Review

Hydrogen and fuel cell technologies for heating: A review

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ABSTRACT

The debate on low-carbon heat in Europe has become focused on a narrow range of technological options and has largely neglected hydrogen and fuel cell technologies, despite these receiving strong support towards commercialisation in Asia. This review examines the potential benefits of these technologies across different markets, particularly the current state of development and performance of fuel cell micro-CHP. Fuel cells offer some important benefits over other low-carbon heating technologies, and steady cost reductions through innovation are bringing fuel cells close to commercialisation in several countries. Moreover, fuel cells offer wider energy system benefits for high-latitude countries with peak electricity demands in winter. Hydrogen is a zero-carbon alternative to natural gas, which could be particularly valuable for those countries with extensive natural gas distribution networks, but many national energy system models examine neither hydrogen nor fuel cells for heating. There is a need to include hydrogen and fuel cell heating technologies in future scenario analyses, and for policymakers to take into account the full value of the potential contribution of hydrogen and fuel cells to low-carbon energy systems.

Introduction

Heat generation in buildings and industry accounts for more than half of global final energy consumption and a third of global energy-related carbon dioxide (CO_2) emissions [1].

There is widespread acceptance that current hydrocarbon fuels used for heat generation will need to be substituted by low-carbon alternatives if global greenhouse gas emissions are to be reduced sufficiently by 2050 to avoid dangerous climate change [2]. Electrification of heat provision, using air or ground-source heat pumps, is one strategy. District heating

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Table 1 – Global final energy consumption in 2011 in residential buildings, commercial buildings (including public sector), and industrial plants. Heat refers to heat from centralised CHP or district heat plants. Most fuels are used only for heat generation but electricity powers a range of machinery including refrigeration, motors and electrical appliances. Data from Ref. [12].

	Residential (EJ)	Commercial (EJ)	Industrial (EJ)	Total (EJ)
Petroleum products	9	4	14	**26**
Coal	3	1	31	**35**
Natural gas	17	7	21	**46**
Biofuels and waste	35	1	8	**44**
Electricity	18	15	28	**61**
Heat	5	1	5	**11**
Other	0	0	0	**1**
Total	87	30	107	**224**

(using low-carbon fuels), solar heating and biomass are other potential options [3,4].

Fuel cells and hydrogen have received less attention in the literature, but could potentially generate low-carbon heat and electricity while avoiding some of the practical consumer acceptance issues faced by other low-carbon technologies (see Refs. [5–7] for examples of these issues). Japan and Korea have deployment programmes for residential fuel cell micro-CHP[1] [8,9], while larger fuel cells have penetrated the commercial heat market in the USA [10]. In the UK and in some other parts of Europe, the debate on low-carbon heat has largely neglected hydrogen and fuel cell technologies. Yet hydrogen is potentially an alternative zero-carbon gaseous fuel to natural gas. Existing fuel cells have built-in reformers that produce hydrogen from natural gas, but an alternative fuel such as hydrogen produced from a low-carbon energy source or bio-SNG[2] could be used to power fuel cells in the future. There are also several hydrogen-powered heat technologies in addition to fuel cells.

In May 2014, the UK Hydrogen and Fuel Cell Supergen Hub published a White Paper that systematically examines the evidence base for using hydrogen and fuel cells to provide low-carbon, secure, affordable heat in the UK [11]. This paper synthesises that White Paper but takes a broader perspective that includes developments and potential applications across the globe. Three broad methods were used in the development of this review. First, there was an extensive review of the technical, academic and commercial literature surrounding hydrogen and fuel cells. Second, the findings from this review were tested through consultations with core industry stakeholders.[3] Third, the findings were augmented with a comparative analysis of heating technologies that used residential data from several UK field trials, in conjunction with models, to consider the potential impacts of fuel cells on the wider UK energy system. All data in the paper except for case study results in Section 5 are secondary data.

The paper is set out as follows. Potential markets for hydrogen and fuel cell technologies are examined in Section 2. Section 3 reviews fuel cell micro-CHP, while hydrogen as a heating fuel is examined in Section 4. The integration and potential benefits of hydrogen and fuel cells for national energy systems are considered in Section 5, using a case study of the UK. Policy issues are highlighted in Section 6.

Potential markets for hydrogen and fuel cell technologies

In 2011, total global energy use for heat in buildings and industry was 172 EJ [1]. Around 75% of this heat was generated using fossil fuels, leading to emissions of 10 GtCO$_2$. The only substantial renewable fuel contribution was from biomass, which provided 9% of the total energy use. Table 1 shows a breakdown of fuel consumption in the residential, commercial and industrial sectors. Markets for low-carbon heating are emerging as a result of policy drivers, of which some are discussed in Section 6, and in response to the emergence of a number of low-carbon technologies, including fuel cells.

Residential sector

The residential sector accounts for 39% of global final energy in buildings and industry. Fuels are used to provide space heating, water heating and cooking, but the demand for these varies widely according to the climate, house size and building construction. For example, Fig. 1 shows that houses in the UK have a wide range of heating demands in winter but similar demands in summer. Peak electricity consumption occurs in winter in cold temperate countries such as the UK, but in summer in warmer countries when air conditioning is widely used. This has important ramifications for the relative competitiveness of fuel cell CHP and heat pumps, as part of their value is determined by their impact on the electricity system, as discussed in Section 5.

Biomass and waste currently supply more than 40% of residential heat provision, primarily in less developed countries or in areas of low population density. For people in poorer countries, access to modern energy services using clean gaseous or liquid fuels, or electricity, is a priority, but hydrogen and fuel cell technologies are likely to be prohibitively expensive for such applications in the near and medium-term due to the high capital costs relative to other options. Natural gas supplies around 20% of global residential heat, primarily in OECD countries. Gas is widely used in highly-populated regions of Northern Europe and North

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[1] CHP stands for Combined Heat and Power, and is also known as cogeneration.
[2] SNG stands for Synthetic Natural Gas.
[3] Stakeholders that contributed extensively to the review are listed in the Acknowledgements.
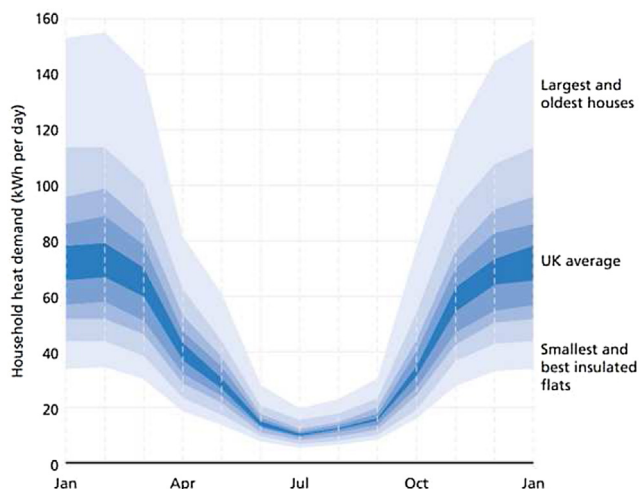
Fig. 1 – Heat demands from different households throughout the year in the UK. The demands include both space and water heating. Winter consumption is strongly temperature-dependent and the winter peaks can be much higher in a cold year. Based on data from Ref. [14].

America; for example, in the UK and the Netherlands more than 80% of houses use in-house gas boilers[4] [13]. This is important for two reasons. First, such a strong incumbent technology could prove difficult to displace with alternatives, particularly as studies of consumer preferences regarding heating systems show a strong cultural affinity in these countries for gas boilers, which are perceived as safe, cheap, effective and easy to control [6,7]. Second, markets and infrastructure already exist for gaseous heating fuels and it might be possible to convert these to use hydrogen, while providing a similar service to households that natural gas provides at present.

Commercial sector

Space and water heating are the most important energy service demands for commercial and public sector buildings, but the diversity of buildings is much greater than for the residential sector in terms of their size, shape, and level of heat demand. This diversity, coupled with the low fuel consumption relative to the residential and industrial sectors (Table 1), means that decarbonising the commercial sector often receives much less attention than the residential sector.

Natural gas and electricity are the dominant fuels. In contrast to residential buildings, electrically-powered HVAC[5] systems are used in many larger commercial buildings and these could run in cogeneration with fuel cell CHP, with the fuel cell contributing to the power and heating loads as well as providing an alternative electrical backup to UPS systems and/or diesel generators. The major barriers to the deployment of hydrogen and fuel cell heating systems are high costs when

compared against alternatives, and their perceived technological immaturity [15]. Many commercial organisations are often reluctant to adopt innovative technologies, favouring instead established technologies and processes [16,17]. CHP is an important commercial technology in some countries, whether supplying only single large buildings or providing district heat to a range of residential and/or commercial properties.

Industrial sector

The potential market for low-carbon heat technologies in the industrial sector is distinct from the commercial and residential parts of the economy because space heating is a relatively minor end use for heat demand. Demands for water heating and for the direct supply of industrial processes at different temperatures are much larger, particularly outside the food and drink sector [4]. Table 1 shows that industrial fuel use is quite different to the other two sectors, with a greater dominance for fossil fuels. Coal is the most used fossil fuel, followed by natural gas and petroleum products.

Possible roles for hydrogen and fuel cell products include the substitution of hydrogen for natural gas in some processes and the use of CHP technologies. Industry is a major market for CHP, as many companies that use significant amounts of process heat find that generating their own electricity on site can help to offset production costs [18].

Fuel cells

Fuel cells can produce the highest proportion of electricity of any CHP technology. They are a flexible, modular technology that can easily be scaled up from serving individual homes to large office blocks and industrial complexes. While some systems are designed to solely produce electricity, the most common stationary application is CHP, which can provide exceptionally high efficiency – up to 95%[6] in total – and reduce dependence on centrally-generated power, potentially saving on electricity costs and carbon emissions.

Fuel cells are not the only technology for heating with hydrogen (see Section 4.1 for other options), but they are the most prominent because of their electrical efficiency advantage. Similarly, hydrogen is not the only fuel that can power fuel cells, and most currently produce hydrogen internally by reforming a supplied hydrocarbon fuel. For stationary heat applications, natural gas is most widely used, along with LPG and biogas.

Types of fuel cells

PEMFCs (proton exchange membrane fuel cells[7]) are the most developed technology, powering around 90% of systems

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[4] Boilers are also furnaces or stoves in North America. Hydronic boilers supplying hot water for heating are commonly used in Europe while forced-air furnaces supplying hot air through ducts are often used in North America.

[5] HVAC stands for Heating, Ventilation and Air Conditioning.

[6] Following heating industry conventions in Europe, all efficiencies in this white paper are expressed relative to the lower heating value (LHV) of the fuel input.

[7] PEMFC is also widely known as PEFC (polymer electrolyte fuel cell) and SPFC (solid polymer fuel cell). The direct methanol fuel cells (DMFCs) used in portable applications are technically very similar to PEMFCs.

shipped to date [10]. They are most widely used in residential heating systems (1–3 kW thermal), such as those in the Japanese 'EneFarm' programme, and are also the stack technology used in fuel cell vehicles. After more than a decade of intense R&D effort, PEM technology offers high efficiency, durability and reliability, and costs have fallen rapidly due to mass production. Current research is aimed at system simplification: removing the platinum could avoid complex engineering solutions [19,20], while high-temperature (HT-PEM) cells can operate on dry hydrogen over 100 °C, removing the need for humidifiers [21,22].

SOFCs (solid oxide fuel cells) are high-temperature fuel cells used in both large industrial CHP (100–1000 kW) and residential heating systems (1–3 kW), that have recently grown to reach 10% of global sales [10]. SOFC benefit from the highest electrical efficiency and greater fuel-flexibility, but operate less dynamically than PEMFC due to their temperature requirements [23]. In particular, start-up and shut-down are sensitive operations taking 12 h or more, and so systems tend to run "always-hot", reducing their output when there is little or no demand. Fundamental research has been aimed at improving durability and material fatigue, and there is a trend towards intermediate temperature devices (IT-SOFC) that operate at 500–750 °C [24]. This allows a wider range of materials to be used, lowering costs and improving dynamic performance.

MCFCs (molten carbonate fuel cells) are another high-temperature fuel cell used in large industrial CHP and grid-scale electricity production (3–60 MW), which have become the market leader for large stationary applications [10]. MCFCs benefit from relatively low capital costs due to non-platinum catalysts and simpler ancillary systems, but suffer from low lifetime and low power density [25]. The key research issue is improving stack lifetimes, which stand at only five years due to the aggressive chemistry of the stack and electrolyte leakage, meaning a stack replacement is required half-way through a system's lifetime [26]. Power density is also a research focus, to reduce cell size and thus material costs.

PAFCs (phosphoric acid fuel cells) were the first fuel cell technology employed for heating, being used since the 1970s in commercial-scale CHP systems (100–400 kW electric) [27]. Around 400 systems (85 MW) are in operation, predominantly in the US, Germany, Japan and Korea [28,29]. A small number of demonstration systems have been made at the 1 kW scale [30], but no residential products have been brought to market.

Global deployment of fuel cells for CHP

Stationary combined heat and power (CHP) is currently the largest and most established market for fuel cells. The commercialisation of micro-CHP fuel cells has proceeded rapidly since the first launch in 2009. In Japan, nearly 60,000 systems have been sold in the four years to October 2013 [8], and 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 [31]. As shown in Fig. 2, Japan is leading the way in terms of deployment, some 6–8 years ahead of South Korea and Europe; however, all regional markets are roughly doubling in size year on year. This impressive growth is expected to continue in the near future: the Japanese
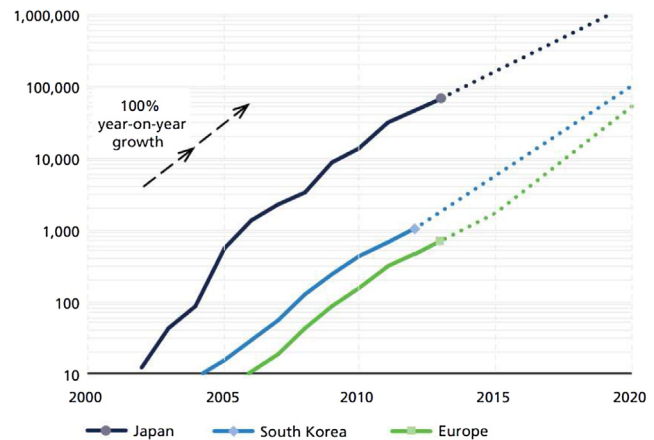

Fig. 2 – Cumulative number of fuel cell micro-CHP systems deployed in three major regions, showing historic growth (solid lines) and near-term projections (dotted lines). Based on data from Refs. [8,32–38].

government has a target for 1.4 million fuel cells installed by 2020, and the European Union anticipates 50,000 systems deployed by 2020 followed by commercial roll-out [8,32].

Japan
By far the greatest activity has occurred in Japan, as the result of generous government funding (circa €200 m per year) over the last 10–15 years for both research and demonstration projects to catalyse fuel cell micro-CHP development. A series of large demonstration programmes were carried out between 2002 and 2010, resulting in the installation of 3352 PEMFC and 233 SOFC units into private homes [39,40]. After the completion of the Japanese Large-scale Stationary Fuel Cell Demonstration Project in 2009, the Ene-Farm brand of PEMFC systems was launched collectively by Panasonic, Toshiba and Eneos (a joint venture between JX Nippon Oil & Sanyo). The commercialisation of Ene-Farm has proceeded swiftly with sales approximately doubling each year, with a total of 57,000 systems sold as of October 2013 [8].

Japan also lies at the forefront of SOFC development. Companies such as Kyocera, Nippon Oil and Toto have been engaged in residential demonstrations of 0.7–1 kW systems since 2007. Two models of EneFarm-S were launched by Kyocera and Eneos in 2012, and over 1000 systems had been sold in their first 2 years [41]. The government roadmap aims for widespread commercialisation of SOFC from 2015 to 2020 [39].

South Korea
South Korea saw an initial field test of 1 kW residential power generators (RPGs) in 2004, which led to a larger demonstration by four Korean companies (GS Fuel Cell, FuelCell Power, HyoSung and LS) beginning in 2006. 210 systems were installed between 2006 and 2009, backed by a government subsidy of 80% of the purchase price (~$47,500 in 2012) [36], at a cost of $18 m [9]. The subsidies provided in this trial were significantly higher than the purchase price of other systems at the time – reflecting the relative immaturity of Korean systems at the time, and the government's desire to catalyse a

Table 2 — Summary of fuel cell performance.		PEMFC	SOFC	PAFC	MCFC
Application		Residential	Residential/commercial	Commercial	
Electrical capacity	(kW)	0.75—2	0.75—250	100—400	300+
Thermal capacity	(kW)	0.75—2	0.75—250	110—450	450+
Electrical efficiency[a]	(LHV)	35—39%	45—60%	42%	47%
Thermal efficiency[a]	(LHV)	55%	30—45%	48%	43%
Current maximum lifetime	'000 h	60—80	20—90	80—130	20
	years	10	3—10	15—20[c]	10[c]
Degradation rate[b]	Per year	1%	1—2.5%	0.5%	1.5%

[a] Rated specifications when new, which are slightly higher than the averages experienced in practice.
[b] Loss of peak power and electrical efficiency; thermal efficiency increases to compensate.
[c] Requires an overhaul of the fuel cell stack half-way through the operating lifetime.

domestic market for producers [36]. The Korean government's roadmap sees trials continuing through 2014, then commercial sales expanding rapidly from 2015 onwards. More detailed plans are not yet available, so it remains to be seen whether these aggressive targets can be met.

Europe

After a decade of small trials in Europe, the Callux residential field trial of fuel cell micro-CHP began in 2008 with three major German manufacturers — Hexis and Vaillant (both SOFC) and Baxi Innotech (PEMFC). Up to 560 fuel cells were installed into German homes between 2008 and 2013, and will be monitored for at least two years [38]. Other European demonstrations include the Danish Micro Combined Heat & Power project and the FC-District Project which is operating in Spain, Greece and Poland.

More recently, the Ene.field trials have begun to deploy 1000 systems across 12 European countries between 2014 and 2016. This project involves nine manufacturers, including Baxi, Bosch, Ceres, Hexis, SOFCPower and Vaillant, and will demonstrate novel intermediate temperature IT-SOFC and high temperature HT-PEM technologies as well as the more established stack technologies [32].

North America

There has been little residential fuel cell activity in North America to date, despite one of the largest fuel cell manufacturers, Ballard, being located in Canada. However, the USA is one of the largest current markets for fuel cells in commercial and industrial applications [10], including in CHP applications.

Technical performance

The technical performances of the different fuel cell stacks are summarised in Table 2. Fuel cells offer the highest electrical efficiency of any CHP technology, and rival even the best conventional power stations [42]. The leading SOFC systems at both residential and larger scales have rated electrical efficiencies of 45—60%, and total efficiencies of 80—90% against LHV. Fuel processing incurs greater losses in low temperature fuel cells, so electrical efficiencies are lower but thermal efficiencies are higher. The leading residential PEMFCs are rated at 39% electrical and 95% total efficiency [43,44]. European and

American systems have not yet matched the leading Japanese and Australian models, with efficiencies being five to ten percentage points lower than the above values (34% electrical for both PEMFC and SOFC) [45,46]. The efficiency of these residential models is somewhat lower in intermittent real-world usage, due to part-load operation, auxiliary power consumption and varying flow/return temperatures [38]; for example, CFCL's BlueGen is rated to be 60% efficient, but achieves 51—56% in practice.

For many years, durability was a key issue holding back fuel cells. Stack lifetimes were around 10,000 h (around 2 years of intermittent operation)[8] for all but PAFC technology [37], which proved a serious barrier to practicality and cost competitiveness. Recent improvements in both PEMFC and SOFC technology, particularly by Japanese manufacturers, have seen lifetimes improve past the critical milestone of 40,000 h (10 years). The leading Japanese residential systems are now expected to operate for 60—80,000 h for PEMFCs [43,44], and up to 90,000 h for SOFCs [47]. Except for PAFCs, these lifetimes have not yet been proven in the field as the latest generation of systems have only been operating for around two years.

Being a newly commercialised technology, fuel cells need to gain public acceptance as a safe and dependable technology. Although the public are familiar with using natural gas and petrol, the association with hydrogen (flammable and explosive) gives the impression that fuel cells could be dangerous. In natural gas-fired CHP systems, hydrogen is generated on-demand and almost instantaneously consumed, so only a fraction of a gram is present in the system at any given moment. Safety considerations are therefore very similar to a conventional gas boiler and other electricity-producing technologies such as solar PV.

Economic performance

Upfront capital cost remains a major hurdle for fuel cells to overcome. Even with the current subsidies offered in Japan and the UK, residential micro-CHP systems are unable to recover their initial cost within their expected operating

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[8] Lifetimes assume 5000 operating hours per year for intermittent residential operation. Calendar lifetimes would be lower for commercial and industrial installations with longer running hours.

lifetime [11]. These systems are currently targeted at premium consumers on the grounds of their environmental credentials and improved features (for example, the ability to provide heat and power during a blackout in Japan).

The economics of commercial and industrial CHP need to be better than for residential systems as they must offer an attractive payback period to gain sales. For example, the annual return on investment (ROI) can range from 8 to 12% in Europe, depending on the customer and their energy costs [48,49].

Capital costs
As production has expanded rapidly, capital costs have fallen in recent years. Fuel cells are still more expensive than competing technologies but this gap is rapidly narrowing. As of 2014, the purchase price of a 0.7 kW PEMFC or SOFC residential system was £12,000 to £16,000 in Japan, the 1.5 kW BlueGEN SOFC was £20,000 in Australia [43,50], and European systems are estimated to be around £26,000 [51]. Economies of scale mean that larger commercial MCFC and PAFC systems are cheaper per unit output, costing in the region of £2500–3500 per kW [25,50,52].

The price of residential systems has fallen dramatically — by 85% in the last 10 years in Japan [50], as shown in Fig. 3, and by 60% over the last four years in Germany [38]. These are prime examples of industry 'learning by doing' — as companies gain experience with manufacturing a product, they optimise the design and production process, and so cost falls with cumulative output.

Capital cost trends
During early demonstration projects in Japan and Korea, the price of residential PEMFC systems reduced by 20% for each
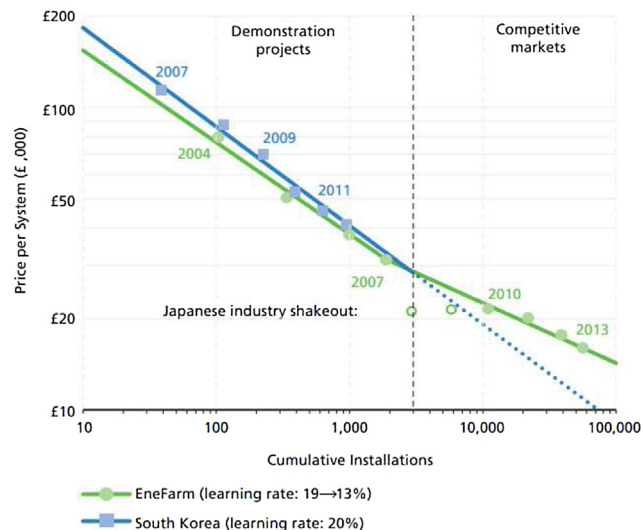

Fig. 3 – Experience curves fitted to the historic price of Japanese EneFarm and South Korean residential PEMFC systems from the last ten years. For each doubling in the number produced, EneFarm prices have fallen by 15% and Korean prices by 20%. Prices are British pounds in the year 2012; exchange rates for that year were £1 = €1.12 = US$1.45 = ¥152. Data are from Refs. [36,43,50].

doubling in cumulative production [33,50] — the same downwards trajectory that has brought solar photovoltaic panels into the mainstream [53]. However, as seen in Fig. 3, the price of Japanese systems has fallen more gradually since their commercialisation in 2008. This slowdown could have natural causes [50]:

- the greatest gains from system optimisation were made earlier in the product's development;
- R&D expenditure has not kept pace with sales volumes since commercialisation; and,
- the fuel cell stack is now a minor cost component, so a greater fraction of the system cost comes from relatively standard components that have already moved down their learning curves.

The transition from demonstration projects to a competitive market in Japan (2008–09) sparked a price war that forced two manufacturers to leave the industry and caused prices to stagnate for three years (the first two of which were not used in the fitting of the learning curve shown in Fig. 3). Subsequently, prices reduced at a rate of 13% per doubling in production between 2010 and 2013.

If the historic trends from Fig. 3 continue into the future, we could expect the millionth residential system to be installed in the next 4–6 years and to cost between £4500 and £9000. The main measures for future cost reduction at all scales are [50]:

- reducing system complexity through design optimisation;
- eliminating major system components such as fuel processing stages;
- cell-level design improvements such as reducing catalyst content and increasing power density;
- greater collaboration between manufacturers to standardise minor components and overcome research challenges more effectively; and,
- further expansion of manufacturing volumes and mass production techniques.

In contrast to PEMFC and SOFC systems, the cost of larger PAFC systems has remained stable for many years as they have yet to take off in the commercial CHP sector. Recently, ClearEdge (now Doosan Fuel Cell America) have halved their costs per kW by scaling up from 200 to 400 kW systems [28]; however, the platinum content in PAFC stacks remains a major obstacle, contributing 10–15% of the total system cost [52]. In contrast, sales of large MCFCs have grown steadily over the years, with prices falling by 60% in the transition from initial field trials to commercial product (2003–9). FuelCell Energy are targeting a further 20% cost reduction in the near term [25].

Running costs
The high capital cost of fuel cell systems is offset by lower running costs which result from lower consumption of grid electricity. Residential systems are advertised by their manufacturers as reducing household bills by £350–750 per year [43,47,54]; the attainable savings depend strongly on the ratio of electricity to gas prices and the levels of subsidy offered.

Subsidies such as feed-in tariffs have proven very effective at bringing technologies such as solar PV to market, particularly in Germany. The UK offers a feed-in tariff to micro-CHP which pays 13.24 p for each kWh of electricity generated, and allows excess electricity production to be exported for a fixed rate of 4.77 p/kWh [55].

The running costs experienced in one country are not necessarily transferable abroad because of climatic and social differences, as mentioned in Section 2.1. For example, computer simulations of Japanese fuel cells in UK houses using two independent models, *CODEGen* [56] and *FC++* [37], suggest that fuel cells would perform better in the UK climate, given the higher UK demand for space heat and with peak electricity demand being in winter rather than summer, when the fuel cell is likely to contribute to the peak load. Annual savings from a 1 kW fuel cell in an average UK home are estimated to be around £850 per year, which primarily comes from feed-in tariff income [11]; however, this is not sufficiently high to repay the current upfront cost during the fuel cell's lifetime.

Environmental impacts

Carbon footprint of construction

Fuel cells are larger and heavier than the gas boilers they replace, and require catalyst metals such as nickel and platinum which are extremely energy-intensive to produce. Just as with other low-carbon technologies (e.g. solar PV and nuclear), the energy required to manufacture the fuel cell and the resulting carbon emissions are important as these offset the savings made during operation.

Several life-cycle assessments (LCAs) have estimated these carbon emissions − known as the embodied carbon or the carbon footprint − by considering how the fuel cell is manufactured, the quantity of materials required and how these materials are produced. Manufacturing a 1 kW residential CHP system results in emissions of 0.5–1 tCO_2, while a 100 kW commercial system results in 25–100 tCO_2 [57–59]. There are small differences between technologies (e.g. between PEMFC and SOFC), but these are outweighed by differences in the country of manufacture and production methods employed by different brands. The carbon footprint would greatly reduce if the manufacturing processes were decarbonised.

If these emissions are averaged over the system's lifetime, they equate to around 10–20 gCO_2/kWh of electricity, or 8–16 gCO_2/kWh of heat [57]. For comparison, the carbon intensity of construction is widely estimated to be 40–80 gCO_2/kWh for solar PV and 10–30 gCO_2/kWh for nuclear fission [60,61].

CO_2 emissions from operation

In countries with high-carbon electricity systems, fuel cells can reduce carbon emissions relative to conventional heating technologies. For example, for deployment in the UK, fuel cell manufacturers advertise 0.7–1 kW systems as saving 1.3–1.9 tCO_2/year in a four-person household (35–50% reductions) [43,44,47,54], while the larger CFCL BlueGen device is claimed to save around 3 tCO_2/year [62]. Modelling suggests that these figures are broadly transferable to northern Europe [37]. Similar percentage savings can be made by commercial CHP systems.

As with financial savings, CO_2 savings are country- and site-specific, depending on the carbon intensity of grid electricity and on the heating system that is displaced. A modern gas-fired condensing boiler produces heat with an intensity of 215 gCO_2/kWh [63]. Most electricity systems have substantially higher CO_2 emissions; for example, the average carbon intensity in 2011 was 441 gCO_2/kWh in the UK [64], 503 gCO_2/kWh in the USA and 477 gCO_2/kWh in Germany [65]. However, marginal plants, which are those that respond to changes in demand (and whose output would be reduced by micro-CHP generation) are typically coal or gas (as these are flexible and controllable), and emissions may average up to 690 gCO_2/kWh, depending on the country [66]. Fig. 4 compares the emissions by a household per day during the heating season when using a condensing boiler, an air source heat pump and a micro-CHP system respectively. The model in Ref. [67] considers the impact of grid electricity emissions on the overall emissions for supplying electricity and heat to an average house. These have no effect on gas boilers but are critical for the relative performance of heat pumps and fuel cells. With high grid emissions, micro-CHP is the technology with the lowest overall emissions. Fuel cell micro-CHP currently produces lower emissions than both gas boilers and heat pumps in all three countries, and will continue to do so until the marginal electricity generation carbon intensity reduces to 330 gCO_2/kWh. Decarbonisation pathways for the UK suggest that even the average grid emissions, which tend to be lower than those of the marginal plants, could still exceed this level for another 10 years [68]. The realisation of these targets is by no means guaranteed, such that micro-CHP could remain the lowest emission option for the foreseeable future.

Other airborne emissions

Fuel cells also offer significant benefits to local air quality even when fuelled on natural gas. The process of reforming the fuel at low temperatures in the absence of air, rather than combusting it, results in lower emissions of harmful air pollutants, including oxides of nitrogen (NO_x), carbon monoxide (CO) and particulates (PM10). Emissions from fuel cells are around a
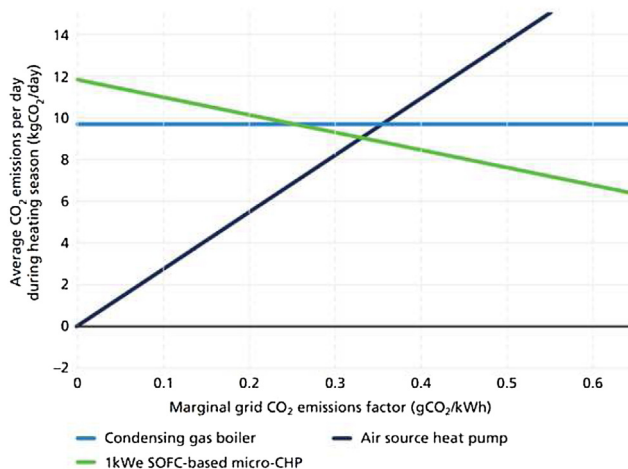

Fig. 4 − Comparison of CO_2 emissions from fuel cell micro-CHP, heat pumps and gas boilers for different electricity generation emission factors. Based on Ref. [67].

tenth of those from other gas-burning technologies, as shown in Table 3.

User experience compared to other heat technologies

Fuel cell CHP faces competition from five established and emerging technologies: condensing gas boilers and furnaces, biomass boilers, engine-based CHP, electric heat pumps and gas-engine heat pumps. Barriers to low-carbon technologies include high capital and installation costs, uncertain fuel costs, house space requirements and noise pollution [5].

Installation of a fuel cell is comparable to that of conventional heating, requiring the skill-sets of a heating engineer and an electrical engineer. Installation can take as little as a day, and involves relatively little disruption to the premises. In contrast, heat pumps require more specialised skills: for example, a refrigeration technician is needed along with a geological borehole specialist for ground-source pumps [70], and the requirement for low output temperatures can lead to intrusive changes to household heat distribution systems [5].

Residential fuel cells are physically larger than gas boilers, around the size of a large fridge-freezer, and so they are installed in basements or outside. A typical system (1 kW electric) weighs 150–250 kg and has a 2 m^2 footprint, including the hot water tank and supplementary boiler [38,43]. Smaller wall-hung systems are being developed (e.g. by Ceres Power and Elcore) which weigh as little as 60–100 kg (comparable to a boiler). The need for a hot water storage tank poses a problem in smaller urban houses, although this is a common requirement for all low-carbon heating technologies [69]. Commercial fuel cells are similarly larger than boilers: 300–400 kW generators can fit into a small shipping container, occupying 22–36 m^2 and weighing 30–35 tonnes [71,72]. For context, 1–2 MW of electrical capacity can be installed into the area of a tennis court.

Apart from their physical size, fuel cells are relatively unobtrusive. The only moving parts are pumps and fans so noise levels are similar to boilers, around 40 dB for residential systems (equivalent to a library) [44], and 60–65 dB for commercial systems (a busy road) [71,72]. Noise levels from air source heat pumps are higher due to the large fan [70], and CHP engines can be significantly louder, although modern sound-proofing reduces residential systems to around 45 dB [69]. Fuel cells could therefore be suitable for installation in living spaces if their size can be reduced sufficiently.

One clear advantage that fuel cells and other CHP devices have is the ability to operate during a blackout. This became a highly prized selling point as the Great East Japan Earthquake of 2011 caused lasting power shortages across Japan, and hurricanes Katrina and Sandy caused extensive power loss in the US. Provided that the natural gas network is not disrupted, the fuel cell can provide hot water and sufficient power for refrigeration, a TV, computer and lighting during an emergency [34]. Similarly, commercial fuel cells continue operating throughout power outages, enabling shops and offices to continue functioning as normal.

Hydrogen

Hydrogen can be used as an alternative to natural gas for space heating, water heating, and for gas cooking. There are numerous engineering factors which determine the compatibility of appliances with different types of gases, with the simplest and most commonly-used comparison metric being the Wobbe index. Even across Europe, natural gas varies in terms of its exact composition, with different Wobbe band standards being used in different countries for historical reasons. The Wobbe number is used, amongst other indicators, as a yardstick of compatibility when gas shippers import gases from other territories. Using a gas device with a fuel that is outside of the Wobbe band it is designed for can cause a number of undesired effects, such as incomplete combustion, the flame extinguishing easily, or the burner overheating.

Pure hydrogen has a Wobbe index number of around 48 MJ/m^3 [73], which is within the natural gas safety regulation range for burners in some European countries [74]. Despite the close match of Wobbe band numbers, gas appliances that are designed for use with natural gas cannot generally be used directly with hydrogen.[9] This is principally because the combustion velocity, also called the flame speed, is much higher for hydrogen than for natural gas, so controlling the flame is more challenging and requires different burner head designs. Practically, this means that all existing burner heads would have to be replaced in order to combust hydrogen instead of natural gas.

The physical and chemical properties of hydrogen are well understood and safety standards are in place for industrial processes. In contrast, there is very limited knowledge of the risks associated with hydrogen as a fuel in buildings [75,76]. The overall risk of hydrogen ignition within a building is higher than for natural gas. Moreover, hydrogen has no smell and suitable odorants have not yet been developed, and hydrogen flames are invisible.

In the short-term, several studies have proposed mixing natural gas with biologically-derived methane to lower the net CO_2 emissions from gas combustion [77–80]. Hydrogen injection has been proposed as an alternative or in some cases, a compliment to biomethane injection as a means of lowering the carbon content of supplied gas without changing existing appliances.

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[9] The Wobbe index number is principally a method of comparing the energy produced when different gases are burned, which while useful, doesn't capture all of the variables that are important for designing gas-using equipment (NGC + Gas Interchangability Working Group 2005).

Table 3 – Measured emissions of major pollutants from fuel cells (averaged over 8 sources), condensing boilers and CHP engines. All emissions are given in g/MWh of fuel input [37,69].

	Fuel cell	Condensing boiler	CHP engine
NO$_x$	1–4	58	30–270
CO	1–8	43	10–50
CH$_4$	1–3	13	No data
SO$_2$	0–2	2	No data

Hydrogen heat technologies

In homes, hydrogen could be used to power fuel cell micro-CHP, direct flame combustion boilers (similar to existing natural gas boilers), catalytic boilers and gas-powered heat pumps. A variety of larger district heat and CHP devices that use natural gas could also be redesigned to use hydrogen [81]. It would also be possible to replace a large number of natural gas processes in industry [82]; for example, hydrogen could be used to fuel cement kilns, although substantial plant re-designs would be necessary [83].

A direct flame combustion H_2 boiler is functionally identical to the gas boilers installed in Europe and North America to supply residential central heating [84], except that it burns hydrogen instead of natural gas. Like natural gas boilers, direct combustion of the gas produces a series of flame jets that heat water. From a consumer perspective, there is no difference in the appearance or operation of hydrogen boilers when compared to their natural gas equivalents.

A catalytic boiler passes hydrogen gas over a highly reactive metal catalyst, which undergoes an exothermic chemical reaction to produce heat for space and hot water heating without a flame. The process results in very low nitrogen oxide emissions, and the heat output is potentially more easily controlled than that of a naked flame burner [85,86]. From a consumer perspective, catalytic hydrogen boilers can be designed to look and perform in a very similar fashion to existing natural gas boilers, except for the absence of a pilot light.

Gas heat pumps operate on similar principles to electric heat pumps, upgrading ambient heat from air, ground or water sources to useful temperatures. A phase-change working fluid is used to absorb heat from an ambient source and to transfer it to the building heating system. Instead of an electric vapour compressor, gas is combusted to provide the heating energy for the phase-change. Gas heat pumps use this refrigeration cycle to increase the delivered thermal energy beyond what would have been obtained from direct gas combustion alone. They have principally been developed for larger commercial buildings to date, although residential-scale models have also been successfully deployed in the German market [87].

Using hydrogen would remove CO_2 emissions at the point-of-use but would only reduce emissions across the energy system if low-carbon hydrogen production technologies and feedstocks were used. Moreover, while the use of fuel cells would greatly reduce emissions of non-CO_2 airborne pollutants, high-temperature hydrogen combustion would greatly increase NO_x emissions in comparison.

Hydrogen delivery infrastructure

Widespread consumption of hydrogen for heating would require the production of huge quantities of the gas. Constructing a pipeline network would likely be more economic than bulk delivery by freight transport vehicles to supply cities [88]. Possible routes for achieving widespread pipeline distribution include scaling up and expanding existing hydrogen networks, constructing entirely new ones, or converting some or all of existing natural gas distribution networks. It is likely that the pathway taken would depend on market-specific factors in different countries, and, in some cases, it is possible that a combination of all three approaches could be optimal. The repurposing of existing grids is highly attractive in markets with established gas networks because it avoids some of the potentially-enormous costs of building an entirely new hydrogen infrastructure from scratch [89–91].

Constructing hydrogen pipeline networks

A small number of high-pressure pipelines already exist to transport hydrogen between industrial producers and consumers. There are around 1600 km of hydrogen pipes in Europe across 15 main networks, with the largest operators being Air Liquide, BOC and Sapio [92]. Globally, about 3000 km of pipelines had been constructed by the year 2010 [93]. Hydrogen transmission pipelines are typically constructed using low-carbon steel coated with epoxy to prevent corrosion.

Pipe costs for hydrogen are difficult to generalise as they are heavily influenced by geographic considerations such as the routing of pipelines and the way they are trenched and installed in the ground. This depends on factors such as geology, topography, coordination with other buried electrical or fluid conduits, the costs of securing the rights to install pipes through private land, etc. [93–95]. On average, costs for hydrogen pipe infrastructure are estimated to be around 10%–20% more expensive than for natural gas [93,96].

Converting existing gas networks to deliver hydrogen

The potential role of hydrogen in the existing gas networks has attracted interest from government [3,4], academia [13,97], and industry [98]. One of the main attractions of this concept is that it offers a long-term transition pathway towards a low-carbon future for countries with established gas networks, which have received significant public and private investment over decades. The re-use or conversion of existing networks potentially avoids the significant costs of building entirely new parallel infrastructures for heat supply, such as district heating, or upgrading electricity distribution networks to cope with heat pumps [98,99]. In the case of the gas network, all of the required land rights have already been secured and could in principle be re-used. While existing high pressure networks are unlikely to be suitable for carrying pure hydrogen, the majority of investments in the gas grid are in intermediate and local distribution networks and not in transmission systems [100]. Leakage from low-pressure pipes, particularly those constructed of polyethylene, is likely to be too small to be important unless the escaping hydrogen can accumulate in houses, the likelihood of which is not well understood [97].

One challenge for converting existing gas networks is the 20–30% lower energy carrying capacity for hydrogen for a pipeline of the same pipe diameter and pressure drop, when compared to natural gas [90,101]. This limitation could be exacerbated by increasing gas demands, with fuel cell micro-CHP having a 25% higher fuel consumption than condensing boilers, although this increase could be offset by fitting energy conservation measures [97]. An engineering appraisal is required to understand the extent to which the networks would require reinforcement in order to transport sufficient hydrogen to meet demand.

Another issue is the role of the networks as an energy storage medium to meet daily gas demand peaks (commonly called the linepack). The linepack capacity of a network for hydrogen is less than a quarter of the natural gas capacity as it depends only on the relative volumetric energy densities of the two fuels [90]. It is not clear whether the network operators would be able to follow current natural gas operating practices for hydrogen, or whether additional storage would be required. One option to increase hydrogen linepack capacity would be to increase the operating pressures across the networks [102].

A national programme would be required to convert the existing gas networks. It would be necessary to fit hydrogen sensors in each home for safety reasons and new meters to accurately measure consumption. There is a precedent for such a programme in the conversion programmes from town gas to natural gas, but such programmes would be more complex today because current gas networks are much more interconnected than previous town gas networks, so it would be more difficult to limit the length of supply disruptions during conversion. It would also be more difficult to organise and finance a national program in those countries with fragmented low-pressure networks owned by several private companies. Section 6.2 explores some of the policy issues surrounding conversion.

Hydrogen production

Europe and North America possess significant industrial infrastructure for large-scale hydrogen production [103]. Hydrogen has been used to make ammonia for crop fertiliser and for "cracking" heavy oil into common fuels like petrol, kerosene and diesel for more than 100 years. It is also used in a wide variety of industries such as food processing and metal fabrication [104].

Hydrogen can be produced from fossil fuels, biological material or water [105]. Current hydrogen production is largely from steam methane reforming, but there is also strong interest in the electrolysis of 'green' hydrogen from water that in the future would use zero-carbon electricity. Low-carbon electricity is a relatively expensive resource and some energy system studies have identified fossil or biomass-fuelled plants fitted with carbon capture and storage (CCS) technologies as more competitive long-term options for hydrogen production [e.g. 13]. There are also a number of

production methods under development that could become significant in future hydrogen supply chains, including:

- Electrolysis at high temperatures, using heat from nuclear reactors or concentrating solar power [106], which makes the process more efficient.
- Thermolysis, which uses extreme heat from nuclear or solar energy to split hydrogen from water [107,108].
- Photocatalytic water splitting, the process of obtaining hydrogen directly from water using sunlight [109].
- Production of hydrogen from direct fermentation of biological material [110].

Hydrogen is not a sustainable energy vector unless the production process produces low emissions. In Germany, a 'green hydrogen' standard has been developed by TÜV-SÜD [111], and is increasingly widely used as a benchmark in projects and demonstration activities for defining 'green' hydrogen. The European Commission Joint Undertaking on Hydrogen and Fuel Cells is funding the development of a European framework for guarantees of origin of green hydrogen, to enable the harmonised development of green hydrogen standards.

The benefits of hydrogen and fuel cells for national energy systems

The previous sections have shown that fuel cells and other hydrogen-fuelled technologies have the potential to be low-carbon options for heat provision. This section considers why these technologies have not featured in heat decarbonisation pathways in different countries, concentrating on Europe in particular. It also examines how fuel cell micro-CHP could be integrated into existing energy systems to support electricity generation and distribution.

Heat decarbonisation pathways

Decarbonisation pathways across economies are often identified using energy system models. These models represent commodity flows through the entire economy and are used to identify the energy system that meets energy service demands with the lowest discounted capital, operating and resource cost, subject to constraints such as greenhouse gas

Table 4 – Representation of hydrogen and fuel cell heating technologies in several national and international energy system models.

Model	Scope	Representation of hydrogen and fuel cells for heat
ETSAP-TIAM [114]	World	None
US EPA 9R [115]	USA	None
Canada TIMES [116]	Canada	Included, but no specific details available
Pan-European TIMES [117]	Europe	No information available
JRC-EU-TIMES [118]	Europe	Includes a hydrogen "burner", but with a very high costs/kW, and also hydrogen injection to the gas networks
Belgium TIMES [119]	Belgium	None
Norway TIMES [120]	Norway	None
UK MARKAL [121]	UK	Includes only natural gas-powered fuel cells
UKTM [122]	UK	Includes fuel cell and hydrogen boiler technologies

emission targets and government policies. Energy system models are used to inform climate policy in many countries. It is therefore important that these models have an appropriate representation of hydrogen and fuel cell heating technologies so that any benefits of these technologies can be properly understood and communicated to policymakers.

While energy system models have comprehensive representations of the entire energy system, they tend to have aggregated representations of the individual sectors [112] and also coarse spatial and temporal resolutions [113], in order to restrict the model complexity and the computational running time. Yet despite these trade-offs, they still tend to represent thousands of different technologies. It is often difficult to find specific information about the many assumptions in such models if the documentation is poor or not made available [113]. This is the case for some of the models that are listed in Table 4.

The models in Table 4 are prominent energy system models that operate from global to regional and country scales. Several models do not include hydrogen and fuel cell heating technologies at all; these effectively assume that such technologies are technically or economically infeasible in the short and long-term. Some of the recently-developed models do include hydrogen-fuelled technologies, although the JRC-EU-TIMES model uses what appears to be an excessively high capital cost that would render the technology uneconomic. Since hydrogen and fuel cell technologies have not been considered in many of these models, they could not appear in long-term decarbonisation pathways even if they formed part of the most economic technology portfolio.

Case study: UK heat decarbonisation pathways

The energy system models of the UK in Table 4 are of particular interest as they both include hydrogen and/or fuel cell heating technologies. It is interesting to take a closer look at the representation of these technologies in UK energy system and building stock models.[10] Table 5 compares several of these models for the UK, as well as hybrid versions that combine detailed housing stock representations within a wider energy system model. They principally differ according to the model type, the number of represented house categories and the breadth of low-carbon heat technologies.

Most of the models in Table 5 also do not include hydrogen and fuel cell technologies as an option, which explains why they have not generally featured in most UK decarbonisation pathways. Only UKTM and RESOM have wide ranges of heat technologies that include hydrogen and fuel cell technologies. RESOM represents a much greater number of house categories but UKTM has a more detailed representation of the commercial and industrial sectors. However, conversion of the gas networks to deliver hydrogen, which Section 4.2 identifies as a

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[10] Building stock models are used to identify decarbonisation pathways for the residential, public and commercial sectors. The sectors are highly disaggregated with many different types of buildings separately represented by, for example, the physical variables for houses might include the house type, size, age, region, conurbation (urban/rural), level of insulation and heating technology.

Table 5 — Summary of models used for UK heat decarbonisation studies. "ES" are energy system models. For the house categories, "location" refers to urban/rural while "region" refers to different parts of the UK. "Fabric" is the building construction (e.g. solid or cavity wall). The "base" heat technologies are fossil fuel, electric and biomass boilers, heat pumps, solar thermal and district heating.

Model	Type	House categories	Heat technologies	H_2 heating fuel
UK MARKAL [123]	ES	2 (age)	Base, mCHP, fuel cell mCHP	No[a]
UKTM	ES	2 (age)	Base, mCHP, hydrogen boilers, fuel cell mCHP, hybrid HPs	Yes
ESME [124]	ES	12 (type, fabric)	Base, mCHP	No[b]
UKDCM [125]	Stock	20,000 (region, type, age, tenure, fabric, floors)	Base, mCHP	No
BREHOMES [126]	Stock	1000	Unknown	No
N-DEEM [127]	Stock	0 (80 non-residential)	Base	No
NERA/AEA [128–130]	Stock	8 (type, location, fabric)	Base	No
Element/AEA [131]	Stock	Not specified	Base	No
AUB [132]	Hybrid	26 (type, location, age)	Base, mCHP, hydrogen boilers, fuel cell mCHP, hybrid HPs	Yes
RESOM [133,134]	Hybrid	30 (type, location, age)	Base, mCHP, hydrogen boilers, fuel cell mCHP, hybrid HPs, gas heat pumps	Yes
DynEMo [135]	Hybrid	30 (type, fabric, occupants)	Base, mCHP, hybrid HPs	No[b]

[a] Hydrogen technologies for heating and fuel cell micro-CHP have been included in a research version of UK MARKAL.
[b] There are plans to add hydrogen and fuel cell technologies to these models.

key option for the future, has only been assessed using a research version of UK MARKAL that added many hydrogen and fuel cell technologies.[11] Those studies concluded that using fuel cells powered by hydrogen from a converted gas network could be the lowest-cost option for decarbonising heat, reducing the number of houses using heat pumps while supporting heat pump operation through high micro-CHP generation output at peak demand times [13,97]. The RESOM decarbonisation scenarios do not find a role for fuel cells and instead identify hybrid heat pumps as a key technology for the future.

Case studies of fuel cells in individual homes

The exact role of fuel cell micro-CHP in a low-carbon energy system remains unclear from the models summarised in Tables 4 and 5. The coarse temporal resolution that is common in both energy system and housing stock models is unlikely to fully reflect the integrated functionality that fuels cells may perform as a constituent part of future energy systems and their ability to support system operation. In particular, technologies that tend to generate electricity at times of peak demand offer additional value to the energy system by reducing the need for storage and back-up generation capacity.

In Asia, where fuel cell micro-CHP has been mostly deployed, peak electricity occurs during summer when there is high demand for air conditioning. It is therefore surprising that fuel cells are not more prevalent in northern Europe, where peak electricity demand occurs in winter and is linked to the overall space heating demand. Fuel cell micro-CHP should offer additional value to the energy system in such climates by generating electricity and heat at times of peak demand. Moreover, the value is likely to increase in the future if heat is electrified through the deployment of heat pumps in many houses, which would greatly increase the winter peak demand.

The literature on fuel cells and heat pumps has tended to present them as alternative or rival technologies, with either one or the other expected to achieve market dominance [136,137]. More recently, the potential benefits of combining heat pumps and CHP technologies have been discussed [67,138–140]. In Denmark, for instance, municipal CHP systems with heat networks have been investigated for their ability to better integrate large wind resources [141–143]. This section explores whether heat pumps and fuel cells can complement each other, using two case studies of the UK energy system.

Case study 1: fuel cell contribution to meeting peak electricity demand

For the power sector, all long-run UK energy system decarbonisation scenarios entail significant shares of wind and nuclear generation entering the electricity system. This poses new challenges in terms of system flexibility and provision of peak demand capacity. The scale of generation, transmission and distribution infrastructures in the UK, and the substantial costs associated with these assets, are to a large extent

governed by peak demands in a few hours each year. Any increase in load during these periods, for example through electrification of heat or transport, could result in costly infrastructure expansions. This case study focuses on the week in which peak electricity consumption is most likely to occur (typically mid-December) and examines the interactions of fuel cells and other heating technology during that week.

Reducing peak demand can bring about a host of benefits for many different stakeholders across the energy system:

1. All other factors being equal, a reduction in peak demand could lead to higher asset utilisation across the electricity system, which in turn implies a lower levelised cost of electricity.
2. Peak demand periods constitute a high risk of system failures and potential black-outs. Reduction in peak demand thus contributes to the security of the system and its resilience to shocks.
3. Distribution and transmission systems are also sized to cope with their respective peak demands. Any avoided increase in peak demand can therefore defer costly network upgrades and lead to better utilisation of existing infrastructure.

In common with many cold-temperate climates, the UK tends to experience peak electrical demand at roughly the same time as peak thermal demand in the residential sector. Both typically fall on a cold December weekday at around 5:30 pm.

The relationship between CHP load profiles and national electricity loads is shown in Fig. 5. During high electricity demand periods, micro-CHP units tend to generate more electricity, thereby potentially supporting peak generation requirements. Such a relationship does not exist for heat pumps, whose loads do not correlate with the national demand. It is conceivable that a change in operating strategy
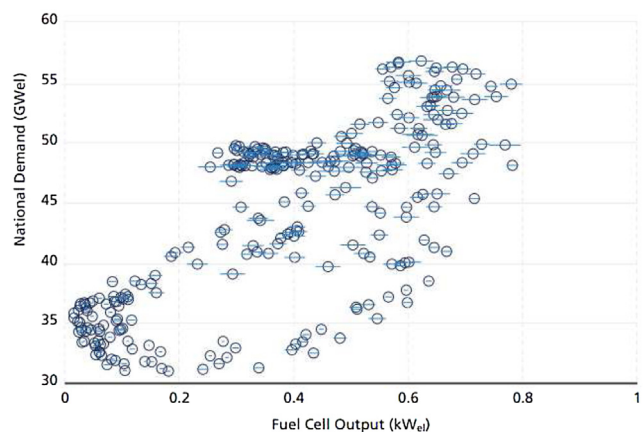

Fig. 5 – **Coincidence of combined electricity generation from 46 sites with SOFC-based CHP and national load in each half hour of the coldest week. CHP units load follow thermal demand and are therefore correlated to national electricity demand. Lines mark the range for heat-to-power ratios of different fuel cell technologies between 1:1 and 2:1. Based on data from Refs. [144,145].**

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[11] UKTM was developed from this research version of UK MARKAL.

may better schedule heat pump loads with respect to national loads. However, the continuous operation of heat pumps in the same trial suggests that the scope for changes to their load profile is limited.

The impact of heat pumps on a low-voltage feeder with 46 residential dwellings is shown in Fig. 6. Each 5-min period in the coldest week of the year is ranked in this graph by its load. The highest point on the left of this load-duration curve represents the peak demand on this feeder. Its value defines the capacity a low-voltage network would have to support in the absence of storage or demand response measures. The addition of heat pumps in 20% of the dwellings in this example raises the load duration curve throughout, with a notable increase in peak demand, potentially necessitating costly network reinforcements and transformer upgrades. Adding fuel cells alongside heat pumps, in the ratio 2.5:1, mitigates the demand increase and avoids such investments. Moreover, the load duration curve of the combined heat pump and fuel cell case is flatter than the alternatives, suggesting improved asset utilisation and probably reducing the average levelised cost of electricity.

Case study 2: complementing electric vehicles with fuel cell micro-CHP

Electrification of transport could also increase future electricity system loads. Presently transport, heat and electricity are delivered from separate sectors within the UK energy system and from broadly different energy commodities (oil, gas and electricity, respectively) [146]. Electric vehicles would shift a substantial energy demand from petroleum products towards electricity. As with heat pumps, the timing and distribution of this added load is crucial for its system impact.

A shift from petrol and diesel to electricity would move away from a fuel with some degree of storage in its supply infrastructure towards the 'just-in-time' electricity network [147]. Depending on the timing of charging, this could add or alleviate electricity network challenges [148]. The potential impact of charging patterns for electric vehicles on

distribution networks, and the potential for SOFCs to mitigate their impact, have been examined in Refs. [149,150]. Vehicle charging tends to fall into the early evening period, when many people return home and seek to recharge for the next day. This behaviour pattern has the potential to adversely affect peak demand periods. The load profiles in Fig. 7 show the timing of electric vehicle charging as experienced on a low-voltage network. The electricity generated by heat-led fuel cell micro-CHP operation counteracts the main load from electric vehicle charging in the period from 5 pm to 11 pm. For a scenario with a 30% penetration of plug-in hybrid electric vehicles (PHEVs) matched by a 30% penetration of fuel cell micro-CHP systems, the combined load profile over a typical day is fully compensated during the critical evening peak hours and the maximum impact at any time of day is reduced by 30%.

Energy system models have coarse temporal scales while housing stock models generally do not consider variations in intraday heat generation. This means that none of the models listed in Tables 4 and 5 simulate the contribution of fuel cells to balancing potential demands from heat pumps and electric vehicles using the temporal resolution shown in Figs. 6 and 7. The potential role of fuel cells as system-integrating solutions may therefore have been underestimated in the resulting scenarios.

Policy issues

Despite making up a large share of overall energy consumption and greenhouse emissions globally, heat has only recently become prominent in discussions of energy policy. Most efforts have focused on the power and transport sectors, with heat appearing marginalised in comparison. Heat policy is often characterised by four overarching objectives: (i) reducing greenhouse gas and other environmentally harmful emissions; (ii) affordability to consumers and business; (iii) security and reliability of supply; and, (iv) the potential to stimulate the development of technologies with export opportunities [3,4].
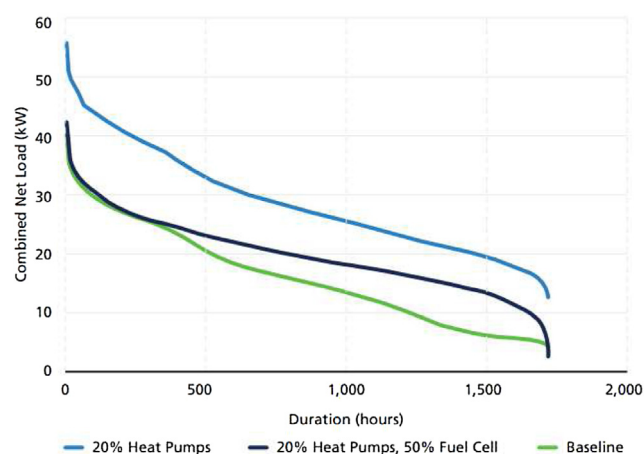
Fig. 6 – Load duration curves for homes heated using: (i) natural gas (baseline); (ii) 20% of gas boilers replaced by heat pumps; and, (iii) 20% heat pumps and 50% micro-CHP fuel cells. Data are based on measurements in 46 dwellings [145].
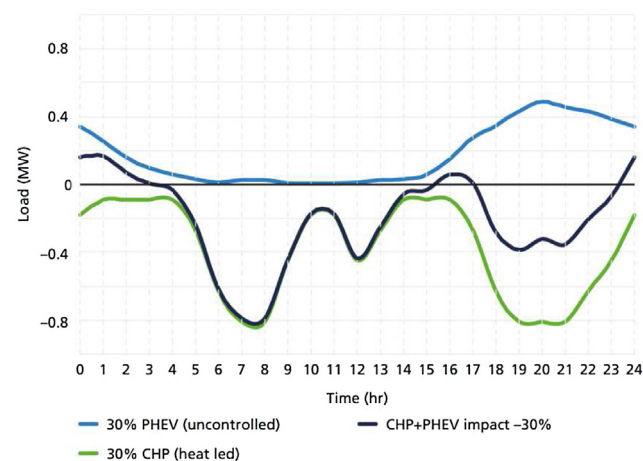
Fig. 7 – Fuel cells can compensate for the evening load increase from PHEVs on distribution networks. Based on Ref. [150].

In meeting these objectives, policymakers in many countries attempt to take a broadly technology neutral approach to heat policy, relying on markets to efficiently determine the relative shares of different heating technologies and fuels (typically based on arguments about information asymmetries and government failure [151]). The task of policy is seen as the efficient regulation of the market to protect consumers, in the context of significant network effects and natural monopolies related to large physical infrastructures such as gas or electricity networks. Policy should intervene where market failures prevent markets from efficiently determining a socially beneficial outcome; the most significant failures often relate to various externalities and public goods, including carbon emissions and energy security.

Support for new heat technologies

An additional set of policy rationales comes into play for emerging energy technologies, associated with the necessity of state action to support a well-functioning innovation system [152,153]. Policymakers typically seek to provide some support for emerging energy technologies—through basic research support and R&D funding, and through support for demonstration trials, testing and other mechanisms—where these technologies are thought to offer benefits. The rationale for such support is typically framed in terms of spill-overs arising from R&D, which result in reduced incentives for firms to invest in innovation [154].

Hydrogen and fuel cell technologies for heating markets lie at the intersection of these two policy domains—heat policy and energy innovation policy—and different countries have adopted a diverse range of approaches to supporting technologies, driven by differing rationales and objectives. Key policy rationales for dedicated support instruments for hydrogen and fuel cell technologies include:

1. Market design. Existing market arrangements may fail to reward system benefits provided by particular technologies (such as those discussed in Section 5.3), resulting in suboptimal investment and deployment of those technologies.
2. Optionality. There may be a need to provide support to emerging technologies—such as hydrogen and fuel cells for heating—where failure to do so would close off a potentially important long-term option, or result in an unacceptable delay. Failure to invest in keeping options open would result in the loss of such options in the future, even where they were potentially the best long-term pathway.
3. Innovation and industrial development. Support for hydrogen and fuel cell technologies may enable the development of a successful domestic industry, with the ultimate aim of achieving net economic benefits arising from exports. Clearly this is true for all emerging technologies, and there is a risk that the potentially high cost of providing strong technology-specific support based on this argument could yield few benefits if industrial development is unsuccessful.

Numerous policy instruments in different countries support the development and deployment of hydrogen and fuel cell technologies. There are a suite of R&D, demonstration and industry development support measures (e.g. Germany's NOW programme; the European Commission Joint Undertaking on Hydrogen and Fuel Cells; the US Department of Energy's Hydrogen Program). Some countries and regions provide direct subsidy support for manufacturing facilities (e.g. USA). There are subsidies for capital costs (e.g. in Japan, Nord-Rhein Westphalia), tax incentives, or feed-in tariffs for fuel cell CHP (e.g. in Germany, Korea). Deployment subsidies currently in place are focused on CHP and frequently reward power generation rather than the use of heat directly; in fact, many existing policies offer general support for hydrogen and fuel cell technologies in stationary applications and are not specific to heating. Another area of support is from regulatory and planning incentives, with hydrogen and fuel cells sometimes treated preferentially by local planning authorities, providing incentives for developers to deploy fuel cells in new buildings (e.g. in London, UK and Bloomington, Indiana).

Keeping options open: the special case of hydrogen in the gas grid

A particularly important and long-term policy issue is the future of the extensive natural gas distribution networks in many countries. As discussed in Section 4.2, there is potential to: (i) inject hydrogen into gas networks to provide marginal decarbonisation of delivered gas while enabling wider system benefits through reducing wind curtailment and deferred investment in electricity networks; and, (ii) convert gas networks to deliver pure hydrogen as a zero-carbon heating fuel.

It is in this policy area that the "optionality" argument is most clear. Research and innovation are required to keep open the option of a long-term transition to a pure hydrogen network, and the timescales of a cost–effective transition are sufficiently long that there is a strong case for embarking on that work now.

In the long term, it is clear that a decision will have to be made about whether the gas network—or sections of it—will distribute pure hydrogen. It is difficult to envisage a scenario in which market forces (allied to strong carbon prices) drive network conversion without governments playing a strongly supportive role. This is because of the co-ordination and regulatory challenges required in enabling consumer appliances, infrastructure regulation and investment in a conversion programme to be aligned. Making this decision is therefore a key long-term policy goal, for which a great deal of development work is necessary. Clearly, a transition of this kind would require appropriate regulatory frameworks to be developed, as well as a carefully designed process for change. While there might be learning points for the technical aspects of conversion from the various town gas conversion programmes around the world, most of these were centrally-planned and took place in a very different regulatory environment that is not comparable to the contemporary system of multiple private operators that operates in many countries.

Conclusions

Heat makes up a large share of overall energy consumption and CO_2 emissions globally, but decarbonisation of heat has had

relatively little attention compared to electricity generation and the transport sector. One reason is that many high-income countries predominantly use natural gas for heating and there is no clear cost-effective, low-carbon alternative at the moment. Fuel cell CHP has been supported towards commercialisation in Asia over recent years but hydrogen and fuel cell technologies have not generally featured in European heat decarbonisation studies. Yet fuel cell CHP is maturing into a reliable and commercially-viable heat technology with a good safety record, with potential applications at different scales across a range of markets. Moreover, hydrogen is potentially a credible zero-carbon alternative to natural gas, particularly if economic low-carbon hydrogen can be produced and delivered using existing gas network infrastructure.

In May 2014, the UK H2FC Hub published an assessment of the evidence on the potential for hydrogen and fuel cells to meet the goals of UK heat policy, which are the provision of secure, affordable, low-carbon heat. This paper has expanded on the White Paper by examining the potential benefits of these technologies across different markets in high-income countries. Steady cost reductions through innovation have brought fuel cells close to commercialisation. Fuel cell CHP has lower net emissions than existing natural gas-fuelled heat and electricity systems, and also lower emissions than heat pumps supplied by the current electricity generation portfolios of most countries. Fuel cells also offer additional value to the energy systems of high-latitude countries by generating electricity at times of peak demand, and this will become increasingly important in the future if these peaks increase through the electrification of heat and transport.

Decarbonisation scenarios are often produced using energy system models and a review of several global, regional and national models shows that most do not consider hydrogen and fuel cell heating technologies, and hence make the implicit assumption that these technologies are not technically viable. However, there is evidence that these technologies are starting to be incorporated into some more recent models. There is a need for the academic community to include these technologies in future assessments and for policymakers to consider these technologies when devising policies to reduce greenhouse gas emissions from heat provision.

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