THE ROLE OF HYDROGEN AND FUEL CELLS IN FUTURE ENERGY SYSTEMS

A H2FC SUPERGEN White Paper

March 2017
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BACKGROUND

This White Paper has been commissioned by the UK Hydrogen and Fuel Cell (H2FC) SUPERGEN Hub to examine the roles and potential benefits of hydrogen and fuel cell technologies within each sector of future energy systems, and the transition infrastructure that is required to achieve these roles. The H2FC SUPERGEN Hub is an inclusive network encompassing the entire UK hydrogen and fuel cells research community, with around 100 UK-based academics supported by key stakeholders from industry and government. It is funded by the UK EPSRC research council as part of the RCUK Energy Programme. This paper is the third of four that were published over the lifetime of the Hub, with the others examining: (i) low-carbon heat; (ii) energy security; and (iv) economic impacts.

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- John Loughhead (BEIS)

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# GLOSSARY

## Hydrogen and Fuel cell technologies:

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<th>Description</th>
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<tbody>
<tr>
<td>AEC</td>
<td>Alkaline electrolysis cells</td>
</tr>
<tr>
<td>AFC</td>
<td>Alkaline Fuel Cell</td>
</tr>
<tr>
<td>FC</td>
<td>Fuel cell</td>
</tr>
<tr>
<td>H2FC</td>
<td>Hydrogen and fuel cells</td>
</tr>
<tr>
<td>MCFC</td>
<td>Molten Carbonate Fuel Cell</td>
</tr>
<tr>
<td>PAFC</td>
<td>Phosphoric Acid Fuel Cell</td>
</tr>
<tr>
<td>PEM</td>
<td>Polymer electrolyte membrane</td>
</tr>
<tr>
<td>PEMFC</td>
<td>Proton Exchange Membrane Fuel Cell</td>
</tr>
<tr>
<td>PtG</td>
<td>Power-to-gas</td>
</tr>
<tr>
<td>SMR</td>
<td>Steam methane reforming</td>
</tr>
<tr>
<td>SOEC</td>
<td>Solid oxide electrolysis cells</td>
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<tr>
<td>SOFC</td>
<td>Solid Oxide Fuel Cell</td>
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## Other acronyms:

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>BAT</td>
<td>Best available techniques</td>
</tr>
<tr>
<td>BECCS</td>
<td>Bioenergy with CCS</td>
</tr>
<tr>
<td>BEIS</td>
<td>Department for Business, Energy and Industrial Strategy</td>
</tr>
<tr>
<td>BEV</td>
<td>Battery electric vehicle</td>
</tr>
<tr>
<td>CAES</td>
<td>Compressed air energy storage</td>
</tr>
<tr>
<td>CCC</td>
<td>Committee on Climate Change</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
</tr>
<tr>
<td>CCL</td>
<td>Climate Change Levy</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture and storage</td>
</tr>
<tr>
<td>CfD</td>
<td>Contracts for Difference</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined heat and power</td>
</tr>
<tr>
<td>CM</td>
<td>Capacity Mechanisms</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed natural gas</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon monoxide</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>COMAH</td>
<td>Control of Major Accident Hazards</td>
</tr>
<tr>
<td>CPF</td>
<td>Carbon Price Floor</td>
</tr>
<tr>
<td>DECC</td>
<td>Department of Energy and Climate Change</td>
</tr>
<tr>
<td>ECA</td>
<td>Enhanced capital allowances</td>
</tr>
<tr>
<td>ETS</td>
<td>Emissions Trading System</td>
</tr>
<tr>
<td>EV</td>
<td>Electric vehicle</td>
</tr>
<tr>
<td>FC</td>
<td>Fuel cell</td>
</tr>
<tr>
<td>FCEV</td>
<td>Fuel cell electric vehicle</td>
</tr>
<tr>
<td>FiT</td>
<td>Feed-in-Tariffs</td>
</tr>
<tr>
<td>GDHP</td>
<td>Gas-driven heat pump</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gases</td>
</tr>
<tr>
<td>H₂</td>
<td>Hydrogen</td>
</tr>
<tr>
<td>H2FC</td>
<td>Hydrogen and fuel cells</td>
</tr>
<tr>
<td>HGV</td>
<td>Heavy goods vehicle</td>
</tr>
<tr>
<td>HICE</td>
<td>Hydrogen internal combustion engine</td>
</tr>
<tr>
<td>HRS</td>
<td>Hydrogen refuelling station</td>
</tr>
<tr>
<td>ICE</td>
<td>Internal combustion engine</td>
</tr>
<tr>
<td>IED</td>
<td>Industrial Emissions Directive</td>
</tr>
<tr>
<td>LGV</td>
<td>Light goods vehicle</td>
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</tbody>
</table>
Glossary

LPG  Liquid petroleum gas  RHI  Renewable Heating Incentive
NG  Natural gas  RTFC  Renewable transport Fuel Certificates
NGV  Natural gas vehicle  RTFO  Renewable Transport Fuel Obligations
NMVOC  Non-methane volatile organic compounds  SMR  Steam Methane Reformation
NOx  Oxides of nitrogen  SOx  Oxides of sulphur
PHEV  Plug-in hybrid electric vehicle  TCO  Total cost of ownership
PHS  Pumped hydro storage  TIMES  The Integrated MARKAL-EFOM System
PM  Particulate matter  UAV  Unmanned aerial vehicles
PSA  Pressure-swing adsorption  UKTM  UK TIMES Model
PV  Photovoltaic  V2G  Vehicle to Grid
RE-EV  Range extender electric vehicle

Units of energy and power:
MJ, GJ, TJ, PJ  megajoule, gigajoule, terajoule, petajoule
kW, MW, GW  kilowatt, megawatt, gigawatt
kWh, MWh, GWh, TWh  kilowatt-hour, megawatt-hour, gigawatt-hour, terawatt-hour

Note that the chemical energy of a fuel can be expressed relative to higher heating value (HHV) which is the thermodynamic definition of energy content, or lower heating value (LHV) which neglects the latent heat of the water vapours produced during combustion. To convert efficiency expressed against LHV into HHV, for:

- fuel cells or turbines running on hydrogen: divide by 1.183;
- fuel cells or turbines running on natural gas: divide by 1.109;
- electrolysers producing hydrogen: multiply by 1.183;
- converting hydrogen to natural gas: divide by 1.067.
### 1. INTRODUCTION

Hydrogen and fuel cells are now being deployed commercially for mainstream applications. Hydrogen has fallen in and out of favour since the oil shocks of the 1970s, but remains a marginal energy system option. However, mainstream products are now emerging: Honda, Toyota and Hyundai have launched the first mass-produced hydrogen vehicles, and fuel cells now heat 180,000 Japanese homes. Early-mover companies, notably in Japan, are beginning to see lucrative export opportunities.

**Hydrogen can play a major role alongside electricity in the low-carbon economy.** Electricity is being decarbonised rapidly and has the ability to cross over into heat and transport. Hydrogen possesses this same versatility and enables routes to deeper decarbonisation through providing low carbon flexibility and storage. The numerous hydrogen production, distribution and consumption pathways present complex trade-offs between cost, emissions, scalability, and requirements for purity and pressure.
Hydrogen and fuel cells are not synonymous; they can be deployed in combination or separately. Fuel cells can operate on natural gas, which avoids combustion and thus 90% of airborne pollutants. Hydrogen can be burnt in engines and boilers with no direct CO₂ and near-zero NOₓ emissions. When used together, hydrogen fuel cells are zero-emission at the point of use, with overall emissions dependent on the fuel production method (as with electricity).

2. LANDSCAPE

Modelling suggests that both hydrogen and fuel cells form part of the least-cost solution to decarbonising the UK economy out to 2050. With no government intervention they offer the best value route to decarbonising heavy goods vehicles, some industries and peak power generation. However, with consistent long-term commitment as much as 50% of final energy demand could be met by hydrogen in 2050, with wide-ranging uses across transport, heat and industry.

Low-cost strategic investments can be made to ‘keep the door open' for hydrogen technologies. The option to use hydrogen in strategically important sectors can be retained for a slight increase in decarbonisation cost. This can reinforce energy security and provide insurance against other technologies failing to deliver as anticipated (e.g. carbon capture or heat pumps). Hydrogen technologies have a familiar look and feel for consumers, enabling greater personal choice in decarbonisation.

3. TRANSPORT

Fuel cell vehicles are now being produced on assembly lines by major manufacturers. Costs have significant potential to fall with mass production and can achieve parity with electric alternatives by 2025–2030. Driving range and refuelling time are significantly better than premium electric vehicles, which is particularly advantageous for buses, heavy goods and other highly-utilised vehicles. Fuel cells are therefore among a portfolio of powertrains expected to replace the internal combustion engine. As with electric and unlike biofuels, fuel cell vehicles also improve urban air quality by producing zero exhaust emissions. This is driving deployment of hydrogen vehicles in cities, railways, airports, seaports and warehouses.

4. HEAT

Decarbonising heat faces several challenges, with strong user requirements that hydrogen boilers and fuel cells can meet. Innovations in heat lag behind other sectors as electrification with heat pumps, district heating and burning biomass face multiple barriers. UK households are accustomed to compact powerful heating systems, which can be modified to use hydrogen. Fuel cell combined heat and power can operate on today’s natural gas network, albeit with limited carbon savings. Hydrogen presents various options for decarbonising this network in the longer term.
5. ELECTRICITY

Hydrogen technologies can support low-carbon electricity systems dominated by intermittent renewables and/or electric heating demand. Fuel cells provide controllable capacity that helpfully offset the additional peak demand of heat pumps. In addition to managing short-term dynamics, converting electricity into hydrogen or other fuels (power-to-gas) could provide the large-scale, long-term storage required to shift renewable electricity between times of surplus and shortfall. Data centres, backup supplies and households are major applications for hydrogen and fuel cells.

6. INFRASTRUCTURE

The ‘hydrogen economy’ is not necessary for hydrogen and fuel cells to flourish. Too much is made of the ‘chicken and egg’ strategy problem of whether consumer demand or large central infrastructure should come first. Instead, markets can be established while avoiding potentially high-regret investments early on. On-site hydrogen production can use existing electricity and gas infrastructures (e.g. distributed refilling stations and fuel cell heating). Focussing on specific users such as captive vehicle fleets (e.g. urban buses with central refuelling depots) could provide the high utilisation and demand certainty needed for investment. Given the diversity of decarbonisation pathways, a clear strategy will reduce the costs of introducing hydrogen and fuel cell technologies.

7. POLICY

Successful innovation requires focused, predictable and consistent energy policy. Frequent policy changes undermine business and industry confidence for making long-term investments in low-carbon technologies such as hydrogen and fuel cells. The UK must develop a system of policy support that fits its context and circumstances. Much can be learned from experiences abroad, but the wholesale transfer of policies from other countries is unlikely to be successful. The UK’s hydrogen and fuel cell deployment is heavily funded by Europe, and is at risk with Britain exiting the European Union.

Developing a green hydrogen standard is necessary to include hydrogen in many energy policies. A guarantee of origin scheme would enable hydrogen from low-carbon and renewable energy sources to be verified and rewarded. EU member states have developed several competing standards; the UK has the opportunity to implement a standard that reflects its national interests.

UK firms are international leaders in power-to-gas, fuel cell vehicles, alkaline fuel cells and component supply chains for the hydrogen industry. In contrast with competing countries, UK energy and industrial policy implicitly neglects the development and deployment of hydrogen and fuel cell technologies. Levelling this policy playing field would catalyse technology uptake and embolden UK companies to take a leading position in the global hydrogen and fuel cell sector.
This White Paper is split into three broad parts:

Part I (Chapters 1–2) introduces existing hydrogen niche markets and considers the potential role of hydrogen and fuel cells in the future across the economy, using the literature supported by scenario modelling with the UKTM model.

Part II (Chapters 3–5) examines hydrogen and fuel cell systems for transport, heat and electricity generation. It provides the core evidence base for the White Paper, delivered via review and synthesis of the relevant literature, and shows various aspects of their system-level value proposition, their potential role in more integrated energy systems, and the synergies and options they create with regard to infrastructures, storage and efficiency.

Part III (Chapters 6–7) explores how a transition to hydrogen and fuel cells might be achieved, considering the development of hydrogen infrastructure across the UK, and the current strategic direction for hydrogen policy plus the role of existing and future policy instruments.

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1.3 Introduction to hydrogen and fuel cells

1.4 Future roles for hydrogen and fuel cells

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1. THE OPPORTUNITY FOR HYDROGEN AND FUEL CELL TECHNOLOGIES

The potential for hydrogen and fuel cells to make a substantial contribution to clean energy systems has long been identified. This White Paper reviews the evidence base for using hydrogen and fuel cells across the UK energy system and draws together key insights around the roles they may play in the future.

The UK has committed to reducing all greenhouse gas (GHG) emissions, including those from international aviation and shipping, by 80% in 2050 compared to 1990. As of 2015, the UK is 38% below 1990 emissions, and a set of interim targets ("carbon budgets") have been enacted into law, notably a 50% reduction by 2025 and 57% by 2030. The majority of emissions arise from the combustion of fossil fuels, so the Government must manage a transition away from coal, oil and natural gas towards a low-carbon energy system over the coming decades. An allied policy priority is the improvement of air quality in cities, which could also be achieved through reducing fossil fuel use or using these fuels without combustion.

Other energy policy objectives include the provision of secure and affordable energy. There will inevitably be tensions between these objectives; for example, moving to a low-carbon system is likely to increase the overall cost of delivering energy, at least in the short term. But the development of low-carbon energy technologies, including hydrogen and fuel cells, also offers opportunities to create innovative new businesses. The costs of hydrogen and particularly fuel cell technologies have fallen rapidly over the last decade. Early movers with these technologies have an opportunity to build a lead in this emerging market, with potential both to create manufacturing exports and to avoid primary energy imports.

Hydrogen has been used in the UK energy system since the 1800s, as the largest constituent of town gas produced by coal gasification. Since the switch from town gas to natural gas in the 1970s, hydrogen has continued to be used in industry for ammonia production and refining oil. Hydrogen is highly versatile: it can be produced from coal, natural gas, biomass or electricity, and be transported by pipeline or road, or be produced locally in a decentralised system.

Looking forward, hydrogen is the only alternative zero-carbon energy carrier (transmitter of energy) to electricity under serious consideration for transport, heat and industry in the UK. It could replace or supplement natural gas to power high-efficiency fuel cells, and is easier and cheaper to store than electricity.

A range of hydrogen-fuelled technologies has been developed that offer significant advantages for consumers when compared to electric alternatives. Most technologies that run on natural gas have been redesigned to use hydrogen; for example, household boilers and vehicle internal combustion engines. Fuel cells are advanced technologies that avoid combustion, producing electricity from hydrogen at high efficiencies with no pollutants. They are scalable, with high conversion efficiencies at even very small sizes. They can be used in a variety of sectors, for example to power electric motors.
in fuel cell vehicles, for combined heat and power (CHP) generation in buildings, and for electricity generation at a range of scales.

Fuel cell electric vehicles (FCEVs) have long been the most promising market, as in contrast to battery electric vehicles they offer driving ranges and refuelling times that are similar to existing petrol vehicles. The UK has a substantial engine and vehicle manufacturing industry. This could be threatened by the rise of both battery electric and FCEVs, or UK industry could adapt to exploit these new markets by developing expertise and capacity in low-carbon vehicle technologies. One estimate suggests that investment in hydrogen and fuel cell technologies for transport could create UK industries with an export potential of £10–26bn (cumulative) by 2050. This opportunity is unlikely to be realised unless the Government and industry recognise and react at an early stage to the opportunities presented by these new technologies.

2. TOWARDS A LOW-CARBON UK ENERGY SYSTEM

The UK energy system is currently dominated by oil, natural gas and coal, although the latter is declining. Figure S1 shows final energy consumption by sector for the year 2015. Most heating is fuelled by natural gas, while virtually all transport is powered by oil products. Electricity is used primarily for applications that cannot use other fuels, and more than half of UK electricity generation is generated from natural gas and coal.

Figure S1 UK final energy consumption by sector and fuel in 2015, data from DUKES.¹

In the short term, fossil fuel emissions can be reduced by using more efficient technologies such as condensing boilers and hybrid cars, reducing demand through energy conservation measures, or fuel switching from coal to natural gas. Ultimately these fossil fuels must be replaced or their CO₂ emissions captured to achieve the low-carbon energy system required by law.

Numerous low-carbon technologies are available or are under development. Decarbonising electricity generation is the first major step through renewable generation, nuclear power and carbon capture and storage (CCS). Many see this as a prelude to electrifying heat and transport with high-efficiency technologies such as heat pumps and battery electric vehicles. Biomass technologies are under development and a range of hydrogen and fuel cell technologies are also ready to contribute to the transition. Hydrogen is a zero-carbon energy carrier like electricity, with numerous potential uses across the whole economy and many ways to be integrated into the UK’s energy system.

3. SCENARIOS OF ALTERNATIVE ENERGY SYSTEM FUTURES

The UK energy system converts a range of primary resources (e.g. crude oil; wind) into usable energy carriers (e.g. petrol; electricity), which are used to meet energy service demands (e.g. heat, light and mobility). A range of low-carbon resources and energy carriers have been proposed for the future, which could be linked across different sectors through markets and investments.

To gain insight into how energy systems may develop, scenarios with different assumptions about costs, constraints and conditions are explored using energy system models. The UK TIMES Model (UKTM), which is employed by the UK Government, is used in this White Paper to examine six scenarios for hydrogen and fuel cell development in different UK energy system futures. They all assume that the UK will meet the 80% greenhouse gas (GHG) reduction commitment, but take different technological pathways. Box S1 gives a brief overview of the six scenarios.
BOX S1 OVERVIEW OF THE SIX SCENARIOS

**Least Cost**: the lowest-cost method of achieving the GHG target based on input assumptions.

**Critical Path**: the hydrogen option is kept open to 2030 through small investments in infrastructure and road vehicles; deployment ramps up in 2050 for strategically important end uses (transport and electricity).

**Gas Conversion**: gas networks are converted to deliver hydrogen; homeowners choose between low-carbon heating and transport technologies primarily on cost.

**Full Contribution**: hydrogen is taken up across the economy; hydrogen boilers and hybrid heat pumps heat most houses by 2050; almost all road vehicles use fuel cells; substantial contributions from hydrogen in industry and electricity generation as well.

**No Hydrogen**: a counterfactual scenario that is the same as Least Cost, except that no hydrogen technologies are available.

**Electrification**: a counterfactual scenario with widespread electrification of end-use technologies that relies primarily on renewable generation.

Table S1 summarises the assumptions and constraints that are applied to each scenario.

**Table S1 Assumptions and constraints concerning hydrogen (H2) and natural gas (NG) across energy sectors in each scenario. The industry figures are for the year 2050.**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Transport</th>
<th>Buildings</th>
<th>Industry</th>
<th>Electricity</th>
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<tbody>
<tr>
<td>Least Cost</td>
<td>Flexible</td>
<td>0% H₂⁺</td>
<td>Flexible</td>
<td>Flexible</td>
</tr>
<tr>
<td>Critical Path</td>
<td>Strategic H₂</td>
<td>No H₂</td>
<td>8 TWh</td>
<td>H₂ peak only</td>
</tr>
<tr>
<td>Gas Conversion</td>
<td>Flexible</td>
<td>No NG**</td>
<td>Max 30% NG</td>
<td>Flexible</td>
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<tr>
<td>Full Contribution</td>
<td>Maximum H₂</td>
<td>All gas to H₂</td>
<td>Min 40% H₂</td>
<td>H₂ mid-merit</td>
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<td>No Hydrogen</td>
<td>No H₂</td>
<td>No H₂</td>
<td>No H₂</td>
<td>No H₂</td>
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<tr>
<td>Electrification</td>
<td>No H₂</td>
<td>No H₂</td>
<td>No H₂</td>
<td>No fossil fuels</td>
</tr>
</tbody>
</table>

* Gas network conversion is assumed to be a government-led strategy that does not occur in the Least Cost scenario.

** The gas networks are assumed to be systematically converted to hydrogen from 2025 to 2045, so no NG heating is available after 2045.

Figure S2 shows the very different levels of hydrogen in final energy demand in the six scenarios. Total final energy consumption in the first five scenarios is similar, with increases in hydrogen generally balanced by decreases in natural gas consumption. The Electrification scenario has a much greater reliance on both biomass and electricity for final end-use consumption, and is the only scenario with virtually no gas or hydrogen consumption.
**Figure S2** Final energy consumption in 2050, in the six scenarios.

**Figure S3** Hydrogen consumption in each sector in 2050, in the six scenarios.
Figure S3 shows how hydrogen is used across sectors of the economy in the six scenarios. Hydrogen is the most economic option for haulage and some buses, and so a substantial amount is used in the Least Cost and Critical Path scenarios. Hydrogen consumption is highest in the Gas Conversion and Full Contribution scenarios, where it is used across a range of sectors. Residential hydrogen consumption is higher in Gas Conversion as fuel cell combined heat and power (CHP) is used as well as hydrogen boilers, highlighting the possibility for wide variations in consumption even if all gas networks are converted.

The scenarios suggest that hydrogen and fuel cell technologies could play a substantial role in the future, in one or more sectors. In Full Contribution, almost 50% of end-use demand is met by hydrogen in 2050, and fuel cells are deployed as least-cost options in both the transport and heat sectors in different scenarios. A major role for fuel cell vehicles is identified for haulage even in the Least Cost scenario, and to a lesser extent for cars, as battery electric vehicles are not cost-competitive for long distance or high utilisation activities.

The different levels of hydrogen consumption across the first four scenarios lead to different choices of demand-side technologies. Despite this, impacts on the supply side are quite minor. The natural gas displaced by hydrogen in heating is mostly used to manufacture hydrogen, meaning that primary energy consumption and the electricity system are very similar across all scenarios. The move towards greater electrification in No Hydrogen and Electrification has a greater impact on the supply side than introducing hydrogen.

The total costs of the scenarios are listed in Table S2 relative to the unconstrained optimum of the Least Cost scenario. The costs of Critical Path and No Hydrogen are close to Least Cost. A common feature of these three scenarios is the continued use of gas heating in many homes. Gas Conversion is 50% more expensive, while Full Contribution more than doubles the cost of decarbonisation. Electrification is by far the most expensive scenario, at 7 times the least-cost decarbonisation pathway, reflecting the importance of fossil fuels to meeting emission targets at low cost. The table also highlights the importance of carbon capture and storage (CCS) technologies to minimising the cost of decarbonisation. If bioenergy with CCS (BECCS) or all CCS technologies are not available at the costs assumed in the model, then the cost of decarbonisation increases substantially. The additional cost of extensively using hydrogen in these cases is reduced, highlighting their importance as an ‘insurance option’ in diversifying the country’s routes towards decarbonisation.
The additional costs of the hydrogen scenarios might be considered acceptable by consumers, particularly since they look and operate in a similar way to existing fossil-fuelled technologies and avoid certain negative characteristics of electrical technologies (e.g. space requirements and limited output from heat pumps, or shorter range and long recharging time of battery electric vehicles). From this perspective, hydrogen offers a low-carbon, business-as-usual approach for consumers that alternative technologies cannot currently match. Offering consumers greater choice in how they decarbonise their energy consumption could be vital in fostering the long-term public commitment that will be required.

### Table S2 Total discounted costs of the energy systems in each scenario.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Basic scenario</th>
<th>No BECCS</th>
<th>No CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Least Cost</td>
<td>1.0</td>
<td>1.8</td>
<td>2.0</td>
</tr>
<tr>
<td>Critical Path</td>
<td>1.2</td>
<td>2.0</td>
<td>2.1</td>
</tr>
<tr>
<td>Gas Conversion</td>
<td>1.5</td>
<td>2.2</td>
<td>2.6</td>
</tr>
<tr>
<td>Full Contribution</td>
<td>2.3</td>
<td>2.6</td>
<td>3.0</td>
</tr>
<tr>
<td>No Hydrogen</td>
<td>1.1</td>
<td>2.2</td>
<td>2.3</td>
</tr>
<tr>
<td>Electrification</td>
<td>7.0</td>
<td>7.0</td>
<td>7.0</td>
</tr>
</tbody>
</table>

All costs are relative to the difference between the Least Cost scenario cost and the cost of an unconstrained reference scenario with no GHG emission targets. The Least Cost scenario therefore has a cost = 1. BECCS is bioenergy with carbon capture and storage (CCS).

### 4. HYDROGEN AND FUEL CELLS FOR TRANSPORT

Fuel cell electric vehicles (FCEVs) show great cost reduction potential, with several recent studies concluding that total cost of ownership can converge with alternative options as production volumes rise. Their technical characteristics are widely seen as preferable to battery electric vehicles (fast refuelling and long driving range), and they offer more efficient powertrains and quieter, smoother driving than internal combustion engines.

FCEVs have no exhaust emissions other than small amounts of water and so can contribute to improving air quality in urban areas. As the significant health costs of diesel emissions become more apparent and cities come under increasing pressure to tackle air pollution, there is a compelling argument for the immediate rollout of FCEVs into niche high-mileage urban fleets (e.g. buses, taxis, delivery vans and bin lorries).

An early rollout of hydrogen vehicles could also be stimulated by a desire for energy security in nations with limited access to fossil fuels, and similarly in remote regions with high renewable availability, such as the Highlands and Islands of Scotland, where fuel costs are higher. A further draw is the opportunity for early movers to capture commercial advantage in a new sector, including opportunities for supply chains and local economic development.
FCEV sales to date have been slow but are now seeing significant uptake as major manufacturers (Toyota, Honda and Hyundai) have recently launched mass-produced vehicles. Hydrogen buses are also being employed in several capital cities, and are achieving or in some cases exceeding availability and longevity targets.

The purchase price of FCEVs is likely to remain high in the short term. Low running costs mean they are more cost-effective in high-utilisation sectors such as taxis, buses and lorries, particularly those able to refuel from a small handful of refuelling depots. This also makes FCEVs a candidate to be a successful operator in a car-sharing economy and among commercial fleets, where the utilisation of battery electric vehicles is handicapped by their need for frequent, time-consuming recharging.

5. HYDROGEN AND FUEL CELLS FOR HEAT

As shown in Figure S4, nearly half of UK energy is used to provide heat.

Figure S4 Energy consumption by end use and sector.

Heat has acquired a “hard-to-decarbonise” reputation compared to other sectors, with modest emission reduction projections by 2030. Several low-carbon options for heat have been identified, including demand reduction, heat pumps, district heating, green gas and onsite combined heat and power (CHP) generation. Heat pumps and district heating have seen significant deployment in other countries, but these are not widely used in the UK and experience with them so far has been poor. While some studies have tended to favour widespread rollout of one of these technologies to the exclusion of others, the concept of a ‘portfolio’ of heating systems has gained popularity recently, with a mix of technologies that varies according to local availability and building type. This would mark a departure from current practice where gas boilers dominate, but has precedence historically and is widely practised abroad.

A particular problem in decarbonising the heat sector is that demand undergoes significant daily and seasonal swings, much more so than for transport or electricity. The current gas-based system (high output boilers and flexible networks) handles this well, but electric or district heating systems could struggle as they tend to have limited output and slower response times. Options exist for reducing peak demand, including better-insulated buildings, more efficient heating appliances and thermal storage, but there are limits to what they can achieve, not least because of strong preferences and conservative behaviour in households. The ability to provide high power from a small device is likely to remain a priority for many British consumers.

Gas-fuelled boilers have many attractive features, including low capital and running costs, high reliability and long life, high power output and fast response times, and their small size and ability to work without hot water storage. In addition, their maturity means supply chains and associated servicing industries are well established. Hence there is considerable interest in implementing low-carbon gas-based heating systems.

Biogases are one option for low-carbon heating, but question marks remain over their availability and whether their use is best reserved for the most difficult sectors to decarbonise, such as industry and aviation. Hydrogen injection into the existing natural gas streams is a second option, but current regulations effectively prevent this in the UK. Only a few percent can be blended without impacting on the performance of modern devices, and any such efforts would likely require an inspection of all gas-burning appliances to ensure absolute safety.

A third option is conversion of a large part of the existing natural gas network to deliver pure hydrogen instead of natural gas. There is a precedent from the use of town gas, which was delivered to UK homes through the gas networks until the 1970s and contained around 50% hydrogen. The new plastic pipes being installed under the UK’s Iron Mains Replacement Programme are likely to be compatible with hydrogen, although its different combustion qualities mean that all appliances would need to be replaced, including boilers, cookers, wall-fires and furnaces. A phased transition could be used, where ‘hydrogen-ready’ devices are sold for many years ahead of the switch, as practised with the changes to unleaded petrol, digital radio and television.

There are several options for efficient gas-based heating appliances. Existing condensing gas boilers could be augmented with flue gas heat recovery systems. Gas-driven heat pumps are more efficient, as are hybrid heat pumps that combine an electric heat pump with a gas boiler for meeting peak demand. Hydrogen-fuelled versions of all these technologies can be produced.

3 Hydrogen leakage rates from iron gas mains prior to the introduction of natural gas would not be acceptable today for safety reasons, but plastic pipes have very low leakage. The Iron Mains Programme has been replacing all iron pipes near buildings with plastic pipes for the last 20 years to improve gas safety, and is expected to conclude in the mid-2030s.
Combined heat and power (CHP) systems are another option which generate electricity as well as heat with high overall efficiency, and can be either engine or fuel cell-based. Fuel cells are now the dominant technology for residential micro-CHP, as costs have halved and lifetimes doubled with increasing rollout in Japan and also more recently in Europe. These systems mostly operate on natural gas, but could switch to hydrogen (which would reduce capital cost) if it became widely available.

CHP systems are also popular in the commercial sector, where they can benefit from economies of scale and have fewer space constraints. Low fuel costs are important, as is reliability, long lifetime, high utilisation and effective policy support. Heating systems are long-life assets, meaning it can take decades for new technologies to be introduced.

6. HYDROGEN AND FUEL CELLS FOR INDUSTRIAL PROCESSES

Industry in the UK accounts for around 30% of fuel consumption used to generate heat, and also has a reputation for being difficult to decarbonise. Hydrogen is already widely used in industry, and there are opportunities for existing usage to be extended and decarbonised. Several chemical manufacturing processes produce hydrogen as a by-product, and it is used to make ammonia, upgrade hydrocarbon fuels and to hydrogenate fats. Hydrogen could replace natural gas as a fuel for providing heat across a range of temperatures across several industries, although burners and furnaces might need replacement. Hydrogen is one of the few fuels that has the potential to decarbonise high-temperature processes such as steelmaking and cement.

7. HYDROGEN AND FUEL CELLS FOR POWER GENERATION

Figure S5 shows that industry, the service sector and houses are the three largest groups of electricity consumers globally, though transport may grow rapidly with the adoption of electric vehicles. Around a quarter of electricity consumption is used for providing thermal comfort, which may also grow if electric heat pumps take hold.
Extended summary

More than two thirds of the electricity generated worldwide is produced through burning fossil fuels, but with a range of low-, zero- and even negative-carbon alternatives available, rapid reduction in the carbon emissions from power generation are achievable. A central challenge for the UK is balancing the inherently unpredictable and uncontrollable outputs of solar and wind farms with electricity demand.

Gas turbines and engines are among the technologies used to balance renewable output and provide the stabilisation services that the grid needs. These are amongst the highest carbon technologies on the grid, but could be adapted to run on decarbonised hydrogen.

Fuel cells can supply controllable output and offer efficiencies that rival the most advanced combined cycle gas turbines (CCGTs) at up to 60%. They can be used for utility-scale power, commercial buildings (such as data centres) or individual households. They currently run on natural gas or other hydrocarbon fuels, but could more easily operate on hydrogen if it were widely available. Fuel cells are also quiet, non-polluting and compact, making them ideal for urban environments.

Up-front costs for fuel cells are higher than for other technologies, but have fallen 75% in the last 10 years. Deployment has been subsidised for several years in Japan, where 180,000 homes are now heated and powered by fuel cells. Product lifetime and reliability have improved significantly, to the point where they match modern gas-fired boilers.
Depending on their fuel source, fuel cells can at best be carbon neutral; at worst, when running on natural gas, their emissions are similar to those of new CCGTs. However, the UK’s electricity system is rapidly decarbonising, and average grid carbon emissions are now equivalent to those of fuel-cell CHP, when credit is given for the heat that is also produced. A low-carbon source of hydrogen is therefore required for fuel cells to contribute towards deep decarbonisation.

Fuel cell CHP could also remove a barrier to electrifying heat, namely the large expansion in generating capacity that would be required if millions of homes were to adopt electric heat pumps. These would increase peak electricity demand, which occurs on the coldest winter evenings when fuel cell CHP would be operating and generating electricity.

Electrification of road transport could similarly affect security of supply, as unregulated charging of battery electric vehicles could greatly increase peak demand. Fuel cell electric vehicles remove this issue entirely, whilst potentially delivering an additional benefit of distributed vehicle-to-grid capacity. With advances in smart-grid technology, system operators could potentially access energy stored within vehicle batteries and hydrogen tanks to meet peak demand, balance renewables and supply other grid services. Moreover, a typical vehicle’s tank of hydrogen could generate enough electricity to supply an average household for around four days, offering the potential for emergency back-up.

Hydrogen technologies also have the potential to provide the type of large-scale, long-term storage that is required to shift electricity from times of surplus to those of shortfall, helping to eliminate the need to curtail renewables. Power-to-gas technologies produce hydrogen from water through electrolysis, which may then be stored for later use, injected into gas networks in small concentrations, or converted into a variety of chemical feedstocks. The hydrogen could be further converted to methane using captured CO₂, allowing it to be injected into the existing gas distribution and storage network without need for wholesale infrastructure replacement.

8. HYDROGEN INFRASTRUCTURE

Like electricity, pure hydrogen does not occur naturally as a fuel and must be produced and transported to its point of use. Compared to natural gas, hydrogen is more difficult to handle as the energy density is much lower, the smaller molecules can escape through materials and damage unprotected steel through embrittlement. The costs of installing and operating hydrogen distribution infrastructure can be considerable and need to be quantified.

There are a number of potential distribution pathways for hydrogen, some of which are summarised in Figure S6. On-site production can make use of the existing gas and electricity distribution infrastructures to provide a low-cost, low-risk initial route to market. This is currently employed by residential fuel cell systems (with internal natural gas reformers) and some refuelling stations (with forecourt electrolysers). Centralised production with bespoke hydrogen distribution channels may become
preferable in the longer term once significant hydrogen demand is established, as economies of scale allow them to deliver a lower cost per kg of fuel. Hydrogen for transport applications could be distributed as a compressed gas by tube trailer, where not produced on-site. While costs per kg are relatively high, total outlays are less than for alternative options until demand is established and growing.

**Figure 56** Hydrogen delivery pathways discussed in this White Paper. This diagram is simplified and non-exhaustive, and serves to highlight the diversity of options at each stage of the system.

In the longer term, hydrogen transmission pipelines would be the most cost-effective means for distributing large quantities of fuel, and could supply hydrogen for the transport, heat, industry and power sectors. However, pipeline installation is sufficiently costly and disruptive for careful analysis to be needed to establish whether hydrogen is the best option across all these sectors, so that a hydrogen transmission system could be appropriately sized to cater for this level of demand. These costs could be significantly reduced if the existing low-pressure natural gas distribution network is repurposed to transport hydrogen. New dedicated high-pressure hydrogen pipelines will still be needed to avoid embrittlement and to supply the high-pressure transport sector.

Liquefaction is a further option that can transport more hydrogen than compression and with lower upfront costs than using pipelines. It is particularly promising for
large-scale transport and bulk storage, and is being considered for shipping hydrogen to Japan from Australia. However, high cooling costs and boil-off rates could limit usage to early stage infrastructure development and a few heavy-duty transport sectors in the long-term.

Table S3 summarises some of the main characteristics of the principal hydrogen transmission and distribution options. Several alternative hydrogen carriers which do not require high pressures or low temperatures are also at various (earlier) stages of development.

**Table S3** Qualitative overview of hydrogen transmission and distribution technologies for hydrogen delivery in the transport sector. Adapted from the IEA.  

<table>
<thead>
<tr>
<th>Distribution route</th>
<th>Capacity</th>
<th>Transport Distance</th>
<th>Energy Loss</th>
<th>Fixed Costs</th>
<th>Variable Costs</th>
<th>Deployment Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-site production</td>
<td>Low</td>
<td>Zero</td>
<td>Low</td>
<td>Low</td>
<td>High</td>
<td>Near term</td>
</tr>
<tr>
<td>Gaseous tube trailers</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>High</td>
<td>Near term</td>
</tr>
<tr>
<td>Liquefied tankers</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium to long term</td>
</tr>
<tr>
<td>Hydrogen pipelines</td>
<td>High</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>Medium to long term</td>
</tr>
</tbody>
</table>

The ‘chicken and egg’ problem is synonymous with hydrogen: fuel cell vehicle sales are held back by a lack of refuelling infrastructure, and investors are reluctant to build costly infrastructure until there is significant demand. This is being addressed through a series of public-private stakeholder initiatives committed to rolling out initial hydrogen infrastructure. There is a target to install over 3,000 refuelling stations globally by 2025, after which it is expected further refuelling infrastructure will be justified by increasing uptake of hydrogen vehicles.

Urban hydrogen refuelling stations may face space challenges due to the need for additional equipment. Safety considerations associated with refuelling infrastructure are under continuous review by experts in the UK and internationally. Several knowledge gaps are yet to be closed and relevant regulations, codes and standards may need to be updated.

Some transport uses, for example car fleets, buses, lorries, trains, ferries, airport/seaport vehicles and forklift trucks, are likely to use centralised refuelling depots. These could serve as an entry point for developing hydrogen infrastructure, as high initial utilisation could be guaranteed from a lower number of stations with fewer space constraints.

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Hydrogen for transport applications typically requires compression to 350 bar (for buses) and 700 bar (for cars) to achieve acceptable driving ranges. 700 bar (~10,000 psi) is considerably above the hydrogen pressures used in industry, and the compression work needed for refuelling stations is estimated to cost around £1/kg and consume around 10% of the energy content of the fuel.

Transport applications also require hydrogen with very high purity. This could be up to 99.9999% depending on carbon monoxide content and fuel cell specifications to maintain the longevity of fuel cell vehicles. Purification increases the cost of fuel, but is partially offset by lower fuel cell capital and maintenance costs (as less platinum catalyst is required) and longer lifetimes. Hydrogen generated from electrolysis is close to this required purity; however, steam methane reforming (SMR) and other sources require considerable cleaning stages to reach these levels, which would likely result in yield reduction.

Understanding and managing the risk of uncertain future demand for hydrogen is a key challenge when planning major infrastructure deployments. It is not clear who should be responsible for driving a transition and how such financial risks should be apportioned, although evidence from the literature suggests the need to involve several levels of government, private companies, NGOs and the public. Given the diversity of transition options, a clear strategy will help to reduce the costs of introducing hydrogen and fuel cell technologies, although this must be balanced against the need for flexibility to manage the risk of lock-in to a suboptimal design for the future energy system.

9. POLICIES FOR HYDROGEN AND FUEL CELLS

There is now widespread experience in the UK and elsewhere on giving policy support to low-carbon technologies. However, hydrogen and fuel cell technologies are not included within most current UK policy instruments. This means that hydrogen does not qualify for support like renewables, and fuel cells similarly receive little support compared to electric powertrains and heating devices.

The numerous sources of hydrogen mean that, like electricity, it could be zero-carbon (from renewables), low-carbon (from natural gas with carbon capture and storage) or high-carbon (from coal gasification). The development of a green hydrogen standard is necessary to facilitate the inclusion of hydrogen in policymaking. A guarantee of origin scheme would enable hydrogen from low-carbon and renewable energy sources to be verified and rewarded, as has proved successful with renewable electricity (ROCs) and transport fuels (RTFCs). EU member states have developed several competing standards, which could be harmonised. The UK has an opportunity to develop a standard that is tailored to its specific policy objectives, focussing on carbon intensity or promoting renewable feedstocks.

Hydrogen and fuel cell systems are currently at a competitive disadvantage compared to incumbent technologies due to low economies of scale and the fact that the negative externalities of fossil fuels (carbon and air quality emissions) are not internalised in the costs of fuels and the technologies that use them.

Evidence suggests that policy intervention in other countries has enabled fuel cell technologies to reach commercialisation and become competitive in some niche applications. Strong and sustained policies in countries such as Japan have successfully underpinned the initial deployment of fuel cells, greatly reducing capital costs and creating a new export industry through accelerated innovation. However, this strategy cannot be directly transferred to the UK without changes to account for the local context (e.g. the lack of large industrial conglomerates). With an industrial strategy that provides the right policy support, in a consistent, long-term manner, the UK could also be in a strong position to claim a leading role in the hydrogen and fuel cell industry, which would build on its substantial research and small and medium enterprise (SME) capacity in this area.

10. CONCLUSIONS ON HYDROGEN AND FUEL CELLS IN ENERGY SYSTEMS

Hydrogen and fuel cell technologies are clean options that contribute to cost-effective decarbonisation across several sectors of the energy system and to wider environmental goals such as minimising air pollution, while having minimal impact on the consumer experience. Scenarios in this White Paper show that the long-term penetration of hydrogen and fuel cell technologies could vary from a few small niches to providing virtually all transport and heat demands, as well as supporting a low-carbon electricity system. Moreover, hydrogen offers a low-carbon, business-as-usual approach for consumers that alternative low-carbon technologies cannot currently match. Hydrogen and particularly fuel cell technologies have long been touted as revolutionary, but are now reaching maturity in many markets.

The transition to hydrogen could be led by heat or transport, taking a decentralised or centralised approach. Any large-scale infrastructure would probably require government support and forward planning to cope with the scale and uncertainties involved. Transmission pipelines and distribution networks are natural monopolies and so would likely be heavily regulated. In contrast, several hydrogen refuelling stations are already in operation in the UK with distributed on-site electrolysers. These could benefit from standardisation and modularity and therefore essentially from mass production. So while the early stages of a transport-led transition might be achieved with limited Government intervention, a heat-led transition would require a joint decision from Government and industry in order to be viable. The longer-term success of a transport-led transition would also be more likely if it were underpinned by Government support.
Transport has long been seen as the most promising market for hydrogen and fuel cells. Numerous companies have active development programmes for fuel cell cars. It is entirely possible that a material number of fuel cell vehicles will be driving on UK roads in the next 5 years if the minimum necessary refuelling infrastructure can be constructed. Initially, the use of refuelling infrastructure for buses is envisaged, as is already the case in some parts of the UK. Environmental challenges such as air quality in London and other major cities are likely to provide a spur for such zero-emission vehicles, particularly for high-mileage vehicles such as taxis and buses. Whether or not FCEVs become the cheapest technology in the longer term will depend on innovation successes for these and competing technologies, as the cost differences are small and the uncertainties are large. Heavy goods vehicles (HGVs) and buses are arguably the most promising market for FCEVs in the near term due to the lack of obvious low-carbon alternatives.

Fuel cell CHP has been deployed for commercial and district heat-scale technologies for several decades, and fuel cell micro-CHP is now being widely deployed with little or no subsidy in homes in Japan, South Korea and several other countries. Hydrogen can also be used to generate heat in hydrogen boilers and hybrid heat pumps. Using hydrogen to decarbonise heat by repurposing existing low-pressure gas networks has recently received much attention in the UK, as it would remove CO₂ emissions at point-of-use while providing a comparable service to existing gas boilers. The scenarios presented in this White Paper show that the most cost-effective approach would be for some households to stop using gas for heating and for those that adopt hydrogen to consider a range of technologies other than gas boilers.

Hydrogen could also be used to decarbonise many industrial heat and CHP processes, with the principal challenge being to supply sufficiently low-cost hydrogen. For example, hydrogen could be piped to boilers, direct fired heaters and furnaces in large industrial sites that currently use natural gas, in which the disparate locations and sizes of the boilers would prevent CO₂ from being economically captured.

Hydrogen and fuel cell technologies are often perceived as competitors to high-efficiency electrical appliances for heat and transport. Yet both hydrogen and fuel cells could support the operation of a low-carbon electricity system, and would be particularly valuable if it were composed primarily of low-carbon technologies which are primarily inflexible or intermittent (e.g. nuclear and renewables).

Hydrogen turbines and engines could provide zero-carbon peak power generation at times of greatest demand. Similarly, distributed generation which operates at peak times (such as fuel cell micro-CHP on winter evenings) can avoid investment in peak generation plant. At the same time, power-to-gas provides a flexible energy conversion method that can minimise the need to curtail renewables due to there being insufficient demand at times of high generation. A combination of these technologies offers a potentially cheaper alternative to power-to-power electricity storage such as household battery storage systems. Strategically investing in new capacity that is both flexible and low carbon, such as fuel cells and power-to-gas, could help the UK achieve the goals of high security, low cost and low emissions.
Other environmental impacts such as emissions that affect urban air quality are also becoming increasingly important. To achieve these objectives UK energy policy has encouraged renewables, electric vehicle powertrains and combined heat and power, but not hydrogen and fuel cells. It seems likely that a certification system for ‘green hydrogen’ will be required for it to contribute to a low-carbon economy, and hence for be included in future policy instruments. The UK Government has had a working group on Green Hydrogen in the past; reviving this would underpin the sustainable use of hydrogen for transport or heat applications.

Hydrogen could support the integration of renewable generation into a stable and resilient electricity system, both through zero-carbon peak generation at times of high demand and through power-to-gas at times of excess supply, but it is not clear that existing market structures would enable profitable private-sector investments in these technologies. There is currently little incentive for producers, transmission or delivery companies to fund such projects on their own. Demonstration projects would help private actors to understand and become familiar with these technologies, reducing uncertainty and risk, whilst facilitating cost reductions and helping to identify how they could be integrated into existing or new market structures.

An inescapable conclusion of this analysis is therefore that robust government policy is required across several fronts if hydrogen and fuel cells are to fulfil their potential, both in providing low-carbon and clean, sustainable energy in the UK transport, heat and power sectors, and in becoming a source of UK industrial growth, exports and employment.
1.1 INTRODUCTION

The potential for hydrogen and fuel cell energy systems to make a substantial contribution to clean, sustainable energy systems has long been identified. Hydrogen-powered fuel cell electric vehicles (FCEVs) received much exposure during the 2000s, but a lack of commercial models contributed some disillusion and a switch of attention to battery electric vehicles [1]. Nevertheless, hydrogen and fuel cell vehicles may now be approaching commercial maturity as major manufacturers including Honda, Toyota and Hyundai launch the first mass-produced FCEV passenger vehicles. FCEVs are also becoming dominant in niche markets such as forklift trucks. After ten years of commercialisation, fuel cells are also taking off for residential combined heat and power (CHP), with over 180,000 systems now sold in Japan, and large field trials featuring a British manufacturer (Ceres Power) continuing in Europe. In the UK, the potential for hydrogen to decarbonise heat is gaining traction. Hydrogen is also used to support the integration of renewables in Germany, through power-to-gas plants that convert excess electricity into hydrogen injected into the gas networks.

These developments highlight the numerous potential uses of hydrogen and fuel cells, across many sectors of the economy, and some of the many ways they could be integrated into the UK’s energy system. This White Paper reviews the evidence base for hydrogen and fuel cell products and their role in the UK’s future energy system.

1.2 THE CHALLENGE: LOW-CARBON, SECURE, AFFORDABLE ENERGY

The UK has committed to reducing all greenhouse gas emissions, including international aviation and shipping emissions, to below 155 MtCO$_2$e in 2050, a reduction of 80% compared to 1990 [2]. The majority of these emissions are caused through energy consumption (Figure 1.1). A key energy policy for the government is to transition the UK to a sustainable energy system over the coming decades, which is low-carbon but which also minimises other environmental impacts such as poor air quality in cities.

The Committee on Climate Change (CCC) establish interim targets in their five-yearly Carbon Budgets, the first five of which have been accepted into law. These specify a 35% reduction by around 2020, 50% by 2030, and 57% by 2035 [4]. The CCC’s Central Scenario gives the sectoral breakdown for 2030 shown in Figure 1.2, with reduction targets of 16% in industry and 24% in buildings through to 48% in transport and 72% in electricity generation [5]. This wide range reflects the relative difficulty of decarbonising very different activities.
Figure 1.1 UK greenhouse gas emissions since 1990 and the target in 2050,\textsuperscript{6} data from [3].

Figure 1.2 Sector breakdown of near-term UK carbon emissions reductions, from the CCC’s Central Scenario [5]. Other includes agriculture, land use, waste and F-gases.

\textsuperscript{6} International aviation and shipping emissions are not included in the 2050 target, but the CCC recommends that they be included.
The other two pillars of the energy trilemma that underpins government policy are secure and affordable energy. The implications of hydrogen and fuel cells for energy security are examined in the fourth H2FC Hub White Paper on Energy Security [6]. There will inevitably be tensions between these three drivers; for example, moving to a low-carbon system is likely to increase the overall cost of delivering energy, in the short term at least [7].

But there are also opportunities to create innovative new businesses in green technologies. The costs of numerous hydrogen and particularly fuel cell technologies have fallen rapidly over the last few years through innovation. The first adopters of such technologies have an opportunity to build an early lead in this emerging market, with the potential both to create manufacturing exports and to avoid primary energy imports. The UK has a substantial industry related to the manufacture of internal combustion engines and vehicles that could be threatened by the emergence of FCEVs unless the UK were also to develop industrial expertise and capacity in hydrogen and fuel cell technologies and vehicles. One estimate suggests that investment in hydrogen technologies for transport could create UK industries with the potential to contribute economic value of £10–26bn to 2050 [8]. The economic implications of deploying hydrogen and fuel cell technologies are explored in the second H2FC Hub White Paper on Economic Impacts [9].

1.2.1 Options for evolving to a low-carbon energy system

The UK energy system is dominated by oil, natural gas and coal, as shown in Figure 1.3. Most heating is fuelled by natural gas, while virtually all transport is powered by petroleum products. Electricity is used primarily for applications that cannot use other fuels, and more than half of UK electricity generation is from coal and natural gas plants.

Figure 1.3 UK final energy consumption by sector and fuel in 2015, data from [10].
Fossil fuel emissions can be reduced by using more efficient technologies such as condensing boilers and hybrid cars, or by reducing demand through energy conservation measures, or by fuel switching from coal to natural gas. Ultimately though these fossil fuels must be replaced, or the CO₂ emissions captured, in order to move to a low-carbon energy system.

Numerous low-carbon technologies are available or are under development. Decarbonising electricity generation is the first major step [7], through renewables, nuclear power and carbon capture and storage (CCS). Many see this as a prelude to electrifying heat and transport with high-efficiency technologies such as heat pumps and battery electric vehicles. Biomass technologies are under development and a range of hydrogen and fuel cell technologies could also contribute to a transition. Hydrogen is a zero-carbon energy carrier, like electricity, meaning that there are no emissions at point-of-use and the overall emissions depend on the choice of hydrogen production and delivery systems. Hydrogen and fuel cell technologies are very flexible and could contribute in many different ways to different sectors.

1.2.2 A systems perspective of energy system evolution

This White Paper examines future energy systems. Energy systems fundamentally provide energy services to end-users, but the concept of an energy system has a range of interpretations across academic disciplines.

From an economic perspective, energy systems can be viewed as a series of interconnected markets and investments that meet energy service demands in the economy. Chapter 2 takes this perspective to model various scenarios for the integration of hydrogen and fuel cell technologies.

In engineering, energy systems tend to refer to a complex network or group of interacting or integrated technologies. In this White Paper, an engineering perspective is used in Chapters 3–6 to review the principal hydrogen and fuel cell technologies across a range of sectors and to consider how they might be integrated with the wider energy system.

The importance of providing a reliable and affordable energy supply means that most energy systems are heavily regulated. Since regulations are normally designed for incumbent technologies, they can unintentionally lead to lock-in of these technologies and their associated fuels, and lock-out of alternatives. To transition towards a low-carbon energy system, institutional, social, political and other factors will need to be taken into account [11]. Chapter 7 examines policy issues surrounding hydrogen and fuel cells systems, and considers the role of the Government in developing hydrogen systems.

An overarching systems view should aim to account for all of these influences. To understand the many factors that underpin the transition to an alternative energy system, it should consider questions around infrastructure choices; the technical, social and economic implications of technologies and energy vectors; how people interact with energy technologies; and how innovation works.
1.3 INTRODUCTION TO HYDROGEN AND FUEL CELLS

Hydrogen is the only zero-carbon alternative energy carrier to electricity under serious consideration in the UK. It has many potential uses across all sectors of the economy, as a supplement or replacement for natural gas, to power high-efficiency fuel cells, and to provide storage in a variety of forms and scales. These technologies potentially offer some significant advantages for consumers compared to electric alternatives.

Hydrogen has been used in the UK energy system since the 1800s, as the largest constituent of town gas, which was produced by coal gasification. Since the switchover from town gas to natural gas in the 1970s, hydrogen has primarily been used in industry, for ammonia production, in oil refineries, and elsewhere. There are 2,400 km of high-pressure hydrogen pipelines worldwide, principally in Europe and North America, with the oldest operating since 1938 [12]. The UK has only a few short pipelines that connect merchant hydrogen plants to customers at present. Hydrogen can be produced from coal, natural gas, biomass or electricity, and transported by pipeline or by road to the point of consumption, or produced locally in a decentralised system [13].

A range of hydrogen-fuelled technologies has been developed. Most technologies that are fuelled by natural gas can be adapted to use hydrogen, including boilers in homes and internal combustion engines in compressed natural gas (CNG) vehicles. Fuel cells are an advanced technology that produces electricity from hydrogen at high efficiencies, with no air quality emissions. They are scalable, with high conversion efficiencies at even very small sizes. They can be used in a variety of sectors, for example to power electric motors in vehicles, for CHP generation in buildings, and for electricity generation. FCEVs have long been the most promising market, since hydrogen can be stored more easily in tanks than electricity in batteries, and tanks can be refilled in a similar time to existing petrol vehicles.

1.4 FUTURE ROLES FOR HYDROGEN AND FUEL CELLS

Hydrogen and fuel cells are already taking a strong role in several markets:

- Transport: Fuel cell forklift trucks are taking an increasing market share in warehouses in preference to battery forklifts due to their longer lifetime, zero emissions, smaller space requirements and fast refuelling.
- Heat provision: Fuel cell CHP has been deployed in commercial buildings and district heat networks for several decades. Fuel cell micro-CHP is supported by both governments and industry, and is now being deployed in Japan, South Korea and Europe, with over 180,000 houses using a fuel cell in Japan alone [14].
- Electricity: fuel cells are widely used to provide emergency backup power (e.g. for telecommunications during natural disasters), and primary power in computer data centres. Electrolysers are being used in Europe and the US in power-to-gas applications to help integrate high levels of renewables into electricity systems.
Chapter 1 Introduction

Road transport has long been seen as the most promising market for hydrogen and fuel cells. Numerous companies have active development programmes for FCEVs, and Hyundai and Toyota have recently launched mass-produced FCEVs for the first time. The industry has sponsored research to examine the case for FCEVs [15] and public–private H2Mobility programmes have been founded in several countries to explore how refuelling infrastructure could be provided economically. At Davos in 2017, a new “Hydrogen Council” of CEOs from thirteen vehicle manufacturers and chemical companies was announced, which intends to invest $10bn over five years on refuelling infrastructure [16]. Such investments suggest that many vehicles companies believe that FCEVs are ready for widespread commercialisation. Environmental challenges such as air quality in London and other major cities are only likely to increase the pressure for investing in such zero-emission vehicles.

The use of hydrogen to decarbonise heat provision through the repurposing of existing gas networks has recently received much attention in the UK. Previously, electric heat pumps were considered the most appropriate low-carbon technology. Hydrogen could replace natural gas, which currently heats 85% of UK homes, removing CO₂ emissions at point-of-use. Homeowners could use hydrogen boilers, hybrid heat pumps or fuel cell micro-CHP, with the latter two options supporting operation of the electricity system.

Hydrogen and fuel cells present a commercial opportunity for companies and countries which take a technological lead. Japan is reaping the benefits of its long-standing support for fuel cells in residential heat and transportation, with companies including Honda, Toyota and Panasonic beginning to establish export markets in Europe for FCEVs and micro-CHP fuel cells. There are opportunities for British companies as well. For example, Ceres Power has attracted inward investment from Asia and the US and begun testing its technology in Asian markets. Both ITM Power and AFC energy have exported their technologies to Germany. Globally, the fuel cell market has been growing by about 20% annually [14].

1.5 AIMS AND OBJECTIVES OF THE WHITE PAPER

This aim of this paper is to examine how hydrogen and fuel cells may operate within each sector of future energy systems, and to characterise the transition infrastructure that is required to achieve these roles. It provides a critical review of the key technologies and considers potential markets. It examines the potential benefits of these technologies from an energy system perspective and for consumers, and identifies policy issues that need to be addressed. It is split into three parts that are outlined below.

1.5.1 Part 1: Potential role of hydrogen and fuel cell systems

Part 1 considers the potential role of hydrogen and fuel cells in the future, across the UK energy system, through the lens of scenario modelling with the UK TIMES energy system model. Chapter 2 provides evidence of the benefits that these technologies could offer and the economic case for deploying these technologies. It also considers how hydrogen technologies could be integrated with other parts of the energy system.
1.5.2 Part 2: Hydrogen and fuel cell systems for transport, heat and electricity generation

Chapters 3 to 5 provide the core evidence base for the White Paper, delivered via review and synthesis of the relevant literature. Chapter 3 examines the transport sector, including the technical requirements of FCEVs, innovation in the sector and consumer experience. Chapter 4 evaluates the technical requirements of boilers and micro-CHP fuel cells, and considers UK prospects including gas network conversion to hydrogen. Chapter 5 examines how hydrogen and fuel cells might contribute to the secure operation of a low-carbon electricity system, through flexible generation with fuel cells and balancing the intermittency of renewables with power-to-gas.

These three chapters identify key engineering challenges such as the hydrogen purity and pressure requirements of various technologies, consider in detail the potential integration of these technologies into the UK energy system, and identify the various aspects of their system-level value proposition.

1.5.3 Part 3: Transition to hydrogen and fuel cell systems

Part 3 explores how a transition to hydrogen and fuel cells might be achieved. Chapter 6 presents an overview of key hydrogen infrastructure systems and considers how hydrogen infrastructure could be developed across the UK using a spatial infrastructure planning model. Chapter 7 examines policy issues, detailing the current strategic direction for hydrogen policy and examining the role of existing and future policy instruments. Chapter 8 draws out conclusions.
CHAPTER 2
FUTURE ENERGY LANDSCAPE

Paul E. Dodds – UCL
2.1 INTRODUCTION

Since the term “hydrogen economy” was coined in the 1970s, several visions have been proposed for the role of hydrogen and fuel cells in future economies. Some promote hydrogen as a clean energy carrier as it can be produced from sustainable and renewable energy sources and could therefore create a more secure energy system without reliance on fossil fuels [17]. Other visions concentrate on the myriad of applications: transport [15]; supporting renewable electricity generation [18]; or decarbonising gas heating [19].

These different viewpoints reflect several challenges in understanding potential roles for hydrogen:

1. Hydrogen can be produced from many feedstocks using many technologies, with greenhouse gas (GHG) and other air quality emissions ranging from zero to high and with varying levels of purity.
2. Hydrogen and fuel cells could contribute in several diverse ways across the energy system.
3. Hydrogen can be used without fuel cells (e.g. in gas boilers), whilst fuel cells can operate using fuels other than hydrogen.

This chapter looks at how hydrogen technologies might be integrated into a future energy system, then subsequent chapters examine the technologies and applications in detail. The key challenges are to understand the potential deployment of hydrogen and fuel cells sector-by-sector and in total, to estimate its economic implications, and to consider how hydrogen and fuel cells might integrate into a rapidly evolving energy system.

2.1.1 Tools to explore scenarios

Scenarios of future energy systems are often used to consider the potential roles of novel technologies. One method creates descriptive storylines of how the energy system evolves over time, which can explain the roles of institutions and other actors. Another method uses accounting approaches, such as the DECC 2050 Calculator [20], to quantify changes in the energy system.

Energy affordability is an important part of the Government’s energy strategy, so economic models are often used to examine scenarios. Bottom-up energy system optimisation models identify the most affordable method of transitioning to a desired energy system (e.g. one with restricted GHG emissions). Scenario costs are calculated by balancing the supply and demand of commodities across the energy system to calculate market prices and volumes consumed at each time point. Modelled scenarios are often quantitative representations of qualitative storylines [21]. Further scenarios can be derived from the principal scenarios to explore the implications of uncertainties. This approach is used in this chapter.

2.1.2 H2FC studies using energy system models

The potential of hydrogen to contribute to low-carbon transport has been explored using energy system models for the European Union [22], the UK [23], Norway [24]
and California [25], for example. A global model has shown that early investment in zero-carbon vehicles can be justified if this leads to cost reductions through innovation [26]. A series of studies in the UK have examined the socioeconomics of hydrogen as part of the EPSRC UKSHEC and H2FC Hub centres, culminating in the first book on this subject [27]. More recently, the potential for using hydrogen for low-carbon heat provision in the UK has been examined [28, 29], and a detailed study of the engineering implications has been carried out for the city of Leeds [19]. The Committee on Climate Change (CCC) commissioned a report in 2014 on the potential long-term role of hydrogen for both transport and heat provision using two scenarios, as part of their evidence base for the Fifth Carbon Budget report. They concluded that hydrogen has the potential to make a substantial contribution to meeting UK GHG emission targets [30].

This chapter uses the UK TIMES model (UKTM) to examine these two CCC scenarios together with other hydrogen scenarios, and compares them against counterfactual scenarios with no hydrogen. It assesses the implications of some major uncertainties and considers the integration of hydrogen technologies with the wider energy system.

### 2.2 FUTURE ENERGY LANDSCAPE

Figure 2.1 shows the scale of Britain’s current energy demands. Natural gas is the largest of these, with strong seasonal swings as it provides the majority of heating. Transport fuel demand is relatively constant through the year, and electricity demand is slightly seasonal, due to both heating and lighting, but varies strongly between day and night. This illustrates one of the major challenges for decarbonising the energy system: a low-carbon energy vector is required that can accommodate significant winter demand peaks, providing daily power flows that are substantially higher than current UK electricity generation.

**Figure 2.1 Daily demands for major energy vectors in Britain [31].**
The six scenarios in this chapter all meet the UK’s commitment to 80% decarbonisation, but they take different pathways and evolve in different ways. Box 2.1 gives a brief overview of the six scenarios, and each is described in more detail below.

**BOX 2.1 OVERVIEW OF THE SIX SCENARIOS**

**Least Cost**: the lowest-cost method of achieving the GHG target based on input assumptions.

**Critical Path**: the hydrogen option is kept open to 2030 through small investments in infrastructure and road vehicles; deployment ramps up in 2050 for strategically important end uses (transport and electricity).

**Gas Conversion**: gas networks are converted to deliver hydrogen; homeowners choose between low-carbon heating and transport technologies primarily on cost.

**Full Contribution**: hydrogen is taken up across the economy; hydrogen boilers and hybrid heat pumps heat most houses by 2050; almost all road vehicles use fuel cells; substantial contributions from hydrogen in industry and electricity generation as well.

**No Hydrogen**: a counterfactual scenario that is the same as Least Cost, except that no hydrogen technologies are available.

**Electrification**: a counterfactual scenario with widespread electrification of end-use technologies that relies primarily on renewable generation.

### 2.2.1 Least Cost

This scenario identifies the lowest theoretical cost of a transition to a low-carbon energy economy, as calculated by UKTM with minimal constraints. It is included to understand the extent to which H2FC technologies are competitive purely from an economic perspective (i.e. before issues such as public preferences are taken into account).

### 2.2.2 Critical Path

The Critical Path scenario was developed for the CCC [30], based on retaining the option to use hydrogen in end-uses deemed to be ‘strategically important’. These are either hard to decarbonise by means other than hydrogen, or the alternatives have inferior performance characteristics relative to incumbent technologies (e.g. vehicles with short range or slow refuelling).

Therefore, in this scenario, there is no wholesale and technology-specific commitment to an extensive roll-out of hydrogen technologies, in preference to other options. It avoids large anticipatory investment commitments, such as hydrogen delivery infrastructure, ahead of clear evidence of demand. The strategy that policy makers wish to follow is to “buy” some optionality for allowing a contribution from hydrogen in some key sectors, at some point in the future, but without premature commitment to, or paying too much for this “option”. Consequently, hydrogen has a minor role until 2030, and all hydrogen to 2035 is produced on-site at refuelling stations using electrolysers.
The strategically important end uses for hydrogen in 2050 are primarily in road transport (Figure 2.2). In particular, hydrogen powers:

- HGVs that operate within the UK only (90% of distance travelled).
- Long distance and urban buses and coaches operating with in the UK and outside of dense urban areas (estimated to be 75% of distance travelled).
- Car journeys over 100 km due to uncertainty over whether battery vehicle range will extend comfortably beyond this (40% of private car vehicle kilometres).
- Power generation for flexible peaking plant, to help balance a system with high penetrations of variable renewables and inflexible nuclear.

Strong alternatives to hydrogen exist for heat and power, and private road vehicles covering short distances, hence these end-uses were not considered strategically important by the CCC. A limited role is envisaged in decarbonising fuel supply for heat demand in industry, especially for end-uses where electrification is not suitable.

**Figure 2.2 Fuel cell vehicle deployment in the Critical Path scenario,** source: [30].

**2.2.3 Gas Conversion**

The UK government is committed to market-based solutions, and mandated to meet GHG emission targets by stimulating low-carbon technologies that are more expensive than incumbent technologies. The tension between these two goals is particularly strong for decarbonising residential heat: 85% of UK householders currently use natural gas boilers and are accustomed to small, quiet, reliable, responsive, low-cost, high-power heating systems; all alternative options are more expensive and, in many cases, inferior. The population has a very favourable view of gas heating [32], making it difficult to promote alternatives.

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7 LGV = Light Goods Vehicle; HGV = Heavy Goods Vehicle
One option is to decarbonise the gas supply by converting networks and all end-use technologies to deliver and use hydrogen [33]. The Gas Conversion scenario examines the implications of this over the period 2025–2045, in accordance with the plan designed by the H21 Leeds City Gate Study [19]. Natural gas heating becomes unavailable by the end of this conversion. In contrast to the Leeds study, this scenario does not restrict customers to adopting hydrogen boilers or hybrid heat pumps. Rather, consumers may adopt any available low-carbon technology, including fuel cell micro-CHP. Hydrogen technologies are similarly available in other sectors and adopted to the extent that they are cost-optimal.

2.2.4 Full Contribution

The Full Contribution scenario was developed for the CCC [30] to model aggressive uptake characterised by early, consistent, long-term commitment to hydrogen throughout the economy. This commitment is equally strong throughout the scenario timeframe, allowing strategic, anticipatory investments in hydrogen-enabling infrastructure in advance of hydrogen demand growth. It is driven by an early decision to decarbonise heat by delivering hydrogen using existing infrastructures. The current gas networks are repurposed to carry hydrogen to houses and local refuelling stations in accordance with the H21 Leeds plan [19]. This subsequently provides infrastructure for fuel cell electric vehicle (FCEV) adoption in the transport sector. The high-pressure gas network cannot be repurposed to carry hydrogen and a new high-pressure hydrogen transmission network needs to be constructed.

The use of hydrogen in the Full Contribution scenario in 2050 can be described as follows:

- FCEVs are the dominant technology for all private road transport, buses and light and heavy goods vehicles (HGVs), as shown in Figure 2.3.
- Hydrogen is piped into residential, public and commercial buildings via existing natural gas networks. It is used by hydrogen boilers and hybrid heat pumps in larger homes, but no fuel cells are deployed. Where district heating infrastructure is developed, hydrogen may also be used as a zero-carbon energy carrier for small CHP units and district heat boilers.
- Hydrogen is used extensively as a clean fuel in some industry sectors, providing heat for iron and steel, non-metallic minerals, non-ferrous metals, paper, chemicals and food and drink.
- Hydrogen is used as a storage medium for excess renewable electricity generation, primarily at a large scale (salt caverns and other large-scale storage). Hydrogen is also used in power generation for peak generation and some mid-merit generation in gas turbines.

---

8 Hybrid heat pumps are air-source heat pumps with a built-in gas boiler (see Chapter 4.5.3).
9 Fuel cells were excluded by the CCC in this scenario to avoid reliance on as-yet uncertain cost reductions. The Gas Conversion scenario retains the flexibility to use fuel cells.
2.2.5 No Hydrogen

This counterfactual scenario assesses the implications of not adopting hydrogen in any sectors other than for existing uses in industry (primarily ammonia production and hydrocarbon processing). It is otherwise similar to the Least Cost scenario.

2.2.6 Electrification

Heat pumps and battery electric vehicles have high conversion efficiencies, which combined with electricity generated from renewable sources, would form a sustainable energy system. Such a system is designed to minimise usable energy (i.e., exergy) losses and avoids fossil fuel consumption as far as possible. This electricity-focused scenario provides a counterpoint to the hydrogen-focused Full Contribution scenario. Hydrogen can be used upstream to support renewable generation and other technologies in this scenario, but cannot be used to power end-use technologies.

Referring back to Figure 2.1, this would have serious impacts on the size and operation of the electricity system. Winter heating demand in the UK is around 2–3 TWh per day, compared to around 1 TWh daily electricity demand. If a sizeable share of this heating demand were electrified, even with high-efficiency heat pumps, it would necessitate a sizeable and expensive expansion in both electricity generation and transmission infrastructure [34, 35]. This led the CCC to roll back its projections for the uptake of electric heating, further complicating the challenge of decarbonising heat [5].

Transport demand is more constant through the year, meaning electric vehicle demand could theoretically be met by baseload generation with high utilisation (e.g., nuclear plants). However, uncontrolled charging of electric vehicles is likely to occur after the last journey of the day, which coincides with the UK’s peak demand, suggesting that ‘smart charging’ infrastructure is also required to avoid a disproportionate expansion of the power system [36, 37].
2.3 INTERPRETING THE SCENARIOS IN AN ENERGY SYSTEM MODEL

The six scenarios have been modelled using the UK TIMES model (UKTM), a multi-time period, bottom-up, technology-rich cost optimisation model of the UK energy system. It is the successor of the UK MARKAL model, which was originally developed to provide insights for the Energy White Paper 2003, and was developed until 2012 [38]. UKTM was recently used by the UK Department of Business, Energy and Industrial Strategy (BEIS) to inform its Fifth Carbon Budget Analysis [39].

The simplest formulation of UKTM is to minimise discounted energy systems cost under various physical and policy constraints. This minimisation takes into account evolving costs and characteristics of resources, infrastructures, technologies, taxes and conservation measures, to meet energy service demands.

2.3.1 Data sources and assumptions in UKTM

UKTM includes 2000 technologies, 600 energy carriers, plus constraints, taxes and emissions; totalling almost 300,000 data elements. Model data are obtained from a wide range of sources and have undergone quality assurance. Documentation will be available from the UKTM website.

The transport sector has a wide range of technologies across all modes [23, 40]. The residential sector includes boilers, heat pumps, micro-CHP and district heat technologies that can be fuelled by hydrogen and other fuels [41]. Solid- and cavity-wall houses and flats are represented as distinct groups. Conversion of the gas networks to hydrogen is based on the CCC study [30], which drew on previous UK research [29, 42]. Hydrogen production costs were updated during the CCC study [30]. Changes to the model since then include new options for using hydrogen in industry and the addition of power-to-gas technologies such as methanation.

2.3.2 Interpretation of the scenarios in UKTM

The Full Contribution and Critical Path scenarios are modelled within UKTM by specifying the hydrogen uptake in road transport over the period to 2050 for each transport mode. In the Full Contribution scenario, conversion of the gas networks to hydrogen and the take-up of hydrogen for heating in boilers are similarly imposed into the solution. Constraints are also placed on hydrogen infrastructure, for example a minimum number of refuelling stations with on-site electrolysers are constructed in the early years when a comprehensive hydrogen infrastructure cannot be justified. The remainder of the energy system is not constrained and the model identifies the least-cost evolution to achieve an 80% reduction in greenhouse gases by 2050.

The Gas Conversion scenario has the same conversion of the gas networks as Full Contribution. However, whereas Full Contribution is constrained so householders with a gas connection must use hydrogen boilers or hybrid heat pumps, Gas Conversion places no restrictions on technology adoption except that use of natural gas reduces from 2025 and is not possible anywhere after 2045.

Further information on UKTM is available at www.ucl.ac.uk/energy-models/models/uktm-ucl.
In the No Hydrogen scenario, no constraints are applied except to exclude hydrogen technologies. This scenario is otherwise similar to the Least Cost scenario. The Electrification scenario restricts fossil fuel use to aviation and industry feedstocks, while nuclear power deployment is restricted to encourage additional renewable generation.

These interpretations are summarised in Table 2.1.

**Table 2.1** Representation of hydrogen (H\(_2\)) and natural gas (NG) across energy sectors in each scenario. The industry figures are for the year 2050.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Transport</th>
<th>Buildings</th>
<th>Industry</th>
<th>Electricity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Least Cost</strong></td>
<td>Flexible</td>
<td>0% H(_2)(^{11})</td>
<td>Flexible</td>
<td>Flexible</td>
</tr>
<tr>
<td><strong>Critical Path</strong></td>
<td>Strategic H(_2)</td>
<td>No H(_2)</td>
<td>8 TWh</td>
<td>H(_2) peak only</td>
</tr>
<tr>
<td><strong>Gas Conversion</strong></td>
<td>Flexible</td>
<td>No NG(^{12})</td>
<td>Max 30% NG</td>
<td>Flexible</td>
</tr>
<tr>
<td><strong>Full Contribution</strong></td>
<td>Maximum H(_2)</td>
<td>All gas to H(_2)</td>
<td>Min 40% H(_2)</td>
<td>H(_2) mid-merit</td>
</tr>
<tr>
<td><strong>No Hydrogen</strong></td>
<td>No H(_2)</td>
<td>No H(_2)</td>
<td>No H(_2)</td>
<td>No H(_2)</td>
</tr>
<tr>
<td><strong>Electrification</strong></td>
<td>No H(_2)</td>
<td>No H(_2)</td>
<td>No H(_2)</td>
<td>No fossil fuels</td>
</tr>
</tbody>
</table>

**2.4 COMPARISON OF THE SCENARIOS**

Primary energy consumption in the six scenarios in 2050 is compared in Figure 2.4. Biomass consumption is similar in each, and the first five scenarios have substantial roles for natural gas, oil and nuclear power, though shares vary. The Electrification scenario has lower primary energy consumption, reflecting the reliance on electricity from renewables (which are treated as 100% efficient) and minimal fossil fuel consumption.

Total final energy consumption in the first five scenarios is similar, with increases in hydrogen generally balanced by decreases in natural gas consumption (Figure 2.5). Oil has a minimal role in all scenarios, except for aviation and chemical feedstocks. The Electrification scenario has a much greater reliance on both biomass and electricity for final end-use consumption, and is the only scenario with virtually no gas consumption.

---

\(^{11}\) Gas network conversion is assumed to be a government-led strategy that does not occur in the Least Cost scenario.

\(^{12}\) The gas networks are assumed to be systematically converted to hydrogen from 2025 to 2045, so no NG heating is available after 2045.
Figure 2.4 Primary energy consumption in 2050, in the six scenarios.

Figure 2.5 Final energy consumption in 2050, in the six scenarios.
2.4.1 Hydrogen consumption

Hydrogen consumption in 2050 is shown in Figure 2.6. Hydrogen is the most economic option for parts of the road transport sector, so a similar and substantial amount is used in the Least Cost and Critical Path scenarios. Far more hydrogen is used in the Gas Conversion and Full Contribution scenarios across a range of sectors, yet hydrogen only ever accounts for a minority of total transport sector consumption (Figure 2.7). Petroleum products continue to have the largest share in all but the Full Contribution scenario, partly because of aviation demands, but also because petrol hybrid vehicles have sufficiently low emissions to retain market share even in 2050.

**Figure 2.6** Hydrogen consumption in each sector in 2050, in the six scenarios.
Residential heat provision is shown in Figure 2.8. The Least Cost, Critical Path and No Hydrogen scenarios all retain substantial use of unabated natural gas boilers in 2050, reflecting the difficulty of decarbonising heat. The other three scenarios take quite different routes. Full Contribution is, by design, dominated by hydrogen boilers – either standalone or part of hybrid heat pumps. Gas Conversion has a markedly different portfolio, with few boilers but a high penetration of micro-CHP fuel cells supporting deployment of heat pumps in other houses, as proposed in [43, 44]. This scenario is also notable for the high penetration of hydrogen-fuelled district heating.

The transition to a varied, low-carbon heating portfolio in the Gas Conversion scenario is illustrated in Figure 2.9. Heat pumps and hydrogen gradually increase as gas is phased out. Fuel cells are deployed from 2035 as capital costs reduce and the value of generated electricity increases to make a viable business case. Gas Conversion considers the H21 Leeds plan within the context of the wider energy system, and shows that deploying fuel cells instead of boilers makes a substantial contribution to the electricity system and reduces the overall transition costs compared to the restricted Full Contribution scenario. It highlights the importance of taking a holistic approach to transforming the energy system rather than concentrating on just a single sector in isolation.
Chapter 2  Future energy landscape

Figure 2.8 Residential heat provision in 2050, in the six scenarios
Space heating and hot water are combined in this graph.

Figure 2.9 Residential heat provision in the Gas Conversion scenario
Space heating and hot water are combined in this graph.
2.4.2 Hydrogen production and electricity generation

Hydrogen production within the scenarios is primarily from natural gas via steam-methane reforming (SMR) with carbon capture and storage (CCS). Figure 2.10 shows that hydrogen has an important role in Least Cost as the least expensive technology in some markets. Decentralised electrolysis at refuelling stations has a substantial role by design in both Critical Path and Full Contribution (but not in the other scenarios), with some centralised electrolysis also contributing in Full Contribution.

The high level of hydrogen production from centralised electrolysis in Electrification is largely used as a feedstock for methanation, where it is mixed with captured CO₂ to produce synthetic natural gas (SNG) for use across the energy system. This is the only scenario in which methanation is cost-effective.

Electricity generation and capacity are shown in Figure 2.11 and Figure 2.12, respectively. Least Cost and the three hydrogen scenarios are broadly similar. No Hydrogen has higher generation to compensate for the unavailability of hydrogen, while Electrification has substantially higher generation and capacity, reflecting the unavailability of fossil fuels and the high deployment of intermittent renewable generation with low capacity factors.

Figure 2.10 Hydrogen production in each sector in 2050, in the six scenarios.
Figure 2.11 Electricity generation by source in 2050, in the six scenarios.

Figure 2.12 Electricity generation capacity in 2050, in the six scenarios.
Apart from in the Electrification scenario, renewables are seen to provide a relatively small share of generation (less than in 2015), while nuclear sees a large expansion. UKTM finds the cost-optimal share of generation without subsidies given to individual technologies, and based on the input data, nuclear becomes cheaper than wind or solar in the long term. The total installed power capacity is also lower than in 2015 (a minimum of 75 GW vs. 90 GW today) as technologies are chosen in the residential and service sectors to flatten the load profile over time, so as to minimise the need for little-used peaking capacity. The extent to which this would be feasible in reality is uncertain.

### 2.4.3 Scenario costs

The total costs of the scenarios are listed in Table 2.2 relative to the unconstrained optimum of the Least Cost scenario. The costs of Critical Path and No Hydrogen are close to Least Cost. A common feature of these three scenarios is the continued use of gas heating in many homes. Gas Conversion is 50% more expensive, while Full Contribution more than doubles the cost of decarbonisation. However, Electrification is by far the most expensive scenario, reflecting the importance of fossil fuels in meeting emission targets at low cost.

Two sensitivity studies were run for all of the scenarios: (i) with no option to use bioenergy with CCS (BECCS); and, (ii) with no CCS technologies available. These emulate the impact of CCS technologies either being technically infeasible, or more expensive than is anticipated by the UKTM assumptions. The lack of CCS technology raises costs across the board (except in Electrification, where they are forbidden), but reduces the cost differential between the hydrogen and the Least Cost pathways. The premium for Full Contribution falls from 140% in the basic scenario to 50% with no BECCS and 60% with no CCS.

**Table 2.2 Total discounted costs of the energy systems in each scenario.**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Basic scenario</th>
<th>No BECCS</th>
<th>No CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Least Cost</td>
<td>1.0</td>
<td>1.8</td>
<td>2.0</td>
</tr>
<tr>
<td>Critical Path</td>
<td>1.2</td>
<td>2.0</td>
<td>2.1</td>
</tr>
<tr>
<td>Gas Conversion</td>
<td>1.5</td>
<td>2.2</td>
<td>2.6</td>
</tr>
<tr>
<td>Full Contribution</td>
<td>2.3</td>
<td>2.6</td>
<td>3.0</td>
</tr>
<tr>
<td>No Hydrogen</td>
<td>1.1</td>
<td>2.2</td>
<td>2.3</td>
</tr>
<tr>
<td>Electrification</td>
<td>7.0</td>
<td>7.0</td>
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</tr>
</tbody>
</table>

All costs are relative to the difference between the Least Cost scenario cost and the cost of an unconstrained reference scenario with no GHG emission targets. The Least Cost scenario therefore has a cost = 1. BECCS is bioenergy with carbon capture and storage (CCS).
2.4.4 Discussion

This analysis shows that hydrogen and fuel cell technologies could play a substantial role in the future, in one or more sectors. In Full Contribution, almost 50% of end-use demand is met by hydrogen in 2050, while fuel cells are deployed as least-cost options in both the transport and heat sectors in other scenarios.

If current forecasts for technology cost reductions are realised (as described in the references in Section 2.3.1), hydrogen and fuel cell technologies will become cost-competitive with other low-carbon technologies. Across the scenarios, a major role is identified for FCEVs in haulage, and to a lesser extent for cars. Battery electric vehicles are more expensive for long-distance transport, a finding that is consistent with previous research showing that the difference in total cost of ownership between vehicle powertrains is very narrow after 2030. It is therefore too early to identify a clear frontrunner based on cost alone [23], and a portfolio will likely develop based on applications and individual preferences [15].

The different levels of hydrogen consumption across the first four scenarios lead to different choices of demand-side technologies. Despite this, supply-side impacts are quite minor. The move towards greater electrification in the two counterfactual scenarios has a greater impact than introducing hydrogen end-use technologies, which mostly replace fossil-powered technologies. Natural gas is mostly used to manufacture hydrogen and primary energy consumption and the electricity system are very similar across the four scenarios.

Hydrogen technologies avoid some limitations of electrical alternatives, such as the space requirement and limited output of heat pumps, or the range and refuelling time of battery electric vehicles. From this perspective, hydrogen offers a business-as-usual approach for consumers that is unmatched by other low-carbon technologies. Research on public attitudes to hydrogen has primarily considered hydrogen safety [45]. The additional cost that consumers would accept for a higher-quality low-carbon energy service is less well understood.

The cost premium of hydrogen technologies is therefore potentially acceptable since they look and operate in a similar way to existing fossil-fuelled technologies. The strategy to keep the hydrogen option open in the Critical Path scenario has a small premium of 5–20% over Least Cost. This cost should be balanced against the value of having greater diversity and security in the energy system. The most unaffordable scenario is Electrification, which suggests that the continued but more sustainable use of fossil fuels could be an important factor in minimising future transition costs.

2.5 INTEGRATION OF HYDROGEN AND FUEL CELLS WITH OTHER PARTS OF THE ENERGY SYSTEM

Both hydrogen and electricity are zero-carbon energy carriers, so they are often viewed as competitors in future low-carbon energy systems. Yet hydrogen, fuel cells and electrolysers can instead complement the electricity system by acting as a convenient chemical buffer, as detailed later in Chapter 5. This section presents insights
from modelling these interactions in UKTM. It also discusses the implications for fossil fuel use and reflects on how a transition might occur.

2.5.1 Supporting renewable integration through power-to-gas

As the proportion of renewable generation in the UK electricity system increases, the difficulty of balancing supply and demand will increase [46]. A cheaper option than energy storage for facilitating integration of renewables could be a combination of flexible generation with hydrogen production from power-to-gas. Power-to-gas (described in Chapter 5) uses electrolysers to produce hydrogen, which can then be mixed in small quantities with natural gas in the gas networks, or potentially used in a higher-value market such as a hydrogen refuelling station. Several pilot power-to-gas plants have been constructed [47], including a 325 kW power-to-gas electrolyser in Germany [48].

The first step in assessing the feasibility of this option is to estimate the potential resource availability and economic implications of producing hydrogen from power-to-gas. Energy system models such as UKTM have insufficient temporal resolution to measure excess electricity generation. Instead, the ‘Hydrogen’s Value in the Energy System’ (HYVE) project used an hourly-resolution electricity dispatch model to output excess generation from renewables for scenarios, which UKTM can then decide how to utilise (if at all). Results showed hydrogen production to be the most cost-effective option for excess generation, producing 40–50 TWh/year. Compressed air energy storage (CAES) played a smaller role, producing 8–10 TWh/year.

The maximum potential resource base for hydrogen storage is therefore around 50 TWh. Referring to Figure 2.10, this is a substantial contribution compared to the Critical Path scenario, but is less than 10% of Full Contribution consumption in 2050. Power-to-gas has a wider applicability than simply being a sink for excess renewable energy; used more widely, power-to-gas would increase electricity demand and could stimulate more investment in low-carbon generation.

Ongoing research aims to better understand the various restrictions and synergies around this, and their implications for potential hydrogen production.

2.5.2 Does hydrogen complement or compete with electricity?

The case study above shows how hydrogen can support the economic integration of renewable generation into low-carbon energy systems. For end-uses, however, hydrogen could be viewed as a competitor to electrification for heat and transport provision. A closer examination suggests a more nuanced picture. Hydrogen boilers and fuel cells would likely compete with electrical technologies such as heat pumps, offering a solution in smaller homes where space requirements preclude deploying heat pumps. Hybrid heat pumps could reduce the peak electricity demand while micro-CHP fuel cells would generate electricity to help meet such peaks [49]. Fuel cell vehicles might similarly be expected to compete with battery vehicles; yet it is quite possible that plug-in hybrid fuel cell vehicles will emerge that combine the best traits of both hydrogen and electricity.
Hydrogen is fundamentally an alternative energy carrier to electricity that is cheaper and more efficient to produce from fossil fuels, as shown in Figure 2.13. It can be stored more easily (and cheaply), but is used less efficiently by end-use devices. The deployment of hydrogen technologies adds diversity to the system and increases energy security [50], as explored in the fourth H2FC White Paper [6].

**Figure 2.13** Comparison of hydrogen production and electricity generation levelised costs from a range of carbonaceous fuels, assuming a carbon tax of £50/tCO₂ in 2020 and £250/tCO₂ in 2050.

### 2.5.3 Hydrogen and fossil fuels

The six scenarios have shown that introducing hydrogen changes the role of fossil fuels in the energy system. In most scenarios, natural gas is still used to produce hydrogen, yet hydrogen-fuelled heating tends to displace end-usage of natural gas. This means that though primary energy consumption is very similar, final energy consumption is quite different. The Electrification scenario shows that abandoning natural gas and hydrogen for heating is potentially a very expensive approach. This dominance of natural gas in hydrogen and heat production poses a problem if BECCS, or CCS in general fail to mature for engineering, cost or ethical reasons. All of the hydrogen scenarios have substantial “negative emissions” from BECCS, which gives additional scope to increase emissions in end-use sectors such as heat and transport, but this is a very uncertain technology that is yet to be demonstrated.

Figure 2.14 examines the sensitivity cases where CCS technologies are unavailable and the impacts on hydrogen production. Electrolysis and carbon-neutral biomass gasification take a greater role, dominating the No CCS scenarios and replacing natural gas as the primary feedstock for hydrogen production. More generally, there is greater electrification in the energy system and a shift towards dual-fuel technologies in these cases (e.g. hybrid heat pumps and plug-in hybrid cars). Without CCS technologies, electrolysis becomes an important route to producing hydrogen and increases its share of total electricity demand.
Earlier, Table 2.2 showed that the unavailability of CCS substantially increases the costs of decarbonising the energy system in all of the hydrogen scenarios except Full Contribution, where the increase is much smaller.

**Figure 2.14** Hydrogen production in the Critical Path and Full Contribution scenarios. The No BECCS versions of the scenarios prohibit the use of negative emissions technologies such as biomass CCS, and the No CCS scenario similarly prohibits the use of all CCS technologies.

2.6 TRANSITION TO HYDROGEN AND FUEL CELL SYSTEMS

Fuel cells are by their nature scalable and modular devices. If they are commercially competitive, then they can be deployed wherever a supply of hydrogen, natural gas or other feedstock is available. Supplying cost-effective hydrogen is potentially a very difficult challenge because delivery infrastructure can be expensive and will have low utilisation in the early years of a transition as demand ramps up. That makes it difficult for providers to recoup their costs unless the price of hydrogen is increased to uncompetitive levels. If the future demand for hydrogen is uncertain, then the risk of that demand emerging must also be taken into account and this further reduces the economic case. Government intervention might be justified to overcome this hurdle.

Two broad approaches for developing hydrogen infrastructure can be identified from the scenarios – transport-led and heat-led – and these are discussed below. Infrastructure systems are examined further in Chapter 6.
2.6.1 Transport-led infrastructure

Transport is the primary driver for introducing hydrogen, but demand growth is very uncertain and so risks are high. The need for a national refuelling infrastructure system means that a decentralised approach is likely, leading to electrolytic hydrogen production on-site at a small number of refuelling stations around the country. These would initially have small capacities to minimise costs, with larger stations being constructed as demand increases. The UK H2Mobility programme has estimated that 60 refuelling stations would be able to cover the whole population [51]. This transport-led approach is used in the Critical Path scenario, in which centralised hydrogen production infrastructure is not deployed before the mid-2030s.

The dispersed nature of renewables, if combined with power-to-gas, offers a potential synergy with the required wide geographical distribution of hydrogen refuelling stations – provided there is adequate matching of deployment rates of FCEV and renewables. This offers a potential high-value market for the hydrogen, though consideration of electrolyser capacity factors would be required to ensure that supply was able to meet demand.

2.6.2 Heat-led infrastructure

A heat-led transition occurs following an early decision to convert the gas distribution networks to deliver hydrogen instead of natural gas. Urban areas across the UK are progressively converted over a 20-year period, with hydrogen production plants located on high-pressure pipes on the outskirts of cities. Eventually, national hydrogen demand is high enough to justify building a transmission network to link regional networks. Regional infrastructure development would enable refuelling stations to be located close to high-pressure distribution pipes, supplying substantially cheaper hydrogen for the automotive sector. There would be additional compression penalties and purification issues at most of these stations, and these issues are explored further in Chapter 6.

The heat-led infrastructure transition is followed in the Full Contribution scenario. Gas Conversion represents a derivative of this scenario in which the gas networks are converted, but using hydrogen for heating and transport is not mandatory. This brings uncertainty over demand growth, making it difficult to construct an appropriate capacity of hydrogen production plants. In this scenario, the most prudent strategy might be early construction of a national transmission network, in order to mitigate possible regional imbalances in hydrogen demand. This would incur significant upfront investments, and so would rely on the strong expectation of high future demand (e.g. from heating). Further work is required to understand both the optimal hydrogen policy in this scenario, and the minimum take-up of hydrogen necessary to justify converting the gas networks.

2.6.3 Driving an infrastructure transition

Achieving an infrastructure transition would not be straightforward, and it is not clear who should be responsible for driving it. The government and gas network owners would likely have to drive a heat-led transition, and the government would equally have a facilitating role in a transport-led transition, perhaps through public-private
partnerships such as UK H2Mobility. It would be important to consider the roles of various stakeholders, including national, regional and local government, institutions and the public. While cost and decarbonisation are long-term reasons for adopting low-carbon technologies, more local factors such as improving air quality in cities might have greater influence in the shorter term [52].

2.7 CONCLUSIONS

This chapter has analysed six scenarios using the UKTM energy system model to understand how hydrogen and fuel cells might be integrated into a future UK energy system. Hydrogen and fuel cell technologies could play a substantial role in the future, across multiple sectors, with up to 50% of end-use demand met in one scenario by 2050. Current forecasts for technology cost reductions through innovation would have to be achieved if these market penetrations were to be realised, and the small differences between the costs of different road transport technologies in particular might lead to a much more diverse portfolio of powertrains being deployed in the future.

Hydrogen tends to displace fossil fuels rather than electricity in end-uses within low-cost, low-carbon scenarios. However, adopting hydrogen has only a minor impact on the consumption of fossil fuels, as natural gas is instead used in hydrogen production. The result is that the costs of hydrogen scenarios are not substantially higher than the Least Cost scenario, and any additional cost might be acceptable to the public in order to use technologies that look and operate in a similar way to existing fossil-fuelled technologies.

The Electrification scenario, in contrast, is much more expensive than the Least Cost scenario, and it seems unlikely that many consumers would be willing to pay the high cost of significant electrification through renewables.

Both hydrogen and fuel cells could support the operation of a low-carbon electricity system, and would be particularly valuable if it were composed primarily of inflexible generation such as nuclear and renewables. Power-to-gas from excess renewable generation could potentially be part of a hydrogen production system, particularly at geographically-remote refuelling stations. In even the most optimistic scenario, however, insufficient hydrogen could be produced to meet a substantive demand. Although hydrogen is often viewed as a competitor to electrification of end-uses and other low-carbon technologies, there are hybrid and micro-CHP technologies that could contribute to building a more flexible and more resilient electricity system.

The transition to hydrogen could be transport-led or heat-led, taking a decentralised or centralised approach. Understanding and managing the risk of uncertain future demand for hydrogen is a key challenge when planning major infrastructure deployments. It is not clear who should be responsible for driving a transition, and how such financial risks should be apportioned, but it would likely involve several levels of government and some combination of private companies and institutions. Given the diverse nature of the transition options, a clear strategy might help to reduce the costs of introducing hydrogen and fuel cell technologies.
CHAPTER 3
THE TRANSPORT SECTOR

Daniel Scamman – UCL
3.1 INTRODUCTION

The UK’s 5th Carbon Budget requires a 57% reduction in CO₂ emissions by 2030, with the transport sector expected to achieve a 48% reduction from 130 MtCO₂e in 2014 to 68 MtCO₂e in 2030 [5]. However, UK emissions from domestic transport have actually risen since 2013, bringing calls for stronger policies for decarbonising transport [53]. Likewise, the UK is on track to miss its 2020 target of 15% of its energy needs coming from renewable sources; with the share of renewable energy in transport actually falling from 4.9% to 4.2% in 2015, versus a target of 10% [54].

While the electricity sector has received considerable attention and achieved significant progress on decarbonisation to date, pressure is now growing for the UK to identify and implement quickly options for decarbonising its transport sector. Hydrogen continues to attract serious attention as one of three main options for low-carbon transport. It avoids the land-use impacts and air quality problems of biofuels and the limited range and long refuelling times of battery-powered vehicles, particularly for hard-to-decarbonise sectors including high-usage and heavy-duty vehicles.

In addition to tackling climate change, improving air quality has become a top priority. 40,000 premature deaths are attributed to UK air pollution across each year, costing businesses and health services £20 billion [55]. There are 467,000 premature deaths across Europe due to particulates and 71,000 due to NOx [56, 57]. A significant proportion comes from the transport sector with the rising use of diesel vehicles blamed for NOx and particulate emissions, despite their carbon emissions being lower than petrol engines. 92% of the world’s population are exposed to air quality levels that exceed World Health Organisation (WHO) limits, and the UN’s Sustainable Development Goals target a reduction in the adverse effects of air quality in cities by 2030 [58, 59]. The UK missed its 2010 deadline for meeting air quality limits, with the Supreme Court ruling that the Government has failed in its legal duty to protect the public from air pollution [60, 61]. The Ultra Low Emission Zone (ULEZ) is being launched in 2020 to reduce vehicle emissions in central London, with all cars, motorcycles, vans, buses and heavy goods vehicles required to meet exhaust emission standards or pay a daily charge [62]. All single decker buses using the ULEZ will be zero-emission and all double deckers will by hybrids by 2020, and from 2018 no new diesel taxis will be permitted with all new taxis being zero-emission capable [63]. A number of efforts internationally are also underway, with four major cities recently announcing a ban on all diesel-powered cars and trucks by 2025, a move likely to be copied in other cities and to drive investment in low-emission vehicles [64].

Table 3.1 indicates the size of each segment of the UK’s transport sector. Road transport dominates, particularly cars, followed by freight. This chapter discusses the role that hydrogen and fuel cells could play across these diverse sectors. It analyses the merits of the various low-emission options in different transport sectors and whether the challenges facing the deployment of hydrogen vehicles can be overcome.
Table 3.1 Transport sector demands in the UK in 2010 [65]. GVkm = billion vehicle-km; GPkm = billion passenger-km; GTkm = billion tonne-km. Note that 85.4 PJ = 1 kWh per person per day.

<table>
<thead>
<tr>
<th>Transport sector</th>
<th>Service demand</th>
<th>Energy consumption (PJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Car passenger transport</td>
<td>413 GVkm</td>
<td>1,044</td>
</tr>
<tr>
<td>Heavy-duty freight transport</td>
<td>27 GVkm</td>
<td>344</td>
</tr>
<tr>
<td>Light-duty freight transport</td>
<td>68 GVkm</td>
<td>227</td>
</tr>
<tr>
<td>Bus passenger transport</td>
<td>5 GVkm</td>
<td>71</td>
</tr>
<tr>
<td>Domestic shipping</td>
<td>42 GTkm</td>
<td>62</td>
</tr>
<tr>
<td>Rail passenger transport</td>
<td>62 GPkm</td>
<td>40</td>
</tr>
<tr>
<td>Domestic aviation</td>
<td>11 GPkm</td>
<td>34</td>
</tr>
<tr>
<td>Two-wheel passenger transport</td>
<td>5 GVkm</td>
<td>9</td>
</tr>
<tr>
<td>Rail freight transport</td>
<td>15 GTkm</td>
<td>7</td>
</tr>
<tr>
<td><strong>Total fuel demand in 2010</strong></td>
<td><strong>1,838</strong></td>
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3.2 POWERTRAINS FOR ROAD TRANSPORT

3.2.1 Hydrogen powertrain configurations

A variety of powertrain options exist for low carbon vehicles (Figure 3.1) [15]. Technically, most FCEVs are hybrids with small on-board batteries of around 1 kWh [66] to cover warm-up periods, allow regenerative braking and provide faster acceleration. PEM fuel cells are the dominant technology for FCEVs due to their high efficiency (up to 60%), high power density, low operating temperature, short start-up periods and excellent cold-start capabilities. However PEMFCs are prone to poisoning due to impurities in their fuel and water management is complex [30, 67]. PEMFCs are normally around 60 kW for a typical 75 kW European car [23] i.e. substantially larger than domestic fuel cells (~1 kW).
A variant of this powertrain, known as a plug-in hybrid (PHEV) or range-extender FCEV, exploits the fact that the majority of car journeys are less than 10 km [66]. Hence a larger battery allows the majority of journeys to be completed using the more efficient battery (which then needs to be recharged externally), with the vehicle switching to petrol, diesel or a smaller fuel cell to complete longer journeys. PHEVs have an electric range of around 50 km, which strikes a good balance between vehicle cost and distance driven [66]. For some PHEVs this leads to batteries of around 8 kWh [23, 68]; larger PHEVs may need around 17 kWh for the same range [69]. Although hydrogen PHEVs could be attractive low-emission vehicles long-term, taking advantage of the high efficiencies of batteries and the long range and short refuelling times of fuel cells, manufacturers appear to be focussing for now on commercialising the cheaper, simpler BEVs and FCEVs separately.
PEM is currently the dominant fuel cell technology, although solid oxide fuel cells are of interest for their high efficiency, cheaper catalysts and tolerance to fuel impurities. However their high operating temperature (500–900 °C) increases start-up times and lower power density increases size and weight [70, 71]. Nissan and British SOFC developer Ceres Power, plan to commercialise an SOFC FCEV by 2020 using ethanol as a hydrogen source [72, 73]. A large battery (24 kWh) allows rapid acceleration and time for SOFC warm-up, which is charged by the 5 kW fuel cell without plug-in. The FCEV will be targeted at regions with existing ethanol uptake (e.g. Brazil), but the concept should be transferrable to other fuels. Waste heat from the fuel cell will be sent to the reformer, improving efficiency, and ethanol will be safer (less combustible and low pressure) and cheaper (no carbon-fibre tanks) than hydrogen vehicles.

Conventional internal combustion engines need some modifications to run on pure hydrogen (“HICEs”), and are currently substantially cheaper than fuel cells. However HICEs are not zero-emission (releasing NOX) and much less efficient, either increasing storage requirements or substantially reducing range. They are therefore not expected to play a significant long-term role in transport. Alternatively hydrogen can be blended into existing CNG (“hythane”) or diesel ICEs using existing infrastructure; however these are not zero-emission either and likewise would probably ultimately be displaced by lower-carbon options [30].

### 3.2.2 Comparison with alternative powertrains

How hydrogen powertrains compare with alternatives varies significantly between sectors, as discussed in Sections 3.4 and 3.5. There are several common themes throughout:

**Cost**

FCEVs, like BEVs, have greater capital costs than ICEs but can have lower running costs due to higher efficiency and reduced maintenance (fewer moving parts and less vibration). FCEVs in particular are expected to see considerable cost reduction as manufacturing volumes rise, and could end up cheaper than alternatives. Fuel costs are likely to remain higher for FCEVs than BEVs due to lower conversion efficiency (approx. 50% vs. 90%) [74], and electricity is widespread, unlike hydrogen. The net result all this is that many studies anticipate the total cost of ownership (TCO) of FCEVs can converge with other powertrains in the medium-term (see Section 3.4.1) so cost need not be prohibitive [75]. Considerable support will be needed to reach this, and creative approaches such as leasing schemes and targeting sectors with high utilisation may be required.

**Range**

A significant advantage of FCEVs is a considerably longer driving range than BEVs, which approaches drivers’ expectations from ICEs [74]. More compact, lightweight battery designs and chemistries could close this gap between BEVs and FCEVs, but probably not completely [74]. BEV range diminishes during summer and winter

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13 Engines require ceramic coatings because hydrogen has a hotter flame, increasing costs compared with LNG or LPG engines.
driving when power is diverted to heating and cooling. Battery capacity and power output also decrease in cold temperatures, reducing range and performance [76]. FCEVs have much better prediction of range as the fuel cell operation is not so dependent on external temperature, reducing the perception of “range anxiety”.

FCEV’s longer range means a smaller refuelling network is needed than for BEVs. Most – but not all – car journeys are short and can be covered by BEVs; however, versatility is one of the key appeals of personal transport. Heavy-duty and long-range vehicles, in particular, are likely to need the greater energy storage of FCEVs rather than BEVs.

Refuelling times
FCEVs also benefit from far shorter refuelling time than BEVs, again approaching that of ICEs. Although hydrogen refuellers are considerably more expensive than BEV chargers, fewer are needed as they can refuel more vehicles per hour, making it easier for operators to recover their investment selling hydrogen than electricity. Superchargers can accelerate BEV charging to ~30 minutes, but are expensive, require infrastructure upgrades, compromise battery lifetime, reduce efficiency, and require larger cooling systems [77]. BEVs are normally unattended during charging, clogging up charging spots once recharging is complete – leading Tesla to charge drivers for overstaying [78].

Environmental
Unlike ICEs or bio-fuelled engines, FCEVs are zero-emission at the point of use, releasing only water vapour. This is particularly helpful in urban areas suffering with air pollution. Hydrogen is zero-emission at the point of production if made from renewable-powered electrolysis, or low-emission if from reformation/gasification of fossil fuels with CCS. Until CCS is commercialised and the electricity grid is decarbonised hydrogen will have an appreciable carbon footprint, and a system of green certificates can be used to quantify carbon savings from hydrogen usage to ensure interim decarbonisation goals are achieved. The lower efficiencies of FCEVs relative to BEVs mean that FCEV usage can release more CO₂ than BEVs until hydrogen production routes are decarbonised.

Lifetime
Batteries are expensive, yet considerable uncertainties persist over how long they last. Degradation mechanisms vary considerably with battery chemistry, operating conditions and pack configurations, and batteries can have much shorter lifetimes in hot climates and require sophisticated thermal management systems [76]. Overcharging, deep discharge and high charging/discharging rates also shorten lithium battery life [79]. Manufacturers are increasing BEV ranges to around 200 miles [79, 80], narrowing the state-of-charge range used for short journeys and extending battery life. Tesla expect their batteries to last at least 10–15 years, yet most BEVs are under 5 years old so battery lifetimes under real-world conditions are questionable [66]. In contrast to batteries, hydrogen tanks can undergo fast refuelling and frequent, deep discharging without compromising lifetime [81].

14 Hydrogen ICEs release NOₓ, although the Mazda RX-8 HRE achieves “near-zero” emissions.
The US DoE reported average FCEV durability of 4,100 hours in 2016, with a maximum lifetime recorded of 5,600 hours [82]. Its ultimate target is 8,000 hours (at least 150,000 miles on a lower average speed drive-cycle in urban conditions). For buses the ultimate target is 25,000 hours and a bus lifetime of 500,000 miles, suggesting longer runtimes with fuel cells in transport applications are achievable.

**Safety**

Safety considerations associated with refuelling infrastructure are under continuous review by experts in the UK and internationally. A number of knowledge gaps such as hazards and associated risks of hydrogen vehicle performance in tunnel fires are yet to be closed and relevant Regulations, Codes and Standards (RCS) may need to be updated.

BEVs can be subject to battery fires. However hydrogen is also dangerous as a compressed, flammable fuel, with particular care needed during refuelling and parking in enclosed spaces, though these risks can be mitigated with safety standards.

**User experience**

Both BEVs and FCEVs are quieter than ICEs, which improves quality of life near busy roads, reduces noise mitigation costs and increases property values. FCEVs and BEVs offer a smoother driving experience than ICEs with no gear-shifting, less vibration and faster acceleration. Hydrogen tanks can be tricky to locate inside vehicles, which could have implications for luggage space. Driving range and refuelling times are important considerations for many users, as is ability to start and operate in sub-zero temperatures in some regions. FCEVs offer similar capabilities to combustion engines, which BEVs struggle to duplicate.

**Network effects**

There is considerable concern about upgrades to the electricity network and balancing required for significant BEV penetration (though smart charging could reduce this), and hydrogen refuelling infrastructure could be cheaper and less destabilising. Both BEVs and FCEVs can offer grid-balancing services; reducing load during charging (if using electrolysis), and discharging back to the grid when plugged in. This may not be cost-effective though, as shown later in Chapter 5.2.4.

### 3.3 PRESSURE AND PURITY REQUIREMENTS

There are important distinctions between hydrogen usage in transport and in other sectors such as heat and industry; primarily the need for high-pressure (up to ~1000 bar), high-purity (around 99.9999%) hydrogen.

#### 3.3.1 Hydrogen pressure requirements for transport

Most FCEVs store hydrogen as a compressed gas. Liquefaction could be an option to extend range for heavy duty vehicles such as lorries, ferries and aircraft, but high losses and safety concerns due to boil-off makes it unsuitable for low-utilisation vehicles. Other options such as solid hydrides, liquid organic hydrogen carriers (LOHCs), biofuels and synthetic fuels are under investigation, but are currently technologically immature and/or not widely available.
350 bar compressed storage was previously used for passenger vehicles, and is used currently for buses with their significant roof storage space. Most countries now use 700 bar storage for passenger vehicles to increase range, at the expense of higher compression costs and energy input, costlier tanks and fittings and greater safety requirements. Hydrogen tanks are more difficult to locate inside vehicles than petrol tanks or batteries due to their size and requirements to be cylindrical in shape. Hydrogen tanks comply with extreme safety standards and are capable of withstanding high-impact collisions, gunshots and vehicle fires [83]. The off-board infrastructure, costs and energy consumption needed to deliver hydrogen at these pressures are discussed in Chapter 6.

3.3.2 Hydrogen purity for transport applications

Manufacturers are seeking considerable FCEV powertrain cost reductions to compete with alternative technologies. One approach is reducing stack catalyst loadings, as automotive fuel cells are relatively large, even marginal reductions can lead to tangible cost savings. However, this requires highly pure hydrogen to avoid reducing stack life. Higher purity will increase fuel costs, but reduced purchase costs of FCEVs would remove a more significant barrier to uptake of FCEVs, and fuel costs will come down as volumes rise. Moving to high temperature PEMFCs or SOFCs could eventually reduce purity requirements, as could internal measures to mitigate poisoning issues. Hydrogen combustion engines (HICEs) have lower purity requirements, but are not expected to achieve significant deployment due to their low efficiency, low range and high storage requirements.

Manufacturers have adopted the international ISO 14687–2 purity standard to limit FCEV stack degradation from fuel impurities. This specifies a hydrogen purity of 99.97% (i.e. a maximum total impurity level of 300 ppm). Further sub-specifications for individual impurities means hydrogen must generally exceed this overall target. A recent EU funding call targeted 99.999% purity (5N or 10 ppm) for fuel cells used in stationary and transport applications [84], and a recent feasibility study reported 99.9999(9)% (at least 6N or 1 ppm) requirement for PEM fuel cells [19]. The off-board infrastructure requirements required to achieve and verify this very high level of purity are discussed in Chapter 6.

3.4 ROAD TRANSPORT

This section analyses the suitability and challenges for hydrogen and fuel cell technologies for different road transport sectors.

3.4.1 Passenger cars

Over 50% of energy demand in the UK transport sector is consumed by light duty vehicles (Table 3.1), and the number of passenger cars worldwide is set to rise to 2.5 billion by 2050 [15]. Therefore, any attempt to achieve deep decarbonisation of transport must focus on private cars. Much of the progress to date towards the UK’s 2020 target of 10% renewable energy has been achieved by blending biofuels with petrol and diesel; however biofuel supplies are limited and do not always meet air quality and decarbonisation standards.
BEVs and FCEVs are therefore attracting significant attention. A 2010 report by a coalition of 30+ industry stakeholders (the Coalition) argued that the potential for FCEV cost reduction at mass-production means their total cost of ownership (TCO) should converge with other principal powertrains by 2030 [15]. FCEVs could have the lowest TCO of all powertrains for large cars by 2050, with a slightly higher TCO for small cars. More recent analyses have updated these assumptions but have reached broadly similar conclusions (Figure 3.2) [23, 67, 85–87].

**Figure 3.2 TCOs of major powertrains could converge by 2030 [23].**

This potential for cost parity allows powertrains to be chosen using alternative criteria than pure economics. This could include metrics like user experience, with FCEVs allowing longer range and faster refuelling times than BEVs, or network implications with FCEVs reducing the infrastructure upgrades BEVs could require. OEMs are currently torn between proven technologies and new but immature trends (including digitisation and autonomous driving as well as alternative powertrains). Faster refuelling leads 78% of automotive executives to believe FCEVs will be the breakthrough for electric mobility, with 62% thinking BEVs will fail as 30+ minute recharging times remain an insuperable obstacle to acceptance [88].

This optimism feeds into high-profile projections of strong FCEV update. These are of course speculative, and historically have tended to be optimistic. Some are based on carbon reduction targets: the IEA’s Hydrogen and Fuel Cell Roadmap concludes that global warming could be limited to 2 °C with FCEVs achieving 8 million sales by 2030 in developed nations, and 150 million sales and a 25% share of road transport by 2050 [67]. The H2Mobility programme projected 1.6 million FCEVs in the UK by 2030 [51], while E4Tech estimate 700,000 in 2030 and 17 million in 2050 in a ‘Critical Path’ scenario [30] (see Chapter 2).

In the near-term, a number of car manufacturers are bringing FCEVs to market with Toyota, Hyundai and Honda now offering production vehicles, while Audi and Mercedes-Benz are preparing launches [89]. Take-up, however, has been muted so far with FCEVs only being offered in a handful of countries whilst supply-chains
and production capacity gradually expand [30, 90]. Around 1,000 FCEVs have been sold in the US as of 2016, with a similar number in the rest of the world [14, 91]. For comparison BEVs, aided by lower initial infrastructure hurdles, are several years ahead, reaching 448,000 in 2015 as battery pack prices have fallen 65% since 2010 to $350/kWh [86, 92].

This could be about to change, as Toyota will produce 3,000 FCEVs in 2017 and anticipates 30,000 p.a. by around 2020 [90, 93]. Honda also aims for tens of thousands of sales from 2020 [94]. Japan has targeted around 40,000 FCEVs by 2020 and 800,000 by 2030 [95]. South Korea plans to have 10,000 FCEVs by 2020 with a further 14,000 of exports [96]. California is projected to have 43,600 FCEVs by 2022 as part of a wider mandate for 1.5 million zero-emission vehicles (ZEVs) by 2025 [97]. In January 2017 thirteen companies formed a Hydrogen Council to accelerate the commercialisation of H2FC technologies, currently worth €1.4 billion p.a. [98].

The 2017 Honda Clarity fuel cell vehicle [99].

The lack of expensive refuelling infrastructure presents a chicken-and-egg problem which is more challenging for FCEVs than for BEVs due to not having the backup of every home having a power socket to charge from. It is therefore important to identify transport sectors which have the lowest initial hurdles. Passenger cars are a difficult market due to the maturity of ICEs. Passenger FCEVs currently have the largest TCO gap to ICEs, and require significant production volumes of around 100,000 units per year (and hence considerable financial support) to approach cost parity by 2030. However, with global passenger car sales of 60 million per year, even a small penetration can represent a sizeable market [86].

Several road transport sectors could be targeted with smaller initial hurdles:

1. Range-extender EVs (FC RE-EVs). Smaller FC stacks (<20 kW) and lower fuel consumption mean FC RE-EVs can be competitive at smaller volumes [86].
2. Captive fleets, such as buses, delivery vans and taxis. Return-to-base fleets with high utilisation can use a single refuelling depot.
3. Air Quality zones. Vehicles which need regular access to low emission zones such as London’s Ultra Low Emission Zone could face considerably lower charges over their lifetime. London will ban new diesel taxis from January 2018, and four major cities have announced bans on all diesel vehicles by 2025 with incentives for electric and hydrogen vehicles, with more cities likely to follow suit [63, 64]. Paris has recently announced it will purchase 60 new FCEV taxis with plans for hundreds more [100].

4. Noise. FC delivery vans and trucks could continue to operate in areas with night time noise curfews provided speeds are low enough to limit tyre and air noise [86].

Looking to the future, FCEVs could play an interesting role in a shift towards a car-sharing economy. High capital cost and low running costs favours higher utilisation of vehicles. Private passenger cars are poorly utilised, but this increases with car-sharing. Access to low-cost hydrogen would be needed and is more likely in a car-sharing economy as high utilisation of production and distribution assets lower the costs of these too. FCEVs are more suited to car-sharing than BEVs, whose long, frequent charging periods constrain achievable utilisation. FCEVs will need to increase stack longevity to avoid frequent replacement; however fewer start-ups and smoother driving with autonomous vehicles could help extend stack lifetimes. Hence there is good reason to think FCEVs can, in fact, help reduce the cost of motoring in a car-sharing economy.

3.4.2 Buses

Interest in urban hydrogen buses is growing, with the FCH-JU reporting that 81% of Europeans think air pollution needs to be addressed, and that 72% think urban noise pollution is a problem [101]. Fuel cell buses can completely mitigate CO2 and other emissions (depending on the hydrogen source), improving citizens’ health and reducing health costs; and can reduce perceived noise by about 60% compared to diesel (increasing quality of life, reducing noise mitigation costs and increasing property values) [101]. Hydrogen buses achieve ranges of 300 km, with performance comparable to diesel, improved passenger experience from lower noise and smoother driving, fast refuelling (7 minutes), and proximity to technological maturity with 7 million kilometres of operational experience so far in Europe [101].

Fuel cell buses use an electric drive train powered by a hydrogen fuel cell, normally hybridised with a battery or supercapacitor [30]. On-board tanks typically hold around 40 kg of hydrogen stored in the bus roof. Relaxed space constraints compared to cars mean this is typically stored at 350 bar, reducing tank and compression costs and losses, but requiring distinct refuelling infrastructure from cars refuelling at 700 bar (and hence reduced potential for technological learning and volume production crossover). Refuelling infrastructure does not need to be as widespread as for passenger cars due to back-to-base operation, making hydrogen buses an early candidate for deployment. Hydrogen buses have been demonstrated since the mid-1990s, and early commercial fleets are now being introduced [30]. The NREL considers most fuel cell buses to be at Technology Readiness Level (TRL) 7 i.e. full-scale validation in a relevant environment [102].
In the UK fuel cell bus deployment has focused on two urban centres to date. Building on its worldwide reputation in the energy industry, Aberdeen boasts Europe’s largest fuel cell bus fleet with ten Van Hool hydrogen buses in a £21m project including a central BOC-operated refuelling station. In its first year of operation to March 2016 the fleet racked up 250,000 miles, carried 440,000 passengers and refuelled more than 1,600 times [103]. A second refuelling station became operational in August 2016 [104] and Aberdeen has plans to increase its fleet to 30 buses, although securing funding after the Brexit referendum vote could prove a challenge [105].

London currently has a fleet of eight operational Wrightbus fuel cell buses, which have accumulated in excess of 117,000 operating hours (with four exceeding 18,000 hours each) [106]. In November 2016 the world’s first double-decker hydrogen bus was unveiled in London [107], alongside an announcement that 20 more new hydrogen buses had been ordered and that no more pure diesel double-decker buses will be added to London’s fleet from 2018 [108]. In all, 83 fuel cell buses are currently in operation or about to start operation in Europe, with 20 buses in Whistler, British Columbia and 24 in the US (mainly in California) [106, 109]. In 2015 two Chinese cities (Foshan and Yunfu) ordered 300 fuel cell buses with the first 22 buses delivered in late 2016 [110, 111]. Forty-eight Chinese cities could deploy 1,000 clean buses each to address severe air quality issues [110]. Toyota is planning to introduce over 100 fuel cell buses in time for the Tokyo 2020 Olympic Games [112].

Early operational data indicates that refuelling station availability averaged over 95% in Europe, with fuel cell bus availability exceeding 90% in some cities relative to a target of 85% [106]. A fleet of 13 hydrogen buses in California has surpassed 1.3m miles of service and 152,000 hours of operation at [113]. Ten of the buses have surpassed 12,000 hours of operation with one accumulating 22,400 hours, which is a record for a fuel cell in a transit application, more than the US Department of Energy’s 2016 target of 18,000 hours, and close to its ultimate target of 25,000 hours [114]. Bus availability of 74% in 2015 was below the 2016 target of 85%, but rose to 86% when the data from two vehicles affected by atypical maintenance issues was removed.
Industry projections for bus costs were reported in 2014 as €400–600k in 2020 at production volumes of 500–1,000 per year [109], and €400–450k in 2030, corresponding to a 40% premium over diesel [101]. This gap could virtually close by 2050, with one cost estimate for fuel cell buses at £154k [30]. On a total cost of ownership (TCO) basis fuel cell buses may have only a small premium (10–20%) compared to diesel by 2030, and could be cheaper if deployed at scale [115]. To help overcome the higher up-front capital and infrastructure costs of greener buses, coordinated activities are required to help cities unlock funding for more zero emission buses and supporting infrastructure [108]. To date UK deployment has been strongly linked to EU projects including CHIC, HyTransit, High V.LO-City and 3Emotion [101]; alternative initiatives may be needed to replace them in the coming years.

### 3.4.3 Lorries

There is considerable potential for FCEV lorries as, despite some current attempts at electric lorries [116, 117], heavy-duty lorries have few low-emission alternatives due to their high energy requirements. Light urban delivery vehicles with low speeds, low travelling distance and regenerative braking could potentially be managed with batteries. Indeed, compared to passenger cars, a larger proportion of current hydrogen-powered light goods vehicles (LGVs) are range extender vehicles (particularly in France), where a small fuel cell system augments the range of an efficient battery [30]. Long haul heavy duty vehicles driving at high speeds are more likely to require hydrogen rather than batteries, potentially in liquid form. High utilisation is also critical in logistics operations, making the long recharging times of batteries and the impact on vehicle payload unsuitable. Low volumes of FCEV lorries are required (100s to 1,000s of units per manufacturer per year) to reach economies of scale and achieve cost parity with other low-carbon alternatives [86]. Long-range HGVs need an adequate refuelling network, but return-to-base delivery vehicles can manage with a single refuelling depot.

However, FCEV lorries face many initial obstacles to deployment. Capital costs must fall as the HGV market is very cost sensitive [30]. High reliability is needed in logistics operations; FCEVs have yet to prove sufficient reliability and hauliers are wary of being pioneers. Longer-lived stacks are required due to the very high mileage lorries are expected to achieve (one Japanese program targets 50,000 hour stack lifetime [30]). High efficiency and low fuel costs are needed due to the large amounts of hydrogen consumed, and the comparatively good efficiency of diesel engines (~40%) during constant motorway operation [67]. Only one major OEM is actively considering hydrogen trucks [118], leading some to conclude that FCs are likely to be commercialised in the LGV, bus and passenger car sectors before HGVs [30].
This could begin to change as diesel trucks begin to be banned from the centres of major cities [64], with range extenders already being demonstrated for delivery and refuse collection vehicles [30]. The US company Nikola is developing a zero-emission long-distance HGV using liquefied hydrogen with a 1,200-mile range (hence requiring a smaller refuelling station network) [119]. The fuel economy is expected to be twice that of diesel due to a 60% efficient fuel cell, regenerative braking, improved aerodynamics and no idling. They intend to lease the vehicles at a premium over equivalent diesel trucks, but this may be offset by lower running costs as fuel is included for free. They plan to start work on a manufacturing facility in 2017, with an initial network of 50 refuelling stations in place by 2020.

3.4.4 Other road transport

Motorbikes and scooters are popular in many regions of the world (particularly Asia), and UK fuel cell company Intelligent Energy had developed a 4 kW fuel cell system for 2 and 4 wheel vehicles in cooperation with Suzuki [30]. Their lightweight nature reduces fuel consumption, allowing them to be refuelled using hydrogen canisters from vending machines. However Intelligent Energy has since withdrawn from the automotive sector, citing the high costs of developing manufacturing facilities and the lack of refuelling infrastructure [120]. With many motorbikes used in cities, the potential for FCEV motorbikes to contribute toward air quality and noise pollution targets could also drive deployment in this sector.

Fuel cells are also being developed as Auxiliary Power Units (APUs) for HGVs [30]. This can be for cargo refrigeration or ‘hotel’ loads on stationary HGVs (e.g. cabin heating, cooling, lighting, and electrical devices). Currently both SOFCs and PEMFCs are used coupled with diesel reformers, given this fuel is already available on board the lorry. Clearly such fuel cells could be adapted to run on hydrogen if HRSs become widely available.

3.5 OFF-ROAD TRANSPORT

3.5.1 Trains

Hydrogen train prototypes have been tested in several markets for 10–15 years, mostly using PEM fuel cells. Electrification is viewed as the obvious option to reduce the share of diesel trains, but electrification has slowed recently in a number of European states including the UK [30], with Germany expected to take 95 years to electrify the remainder of its network [121]. Hence hydrogen trains could reduce emissions on routes which are difficult or uneconomic to electrify (e.g. due to lack of space in urban areas) and avoid high electrification costs (around $12m per mile in the US [122]).

Hydrogen FC trains reduce well-to-wheel GHG emissions by 19% compared with conventional diesel traction locomotives (when hydrogen was produced via SMR) [123]. Local air pollution is eliminated, which is of particular importance for urban areas.

The German state of Lower Saxony has begun testing a fuel-cell powered train with roof-mounted hydrogen tanks and a range of 500 miles [124], which should begin public operations in December 2017 [125]. Lower Saxony has already ordered
14 hydrogen trains from French company Alstom, and 40 could be in service across four German states by 2020 [126]. Light rail also presents opportunities for hydrogen trains. Ballard is currently developing a fuel cell system for trams in China, and a FC-powered tram is currently operating in Qingdao [86, 127].

Given low anticipated rail fuel cell volumes, hydrogen trains are expected to use the same heavy duty stacks and storage tanks used for buses and lorries, hence cost reductions will be driven by the automotive sector. Although hydrogen powertrains could be around 50% more expensive than diesel (including stack replacements), long lifetimes mean that the economics are likely to be dominated by fuel costs. Costs significantly below £5/kg are recommended, and although high asset utilisation can help reduce the cost of hydrogen, access to low cost energy sources may still be needed [86]. One study thinks that FCEV trains are already cost competitive with diesel trains from a TCO perspective [87].

3.5.2 Shipping and ports

The marine industry is historically conservative on propulsion innovation due to high requirements for safety and reliability. Some early hydrogen projects therefore use dual-fuel configurations where only one conventional engine is replaced with a hydrogen technology to protect against breakdowns [86]. Fuel cells have already been used for propulsion for a handful of projects including ferries and other boats, including in the UK [30, 86]. It is thought that hydrogen might not play an important role as a propulsion fuel in shipping until after 2030 [30]. However the growth of emissions controlled zones (such as the Baltic Sea region and ports in urban areas) could drive interest in hydrogen earlier than this, particularly as it offers a higher efficiency than LNG [30].

As with rail, shipping is likely to use systems based on automotive designs due to the low production numbers involved. Long system lifetimes mean low fuel costs
and low maintenance are more important than low capital costs. With ferries potentially consuming 2,000 kg of hydrogen per day, fuel costs significantly below £5/kg have been recommended (as for trains) [86, 128]. Such large usage rates could lead to a requirement for cryogenic storage; boil-off should not be a safety hazard here and the hydrogen released could be captured and used. Most marine vessels are built in small numbers and highly tailored to specific uses; this could hamper the rollout of new propulsion systems [86].

Fuel cells for auxiliary power could be adopted earlier than for propulsion – though would be limited to routes with hydrogen refuelling infrastructure in ports [30]. Port vehicles could also be early adopters of hydrogen with their ability to improve local air quality with a single refuelling depot.

### 3.5.3 Aircraft and airports

Aviation is regarded as a hard-to-decarbonise sector. Low-emission aircraft propulsion has received relatively little attention, though rising emissions from the aviation sector mean this cannot be ignored if global targets are to be met. Some hybrid electric concepts are being studied, though emission reductions will be limited [129]. Aviation is one sector that many think should be reserved for biofuels due to their higher energy density than hydrogen or batteries, but biofuels are not completely emission-free and could remain costly with limited availability. The International Civil Aviation Organization struck a deal to cap aviation emissions at 2020 levels, but primarily achieved through carbon offsetting rather than using lower-emission fuels [130]. Hydrogen could be used as a propulsion fuel, but will need to be liquefied to supply the required range. Its high volatility means it has to be stored in the fuselage rather than the wings leading to a larger fuselage and higher drag, but this is compensated by hydrogen’s lower weight. Combustion turbines are still likely to be needed as fuel cells lack the power density required for take-off.

The climate benefits of hydrogen for aviation have been questioned because it produces more than double the water vapour emissions of kerosene. Water vapour at high altitudes, although short lived in the atmosphere, causes radiative forcing and thus contributes to net warming [131]. Significant hydrogen deployment has been deemed unlikely before 2050 except perhaps for small or low-flying aircraft [30]. Much work remains on developing options for low-carbon aircraft propulsion.

Other aviation-based sectors are more promising. Fuel cells have been tested for aircraft auxiliary power units and taxiing aircraft to/from airport terminals [132]. There is an increasing motivation to improve air quality around airports and fuel cells could play an important role in powering ground vehicles and buses in the next 10 to 20 years [30], aided by the need for a low number of refuelling stations experiencing high utilisation.

Unmanned aerial vehicles (UAVs) are also attracting considerable interest, with a potential market size of up to $15 billion by 2025, driven mainly by military applications [86]. FC UAVs are quieter, more efficient, and have lower vibration and infrared signatures than fossil fuel-powered vehicles. They are also lighter than battery
systems, offering longer ranges. Civilian applications include surveillance, infrastructure maintenance, agriculture, deliveries and surveying. PEMFCs have shown the most promise to date, augmented by batteries to assist with take-off. Ultra-lightweight hydrogen storage is needed, and it is thought chemical hydrides will become a prominent storage technology. FC UAVs are currently considerably more expensive than battery UAVs; the cost gap will close with manufacturing volume, but fuel cells could still be restricted to long-duration or high energy applications.

3.5.4 Other non-road transport

Forklifts are a promising market for fuel cells, with around 12,000 units deployed in the US [133]. The zero emissions from FC forklifts allow them to operate indoors, and their faster refuelling than batteries can lead to TCO savings of 24% in a typical high throughput warehouse. FC forklifts also have a wide temperature range, capable of operating in temperatures as low as -40 °F. PEMFCs are most widely used with longer lifetimes but high cost of ownership, but direct methanol fuel cells (DMFCs) are also found in lower usage applications. Plug Power supplies 85% of FC forklifts in the US. There has been negligible deployment of FC forklifts in the UK to date.

Agricultural equipment such as tractors is another sector that could see FC usage and has received some attention [134]. Recreational applications such as caravan APUs and golf carts are also significant sectors, and one of the few where manufacturers are returning a profit [14].

3.6 CONCLUSIONS

Hydrogen vehicles can make a significant contribution to decarbonising the UK’s transport sector, which lacks many viable alternative options. Recent modelling indicates the UK could achieve its decarbonisation targets with 700,000 hydrogen cars in 2030 and 17 million in 2050 [30]. Air quality concerns could speed the rollout of hydrogen technologies, particularly urban transport vehicles including cars, buses, lorries, taxis and trains. Other drivers that could accelerate the rollout of hydrogen vehicles include energy security for nations with limited access to fossil fuels, the need for grid stability, and the opportunity for early movers to capture commercial advantage in a new sector.

Hydrogen and fuel cell vehicles show great potential for contributing towards these goals with zero-emissions at the point of use, and zero emissions during production depending on production route. Numerous studies show that FCEVs exhibit considerable cost reduction potential and can achieve parity with alternative powertrains by the 2030s as production volumes rise. Fuel cell vehicles also offer faster recharging and longer range than battery electric vehicles without compromising lifetime, and more efficient drivetrains, lower maintenance costs, quieter and smoother driving than IC engines. Three major manufacturers have launched hydrogen passenger cars and are ramping up production, with Toyota and Honda targeting FCEV sales of around 30,000 p.a. by 2020. National and regional governments are also setting targets for the deployment of tens of thousands of FCEVs in the early 2020s, alongside the refuelling infrastructure required to support them.
Hydrogen is also the leading option for zero-emission heavy-duty transport. Hydrogen buses are a sector gaining significant early deployment with their ability to improve urban air quality and use a small number of central refuelling depots, and good progress is being made towards achieving availability and longevity targets. High up-front costs are hampering rollout, causing stakeholders from manufacturers to city authorities to cooperate. Hydrogen could also see widespread deployment for lorries, trains and ferries, but needs to demonstrate high reliability to gain market share in these sectors.

The costs of purchasing and driving FCEVs are likely to remain high relative to ICEs in the short term. However cost-competitiveness could be achieved earlier in smaller production volumes in sectors including range extender EVs, buses and lorries, though the slow turnover in some sectors could hamper this. The lower running costs of FCEVs mean they can achieve more favourable economics than IC engines in high-utilisation sectors such as car fleets, taxis, buses and lorries, particularly those able to refuel from a small handful of central refuelling hubs. This also benefits FCEVs in potential car-sharing economies, where the utilisation of BEVs are capped due to their need of frequent, time-consuming recharging. Other transport sectors including forklift trucks and unmanned aerial vehicles (UAVs) also hold significant promise for hydrogen technologies.
CHAPTER 4
HEAT AND INDUSTRIAL PROCESSES

Daniel Scamman – UCL
4.1 INTRODUCTION

Supplying heat and hot water to buildings currently consumes around 40% of UK energy demand and releases 20% of the UK’s greenhouse gases. These emissions need to be largely eliminated to achieve 2050 decarbonisation targets, but the CCC’s modelling for the 2030 period suggests that industry and buildings might only reduce their emissions by 16% and 24% respectively, compared to the overall target of 57% [5]. These modest reductions by 2030 indicate the perceived difficulties in achieving deep decarbonisation in these sectors in the near term.

This suggests the UK currently has a window to identify, plan for and test preferred decarbonisation options for these sectors, and needs to grasp this opportunity as rapid decarbonisation of these sectors needs to commence post 2030 to meet longer term obligations. The UK is currently on track to fall well short of these Fifth Carbon Budget commitments, leading the CCC to call for new and stronger policies for decarbonising the heat and industry sectors [53]. The Government has recognised this policy shortfall and has promised an emission reduction plan for meeting the Carbon Budgets, currently expected in early 2017 [135].

The UK is also less than halfway towards its 2020 target of providing 12% of heat requirements from renewable sources [54, 136]. In December 2016 the government announced more modest reforms than feared to its flagship support scheme, the Renewable Heat Incentive. This should allow low-carbon heat technologies to continue deployment, although it currently excludes hydrogen [137, 138].

The first H2FC white paper analyses the role of hydrogen and fuel cells in providing low-carbon heat [49]. This chapter builds upon its evidence base, adding insights gained since its publication in 2014.

4.2 DECARBONISATION OPTIONS FOR HEAT

Decarbonising heat is a significant challenge for several reasons [139, 140]:

1. Heat is the UK’s biggest energy demand and presents a problem of scale (see Figure 4.1);
2. There is a wide range of heating needs, from low temperature space heating to high temperature industrial loads, with no one solution capable of meeting them all;
3. Heating fuels are cheaper than those for power and transport and large quantities are used, making them harder to displace without increasing energy poverty;
4. Heat demand has huge daily and seasonal swings, which are adequately met by existing technologies but which new technologies might struggle to deliver (see Chapter 2.2).
Heat has therefore developed a reputation for being difficult to decarbonise and has received less attention than other energy sectors to date, though this is now changing as challenging medium- to long-term emission targets begin to bite. Five main options have been proposed for decarbonising the UK’s heat supply [141, 142], which are outlined in the following sections.

4.2.1 Demand reduction

There is a wide array of options for improving energy efficiency and reducing demand, including using more efficient heating devices such as condensing boilers, fuel cells and heat pumps. Smart meters and pricing can encourage residents to use less energy. Newly-built homes and offices can meet tougher building standards, although 80–90% of homes in 2050 may have already been built, limiting the contribution this can make [136]. Existing UK homes are generally poorly insulated; retrofit technologies can help, but are not suitable for some properties. An expected growth in the number of households could increase energy usage due to population growth and smaller households. The net result of these factors is that demand reduction could cut domestic heat demand by up to 20% by 2050 [141]: a significant contribution to decarbonising heat, but far from sufficient on its own.

4.2.2 Electrification

The electrification of heat using renewable generation attracted strong support in the UK, with DECC’s 2013 Heat Strategy proposing 85% of homes using electric heat pumps in 2050 [33]. Several factors have since tempered this enthusiasm: difficulty in meeting peak winter demand, the need for network upgrades, and consumer acceptance. Heat pumps can be noisier, bulkier and with slower response times than gas heating; although 80% of heat pump owners within the Renewable Heat Incentive scheme (RHI) are very satisfied with the technology [137].

Heat pumps are still expected to play an important role, but less than that initially proposed by DECC [141]. They are particularly appropriate for rural homes (19% of UK housing stock, Figure 4.2) too remote for district heating or gas networks, using expensive high carbon fuels such as heating oil and with space for larger
systems [143]. Heat pumps are well-established technologies, with around 1 million sold in each of France, Italy and Sweden between 2005 and 2013, compared to 100,000 in the UK [144]. High upfront costs are hampering deployment but these might fall as rollout progresses. Electric resistive heating could also be suitable for blocks of flats where gas-fired boilers cannot be used and space heating requirements are lower [143].

Figure 4.2 Strategic framework for low carbon heat in buildings over time [33], source: DECC.

4.2.3 Heat networks

District heating systems also attract interest, with potential to provide 10–20% of UK residential heat by 2050 [141, 145]. 50–60% of Scandinavian buildings are supplied by district heating, compared to about 1% in the UK [144]. These are relatively expensive and disruptive to install, and heat losses limit transmission distances to around 30 km [146]. They are primarily suited to new buildings and densely populated areas, but offer 30% lower heating costs than individual gas boilers [137]. They are well-suited to recycling waste heat from industry and data centres, while other sources such as geothermal can be used where available. Large CHPs district heating schemes are cheaper and more efficient than individual residential CHP systems. Not all energy sources for heat networks are low-carbon, so a pathway towards decarbonised heat networks need to be identified before installation. The Government has established a Heat Network Delivery Unit (HNDU) to drive the rollout of heat networks, and is launching the £320m Heat Network Investment Project (HNIP) to fund new heat networks [145].
4.2.4 Green gas

An advantage of continuing to use the existing gas network to supply heat is that it substantially reduces the disruption and cost of installing alternatives [143]. The advantages are augmented by a greater use of more efficient gas-powered technologies including condensing boilers, micro-CHP (which can also supply power) and gas-driven heat pumps (GDHPs) [147].

Two main options for decarbonised gas are biogas and hydrogen. Biogases and synthetic methane are under significant consideration, but are likely to suffer from limited availability, gas quality concerns and/or excessive costs.

Biogases can be generated by anaerobic digestion or gasification from a wide range of sources including municipal solid waste, sewage, agricultural residues, wood, landfill gas, energy crops etc. Bio-propane is also considered to be a drop-in substitute for LPG, currently used in about 200,000 homes across Great Britain not connected to the existing gas grid, and should become available in the UK from 2017 onwards [141]. The processing and transportation of these fuels must be carefully considered to ensure they lead to a reduction in emissions. There is much uncertainty about future availability of biomass in the UK: estimates range from 100 to 550 TWh p.a. in 2050, with a central estimate of 140 TWh from domestic sources and 70 TWh from imports [141]. Most studies conclude that limited biomass resources are best used for energy-intensive sectors like industry and transport; the DECC UK bioenergy strategy limits bioenergy usage for heating to 15% [141]. There are practical difficulties with inserting biogas into the grid, raising significant question marks over how large a contribution biogases can make to the UK’s long-term heat decarbonisation targets. Biogases currently have lower energy densities than natural gas and do not meet current standards; they can undergo further cleaning, be upgraded by adding propane (increasing carbon emissions), or gas standards can be adjusted to accommodate a broader range of parameters [141].

Hydrogen can be safely mixed in small quantities with natural gas and injected into the existing gas network, but caps on permissible hydrogen content limits the carbon savings. The level of hydrogen that can be safely added depends on the characteristics of the natural gas, the distribution system and end-use appliances. A Dutch study concluded that off-the shelf gas appliances operated with no serious problems with up to 20% hydrogen blends by volume [42]. However the wide range of gas appliances in use, many installed decades ago, means gas suppliers may need to undertake widespread inspection and replacement programs before introducing hydrogen into the UK gas network. The UK has amongst the lowest legal limits of any country, at 0.1%, compared to 10–12% in Holland and Germany (Figure 4.3). Even if this were relaxed, a 20% blend represents only 7% hydrogen by energy content, and so hydrogen injection can only provide a small step towards decarbonisation.
Alternatively the existing gas network could be converted to distribute hydrogen rather than natural gas, which is studied later Section 4.5 and in Chapter 6.5. High customer satisfaction with gas means the government views network conversion to hydrogen as a potentially popular low-carbon choice [149]. However, this is currently a novel and untested option, and further work is needed to demonstrate technical and economic feasibility. The UK is among the only countries considering this option, in part for its extensive gas network coverage. Questions remain over the availability of sufficient low-cost natural gas for steam methane reforming (currently viewed as the cheapest source of hydrogen), the viability and capacity of the Carbon Capture and Storage (CCS) facilities needed to store the carbon dioxide produced, and the availability of adequate seasonal storage for hydrogen. If these facilities have sufficient capacity to partially meet national demand for hydrogen, then one option is to implement hydrogen networks in areas with good access to these facilities, with other low-carbon heating technologies deployed elsewhere.

### 4.2.5 Onsite renewables

More buildings are generating their own renewable heat onsite, amounting to several TWh p.a. in the UK. Table 4.1 shows the cumulative installations and energy generated under the UK’s RHI scheme since its inception. It is questionable how great a role onsite renewables can play. Biomass resources are limited and contribute to local air pollution, with biomass stoves responsible for 7–9% of particulate matter in London [150]. Solar thermal exhibits a poor match with demand, and requires backup from other heating systems [141, 151].
### Table 4.1 Biomass, biogas and solar thermal installations accredited by the Renewable Heat Incentive scheme (RHI) [152].

<table>
<thead>
<tr>
<th></th>
<th>Non-Residential</th>
<th>Residential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Period</td>
<td>Nov 2011 to Nov 2016</td>
<td>Apr 2014 to Nov 2016</td>
</tr>
<tr>
<td>Accredited Installations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy generated to date</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biomass, Biogas</td>
<td>14,722 GWh</td>
<td>12,088 GWh</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>249 GWh</td>
<td>8,002 GWh</td>
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</tbody>
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#### 4.3 HYDROGEN AS A LOW-CARBON OPTION FOR HEAT

The merits of the various options discussed above are summarised in Table 4.2. There is significant uncertainty surrounding choices of heating technology, with open questions around technical feasibility, cost, suitability across regions and building types, user acceptance and safety. The government recognises the lack of consensus on the optimal technology mix to deliver the required long-term changes, and the need to thoroughly re-assess the evidence and test different approaches [137]. Figure 4.4 shows that the dominance of gas-fired heating is a recent phenomenon in the UK; returning to a portfolio of complementary technologies (as used in electricity and transportation) seems increasingly appropriate for heat [153].

### Table 4.2 Decarbonisation options for heat.

<table>
<thead>
<tr>
<th></th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
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| Demand Reduction | • More efficient devices, more insulation and more awareness can all reduce demand and energy bills  
• Low-regret option    | • Low turnover rate of existing, poorly insulated stock could limit demand reduction to 20% by 2050  
• Consumer indifference |
| Green Gas     | • High customer satisfaction/familiarity  
• Gas appliances increasingly efficient and lower cost  
• Good option for meeting peak demand  
• Less conversion costs/disruption | • Difficult to decarbonise  
• Biogases have limited availability and need cleaning.  
• Hydrogen networks unproven with uncertain availability, costs and safety implications |
| Electrification | • Efficient heat pumps can reduce demand  
• Good fit for UK with mild winters; could heat up to 85% of properties  
• Good option for rural properties far from gas/heat networks  
• Proven/widely-used abroad | • Requires power system expansion  
• Could struggle to meet peak demand, though efficient devices and improved insulation can reduce peaks  
• Can require heat storage  
• Larger space usage and high conversion costs/disruption reduce suitability for densely-populated areas |
Until recently, most energy systems and building stock models did not include hydrogen and fuel cell technologies for meeting decarbonisation targets [49]. A recent study proposed using 27–40 TWh p.a. of decarbonised gas whilst retaining substantial numbers of popular gas appliances to hit 2050 climate targets [141]. Biomethane or localised hydrogen networks were suggested as the main zero-carbon options, but with reservations over the availability of the former and the costs of the latter. Analysis for the CCC identifies two plausible routes for achieving 2050 decarbonisation targets: a Critical Path scenario where hydrogen usage was restricted to the transport sector, and a Full Contribution scenario where hydrogen replaced natural gas more widely across the economy, contributing 83% of residential heat, 67% of commercial heat and 51% of industrial energy consumption [30]. Within this context, this chapter now studies the latest evidence on the role that hydrogen and fuel cell technologies can play in decarbonising the heat network in multiple sectors.

### Table: Advantages and Disadvantages

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Heat Networks</strong></td>
<td><strong>Limitation availability of assured, low-carbon sources</strong></td>
</tr>
<tr>
<td>• Could meet ~10–20% of heating needs</td>
<td>• Cannot be transported long distances, unlike gas and electricity</td>
</tr>
<tr>
<td>• Good option for new-builds and densely-populated regions</td>
<td>• High conversion costs/disruption</td>
</tr>
<tr>
<td>• Proven/widely-used abroad</td>
<td>• User scepticism</td>
</tr>
</tbody>
</table>

| **Onsite Renewables** | **Limitation availability and high emissions (biomass)** |
| • Use local energy sources where available | • Small schemes less cost-effective |
| • Reduce network dependence/upgrade requirements | • Other heat sources needed |

**Figure 4.4 Installed central heating by type in the UK [154].**
4.4 MEETING PEAK HEAT DEMAND

A particular challenge with low-emission heating options is meeting winter peak heat demand [49, 137, 141], as this is considerably higher and more variable than peak electricity demand (Figure 4.5).

**Figure 4.5** Variation in household heat demand between classes of housing for an average year. Heat demand includes space and water heating. Winter consumption is strongly temperature-dependent and the winter peaks can be much higher in a cold year [49].

This strong seasonal variation is adequately met by the prevailing gas system, as gas boilers are routinely oversized for buildings [151] and the gas network can store up to a month’s worth of consumption [141]. This presents a challenge for electric and district heating systems, which have limited output or slower response times. Retaining the flexibility of the gas network with a low-carbon fuel (such as hydrogen) sidesteps this problem. Improving insulation to reduce demand, and incorporating thermal storage (either domestic water tanks or communal reservoirs) would reduce the size of demand peaks. Hybrid heat pumps are gaining attention, using an electric heat pump for supplying most heating needs, backed up by a gas boiler for peak demand [141].

Literature on heat decarbonisation tends to present CHP and heat pumps as competing technologies, with one or the other expected to become the dominant heat provider [155, 156]. Only recently have the potential benefits of combining the two been considered [157–160]. In cold temperate countries such as the UK, fuel cells CHP systems will be primarily heat-led, generating electricity at times when heat pumps

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15 The gas network can store around 50,000 GWh of chemical energy, whereas only 27 GWh of electricity can be stored in Britain.
demand it, thus balancing out their impacts on the electricity network [158, 161]. Based on a UK case study, a 50% penetration of fuel cell micro-CHP would balance a 20% penetration of heat pumps, mitigating the 30% rise in peak demand caused by the heat pumps alone [49]. This would have profound implications for local distribution networks, the national transmission system and need for peaking generation plants, suggesting that policy should consider targeting a balanced and diverse deployment of microgeneration. More effort needs to be made to identify and exploit synergies such as these.

4.5 HYDROGEN AND FUEL CELL HEATING TECHNOLOGIES

This section discusses the various hydrogen and fuel cell options for heating, including technical requirements, market-readiness, costs and UK rollout.

4.5.1 Boilers

Gas-fuelled boilers are currently the most common heating technology in the UK (Figure 4.4). They have many attractive features, including low capital and running costs, high reliability and long life, high power output and fast response times, their small size and ability to work without hot water storage. In addition, their maturity means supply chains and associated servicing industries are well established. Hence there is considerable interest in developing a decarbonised heat sector that closely replicates the operation and experience of the existing gas-based system.

The issues with a straight switch of natural gas for biogas or synthetic methane, or the injection of some hydrogen into the natural gas network were discussed in 4.2.4. An alternative is to convert sections of the existing natural gas network to distribute pure hydrogen. This is a relatively recent concept with much work still required to demonstrate technical and economic feasibility, but is gaining popularity.

Several factors indicate that limited work will be required for conversion. The current Iron Mains Replacement Programme will make the majority of the UK’s pipeline compatible with hydrogen. Hydrogen has sufficiently similar energy flowrates to natural gas for use in existing appliances. Its Wobbe Index is 48 MJ Nm⁻³ which lies within the range accepted by gas appliances (47.2–51.4 MJ Nm⁻³) [49].

However hydrogen’s combustion characteristics are significantly different to natural gas. It has a higher flamespeed than methane which requires redesigned burners to prevent flashback. Hydrogen also burns with a hotter flame, generating more NOₓ and requiring more heat-resistant materials, though several options exist for ameliorating this [162]. While much of the existing natural gas infrastructure could be retained on conversion to hydrogen, most existing combustion devices would need to be replaced or retrofitted.

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16 Wobbe index = HHV energy density/specific gravity. HHV = 12.7 MJ/m³ for hydrogen, 39.6 MJ/m³ for methane; specific gravity = 0.0696 for hydrogen, 0.5537 for methane (relative to air = 1).
17 Where the gas flame travels back into the feed tube causing hotspots and potentially explosions.
18 For example, using pre-mixed burners, staged combustion and/or fuel dilution with, for example, flue gas recirculation [162].
Chapter 4  Heat and industrial processes

Such a wholesale refitting of appliances is not unprecedented in the UK: the switch from town gas in the 1960s and 70s necessitated the replacement of 40 million appliances, at a cost of £500m (£8bn in 2015 money) [162]. One contemporary analysis estimated conversion rates of 1m properties per year at a cost of £3,500 per house [30]. Gradual conversion of the heating stock as products reach end of life would avoid excessive additional costs. Dual fuel boilers have been suggested that can run on natural gas but which can easily switch to hydrogen when network conversion occurs [162].

Gas boiler efficiency has improved with widespread adoption of condensing boilers. Condensing water vapour in the exhaust is even more important for hydrogen boilers as about 20% of the heat released from combustion is captured from the heat of condensation compared to 10% for natural gas [30]. There is scope for further efficiency improvements with flue gas heat recovery (FGHR) systems, which additionally cool the water condensed from the steam. This can reduce gas use by up to 5% at relatively low cost, and some boiler manufacturers are already adopting it [141].

An alternative boiler technology also under consideration is catalytic boilers. This is an emerging technology at the very early stages of commercialisation. These use a catalyst to combine hydrogen and oxygen to form water and release heat without a flame. Advantages of catalytic boilers are that the low operating temperature (300–350 °C) prevents the formation of NOX [30] and heat output is more easily controlled than with combustion burners [49]. On the other hand, the power rating of current systems is 5 kW [162], which may not be sufficient to meet peak demand without thermal storage units, and they require higher purity hydrogen [162]. Since alternative options exist for eliminating NOX emissions from combustion, most manufacturers assume that combustion boilers will remain the dominant technology.

4.5.2 Combined heat and power

CHP systems are a major option for low-emission heating systems which also provide electric power. An overview of their electrical performance and market penetration is given later in Chapter 5. Here we consider their heat production.

CHP systems are powered by gas, allowing operation with the existing gas network. They are a possible solution to the problem of the additional load that reliance on electric heat pumps would place on the electricity network: not only do they operate on gas but they also export electricity to the grid at peak times [49]. They are highly efficient devices, recovering most of the energy from the fuel, although thermal output is lower than from boilers as heat is sacrificed to produce electricity.

There are a variety of CHP devices, with the balance between electrical and thermal output being a major feature. Figure 4.6 compares the electrical and thermal efficiency of several technologies. The ‘traditional frontier’ combines the UK’s average power stations with modern condensing gas boilers. All CHP technologies lie above-right of this, implying more efficient usage of primary resources. However, the combination of the best combined-cycle gas power stations with ground source heat pumps (the ‘all-electric frontier’) is more efficient than CHP engines. Fuel cells are the only...
technology to offer a higher combined conversion efficiency due to their high electrical efficiency [163].

**Figure 4.6** Thermal and electrical efficiencies of CHP devices [163]. The ‘thermal efficiency’ of heat pumps is their coefficient of performance (COP) [147] multiplied by the efficiency of power generation.

Combustion devices, including IC engines and Stirling engines, generate more heat than electricity, so might be better suited to large, poorly-insulated buildings with high heat loads. These devices release both particulates and NOX, which is undesirable from an air quality perspective. Electricity from engine CHP systems has a carbon intensity of 250–300 g/kWh, when heat is credited with avoided production from a condensing boiler [164], which is about two-thirds that of the best gas power stations. To contribute towards decarbonisation in the longer-term, engine CHP systems would have to switch to burning low-carbon gases, probably hydrogen. As discussed above, this would require alteration of the combustion systems to accommodate the different properties of hydrogen as a fuel [162].

Fuel cell CHP systems are a newer technology, with higher electrical efficiencies than combustion systems and with lower noise, vibration and pollutant emissions (Table 4.3). As a result they have recently grown to take the largest share of all micro-CHP systems globally [86].
As they deliver a higher fraction of their output as electricity they are more suitable for well-insulated buildings with lower heat loads (especially true for SOFCs). Systems typically use PEMFCs and SOFCs for domestic systems, and SOFCs, PAFCs and MCFCs for larger commercial systems. Most current systems are fuelled by natural gas (and in some cases LPG), which is converted to hydrogen using reformers, meaning they are not zero-emission at the point of use. Fewer adjustments may be required to switch existing FC systems to hydrogen, saving on capital cost. MCFCs however require carbon dioxide in their fundamental electrode reactions and so may have a diminishing role in the longer term.

### Table 4.3 At-a-glance summary of fuel cell performance.

<table>
<thead>
<tr>
<th>Application</th>
<th>PEMFC</th>
<th>SOFC Residential</th>
<th>SOFC Commercial</th>
<th>PAFC</th>
<th>MCFC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrical capacity</td>
<td>(kW)</td>
<td>0.75–2</td>
<td>0.75–250</td>
<td>100–400</td>
<td>300+</td>
</tr>
<tr>
<td>Thermal capacity</td>
<td>(kW)</td>
<td>0.75–2</td>
<td>0.75–250</td>
<td>110–450</td>
<td>450+</td>
</tr>
<tr>
<td>Electrical efficiency</td>
<td>(LHV)</td>
<td>35–39%</td>
<td>45–60%</td>
<td>42%</td>
<td>47%</td>
</tr>
<tr>
<td>Thermal efficiency</td>
<td>(LHV)</td>
<td>55%</td>
<td>30–45%</td>
<td>48%</td>
<td>43%</td>
</tr>
<tr>
<td>Current maximum lifetime</td>
<td>years</td>
<td>60–80</td>
<td>20–90</td>
<td>80–130</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td></td>
<td>10</td>
<td>3–10</td>
<td>15–20</td>
<td>10</td>
</tr>
<tr>
<td>Degradation rate</td>
<td>Per year</td>
<td>1%</td>
<td>1–2.5%</td>
<td>0.5%</td>
<td>1.5%</td>
</tr>
</tbody>
</table>

#### 4.5.3 Gas-driven and hybrid heat pumps

An alternative gas-based heating technology is gas-driven heat pumps (GDHPs). These are similar to electric heat pumps, but with a gas-powered CHP engine driving the compressor instead of an electric motor [49]. Though probably too large for domestic applications, tens of thousands of non-residential engine-based GDHPs have been sold across Europe and Asia. Adsorption and absorption-based GDHPs are also available, and GDHPs for the residential sector have now been introduced [141, 162]. Costs are currently high, but should come down significantly. Current GDHPs can achieve energy savings of 26–43% compared to condensing boilers; this is expected to improve [49, 141]. While this is significantly less than for electric heat pumps, GDHPs avoid the upstream efficiency penalty of producing electricity, and are still an improvement on conventional gas appliances. Future models could potentially run on hydrogen.

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19 See the first H2FC White Paper for further details on these technologies [49].
Another gas-based heating technology attracting interest is hybrid heat pumps. These are electric heat pumps that provide the majority (60–95%, depending on size) of a building’s annual heat demand, but with a gas boiler retained for meeting peak demand. These heat pumps can reduce fuel costs by switching between the two fuel sources, depending on which is the most efficient or cheapest at a given time [141]. A decarbonised grid powering the heat pump and hydrogen usage for the boiler could lead to a zero-carbon heating solution. Several studies (though not all) have identified hybrid heat pumps as meeting the heating needs of a significant number of buildings in 2050 [30, 49, 141]. Such systems require ongoing connection to both electric and gas networks.

4.5.4 Hydrogen cooking appliances

There is considerable scope for hydrogen to replace natural gas as a cooking fuel. Historically UK residents used cookers and stoves powered by town gas with a significant fraction of hydrogen, and today residents of Singapore and Hong Kong are supplied with a gas containing 49% hydrogen. Burners and barbecues running on pure hydrogen are in development today [49]. Hydrogen used for cooking will need food-safe odourants and colourants, and the higher flame temperature may affect appliance design and component specifications [162]. Hydrogen pre-mixed burners (the default for natural gas) may need flashback arrestors due to hydrogen’s higher flamespeed. However lift-off is also a concern as nozzle velocities may be higher to achieve the same energy release rate due to hydrogen’s lower density. Mixing hydrogen into air (rather than the other way round) is recommended, or carefully-designed non-aerated (i.e. diffusion) hydrogen burners could be an option as these lack the sooting problems of natural gas [162].

Hydrogen produces about 60% more water vapour when burnt than natural gas. This is unlikely to impact hobs, but could affect ovens’ performance: it can help prevent some foods from drying out but would extend the baking time of others. Solutions have been proposed for these issues [162]. Electric ovens could also be used, which would reflect current residential trends, although electrification could be more difficult for large commercial and industrial ovens.

Catalytic hobs and ovens could also be used for converting hydrogen rather than combustion, as for boilers, though with a similar requirement for pure hydrogen [49].

4.5.5 Wall-mounted fires

The other main domestic gas-fired heating appliance that needs to be considered are wall-mounted fires. These have seen widespread adoption for heating individual rooms in people’s homes. More recently their usage has waned in favour of central heating systems, though they are often retained in modern homes for aesthetic reasons or as backup heating. Several hydrogen-powered fireplaces have been designed (e.g. from Kiwa). They have the added safety advantage of not generating carbon monoxide [162]. Conversion to a 100% hydrogen network would likely require older existing gas-fuelled wall fires to be removed for safety reasons.
4.5.6 Heat networks

Hydrogen can be used in large boilers, CHP systems and gas turbines with the thermal energy output used for district heating, though the heat recovered cannot be transported long distances. Additionally, heat networks which are installed with non-hydrogen technologies initially can be retrofitted to use hydrogen as a heat source in the longer term [49].

As with the combustion of hydrogen in other settings, one challenge for adapting gas turbines to use hydrogen is limiting flame temperatures to limit NOx production. One solution is to introduce a diluent gas (typically steam or nitrogen), which leads to minor decreases in efficiency. NOx generation cannot be eliminated completely in any gas turbine system, though catalytic options exist for its removal. Hydrogen-powered gas turbines have demonstrated that very low NOx levels can be achieved [162].

4.5.7 Purity requirements of hydrogen and fuel cell technologies

One requirement for FC-CHP systems is for hydrogen with sufficient purity, particularly for low-temperature PEMFCs. Generally speaking domestic FC systems need less pure hydrogen than fuel cells in transport applications as they run on reformed methane, and catalyst loadings can be higher without adding significantly to cost (as they are smaller systems). PEMFC systems in Japan typically use 75% pure hydrogen, with the remainder being carbon dioxide, nitrogen and unconverted methane from the reformer exhaust [165]. FC systems generally use desulphurisers as sulphur is poisonous to fuel cells; the other problematic contaminant is carbon monoxide, which must not exceed 10 ppm [166]. Such cleaning steps increase system cost; but less cleaning should be needed if the gas network converts to hydrogen. Cleaning cannot be avoided entirely as inlet hydrogen is likely to have acquired impurities from the distribution network.

For safety reasons colourants and odourants are likely to be needed for hydrogen supplied from pipelines which could also have purity implications for stationary fuel cells. Cyclohexene has been proposed as an odourant that is compatible with fuel cells, but may not be sufficiently pungent [19]; if a sulphur-bearing compound or similar is used, this will need removal. It may be possible to identify a suitable colourant that will not need cleaning.

Unlike hydrogen for transport applications, high pressures are not needed for heating appliances as large quantities do not need to be stored before use. It is likely that seasonal and diurnal cycles in hydrogen demand for heating can be smoothed through central geologic storage facilities and linepacking in pipelines.

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20 One Japanese supplier uses a ruthenium-based catalyst to get carbon monoxide levels below 1 ppm [165].
4.6 RESIDENTIAL HEATING

The residential sector accounts for more than half of UK heat consumption. Space heating is the largest demand, followed by water heating and cooking [49], with winter peak demand around seven times the average summer consumption (Figure 4.5). As outlined above, one option for zero-carbon heating is the conversion of the existing natural gas network to carry 100% hydrogen. This would allow the use of existing heating infrastructure and satisfy consumers happy with existing gas-based systems. More efficient alternatives have already been discussed, including GDHPs and hybrid heat.

Another gas-based option is fuel cell micro-CHP, which is gaining traction in residential applications. Fuel cell micro-CHP can cut primary energy by 25% due to local cogeneration and reduce energy bills by 25–34%. They can avoid the need for electricity network upgrades, have zero NOx emissions, and are easily scalable without losing efficiency [86]. A drawback is that systems require more space than boilers and typically need hot water tanks, so may be less suitable for smaller urban households [86].

PEM fuel cells are the dominant technology, providing high efficiency, durability and reliability, rapid start-up and shut-down times, part-load capability and operating temperatures of around 80 °C [49]. Their electrical efficiency is lower than some other fuel cells (~35%), but this means their thermal efficiency can be higher (55%). Their low-temperature heat output makes them suitable for domestic applications without long transport distances required.

Solid Oxide Fuel Cells (SOFCs) are also becoming more widely used in domestic applications. They provide less flexibility than PEMFCs; indeed start-up and shut-down times can exceed 12 hours, so they tend to run constantly [49]. However, they offer a number of possible advantages, including high electrical efficiency, greater fuel flexibility and reduced purity requirements. Their higher operating temperatures reduce catalyst costs and also make them more suitable for existing building stock, which tends to have smaller radiators operating at high temperatures [86].

Japan is the global leader having launched the EneFarm program in 2009 for mass rollout of domestic fuel cells backed by generous subsidies. 181,000 systems were heating Japanese houses as of September 2016, and the government’s Hydrogen and Fuel Cell roadmap targets 1.4m units by 2020 and 5.3m by 2030. Japan has about 52m households, so market share will remain low for some time. Most systems are PEMFCs, with about 7% SOFC systems and most run on natural gas, though 10–15% use LPG [167]. Mass rollout has realised considerable cost reductions, with learning rates of 15–20% observed [168].

In Europe, the ene.field project [169] is a five-year field trial (2012–17) which has installed around 850 systems in eleven European countries. The majority are in Germany [170], though a number have been installed in the UK by Ceres Power [171]. This program is now being replaced by the PACE project (Pathway to a Competitive European FC mCHP market), supporting an additional 2,650 mCHP systems by
2021 with four leading manufacturers ramping up production to 1,000 units p.a. as a result [172].

Total cost of ownership is dominated by capital and stack replacement costs. Early systems have tended to be small to maximise utilisation [30]. One recent study concluded that FC-mCHP could be cost competitive with gas boilers without subsidies by around 2025 once production volumes reach 10,000 units per manufacturer. This could be achievable with sufficient policy support, as installations in Europe could reach 100,000 units in 2020, with 90,000 in the UK by 2025 [86]. Until then, capital grants could be more effective than Feed-in-Tariffs (FiT) at encouraging roll-out as domestic buyers tend to have less economic awareness than commercial buyers [49, 86]. Accessing export payments and time-of-use tariffs and providing grid-balancing services is also too complex for many homeowners, so new providers may be needed to access these benefits [86]. Another study argued that the levelised cost of heat production for a number of technologies could converge by 2050 with fuel costs becoming dominant, although micro-CHP costs could still be higher than for other technologies [49]. Slightly larger units (2–20 kW) could be competitive at smaller production volumes (500 units per manufacturer) than for mCHP, but there could be a shortage of suitable premises (residential blocks, commercial and small industrial) [86].

4.7 COMMERCIAL SECTOR

Heat demand in the UK commercial and public sector has been estimated to be around 20% of total national demand, with a national stock of around 2 million existing commercial boilers and catering equipment units using natural gas. CHP systems hold considerable potential in the commercial sector, with systems co-located with large heat users or distributing heat to smaller users through heat networks [30].

Engine CHP systems are more suitable than for domestic applications due to fewer noise and space constraints [49]. High-temperature waste heat is also an advantage for distributing heat through lengthy pipework. However ICE-CHP systems release NOx, as well as particulates and carbon dioxide when operating on fossil fuels.

Large stationary fuel cells are among today’s most mature fuel cell technologies with 100s of MWs installed globally [86]. The US and South Korea are global leaders in commercial FC-CHP systems [30], with Fuel Cell Energy (MCFCs) and Doosan (PAFCs) both producing 10s of MWs per year [86]. MCFCs and PAFCs are appropriate for commercial systems with more stable operation, cheaper catalysts and high efficiencies, although their more complex subsystems do not scale down well for smaller applications. SOFCs are also seeing greater deployment in commercial applications. PEMFCs are less suitable for large CHPs systems as their expensive catalysts undermine economies of scale and due to their low temperature heat output (though high temperature PEMFCs can address both these issues). The UK’s only commercial fuel cell CHP installations at present are found in London, driven mainly by requirements for on-site generation from local planning legislation [49]. However London does have the largest installed capacity of commercial FC-CHP systems of any European city,
with three office blocks powered by two 300 kW MCFCs and one 200 kW PAFC [86].

FC-CHP systems are quiet and low-emission (particularly once converted to run on hydrogen), making them an ideal option for urban areas [86].

MCFCs have higher electrical efficiencies (50%) but correspondingly lower heat production, and could reach around 60% electrical efficiency to become power-only FCs capable of matching the most efficient gas power stations. However they are inflexible with short lifetimes (20,000 hours) and high degradation rates due to corrosive electrolytes (Table 4.3). Their reliance on carbon dioxide for fundamental electrode reactions also make them unsuitable for operating on hydrogen [30]. PAFCs have a lower electrical efficiency than MCFCs but a higher thermal and overall efficiency, making them more of a like-for-like swap with ICE-CHPs (Table 4.3). They last longer (80,000–130,000 hours) with lower degradation rates and are more flexible, giving scope for load-following capability [86]. PAFCs could potentially be cost-competitive with ICE-CHP by 2025 at relatively low production levels of 100 units per manufacturer, although high-utilisation is required to increase export revenue [86]. Fuel costs are a major component of the Total Cost of Ownership (TCO) (unlike mCHP where capital costs dominate, at least for early systems), driving improvements in efficiency [86]. Commercial buyers generally purchase on a TCO basis so are likely to favour Feed-in Tariff (FiT) schemes, unlike domestic buyers likely to prefer capital support [86]. Businesses value reliability, and hence tend to prefer established technologies with long lifetimes. They tend to only replace equipment when it becomes uneconomic to repair them, meaning there can be gaps up to 30 years before new technologies can be integrated [49]. Previous CHP deployment targets have been missed due to unforeseen gas and electricity price shifts, and deployment also slowed by unfavourable electricity market structures and a lack of effective policy support [49].

4.8 INDUSTRY

Industry accounts for around 20% of fuel consumption in the UK heat sector. Industry is different to the commercial and residential sectors as space heating only consumes around 17% of demand, with water heating and the direct supply of heat to industrial processes at different temperatures accounting for the majority of demand [49]. The industrial sector may need to cut emissions by as much as 70% by 2050 for the UK to achieve its 80% carbon reduction target [86]. Options identified include CCS, biomass as a fuel, electrification, energy efficiency and heat recovery, industrial clustering and switching to hydrogen.

Hydrogen’s potential as a future energy carrier is receiving considerable attention, but hydrogen is already widely used today as an industrial feedstock. This is primarily for ammonia production for fertiliser (50%) and in oil refineries and chemical industries (40%). Some by-product hydrogen is used for onsite fuel and heating. This hydrogen demand cannot readily be displaced by other sources as hydrogen is integral to the underlying chemical processes (although opportunities may exist to reduce hydrogen demand through process improvement), and hence its production needs to be decarbonised. The vast majority (about 95%) of global hydrogen demand is thought to be met by onsite production as part of a larger industrial process, although statistics
for this do not always exist [30]. Provision is assisted by industrial demand being less variable than in other sectors which reduces storage requirements [146].

4.8.1 Recycling by-product hydrogen

Hydrogen is produced as a by-product in the manufacture of various chemicals, for example chlorine, sodium chlorate, ethylene and styrene [49]. It is often burned onsite to provide process heat (sometimes after blending with natural gas), or may be sold as a chemical feedstock, or vented to atmosphere. It could be used for CHP applications or, reserved for transport or fuel cell applications. Industrial by-product hydrogen may therefore offer a potential early market for hydrogen and fuel cell technology within industry. Another potential industrial niche is energy from waste, such as reforming landfill gas into hydrogen for CHP plant [49].

4.8.2 Decarbonisation of hydrogen as a feedstock

Ammonia, primarily for fertiliser production, is made by combining hydrogen with nitrogen in the Haber-Bosch process. The hydrogen is usually made from steam methane reforming, although some regions use alternate means. China uses coal gasification, while Canada, Norway and Egypt use electrolysis from hydropower. UK demand for hydrogen for ammonia production is around 200 kt p.a., which could be decarbonised by retrofitting CCS plant to existing onsite facilities or supplying zero-carbon hydrogen via pipeline.

Hydrogen has also long been used in oil refineries, primarily for hydrocracking and hydrodesulphurisation [30]. Historically this demand has been met from onsite production from dehydrogenation in catalytic reforming. Nowadays, oil refineries present a net demand for hydrogen which is typically produced from onsite SMR plants, with demand thought to total around 500 kt p.a. in the UK. Decarbonisation of the oil refining sector requires the supply of zero-carbon hydrogen. This could be achieved by fitting CCS plant to existing onsite SMR facilities or, as these are likely to be relatively small and uneconomic, supplied by pipeline from a central production facility.

4.8.3 Hydrogen as a fuel for low-temperature heat

Many industries use low-temperature heat for process heating and drying. This heat is often generated using natural gas, and this could be switched to hydrogen. As discussed earlier, this switch may require replacement of existing combustion equipment, but hydrogen burner technology is well established so this would be a low-risk option [86]. For large-scale processes using 100% hydrogen, oxyfuel burners could combust hydrogen with pure oxygen rather than air to prevent NOX formation and increase the combustion efficiency by 15% compared to conventional natural gas boilers [30].

Industry is also a major market for CHP, as many firms that generate significant amounts of process heat also find that generating their own electricity onsite can reduce their energy costs. There is significant potential for expanding CHP deployment further [49].
4.8.4 Hydrogen as a fuel for high-temperature heat

There are several opportunities for introducing hydrogen into new industries to supply low-carbon high-temperature heat. One is the iron and steel industry, where coke is used to reduce iron ore in blast furnaces before subsequently being refined to steel in an oxygen furnace. Some steel is also made in electric arc furnaces from directly-reduced iron; reduction is performed syngas made from reformed natural gas. In both these cases the reductant can be replaced by hydrogen [67]. However, both these advances require fundamentally new furnace designs [30] and commercialisation is not expected before 2030. The slow turnover of steelmaking plant will also hinder deployment.

There is also the potential to use hydrogen to reduce carbon emissions in the cement-making industry. Hydrogen is more suitable substitute for coal than natural gas, as it burns at a similar temperature. However, the low luminosity of hydrogen flames[21] and its explosive properties would both require kiln redesign [30].

4.8.5 Challenges for hydrogen usage in industry

This section has outlined how existing hydrogen technology usage can be decarbonised, and how hydrogen’s contribution to decarbonising the industrial sector can be increased. Industrial processes prioritise efficiency and cost, but there may remain opportunities for reducing energy demand that have been overlooked previously such as recycling waste heat or reusing by-product hydrogen that previously had little value. Most industrial processes do not require high purity hydrogen, easing take-up in this sector.

The motivations that drive the industrial market for heating have more in common with the commercial sector than with domestic users. Purchasing decisions are based purely on technical performance and economic rationality; space constraints and aesthetic concerns can be largely ignored; reliability is paramount; and replacement of equipment only tends occur with obsolescence [49]. Adoption of hydrogen is likely to be hindered in the UK owing to the market for heating installations and services being fragmented with a lack of qualified technicians [86] and a lack of standards and regulations to govern the safe operation of hydrogen burners.

Increasing hydrogen’s usage to provide low-temperature process heat is reasonably straightforward as it is already in use to some extent. However due to low technology maturity, uncertain costs and the likelihood of needing fundamentally redesigned furnaces rather than retrofits, the use of hydrogen in high temperature processes faces much more significant barriers to deployment [86].

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21 Cement clinker is primarily heated by radiant heat transfer making flame luminosity an important factor.
4.9 CONCLUSIONS

Heating requires 40% of the UK’s energy, but has received less attention than other sectors, and acquired a “hard-to-decarbonise” reputation, with modest emission reduction projections of only 20% by 2030. This buys time to examine the various low-carbon options and create the right market and support structures for deployment of the selected options. However, it is essential that this opportunity is not wasted, because deep decarbonisation of the heat sector is likely to be a necessity between 2030 and 2040 to meet decarbonisation targets.

A number of low-carbon options for heat have been identified, including demand reduction, electrification, district heating, green gas and onsite generation. None of these is currently widely used in the UK. Heat pumps and district heating have seen significant deployment in other countries, bolstering confidence in their technical reliability. Some previous studies that have favoured widespread rollout of a single technology to meet decarbonisation needs. Now, however, the concept of a portfolio of heating systems is gaining recognition. This technology mix could vary according to regional availability and building type and provide a hedge against uncertainties over technology feasibility and fuel prices. This would mark a departure from current status quo in the UK, where gas boilers dominate heating.

A particular problem in decarbonising the heat sector is that heat systems must manage very large daily and seasonal swings in demand. A number of options exist for reducing the size of the demand peak including improved insulation, more efficient heating appliances, thermal storage, and hybrid devices that supplement base-load heat pumps with a peaking gas boiler. The extent to which peak reduction can be achieved is uncertain, hence any low-carbon solution for heat also needs to solve the problem of meeting peak heat demand.

Current gas-based heating systems are highly popular, which will present significant hurdles to non-gas based low-carbon heating systems face in penetrating the market. This is driving the interest in finding low-carbon, gas-based systems that can use existing infrastructure and replicate existing functionalities.

Biogases are one option for low-carbon gas, but question marks remain over their availability and whether their use is best reserved for even more difficult-to-decarbonise sectors such as industry and aviation. Hydrogen injection into the existing natural gas network is another possibility, though questions remain about what constitutes a safe upper limit for hydrogen concentrations.

A further option is conversion of the existing natural gas network to 100% hydrogen, a concept which is still relatively recent and requires thorough analysis and testing, but appears to hold considerable promise. Hydrogen is likely to be able to use the majority of the existing low-pressure gas distribution system, although its different combustion qualities will require widespread replacement of heating appliances including boilers, cookers, wall-fires and furnaces. The two most likely sources of large-scale hydrogen are from steam methane reforming combined with carbon
capture and storage (CCS) and electrolysis from renewables, with the former expected to be considerably cheaper (despite the unproven nature of CCS).

There are several options for efficient gas-based heating appliances. Existing condensing gas boilers can become more efficient with flue gas heat recovery systems. Gas-driven heat pumps are even more efficient, as are hybrid heat pumps that combine an electric heat pump with a gas boiler for meeting peak demand. CHP systems are another option which generate electricity as well as heat with high overall efficiency, and can be either engine or fuel-cell based. The latter are currently expensive, but costs have halved and lifetimes have grown with increasing rollout in Japan and also more recently in Europe. Existing CHP systems mostly operate on natural gas as hydrogen is not currently widely available, but can switch to hydrogen with relatively few modifications. Homeowners have a number of factors to consider when choosing a heating system, including space constraints, noise, peak demand and cost.

CHP systems are also popular in the commercial sector, where they can benefit from economies of scale and have fewer space constraints. Low fuel costs are important, as is reliability, long lifetime and effective policy support. Heating systems are replaced relatively rarely, meaning it can take a long time for new technologies can be integrated.

Industry accounts for around 30% of fuel consumption in the UK heat sector, and also has a reputation for being especially difficult to decarbonise. Hydrogen is already widely used in industry, and there are opportunities for existing usage to be decarbonised and extended. It is produced as a by-product in a number of chemical manufacturing processes, and can be more widely recycled. It is used as a feedstock in making ammonia and oil refining, and low-carbon sources for these are required. Hydrogen could replace natural gas as a fuel for providing low-temperature heat and CHP in a number of industries, although burners and furnaces may need replacement. Hydrogen could also be introduced into several high-temperature industries including steelmaking and cement, although this is less certain at this stage. Industry requires cost-effective and reliable systems, and long plant lifetime means the replacement of heating systems are rare.
5.1 INTRODUCTION

Electricity is fundamental to the modern way of life in the developed world. Global electricity consumption has doubled since 1990, and represents 40% of primary energy demand [173, 174]. Two-thirds of the world’s electricity is produced from fossil fuels, emitting 15 GtCO₂ each year, or 42% of the global total [175]. The whole electricity system must be radically redesigned for the world to meet ambitious carbon reduction pathways.

The power sector will be pivotal in decarbonising the global economy. National roadmaps [5, 176] and international modelling studies [177–179] broadly agree that electricity should be rapidly decarbonised during the 2020s, then used to provide an increasing share of heat and transport. The drive meet climate targets over the last decade has led many governments to support renewable energy, resulting in ten-fold growth of wind and solar power to 665 GW of capacity, or 11% of global generating capacity [174].

Wind and solar power are forms of intermittent renewable energy: their output cannot be fully controlled or predicted as they rely upon the weather. Increasing renewable capacity makes meeting increasingly variable electricity demand more difficult. Balancing supply and demand is largely carried out by central flexible fossil fuel plants, but new solutions are required if electricity systems are to fully decarbonise whilst maintaining current levels of cost and reliability.

Hydrogen technologies are ideally placed to be a core part of this solution: hydrogen-fuelled turbines and fuel cells provide controllable low-carbon electricity and peak output when it is required, whilst power-to-gas provides the large-scale long-term storage required to shift electricity from times of renewable surplus to those of shortfall.

This chapter provides an overview of electricity systems in the developed world, the transition they are going through and the problems this is causing. It then reviews the current status of stationary fuel cells and power-to-gas technologies, and then explores the role they could play in the near-term.

5.2 THE ELECTRICITY SECTOR

Electricity has a two-fold role in achieving a low-carbon economy. Firstly, there are numerous options for generation: renewables (hydro, wind and solar), biomass, nuclear power, and carbon capture and storage (CCS). Secondly, low-carbon electricity can bridge across into transport and heat by powering vehicles and heating, decarbonising these more difficult sectors. The Committee on Climate Change (CCC) expects that low-carbon electricity will provide a third of carbon reductions in the heat and transport sectors by 2030 [5].
**5.2.1 Electricity demand**

Electricity makes up 15–25% of the final energy consumed in developed countries [173, 180]. The UK consumes around 300 TWh of electricity per year (an average power consumption of 34 GW), France and Germany consume around 500 TWh (57 GW), and the US and China consume around 3,500 TWh (400 GW) [173].

Industry, services and houses are the three largest consumers – each around a 1/3 share in Europe (Figure 5.1). Electric transport is negligible in most countries, primarily rail and rapid urban transit. This is expected to grow rapidly with the adoption of electric vehicles in the coming decades. Around a quarter of electricity is used for providing thermal comfort. This proportion is also anticipated to grow if electric heat pumps are used to decarbonise the heating sector (see Chapter 4).

Maintaining cost efficiency is important for both consumer welfare and industrial competitiveness. Households spend a sizeable share of their disposable income on electricity, averaging £586 per year in the UK [181]. The UK’s industrial electricity prices are amongst the highest in Europe, at 40% above the median [181].

**Figure 5.1** Breakdown of national electricity demand by sector, highlighting the share of thermal uses summed across all sectors. Average electricity consumption per person is highlighted on the top axis.
System reliability is paramount as society’s absolute dependence on electricity means that disruptions to supply have severe social and economic consequences. Power outages damage a country’s economy in four ways [182]:

- Indirect costs from lost time and productivity;
- Direct costs from lost assets, such as damaged production lines or spoiled food;
- Loss of investor confidence leading to an out-flow of industry;
- Long-term increase in electricity prices, increasing the burden on industry and households.

California suffered a capacity crisis in 2000–01, with 1.5 million people suffering rolling blackouts for several months. This was estimated to add ~$40 billion to energy costs during 2001–03 and reduce the state’s GDP by around 1% [183]. Wholesale prices increase dramatically as the capacity margin falls towards zero, and retail prices in California increased by 35%, after the crisis. Britain’s capacity margin has fallen in recent years due to extensive retirements of fossil plants (50% of coal in the last four years) [184].

5.2.2 Electricity supply

The perennial struggle facing the electricity sector is summarised by the ‘energy trilemma’: the need to simultaneously maximise security (reliability) whilst minimising cost and environmental impacts. Conventional fossil-fuelled power stations are reliable and (relatively) cheap, but no longer acceptable in terms of carbon emissions and other air pollutants. Nuclear used to be comparable in cost, but this has escalated in recent decades in the West (in part due to stricter safety standards); and although low-carbon, it creates long-lived waste and faces strong opposition in many regions. Renewables have minimal environmental impact and are approaching cost-parity with conventional generators, but pose reliability and security problems, as they cannot be controlled as part of the system.

It is important to understand that power stations must be operated as a coordinated system. Electricity has the fundamental constraint that supply and demand must match precisely with little recourse to storage. The wealth of generation technologies differ in their operating characteristics, suitability and running costs. Countries develop a mix depending on their natural resources, political and public preferences. Europe has a very heterogeneous mix of generation, as shown in Figure 5.2.
Table 5.1 summarises the general characteristics of the main power generation technologies. Utilisation of power plants is governed by running costs, whereas renewables are governed by resource availability. Demand for power varies over the day and between the seasons, and so different stations are started and stop throughout the day to accommodate this. Figure 5.3 shows an example of one week’s operation in Britain, with the mix of generation that meets demand. This highlights the variability of wind and solar power from day to day, and the impact this has on output from other technologies.
Table 5.1 Typical characteristics for the main power station technologies, data from: [186–188].

<table>
<thead>
<tr>
<th></th>
<th>Typical Size (MW)</th>
<th>Capital Cost (£/kW)*</th>
<th>Typical Efficiency (LHV)</th>
<th>Typical Utilisation/ Capacity Factor**</th>
<th>Direct Carbon Emissions (g/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>1,000+</td>
<td>£3,500–5,500</td>
<td>31–39%</td>
<td>65–75%</td>
<td>0</td>
</tr>
<tr>
<td>Coal</td>
<td>1,000+</td>
<td>£1,750–2,500</td>
<td>33–41%</td>
<td>40–60%</td>
<td>880–1,020</td>
</tr>
<tr>
<td>CCGT</td>
<td>500+</td>
<td>£550–850</td>
<td>51–59%</td>
<td>30–60%</td>
<td>380–440</td>
</tr>
<tr>
<td>OCGT</td>
<td>10–100</td>
<td>£350–650</td>
<td>31–37%</td>
<td>1–3%</td>
<td>620–740</td>
</tr>
<tr>
<td>Hydro</td>
<td>1–1,000+</td>
<td>£1,500–3,000</td>
<td>75–90%</td>
<td>30–45%</td>
<td>0</td>
</tr>
<tr>
<td>Onshore Wind</td>
<td>1–100</td>
<td>£950–1,700</td>
<td>–</td>
<td>25–30%</td>
<td>0</td>
</tr>
<tr>
<td>Offshore Wind</td>
<td>10–1,000</td>
<td>£2,000–2,800</td>
<td>–</td>
<td>33–39%</td>
<td></td>
</tr>
<tr>
<td>Solar PV***</td>
<td>1–10</td>
<td>£650–850</td>
<td>–</td>
<td>10–11%</td>
<td>0</td>
</tr>
</tbody>
</table>

* Total investment cost (overnight construction cost plus interest during construction) in 2015 GBP. Exchange rates of £1 = €0.90 = US$0.70.

** Utilisations are specific to Britain, averaged over 2007–16.

*** Ground-mounted solar farms. Residential panels typically 0.001–0.004 MW in size.
5.2.3 Electricity’s role in decarbonisation

Most of the IPCC’s climate stabilisation scenarios require a rapid increase in the global share of low-carbon electricity, from around 30% today to at least 80% by 2050 [190]. Such progress can be achieved in short timescales – for example the UK has risen from 20% to 50% low carbon electricity in the last four years [187].

The carbon intensity of electricity is an important metric for assessing the impacts of electric vehicles, electric heating, microgeneration and demand reduction on national emissions. In Britain, the government and other organisations use various average carbon intensities for British electricity, ranging from 412 to 525 g/kWh [191–193]. Figure 5.4 plots the average carbon intensity over the last eight years, showing a marked reduction since 2013.
So long as fuel cells run on hydrogen derived from natural gas (without carbon capture) they will have an appreciable carbon intensity of 200–400 g/kWh, depending on technology and whether by-product heat is utilised (see Sections 5.3.2 and 5.3.3). This could render them as high-carbon technologies as the rest of the grid decarbonises. Conversely, falling carbon intensity for the electricity used in power-to-gas will improve the carbon saved by the resulting gas.

### 5.2.4 Technical requirements of the electricity sector

There are several problems with electricity as a commodity [37]:

1. Failure to match supply and demand to within a few percent for a few seconds leads to the system collapsing, which can take days to restore and cost billions in lost productivity;
2. It is only possible to store in meaningful quantities using pumped hydro storage and the right geography, or with a revolution in other storage technologies;
3. Demand varies significantly over time due to human behaviour, typically ranging from 60% to 150% of the annual average;
4. Demand is inflexible and so must be followed by supply: relatively few customers can actively manage their consumption, and until the ‘smart meter’ revolution gains a purpose, only a few large industrial consumers can respond to real-time price signals; and
5. Many of the technologies for supplying electricity are also inflexible, or unpredictable due to unplanned outages or weather variability; so they cannot be precisely commanded like a dimmable light bulb.
Conventional responses

These problems are met by two broad responses [37]: build more capacity than is needed, sizing the system to meet peak demand plus a “capacity margin” of typically 10–30%; and keep some power stations online in reserve over and above those needed to meet instantaneous demand.

However, the amount of flexible, controllable capacity is declining in many countries. In Britain, combined fossil capacity has fallen from 65 GW to 45 GW in the last five years [187]. German utilities have suffered from low electricity prices, so 21 GW of gas-fired plant was closed or mothballed in 2013, 11 GW of which was less than ten years old [37].

This response is proven to deliver a reliable system, but backup power stations are costly both to build and to run. Fuel cells cannot compete with simple diesel engines on a pure cost basis for providing backup capacity. However, they provide additional services such as low carbon heat or mobility, which provide flexible peaking capacity as a by-product. A holistic approach to energy systems planning which values these interlinked services together would help to enable fuel cells to take off.

Increasing renewables

Global solar PV capacity has expanded ten-fold in the last six years, with 227 GW installed by the end of 2015, while wind has expanded nearly three-fold to 433 GW [194]. Europe has been at the forefront of renewables investment, as shown in Figure 5.5.

Figure 5.5 Power generation capacity in Europe over the last 25 years, with the installed capacity at the end of 2015, data from [174, 195].
Electricity networks in many countries are now struggling to accommodate such high levels of intermittent generation. Impacts include depressed and volatile wholesale prices, rising balancing prices, greater difficulty in maintaining system stability and the curtailment of renewable output [187, 196].

Because intermittent renewables generate only when the weather allows them, they displace a relatively small amount of peaking capacity [187, 197]. The unpredictability of renewables means that errors in forecasting also increase the amount of reserve that must be held on the system [196]. For the continued expansion of renewables to retain public favour it must not result in significant cost increases, and so novel solutions (which could be provided by H2FC technologies) are of pressing importance.

**Increasing electrification**

Electricity demand is anticipated to increase in future, despite improving energy efficiency, as it has a major enabling role in decarbonising the wider economy by powering cleaner forms of heating and vehicles. For example, UK demand is projected to rise from 335 TWh/yr in 2010 to between 400 and 600 TWh/yr across a range of scenarios for 2050, despite strong assumptions about energy efficiency measures [36].

EREC projects a 55% share of electric vehicles for Europe in 2050, which would consume around 400 TWh per year, adding ~20% to Europe’s current electricity consumption [198]. Electric heating could cause a similar increase – potentially adding 50% to Britain’s peak demand due to its seasonality (as noted in Chapter 4). France electrified the heating in around 3 million homes in the decade to 2012, which caused peak demand to rise 28% from 78 to 101 GW whilst annual demand only grew by 8%.

Unmanaged charging of electric vehicles is likely to occur after the last journey of the day, which coincides with peak demand in many countries, requiring investment in additional capacity and lowering system utilisation. If charging can be combined with smart communications technology, there is potential for using EVs as a trough-filling technology, analogous to the pumping of water in hydro storage plants. This could assist the integration of large quantities of variable renewables, with vehicles parked at workplaces utilising the peak afternoon output of solar, and parked at home keeping overnight demand high.

### 5.3 HYDROGEN AND FUEL CELLS FOR ELECTRICITY PRODUCTION

Hydrogen and fuel cells can benefit the electricity system as they are flexible, controllable, and low-carbon. Fuel cells are typically co-located with demand (minimising losses in transmission and distribution), and likely to generate when demand for electricity is highest if used for combined heat and power (CHP). The current centralised system incurs 6.5–7% losses in distributing electricity to consumers in the US and Europe [173].

Fuel cells therefore offer the possibility of creating distributed electricity generation and robust, local back-up to grid supplies. They deliver a number of obvious

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22 Losses range from 5% in Japan to 14% in Russia and Brazil and 25% in India.
advantages over traditional stationary generators (e.g. diesel generators) in that they are quiet, compact and do not have an adverse effect on local air quality. Fuel cells emit negligible levels of nitrogen and sulphur pollutants and no particulates, which particularly benefits the urban environment. They are also more efficient and therefore are a lower carbon alternative to traditional back-up generators, and dependent on the source of the fuel, their operation can be carbon neutral.

This section looks at four roles for hydrogen and fuel cells: peak power production, large stationary power generators, residential combined heat and power (micro-CHP) units, and fuel cell electric vehicles (FCEVs). The credentials of larger CHP units are covered in the first H2FC White Paper on Low Carbon Heat [49].

5.3.1 Hydrogen peak power generation

Economic peak power generation at times of high demand requires controllable technologies with low capital costs, so renewables and nuclear generation are not suitable. Natural gas-fuelled combined-cycle and open-cycle gas turbines (CCGTs and OCGTs) are often used for peak generation, and these could be converted to run on hydrogen to avoid CO₂ emissions at the point of generation. Different gas turbine designs would be needed, but the engineering challenges are not insurmountable [199]. Existing turbines could not be converted to use hydrogen. In contrast to fuel cells, hydrogen turbines would still produce NOₓ emissions.

A key challenge is to supply sufficient hydrogen to power large gas turbines for short periods, whilst minimising investment in hydrogen infrastructure. A key requirement for peaking power stations is low capital cost, as this must be recovered from relatively few running hours in a year. To avoid investing in hydrogen production plants with low capacity factors, hydrogen storage would be required. A national transmission network might be need to be sized appropriately to deliver large amounts of hydrogen for short periods. The Energy Technologies Institute (ETI) has proposed an alternative system in which a relatively small steam-methane reformer (SMR) with CCS, produces hydrogen constantly for storage in salt cavern underneath. This is connected to a relatively large on-site OCGT for peak generation [200]. Sizing the SMR plant much smaller than the gas turbine minimises infrastructure investment and hence the electricity generation cost.

5.3.2 Power-only fuel cell systems

Introduction

Power-only fuel cell systems are gaining popularity, particularly in the US. Whilst CHP offers higher efficiencies, power-only can still be considered a step in the right direction as it is flexible and produces below-average carbon emissions, but it is insufficiently clean to be a long-term solution unless a decarbonised fuel source can be used.

One key advantage of fuel cells is that they retain their performance at smaller scales, unlike most other technologies. With engines and turbines, increasing size leads to increasing efficiency, as thermal and auxiliary electrical losses diminish relative
to output, and higher boiler temperatures can be achieved. For example, the electrical efficiency of combustion ranges from 30% for < 0.5MW; 35% for 1 MW; 40% for 10 MW (HHV) [201]. Similarly, gas engine CHP increases from 25% to 36% electrical efficiency (HHV) over the range of 1 kW to 1 MW [202]. In contrast, fuel cells can deliver electrical efficiencies that are comparable to the best CCGT power stations (~60%) from several hundred kW down to 1 kW residential units [163, 203].

**Bloom Energy**

The Bloom Energy Server (Bloom Box), manufactured by privately held Bloom Energy, is perhaps the most high-profile producer of stationary fuel cells for the distributed generation market. They chiefly supply large tech companies in the US and Japan, and their announced contracts outstrip those of its three largest competitors combined [204]. In November 2016 the company filed for an initial public offering (IPO).

Their basic product Energy Server delivers 200kW of electrical power and is composed of clusters of solid oxide fuel cells, each with a power output of 25W [205]. Modules may be grouped together to create generators of larger sizes. The Bloom Energy Server may be run on either natural gas or bio-gas and has a stated efficiency of 50–60% [203]. The first commercial units were installed at Google in 2008 [206], and units can now be leased for either 10 or 15 years.

Installers of the Energy Servers have received large subsidies from green generation incentives at a national and state level. In 2010, for instance, Bloom Energy and its customers received over $200 million in subsidies from California’s Self-Generation Program (SGIP) [207]. A further ‘soft’ benefit of these subsidies is that they enhance the green image of these companies, and boost corporate social responsibility ratings. The unexceptional carbon emissions data, however, has led to questions being raised over the eligibility of Bloom’s units for these subsidies [208]. A loss of incentives would make the Energy Server a less attractive option for potential customers.
When running on biogas, the Bloom Box is ‘carbon neutral’ depending on fuel supply chains. Carbon emissions on natural gas are 350–385 gCO2/kWh [203], increasing over time as efficiency declines with age. This compares to the average carbon intensity for British electricity of 353 gCO2/kWh in 2015, and for high-efficiency gas CCGTs of 360–390 g/kWh [187]. Power-only fuel cells therefore match the best conventional production technology, but require decarbonised fuel sources to offer further carbon savings.

The Energy Server offers its customers other benefits that competitor technologies cannot provide, notably an alternative uninterruptable power supply [207]. The traditional combination for dealing with grid power outages is that of battery and diesel generator, but these are costly to install and maintain and do not offer the levels of reliability required. The Energy Server gives access to cheaper electricity (6–10 cents/kWh quoted for 2010 [209] compared to 14 cents/kWh for grid electricity) all year, with higher levels of reliability than traditional grid plus backup options, less noise and vibration and low emissions.

**Other companies**

Fuel Cell Energy specialises in fuel cell power plants using molten carbonate technology configured to operate as CHP units. Electricity is generated from natural gas and biogas with 47% electrical and 80% total efficiency. It has been a keen adopter of the power purchase agreement (PPA) model, owning and running several large fuel cell power plants, with revenues from this approaching those from fuel cell sales [210].

Plug Power has two main business areas: stationary generation and fuel cell packs for forklift trucks, both using PEM technology. Unlike FuelCell and Bloom, however, its market is aimed at providing backup electricity rather than permanent off-grid supply [211].

Like Plug Power, Ballard power has a more diverse range of fuel cell offerings. Its fuel cells use PEM technology with its stationary offering being designed to offer backup power supplies to the telecoms industry. Its revenue in this area is, however, falling year on year [204].

As is often the case with pre-commercial and emerging technologies, there is a wealth of small venture capital companies and subsidiaries of large corporations promising that they have discovered and patented the next big break-through.

**5.3.3 Residential fuel cell systems**

Despite the total growth in building-related energy demand, many national energy or climate change strategies call for substantial and rapid reductions in total building-related energy demand [212, 213]. For example, the EU aims to reduce emissions from existing buildings by 80–95% by 2050 [214]. Further, Europe has set out ambitious targets for building ‘nearly zero-energy’ buildings by 2020 [215], while the UK has supported a target of ‘zero carbon’ for all new buildings by 2019 and near zero emissions from all existing buildings by 2030 [216, 217]. It is widely anticipated that this will require a period of radical change in global energy policy [218, 219].
**Fuel cell technologies**

Fuel cell CHP systems are available at a much smaller scale than other technologies, suitable for residential application. Residential fuel cell systems range from 0.3–5 kW electrical capacity, most commonly 0.7–1.5 kW. This capacity is sufficient to provide all electrical and around half of a household’s thermal demand, the remainder coming from an integrated boiler and heat storage tank.

The physical size and weight of systems poses practical issues, and so installations are usually made outdoors. Smaller wall-hung models are under development. Table 5.2 summarises the characteristics of four leading micro-CHP systems. Other notable manufacturers include Toshiba and Sanyo (Japan), GS and FCPower (Korea), Viessmann and Elcore (Germany), Ceres Power (UK) and ClearEdge (US).

**Table 5.2 Specifications of four leading fuel cell micro-CHP systems [220].**

<table>
<thead>
<tr>
<th>Units</th>
<th>PEMFC</th>
<th>SOFC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Panasonic EneFarm (JP)</td>
<td>Baxi Gamma Premio (DE)</td>
<td>Kyocera EneFarm-S (JP)</td>
</tr>
<tr>
<td><strong>Electrical Output</strong></td>
<td>W</td>
<td>200–750</td>
</tr>
<tr>
<td><strong>Thermal Capacity</strong></td>
<td>kW</td>
<td>1,075</td>
</tr>
<tr>
<td><strong>Electrical Efficiency</strong></td>
<td>LHV</td>
<td>39%</td>
</tr>
<tr>
<td><strong>Total Efficiency</strong></td>
<td>LHV</td>
<td>95%</td>
</tr>
<tr>
<td><strong>Installation Space</strong></td>
<td>m²</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Weight</strong></td>
<td>kg</td>
<td>90</td>
</tr>
<tr>
<td><strong>Noise</strong></td>
<td>dBA @ 1m</td>
<td>38</td>
</tr>
<tr>
<td><strong>System Lifetime</strong></td>
<td>hours</td>
<td>60,000–80,000</td>
</tr>
<tr>
<td><strong>Degradation Rate</strong></td>
<td>per year</td>
<td>1%</td>
</tr>
</tbody>
</table>

**Efficiency**

The leading SOFC systems at both residential and larger scales have rated electrical efficiencies of 45–60%, and total efficiencies of 85–90%. Fuel processing for PEMFCs incurs greater losses, so electrical efficiencies are lower but thermal efficiencies are higher. The leading residential systems are rated at 39% electrical, 95% total efficiency [221, 222]. European residential systems have not yet matched the leading Japanese and Australian models, and the current SOFC and PEMFCs are limited to 30–35% electrical efficiency [223].

When operating in real-world conditions, the efficiency of the systems is around 7–15% lower (in relative terms) due to several factors [220]: self-consumption of electricity by auxiliary systems, reduced efficiency at part-load, energy consumed during start-up and shutdown processes, and dumping of excess heat that cannot be utilised [223, 224]. Other technologies experience similar penalties in residential usage (e.g. CHP engines and heat pumps [163]), due to the non-ideal operating conditions in households.
**Lifetime**

Durability was a key issue holding back fuel cells for many years, with lifetimes well below the critical milestone of 40,000 hours – around 10 years of intermittent residential operation [224]. Recent improvements have been substantial: Japanese PEMFCs are now guaranteed for 60–80,000 hours [221, 222]; and SOFC stacks have demonstrated 30,000 hour durability, with single cells lasting up to 90,000 hours [225, 226]. These EneFarm systems are sold with 10 year warranties giving free maintenance and repairs. European and other residential systems are catching up, with lifetimes currently at 10–20,000 hours [223, 227].

German field trials suggest that residential system reliability was 97% and mean time between failure (MTBF) was 1,300 hours in 2011, implying a failure every three months [223]. MTBF has doubled between 2008 and 2011 though, and the latest generation of systems is expected to continue this trend. Similarly during 2004–07, 90% of EneFarm predecessors in the Japanese residential demonstrations suffered a fault in their first year of operation. Since commercialisation, these early teething problems have been overcome and now only 5% of systems fail in a given year [222], which is comparable to gas boilers. In both trials, failures were broadly distributed amongst components: the stack, reformer, water circuit and electrical control system.

**Emissions**

Fuel cell manufacturers advertise 0.7–1 kW systems as saving 1.3–1.9 T of CO₂ per year in a four-person household (35–50% reductions) [163]. A residential PEMFC emits around 553 g of CO₂ to produce 1 kWh of electricity and 1.4 kWh of heat. A common method for allocating emissions between heat and power is to credit the fuel cell’s heat output with avoided production from a gas boiler and arrive at a carbon intensity for the electricity output alone. Using the PEMFC example above, this would yield $553 - (1.4 \times 215) = 252$ g/kWh of electricity produced, around 40% lower than the best CCGT plants. The carbon intensity of electricity from SOFCs is similar, as higher electrical efficiency is countered by lower thermal efficiency. When displacing heat from modern condensing boilers, current PEM and solid oxide fuel cells range from 240–290 g/kWh [163].

Airborne pollutant emissions from fuel cells are an order of magnitude below those of gas-burning technologies, due to the process of reforming fuel at low temperatures in the absence of air [151, 224].

An additional factor is to consider the upstream emissions from producing and transporting fossil fuels. These increase the carbon intensity of coal by 7–10% and gas by 18–34% (much higher and less precise due to methane leakage) [228–230]. This clearly poses an additional environmental disadvantage to fuel cells running on natural gas, which is seldom considered.
Costs

The price of fuel cells has been the greatest barrier to uptake. As of 2014, the purchase price of a 1 kW PEMFC or SOFC in Japan was £13,000–17,000 [49, 168], while bare fuel cell stacks are available for around £5,000 for 1 kW [231].

The price of residential systems has fallen dramatically – by 85% in the last 10 years in Japan [168], and by 60% over the last four years in Germany [223]. These price reductions are plotted in Figure 3 against the total number of installations to date, revealing a log-log relationship known as “learning by doing”. During demonstration projects in Japan and Korea the price of residential PEMFCs fell by 20% for each doubling in cumulative production [168, 232], and since commercialisation in 2008 the price of Japanese systems has fallen by 13% per doubling. If the historic trends from Figure 5.6 continue into the future, the millionth residential system could be installed in the next 4–6 years and cost between £4,500 and £9,000.

Figure 5.6 Learning curves fitted to historic prices of Japanese and Korean residential PEMFCs. Each doubling in production saw prices fall 19–20% during demonstration projects, and 13% after commercial launch in Japan [168, 232].

5.3.4 Stationary fuel cell markets

In spite of their many advantages, stationary power fuel cells have so far failed to turn a profit, with five leading companies23 losing a combined $120–150m each year during 2013–15 [233]. Inevitably, numerous businesses have become casualties over the last 10 years, including the recent failure of Australian firm CFCL following performance issues with its BlueGen gas-to-electricity fuel cell system.

The challenges that they face include:

- The high capital costs of the units – itself due to small manufacturing volumes whilst the market is pre-commercial, complex manufacturing processes and the need for expensive and rare materials (notably catalysts).
- Difficulty in maintaining the headline performance of their units, and therefore operating costs and carbon-emissions being above expected levels.
- Short unit life-time relative to competing technologies.

Growth within the stationary fuel cell sector has been erratic. Back in 2014, many analysts were predicting large increases in market value ([234–236]). But 2015 saw the number of MWs shipped for all stationary fuel cells dropping back to below 2013 levels, and the decline in MWs of primary power fuel cells shipped is even more severe, making these predictions seem unlikely to materialise [237].

**Figure 5.7** Global market size for stationary fuel cells across all sectors (power-only and CHP, residential and larger) since 2000, data from [237–239].

The global stationary fuel cell capacity stands just short of 1 GW in 2015, with year-on-year growth averaging 25% between 2000 and 2015 (Figure 5.7). For context, wind power reached this threshold around in 1989 and solar photovoltaics in 2000 [174, 240]. It since took them around 18 and 12 years respectively to reach 100 GW of installed capacity; giving a point of comparison for fuel cells. If the stationary fuel cell market launched in the rapid and sustained way that renewables have, then 100 GW would be reached around 2030, and fuel cells could match the current capacity of wind or solar by the mid-2030s.

Navigant Research [241] are optimistic about large stationary fuel cells due to falling costs (reductions of 15–17% per doubling in installed capacity), lower gas prices and rising electricity prices. Though as Adamson comments [237] “Without a small number of very high profile breakout orders […] the sector will continue to be project-by-project, implying a much slower growth pattern than transport [fuel cells].” One alternative business model being tried by larger companies is that of the power purchase agreement (PPA), which sees the company establishing itself as
a service provider rather than a retailer of generating equipment. This opens access to customers who lack the capital necessary to buy the machines outright, or do not wish to take on the technical risk associated with a novel product [237, 242].

In contrast, residential fuel cell systems have been demonstrated for the last 10–15 years, with the number of installations worldwide approximately doubling year-on-year, as shown in Figure 5.8. In 2012 fuel cells outsold engine-based micro-CHP systems for the first time, taking 64% of the global market – approx. 28,000 sales worldwide [243]. Japan leads in global deployment, with over 180,000 systems sold as of September 2016 [244], placing them perhaps a decade ahead of South Korea and Europe. As shown by the dotted lines in Figure 4, the Japanese government targets 1.4 million fuel cells installed by 2020 [245], Korea aims for 1.19 GW installed by 2029 [246], and the European Union originally anticipated 50,000 systems by 2020, but now only 2,650 additional units will be installed as part of the PACE demonstration [247].

**Figure 5.8** Cumulative number of residential micro-CHP systems installed to date (solid lines) and near-term projections (dotted lines).

![Cumulative number of residential micro-CHP systems installed to date (solid lines) and near-term projections (dotted lines).](image)

### 5.3.5 Vehicles to grid

As explored earlier in Chapter 4, fuel cell electric vehicles (FCEV) offer an alternative to battery electric vehicles (BEV) as an option for electrifying the transport sector. FCEV technology is still immature with high costs, meaning novel ways to reduce the cost of ownership (or generate revenue) could help to drive uptake.

Vehicle-to-Grid (V2G) is the name given to a system which allows communication between electric vehicles and the grid, permitting the grid to access both the energy stored within the car and store energy within the car’s battery. V2G has the potential to offer a wide range of benefits to electricity system operators, and with a suitable market framework also has the potential to be financially rewarding to electric vehicle owners.
System level benefits and barriers

Private vehicles spend around 95% of the time parked, and so a large fleet of electric vehicles would provide grid operators with a reliable resource to call upon [248]. Electric vehicles are specifically designed for rapidly fluctuating power output due to typical driving requirements, and thus fit well with grid balancing requirements [249].

V2G would provide grid operators with a distributed resource that can [249]:

- manage demand through requesting additional power when demand is high or additional load when demand is low;
- move load within a country to alleviate transmission bottlenecks;
- manage the rapid fluctuations in supply that arise in systems with a large component of renewable generation;
- provide a large pool of spinning reserve;
- act as a large short-term uninterruptible power supply;
- provide regulation services, such as dispatchable reactive power.

A key barrier is the need to re-engineer the electricity system to accommodate greater bidirectional power flows, and a parallel infrastructure for transmitting electronic information [250]. Current grid components were designed for unidirectional flow from power station to consumer. However, a full implementation of V2G requires bi-directional flows from the consumer back to the grid which may entail component replacement [251]. A corresponding ICT system is required so that command signals, metering and status updates can be sent and received automatically by potentially millions of vehicles, aggregated and used by a central dispatch agent, all with uncompromised security [252].

User level benefits and barriers

V2G is primarily associated with battery electric vehicles, with few considering the role that FCEVs could play. However, there are several reasons why FCEVs could prove more suitable. Two considerations from the driver’s perspective are that driving range is sacrificed by providing power to the grid, and additional running hours will reduce the power train lifetime. As explored in Chapter 3, FCEVs offer greater driving range and lifetime than BEVs.

Battery lifetime will be reduced through participation in V2G due to additional charge/discharge cycles. However, with fuel cell lifetimes around 30,000 hours, additional operation to provide grid services would likely not be life-limiting. A hybrid FCEV would likely use its battery to provide peak power and match rapid fluctuations (e.g. for frequency response), but if providing constant power then the fuel cell could be used alone (e.g. for peak demand or operating reserve).

The second consideration is that drivers will not wish to be left ‘out of gas’ in their garage due to unanticipated discharge events. A successful V2G system must therefore include some mechanism to ensure that the grid operator does not completely drain a vehicle [253]. This is a key issue for BEV due to range limitations, but not so for FCEVs due to the presence of a large store of hydrogen energy. A typical modern
FCEV, the Toyota Mirai, holds 5 kg of hydrogen, or 600 MJ of chemical energy. If this could be converted with 50% efficiency, then half a fuel tank would yield 40 kWh of electricity, which is equivalent to three fully-charged Tesla Powerwall 2 home battery systems, with a value of around £20,000 [254].

The round-trip efficiency of storing excess electricity within distributed car batteries is comparable to pumped hydro (70–80% [229]). However, V2G offers the advantage of the power already being distributed around the country, and not limited by geographic constraints such as mountains. If a V2G system accessed the hydrogen reserves of an FCEV, the round trip efficiency would be substantially lower due to the energetic cost of producing hydrogen, and then of converting it back to electricity. This, combined with the high expected cost of hydrogen relative to electricity means that FCEV owners would require relatively high compensation for providing services.

**Battery vs. fuel cell vehicles**

A BEV is able to act as both a source of demand (charging) and of power (discharging); it could therefore operate within a P2V system in the fullest possible sense. FCEVs however, are limited to participating only as a source of power as they have no equivalent of the charging mode of the BEV. This difference vehicles alters the assessment of the most economical way of deploying them within a V2G system.

For BEV, researchers conclude that it is significantly more lucrative to participate in the provision of regulation and ancillary services because, although there is money to be made in providing peak capacity and load adjustment, the returns do not justify the expense [249]. Provision of capacity is useful only over a handful of hours in a year whereas ancillary services are required by the grid at all times [248]. At present, only large providers which have paid a registration fee and passed pre-qualification assessments can participate in these markets, meaning that new roles for ‘aggregators’ must develop.

Most of the studies examining FCEV date from the early 2000s. These conclude that FCEV can operate profitably within a V2G system by offering peaking capacity and spinning reserve, though the available profits are small. The main costs from V2G arise from purchasing hydrogen and the costs of interfacing with the V2G system [255].

**V2G economics**

Considering an FCEV operating in America, [256] calculated the annual profit from selling spinning reserve was in the range of $174–$262 in California (with reserve priced at $7/MW per hour), or $1751–$1839 in Texas (priced at $23,000/MW per hour). The significant variability in how these services are priced depends on the grid mix within the system (e.g. California is rich with flexible hydro); and thus the need for, and value of, alternative providers will vary significantly depending on the market state.
Reference [256] also examines the profits to be made by FCEV through providing peaking capacity, observing that California experienced 200 hours a year with prices in excess of $50/MWh. An FCEV providing electricity during these peak times could expect an annual profit of merely $290, which is unlikely to justify the associated transaction costs of participating in the capacity market.

The cost of providing electricity is determined by the hydrogen cost and fuel cell efficiency. With hydrogen at long-term goal price of $4/gge (approx. £3/kg), an FCEV could provide electricity for between £150/kWh (60% efficiency) and £225/kg (40% efficiency). In the British electricity market, prices rise above these levels for between 2 and 12 hours per year [187], suggesting limited viability for FCEV providing capacity.

Taken at the level of individual vehicle owners, the economics of V2G for fuel cell electric vehicles seem marginal. However, as noted in [257], a fleet of 100,000 FCVs at 95% availability has the potential to deliver 2.9 GW of power to the grid (assuming 30kW fuel cell output). Even at 50% availability this is 1.5GW, or 5% of California’s typical peak daily demand (as of 2005). At $290 per year per vehicle, this earns $29 million, for peak power delivered at a cost of $0.18/kWh, or $20 million a year for delivery of spinning reserve.

### 5.4 POWER-TO-GAS FOR ENERGY STORAGE

A specific consequence of the extensive deployment of intermittent renewable capacity is the potential for periods where generation exceeds demand, sometimes referred to as “surplus power” [258]. Importantly, these states can be short lived and appear with little warning. This leads to the requirement for fast-response and efficient energy storage facilities [259], with a particular value associated with large-scale, inter-seasonal energy storage. The IEA suggest that 310 GW of energy storage capacity will be required in the United States, Europe, China and India in order to support CO2 emission reduction targets in line with climate change mitigation targets [260]. This surplus energy can readily be converted to provide different services, such as heat or transport, this leads to the question of “power to what?” in Figure 5.9 [261].
For this reason, energy storage technologies are of increasing importance [262, 263]. While these technologies strictly store and later provide power (i.e., Power-to-Power), alternatives are increasingly considered such as Power-to-Mobility, using surplus power in battery powered electric vehicles [264], and Power-to-Heat, via heat pumps [265]. Alternatively, surplus power can be used to produce hydrogen by electrolysis, traditionally referred to as “Power-to-gas” [266] This hydrogen can then be used directly to provide heat or power, or converted to hydrocarbons, such as methanol, methane or dimethyl ether (DME). These compounds, known as platform chemicals, can then be reconverted to electric power, used for mobility, or as chemical feedstock [267, 268]. A significant fraction of the value associated with PtG comes from having this multitude of options.

It is worth noting that PtG as a means to provide hydrogen for transport is already a relatively mature concept. At the time of writing, there are more than 700 projects either planned or in operation worldwide [47], with >95% in Germany, the US, Canada, Spain and the UK (Figure 5.10).
Power-to-gas (PtG) is often used as something of a catch-all term to describe several options for large scale, long term energy storage technology. All options are typically characterised by a water electrolysis plant which delivers hydrogen as the main product gas, with oxygen regarded as a by-product [270], though this high purity oxygen by-product can equally well be sold as an industrial gas. The hydrogen can be stored, and subsequently used directly for power generation, provision of heat, as a transport fuel, or as an industrial feedstock. In this way, the PtG concept allows intermittent renewables to be employed for the decarbonisation of other sectors of the economy. If the hydrogen is to be converted directly to electricity, hydrogen fuel cells are the obvious technology of choice.

However, the storage and distribution of large volumes of hydrogen is not without challenge [271]. Therefore, the methanation of hydrogen via either the catalytic Sabatier process [272] or a biological process [270] allows for the production of synthetic methane, which can be used as a “drop-in” replacement fuel in conventional infrastructure. Moreover, as methane produced in this way can be further converted to methanol or dimethyl ether, power-to-gas can therefore provide several services within a low carbon energy system – energy storage, the production of renewable hydrogen which can be used for the provision of heat, power or transport in addition to an industrial feedstock, and thereafter converted to other, useful, platform chemicals. The principal elements of a power-to-gas process are illustrated in Figure 5.11 below.
5.4.1 Power-to-gas (hydrogen)

Whilst there are several power-to-gas (PtG) options, all involve a water electrolysis plant which delivers hydrogen as the main product (electrolytic hydrogen), with oxygen regarded as a by-product [270]. If the hydrogen is to be converted directly to electricity, hydrogen fuel cells are the obvious technology of choice. The primary electrolysis technologies are proton exchange membrane (PEM) electrolysis and alkaline electrolysis cells (AEC) [261]. Solid oxide electrolysis cells (SOEC) are also under active development, and are perhaps 10 years away from commercial application.

AECs are perhaps the most technically mature and lowest cost technology [273]. Typical operating conditions are in the range of 60–80 °C and greater than 30 bar [266] and will typically produce 12–19 kgH₂ per MWh of electricity input (a specific consumption of 4.5–7.0 kWh/Nm³) on a system basis [274]. However, AECs are not well-suited for intermittent operation [275], which may well be the case for PtG installations. AEC start-up can take several hours [276], owing to the high thermal capacity of the system. In order to operate AECs in combination with intermittent renewable power sources, a wide operational range is required of 20 to 100% of their nameplate capacity [277].
PEM systems operate at 60–100 °C and at a pressure greater than 200 bar. They require 1 MWh of electricity to produce 18–22 kg\(\text{H}_2\) (3.8–4.7 kWh/Nm\(^3\)) [274]. Relative to AECs, PEMs are easier to start-up, have a wider operating window of 5–100% of nameplate capacity [278] and are better suited to sources of intermittent energy [275]. However, large-scale applications of this technology (MW-class) are at a lower technology readiness level (TRL) than AECs and are more costly.

SOEC offer great promise for improving efficiency, although they are currently at a low TRL and are still undergoing laboratory trials. The SOEC operates in a wide temperature range of 500–1,000 °C and at a pressure greater than 25 bar. They require a high thermal energy input, which leads to an increased rate of production of hydrogen. This reduces the quantity of electricity required, increasing the efficiency of the PtG process and also expensive catalysts are unnecessary [279]. Again, SOEC are slow to start-up also, extreme load-transients are not possible [266].

If the hydrogen is to be used without further conversion, intermediate storage is required. Due to the low density of hydrogen, storage volumes will be significant. For comparison, some values for common compounds are provided in Table 5.3.

**Table 5.3 Energy density of common compounds on a mass and volumetric basis.**

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Hydrogen weight fraction</th>
<th>Ambient state</th>
<th>Mass energy density (MJ/kg)</th>
<th>Volumetric energy density (MJ/litre)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquid Hydrogen</td>
<td>1.00</td>
<td>Gas</td>
<td>120.0</td>
<td>8.4</td>
</tr>
<tr>
<td>Methane</td>
<td>0.25</td>
<td>Gas</td>
<td>40.0</td>
<td>21.0</td>
</tr>
<tr>
<td>Ethane</td>
<td>0.20</td>
<td>Gas</td>
<td>47.5</td>
<td>23.7</td>
</tr>
<tr>
<td>Propane</td>
<td>0.18</td>
<td>Gas</td>
<td>46.4</td>
<td>22.8</td>
</tr>
<tr>
<td>Petrol</td>
<td>0.16</td>
<td>Liquid</td>
<td>44.4</td>
<td>31.1</td>
</tr>
<tr>
<td>Ethanol</td>
<td>0.13</td>
<td>Liquid</td>
<td>26.8</td>
<td>21.2</td>
</tr>
<tr>
<td>Methanol</td>
<td>0.12</td>
<td>Liquid</td>
<td>19.9</td>
<td>15.8</td>
</tr>
</tbody>
</table>

The requirement for storage infrastructure can be avoided if the hydrogen is injected into the natural gas grid, as is planned for the Leeds H21 project [280]. However, this option has its own barriers, as discussed in Chapter 4.2.4. This will have limited impacts on climate change, as even a 10% blend of hydrogen by volume (as allowed in Germany) equates to only 3% hydrogen by energy content.
5.4.2 Power-to-gas (methanation)

PtG is not limited to producing hydrogen as an end product, and producing synthetic methane is one option that can be used as a drop-in replacement fuel for conventional infrastructure. Often, this methanation is performed via the Sabatier reaction [272], though biological processes are also feasible [270]. The Sabatier reaction proceeds according to:

\[ \text{CO}_2 + 4\text{H}_2 \rightarrow \text{CH}_4 + 2\text{H}_2\text{O}. \]

This is a highly exothermic reaction, with an enthalpy of reaction (\(\Delta H^\circ\)) of -165 kJ/mol, and typically operates at a pressure of 6–8 bar and a temperature in the range of 180–350 °C and is on the order of 70–85% efficient and uses a Ni-based catalyst. Fixed bed reactors tend to prolong the operational life of the catalyst, but are costly, have slow dynamics and are prone to hot spots and limited material transport, which can lead to catalyst damage. Fluidised bed reactors have a high specific catalyst surface and good heat transfer due to their use of smaller particles. However, the mechanical stress on the catalyst is higher and they are less well suited to dynamic operation.

Key to the operation of a synthetic methane PtG process is a reliable source of CO\(_2\). This can be obtained from capturing CO\(_2\) from an industrial facility or thermal power plant. There are a large number of different technologies for CCS, some closer to deployment than others, but broadly speaking CCS technologies can be decomposed into the following categories:

- Pre-combustion CO\(_2\) capture
- Post-combustion CO\(_2\) capture
- Oxy-combustion CO\(_2\) capture

These technologies are illustrated in Figure 5.12 and described briefly in the following section. Each produces a high purity CO\(_2\) stream, which is directed to a compressor after dehydration and some additional purification in the case of oxy-combustion.
Figure 5.12 Illustration of the primary classes of CCS technology.\textsuperscript{24}

\textsuperscript{24} ASU = Air Separation Unit.
Pre-combustion CO₂ capture
Also referred to as Integrated Gasification Combined Cycle with CCS (IGCC-CCS), pre-combustion capture is based upon a gasification process where a hydrocarbon fuel (either biomass or fossil), is converted into a mixture known as “syngas”, consisting mainly of CO, CH₄, H₂ and CO₂. This is achieved by reacting the material at high temperatures and pressures with a controlled amount of oxygen and/or steam. These gases are converted to a mixture of CO₂ and H₂ via the water-gas shift reaction. After separation from the CO₂, the H₂-rich fuel gas can be used to fire a gas turbine or run a fuel cell. The conditions for CO₂ capture here are very different compared with post-combustion capture as the gas is at elevated pressure (2–7 MPa) and the CO₂ concentration is significantly higher (15–60 vol%).

Post-combustion CO₂ capture
Post combustion capture involves separating CO₂ from a flue gas consisting mainly of nitrogen, water, CO₂. This technology operates via a gas-liquid contacting and separating process in a vertical column (the absorber). The ‘lean’ solvent stream (e.g. an amine) is introduced to the top of the absorption column, and flows vertically down over the packing material, absorbing its preferred components from the gas phase, which is introduced at the bottom of the absorber. Once the solvent stream reaches the bottom of the column, it is now termed ‘rich’, and it is directed to a solvent regeneration process. The absorption process typically operates at 1 bar and 30–60 °C, with the solvent regeneration process at 2 bar and 120 °C. This benefits from being an ‘end-of-pipe’ technology, similar to those already in place for the mitigation of SO₂ emissions. Its addition to power plants, either as a retrofit or as new build, will not unduly affect the flexibility of operation demanded of these facilities.

Oxy-combustion CO₂ capture
Oxy-combustion capture relies upon the combustion of a fossil or biomass fuel in a high oxygen environment – a mixture of oxygen and recycled flue gas (RFG). Unlike conventional fossil fuel-fired power stations that use air as the oxidant, an oxy-fired plant employs an Air Separation Unit (ASU) to produce an oxygen stream. This process then produces an exhaust gas containing ~72–76 vol% CO₂, 11–14 vol% N₂ and 7–10 vol% O₂. This exhaust gas is then treated in a post-combustion Compression and Purification Unit (CPU) where water and other compounds are removed from the flue gas exhaust stream, and high purity, high pressure CO₂ is produced. Owing to concerns around the ingress of air to the system, this technology is not typically considered suitable for retrofit to existing power stations. It is, however, particularly promising for industrial point source emitters such as cement or iron and steel production.

5.4.3 Competing technologies for energy storage
There are a variety of energy storage technologies currently available or under development, including pumped hydro storage (PHS), compressed air energy storage (CAES), flywheels and batteries.
Pumped hydro energy storage offers flexible and efficient storage, and currently comprises the vast majority of total installed energy storage capacity [262]. Moreover, this technology is perhaps the most mature and competitive storage technology. Accounting for social, infrastructural and environmental constraints, the total potential for PHS in Europe and Turkey is estimated to be as much as 80 TWh [281] (around 10 days of these countries’ combined electricity demand). PHS has a round trip efficiency in the range 65–80%, but is also characterised by long construction periods, high specific costs and geographical constraints which conspire to reduce this potential considerably.

Compressed air energy storage (CAES) is based on conventional gas turbine technology and makes use of large storage volumes, such as purpose-built salt caverns or natural aquifers, to store energy in the form of high pressure air. During loading, a compressor stores ordinary air at a pressure of approximately 70 bar. This air is fed to a combustion chamber and the produced exhaust gases expand in a typical gas turbine expander to generate power during unloading [282]. The round-trip efficiency of CAES is strongly dependent on the extent of heat integration within the system. However, whilst the CAES concept relies upon well-known technology elements, only two commercial CAES plants have actually been built [262, 282]. The existing plants require 0.7–0.8 kWh of electricity and 1.2–1.3 kWh of natural gas to generate 1 kWh of electricity [283]. Considering the electricity that could otherwise be produced by that gas (within an average CCGT power station) the total electricity input would be 1.36–1.52 kWh per kWh generated. Heat integration between the compression and expansion cycles strongly influences the round trip efficiency of CAES [284], and is typically in the range 27–70% for diabatic systems. Adiabatic systems can theoretically achieve up to 75% efficiency [284]. As with PHS, a key limiting factor is the availability of appropriately sized air storage infrastructure and their associated costs [285].

Flywheels and batteries are characterised by a high round-trip efficiency. Flywheels however are only capable of storing relatively small amounts of energy for very short time periods and thus are used mostly for frequency control [260]. Batteries are well-suited for long term energy storage, however, they are correspondingly characterised by relatively small scale [263] limited number of charge/discharge cycles, low power density and relatively high costs [260, 286]. Flow batteries are a promising technology for medium scale storage, and are characterised by efficiencies in the range 65–85%, very low self-discharge and high cycle capability, though they have a low volumetric energy density compared to other batteries [287].

5.5 CONCLUSIONS

Britain, and many other countries, could stand to benefit from a more holistic response to increasing intermittent renewables and retiring conventional capacity. Strategically investing in new capacity that is both flexible and low carbon, such as fuel cells and power-to-gas could help achieve the goals of high security and low emissions. The equally-important goal of low costs must not be forgotten though, and hydrogen technologies will only be supported for this role if they can provide value for money.
For these benefits to make the leap from purely theoretical to material significance, hydrogen and fuel cell technologies must either be cost competitive with the array of other options, or offer a markedly improved service. Competition for providing flexible capacity comes from biomass, biogas, battery storage, electric vehicles, micro-CHP engines and gas turbines with CCS (among others); while pumped hydro, compressed air and ‘smart’ demand-side management are options for using ‘excess’ renewable energy. Offering a stand-out service (such as the iPhone did in 2007) is unlikely with so many alternative options, and so hydrogen technologies must aggressively reduce costs to avoid languishing in the realm of R&D and subsidised deployment.

Adding more intermittent and uncontrolled generation to national electricity systems is posing increasing problems for stability and affordability. Distributed generation which operates at peak times (such as micro-CHP on winter evenings), or devices that avoid electricity consumption at peak times such as hybrid heat pumps, can avoid investment in peak generation plant. At the same time, flexible energy conversion methods (such as power-to-gas) can avoid the increasing problem of curtailing renewables due to there being insufficient demand at times of high production.

Whilst various fuel cell solutions are fuelled by natural gas, they can only reduce carbon emissions in the near-term. The British power system has undergone a radical transformation in the past five years, and average carbon emissions are now comparable to those from fuel cell micro-CHP units even when their co-produced heat is accounted for. This situation is of course very different in other countries such as Germany, the US, Australia and China, which will rely heavily on coal and lignite for their electricity for the foreseeable future.

That said, fuel cells in their current form can only serve as a bridging technology, at least until a low-carbon source of hydrogen becomes widely available. Power-to-gas is a prominent route to producing this in significant quantities, with the added benefit of helping to stabilise power systems and absorb renewable energy at times of excess production.

A key benefit of both electricity and hydrogen is its ability to spill over into other sectors. Electricity can power battery vehicles and heat pumps, whilst power-to-gas can deliver synthetic heating and transportation fuels. The decarbonisation of electricity is therefore central to the decarbonisation of the entire energy system. Hydrogen and fuel cells could provide major benefits to the power system: flexible low-carbon peaking capacity that operates when electricity is most required (rather than when the wind blows or the sun shines), and the ability to convert electricity into products that can be stored in bulk on seasonal timescales.
CHAPTER 6
HYDROGEN INFRASTRUCTURE

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6.1 INTRODUCTION

A key challenge identified in Chapter 2 for hydrogen systems is to construct an infrastructure that evolves over time concurrently with developing demand in different sectors. The design and development of hydrogen infrastructure represents unique challenges due to the fuel’s low energy density and volatility.

There is a multitude of production and distribution pathways for hydrogen, as summarised in Figure 6.1. It can be produced from a range of feedstocks both centrally and on-site (Section 6.2). Pressure and purity requirements differ based on application (Section 6.3), which influences the optimal pathway. Storage is critical to energy system functionality, and hydrogen storage ranges from tanks and metal hydrides up to geological formations (Section 6.4). Hydrogen can rely on conventional distribution infrastructures (for electricity and natural gas) to deliver feedstock, or can be distributed itself at small- and large-scale, as a liquid or gas (Section 6.5).

Navigating this array of options to develop a cost-efficient production and distribution infrastructure is a significant challenge. Spatially-explicit models of the UK have been created to assess infrastructure development, and these are examined in Section 6.6 for the CCC’s Full Contribution scenario from Chapter 2.

Figure 6.1 Hydrogen delivery pathways discussed in this chapter. This diagram is simplified and non-exhaustive, and serves to highlight the diversity of options at each stage of the system.
6.2 HYDROGEN PRODUCTION

Numerous technologies have been developed to produce hydrogen from a range of feedstocks. Hydrogen is mostly derived from fossil fuels at present, as these have the lowest costs [288]. Steam reforming is an efficient process to produce hydrogen from gases and light oils, whereas coal, biomass and heavy oils must undergo gasification. Although both of these technologies currently have high CO₂ emissions, carbon capture and storage (CCS) can reduce emissions greatly, or even deliver negative CO₂ emissions when using biomethane and biomass feedstocks.

Another source of hydrogen is via electrolysis. Numerous types of electrolysers have been developed commercially but all have high capital costs, which might reduce in future, and high fuel costs for electricity, which can be reduced through efficiency improvements or finding source of cheap electricity such as surplus renewables. Hydrogen from electrolysis typically has high purity, which is much easier to prepare for use in fuel cell vehicles than hydrogen from other sources. Electrolysers are the most suitable hydrogen production technology for distributed production. In combination with energy storage, they could play a crucial role in supporting the integration of renewable electricity generation, as discussed in Chapter 5.

Alkaline electrolysers are the principal commercial technology used to produce hydrogen via electrolysis at present. A direct voltage current is applied between an anode and a cathode submerged in an alkaline electrolyte. While alkaline capital costs tend to be lower than for other electrolysers technologies, plant output cannot be easily varied and overall costs are very sensitive to the price of electricity. Polymer electrolyte membrane (PEM) electrolysers are smaller than alkaline electrolysers as the electrolyte is a solid plastic material [289]. They have a faster dynamic response and wider load ranges than alkaline electrolysers; however, they have higher capital costs as they require expensive catalysts. The low-temperature operation and power cycling capability makes PEM electrolysers ideal for power-to-gas operation. Solid oxide electrolysers (SOEC) use a solid ceramic material for the electrolyte and operate at very high temperatures (700–900 °C), enabling higher electrical efficiencies than other electrolysers [289] but incurring high capital costs [290].

Several novel hydrogen production technologies are at an early stage of development, including high-temperature steam electrolysis, solar thermo-chemical water splitting and biological hydrogen production. All of the methods discussed in this section are examined further in Chapter 3 of the H2FC White Paper on Energy Security [6].

6.3 COMPRESSION AND PURIFICATION

One important aspect of hydrogen which has often been ignored is the pressure and purity at which hydrogen is produced and at which it is needed, which can often be quite different. Production routes which look cheaper than others may become more expensive if extensive compression and purification is required. Likewise it may be futile to generate high-purity hydrogen if high purity is not required. It can be productive to match low-purity demands for hydrogen with low-purity sources, and to match...
high-purity demands for hydrogen with high-purity sources. This section outlines some of the issues and applications involved.

6.3.1 Compression technologies and costs

Highly-compressed gas is currently the preferred option for on-board storage of hydrogen in most transport applications, avoiding the expense and boil-off losses of liquefaction, the conversion losses of synthetic fuels such as ethanol and the technological immaturity of hydrogen carriers such as hydrides. The focus in this section is on transport as these require the highest pressures, although hydrogen for the heating and power sectors may also require some compression for distribution and seasonal storage but may end up using much of the same infrastructure.

Hydrogen is normally produced at low pressures, but can be generated up to 15–80 bar to reduce subsequent compression requirements. Hydrogen pipelines typically operate at such pressures, and centrifugal compressors can increase this if needed. Pressure falls as gas travels through the distribution network, so regularly-spaced pipeline compressors are sometimes used to repressurise the gas.

Alternatively hydrogen can be distributed by tube trailers. This is well established for low-purity industrial uses with 200 bar transport pressures and 300 kg capacity, but new trailers are being developed specifically for fuel cell electric vehicle (FCEV) refuelling with 1,000 kg capacity at 500 bar for economies of scale [86].

As a light gas, hydrogen must be compressed on-board hydrogen vehicles to very high pressures to enable FCEVs to achieve similar ranges to incumbent ICEs. Buses currently use 350 bar hydrogen as they have more on-board storage space, but most passenger cars use 700 bar. No other widespread hydrogen application uses such high pressures. Refuelling stations store hydrogen in a series of cascade tanks at pressures of 825–950 bar (typically 875 bar), due to the significant pressure drop across the dispenser control system [291]. Although this increases tank capital costs and compression work, it allows faster refuelling and the use of smaller compressors to replenish storage tanks overnight.

The energy penalty of compression to 875 bar is significant, as can be seen in Figure 6.2 for different inlet pressures. A 70% efficient compressor requires about 9% of the hydrogen’s energy content to compress from a 20 bar pipeline to 875 bar. A 100% efficient compressor would require 6% of the available energy. For comparison, compression from 20 to 500 bar (suitable for 350 bar refuelling) requires 7% compression work at 70% efficiency, or 5% for 100% efficiency. While this is notably less than required for liquefaction (see Section 6.5.4), these are still significant energy penalties.
There is considerable interest in converting the UK’s existing natural gas distribution network to hydrogen to meet heat demand [19], but using the network to supply hydrogen to refuelling stations for FCEV usage requires additional compression and increased network loading on small diameter pipelines. The medium pressure (MP) network operates at pressures of 0.075 to 2 bar, which would result in a large compression duty to reach 700 bar for FCEV refuelling, and may be insufficient to deliver the volumes of hydrogen required. Intermediate pressure (IP) pipelines, with pressures up to 7 bar, could require more reasonable compression work (10–15%), but have limited availability. Hence it is unclear whether the existing gas network is suitable for the supply of hydrogen for FCEV refuelling, and dedicated pipelines at pressures around 20 bar (or at least spurs to nearby pipelines at such pressures) may be needed.

Hydrogen from tube trailers, at around 500 bar, needs much less onsite compression (though compression work increases as the trailer empties, meaning most trailers do not empty completely); hydrogen in tube trailers must also be compressed to 500 bar, but centralised compressors can be more efficient and benefit from economies of scale.

Mechanical compressors are the incumbent and mature technology for hydrogen, similar to those for natural gas. Centrifugal compressors tend to be used for large flowrates and low pressure ratios in centralised production facilities and in pipelines [292], while piston compressors are used to achieve high pressures on refuelling stations. Interstage cooling is normally used to lift efficiency towards the isothermal limit (Figure 6.2), though real-world efficiencies are still well below adiabatic.
values. The US DoE has targeted 80% compressor efficiency by 2020 [291], though this is still low compared to some other compressor technologies. Mechanical compressors suffer poor reliability and are a leading cause of HRS unavailability [293]. This is exacerbated by a large number of moving parts and frequent start-ups; compressor rings currently need replacement every 1,000 hrs [291], leading many operators to pay for a spare compressor onsite or for fast-responding service engineers. The use of lubricant leads to hydrogen contamination, requiring post-compression cleaning. In some cases (particularly for hydrogen from tube trailers with lower pressure ratios required for onsite compression) diaphragm compressors are preferred with greater efficiency and reliability.

The advantages and disadvantages of the main compressor technologies are listed in Table 6.1. Electrolysis can generate hydrogen at pressures up to 200 bar; additional voltage is needed, but at power inputs nearer isothermal than adiabatic efficiency levels. High temperature electrolysis increases efficiency further. However higher differential pressures lead to increased crossover, stronger material specifications and a need for more steady-state operation with fewer start-ups. Electrochemical compression has been demonstrated at up to 1,000 bar, and offers high efficiency, high reliability, no contamination (thus higher purity hydrogen) and reduced cooling requirements [294]. It has been suggested as a means for purifying as well as compressing hydrogen [86], though impurities at the inlet may compromise compressor lifetime. High strength membranes and materials will also be needed to withstand extreme differential pressures. Ionic compressors are based on mechanical piston compression but with an ionic liquid layer to prevent lubricant contamination. However they are currently expensive and may have to limit throughput to prevent foaming [295]. Hydride compressors adsorb hydrogen at low pressures and releases it at high pressure, are compact and reliable, but are currently expensive and heavy. Mechanical compressors remain the incumbent technology for refuelling stations, but other options could be developed in due course.
### Table 6.1 Advantages and disadvantages of compression technologies.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical</td>
<td>• Commercially available</td>
<td>• Inefficient (~70%), expensive</td>
</tr>
<tr>
<td></td>
<td>• Wide operating range</td>
<td>• Poor reliability due to many moving parts. A spare may be required</td>
</tr>
<tr>
<td>High-pressure electrolysis</td>
<td>• Up to 200 bar production</td>
<td>• Rings only last 1,000 hrs due to frequent start-ups</td>
</tr>
<tr>
<td></td>
<td>• ~15% less energy</td>
<td>• Purification required due to oil contamination</td>
</tr>
<tr>
<td></td>
<td>• High temperature reduces energy requirements</td>
<td></td>
</tr>
<tr>
<td>Electrochemical</td>
<td>• 800 bar demonstrated</td>
<td>• Recombination catalysts and reduced yield due to increased crossover</td>
</tr>
<tr>
<td></td>
<td>• 3x lower energy</td>
<td>• Stronger materials increase costs</td>
</tr>
<tr>
<td></td>
<td>• 95% target efficiency</td>
<td>• Requires stable supply and few start-ups</td>
</tr>
<tr>
<td></td>
<td>• High reliability (no moving parts)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Pure (no oil contamination)</td>
<td></td>
</tr>
<tr>
<td>Ionic</td>
<td>• Low contamination</td>
<td>• High-strength steels</td>
</tr>
<tr>
<td></td>
<td>• Reliable (fewer moving parts)</td>
<td>• Tough membranes (differential pressures and crossover)</td>
</tr>
<tr>
<td>Hydride</td>
<td>• Compact, reversible</td>
<td>• Low throughput needed to increase efficiency</td>
</tr>
<tr>
<td></td>
<td>• Reliable (few moving parts)</td>
<td>• May need pure inlet stream</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Compression costs are significant but not prohibitive. A US study estimated current HRS costs of £1.05/kg\(^{25}\) for compression from both 20 bar pipelines and onsite production to 875 bar, and £0.28/kg for compression from tube trailers \([291]\). The study expressed doubts that 2020 targets for compression, storage and dispensing costs of £0.49/kg for centralised production and £1.19/kg for distributed production could be achieved due to slow progress in the advancement of compressor technology. With compression a key technology for hydrogen storage, and scarce information on very high pressures due to the small production numbers currently involved, further work is needed in this area to ascertain compression cost forecasts \([67]\).

#### 6.3.2 Hydrogen purity for fuel cell applications

As discussed in Chapter 3, the current ISO 14687–2 standard for PEMFCs in transport applications requires highly pure hydrogen in excess of 99.97%. The technologies required to achieve this purity are discussed below. In addition to the costs of purification itself, technologies for compositional measurement and verification are also required to avoid invalidating warranties \([86]\). This is a particular challenge given the number of sub-species limits, the purity required and the measurement frequency.

25 USD in this paragraph converted to GBP using the 2014 exchange rate: £0.70 = $1.
particularly during start-up or operation in extreme temperatures. Note that purity requirements for stationary applications tend to be lower, as discussed in Chapter 4. Current stationary fuel cells are supplied with natural gas rather than hydrogen, so purification equipment is incorporated within the fuel cells systems themselves.

**Hydrogen from electrolysis**

Hydrogen produced from water electrolysis is typically pure enough for FCEV applications. Recombination catalysts are used to remove oxygen that crosses the membrane. The main contaminant is normally water vapour. Water vapour is not a problem for fuel cells; indeed dry hydrogen normally has to be humidified to provide efficient proton transport. However water vapour is a problem when compressing, storing and transporting hydrogen; water vapour condenses on compression, which can cause rust, corrosion or increased wear in moving parts as it washes away lubrication. It can also freeze in cold temperatures, damaging pipework and valves. This applies to hydrogen generated onsite as well as transported from centralised facilities. Hence electrolyzers normally include dryers, typically regenerative desiccant towers, which are low-cost with low power consumption. However regeneration either involves electrical heating, or sending some dry gas back through the wet tower to pick up the accumulated moisture, typically reducing yield by around 10%, though there is scope for reducing this [296].

**Hydrogen from steam methane reforming (SMR)**

Reforming natural gas is usually the cheapest production route, and the most widely used at present [19]. However, hydrogen generated from SMR needs significantly more cleaning than hydrogen from electrolysis if used in a fuel cell. Pressure-swing adsorption (PSA) is the incumbent technology for purifying hydrogen, and is typically incorporated into the SMR process. It is capable of achieving hydrogen purities of >99.9% at the expense of loss of yield [19]. The trade-off between the two comes down to the specific economics; for example PSA can generate 99.999+% purity but with net recovery of 84.0% [297]. Hydrogen purification costs from SMR have been estimated as £0.51/kg in 2015 and £0.26/kg in 2025, with the claim that well-designed SMR and PSA systems are already capable of achieving the required purity levels and that, once quality assurance technologies are developed, the high-purity SAE J2719 standard should not add to the cost of hydrogen production [86].

An alternative to PSA is pressure-driven diffusion membranes, typically palladium-based. Current palladium filters achieve exceptionally high purity but are expensive, require a 400°C operating temperature and a pressure differential of 10–15 bar [271], reduce yield by 3–5%, and can suffer short lifetimes. One study found a palladium-based separation system that is potentially cheaper than PSA [271], and so diffusion membranes and electrochemical compressors are recommended for further research [86].
Hydrogen from pipelines/salt cavern storage

Hydrogen extracted from pipelines and/or salt-cavern storage will also need additional onsite cleaning before FCEV refuelling to remove lubricants, odourants, colourants, debris or dust acquired. An odourant is probably needed to warn against leaks; cyclohexene has been found to be compatible with fuel cell technology in Japan, but is described as having too pleasant a smell and lacking the stench of current EU odourants [19, 162]. A colourant may also be required to warn users of the location of flames as hydrogen burns with a colourless flame; an extremely dilute strontium solution is being considered [19]. It may be that PSA or activated carbon filters would be appropriate for onsite purification. The cost of cleaning hydrogen from pipelines is currently an unknown and requires further work [86].

6.4 STORAGE

This section discusses compressed hydrogen storage due to its more advanced state of technological maturity and scope for widespread adoption in the short-term. Liquefaction and other hydrogen carriers are discussed in Section 6.5.

6.4.1 Decentralised hydrogen storage

Heat and electricity users primarily use pipelines, and so varying pressures (line-packing) combined with geologic storage could manage mismatches in supply and demand. Significant high-pressure decentralised storage is required for transport applications due to space constraints, particularly at refuelling stations and on-board vehicles. Higher pressures increase tank material and compressor specifications, compression work requirements and safety measures such as minimum separation distances. Low (~45 bar) and medium pressure (200–500 bar) pressure vessels are common in industry, but high pressure tubes and tanks (700–1,000 bar) are rarely used outside the refuelling sector and are currently produced in low quantities [30]. Hydrogen tanks at refuelling stations have higher pressures than in FCEVs (e.g. 925 vs 700 bar) to allow rapid refuelling without requiring a slow compressor to fill vehicle tanks.

Underground storage at refuelling stations can reduce surface land usage in densely populated urban areas. However compressed hydrogen gas has only 15% the energy density of petrol, so refuelling stations will require more physical space to supply the same amount of fuel (though this will be partially offset by the greater efficiency of FCEVs). Indeed it is possible that most current petrol refuelling stations will not be suitable for hydrogen and would have to be rebuilt [30]. A larger hydrogen tank would allow for a smaller (and cheaper) on-site compressor that trickle-feeds it through the night.

6.4.2 Geologic storage

Seasonal storage is less of a requirement in transport and electricity sectors (see Figure 2.1), but could be a requirement for highly-seasonal heating demand. Hydrogen storage in salt caverns is widely suggested as the only feasible zero-carbon inter-seasonal store. This can offer energy densities of 280 kWh m⁻³, which is about
one hundred times the energy density of compressed air storage [30]. Some salt deposits are deeper than others and hence more costly to excavate and operate, but are then capable of storing more hydrogen at higher pressures up to around 200 bar. A limited number of regions in the UK have suitable salt deposits, but several chemical and refinery complexes have used substantial hydrogen salt cavern storage facilities since the 1960s. Comparatively low construction costs make salt cavern storage much cheaper than surface storage in cylinders. Salt caverns are the cleanest form of geologic storage but some post-storage cleaning is still likely to be required, particularly for transport applications.

Aquifers and depleted oilfields are alternative geologic stores for regions without appropriate salt deposits, but the hydrogen recovered could require additional cleaning and these options have undergone little testing to date.

6.5 DISTRIBUTION

There are typically three routes for hydrogen transport, the suitability of which depends on the size of demand and the transport distance. However, associated costs are significant and the credentials of each option is discussed in this section.

6.5.1 Onsite production

Hydrogen can be produced onsite at refuelling stations either by water electrolysis or steam methane reforming. This is a near-term solution employed today as it relies on existing distribution structures for other energy vectors (electric grid or gas network), and so does not incur vast investment costs.

Electrolysis is likely to be more suitable as it is more scalable and emission-free, with CCS unlikely to be economic for decentralised SMR. Onsite production from electrolysis could be an attractive option in the early years of rollout for a number of reasons. It produces a sufficiently high purity of hydrogen for FCEVs [86]. It could be cheaper for refuelling stations a long way from hydrogen production facilities but with a good grid connection. Although relatively expensive per unit of fuel, it could still be simpler and cheaper on a small scale than other options that may suffer from low utilisation. However, urban refuelling stations may not have space for onsite generation equipment, onsite compression and storage is also needed, and electricity network upgrades could also be required (although ‘smart’ electrolysis could offer balancing and network reinforcement services – see Chapter 5).

6.5.2 Tube trailers

An alternative option, particularly for initial rollout, is distributing hydrogen from centralised production facilities as a compressed gas in tube trailers. This is a well-established method, and large trailers specifically for FCEV refuelling hold up to 1,000 kg capacity at 500 bar [86]. The trailer can be parked at the refuelling station to refuel vehicles directly, reducing onsite storage and compression requirements as compression begins from a much higher starting pressure. However this does take up valuable surface space at the refuelling station and delays the trailer’s return for its next load. Distribution by tube trailer becomes a much less economic option.
as demand rises (requiring more deliveries) and when transportation over long
distances are required as more time and fuel is spent on the road [30]. However
it can enable the transition to a low carbon economy as a much lower infrastructural
cost (and lower risk) than liquefaction or pipeline construction. Longer term it
could still present the best option for remote or low-demand areas.

6.5.3 Pipelines

It has been reported that pipelines are the most efficient method of transporting large
quantities of hydrogen, particularly over short distances [30]. However the cost and
disruption of installation means pipeline usage should be delayed until the size
of both hydrogen supply and demand can be known with great certainty well into
the future. Low initial utilisation and high upfront costs are also likely to hinder
financing. New pipelines would be required for high-pressure hydrogen networks
as existing high carbon steel natural gas pipelines would be affected by hydrogen
embrittlement. Likewise the existing natural gas transmission network will probably
be needed for many years to supply gas turbines and industrial users. These high-
pressure pipelines are slightly more expensive than for equivalent natural gas pipe-
lines due to the higher material specifications. Around 3,000 km of high-pressure
hydrogen pipelines are already in use in Europe and North America for industrial
processes, demonstrating their technological maturity [30].

Embrittlement is a pressure-driven process and is less of a concern at lower pres-
sures. Additionally the polythene pipes replacing iron pipelines as part of the Iron
Mains Replacement Programme are compatible with hydrogen. These are currently
limited to 7 bar, but larger plastic pipes up to 17 bar have been proposed. Hence
there is considerable scope for switching the bulk of the lower pressure natural gas
distribution system to running on hydrogen. Much of the UK’s low-pressure network
operates with a 40 mbar inlet pressure compared to a current maximum permissible
limit of 75 mbar, indicating that a significant potential exists to increase the pres-
sure of the low-pressure network to maintain or even increase the existing network
capacity when operating on hydrogen. Hydrogen pipelines have long lifetimes,
although the rate of embrittlement can make this difficult to predict. Capital cost
are often annualised over 30 years for accounting purposes, but pipelines should
last at least 50–100 years [30].

If hydrogen is selected as the primary fuel for both the transport and heat sectors
(and for decentralised electricity generators such as stationary fuel cells), then
great synergies and cost savings could be realised by designing a national hydrogen
pipeline network to meet the demands of all these sectors with a single technology.
This would require thorough analysis to ensure that the resulting hydrogen distribu-
tion network is sized appropriately, but is an option that deserves in-depth attention.
Installing pipelines is costly and disruptive, particularly in densely-populated or
environmentally sensitive areas, but also offers the possibility of removing a great
number of fuel tankers from the nation’s roads.
6.5.4 Liquefied hydrogen

Liquefaction of hydrogen greatly increases its energy density, allowing large quantities to be transported by road tanker or ship. This is particularly attractive for transporting smaller amounts of hydrogen long distances, for which pipelines would not be economic [30]. Over 90% of merchant hydrogen is currently transported in liquid form in the US, indicating an advanced state of technological maturity [298]. Liquefaction consumes considerably more energy than compression; the US’s 2020 target for the energy consumption of large-scale liquefaction is 11 kWh/kg (i.e. 28% of the energy content of the fuel vs HHV) with the potential to reduce to 6 kWh/kg in the long-term [298]. Large centralised liquefaction plants are most likely to be built in the future as they are expected to be significantly cheaper and more efficient, potentially reaching an energy efficiency of up to 84% [30].

Liquid hydrogen tanker capacities are typically 2,000–7,500 kg. This is likely to mean refuelling stations handling liquid hydrogen will be subject to Control of Major Accident Hazards (COMAH) regulations, which are currently required for sites with more than 5 t of hydrogen storage. Industrial sites are already accustomed to complying with COMAH regulations, but this could be a heavy added burden for refuelling stations. Although more dense than compressed hydrogen, liquid hydrogen still has a third of the energy density of petrol, increasing the volumetric requirements of tanks to supply the same amount of fuel (although partially offset by the greater efficiency of FCEVs).

In many cases it is unlikely that hydrogen would be used on-board vehicles in liquid form. Boil-off results in high storage losses for low-utilisation vehicles and is potentially unsafe for parking in enclosed spaces. Many light-duty vehicles can achieve sufficient range with compressed hydrogen. The exception could be heavy-duty transport sectors such as lorries, ferries and aircraft where liquid hydrogen could enable adequate ranges. Hence the usage of hydrogen in liquid form could be primarily for distribution and short-term storage.

In summary, an compressed hydrogen transport via tube trailers are likely to benefit the initial rollout of hydrogen transport, whereas pipelines are better suited for mass deployment. Pipelines also offer the possibility of delivering large quantities of hydrogen for the heat, power and industrial sectors as well as transport in a large-scale switch to a hydrogen economy. Liquefaction for the energy sector could be restricted to a few niche transport sectors and geographical regions. One study suggested a limited amount of liquefied hydrogen distribution over medium timeframes, but largely dying out post 2040 [15].

Table 6.2 gives a comparison of the three principle options for hydrogen delivery in the transport sector.
Table 6.2 Qualitative overview of hydrogen T&D technologies for hydrogen delivery in the transport sector. Adapted from the IEA [67].

<table>
<thead>
<tr>
<th>Distribution route</th>
<th>Capacity</th>
<th>Transport Distance</th>
<th>Energy Loss</th>
<th>Fixed Costs</th>
<th>Variable Costs</th>
<th>Deployment Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-site production</td>
<td>Low</td>
<td>Zero</td>
<td>Low</td>
<td>Low</td>
<td>High</td>
<td>Near term</td>
</tr>
<tr>
<td>Gaseous tube trailers</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>High</td>
<td>Near term</td>
</tr>
<tr>
<td>Liquefied tankers</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
<td>Medium</td>
<td>Medium</td>
<td>Medium to long term</td>
</tr>
<tr>
<td>Hydrogen pipelines</td>
<td>High</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>Medium to long term</td>
</tr>
</tbody>
</table>

6.5.5 Hydrogen carriers

A number of alternative hydrogen carriers are currently under investigation, but are at less advanced stages of maturity. Solid carriers including metal hydrides are already established in a few niche applications including submarines and scooters [30]. They operate at low pressure and hence require lower safety restrictions and separation distances than highly-compressed or liquefied hydrogen, which could be attractive in densely-populated areas. Their gravimetric energy density (around 3% hydrogen by weight) is comparable to compressed gas at 500 bar. Energy is released during charging (i.e. hydrogenation), but energy input of about 30% is required during discharging. Hydrides have cheaper system components (e.g. a small compressor, a heater for discharging) than for compressed or liquefied hydrogen storage. Slow charging and discharging rates limit their suitability for on-board applications, meaning that the hydrogen must be released from the hydrides at the refuelling stations and compressed for on-board storage.

Liquid organic hydrogen carriers (LOHCs) are another class of hydrogen carrier currently attracting attention. Energy densities of 6 wt% are achievable, and like hydrides they offer low pressure operation and the potential for reduced safety restrictions and separation distances in urban environments [30]. Around 25% of the energy content of hydrogen is required to release the fuel, though this could be offset if the equivalent amount of energy released during hydrogenation could be captured. Catalysts can be employed to speed up the reactions, potentially enabling their usage on-board vehicles hence avoiding compression requirements.

Hydrogen can also be distributed in the form of fuels such as ethanol, CNG or ammonia [72], which can be low-carbon if produced from biomass or non-fossil fuel sources. These could offer low-pressure, high-volume energy carriers similar to those used extensively today. However biomass availability is limited and synthetic fuels are costly and difficult to produce, so these options are not currently under widespread consideration. As early-stage technologies it is difficult to be certain whether solid or liquid hydrogen carriers or synthetic fuels will play a significant role in a future hydrogen economy.
6.5.6 Hydrogen refuelling stations

A lack of an existing network of hydrogen refuelling stations is often cited as creating a “chicken-and-egg” barrier to FCEV rollout. Battery electric vehicles faced this to a lesser extent due to the lower cost of electric chargers (albeit with lower throughput), and so over 4,000 charging locations are now available in the UK [299]. The solution for hydrogen transport may be a number of public-private stakeholder initiatives to fund the early rollout of hydrogen vehicles and infrastructure until the industry becomes self-sustaining. The various European H2Mobility programs have suggested a rollout of refuelling stations at critical locations, with a network of 65 refuelling stations for the UK by 2020 to start the market, growing to 1,150 stations by 2030 to cover the whole country [51]. A recent study reported a global target of more than 3,000 refuelling stations by 2025, sufficient to provide hydrogen for about 2 million FCEVs, after which refuelling infrastructure should be self-sustaining [87].

Refuelling stations could be situated on the site of existing petrol refuelling stations, but these may need to be rebuilt for hydrogen delivery. Space for storage and compression is likely to be required. Hydrogen delivered by tube trailers may need less onsite storage and compression, but may not have space to park the trailer. Onsite production could avoid the need for trailer space but will also have a significant footprint, and an upgraded electrical connection could be required for an onsite electrolyser. Liquefied hydrogen could reduce storage and compression requirements, but could require Control of Major Accident Hazards (COMAH) certification. These issues are not as difficult for less space-constrained areas including suburban and rural areas and motorway service stations, but could be challenging in urban areas. Refuelling stations currently cost in the region of £1m; this is expected to drop by two-thirds once this has become a mainstream technology [30].

Other transport sectors will use centralised refuelling depots, including fleets, buses, lorries, trains, ferries, airport/seaport vehicles and forklift trucks. This may negate the space constraints, lead to economies of scale, reduce the number of stations required, and could enable distribution costs to fall more rapidly than in the passenger FCEV sector, suggesting deployment in these sectors should be targeted as well as for light-duty vehicles.

6.6 TRANSITIONING TO A H2FC ECONOMY

Development of hydrogen infrastructure is complicated by the low initial uptake of hydrogen-based technologies, with the implication that expensive hydrogen infrastructure may suffer from low utilisation rates until uptake of hydrogen is more widespread. This is clearly a concern to potential investors who will not commit funds on the hope that such a market will develop. Strategic markets could act as stepping stones to facilitate the transition to an H2FC economy.

Transitions to an H2FC economy can be approached from a normative or descriptive point of view, outlining visions for a desirable hydrogen future or being the basis for a perhaps more pragmatic ‘road-mapping’ exercise [300]. Various authors have focussed on supply-side considerations, the development of an optimal
 infrastructure, acceptance from final consumers, risk considerations, the wider concept of social acceptability and the environmental implications [301–303]. Among those focusing on supply-side considerations, several studies discuss the transition to an H2FC economy either through integrating hydrogen into energy system models (such as in Chapter 2), or by developing tailored Mixed-Integer Linear Program approaches that can model infrastructure development across multiple nodes of a network [304, 305].

Several studies have explored the transitions to a H2FC economy in the UK using spatial models [305–308]. Although similar in terms of mathematical approach, these models differ in their focus, computational requirements (which constrains the level of detail), the length of the horizon period, the temporal and geographical granularity. For example, some models assess how infrastructure could develop over time using a long-term planning horizon [306, 307], while another uses high temporal granularity to examine the extent to which hydrogen storage could contribute to integrating renewables [305].

In the former class of models, computational rigour is focused on accounting for changes in the infrastructure in response to a daily demand for hydrogen, geographically detailed but assumed constant throughout the forecasting step of the model – normally five years. The latter class with high temporal granularity focusses on variability of H2 demand, price, utilisation rates and ultimately revenues. These have been applied to assess the importance of hydrogen in facilitating the penetration of intermittent renewable electricity. The seasonal and daily variability of wind availability is key in determining the value of hydrogen to the energy system.

Both modelling approaches are, however, powerful in assessing the trade-offs between the features of potential transitions to H2FC economies. For example, long-term planning options of an optimal infrastructure are influenced by the trade-offs between production costs and transportation costs and technology uncertainties (e.g. the availability of a specific technology). Different hydrogen penetration pathways are important as increasing the scale of hydrogen production can be achieved earlier in scenarios with a higher penetration rates [307].

As an example, Figure 6.3 shows the evolution of the optimal infrastructure for a possible transition to the Full Contribution scenario discussed in Chapter 2, in which hydrogen becomes dominant in transport and heat provision by 2050, as well as contributing to industry and electricity generation.
Liquid hydrogen is distributed from six import terminals, while all domestically-produced hydrogen is gaseous. Liquid hydrogen allows the model to take advantage of high economies of scale occurring abroad, reducing the cost of hydrogen to consumers. Different production technologies contribute to different phases of the transition; for example, alkaline water electrolysis is the cheapest production technology to begin with when penetration rates are relatively low, while reforming becomes cost competitive as demand grows. As an example of environmental and economic trade-offs, reformers must adopt CCS to remain within the national CO₂ budget, impacting on the cost of hydrogen. Hydrogen for transport evolves from using expensive but flexible tube trailers, to dedicated pipelines once penetration warrants the development of costly infrastructure.

A key challenge for these models is to improve the representation of the risk that the expected level of hydrogen demand in the future will not come to fruition, as the models have perfect foresight of future demands when calculating current infrastructure. This could be achieved by time-step or stochastic modelling, and would likely delay the rate of pipeline deployment in favour of more decentralised technologies.
6.7 CONCLUSIONS

Pure hydrogen, like electricity, does not occur naturally and must be produced and then transported to its point of use. Compared to some fuels, hydrogen is relatively difficult to handle and the costs of installing and operating hydrogen distribution infrastructure need careful consideration.

Hydrogen rollout has struggled due to a chicken-and-egg impasse with a lack of refuelling infrastructure hindering fuel cell vehicle sales. Public-private initiatives are committed to rolling out initial hydrogen infrastructure, with 3,000 refuelling stations targeted globally by 2025. Incremental routes to delivering hydrogen include gas delivery via tube trailer or onsite electrolysis. While these may suffer higher cost per kg, their low initial outlay poses a lower barrier until demand is established.

Liquefaction is another option that can transport more hydrogen than tube trailers and with lower upfront costs than pipelines, but high liquefaction costs and boil-off rates could limit long-term usage to a few heavy-duty sectors and for transporting smaller quantities of hydrogen over long distances. Alternative hydrogen carriers such as metal hydrides, liquid organic hydrogen carriers or synthetic fuels do not require the high pressures or low temperatures of other options and could see take-up in some sectors, but are at early stages of development and may not achieve widespread rollout.

In the longer term hydrogen pipelines are the most cost-effective means for distributing large quantities of hydrogen, and can also enable the use of hydrogen for heat, industry and power sectors. However their installation is sufficiently costly and disruptive to require significant long-term hydrogen demand. The existing low pressure natural gas distribution network could be converted to transport hydrogen, but dedicated pipelines at higher pressures (e.g. 20 bar) may be required to supply sufficient hydrogen for fuel cell electric vehicles (FCEVs) and avoid excessive compression requirements.

FCEVs require compression to around 700 bar to achieve acceptable driving ranges, which expends around 10% of the energy content of the fuel. Compressor technologies are currently expensive and unreliable; alternative technologies have been proposed but are at early stages of development. Transport applications also rely on very high purity hydrogen purity, requiring either electrolysis or significant clean-up stages after steam-methane reforming, which may reduce yield by 10–20%.
7.1 POLICY CONTEXT

Hydrogen is considered a strategic energy carrier in future energy scenarios as it supports the climate change agenda. It can also contribute to energy security and reliability through having multiple production feedstocks, and through storage it can enable the deployment of renewables. The hydrogen economy is expected to spur economic growth, create new supply chains, business models, job opportunities and innovations. At a local level, authorities are also interested in the opportunities of hydrogen and fuel cells as a solution to improve air quality and noise pollution in urban areas. Limited reserves and potential policy interventions that internalise the cost of negative externalities are likely to increase the cost of using fossil fuel in the long term, strengthening the role of H2FC technologies to deliver energy affordability.

7.1.1 Environmental drivers

Environmental policy is concerned with climate change, air, water, noise pollution and the depletion of resources, and it constitutes one of the main drivers for the promotion of H2FC. The Lisbon Treaty states that environmental requirements must be embedded into all EU policies ‘with a view to promoting sustainable development’ [309]. The potential of H2FC technologies to contribute to all dimensions of sustainable development (environmental, social and economic) justifies their inclusion in energy policy instruments. Hydrogen pathways present strong environmental credentials; however, they have not featured in as many policies as renewables because of the UK’s ‘pragmatic’ approach to the development of EU environmental policy [309].

Hydrogen can play a significant role in improving air quality in urban areas as it produces zero emissions at the point of use, and can also reduce noise pollution from the transport sector. Hydrogen produced from renewables yields lower carbon emissions than conventional fossil fuels, and production from fossil fuels can have low GHG emissions with CCS. Regardless of the production route, clear and stable long-term policies provide certainty to investors, facilitating investment in innovation. The range of international agreements ratified by the UK positions H2FC technologies as one of the few pragmatic pathways to deliver low carbon and environmentally friendly energy alternatives beyond 2030.

Air quality drivers

Policies for improving air quality have direct impacts on human health and the environment, for example respiratory problems, premature deaths, acidification, etc. Air pollution from particulate matter was responsible for 29,000 UK deaths in 2008 [310]. 430,000 premature deaths in the EU are related to air pollution, and targets have been established to reduce this to 224,000 by 2030 [311]. The economic costs of air pollution due to sick leave, healthcare, crop yield loss and damage to buildings are around €8 bn, €2.4 bn, €1.7 bn and €0.3 bn respectively [311]; and the benefits of clean air policies continue to significantly exceed the cost of action [312]. The EU imposes severe penalties to member states that consistently exceed the thresholds and occurrences of the legislated air quality pollutants, according to the EU Air Quality Directive 2008/50/EC. These fines are transferred to the local authorities responsible for breaching those limits. As a result, many are considering
now banning diesel vehicles and expelling polluting industries from urban areas while exploring alternative solutions such as promoting electric, hybrid and fuel cell electric vehicles (FCEV). Nowadays, smog is so severe in some megacities worldwide that industrial activity and traffic are restricted during critical days. Madrid for example has a protocol for high NO₂ pollution episodes when vehicles with odd or even number plates are forbidden from driving on alternate days; motorbikes and electric, hybrids and gas vehicles are exempt [313]. FCEVs could decrease the need for imposing such tough restrictions, and allow residents to avoid such restrictions.

**Climate change and energy savings drivers**

Climate change has been a key driver in UK environmental policy. As established in the Climate Change Act 2008, the UK aims to reduce GHG emissions by 80% by 2050 compared to 1990 levels [314]. Carbon Budgets provide interim targets, and by 2028–2032, the savings of 431 MtCO₂e are expected mainly from transport (38%) and the residential sector (30%); areas where H2FC can support decarbonisation goals. The fifth carbon budget recommends limiting the carbon intensity of the power sector to below 100 gCO₂e/kWh by 2030 [315]. Several hydrogen pathways are compatible with this goal and one of the proposals for defining a green hydrogen standard suggests a threshold at 36.4 gCO₂e/kWh [316].

The UK adhered to the Conference of Parties (COP21 and COP22), and so is committed to ‘improving national carbon reduction strategies, advancing innovation to drive forward clean energy, increasing transparency of actions and scaling up ambitious climate finance from a range of public and private sources’ [317]. In response, the Government may promote investment in H2FC technologies so long as they can reach cost parity with incumbent technologies and fit with the Government’s new industrial strategy.

**7.1.2 Energy security, resilience and affordability drivers**

Energy supply disruptions would have significant impacts as the EU imports half of the energy that it consumes; 90% for crude oil and 66% for natural gas [318]. The UK energy security strategy is based on six policy areas: resilience, energy efficiency, reliable networks, maximising UK production, working internationally and decarbonisation [319]. Reliance on single suppliers (e.g. Russian gas or Middle East oil), poor reliability (e.g. intermittency of renewables) and unavailability of energy infrastructure (e.g. natural disasters, failure or cyber-attacks) are significant risks that H2FC technologies can help to mitigate.

Hydrogen can improve national energy independency, as it has numerous production pathways including fossil fuels, biomass and other renewables, easing geopolitical reliance on oil and gas suppliers. Energy system reliability can be improved by building hydrogen storage capacity to balance renewable electricity generation. Furthermore, these technologies can exploit synergies between the power and heating systems with power-to-gas, gas-to-gas and gas-to-power technologies.

Providing cheap energy, while meeting expected demand increases and decarbonisation targets simultaneously is challenging; however, energy affordability is a key
economic and social priority for most governments. Key policy areas to achieve this focus on controlling policy costs on bills by reducing subsidies, increasing competition and developing energy efficiency programs [320]. While some technologies can improve system efficiency (e.g. FC micro-CHP), subsidising them would only increase energy bills in the short-term. The role of H2FC to deliver affordability is currently limited due to immaturity and low production levels. Similarly, the lack of large-scale demonstration projects in the areas of hydrogen storage and CCS limits the achievement of cost reductions. However, in the long-term these technologies could make a significant contribution with a commitment to research, development and deployment.

Examples of policy interventions that could lead to this outcome include:

- The internalisation of negative externalities of energy produced from fossil fuels, such as the Carbon Price Floor.
- Mandatory targets excluding fossil fuels from the energy mix of some systems (e.g. Renewables Obligations or converting the gas network to hydrogen).
- Establishing compulsory storage capacity (including hydrogen) when permitting intermittent renewable energy projects.
- Promoting CCS until hydrogen can be produced from renewables at the scale needed to meet the demand from the energy systems (heating, power, transport).
- Defining hydrogen as a renewable fuel.

### 7.1.3 Latest Policy Developments in Scotland

The Scottish Energy Strategy is part of the Scottish Government’s vision for the future energy system [342]. It explores the role of hydrogen in the Scottish energy system and recognises that by 2050 it could become one of the main components in the energy mix. This strategy applies a whole systems view which recognises the interactions between heating, power and transport systems, and aims at a 50% of energy coming from renewables by 2030 [342].

Hydrogen is an interesting option for Scotland. It eases the transition for the oil and gas industry as there are many similarities and synergies between supply chains and labour skills. The strategy identifies the role of hydrogen to decarbonise heat and considers that it could do so more cheaply than other alternatives. In line with the UK’s Renewable Transport Fuels Obligation (RTFO) consultation process, it supports the inclusion of hydrogen as a renewable fuel of non-biological origin.

Several relevant projects are being taken forwards in Scotland: Orkney’s ‘Surf and Turf’ and ‘BIG HIT’, and the Levenmouth Community Energy Project produce green hydrogen from wind power [342]. In 2017, the Scottish Government published its commitment to invest more than £500m over the next four years in the Scotland’s Energy Efficiency Program, with the goal of delivering near zero carbon buildings by 2035 [343]. The Scottish Government is committed to fund innovative H2FC projects; however, a specific budget has not been allocated yet for promoting these technologies as the current energy strategy is under consultation.
7.2 POLICY INSTRUMENTS

Numerous policy instruments are applied to the heating, power and transport systems. Due to the synergies between heating and power, this section separates energy demand, energy generation and transport policies.

7.2.1 Energy demand policies

The key energy demand policy instruments that influence H2FC technologies outside industry are related to heating and electricity consumption in buildings, as summarised in Table 7.1. These policies focus on developing energy efficiency standards and increasing the share of renewables mostly in heating, with the ultimate goal of reducing GHG emissions. Since the UK’s shift towards a service economy, there is renewed interest in defining a new industrial strategy to rebalance the UK economy.

Industrial processes are responsible for 9% of EU GHG emissions [321], 18% of SOx emissions, 12.5% of NOx and 7% of particulate matter (PM2.5) [322]. EU Policy instruments associated with industry and large corporations are displayed in Table 7.2, while Table 7.3 represents those that are particular to the UK. Typically, their main goal is reducing GHG emissions; however, reducing pollution is also emphasised under European legislation, a concern that is expanded as well under the UK Regulations to energy efficiency and energy security.
Table 7.1 Energy demand policies relevant to H2FC in buildings
(H: Heating; P: Power).

<table>
<thead>
<tr>
<th>Building Regulations System:</th>
<th>Objective: Energy efficiency / GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>H, P</td>
<td></td>
</tr>
<tr>
<td>Sets standards for the construction and design of most new buildings and some renovations. Specify energy conservation requirements and must consider systems such as decentralised energy supply and district heating or cooling from renewables, heat pumps and cogeneration. Understanding hydrogen as a ‘mains gas’ could facilitate H2FC technologies to be installed in new buildings (e.g. hydrogen boilers, FC micro CHP).</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Domestic Renewable Heating Incentive (RHI) System:</th>
<th>Objective: Increase the share of renewables / Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td></td>
</tr>
<tr>
<td>A UK financial incentive to promote the generation and use of domestic renewable heat as a means to reduce GHG emissions. Eligible technologies include heat pumps, biomass boilers and solar thermal panels. A review should be put forward to assess the inclusion of FC micro CHP as this technology could deliver the same policy objectives as the accepted ones.</td>
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<tbody>
<tr>
<td>H</td>
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<tr>
<td>Mandates that all new public buildings built in the EU by 2019 must consume 0 kWh/m²/year and other buildings by 2021. The Directive requires that energy used to operate buildings comes from renewables (mainly), therefore hydrogen must be renewable to be eligible. FC micro CHP running on biofuels could also meet the policy objective.</td>
<td></td>
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</table>

<table>
<thead>
<tr>
<th>Private Rented Sector Regulations System:</th>
<th>Objective: Energy efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td></td>
</tr>
<tr>
<td>Dwellings and non-domestic buildings must reach an ‘Energy Performance Certificate’ rating ‘Band E’ by 2020 and 2023, respectively. Property owners must give consent for the installation of energy efficiency technologies. In the case of non-domestic buildings, they cannot refuse if the payback of the investment is 7 years or less. The funding can be private (e.g. tenant) or via a public scheme. Among the list of appropriate improvements are CHP and gas-fired condensing boilers; both compatible with hydrogen and FC micro CHP.</td>
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<thead>
<tr>
<th>Salix Loans System:</th>
<th>Objective: Energy efficiency and reduction of GHG emissions, energy affordability, innovation</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td></td>
</tr>
<tr>
<td>A finance scheme funded by the UK Government that provides interest-free loans for energy efficiency projects undertaken by public sector organisations that yield a payback period under 5 years in England and 8 years for the rest of the UK. Lifetime carbon savings costs must be less than £100t CO₂ in England (£200t CO₂ in the rest of the UK). These cost savings can be recycled into new capital projects. Despite not including explicitly H2FC, such projects can meet the eligible criteria. Previous projects include boilers and NG CHP, which could also run on hydrogen.</td>
<td></td>
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</tbody>
</table>
Table 7.2 Large and industrial organisations EU energy demand policies relevant to H2FC. (T: Transport; H: Heating; P: Power.)

<table>
<thead>
<tr>
<th>System</th>
<th>Objective: Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU Emissions Trading System (ETS)</td>
<td>System: H, T</td>
</tr>
<tr>
<td>The world’s largest carbon trading scheme, covering 45% of the EU’s GHG emissions. Energy intensive industries are given a carbon emissions allowance cap and the possibility to trade their surplus/deficit. Currently, auction prices of ETS are too low as allowances are still too many. The incentive to reduce emissions for these organisations is low, which is detrimental for the private investment on efficient H2FC. In contrast, the revenues from the allowances’ trade can be invested in hydrogen related projects by national governments as under the EU ETS Directive, 50% of the revenues obtained must be invested in climate and energy efficiency related purposes by member states.</td>
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</table>

| Industrial Emissions Directive (IED)         | System: H, P                          |
| The main EU instrument for regulating pollution from energy and industrial installations. It issues permits and controls installations’ air, water, land, noise and waste pollution, in addition to energy efficiency, safety, use of raw materials and decommissioning. It encourages the following of ‘Best Available Techniques’ (BAT) by participants of different industries. Some of these apply to members of the H2FC supply chain (e.g. technical ceramics, chemical, polymers, oil and gas, waste and precious metals). The IED also regulates GHGs (CO₂, CH₄, N₂O, fluorinated gases) and their precursors (NOx, SOx and black carbon) in facilities not covered under the EU ETS or ‘when it is necessary to prevent local pollution’. As H2FC technologies can produce low pollution and GHG emissions under certain pathways, they should be included in new iterations of BAT as recommended technologies. |

Table 7.3 Large and industrial organisations UK energy demand policies relevant to H2FC. (T: Transport; H: Heating; P: Power.)

<table>
<thead>
<tr>
<th>System</th>
<th>Objective: Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Climate Change Agreements</td>
<td>System: H</td>
</tr>
<tr>
<td>Voluntary agreements between UK industry and the UK Environmental Agency. Enrolled companies can get a rebate of 90% from electricity and 65% from other fuels from their Climate Change Levy (CCL), as long as, they meet energy efficiency and carbon reduction targets established by the Government for their sector. H2FC technologies projects could be funded by the Government from the income obtained from the CCL and the ‘buy-out’ fee.</td>
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</table>

<table>
<thead>
<tr>
<th>System</th>
<th>Objective: Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRC Energy Efficiency Scheme</td>
<td>System: H</td>
</tr>
<tr>
<td>A compulsory scheme that applies to eligible large energy users in the public and private sectors (supermarkets, water companies, banks, central government and devolved administrations). These organisations must report emissions generated from their electricity and gas consumption. It works similarly to the ETS. Allowances can be bought at a fix price and traded in the secondary market. This will be replaced by a Climate Change Levy from July 2019. Organisations using FC micro CHP must report electricity generation only as heat is excluded. Under this scheme, emissions from H2FC vehicles without road license must also be reported (e.g. forklift trucks, excavators, etc.), as well as, energy used to provide heating, power and lighting to railways buildings (e.g. FC auxiliary power units).</td>
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</tbody>
</table>
Chapter 7  Hydrogen policy

### Effort Sharing
Decision, Effort Sharing Regulation

**System:** H, T  
**Objective:** Reduction of GHG emissions / Energy efficiency / Increase the share of renewables

This sets up legally binding carbon targets for sectors not included on the EU ETS. The policy focuses on improving building standards, more efficient and less carbon intensive heating systems and renewable heating. Allowances are too large to drive any H2FC demand in the short term. The revenues of the scheme could be used to fund H2FC innovation in hard to decarbonise sectors such as transport, agriculture and waste (e.g. agricultural tractors and refuse trucks powered by fuel cells).

### Energy Savings
Opportunity Scheme

**System:** H, P, T  
**Objective:** Energy efficiency and reduction of GHG emissions

Regulation transcribed in the UK to implement the EU Energy Efficiency Directive (2012/27/EU). A mandatory energy assessment and saving scheme to audit the energy consumption of buildings, industrial processes and transport from large undertakings. Non-compliance carries penalties. Its aim is to identify (and recommend) cost-effective energy saving measures by assets that represent at least 90% of the total energy consumption. H2FC technologies can be eligible only if they cover this share and are cost-efficient.

### Enhanced capital allowances (ECA)

**Objective:** Energy and water efficiency, reduction of GHG emissions

Allows businesses to deduct the full cost of eligible energy and water efficiency equipment from the profits of each company before tax. As energy efficient technologies such as steam boilers, CHP, and auxiliary power units are eligible, H2FC technologies for energy generation are implicitly acceptable.

### Non-domestic Renewable Heating Incentive (RHI)

**Objective:** Increase the share of renewables / Reduction of GHG emissions

A UK financial incentive to promote the generation and use of renewable heat in buildings and facilities (excluding dwellings) as a means to reduce GHG emissions. The list of eligible technologies includes biomass CHP, biogas and biomethane. FC micro CHP and biomethane (a renewable gas) can deliver the intended policy objectives, and so should be included within future iterations.

#### 7.2.2 Energy generation policies

Energy supply is responsible for a third of UK GHG emissions, and three quarters of this is from power stations [323]. Decarbonising electricity supply is fundamental to achieving meaningful GHG reduction targets, and also to reducing air pollution. Energy production and distribution is a major source of SOx and NOx pollutants, emitting 58% and 20% respectively in Europe [322], or 52% and 30% in the UK [324].

Energy generation policies can be classified in two broad groups. One includes policy instruments that relate to hydrogen production (Table 7.4), whose main objectives are GHG emissions reductions and air pollution. In the short-term fossil fuel pathways are inevitable for producing hydrogen; however, emissions could be drastically reduced when sufficient hydrogen can be generated from renewables. In the
meantime, CCS policies may be necessary to broach the transitionary technological and production gap.

The second group comprises instruments that denote the role of H2FC technologies in supporting conventional power and heating systems (Table 7.5). Among this group, the main policy targets are increasing the share of renewables in the electricity and heating networks, and guaranteeing the energy security of the power system. H2FC technologies have an important role in grid support as they could improve system reliability by providing storage and capacity to balance the intermittency of renewables (as shown in Chapter 5). Many synergies between different energy systems are possible as hydrogen is a flexible energy carrier that can be converted between electricity and synthetic gases.

**Table 7.4 Energy generation policies relevant to the production of hydrogen.**

(H: Heating; P: Power.)

<table>
<thead>
<tr>
<th>Policy Type</th>
<th>System:</th>
<th>Objective: Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Capture and Storage Directive (CCS)</td>
<td>H, P</td>
<td></td>
</tr>
<tr>
<td>System: P</td>
<td>Objective: Reduction of GHG emissions</td>
<td></td>
</tr>
<tr>
<td>Aims to decarbonise the electricity grid by penalising the UK’s high-carbon power generation industry with carbon price support rates. With the development of hydrogen storage and its use to generate electricity, the government might decide in the future to apply the CPF to hydrogen (produced from fossil fuels). It should be determined how the deployment of CCS may alter the carbon price support rates.</td>
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**EU Emissions Trading System (ETS)**

Objective: Reduction of GHG emissions

Introduced earlier in Table 7.2.

**Industrial Emissions Directive (IED)**

Objective: Reduction of pollution / Reduction of GHG emissions

Introduced earlier in Table 7.2. Just one best available technique (BAT) for hydrogen production exists, relating to the chlor-alkali process, which emits mercury. Hydrogen production plants have to follow the IED (e.g. SMR, methanol cracking, coal and biomass gasification, etc.).
Table 7.5 Energy generation policies relevant to the role of H2FC for supporting other energy systems. (P: Power.)

<table>
<thead>
<tr>
<th>Capacity Mechanisms (CM)</th>
<th>System: P</th>
<th>Objective: Energy Security</th>
</tr>
</thead>
<tbody>
<tr>
<td>Provides a payment to electricity generators to ensure that enough capacity is available in moments of stress on the power system. This is necessary given the rising proportions of renewables on the grid and intermittency of their output. Hydrogen storage can respond quickly and for long periods of time and it is adequate for transmission and distribution deferral, arbitrage, inter-seasonal and seasonal storage applications. CM should consider hydrogen as a special case and exempt it from the obligation to provide unlimited capacity, as reservoirs have a finite volume.</td>
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<table>
<thead>
<tr>
<th>Contracts for Difference (CfD)</th>
<th>System: P</th>
<th>Objective: Affordability / Energy security / Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>A contract by which a generator is paid the difference between the ‘strike price’ (the production costs) and the ‘reference price’ (average market price). By doing so, investment risks are minimised and low carbon electricity projects can be deployed at lower cost. The use of electrolysers and reformers could contribute to deliver energy security and lower emissions as electricity could be produced from low carbon feedstocks (wind, biogas or biofuels); however, these projects are unlikely to succeed in the CfD auctions due to the fact that these technologies are not competitive.</td>
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</table>

<table>
<thead>
<tr>
<th>Feed-in-Tariffs (FiT)</th>
<th>System: P</th>
<th>Objective: Increase the share of renewables</th>
</tr>
</thead>
<tbody>
<tr>
<td>A support mechanism to promote the generation of small-scale renewable and low carbon electricity. Eligible installations get paid a regulated tariff rate by electricity suppliers (FiT licensees) for a number of years for the electricity that they generate and the one that they export back to the grid [19] in addition to the energy savings in their bills from their auto-generated electricity. Electricity generated from renewables (PV, wind, hydro, AD) and Micro CHP (≤ 2Kw and powered by fossil fuels) are eligible technologies. So far, just solid oxide fuel cells micro CHP running on natural gas would meet this criteria. An amendment to accept renewable hydrogen makes sense. The scheme has to control that FiT are not claimed twice when converting from electricity to hydrogen and vice versa.</td>
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</table>

<table>
<thead>
<tr>
<th>Renewable Obligations</th>
<th>System: P</th>
<th>Objective: Increase the share of renewables</th>
</tr>
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<tbody>
<tr>
<td>Obligated UK electricity suppliers to source a specific proportion of electricity from eligible renewable sources. Generators obtained Renewable Obligation Certificates to trade with suppliers that need to meet their Obligations, providing an additional revenue stream. The scheme closed for new generators on the 31st of March 2017 and was replaced by the Contracts for Difference scheme. Under the current RO, there is no scope for introducing renewable hydrogen.</td>
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</tbody>
</table>
7.2.3 Energy policies in transport

In the EU and the UK, Transport is responsible for around 23% of all GHG emissions [321, 323], 46% of NO\textsubscript{X}, 15% of PM\textsubscript{2.5} and 12% of NMVOC [322, 324]. As the final energy consumption by transport in 2015 was almost 40% of the total of the country [326], tackling energy efficiency in transport is critical to improve national energy security and air quality.

Hydrogen is recognised as one of the principal alternative fuels with a considerable potential for long-term oil substitution [327]. Many policies are in place to improve transport efficiency and reduce its carbon and air quality footprint (Table 7.6).

There are four main reasons to support the intake of H2FC in transport:

1. Several hydrogen pathways can yield low well-to-wheel GHG emissions [328];
2. FC powertrains are more efficient than internal combustion engines;
3. Tailpipe emissions are negligible,\textsuperscript{26} which supports the Government’s vision for almost every car and van to be an ultra-low emission vehicle by 2050 (and thus all new vehicles sold from 2040) [329];
4. The strong position of the UK’s research capabilities and automotive sector, and their potential to deliver economic growth and job creation.

A summary of the main transport energy policy instruments that can fund the procurement of FCEV appears in Table 7.7.

\textsuperscript{26} Although particle matter from tyre-road interaction remains an issue.
### Table 7.6 Transport energy policies relevant to H2FC. (T: Transport; H: Heating; P: Power.)

<table>
<thead>
<tr>
<th>Energy Savings Opportunity Scheme</th>
<th>System: H, P, T</th>
<th>Objective: Energy efficiency and reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introduced earlier in Table 7.3. Fuel cells and FCEV can be eligible if they are cost-efficient and they represent 90% of the total energy consumption of the large undertaking (e.g. of a logistics or commercial fleet).</td>
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<table>
<thead>
<tr>
<th>EU Emissions Trading System (ETS)</th>
<th>System: H, T</th>
<th>Objective: Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introduced earlier in Table 7.2. Aviation companies are given a carbon emissions allowance cap and the possibility to trade their surplus/deficit. Currently, these have no impact as there are no commercial H2FC powered planes yet.</td>
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<table>
<thead>
<tr>
<th>Rail electrification</th>
<th>System: T</th>
<th>Objective: Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network rail aims to electrify over half of the rail network by 2021 (75% of all traffic miles). This presents an opportunity to discontinue diesel locomotives and electrify segments of the rail network with fuel cell trains.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Renewable Transport Fuel Obligations (RTFO)</th>
<th>System: T</th>
<th>Objective: Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Encourages the supply of renewable fuels. Producers must render renewable transport fuel certificates (RTFCs) to prove that they have met their Obligations (currently around 6% annual by volume). Producers of renewables can get income from their RTFCs. A new RTFO consultation process proposes to include hydrogen as a ‘synthetic fuel from renewable electricity’. If successful, other renewable pathways will also be eligible (e.g. biomass gasification).</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Road emissions and vehicle emissions standards for heavy duty and light duty vehicles. Congestion charges and low emission zones.</th>
<th>System: T</th>
<th>Objective: Reduction of air pollution / GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Policies set the maximum carbon emissions for new vehicles and promote low carbon technologies. Carbon intensities per kilometre are used as proxies for energy efficiency. EU limits exist for cars but not yet for heavy duty vehicles as opportunities for engine improvement and substitution are more limited. As emissions are measured on a tank-to-wheel basis, FCEV benefit from this type of policies, as they produce zero emissions at the tail pipe. PEMFC FCEV will meet even the strictest future Emission Standards. Solid oxide fuel cell vehicles are also likely to meet vehicle efficiency targets when using biofuels (e.g. bioethanol). These vehicles are likely to emit under 75 gCO₂e/km and therefore they will be excluded from the congestion charge. Ultra-low emission zones are not a driver for the uptake of FC powered lorries, as this only affects old vehicles not compliant with Euro 5 and upwards.</td>
<td></td>
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</tr>
</tbody>
</table>
Table 7.7 Transport financing policies for hydrogen, FCEVs and infrastructure. (T: Transport; H: Heating.)

<table>
<thead>
<tr>
<th>Alternative Fuels Infrastructure Directive (AFID)</th>
<th>System: T</th>
<th>Objective: Energy security</th>
</tr>
</thead>
<tbody>
<tr>
<td>Directive 2014/94/EU aims at developing a market for alternative vehicle powertrains, fuel technologies and infrastructure. Measures include direct and tax incentives for the procurement of FC vehicles and the building of infrastructure, facilitating authorisation processes and preferential access to parking and lanes for H2FC vehicles.</td>
<td></td>
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</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Enhanced capital allowances (ECA)</th>
<th>System: T</th>
<th>Objective: Energy and water efficiency, reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introduced earlier in Table 7.3. The ECA scheme allows businesses to deduct the full cost of FCEV (zero emissions company cars and goods vehicles) and refuelling stations and equipment, from the profits of the company before tax.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FCEV Fleet Support scheme</th>
<th>System: T</th>
<th>Objective: Create a market/Information provision</th>
</tr>
</thead>
<tbody>
<tr>
<td>Funded by Office for Low Emission Vehicles to promote deployment of hydrogen refuelling infrastructure and uptake of FCEV and hydrogen hybrid and dual fuel powertrain vehicles (cars and heavy goods vehicles with dual fuel and range extenders) by providing grants for the purchase and maintenance of such fleets.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Local Sustainable Transport Fund</th>
<th>System: T</th>
<th>Objective: Economic growth / Reduction of GHG emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Provides funds to local authorities to deliver sustainable projects that support local development and cleaner environments. Could contribute to the development of local hydrogen supply chains by funding hydrogen refuelling infrastructure and the procurement of FC buses.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Refuelling infrastructure

Directive 2014/94/EU aims to develop a market for alternative vehicle powertrains, fuel technologies and infrastructure. Moving from oil towards alternative fuels will improve energy security and reduce the environmental impact of transportation [327]. Developing sufficient hydrogen infrastructure is considered as essential to increase the market share of hydrogen-powered vehicles, warranting market push. This Directive also encourages member states to deploy refuelling stations considering cross-border links to enable the circulation of the vehicles across the EU.
A range of policy measures is suggested:

- Direct incentives for purchasing hydrogen vehicles and building refuelling infrastructure;
- Tax incentives to promote these means of transport;
- Use of public procurement;
- Demand-side non-financial incentives, for example preferential access to restricted areas, parking policy and dedicated lanes;
- Technical and administrative procedures and legislation with regard to the authorisation of hydrogen supply, in order to facilitate the authorisation process.

### 7.3 A GREEN HYDROGEN STANDARD

The UK’s Fifth Carbon Budget recommends limiting the carbon intensity of the power grid to under 100 g/kWh by 2030 [315]. Any power generated from hydrogen and relevant technologies should meet this limit. There is currently no standard guaranteeing the environmental characteristics of a hydrogen source. However, numerous green hydrogen standardisation initiatives have been undertaken in recent years in several EU countries. This trend has not been observed in other countries, due to greater concern with the take-off of the technology than with the real benefits, as some see fossil fuels as unavoidable in the short-term.

Some of these initiatives define green hydrogen as being derived from renewable energy sources, while the definition intended by the UK Government is more focussed on the embedded carbon intensity. The latter allows hydrogen produced from nuclear power or fossil fuel with carbon capture to be considered as green. Table 7.8 compares technical characteristics of green hydrogen standardisation initiatives. The definitions of these initiatives exclude other broader environmental objectives (e.g. air quality targets and water footprints) and other enhanced sustainability criteria (e.g. impact on biodiversity), mainly because these are not included in other bioenergy standards and it would create standard for hydrogen that are more stringent than for other energy sources.

As with renewable certification for electricity, standards for hydrogen must trace the origins of a homogenous product (hydrogen molecules), so that ‘brown hydrogen’ produced from fossil fuels can be distinguished from a premium lower-carbon ‘green hydrogen’. This is a challenging task as illustrated in the range of initiatives put forward. Before member states include the standard in their policy frameworks, they will have to agree the carbon intensity thresholds, the eligible feedstocks, the boundaries of the system (point of production or at the point of use), and a range of other administrative characteristics related to the Guarantees of Origin (e.g. expiration and value of a guarantee). So far, one of the key strengths of hydrogen has been excluded from all the proposals. The reason is that unless air quality targets are included in the Renewable Energy Directive and apply to biofuels, the green hydrogen standard would be unnecessarily restrictive and discriminatory for hydrogen.
## Table 7.8 European Green Hydrogen standardisation initiatives.

<table>
<thead>
<tr>
<th>Initiative/Country Origin</th>
<th>Policy Objective</th>
<th>Baseline GHG threshold</th>
<th>Qualification level</th>
<th>Qualifying processes</th>
<th>Boundary of the system</th>
</tr>
</thead>
<tbody>
<tr>
<td>AFHYPAC (France)(^{27})</td>
<td>Renewable energy source</td>
<td>None</td>
<td>Must be 100% renewable</td>
<td>Renewable electrolysis; reforming of biomethane</td>
<td>Point of production</td>
</tr>
<tr>
<td>BEIS (UK)</td>
<td>Reduction of CO(_2) emissions</td>
<td>To be determined and revisable according to carbon budgets.</td>
<td>To be determined. A single threshold differentiated according to end use (e.g. transport)</td>
<td>Any (technology neutral)</td>
<td>Point of production</td>
</tr>
<tr>
<td>CERTIFHY (EU wide)</td>
<td>Renewable energy source/CO(_2) emissions</td>
<td>Hydrogen produced via SMR of natural gas</td>
<td>At least 60% lower than SMR(^{28}) (this is ≤ 36.4 gCO(_2)e/MJ H(_2) for the past 12 months)</td>
<td>Any renewable pathway as long as meet the qualification level. Purification quality 99.5%</td>
<td>Point of production</td>
</tr>
<tr>
<td>Clean Energy Partnership (Germany)</td>
<td>Renewable energy source/CO(_2) emissions</td>
<td>None for electrolytic hydrogen; H(_2) produced via SMR of natural gas for hydrogen produced from biomass</td>
<td>For biomass-based hydrogen, lower emissions than the baseline, level not specified</td>
<td>Renewable electrolysis; hydrogen from biomass produced in certified green thermochemical or biological conversion processes</td>
<td>Point of production</td>
</tr>
<tr>
<td>TÜV SÜD (Germany)</td>
<td>Greenhouse gas reduction potential</td>
<td>Hydrogen produced via SMR of natural gas or fossil fuels, depending on process</td>
<td>35–75% emissions reduction below baseline (which is 83.8–89.7 gCO(_2)e/MJ), depending on production process, and time phase</td>
<td>Renewable electrolysis; steam-reforming of biomethane; pyro-reforming of glycerine</td>
<td>Point of use</td>
</tr>
</tbody>
</table>

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\(^{27}\) L’Association Française pour l’Hydrogène et les Piles à Combustible.  
\(^{28}\) The baseline carbon intensity considered by CertifHy for SMR is 91 gCO\(_2\)e/MJ H\(_2\).
7.4 DISCUSSION

7.4.1 Buildings

The energy demand policy instruments that may influence H2FC in buildings (Table 7.1) do not mention these technologies explicitly. There is some room within current building regulations to interpret hydrogen as a mains gas and accept FC micro-CHP an eligible technology within the Energy Performance Buildings Directive, Private Rented Sector, Salix loans and RHI schemes. A key objective of these instruments is improving energy efficiency of buildings; an area in which FCs excel, as reported in Chapter 4. Another objective is increasing the share of renewables, making it important to create a green hydrogen standard. Without a clear certification, despite being more efficient, FC do not necessarily contribute to meet this objective. This distinction is also fundamental for including hydrogen in the domestic RHI.

UK policy making lags behind in this area compared to countries such as Japan, where the ENE-Farm program has subsidised the purchase of 181,000 residential micro-CHP FC systems, and targets 1.4 million by 2020 and 5.3 million by 2030 [330]. In the UK, the H21 Leeds City Gate feasibility study has explored converting the existing gas network to hydrogen [280]. In an interview, the gas distribution company acknowledged that a political mandate to switch from natural gas to hydrogen would be needed for the project to succeed, involving the conversion of domestic appliances. Such a mandate was used when the UK converted the town gas infrastructure to natural gas. There are, however, potential policy conflicts between the trend in heat electrification and the conversion of the gas network to hydrogen. Financing mechanisms would also be needed for roll-out of new appliances and the preparation of new safety standards and codes, and training for the engineers. Regarding energy security, generation could be more decentralised, it could incorporate greener hydrogen into the network over time, and it could take advantages of synergies between the power and heating systems thanks to power-to-gas technologies. Furthermore, if the final hydrogen quality is sufficient, the system could provide hydrogen for FC transportation modes as well.

7.4.2 Industry

Current policy instruments regarding energy demand in industry do not seem particularly effective at promoting demand for H2FC technologies; however, they could become a relevant financing source for projects of national interest via levies. EU Policies regarding large and industrial corporations (Table 7.2) target carbon and air quality emissions. The Industrial Emissions Directive defines ‘Best Available Techniques’ (BAT) that may lead to more efficient industrial processes and lower emissions. BATs do not reflect the progress made with H2FC technologies, which do not feature widely at present. Currently, the EU ETS allowances are too cheap and plentiful, and are not a relevant factor in promoting more efficient but also more expensive fuel cells. However, they can generate revenue for funding relevant projects such as CCS and hydrogen storage, but only with an order-of-magnitude higher carbon price. UK policy instruments that can play a similar financing role include the Climate Change Levy from the Climate Change Agreements and the Carbon Reduction Commitment. Perhaps the UK policy instrument that could have the major
The efficacy of other UK instruments related to industrial energy demand (Table 7.3) is less evident. For example, breaching the Climate Change Agreements carries a fee of £12/tCO$_2$e for those who wish to remain in the scheme. This means that hydrogen and its technologies are competitive only when their costs are inferior to the Climate Change Levy discount\(^{29}\) and the cost of avoiding carbon emissions (£12/tCO$_2$). Above these floor prices, the incentives are either to not participate in the scheme (foregoing the rebate) or simply pay the penalty to remain. The Energy Savings Opportunity Scheme can have little impact because it is difficult to deliver cost-effective solutions for H2FC technologies with current levels of demand. The RHI does not take into consideration the role that FC micro CHP could play to provide renewable heat in industry and while it accepts biomethane, no reference is made to hydrogen. Having a green hydrogen standard could help to accept this quality of hydrogen in the same conditions as biomethane.

### 7.4.3 Electricity

Most energy policy instruments in relation to hydrogen production aim at reducing GHG emissions (Table 7.4). The IED has defined one hydrogen production BAT in regards to the chlor-alkali process (electrolytic production) and other BATs deal with FC components (e.g. catalyst materials, ceramics, etc.). The growth of hydrogen consumption for energy generation purposes may result in the development of new BAT for other production methods (e.g. SMR, Gasification).

Policies dealing with CCS are relevant to the success of hydrogen in the medium term, particularly for countries phasing out nuclear power. Hydrogen produced with fossil fuels cannot exceed the carbon intensity limits established by the CCC (e.g. 100 g/kWh by 2030) if it is to assist with decarbonisation. This is unlikely to occur without CCS or significant expansion of renewables. Unfortunately, the UK Government cancelled its three-year long CCS commercialisation competition weeks before the deadline in 2015 [331]. This abrupt change in policy broke investor confidence, and without policy support (particularly around the areas of insurance and long-term contracting), the private sector is unlikely to fund such schemes.

CCS is restrictively expensive for carbon mitigation (various estimates around €60–150/tCO$_2$) [332–334] which compares to relatively low carbon prices of £18/tCO$_2$ [335] with the UK’s CPF and around £5/tCO$_2$ in Europe [336].

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\(^{29}\) £1.88/MWh for natural gas, £5.41 for electricity, £12.10 for liquefied petroleum gas and £14.76/MWh for others.
Hydrogen can play an important role in supporting the power grid via policy instruments that increase the use of renewables (Renewable Obligations, FiT) or provide energy security (CfD and capacity markets) (Table 7.5). Within the CfD, power generators could include hydrogen storage as part of their production costs. Long-term price stability would reduce investment risks and thus financing costs, supporting the deployment of this technology. This could be an interesting option for renewable generators as storing their surplus output as hydrogen could help them to decrease their production costs (e.g. wind, solar). Complex issues around double-counting of production must be resolved though. Micro-CHP is one area where FC technologies could be applicable for FiTs. Electricity generated from hydrogen that is produced from renewables is unlikely to claim a FiT because it cannot be claimed twice.

The capacity mechanism requires generators to provide power at times of system stress. Hydrogen can provide capacity from hours to a whole season, for applications such as transmission and delivery deferral, arbitrage and seasonal storage. Hydrogen could have an important role in providing energy security and reliability to the grid, but a policy change is needed to accommodate these technologies.

7.4.4 Transport

Transport energy policy instruments target a broad range of objectives (Table 7.6 and Table 7.7). The Renewable Transport Fuel Obligations (RTFO) is a key policy, aiming to increase the share of renewable fuels from biological origin. So far, bioethanol, biomethane and biodiesel are eligible for these certificates. With uptake of FCEVs, renewable hydrogen can support the increase of renewable fuels, and also contribute to improve local air quality. The Department for Transport is considering whether to increase the range of eligible fuels to renewable fuels of non-biological origin [337]. Hydrogen is one such fuel and this proposal opens the door to a broad range of pathways including electrolysis and methanol cracking. Any biological pathways should also be eligible provided they meet the sustainability criteria specified in the Renewable Energy Directive for biofuels. A successful proposal could have a significant positive effect on H2FC transportation by creating an incentive for hydrogen production. It is not clear how this could be managed without a Guarantees of Origin system, as suggested by green hydrogen standardisation initiatives.

Another important instrument for FCEVs is more stringent standards for energy efficiency and emissions. Competition in this regard will be between battery electric vehicles (BEVs) and FCEVs, rather than with fossil fuels. While BEVs are well suited for urban driving and city logistics of small lorries, FCEV strengths are longer range and power. This may result on FCEVs working in long-haul trucks, coaches and high-utilisation vehicles.

The UK aims at electrifying over half of the rail network by 2021 to replace diesel engines; however, there is not a clear roadmap explaining how this will be undertaken. Air quality is again an important driver, of special importance in urban areas, and so new class 66 diesel locomotives are no longer being delivered in the UK for failing to meet emission requirements [86].
The funding instruments for procuring FCEVs (Table 7.7) offer effective routes to increasing market share. The Local Sustainable Transport Fund could be used to deploy fleets of buses. Grants given by the Fleet Support scheme are enabling private companies to test commercial FCEVs and generate operational data to fill the remaining information gap for these novel technologies. This could prove influential in reassuring customers that the FCEVs are safe, mature and reliable. The Alternative Fuels Infrastructure Directive is a positive step; however, participation is voluntary and there are not specific targets for infrastructure. In contrast, Japan has very clear objectives for the number of FCEV cars (800,000 units by 2030), buses (over 100 by 2020) and refuelling stations (320 high pressure by 2025 and 100 low pressure) [330].

7.4.5 Innovation needs

Although H2FC technologies are being commercialised in many areas, challenges must still be overcome. Cost and efficiency can be improved across production, distribution and end-use technologies. Hydrogen distribution is energy intensive, so novel transportation vectors (e.g. as hydrides, encapsulated within other materials), and modes (e.g. shipping tankers) are areas of continuous research. Innovation in the area of hydrogen storage is needed (e.g. nano-materials), and further advances will be made once enough large storage facilities are demonstrated (e.g. salt domes, enhanced oil recovery).

Applications in transport are continuously being rolled-out (e.g. hydrogen trains, hybrid automotive powertrains, mobile refuelling stations, auxiliary power units). The synergies of hydrogen with energy systems (power, heat, transport) are an evolving research topic. New safety, codes and standards are still under development (e.g. a green hydrogen standard). H2FC supply chains require a new skills-base to research, develop and maintain these new technologies. To overcome the lack of technical skills, the KnowHy EU program is offering free training for technicians in the areas of FC for transport, handling equipment, micro CHP and auxiliary power units [338].

Research funding combines private and public sources (e.g. EU Horizon 2020, Innovate UK, Research Councils). In the UK, most of the budget from innovation policy goes to Higher Education; however, policy also stresses the relevance of local strategies for economic development. Many Local Enterprise Partnerships in England recognise innovation as a driver for their economic growth plans and have designed strategies to access EU funding [339]. The impact of Britain leaving the European Union on innovation is still unknown, as it is not clear whether the UK will be able to negotiate its participation in the Horizon 2020 program or if it will match the funds with a new national plan.

Hydrogen powertrains are an area of interest in the national industrial strategy as they could increase the exporting potential of the UK automotive sector. The UK is home to manufacturers of FCEVs (Microcab Industries, Riverside, Wright En-Drive), hybrid powertrains (ULEMCO) and electrolysers (ITM Power), plus global technology developers (Johnson Matthey) and numerous world-class universities active in H2FC research. With the right support, the UK is in a strong position to take a global leading position in the H2FC industry.
7.5 HYDROGEN POLICY IN THE GLOBAL CONTEXT

H2FC policies around the world are very contextual to the specific characteristics of each country, such as industrial capabilities and access to feedstocks, economic situation and the relative strength of different policy objectives (public health, air quality, climate change, energy security and affordability). The most proactive countries, members of the IPHE (International Partnership for Hydrogen and Fuel Cells in the Economy), have developed strategic roadmaps where hydrogen plays a significant future in the energy mix by 2050. This section presents the policies of some of those countries.

7.5.1 China

Currently there are few hydrogen refuelling stations (HRS) in China [344]; however, important policy initiatives were introduced in 2016. The National Development Reform Commission and China’s National Energy Administration released ‘Energy Technology Revolution & Innovation Initiative (2016–2030)’ and the ‘Energy Technology Innovation Oriented Roadmap’ [344]. The objective of these programs is encouraging the uptake of H2FC technologies by 2025 and popularising them by 2050 [345].

China is interested in developing FCEV manufacturing capabilities within its “China Manufacturing 2025” program and is establishing the “New Energy Vehicle Technology Innovation and Demonstration Fund” to this end. Furthermore, in the period 2016-2020 the Ministry of Finance is offering subsidies of £23,000 for FC cars, £58,000 for light duty buses and vans, and £35,000 for fuel cell heavy duty buses and trucks [345]. Subsidies of £465,000 are also available for new HRS with a capacity of 200 kg H2 or more [345].

In the period 2016-2020, the Chinese Government is providing £90m of funding for H2FC and FCEV R&D and demonstration projects, and £20m for ‘New energy vehicles’ pilot projects, where two of these feature FCEVs [345]. Several cities have set plans for procuring FC buses to alleviate air quality issues (e.g. 100 in Beijing, 300 in Yunfu). China has adapted policy instruments to promote FCEV and refuelling infrastructure. Unlike petrol cars, FCEVs are exempt from the lottery to obtain license plates (so consumers avoid the quotas placed on conventional vehicle registrations), and FCEVs can access high speed lanes [344].

Despite the low penetration of H2FC technologies in China, there is a clear industrial strategy combining public and private investments to transform the country in a global leader of FCEVs. FC and vehicle manufacturers are establishing joint ventures and partnerships with local companies to ramp up the manufacturing capabilities of the country; however, the lack of targets for national technology deployment suggest that China is interested in using these technologies in the short to medium term for economic growth and exports.

30 Currency converted using £0.12 = ¥1 Original values are 200,000, 500,000, and 300,000 RMB respectively.
31 Original value: 4,000,000 RMB.
7.5.2 Germany

Germany is a strong participant in European research and development programs such as Horizon 2020. The ‘Ministry of Transport and Digital Infrastructure’ (BMVI) contributed €500 million from 2007–2016 to the ‘Innovation Programme for Hydrogen and Fuel Cell Technology’. This project has been extended up to 2026 (known as NIP2); and BMVI will fund over €80 million per year from 2018 onwards [346], with the ‘Ministry for Economical Affairs and Energy’ providing a further €25 million per year [347]. The project’s objectives are to activate the market, develop demonstration programs and invest in R&D of H2FC technologies applied at the transportation sector [346]. BMVI has also allocated €7.9 million for deploying 200 FC trains in non-electrified routes over the next 10 years [348].

Germany provides strong subsidies and penetration targets to push efficient and renewable heating systems. The ‘Federal Office for Economic Affairs and Export Control’ (BAFA) provides a basic subsidy of €1,900 for fuel cell micro-CHP systems up to 20 kW, which increases to €3,515 once additional heat and power bonuses are considered [349]. In 2016 Germany introduced the kW (Creditbank for Reconstruction) program 433 that provides an upfront subsidy for fuel cells (0.25–5 kW), with a budget of €500 million for the period 2016-2024, and the aim of installing 60-70,000 domestic units per year [350]. The program grants a basic subsidy of €5,700 per unit plus €450 for each 0.1 kW, meaning a 1 kW fuel cell receives €10,200 in subsidy [349].

The KWK law is a subsidy similar to the UK’s feed-in tariff that gives financial support via annual payments for generated (€0.04/kWh) and exported power (€0.08/kWh) to the grid from heating systems (CHP) up to 50 kW. According to Rosner and Appel [349] this makes FC devices in a typical German family household (4 people) almost 30% cheaper than incumbent condensing gas boilers. This scheme benefits local industry, as three of the four major fuel cell micro CHP manufacturers are German (Bosch, Vailant and Viessmann). Germany is also the largest participant in the FCH JU ‘PACE’ project, which will deploy over 2,500 units by 2018 via a grant of €34 million. The intended objective is to generate economies of scale and reducing costs [351].

Rosner and Appel [349] identify subsidies, lobbying and technology reliability as the main success factors for the market penetration of H2FC technologies into the German market. German policies are closely related to EU policy, with decarbonisation as a main objective. To meet with the new EU Alternative Refuelling Directive and with the support of EU funding, Germany emphasises the need to deploy sufficient HRS infrastructure. It is considered that 400 HRS are required for critical mass, whereas there are currently 23 HRS in Germany [344]. As a result, via the H2Mobility/Germany joint venture, €350 million will be invested to deploy HRS nationwide by 2023, regardless of the demand for hydrogen [352].

7.5.3 Japan

Japanese policy focuses on energy security (25% self-sufficiency by 2030), economic efficiency (reducing electricity costs using nuclear and coal power generation) and reducing GHG emissions in line with the EU and US [353].
There is a national commitment to achieving a hydrogen society by 2050. Japan has a clear roadmap for H2FC technologies, and expects to spend £7 bn by 2030 and £57 bn by 2050 [345]. Near-term policies aim to increase the penetration of these technologies and investment in R&D. Japan understands that cost reductions are critical for the commercial success of H2FC, and these are more likely to be attained through economies of scale and faster learning rates [354].

The strategic roadmap of H2FC in Japan follows three stages [355]:

1. Around 2020, expand the usage of fuel cells (household and vehicles) to improve energy efficiency and acquire a new global market;
2. Around 2030, develop a hydrogen supply chain using unconventional energy imports (e.g. Australian brown coal) and improve energy security via hydrogen power generation; and
3. Around 2040, establish a CO2-free hydrogen supply system using renewables and other technologies.

The first stage aims to increase the use of stationary fuel cells for residential, commercial and industrial cogeneration; and the stock of FCEVs and refuelling infrastructure. Carbon emissions may not fall during this phase, or could even increase, as hydrogen is produced from natural gas via SMR.

The Ministry of Economy, Trade and Industry’s (METI) latest strategic roadmap includes new targets for 40,000 FCEVs by 2020, 200,000 by 2025 and 800,000 by 2030, compared to just 909 vehicles currently deployed. Uptake will be promoted through subsidies. METI aim to deploy 160 refuelling stations by 2020 and 320 by subsidising capital and operational expenditure from central and local governments [330].

The ENE-FARM scheme provided subsidies of £500–1,000 for PEMFC residential micro-CHP systems costing under £10,100; and £600–1,300 for SOFC systems costing under £12,000. A secondary policy aim for promoting stationary fuel cells is contributing to ensure energy security by providing power backup when earthquakes occur. METI expects that the number of small stationary FC will increase to 1.4 million by 2020 and 5.3 million by 2030 via procurement subsidies [330].

The second stage (late 2020s), envisages hydrogen supply chains being fully developed and hydrogen becoming a fuel for power production. Some initiatives suggest that hydrogen from brown coal gasification could be imported from Australia, decoupling hydrogen supply from instabilities in global oil and gas markets, but with a sizeable carbon footprint.

In the last phase (late 2040s), a green hydrogen standard or similar will be implemented where the focus will shift towards the use of renewable hydrogen or low carbon hydrogen. By then, hydrogen pipelines will be installed in selected locations...
and the market is expected to be self-sustained as economies of scale will not require further government support [354].

The Japanese Government has sent clear, consistent signals to the market, which has allowed the birth of a robust H2FC industry, where almost 200,000 stationary CHP FC devices have been sold, two of the only three FCEV manufacturers are Japanese, and export potentials are beginning to materialise. The Government clearly supports the industry and it will procure FCEV for the public sector. This approach is similar to the one applied by the USA.

**7.5.4 USA**

The USA has been very active in H2FC policy making. Congress allocated for 2017 a budget of $105.5 million for H2FC R&D, system analysis, technology validation, safety, codes and standards, market transformation and technology acceleration [357]. In contrast, the British Parliament does not have an explicit budget beyond Research Council funding that can support H2FC research.

America’s main incentives include grants for eligible projects’ costs, tax incentives, direct loans, loan guarantees and leases, rebates for the purchase of hydrogen vehicles and fuel, access to high-occupancy vehicle lanes and other requirements to disseminate rules and promote research groups and committees. At the Federal level there are eight main incentives, while at State level there a further 262 incentives; making a complex landscape for organisations to navigate. Similarly, there are eight funded programs that promote the uptake of H2FC technologies.34

While all of these programs focus on improving air quality standards, some have secondary objectives. The ‘Clean Cities’ program also targets ‘energy, economic, and environmental security’ and the ‘State Energy’ program aims to implement renewable energy and energy efficiency programs. Seven of the eight programs focus on actions to reduce emissions from road and off-road vehicles [358].

Regulations focus on vehicle acquisition, fuel use, registration and licensing, fuel taxes, fuel production or quality, renewable fuel standards or mandates, air quality emissions, climate change and energy initiatives [359]. Public procurement initiatives are a key for promoting FCEV uptake. Five federal laws promote vehicle acquisition by state government and federal agencies by setting percentage targets for public fleets. For example, the Energy Policy Act (2008) requires 75% of new light duty federal vehicles must be run on alternative fuels. Executive Order 13693 (2015) also requires federal agencies to reduce fleet-wide GHG emissions 30% between 2014 and 2025, and sets targets for new vehicle acquisitions: 20% zero-emission and plug-in hybrid after 2020 and 50% after 2025. The ‘Procurement Preference for Electric and Hybrid Electric Vehicles’ legislation requires the US Department of Defence to create new regulations for its vehicle fleet (excluding tactical combat

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34 These are (1) Air Pollution Control Program, (2) Congestion Mitigation and Air Quality (CMAQ) Improvement Program, (3) Clean Cities, (4) State Energy Program (SEP) Funding, (5) Clean Construction USA, (6) Clean Ports USA, (7) Voluntary Airport Low Emission (VALE) Program, and (8) Clean Agriculture USA.
vehicles). Several USA states have set up a joint target of 3.3 million ZEVs by 2025, which includes FCEV [344].

There are some American success stories, such as the penetration of FCEV in California where there are 23 HRS with a further 100 expected by 2023 thanks to the $100 million pledged by the state Government. At Federal level, this infrastructure benefits from a tax credit of 30% of the cost up to $30,000 [344]. However, despite many years implementing H2FC demonstration and research programs, the uptake of such technologies by private customers nationwide is rather low. This could be explained by the fact that following the vast and diverse range of relevant regulations requires an extraordinary effort and there is a lack of policy consistency across the states.

7.6 CONCLUSIONS

NREL [340] identified 30 years ago that hydrogen would be “a critical and indispensable element of a decarbonised, sustainable energy system”. They also recognised that hydrogen would “be derived from renewable energy sources, although fossil fuels [could] serve as a transitional resource”, and stressed the importance of hydrogen to provide energy security, cost-effective and non-polluting energy. Similarly, by 2003 the EU recognised the important contribution of H2FC technologies to meet energy security and climate change concerns [341]. These premises are just as valid today and growing in importance, yet these technologies are overlooked in most policy instruments.

H2FC energy policy is active in Europe, the US, Japan and China. Countries recognise the long-term potential of promoting H2FC technologies to deliver objectives related to air quality, climate change, energy security, affordability and economic growth. In the US, policy is driven mainly by the need to improve air quality and relates to transport. China also has serious air quality issues; however, the main objective is developing automotive manufacturing capabilities to deliver economic growth. In Japan, hydrogen is promoted to deliver energy security, while across Europe the main driver is reducing carbon emissions. Japan and Germany have clear roadmaps for the uptake of stationary and transport H2FC systems and use subsidies to progress towards these. In contrast, the UK does not have a defined roadmap with clear targets, and there are no explicit subsidies for hydrogen and fuel cells at national level. Policy lessons from other countries suggest that strong, consistent support for H2FC technologies can deliver large and rapidly-growing markets. By achieving critical mass, economies of scale can reduce costs, making H2FC technologies competitive against other options, removing the need for future subsidies.

The main UK energy policy drivers for H2FC technologies are related to mitigating environmental emissions, improving energy efficiency, energy security and delivering economic growth. A secondary objective in some policies to increasing renewable energy content, which neglects pathways that are equally able to meet the above aims (e.g. GHG reduction and air quality), but are not renewable. The UK Government defends a technology neutral approach in policy making; however, many of the policy
instruments reviewed implicitly exclude H2FC technologies. A broader interpretation of these policies could accept hydrogen as a ‘mains gas’, or fuel cell micro-CHP as a form of CHP. Developing a green hydrogen standard will help to facilitate its recognition in reducing carbon emissions or increasing renewable energy shares.

High capital costs are one of the main weaknesses of H2FC technologies due to low economies of scale. Operating costs can also be higher, and the lack of refuelling infrastructure is a key constraint for uptake of fuel cell vehicles. Countries such as Germany understand this and are investing significantly to provide the early-stage infrastructure needed to drive FCEV sales and make the deployment of further infrastructure profitable. As has been seen with other technologies, notably solar photovoltaics, national governments can play a crucial role in stimulating uptake leading to manufacturing scale-up and competition between private firms, which leads to dramatic cost reductions. The cost of fuel cell vehicle powertrains is expected to converge with that of battery electric vehicles within 10–20 years, and the cost of stationary fuel cells is falling at a comparable rate to wind and solar power. The potential for cost parity with incumbent technologies exists, if market growth can be fostered. Demonstration projects that will enable learning-by-doing to decrease prices in the long run are necessary at the early stages for hydrogen, as with other technologies.

Hydrogen is a very flexible carrier that can be integrated in the power grid but also in heating networks, through gas-to-power, gas-to-gas and power-to-gas technologies. Due to its contributions to energy security and stabilising highly-renewable electricity systems, policy makers should consider the potential of hydrogen when defining policy instruments aiming at improving the capacity and reliability of the energy systems.

Evidence suggests that despite limited policy intervention, H2FC technologies are reaching a commercial stage and are competitive in several niche applications. However, stronger policy signals can yield substantial benefits, as shown in the number of home heating systems and vehicles deployed in Japan, and the strength of Japanese manufacturers. With the right policy support, the UK is in a strong position to claim a leading role in the H2FC industry through a commitment to innovation and manufacturing capabilities.
8.1 HYDROGEN AND FUEL CELLS ARE REACHING MATURITY

The UK must revolutionise its energy system to meet its commitment to reduce greenhouse gas emissions. Hydrogen and particularly fuel cell technologies have long been touted as revolutionary, but are now reaching maturity in many markets. They are clean, versatile options that can contribute to decarbonisation across the energy system, and to wider environmental goals such as minimising air pollution, while having minimal impact on the consumer experience. Hydrogen’s unique selling point is offering a low-carbon, business-as-usual approach for consumers that alternative low-carbon technologies cannot currently match.

The six scenarios examined in Chapter 2 show that the long-term penetration of H2FC technologies could vary from a few small niches to providing virtually all road transport and heat energy service demands, across the economy, as well as supporting a low-carbon electricity system. Small, strategic investments could be made to encourage hydrogen technologies to develop alongside other low-carbon options. These could reap significant rewards for society by improving energy security through diversification and expanding consumer choice.

8.1.1 Transport

Transport has long been the most promising market for hydrogen and fuel cells. Fuel cell forklift trucks are already taking sizeable market share in US warehouses, where they offer longer lifetime and faster refuelling than battery forklifts. FCEVs are now available commercially from major manufacturers, with hydrogen cars and buses beginning to see significant uptake. As Chapter 3 explains, FCEVs offer considerably faster recharging times and longer ranges than battery electric vehicles, and more efficient drivetrains, lower maintenance costs, quieter and smoother driving than internal combustion engines (ICEs). Initial models are meeting vehicle reliability and longevity targets.

The cost of hydrogen FCEVs has been greatly reduced and several recent studies have concluded that total cost of ownership will converge with alternative options in the medium term as production volumes rise. This depends on relative innovation successes for hydrogen and electric technologies, as the cost differences are small and the uncertainties are large. Cost-competitiveness could be achieved earlier in smaller production volumes in sectors including buses and lorries, although slow turnover in some sectors could hamper this. The lower running costs of FCEVs mean they can achieve more favourable economics than ICEs in high-utilisation sectors such as taxis, buses and lorries, particularly those able to refuel from a small number of central depots. This also makes FCEVs a candidate to be a successful operator in a car-sharing economy, where the utilisation of BEVs are constrained by their need for frequent, time-consuming recharging.

It is possible that the first commercial FCEVs will be driving on UK roads in the next 5 years, if the minimum necessary refuelling infrastructure can be constructed. Environmental challenges such as air quality in London and other major cities should provide a spur for such zero-emission vehicles. This could particularly accelerate
adoption for urban transport vehicles including cars, buses, lorries and taxis, but also for vehicles in and around airports and seaports. Fuel cells also have applications outside of road transport. For example, fuel cell trains are starting to be deployed (e.g. in Germany) to avoid the substantial cost of electrifying existing tracks.

Heavy goods vehicles (HGVs) and buses are arguably the most promising market for FCEVs in the longer term, as it is hard to conceive batteries providing the required energy density. The Critical Path scenario in Chapter 2 identifies these as strategically important sectors, and suggests that hydrogen will become the lowest-cost option for HGVs.

8.1.2 Heat

Heat has acquired a hard-to-decarbonise reputation compared to other sectors such as electricity and transport, with modest emission reduction projections of only 20% by 2030 (less than half of the whole-economy target). The key challenge identified in Chapter 4 for the UK is to decarbonise natural gas heating while providing an equivalent and affordable service for consumers and businesses. Current gas-based heating systems are popular for a number of reasons, including low fuel cost, high efficiency, low upfront cost, long lifetime, high power output, fast response, compact physical footprint, lack of hot water storage requirements, low noise, maturity, established supply chains and servicing industries. Hydrogen boilers are a modified version of gas boilers and share many of these positive characteristics, in contrast to alternative low-carbon technologies.

CHP systems are an alternative to boilers that can generate electricity at peak demand times. Hydrogen could be utilised to supply heat for heat networks or in micro-CHP systems in houses. Micro-CHP fuel cells have already been commercialised in several countries, particularly in Japan, South Korea and more recently Germany. The principal technical challenges are to continue reducing capital costs and to create a system to supply affordable, low-cost hydrogen.

Using hydrogen to decarbonise heat through repurposing the existing gas distribution networks has recently received much attention in the UK. The scenario modelling in Chapter 2 shows that hydrogen would be likely to displace natural gas boilers in 2050 rather than electrical technologies such as heat pumps. The complete conversion programme that is examined in the H21 Leeds study is more expensive than electrical and natural gas alternatives, although it is likely that the full costs of deploying heat pumps (e.g. the need for additional home insulation and electricity grid reinforcement) are not fully accounted for in the model assumptions. An alternative to the H21 approach that is more in line with UK energy policy would be to convert the gas networks to supply hydrogen and to allow households free choice from a wide range of hydrogen and alternative technologies. This leads to a substantially cheaper uptake of a combination of heat pumps, district heat and hydrogen-fuelled technologies. Fuel cell micro-CHP and hybrid heat pumps are deployed in preference to hydrogen boilers for their efficiency and ability to support the electricity system, and such synergistic options are strong candidates for further research.
8.1.3 Industry
Hydrogen could be used to decarbonise many industrial low-temperature heat and CHP processes, with the principal challenge being to supply sufficiently low-cost and low-carbon hydrogen. For example, hydrogen could be piped to large industrial boilers that currently use natural gas, which are too small and isolated to make carbon capture economical. Hydrogen could also be introduced into several high-temperature industries including steel and cement, although this is less certain at this stage. Industry requires cost-effective and reliable systems, and long plant lifetime leads to a low turnover of heating systems.

8.1.4 Electricity
Power-to-gas systems have been tested across the world, although the UK has only funded desk studies to date. One of the leading electrolyser companies, ITM Power, is headquartered in Sheffield but has most of its power-to-gas business in Germany. The early performance and reliability performance of these technologies is very promising.

Fuel cells have been used for CHP commercially for decades and are now being widely deployed for residential micro-CHP. These fuel cells currently run on natural gas, with a built-in reformer producing hydrogen, providing electricity with a carbon intensity that is around half that of a modern combined-cycle gas turbine, but comparable to that of the UK after significant progress in decarbonising the power sector. A low-carbon fuel source is required for these fuel cells to continue offering carbon reductions in the longer-term.

8.2 SUPPORTING LOW-CARBON ELECTRICITY
Hydrogen and fuel cell technologies are often perceived to be competitors to high-efficiency electrical appliances for heat provision and transport. Yet they can support the operation of a low-carbon electricity system, and would be particularly valuable in a system such as the UK’s, which is increasingly composed of inflexible and uncontrollable generation such as nuclear and renewables, with limited recourse for storage and interconnection.

Electricity demand in the UK currently has a marked intraday variation, which is met using peak power plants that have low capital but high fuel costs (typically natural gas and old coal power stations), together with pumped hydro. This kind of flexible, controllable generation cannot be decarbonised using renewables or nuclear, but could be with hydrogen as a fuel for gas turbines. If the electrification of heat were to significantly increase peak winter demand (as has happened strongly in France), then hydrogen could offer a cost-effective option for bulk storage on seasonal timescales, and residential fuel cell micro-CHP could provide a counter-balance of extra generating capacity at times of heating need.

Adding more intermittent and uncontrolled generation to national electricity systems is likely to pose increasing problems for stability and affordability. Distributed generation which operates at peak times (such as micro-CHP on winter evenings), and
devices that avoid electricity consumption at peak times such as hybrid heat pumps, can negate the need for additional investment in peak generation plant. At the same time, flexible energy conversion methods (such as power-to-gas) can avoid the need to curtail renewable electricity at times of insufficient demand. Power-to-gas also adds additional flexibility into the energy system, allowing electricity to be converted into fuels for heating, transport, chemical feedstocks, or back into electricity at a later time. A combination of these technologies offers a potentially cheaper alternative to conventional electricity storage. Strategically investing in new capacity that is both flexible and low carbon, such as fuel cells and power-to-gas, could help achieve the goals of high security and low emissions.

8.3 COMPRESSION AND PURITY CHALLENGES

Chapter 6 identifies hydrogen compression and purity requirements as key challenges that are often overlooked. Hydrogen is typically stored in vehicle tanks at 700 bar to achieve acceptable driving ranges. This is considerably above the hydrogen pressures currently used in industry and requires new technologies and components. Pressurised hydrogen production (around 20 bar) could reduce downstream compression requirements, but compression could still consume around 10% of the energy content of the fuel. Compressor technologies are currently expensive and unreliable; while alternative technologies have been proposed, they are at early stages of development.

Hydrogen for fuel cells in transport applications also needs to have very high purity. The threshold could be as high as 99.9999% to help reduce the capital cost of fuel cell electric vehicles (FCEVs) and increase longevity, both of which would likely accelerate their rollout. Purification to these levels increases the cost of fuel, but would be partially offset by lower vehicle maintenance costs. Electrolysis can produce hydrogen at this purity, following the removal of water. However, hydrogen from steam methane reforming (SMR) and other sources requires considerable cleaning to reach these levels. Pressure swing absorption (PSA) can achieve the required purity with careful design, but reduces the hydrogen yield by 10–20%. A further challenge is to design equipment to rapidly measure fuel trace impurities to verify purity levels.

8.4 DEVELOPING HYDROGEN INFRASTRUCTURE

For hydrogen to be adopted, an affordable, low-carbon supply must eventually be delivered to end-users. Hydrogen is relatively difficult to handle compared to fossil fuels so the costs of installing and operating hydrogen distribution infrastructure are appreciable.

Hydrogen can be produced from a wide range of fuels. Producing hydrogen from excess renewable generation, through power-to-gas, could be particularly cost-effective for geographically-remote refuelling stations. However, even in the most optimistic scenario in Chapter 2, this alone cannot meet substantive national demand, and other sources of hydrogen are needed.
Chapter 2 shows that the transition to hydrogen could be transport-led or heat-led, taking a decentralised or centralised approach. Understanding and managing the risk of uncertain future demand for hydrogen is a key challenge when planning major infrastructure deployments. It is not clear who should be responsible for driving a transition, and how such financial risks should be apportioned, but it would likely involve several levels of government and some combination of private companies and institutions. Given the diverse nature of the transition options, a clear long-term strategy will likely be critical to minimising the costs of introducing H2FC technologies.

### 8.4.1 Transport-led transition

There are several potential distribution pathways for hydrogen in transport. Early-stage options should ideally have low capital outlay to minimise investor risk whilst demand is being established, even if this raises the levelised cost per kg of fuel. Hydrogen can be distributed as a compressed gas via tube trailer, or it could be produced on-site by electrolysis, particularly for refuelling stations a long way from hydrogen production facilities.

In the longer term, hydrogen pipelines would be more cost-effective for distributing large quantities of hydrogen to refuelling stations, once a stable long-term demand for hydrogen is established. A large onsite compressor would be needed to deliver the required pressures, along with onsite storage tanks.

Liquefaction is another option for increasing the energy density of hydrogen for vehicles. Liquefied hydrogen would be distributed using road tankers, with lower upfront costs than using pipelines. However, high liquefaction costs and high boil-off rates could limit its long-term usage to a few heavy-duty sectors, and for transporting smaller quantities of hydrogen over long distances.

There are a number of alternative chemical carriers currently under investigation that do not require the high pressures of compressed hydrogen gas or the very low temperatures of liquefied hydrogen. These include solid carriers such as metal hydrides, liquid organic hydrogen carriers or synthetic fuels like ethanol, synthetic natural gas and ammonia. These are at early stages of development and warrant further investigation.

The lack of hydrogen refuelling infrastructure is a barrier to fuel cell vehicle uptake. This is being addressed through a series of public-private stakeholder initiatives that are committed to rolling out initial hydrogen infrastructure. The UK requires a minimum of 60 refuelling stations to kick-start its transition. Hydrogen production at urban depots, for captive fleets of buses or HGVs, could potentially contribute to this target.
Challenges for hydrogen refuelling stations include space requirements and new safety regulations. The lower density of compressed and liquefied hydrogen means that larger tanks are required than at present, which must be separated further apart to satisfy safety requirements. Additional equipment like onsite generation, compression and/or tube trailer storage could also take up considerable space.

### 8.4.2 Heat-led transition

A heat-led transition would require an early decision from the Government to convert the gas distribution networks to deliver hydrogen instead of natural gas. Hydrogen production plants could initially be located on high-pressure pipes on the outskirts of cities until national hydrogen demand was sufficiently high to justify building a transmission network to link the various regional networks. If there were uncertainty over demand growth, a prudent strategy might be to construct a national transmission network earlier to better cope with fluctuating demands for hydrogen in different regions, and to reduce the required number of hydrogen production plants. Further work is required to understand the optimal hydrogen policy for such a scenario, and to understand the minimum take-up of hydrogen that would be necessary to justify converting the gas networks.

The large, early demand for hydrogen for heating and the development of regional hydrogen infrastructure would enable many early hydrogen refuelling stations to be located beside high-pressure distribution pipes, supplying substantially cheaper hydrogen for the automotive sector. One concern is that much of the existing natural gas distribution network operates at very low pressures which, if converted to transport hydrogen, could result in prohibitive energy requirements for compression if hydrogen was extracted from this network for vehicle refuelling. Existing distribution pipelines may also be too small to provide enough gas for refuelling. Hence it is likely that the existing low-pressure gas network could not be economically used for vehicle refuelling and that dedicated pipelines at higher pressures (~20 bar) would be installed to feed urban refuelling stations and depots.

### 8.5 POLICY APPROACHES TO HYDROGEN AND FUEL CELLS

The principal UK energy policy drivers are to reduce greenhouse gas emissions, improve energy efficiency and energy security, and deliver economic growth through affordable energy and job creation. Other environmental impacts, such as emissions that affect air quality, are likely to become increasingly important. A secondary objective in some policies is related to increasing the share of renewables in the energy system, as these are considered low-emission and sustainable in the long-term, and because the UK has agreed a minimum target for renewables by 2020 as part of a pan-EU target.

Research on public attitudes to hydrogen has primarily considered hydrogen safety [45]. The additional cost that consumers would be willing to pay for a low-carbon energy service than enables them to continue current practices, compared to one that requires them to change their behaviour, is less well understood. It does however seem unlikely that many consumers would be willing to pay the very high cost of
electrification that Chapter 2 shows would result from decarbonising primarily with renewable electricity to minimise fossil fuel consumption. Hydrogen and fuel cells contribute towards various government aims and align well with consumer preferences, but policies must be adapted to enable hydrogen and fuel cells to make a large-scale contribution to a future low-carbon energy system.

8.5.1 Regulatory impediments
The UK Government follows a technology-neutral approach to policymaking. In reality, regulations tend to be developed around incumbent technologies, and these can be barriers that prevent competition from other technologies in a market. Chapter 7 concludes that H2FC technologies are not implicitly included in many of the existing policy instruments that have restricted lists of eligible technologies. This exclusivity limits support for hydrogen and fuel cells compared to renewable generation, electric powertrains and natural gas heating. One option would be to broaden the interpretation of these policies to include hydrogen and fuel cells, where appropriate, for example by classifying hydrogen as a ‘mains gas’ or by creating a classification that includes fuel cell micro-CHP for heating.

8.5.2 Development of a green hydrogen standard
Since hydrogen can be produced from high-carbon and low-carbon processes, a certification scheme would be required to demonstrate that supplied hydrogen was sufficiently low-carbon to be included in policy instruments. Several “Green Hydrogen” standard certification schemes are under development across the EU, which could be harmonised. The UK Government has had a working group on Green Hydrogen in the past; reviving this at some point in the future would underpin the use of hydrogen for transport or heat applications.

These standards tend to classify hydrogen as low-carbon, from renewable sources, or both. The UK therefore has an opportunity to develop a standard that is tailored to its specific policy objectives, focusing on carbon intensity or promoting renewable feedstocks.

8.5.3 Hydrogen infrastructure provision
Several hydrogen refuelling stations are already operating in the UK, including some with on-site electrolysers. Any large-scale infrastructure would likely require government backing and forward planning to strengthen investor confidence and overcome regulatory and other constraints. Transmission pipelines and distribution networks are natural monopolies and would need to be regulated in a similar way to the existing gas networks.

The early stages of a decentralised transport-led transition might be achieved with limited Government intervention; however, a heat-led transition would likely require a joint initiative from Government and industry to overcome risk barriers. The longer-term success of a transport-led transition would also be more likely if it were underpinned by Government support.
8.5.4 Incentives for hydrogen to contribute to the electricity system

The electricity markets are designed around existing generation technologies. New markets can be created on an ad hoc basis as a need arises; for example, a capacity market has recently commenced in response to the loss of capacity and tightening reserve margins in recent years. Hydrogen could support the integration of renewables into a stable and resilient system, both through zero-carbon peak generation at times of high demand and through power-to-gas at times of excess supply, but it is not clear that existing market structures would enable profitable private-sector investments in these technologies. Given the way that electricity markets are currently structured, there is little incentive for producers, transmission or delivery companies to fund such projects on their own, even if the value they add to the system exceeds their costs. Small-scale demonstration projects would facilitate cost reductions and help to identify how these technologies could be integrated into existing market structures, or how existing market structures could be amended.

8.5.5 Does policy intervention work?

Evidence suggests that policy intervention in other countries has enabled fuel cell technologies to reach commercialisation and become competitive in some niche applications. Stable and consistent policy signals in countries such as Japan, when well-formulated, have successfully underpinned the initial deployment of fuel cells, greatly reduced the capital costs and created a new export industry. Several UK-owned and UK-based firms are international leaders in hydrogen and fuel cell technologies, and the country possesses a strong scientific research base in these areas. The sector also includes globally-established component suppliers and innovative new entrants developing novel technologies and components. With an industrial strategy that provides the right policy support, the UK could also be in a strong position to claim a leading role in the nascent hydrogen and fuel cell industry.
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