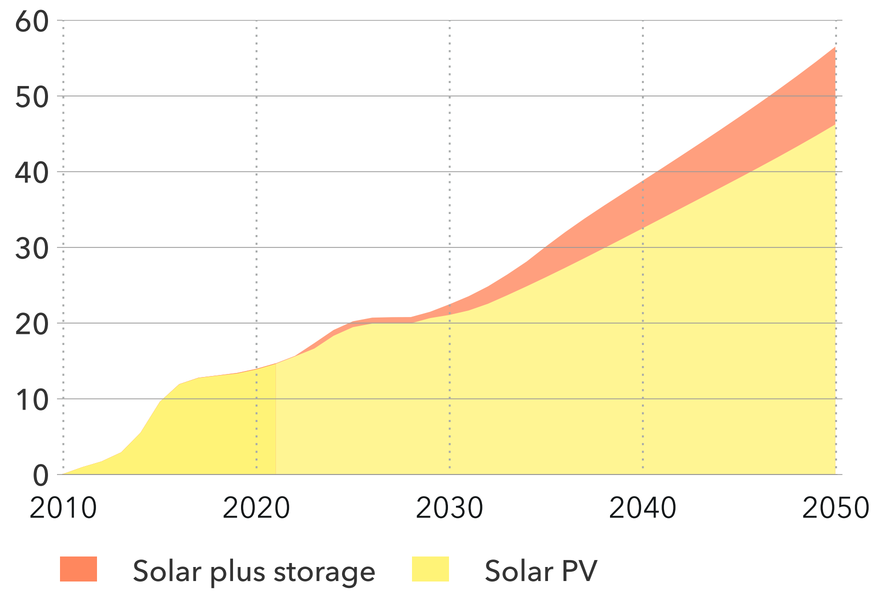
6.2.2 Solar

Solar PV costs have declined spectacularly in recent decades, while the technology's efficiency has increased and the scale and forms in which it is implemented have diversified. The growth of solar PV has been remarkable: Globally, 1 GW/yr was installed for the first time in 2004, 10 GW added in 2010, and 100 GW in 2019. Based on our model, global weighted average levelized cost of energy (LCOE) for solar PV is currently around GBP 46 per MWh. We expect this to halve by mid-century. Globally, solar PV together with onshore wind will be in an unassailable position as the cheapest sources of new electricity.

FIGURE 6.11

UK solar PV power installed capacity

Units: GW



Historical data source: GlobalData (2023)

This is not the case, however, in high northern latitudes with low solar irradiation, such as in the UK. Low solar irradiation leads to low capacity factors and therefore higher levelized costs. For example, solar capacity factor in the UK is half of that in Middle East and North Africa, and levelized cost is over two times higher. However, we expect levelized cost of solar electricity in the UK to decline 35% until mid-century, and for installed capacity (including solar+storage) to grow from 16 GW today to 30 GW in 2035 and 57 GW in 2050.

We model utility-scale solar+storage as a separate category, where storage is co-located with solar plant. Despite its higher capital costs, solar plus battery storage has an advantage over standalone solar PV on capture price[1] due to its ability to store and shift intra-day generated electricity to higher-tariff periods. Plants with storage can charge their batteries when sunlight is plentiful during the day and sell the stored electricity when the price is high. This will make this power station type more attractive in the future. By 2050, we expect that about 18% of all solar installed capacity in the UK (approximately 10 GW) will be with dedicated battery storage.

We expect installed solar capacity to grow from 16 GW today to 30 GW in 2035 and 57 GW in 2050.

1. It may often be the case that at times of peak renewable production, there is insufficient demand for the power generated. Consequently, spot prices may be considerably below baseload prices. The term 'capture price' describes the actual power price achieved.

Hadlow 2020.
Image: © Cubico Sustainable Investments.

Solar

The deployment of new utility-scale solar remains steady in the UK, with a continued market evolution away from serial developers (those progressing projects from inception to 'ready to build' (RTB) stage before selling them to new owners) towards long-term asset developers and investors, especially those seeking to exploit the independent power provider (IPP) business model.

Domestic rooftop solar has also seen a steady increase in new installations since 2021, comprising around one third of all new solar capacity installed in 2022 and 2023. While high electricity prices may have contributed to an increased interest in households seeking to generate their own solar electricity over the past two years, the strength of domestic solar is expected to continue, with increasing installation options for domestic buyers, and decreasing installation costs. Recent years have also seen a growing number of installers not accredited by the Microgeneration Certification Scheme (MCS), though it is not yet clear what long-term impact this will have on the market and installation standards.

While there may be quality and installation standard challenges on the horizon in the domestic space, the interest of long-term asset investors in commercial and utility-scale projects is more positive. Utility-scale developers are increasingly focused on technical quality and assurance of projects from the ground up, as developers and investors take a greater interest in longer and more productive operational lifetimes for new solar PV developments.

Furthermore, developers are continuing to accelerate their commitment to large-scale solar PV developments with several major projects currently being pursued by private developers who will eventually seek consent via the Nationally Significant Infrastructure Project (NSIP) route, each with the potential to contribute hundreds of MW capacity to the UK energy system. 'Go big or go home' is the mantra being ever-more adopted by some. While capacity additions from these large-scale projects may be at least a few years away, construction of the first solar NSIP project, Cleeve Hill in Gloucestershire, is already substantially underway.

The next challenge for the industry will be over-coming technical challenges of increasingly complex sites from both energy production and technical engineering perspectives. However, the sector is well placed to learn from boots-on-the-ground experience with many post-subsidy projects already tackling head-on deployment on complex sites in recent years. ■

Source: https://www.mordorintelligence.com/industry-reports/united-kingdom-solar-power-market-industry

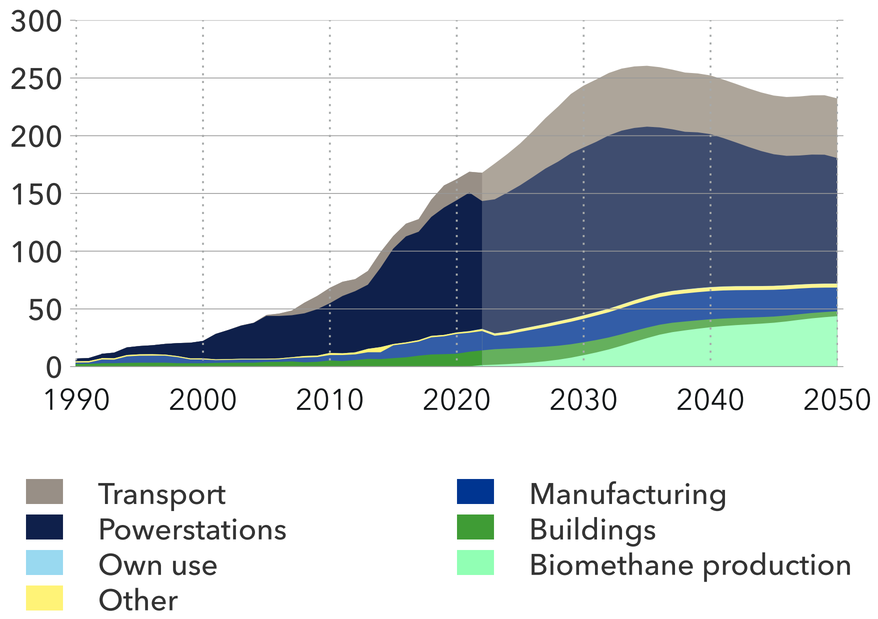
6.2.3 Bioenergy

Bioenergy is currently the largest source of renewable energy and a key option to supply renewable energy needs towards 2050, especially in hard-to-electrify sectors. Bioenergy is derived from many forms of biomass, such as organic waste and residues from agriculture and livestock production, wood from forests, and energy crops. In our model, we also include within the bioenergy category any form of energy obtained from non-renewable industrial and municipal waste, such as the combustion of plastic waste.

FIGURE 6.12

UK bioenergy demand by sector

Units: TWh/yr



Historical data source: IEA WEB (2023), DUKES (2023)

Use of biomass for energy purposes in the UK has grown rapidly over recent decades, from 22 TWh/yr at the beginning of the century to about 170 TWh/yr in 2022; a near 8-fold growth (Figure 6.12). The largest share of the total demand for biomass in the UK comes from power generation, which currently accounts for two-thirds of biomass use. Biomass-powered electricity generation is readily dispatchable; an important advantage over wind and solar, especially given the expensive storage options for variable renewables.

Biomass-powered electricity will increasingly be used as dispatchable generation to complement renewable generation. Furthermore, bioenergy presents a crucial opportunity to achieve net negative emissions via *bioenergy with carbon capture and storage* (BECCS) technologies – which will be sorely needed given the formidable challenge of reaching the net-zero emissions by 2050 target. Other notable usages of bioenergy in order of importance are in the buildings, manufacturing, and transport sectors, together accounting for the remaining third of biomass use.

Going forward, we expect biomass demand to continue growing rapidly up to around 255 TWh/yr by the mid-2030s, at which point it is likely to start being slowly replaced by variable renewables. As a share of total primary energy, however, bioenergy is set to grow its share from 8.5% now to 15% by 2035, playing a more important role in a less carbon-intensive future. By 2050, half of bioenergy will be used in power generation, about 20% in transport and 20% in biomethane production.

The role of bio-energy in the UK energy system

Introduction

Bio-energy is a catch-all term used to describe any energy derived from biological origin. The common components of bio-energy are:

- Biomass – Any solid material of biological origin including both purpose-grown energy crops and any biodegradable waste products.
- Biofuels – Most commonly liquid transport fuels such as bio-ethanol and bio-diesel derived from fermented grains or extracted from vegetable oils respectively.
- Biogas – The raw gas mixture produced by anaerobic digestion of organic matter typically comprising a roughly equal amount of methane and carbon dioxide prior to processing into biomethane (a natural substitute for the fossil fuel).

Bio-energy has the potential to make an important contribution to the UK Governments' commitments to Net Zero 2050 because of the readiness of the technology to deliver a 'drop-in' replacement fuel for the hard-to-abate sectors in transport including aviation and shipping, and also to facilitate negative carbon emissions through the BECCS.

The potential for bioenergy in a future energy mix is tempered by the challenges that come from land use and the scope 3 emissions associated with production and transport. UK official statistics[1] indicate that in 2020 approximately 121,000 Ha of agricultural land in the UK was used to grow energy crops representing 2.1% of the arable land in the UK that might otherwise be used to grow food crops.

The majority of current bioethanol manufacture is produced from food crops such as wheat and sugar and is termed a 1st Generation technology. Most biodiesel is manufactured from waste products such as used cooking oils and greases, food wastes and tallow and is termed a 2nd Generation technology. Future technology evolution might bring 3rd Generation technologies into commercial production such as high yielding algal oils; however, to date the production per acre has been disappointing despite significant investment into research.

Primary bio-energy supply and demand data in the UK

The most recent statistical release for UK primary energy supply and demand (DUKES, 2022) provides a picture of the overall UK bioenergy supply and demand balance: ▸▸

TABLE 6.1
Supply

All data in '000 tonnes oil equivalent	Production	Imports	Exports	Transfers and adjustments	Total supply
Waste wood	341	53	-88		306
Wood	828	77	-4		900
Plant biomass	3,373	3,357	-10		6,719
Animal biomass	233			233	22
Anaerobic digestion	1,543		-531	1,012	50
Sewage gas	383		-54	329	54
Landfill gas	780			780	11
Renewable waste fraction	1,758			1,758	6
Liquid biofuels	693	2029	-375	+2	2,349

Demand

All data in '000 tonnes oil equivalent	Electricity generation	Heat generation	Industry and other	Transport	Total demand
Waste wood		30	186		306
Wood			900		900
Plant biomass	5,115	137	1,467		6,719
Animal biomass	233		0		233
Anaerobic digestion	844		78	90	1,012
Sewage gas	224		92	14	329
Landfill gas	741		14	26	780
Renewable waste fraction	1,637	35	86		1,758
Liquid biofuels	27		46	2,276	2,349

1 Area of crops grown for bioenergy in England and the UK: 2008-2020

The most striking conclusions from an analysis of 2022 bioenergy supply and demand are:

- Most (78%) plant biomass and wood is used for heat and electricity generation.
- Half of the plant biomass supply used for electricity and heat generation is imported.
- Most (86%) of the biofuel supply in the UK is currently imported.
- Anaerobic digestion sewage and landfill gas makes a significant contribution to electricity generation (1,809 ktoe)

The future of bioenergy in the UK fuels mix

Biomass
Biomass is already a key component of the UK energy supply with bioenergy generating 13% of total electricity in 2022. The UK Government has recognized that greenhouse gas removal technologies such BECCS have the potential to balance emissions from hard to decarbonise sectors, and therefore the synergies with the industrial cluster sequencing plan are likely to be exploited.

The limited land area available for forestry and short rotation coppice will limit the extent to which the UK can grow the biomass used in BECCS or bioenergy and therefore the carbon intensity of the biomass supply chain will increase in importance as volumes grow.

Biofuels
The Renewable Transport Fuel Obligation (RTFO) has played a key role in the UK Government's strategy for decarbonizing transport. In 2019 fuels supplied under the RTFO mandate saved almost 5.5 million tonnes of carbon dioxide emissions according to official statistics (DfT, 2021). The government has consulted upon the impact of the RTFO and has determined that the RTFO scheme can be extended to increase the proportion of renewable fuels in the transport mix from a level of 9.6% in 2021 to 14.6 % in 2032 and will have the effect of reducing greenhouse gas emissions by a further 23.6 million tonnes over this period.

The UK Government plans to introduce a requirement that at least 10% of aviation fuels will be made from sustainable feedstock by 2030.

Biogas
Within the UK Biomass strategy, the government outlined some considerations for biomethane and biogas with an increase in the final use of biomethane in heat, transport and power sectors promoting the circular economy with pasteurized digestate returning to the land. The Government notes the opportunity for BECCS from the CO_2 fraction separated from biogas in the process of upgrading to biomethane. ■

6.2.4 Nuclear

Having established the world's first civil nuclear programme with the Calder Hall power plant in 1956, the UK has a long history in nuclear power. The country currently has nine operational nuclear reactors at five locations, all operated by EDF.

Reactors in three locations, Hunterston B, Hinkley Point B, and Dungeness B, have stopped generating and are currently defuelling (ONR, 2023). Following the Fukushima disaster in Japan in 2011, nuclear power has had a rough decade competing against incumbent, fossil-based electricity generation and emerging cheap renewables. With no new nuclear capacity build-outs since 1995, and the upcoming end-of-life decommissioning of existing plants, we expect installed capacity to decline from close to 9 GW in 2020 to a low of around 3 GW by 2028.

Due to the high capital costs, nuclear power is expensive from a levelized cost perspective, as Figure 6.13 shows. As an illustration, it is almost always more than twice as expensive as offshore bottom-fixed wind through to 2050. High capital costs and lengthy lead times will continue to be important barriers for nuclear power. The absence of long-term, viable solutions for managing nuclear waste and the rising costs and construction times, especially because of increased safety concerns, will limit new nuclear power's ability to compete with other renewables in the short term from an exclusively economic perspective.

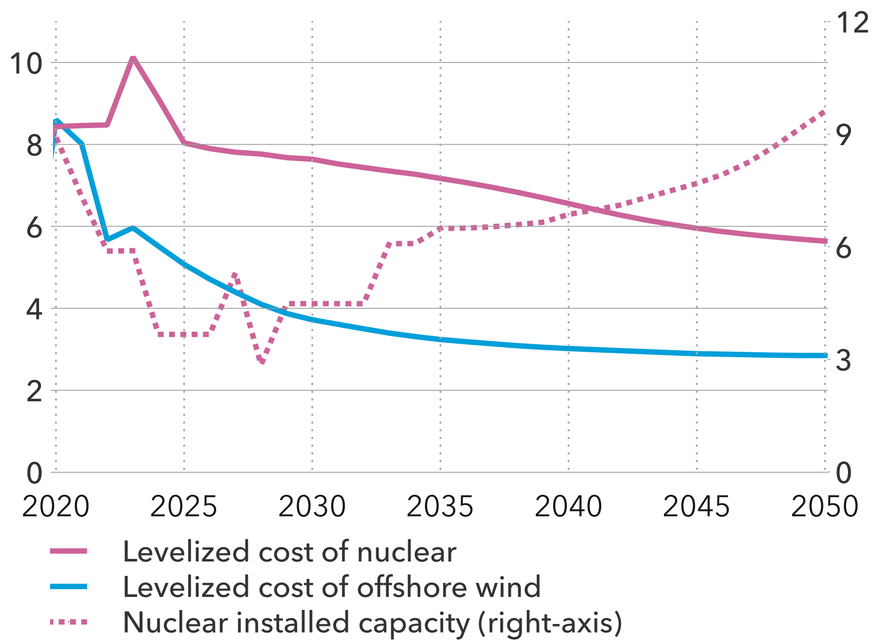
Policy is therefore the key driving force behind capacity additions in nuclear, especially given recently heightened energy security concerns following the Russian invasion of Ukraine and the ensuing energy crisis. Many countries are once again considering nuclear as a viable option free of fluctuations and dependency on other countries. This has also led the UK government to consider extending nuclear plant lifetimes through upgrades and life-extension measures. The government is also set to announce up to £157 million in funding for nuclear projects. This includes up to £77.1 million for advanced nuclear business development and £58 million for the development of advanced modular reactors (AMRs) which run at higher temperatures (Politico, 2023).

Taking existing government ambitions into consideration, we expect to see nuclear capacity rise from a low of 3 GW in 2028 to 6 GW by 2034, and more slowly thereafter to reach 10 GW by 2050. Of the 10 GW new capacity foreseen (some of which is replacing existing capacity being retired), 6.5 GW will come from Hinkley Point C coming online in 2027–29 (3.3 GW) and Sizewell C in 2033–35 (3.2 GW). We expect roughly another 3.5 GW of new capacity to come in the form of small modular reactors from the mid-2030s.

FIGURE 6.13

UK nuclear power installed capacity and levelized cost comparison

Units: p/kWh Units: GW



7 ENERGY EXPENDITURE

7.1 Energy infrastructure investment

There are various definitions of 'energy expenditure', so it is important to clearly define what is covered in our capital expenditure (CAPEX) figures. We have included all investment costs for fossil-fuel extraction, transport, and conversion to hydrogen and electricity. Similarly, all costs in the power sector are incorporated, including power grids, storage capacity, and the installation and operation of renewable energy plants. However, we have excluded investments in energy-efficiency measures and costs related to end-use spending in manufacturing and transport. We also included the costs associated with replacing space heating equipment in buildings and the high estimated costs associated with upgrading insulation of UK housing stock.

We forecast that CAPEX investment in UK energy infrastructure will increase significantly in the next three decades to enable the transition to a more electrified system powered by renewables. The average annual spend for all the considered categories for the decades between 1980 and 2050 are summarized in Table 7.1.

The average annual CAPEX spend on energy infrastructure in the 1981–2022 period was GBP 26bn. We forecast that this will increase by an average of 50% for the next three decades to GBP 38bn, peaking in the early 2030s at around GBP 45bn.

Approximately a third of the energy system investment for the next 28 years will be CAPEX for the addition of new power generation capacity to meet the increased 700 TWh annual electricity demand in 2050. Annual investment in this sector will double to GBP 12–13bn in the 2020s and remain relatively flat until mid-century. The addition of 110 GW of wind capacity will be the largest contributor to this investment (GBP 187bn in total).

In parallel, expansion and strengthening of the current power grid will be required. Annual expenditure will increase more than three-fold from historical levels, rising from GBP 2.8bn today to GBP 9bn in the 2040s. This will account for 22% of energy infrastructure spend in the next 30 years.

Going forward, we see annual upstream oil and gas investment reducing significantly compared with the GBP 10bn historical level, reflecting the maturity of the UK Continental Shelf production basin. For the next decade, annual investment will still be close to GBP 4bn to bring online various remaining large projects and tie-backs to existing hubs, but then reduces further to very low levels after 2030.

Based on our current forecast, there will be limited uptake of hydrogen for domestic heating. Hence, we do not foresee major new investments for

TABLE 7.1
Past and forecast trends in annual capital expenditure on the UK energy system

CAPEX Category	Average annual Energy System CAPEX spend trend 1981-2050 (GBP Bn)					Total CAPEX spend 2023-2050 (GBP bn)
	Historical		Forecast			
	1981-2000	2001-2021	2022-2030	2031-2040	2041-2050	
Power generation total	3.8	6.7	12.4	13.2	12.3	**354**
Wind	0.0	3.1	5.0	7.9	6.8	**187**
Solar	0.0	0.7	0.7	1.3	1.6	**34**
Nuclear	2.4	0.0	2.9	2.7	2.0	**70**
Gas/bio fired	1.0	2.2	2.6	0.9	1.8	**48**
Other power generation	0.3	0.7	1.3	0.5	0.0	**15**
Electrical grid	2.6	2.8	6.4	9.0	8.7	**228**
Upstream oil and gas	10.5	9.1	3.6	0.4	0.0	**33**
Pipelines	1.3	1.2	0.5	0.5	0.3	**5**
Electrolysers	0.0	0.0	0.3	2.3	1.5	**41**
Reformers	0.0	0.0	0.3	0.4	0.3	**9**
CCS	0.0	0.0	0.5	1.9	0.4	**27**
Direct Air Capture	0.0	0.0	0.0	0.6	0.6	**13**
Storage	0.0	0.0	0.5	0.8	1.2	**24**
EV charging infrastructure	0.0	0.1	1.7	2.5	0.4	**43**
Buildings insulation retrofits	1.3	3.3	4.4	4.5	4.8	**128**
Space heating equipment	4.3	4.6	5.4	5.9	6.5	**168**
Total	**23.8**	**27.9**	**36.1**	**42.2**	**36.9**	**1,071**

repurposing the current pipeline network to hydrogen operation. As a result, pipeline CAPEX remains at the current GBP 500mn per year.

Ramp-up of hydrogen production for use in industry, transport, gas-fired generation, and to some extent in domestic heating, will result in increasing investment for electrolysers and reformers; GBP 41bn and GBP 9bn, respectively, over the next 30 years.

Our forecast shows an expected 50 $MtCO_2$/yr carbon capture and storage (CCS) capacity for capturing emissions from the power and process sectors by 2050, requiring a GBP 24bn investment over that period.

Linked to the increased amount of variable renewable sources on the grid, a total of 200 GWh of utility-scale electricity energy storage capacity needs to be added to the network by 2050, requiring GBP 24bn investment over that time frame.

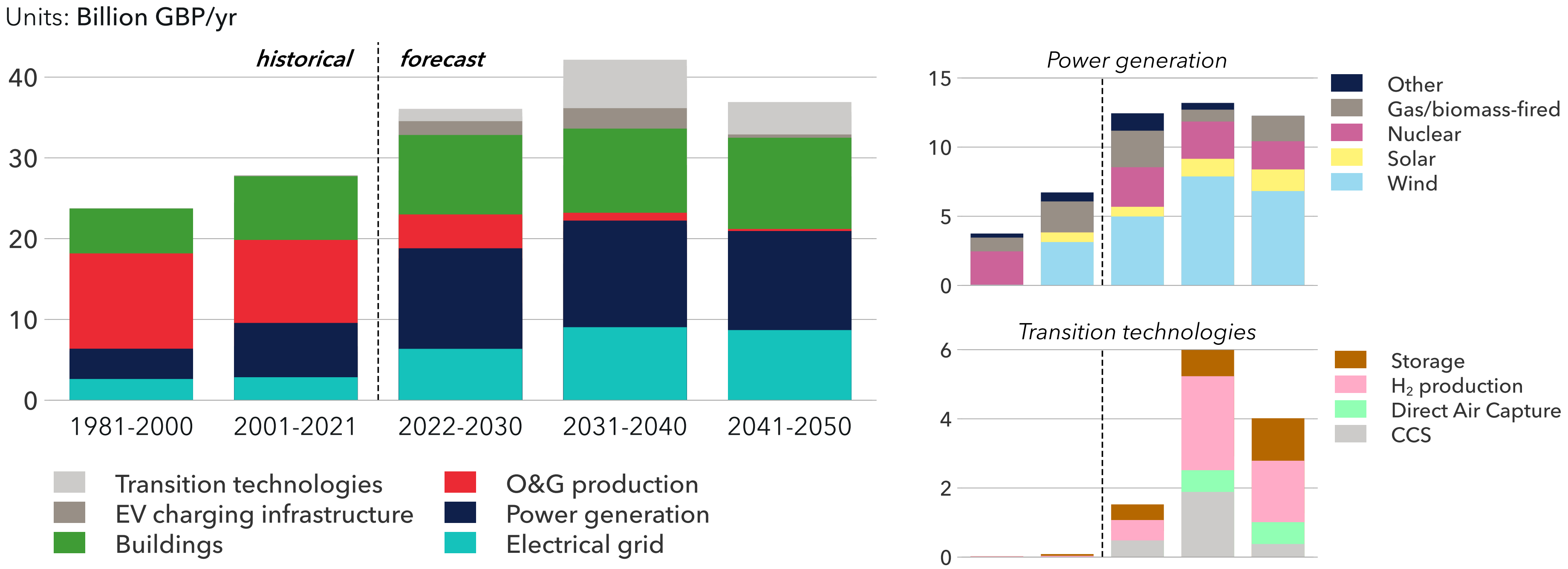
To accommodate the expanding fleet of EVs in the UK, we predict the installation of more than 360,000 fast-charging stations by 2050, requiring total investment of GBP 43bn across the country.

We have also included an estimate for the investment required to upgrade/retrofit insulation in UK buildings to reduce heating energy demand (~35–40% improvement in efficiency) and to allow efficient use of heat pumps across the UK housing stock. We have based our estimates on current retrofit rates of approximately 1% of housing stock per annum (~250,000 homes per annum) and an average retrofit cost of approximately GBP 18,000. This would translate to a cost of approximately GBP 4–5bn per year.

To accommodate the switch from mainly gas-fired central heating to heat pumps for domestic heating, we forecast an increase in annual spend for space-heating equipment across UK residential and commercial properties. Historically, these costs were mainly related to replacing gas boilers at the end of their life (typically 15 years) at an average cost of GBP 4–5bn per year across the UK buildings stock. Going forward, these costs will be a combination of boiler replacements and a gradual introduction of heat pumps. As a result, we expect these average annual replacement costs to increase to GBP 60–7bn/yr by the 2040s.

FIGURE 7.1

Average annual energy system CAPEX spend



7.2 Financing the energy transition

To finance the transition, we need to encourage increased flow of capital into clean-energy projects, but also discourage capital flow into unabated fossil fuels. Capital should flow into projects with the most potential to reduce emissions.

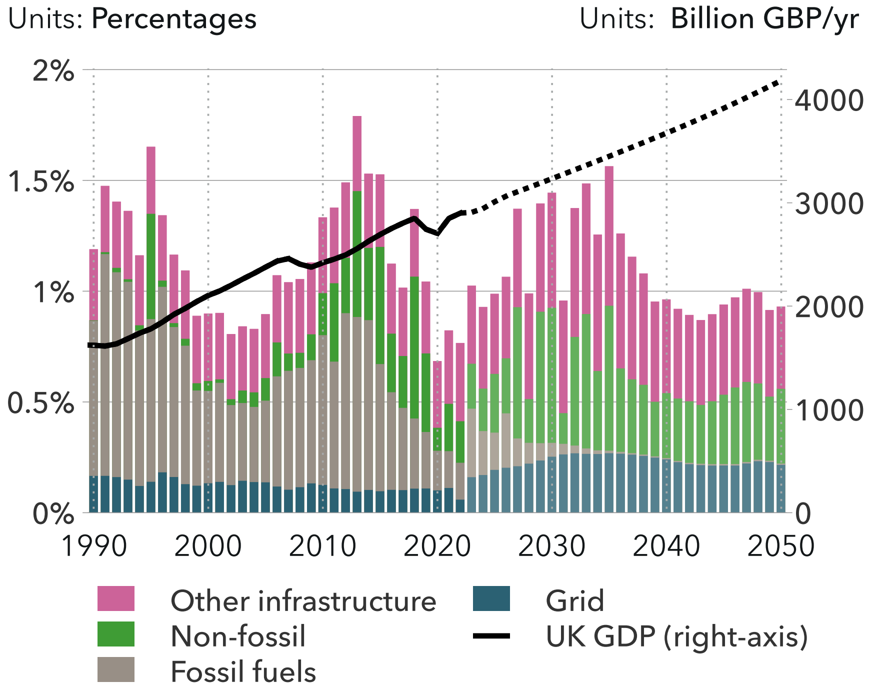
The scale of the challenge is unprecedented, but there are precedents for solutions. Offshore wind in the UK is one such example, where the government 'overpaying' for electricity gave life to the sector and enabled it to scale. The UK is now the world's largest offshore wind market. It now relies less on subsidies, and private investors are the main source of funding for these wind projects.

For the finance community, the capacity of companies to achieve a just transition – both environmental and social – is increasingly among the criteria considered by investors. For energy companies themselves, particularly utilities and others who directly serve the public, a just transition is also about ensuring benefits for consumers and bringing all parts of society along. This offers opportunities if the right business model can be found.

A Paris-compliant energy transition is affordable. As discussed in the previous section, the average annual

FIGURE 7.2

Energy system CAPEX as a percentage of UK GDP



UK energy CAPEX spend will increase in absolute terms from GBP 26bn in the 1980–2022 period to GBP 42bn in the 2040s. However, as the economy grows, the share of GDP devoted to energy CAPEX expenditure remains relatively stable at around 0.9% to 1.1% of GDP across the 1990–2050 period. Energy system spending was significantly higher, at 1.8% of GDP during development of the fossil-fuel industry in the UK in the 1980s.

Fossil energy expenditure represented 50% of UK energy CAPEX expenditure in the previous three decades. We forecast that this share will decline to below 1% in 2050 but will still account for around 15% of total UK energy CAPEX expenditure up to 2030. So, even as capital flows rapidly into clean energy, it is also still flowing into fossil-fuel projects during the coming decade.

This redirection will require significant upfront investment and supportive polices that are costly at least in the short term but with the potential to deliver longer-term cost savings for the consumer.

Financiers

As the redirection of capital away from fossil fuels increases, there will be substantial opportunities for investment in new electricity infrastructure, new generation (most notably wind), in energy efficiency and new energy-use applications.

We recognize that abundant capital is available, and that energy-sector investment decisions will continue to be made relative to returns achievable elsewhere. In this regard, investment in new renewable energy projects remains attractive for many investors. We foresee continued strong interest in onshore/offshore wind and solar PV projects, both from capital moving from oil and gas investments, and from institutional investors with a longer-term investment appetite.

In a declining oil and gas market, priorities are shifting as investors reassess the risks of stranded assets when financing oil and gas projects. The financial markets are increasingly factoring in changing societal sentiment towards a decarbonized future.

There will be increasing opportunities to invest in newer technologies, such as charging infrastructure and new vehicle manufacturers in the EV sector, or CCS or hydrogen production from electrolysis to address hard-to-abate sectors. These newer technologies will require closer scrutiny of their development profiles and potential project risks. They also have greater dependence on government incentives and regulations, and investors will therefore need to remain agile to respond to shifting markets.

Governments/regulators

Governments and regulators play a vital role in mobilizing finance for the energy transition by driving change, enabling a fair marketplace, and underpinning risks.

The right incentive schemes and subsidies can help to accelerate the energy transition. Policy development is crucial when considering how best to enable proven technologies such as wind, solar PV, smart grids and EVs to be swiftly deployed at scale, while also investing in R&D of earlier-stage technologies such as hydrogen electrolysers. Key to this will be clear, consistent policies that provide confidence for private sector investors.

Electricity market regulators should consider how power markets should be designed to efficiently integrate large volumes of variable generation. Dynamic, closer to real-time market operation should remunerate generators for providing network services; for example, for providing reserves to ensure safe network operation in case of major system disturbances, and for providing regulation to ensure networks operate within constraints.

Corporate energy buyers

For large corporates and heavy industry, there is a continued need to strive for more energy-efficient and low-carbon options. Energy efficiency is a low-cost, readily available way to reduce carbon emissions, though its current implementation is far less than the economics would justify. This presents an opportunity for corporate energy buyers to reassess how they fund energy-efficiency initiatives.

Another route for corporate energy buyers to invest in the energy transition is to fund the deployment of local generation at their facilities or invest in utility-scale projects in the neighbouring area. There is also an increasing trend for them to support the energy transition by entering into power purchase agreements with prospective wind and solar projects. This provides businesses with clean power and the developers with greater certainty on their revenue.

Major energy consumers will be able to benefit increasingly from digitalization, enabling energy cost savings through investment in smarter building management. Investment at their own facilities needs to be implemented in parallel with broader smart-city initiatives, which are attracting some interest from the finance sector.


Image: © Cadeler

Household energy expenditure

The feasibility of the UK's energy transition depends in large part on how widespread public acceptability is for the changes required. Public acceptability is in turn influenced largely by the direct financial impacts (costs or savings) on households in their purchase of energy services such as heat and transport. In this section, we look at the likely future development in household energy expenses, which includes annual household energy bills for heating, lighting, appliances, and other energy uses; fuel costs for household vehicles; and the cost of installing (CAPEX) and maintaining (OPEX) heating equipment.

2022 was a year of volatility in energy prices for households. Due to a combination of the effects of the war in Ukraine on energy markets, increasing inflation in the UK economy and a rebound in demand for household transport after the pandemic, total household energy expenditure rose by nearly 20% compared to the previous year. This forced the more vulnerable households into fuel poverty and others to reduce their demand for household energy services. It also forced the government to step in with the setting of price caps on household bills and a winter Energy Bill Support Scheme during the winter of 2022.

Figure 7.3 shows future changes to a typical household's total energy expenditure compared to the year 2021. It shows that, after the initial 20% cost increase in 2022-23, total household energy costs are expected to drop again below 2021 levels by 2026 and then gradually reduce further to nearly 40% below 2021 levels by 2050. The decline in household energy expenditure is driven by increased electrification of both road transport and household heating, leading to an overall reduction in energy demand.

We discuss below the changes in home energy and road fuel costs, which each have their own drivers. From 2023 onwards we expect to see a continual decrease in road fuel costs until 2050. This decrease will be driven predominantly by the increasing rate of households switching from diesel and petrol cars to EVs and the benefits of their higher efficiency. This leads to a 35% energy cost saving by 2050.

In 2022 there was a large upward spike, of a third compared to 2021, in home energy costs. This was because the cost of home energy per kWh rose steeply. Looking forward, we see home energy costs reducing back to 10% above their 2021 level by 2026, and then remaining fairly steady up to 2035, only dropping below 2021 levels in the mid 2040s, reflecting the continued higher costs of electricity and gas for the next two decades. Regarding the net change in home energy expenditure, including both energy and equipment expenses, there is a small net decrease of expenditure by 2050 compared to 2021.

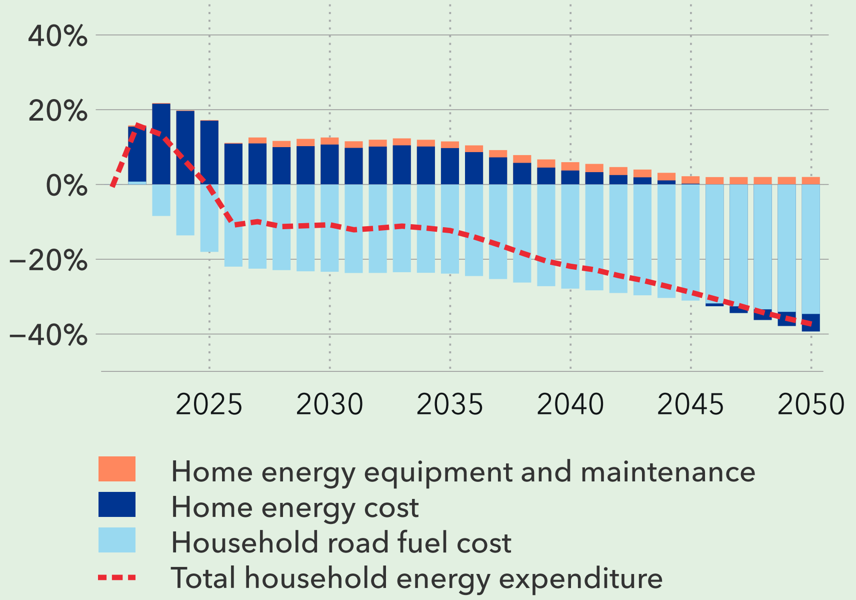
The limits of our assumptions

While these findings are heartening, it is important to articulate that these household energy expenditures invariably do not consider some segments of expenditure and are bound by our explicit assumptions. The cost of retrofitting and better insulation is not considered, but the impact of insulation conditions of the housing stock is accounted for in our heat pump uptake forecast. Neither is the cost outlay for an electric passenger car considered, since we do not consider passenger cars as part of energy infrastructure and because there is a certain degree of flexibility on the consumer side on the car cost. Nevertheless, our EV uptake forecast is driven by our forecast that the total cost of ownership for EVs will continue to decrease steadily over the next decade. ■

FIGURE 7.3

Variation in UK household expenditure on energy, compared to 2021

Units: Difference to 2021 (%)



8 UK EMISSIONS AND CLIMATE IMPLICATIONS

Our forecast shows that the UK will overshoot both its 2030 Nationally Determined Contribution (NDC) commitment under the Paris Agreement and its own legally binding 2050 target of net zero. The buildings and transport sectors are the largest energy-related contributors to the emissions overshoot. There is still opportunity to deliver on the targets, but this will require a transformative approach backed by clear implementation plans. Adaptation and resilience of physical assets to increasing climate hazards should also be included in the implementation plans to deliver an energy secure future.

In this chapter, we discuss the emissions trajectory for the UK based on our forecast primary energy mix up to 2050. In 2020, CO_2 emissions accounted for around 80% of UK GHG emissions, nearly all of them being energy-related. Our ETO model provides a forecast of those energy-related CO_2 emissions up to 2050 based on assumed emission factors for the energy supply mix. To derive the total UK GHG emissions, we add the contribution of other energy and non-energy-related (mainly the agricultural sector) anthropogenic emissions based on decarbonization assumptions.

UK total GHG emissions trajectory

The total UK emission in 2050 is around 125 $MtCO_2e$ approximating to an 85% reduction since 1990. This is a significant reduction but falls well short of the 2019 amendment to the Climate Change Act, which legislated for net zero by 2050.

Our forecast also shows that the UK will not meet its Nationally Determined Contribution (NDC) where the UK committed to a 68% reduction in GHG emissions between 1990 and 2030. We expect the actual reduction to be around 55% by 2030.

To date, the UK has met its first three carbon budgets CB1 (2008–2012) and CB2 (2013–2017) and CB3 (2018–2022). For the next three carbon budgets, we note that the emissions reduction level is correlated to the timing of implementation of government policies and business models which dictate the pace of change in the various sectors of the economy.

Carbon budget 4 (CB4): Our model shows the UK will fail to meet its budget of 1,950 $MtCO_2e$ over the period 2023–2027 as total emissions are expected to be around 2,169 $MtCO_2e$ (average of 434 $MtCO_2e$/yr compared to a budget average of 390 $MtCO_2e$/yr). This can be attributed to the slow pace of emissions reduction in the hard-to-abate sectors such as industrial clusters, heating in buildings, and transport. Hydrogen and carbon capture, utilization and storage business models and allocation rounds

have been announced but we are yet to see the transformative approach required to deliver on the government targets.

Carbon budget 5 (CB5): We expect the UK to slightly overshoot its fifth carbon budget of 1,725 $MtCO_2e$ over the period 2028–2032 with total emissions from our forecast being around 1,806 $MtCO_2e$ (average of 361 $MtCO_2e$/yr compared to a budget average of 345 $MtCO_2e$/yr). There are three main drivers that contribute to average emissions being higher than the CB5 budget.

First, despite the recent announcements on carbon capture and hydrogen, we forecast a slow ramp-up of these technologies in the hard-to-abate sectors of the economy. Second, the delay on the ban on sales of new ICE vehicles in the transport sector to 2035 will impact sales of electric vehicles with significant ramp-up expected to happen beyond 2030. Finally, the current sluggish deployment of renewables implies that the 2030 capacity targets for these power generation assets will not be met and, hence, there will be higher contribution from fossil generation.

Carbon budget 6 (CB6): The UK will not meet its sixth carbon budget of 965 $MtCO_2e$ over the period 2033–2037. Our forecast shows that total emissions over that period will be around 1,319 $MtCO_2e$. The sixth carbon budget is a significant step-up in emissions reduction compared to the previous budgets – the average of 190 $MtCO_2e$ per year for CB6 compared to 345 $MtCO_2e$ per year for CB5 corresponds to a reduction of around 45%.

The key reason for missing the target is that the pace of decarbonization is not fast enough across all the sectors of the economy. The current approach to the energy transition is incremental with no clear implementation plan. To deliver on the 2030 NDC target and the legally binding 2050 net-zero target, a transformative approach backed by clear implementation plans that consider all the stakeholders is required to successfully deliver each target or initiative.

FIGURE 8.1

UK greenhouse gas emissions by sector

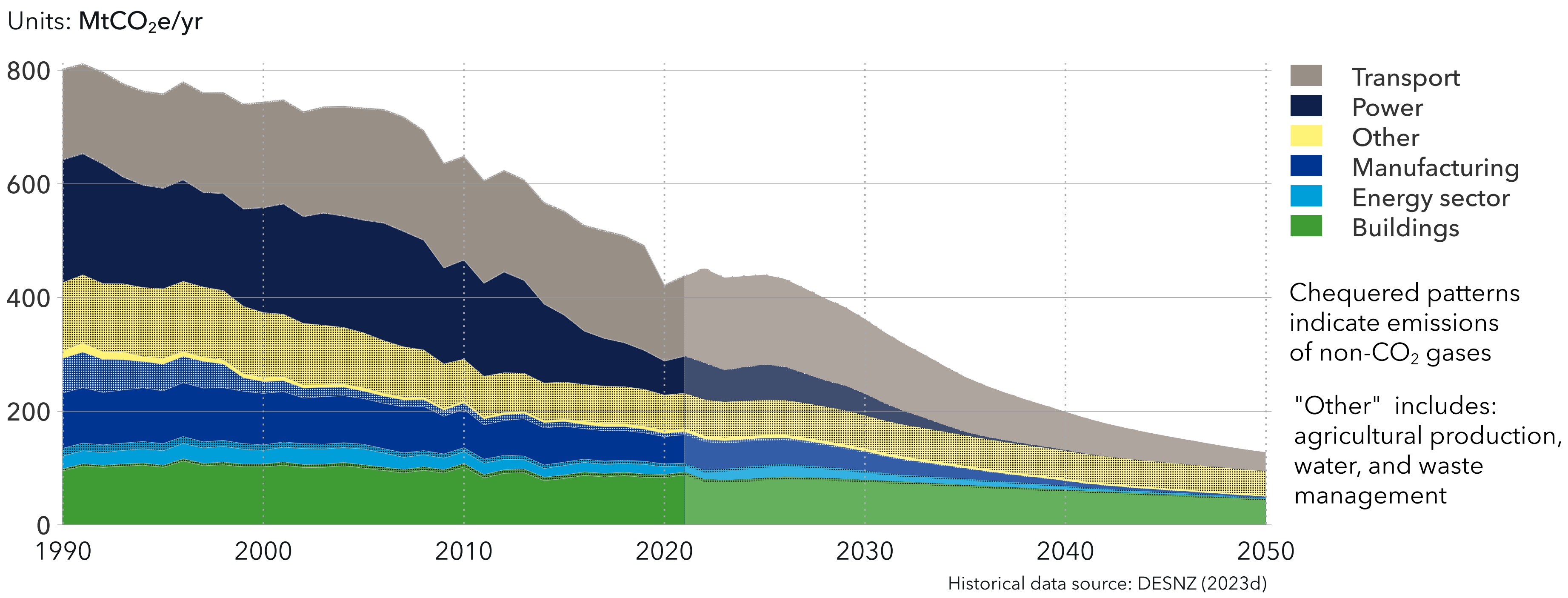
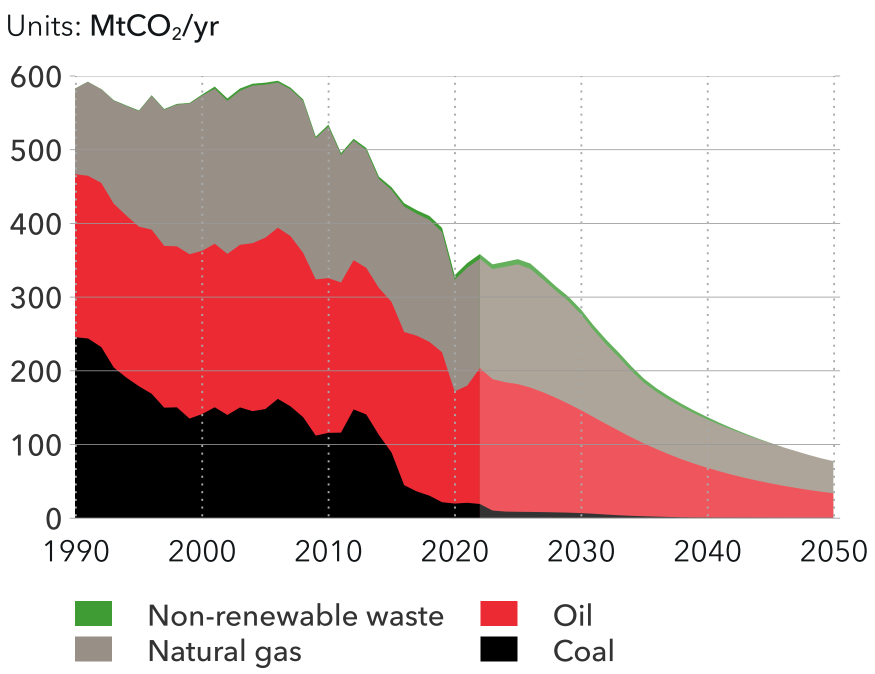


FIGURE 8.2

UK energy-related CO_2 emissions by fuel source



Energy-related emissions by source

UK energy-related CO_2 emissions have fallen by around 38% over the period 1990–2022. Our forecast, as illustrated in Figure 8.2, shows that the energy-related CO_2 emissions will continue to fall over the entire forecast period in lockstep with the decline in use of fossil fuels in our energy system.

- The phase-out of coal in the UK's energy system continues with coal use limited to the manufacturing sector beyond 2024. We have assumed that the UK will stick to its plan to stop the use of unabated coal for electricity generation from October 2024. Coal use in manufacturing will be mainly for high-heat processes such as iron and steel production. We expect that such use will also decrease because of increased recycling, energy efficiency, direct electrification, use of hydrogen and bioenergy, so that there will be minimal emissions from coal use beyond 2030s.
- Natural gas use has grown by around 40% over the period 1990–2021, mainly to replace coal in electricity generation. We expect that gas use will decrease as the power sector decarbonizes and that by 2050, emissions from natural use in the energy system will be around 63% less than in 1990.
- Oil use is on a downward trajectory with emissions from combustion of oil and oil products forecast to be 85% lower than in 1990. This is mainly driven by the electrification of road transport and use of low-carbon fuels in aviation and shipping.

Energy-related emissions by sector
The sectoral breakdown of energy-related CO_2 emissions is shown in Figure 8.3.

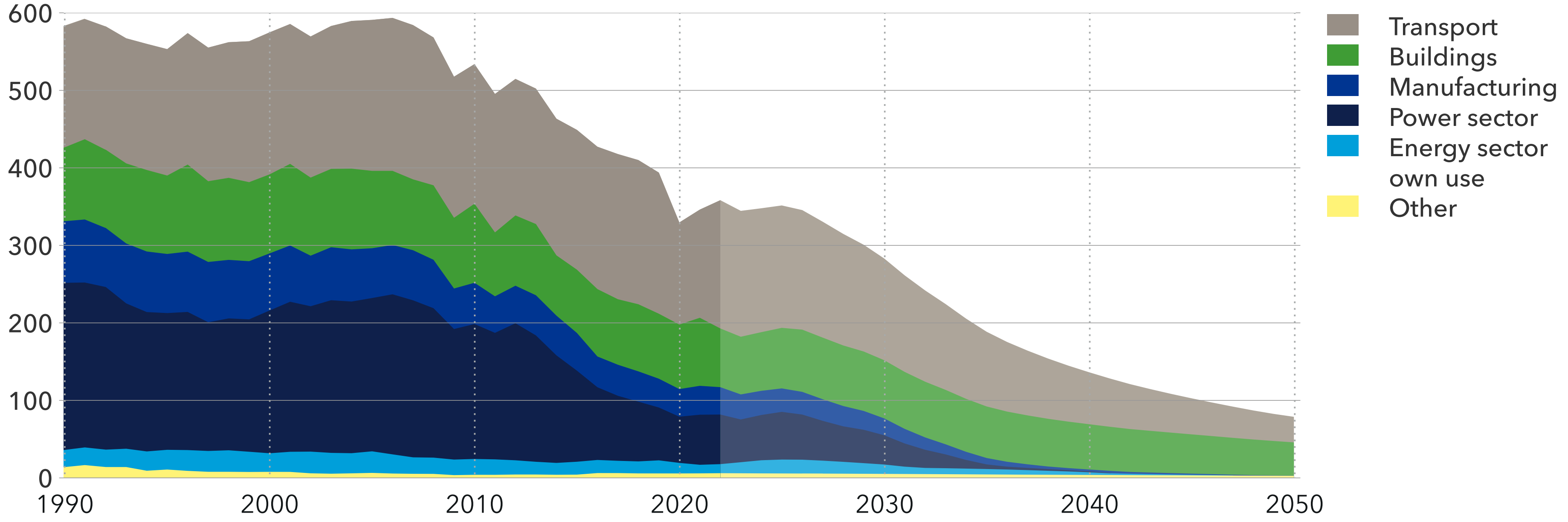
Transport is currently the largest sectoral contributor to energy-related CO_2 emissions with 167 $MtCO_2$ in 2022, around 45% of all energy-related emissions that year. The buildings sector emitted 23% (76 $MtCO_2$) of the total that year while power and manufacturing accounted for around 17% (64 $MtCO_2$) and 13% (50 $MtCO_2$), respectively.

In 2050, emissions from transport will be around 34 $MtCO_2$, 80% less than in 1990. The sector saw a sharp decline in emissions in 2020 due to the COVID-19 pandemic. Its energy demand rebounded in 2021, but in the long term, the UK government ban on sales of new petrol and diesel cars and vans from 2035 will result in sharp decline in transport-related emissions. The impact of the government ban will filter through the sector rapidly, and we see 57% less emission in 2040 than today.

Use of petroleum products will persist within the sector. In road transport, there will be an existing stock of ICEVs, particularly commercial ICEVs, that will continue to use oil products. Within aviation, we see penetration of low-carbon fuels such as synthetic e-fuels and hydrogen emerge for medium to long-haul flights, but this will not fully displace jet fuel by 2050. A similar picture is seen in shipping where ammonia, bio-based fuels and synthetic fuels play an increasing part in long-distance shipping, but marine bunker fuel and LNG will comprise around 30% of the total energy demand in 2050.

FIGURE 8.3
UK energy-related CO_2 emissions by end use

Units: $MtCO_2$/yr



Emissions from hydrogen production is allocated to own-use sector.

The buildings sector also sees a large fall in emissions to around 43 $MtCO_2$ in 2050, around 56% less than in 1990. This fall is driven by a combination of improved energy efficiency of buildings and appliances, as well as the switch to low-carbon sources for heating, primarily in the form of heat pumps, which reach a penetration of around 38% of households by 2050. The remaining emissions in 2050 arise from use of natural gas which comprises over 45% of final energy demand for buildings in 2050, around 55% less than in 2022. The continued use of natural gas is due to the higher levelized cost of hydrogen, which has limited penetration in the buildings sector in 2050.

The power sector is nearly net zero by 2050 (residual emissions of around 3 $MtCO_2$). The government's ambition is to have a fully decarbonized power sector by 2035, but we forecast emissions from that sector to be around 11 $MtCO_2$ by then. Unabated gas generation is the key factor in the grid not being decarbonized by 2035.

The manufacturing sector currently emits around 54 $MtCO_2$, 65% less than in 1990. A significant part of this reduction is due to the offshoring of heavy industries from the UK. We see emissions from this sector declining to around 7 $MtCO_2$ by 2050, 95% less than in 1990. The significant decline is due to several factors including increased circularity within the sector leading to reuse of materials, better design of products, increased efficiency of manufacturing processes, and the use of CCS to capture process emissions.

Adaptation and resilience increasing in prominence

The world experienced a "deafening cacophony of broken records" in 2023 according to the World Meteorological Organization (WMO, 2023). 2023 is set to be warmest year on record, greenhouse gas levels continue to increase, sea surface temperatures are at a record high, and extreme weather is causing death and devastation.

The last few years have left no doubt that climate change is a clear and present danger and is no longer a tragedy on the horizon. While mitigation is key to circumventing global warming, we also need to adapt to the changing climate and ensure that our physical infrastructure and supply chains are resilient to the increasing impact of climatic changes. This is particularly important when we consider how to construct the infrastructure needed for the energy transition. All new infrastructure needs to be sufficiently future-proofed to account for the changes that will occur in our climate.

The government has published its third National Adaptation Programme (NAP) which outlines the UK's strategy to maintain its resilience to the impacts of a changing climate. Further details on the strategy are expected in 2024 as well as the fourth round of the Adaptation Reporting Power (ARP) which gives the government the discretionary power to require infrastructure and public service providers to assess their readiness for climate change. The scope of the assessment includes:

- An assessment of risks, threats and opportunities posed by climate change impacts.
- Developing a programme of adaptation measures on prioritized risks.
- Embedding and monitoring climate change adaptation into existing organizational structures.

In general, environmental reporting requirements for financial institutions and corporates are becoming stronger, with the implementation of the Taskforce on Climate-related Financial Disclosures (TCFD), the publication of the IFRS Sustainability Disclosure Standards, and the recommendations from the Transition Plan Taskforce. Evidence from the annual TCFD status report, however, suggests that organizations are struggling with aspects of reporting requirements for physical climate risks.

> We need to adapt our physical infrastructure to the new reality of increased intensity and frequency of climate hazards.

Assessment of physical climate risks should be conducted as a staged process that should include:

- Developing two climate scenarios, preferable one in line with the Paris Agreement to keep global warming 'well below 2°C' compared with pre-industrial levels, and a second one based on the current trajectory, which is heading for well above 2°C.
- Conducting a high-level screening assessment of the potential impact of various climate hazards over time on the physical assets as well as along the value chain under both climate scenarios.
- Deep diving on critical assets / major risks areas for detailed risk assessment under both climate scenarios.
- Developing adaptation and resilience measures including early warning systems and disaster risk management. ■

Biodiversity matters

Climate change has been the subject of over 30 years of global advocacy and diplomacy with high media coverage on the topic coupled with extensive reporting of the impact of extreme events attributed to global warming.

Biodiversity loss, however, has received much less attention over the years but is rapidly rising in importance as our whole economic system is underpinned by nature, using its natural capital of land, water, and biodiversity. However, the failure to account for the full economic value of the natural capital and its associated biodiversity and ecosystem services is a significant factor in their continuing loss and degradation.

December 2022 saw the ratification of the Kunming-Montreal Global Biodiversity Framework (GBF) by 188 countries as part of COP15 on biodiversity. The GBF aim is to halt and reverse biodiversity loss and put nature on a path to recovery by 2050. The framework includes 23 global targets for urgent action over the decade to 2030.

Target 15 of the GBF is particularly relevant for large and transnational companies and financial institutions as it requires such organizations to regularly assess, monitor, and disclose their impacts and dependencies on biodiversity along their operations, across their value chains and their portfolios.

The recently published recommendations from the Taskforce on Nature-related Financial Disclosures (TNFD) provides a framework for corporates and financial institutions to assess their biodiversity footprint as well as metrics and targets for reporting and disclosure.

The key challenge with assessing biodiversity risks, however, is that nature is far more complex and interrelated than carbon emissions measurement. Biodiversity impact is generally local and requires local data on species, habitats, and ecosystems to assess the actual impact. Such data is, in many cases, unavailable and requires site surveys to be conducted. Seasonality will also play a part in such assessment given migratory and hibernation patterns of certain species and plant growth cycles. In addition, translating the findings from site data into clear action plans can be challenging given that the assessment methodologies to quantify net gain and/or offset strategies are still evolving.

Biodiversity assessment in practice

A staged biodiversity materiality assessment tailored to meet the specific requirements of projects and/or organizations can address the above challenges. The biodiversity materiality assessment would aim to answer key questions in a series of steps:

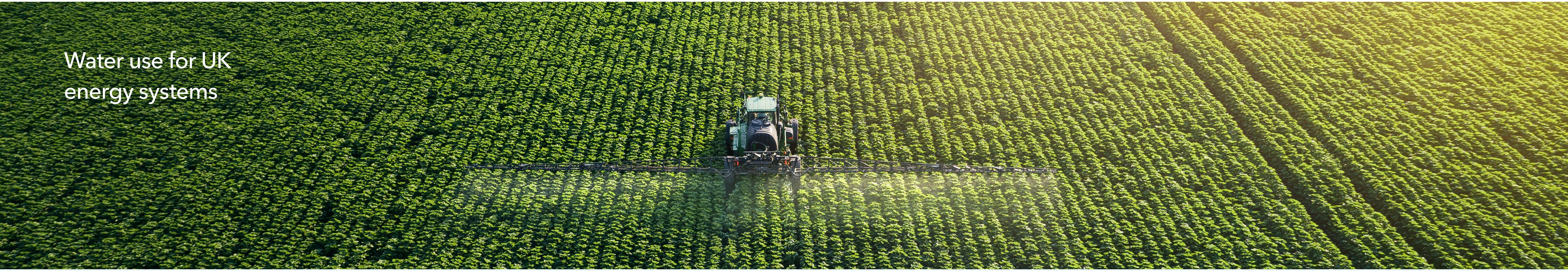
What do we have to worry about? – Screen for material impacts and dependencies by identifying the interface with nature along a company's operations and across its value chains and evaluating the material impacts of those interfaces. The screening will identify high impact and/or high dependency sites based on biodiversity heat maps and local knowledge as far as is available.

To what extent should we be concerned? – Deep dive at the high impact / high dependencies locations to assess the actual state of nature. This can be conducted as a combination of site surveys and satellite data. The outcome would be a detailed view of the species and ecosystem status at those specific sites.

How do we turn the biodiversity data into insights and actions to deliver a positive solution? – Build a risk and opportunity picture by integrating the findings on the state of nature at the high impact / high dependencies locations and the potential impact on relevant stakeholders (through open dialogue) such as local communities, regulators, NGOs, and so on.

How do we ensure we are doing the right things? – Develop company's biodiversity strategy, targets, and metrics. Implement appropriate mitigation and monitoring programmes and ensure transparent reporting and disclosure of performance.

This assessment will enable organizations to understand their potential level of biodiversity risk exposure and their readiness (in terms of resources, data availability, internal capabilities, etc.) to address those risks and deliver positive solutions. The approach will necessarily vary between organization types and will support them in meeting regulatory requirements in various jurisdictions. ■



Water use for UK energy systems

The production of almost all types of energy relies on the water required for the extraction of raw materials, steam generation, hydrogen production, carbon capture and storage, cultivation of crops for biofuels, and cooling for thermal processes. However, some renewable power systems, such as wind and solar PV, require very little water.

We forecast that as we move towards 2040 and beyond, the energy split in the UK will shift so that electricity will deliver around 50% of the final energy demand. Renewable wind and solar generation will account for nearly a third of total primary energy supply. The shift to new low-carbon technologies will change the demand for water and it will remain a key challenge for future low-carbon energy systems.

Hydrogen is likely to be an important part of the energy mix in the future. Although it is the most abundant element on earth, it does not occur naturally. Hydrogen therefore needs to be extracted from either water (using low-carbon electricity) or by reforming fossil-fuel hydrocarbons in the presence of steam. For hydrogen to be a low-carbon fuel, the electricity for electrolysis needs to be low-carbon, and carbon capture and storage (CCS) needs to be part of reforming fossil fuels. We have distinguished between primary and secondary water as described to the right.

Primary Water

Primary water is defined as the boiler make-up water required for steam cycle heat transfer in thermal power generation and water required for the reaction in hydrogen production. The chemical reactions around hydrogen production using primary water are shown in the infographic (see Figure 8.5). The actual quantities of water required will be slightly greater than the theoretical values as shown in Figure 8.4.

Secondary Water

Secondary water is defined as the water required for cooling. Other secondary water uses might include steam or water injection in the gas turbine, or air inlet cooling. ▸▸

FIGURE 8.4

Water demand for hydrogen production by technology

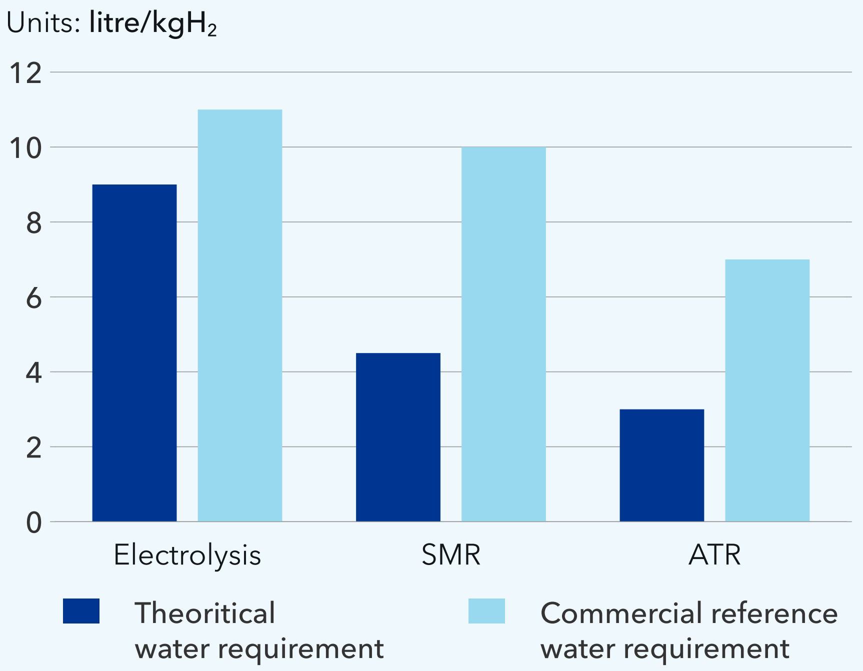
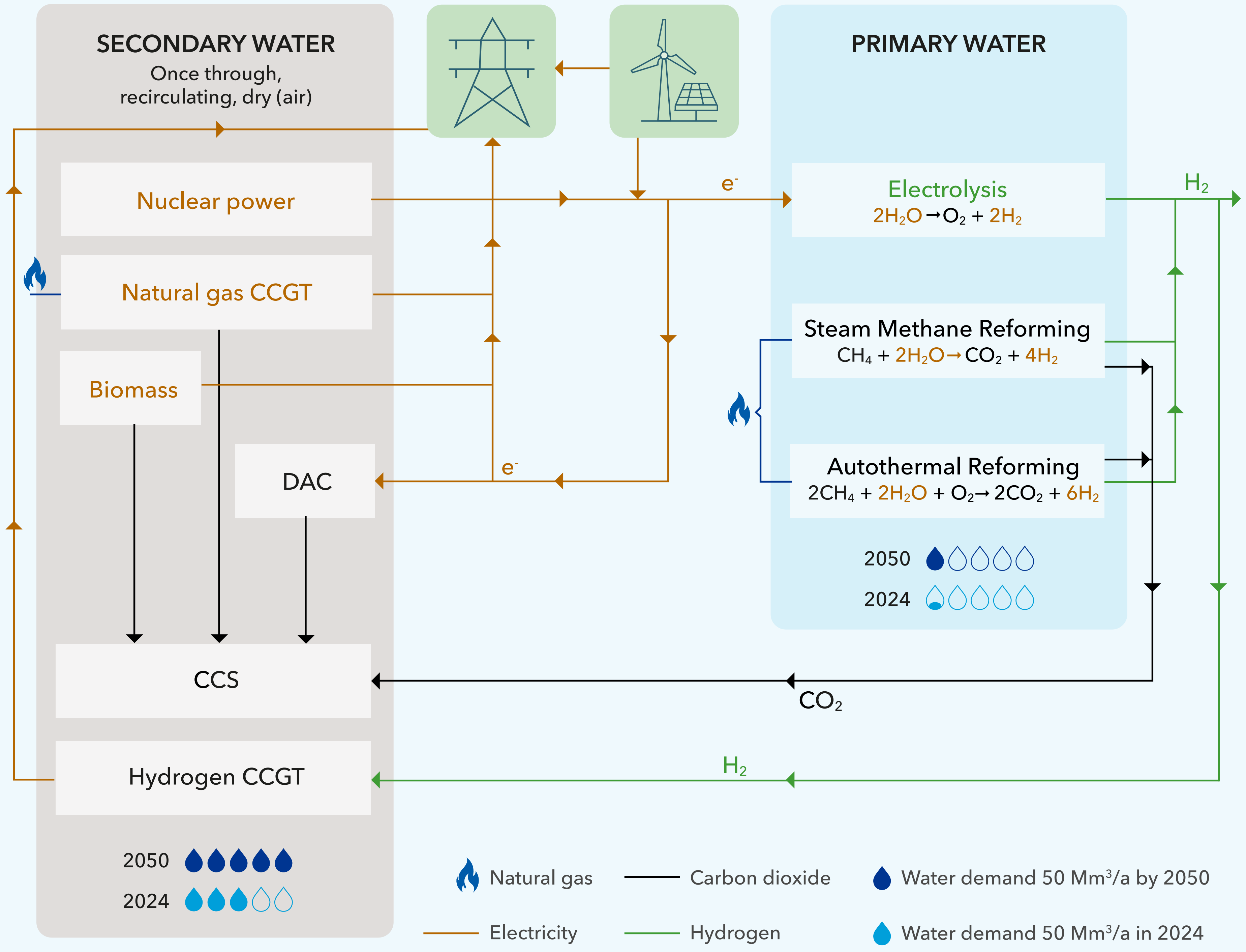


FIGURE 8.5

Water in the energy transition



The role of water in the energy transition is shown in Figure 8.5. Primary water is largely required for hydrogen production and its use will rise 5-fold by 2050. Secondary water is required in all forms of thermal power generation; growing and using biomass; and carbon capture processes. Although secondary water is returned to the environment (for example, cooling water taken from rivers or the sea and returned to them), the quantities required are five to ten times greater than primary water and, most importantly, the power generators and CCS plant cannot run without it. One of the most water-intensive processes is BECCS (bioenergy with CCS), though on the positive side this creates net negative carbon emissions. Also, post-combustion CCS plant installed on coal- and gas-fired power plant decreases the efficiency of electricity production. ››

Five key points about water supply and demand in the UK

1. Water is crucial to almost every aspect of energy supply, from fossil fuel extraction and processing, biofuels cultivation and electricity generation.

2. Reliable access to usable water sources is a worldwide concern and will affect the feasibility of both hydrogen projects and projects in the wider energy sector. Availability of suitable water resources is already having an impact on energy production and reliability, affecting a wide variety of locations and technologies.

3. The availability of water resources to supply new hydrogen production will ultimately be contingent on the selected location and scale of production. The identification and evaluation of suitable water supply sources should be a key consideration when deciding the location and design parameters of a hydrogen production plant. Climate change is already having an impact on water supply, security and demand – this is likely to get worse in the future.

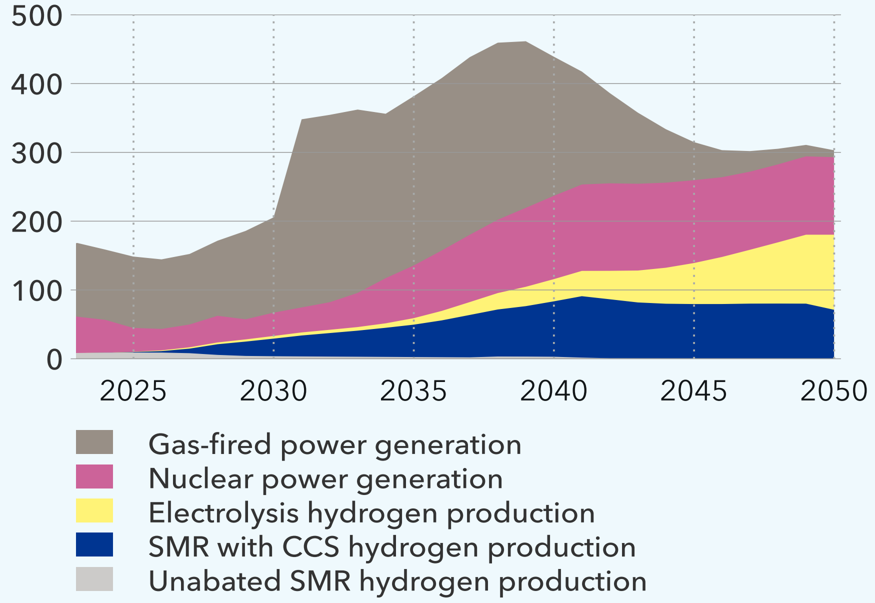
4. As the share of renewable power in the energy supply increases, replacing gas-fired power, the demand for cooling water at gas-fired power stations will correspondingly decrease. Despite this, water demand will remain above current day figures, as primary water demand for hydrogen production and secondary water demand for nuclear power cooling increase over time. The fuels or technologies used to achieve the energy transition, if not properly managed, may increase water stress or be limited by it.

5. Water usage for energy production in the UK is projected to reduce until 2025, after which it will increase out to 2050. This is attributed to an increase of primary water demand for hydrogen production and secondary water demand for nuclear power cooling and carbon capture technology. ■

FIGURE 8.6

Water demand for energy processes

Units: Million m^3/yr



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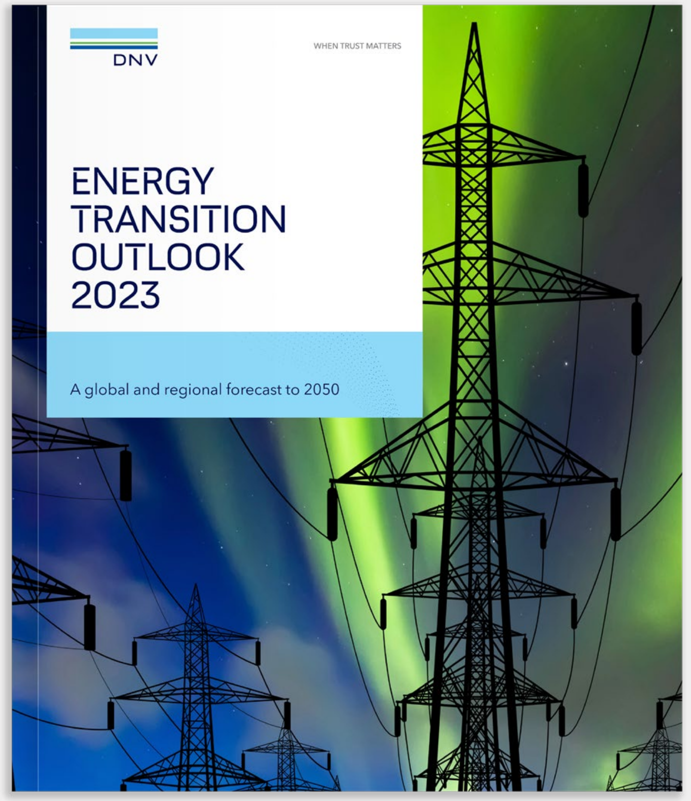

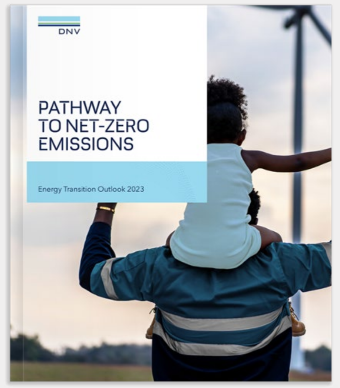

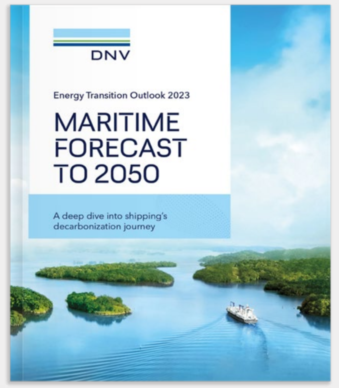

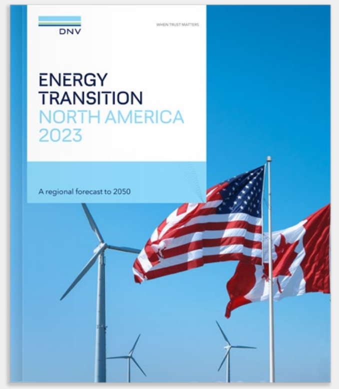

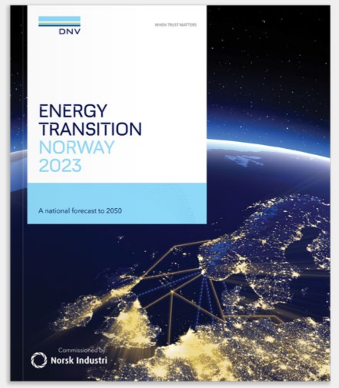

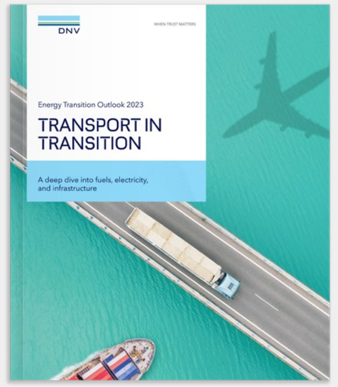

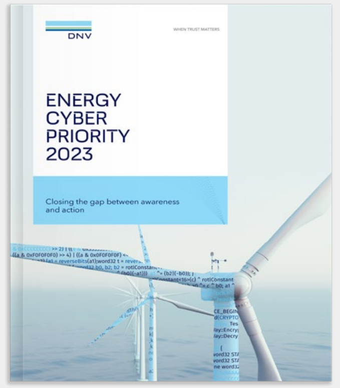

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