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Hydrogen for heating? Decarbonization options for households in the United Kingdom in 2050

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EXECUTIVE SUMMARY

The heating sector makes up 10% of the United Kingdom's carbon footprint, and residential homes account for the vast majority of demand (UK Green Building Council, 2020). At present, central heating from a natural gas-fired boiler is the most common system in the United Kingdom, but this will need to be phased out to achieve reductions in greenhouse gas (GHG) emissions (Energy Savings Trust, 2020). Hydrogen with a low carbon intensity and renewable electricity are the two primary energy replacement options for the heating sector. In February 2020, the UK Parliament launched a Hydrogen Task Force with the goal of developing a mandate for hydrogen boilers to achieve 100% hydrogen in heating. At the same time, the UK Committee on Climate Change projected that electrification will account for most heat decarbonization in the country and that hydrogen could play only a limited role. An important consideration is how either decarbonization strategy would affect heating costs.

In this assessment, we project the costs for a typical single-family UK household and climate performance in 2050 using low-GHG or GHG-neutral hydrogen, renewable electricity, or a combination of both. The two most likely heating technologies that would use hydrogen in 2050 are boilers or fuel cells with an auxiliary hydrogen boiler for cold spells. We assess the cost of using each type of technology in 2050 with two types of hydrogen, produced via:

1. Steam-methane reforming (SMR), combined with carbon capture and storage (CCS).
2. Electrolysis using zero-carbon renewable electricity.

The most promising heating technology for the direct use of renewable electricity is heat pumps, given that this is already a mature technology. We assess the costs of heat pumps in two scenarios:

1. Heat pump only: The home is heated solely by heat pumps running on renewable electricity.
2. Hybrid heat pump with an auxiliary hydrogen boiler.

We show average carbon intensity in different pathways in Figure ES1. At present, fossil energy is used for SMR + CCS, which means that producing hydrogen this way provides GHG emission savings of 42%–61% compared with fossil gas, assuming a carbon intensity of 72 grams of carbon dioxide-equivalent per megajoule (gCO_2e/MJ) for fossil gas. In 2050, combustion of fossil gas without CCS is likely to be phased out, so we adjust the life-cycle emissions and corresponding costs of the SMR + CCS hydrogen pathway accordingly. When we assume that hydrogen rather than natural gas will be used as process fuel, we find that producing hydrogen with SMR + CCS provides GHG savings of 69%–93% compared with fossil gas (shown as an average of 13 gCO_2e/MJ in Figure 1). As for renewable electricity used in heat pumps, we assume it is produced from wind and solar electricity with zero carbon intensity. Similarly, electrolysis hydrogen produced from wind and solar electricity has a carbon intensity of zero.

Figure ES1 shows that in 2050 both heat pump scenarios would be more cost-effective than the four hydrogen-only technologies, which policymakers should note as they decide how to support decarbonization options for the heating sector. We find that hydrogen boilers using SMR + CCS are less expensive than those using electrolysis hydrogen from zero-carbon electricity. Our analysis shows that fuel cells, using either type of hydrogen, will be significantly more expensive than the other options.

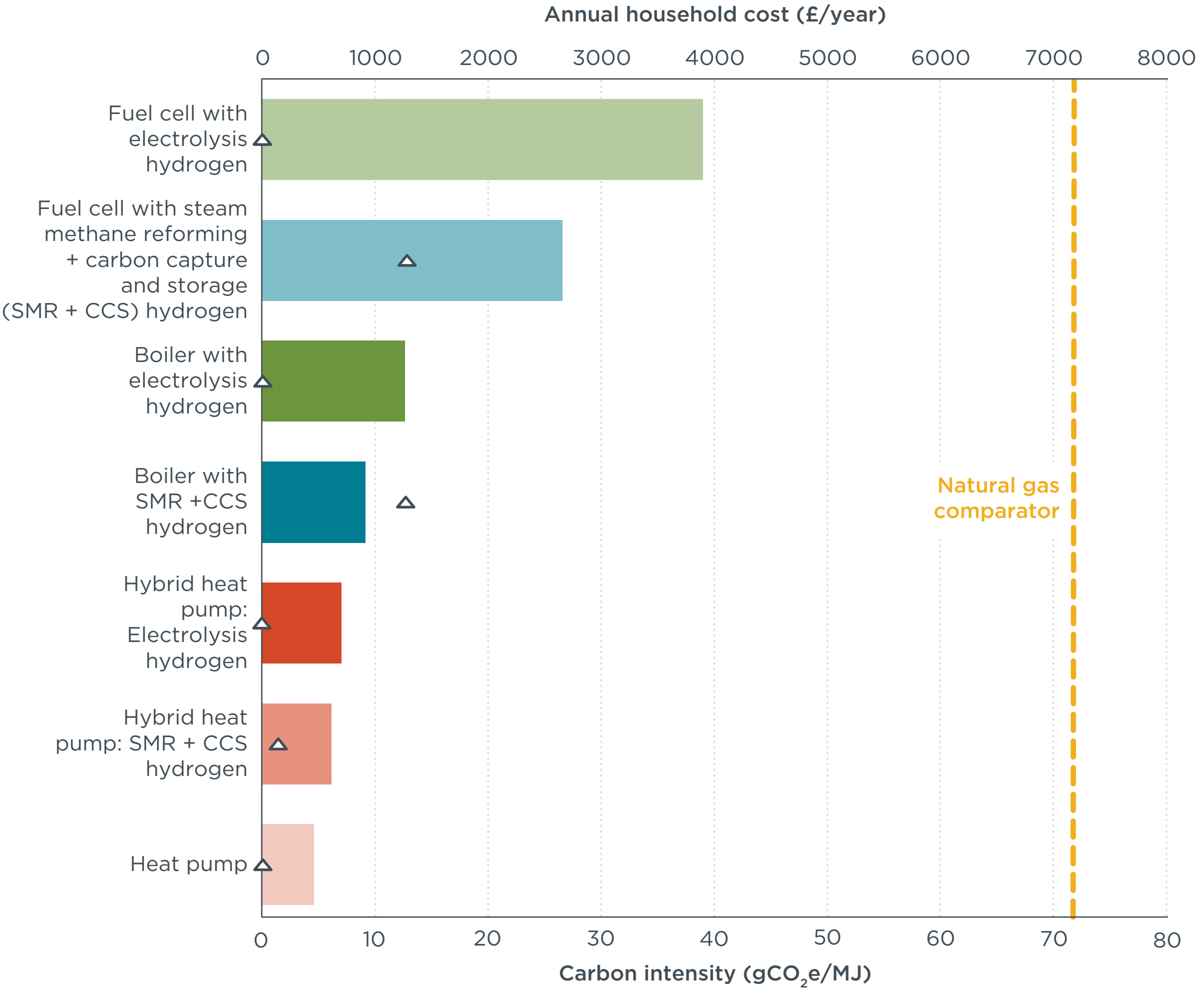

Figure ES1: Cost comparison and carbon intensities of different technology options for heating a typical UK single-family house for one year in 2050. Triangles represent the median values for the carbon intensity of each pathway along with a natural gas comparator.

At the same time, these findings come with uncertainties. The cost of natural gas makes up 50% of the final costs of all heating scenarios, and renewable electricity, 75%. Because it is difficult to know what energy prices will be in 2050, we conduct a sensitivity analysis on renewable electricity prices, natural gas prices, and gas distribution fees. Based on this analysis, we find that costs for each scenario could be 20%–30% higher or lower than shown in ES1. Were renewable electricity prices to be 50% lower, or natural gas prices 50% higher, the cost to use a boiler with electrolysis hydrogen could become cost competitive with a boiler using SMR + CCS hydrogen, and the cost advantage of the hybrid heat pump scenarios would increase. Even in the case that both renewable electricity prices were 50% higher and natural gas prices 50% lower than we assume, a heat pump would still be the most cost-effective option.

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INTRODUCTION

Heating is one of the most difficult sectors to decarbonize in the United Kingdom because it relies heavily on fossil gas, and decarbonization will directly affect consumers because infrastructure will need to be retrofitted in the majority of buildings. Heating represents 10% of the UK carbon footprint, with residential homes making up the vast majority of demand for heat (UK Green Building Council, 2020). Hydrogen is one option to help achieve decarbonization in this sector, and the UK government is making key decisions regarding its hydrogen strategy. In February 2020, the UK Parliament launched a Hydrogen Task Force to develop an overarching hydrogen strategy across multiple sectors. This includes a mandate for hydrogen boilers to achieve 100% hydrogen by 2025 (Burgess, 2020). At the same time, the UK Committee on Climate Change (CCC) released a report describing sectors where hydrogen could best be used to achieve carbon reductions (Joffe, Livermore, & Hemsley, 2018). They write that electrification will account for most heat decarbonization in the United Kingdom and that hydrogen could play only a limited role. Particularly, hydrogen would be necessary during cold spells and could be used to balance the electricity grid. Given these different policy developments, there is clearly a need to better understand the relative costs of using hydrogen and renewable electricity in heating. In this study, we assess the total heating costs for a typical UK single-family house in 2050 to show how choosing to use low-carbon hydrogen, renewable electricity, or a combination of both would affect consumers.

Approximately 95% of the world's hydrogen is produced from fossil fuels (Philibert, 2017). One option for decarbonizing heating is to produce or import low-GHG fossil-derived hydrogen, also known as "blue" hydrogen (Searle & Pavlenko, 2019). This is fossil gas that has undergone a carbon-removal process such as steam-methane reforming (SMR), combined with carbon capture and storage (CCS). The UK CCC report mentions that to bring UK production of hydrogen to scale in 2050, some will need to be SMR + CCS hydrogen. There is also the potential to produce zero-carbon or low-carbon hydrogen from electrolysis using renewable electricity, also known as "green" hydrogen.

The two most likely technologies for using hydrogen to heat a home in 2050 are either hydrogen boilers or fuel cells as they are the most commercially mature. A hydrogen boiler is similar to a natural gas boiler but burns hydrogen, and a fuel cell is a small-scale, end-use combined heat and power (CHP) system. We include two scenarios where homes are heated solely by hydrogen. One would combust SMR + CCS hydrogen, and the other, electrolysis hydrogen using zero- or low-carbon renewable electricity, such as wind and solar. In a fuel cell scenario, we assume that an auxiliary hydrogen boiler is used during cold spells as the fuel cell alone would not be able to handle the heat demand.

We assess heat pumps as the main technology for using renewable electricity directly for heating given that they are already a mature technology (Staffell, 2019). We assess two scenarios using heat pumps. In one, the home is heated solely by heat pumps running on renewable electricity. Given rising temperatures because of climate change and improvements in home insulation, this scenario may be possible in 2050. However, if there are still too many cold days for a heat pump alone to be a popular choice, an auxiliary hydrogen boiler would be necessary. We thus also consider a hybrid heat pump scenario.

METHODOLOGY

HYDROGEN PRODUCTION COSTS

The United Kingdom is the third-largest natural gas producer in Europe, obtaining 47% of its natural gas from fields in the North Sea. For simplicity we assume that all UK hydrogen from natural gas will be produced domestically (EIA, 2018). At present, steam methane reforming is the technology most widely used to produce hydrogen from natural gas. In this process, natural gas reacts with steam at high temperatures with a catalyst to produce syngas, a mixture of primarily hydrogen and carbon monoxide (CO), as well as some unreacted methane (CH_4) and carbon dioxide (CO_2). The syngas is further processed using a water-gas shift reaction, where hydrogen and CO are reacted with more steam to produce even more hydrogen and CO_2 (Joffe et al., 2018).

Autothermal reforming, molten metal pyrolysis, and chemical looping reforming are other potential technologies that could be used to produce hydrogen in 2050. One techno-economic model showed that autothermal reforming could achieve hydrogen production costs similar to SMR, and another found that with a carbon tax chemical looping reforming could compete with SMR (Cloete, Khan, & Amini, 2019; Salkuyeh, Saville, & MacLean, 2017). In molten metal pyrolysis, hydrogen is produced by running natural gas through molten metal. Solid carbon is a byproduct from this process and could be used for material production, such as tires, or it could be stored more easily than gaseous CO_2. However, this technology is only in the research stage, and some experts estimate it will take at least a decade to reach the pilot stage (TNO, n.d.).

Given that SMR is currently more cost-effective than the other available technologies and is already commercially mature, we assume that SMR will be the primary technology used to produce hydrogen in 2050 and that real costs will remain at their current level. For the production of hydrogen from SMR to be low carbon, the CO_2 must be captured and stored. CCS generally consists of three components: 1) the capture and compression of CO_2, 2) the transportation of compressed CO_2 from its source to the storage site, and 3) the long-term sequestration of CO_2. Carbon dioxide sequestration can be done in oil wells, geological formations, oceans, and mineralization (IPCC, 2005). CCS differs from carbon capture and utilization (CCU), which converts the captured CO_2 into products such as biofuel and chemical synthesis instead of storing carbon permanently. In the case of hydrogen production, after the water-gas shift reaction, the CO_2 is removed from the syngas using an alkaline-based solution (Mueller-Langer, Tzimas, Kaltschmitt, & Peteves, 2007).

We base our estimate of the lowest cost of hydrogen (LCOH) production on a number of studies assessing the cost of SMR + CCS (Ewan & Allen, 2005; Hosseini & Wahid, 2016; Collodi, Azzaro, Ferrari, & Santos, 2017; Keipi, Tolvanen, & Konttinen, 2018; Molburg & Doctor, 2003; Mueller-Langer, Tzimas, Kaltschmitt, & Peteves, 2007; Muradov, 2002; National Research Council and National Academy of Engineering, 2004; Salkuyeh et al., 2017). We find that the LCOH reported in these studies depends greatly on assumptions of natural gas price. We thus adjust the results of these studies to use a consistent natural gas price. For each study included in our analysis, we estimate and subtract the portion of the total production cost that is due to natural gas inputs from the final LCOH estimate. We then re-incorporate the component of LCOH that is due to the natural gas using a projected price of natural gas in 2050 from a UK government projection (UK Department for BEIS, 2020) and the yield of hydrogen that is produced per unit of natural gas in industrial SMR processes, which is an average of the yields presented in Keipi et al. (2018), Mueller-Langer et al. (2007), Natural Research Council and National Academy of Engineering (2004), and Salkuyeh et al. (2017).

The LCOH studies we use generally assume CCS occurs in on-shore oil wells, but we expect off-shore CCS to be more likely in the United Kingdom, given that drilling occurs in the North Sea. We thus add a cost for the expected premium of off-shore over on-shore CCS from Irlam (2017). This additional fee helps account for the likelihood that by 2050, enhanced oil recovery will occur to a much lesser extent, reflecting depressed demand for fossil resources. At present, additional revenue from enhanced oil recovery reduces the cost of CCS.

For generating renewable hydrogen from electrolysis, we take UK production costs from a recent ICCT study (Christensen, 2020). Specifically, we assume that electrolyzers are grid-connected, and we assume a median renewable electricity price from that study. We use the most optimistic assumptions for capital expenses (CAPEX) and other costs.

GREENHOUSE GAS PERFORMANCE OF HYDROGEN PRODUCTION

We calculate the carbon intensity of SMR + CCS hydrogen and electrolysis hydrogen pathways using zero-carbon energy inputs including solar and wind power using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model (Wang, 2017). At present, fossil fuel is used to power SMR + CCS. In 2050, renewable energy will be used in the SMR + CCS process, so we adjust the life-cycle emissions and corresponding costs of the SMR + CCS hydrogen pathway accordingly. We adjust the cost of the SMR + CCS pathway by assuming that some of the hydrogen that is produced will be used as process fuel instead of natural gas. We include an upstream leakage rate of natural gas production and transport of 0.5%–2% and a range in carbon-capture efficiency of 70%–90% (Parkinson, 2019). For the heat pump scenarios, we assume the renewable electricity will be zero-carbon as well. In the hybrid heat pump scenario that uses SMR + CCS, we calculate the carbon intensity by multiplying the median carbon intensity of this hydrogen by the percentage of UK heat demand that will be met by hydrogen because of cold spells in 2050, estimated at 21%. We explain the methodology for deriving this percentage below. We do not calculate emissions from the manufacture of the different heating technologies or differences in emissions due to the efficiency of hydrogen or electricity use in each heating pathway scenario.

HYDROGEN TRANSPORT

Hydrogen must be transported from production facilities to end users by either pipeline or truck. We assume pipeline transport will be more likely in scenarios of high hydrogen demand in which hydrogen boilers and fuel cells are the primary source for heat. In scenarios where auxiliary hydrogen boilers supplement heat pumps, we expect that hydrogen is more likely to be transported by truck, reflecting lower demand.

Steel pipelines cannot transport hydrogen because the metal becomes embrittled, so we incorporate the cost of building hydrogen-ready pipelines in our analysis (Dodds & Demoullin, 2013). We do not include, however, the cost of retrofitting medium-pressure and low-pressure pipelines made of iron because all low-pressure UK pipelines will already be hydrogen-ready by 2030 under the Irons Mains Replacement Programme. The program mandates that these pipelines be upgraded with polyethylene, which is a material suitable for transporting hydrogen at low pressures (Dodds & Demoullin, 2013). We estimate total construction costs for the remainder of the pipelines, primarily high-pressure pipelines, based on per-km costs and the present-day length of transmission lines (Dodds & McDowall, 2012). We apply a per-kg hydrogen pipeline fee based on an estimate of hydrogen demand in 2050, which we assume will be similar to projections for total UK natural gas demand in 2050 that we retrieve from the EU Reference Scenario (European Commission, 2016). We amortize the total construction cost over 30 years.

Hydrogen also could theoretically be mixed with natural gas in compatible pipelines and extracted at the end user. We review three gas-separation technologies that could perform this extraction: (1) pressure swing adsorption (PSA), (2) membrane separation, and (3) electrochemical hydrogen separation (also known as hydrogen pumping) (Melaina, Antonia, & Penev, 2013). Of these, PSA is the most commercially ready. PSA units operating on low hydrogen concentrations, such as 20% mixtures, are feasible. However, the size of these units depends on the volume of hydrogen and amount of impurities in the gas, so with low hydrogen concentrations, the PSA units become capital-intensive and thus an expensive solution. Diluted hydrogen also presents a problem for membrane separation. Electrochemical hydrogen separation is not a mature technology and requires water for humidification. Given these technological hurdles, we find carbon hydrogen extraction from natural gas pipelines at the household level to be cost-prohibitive.

We incorporate a short-term storage fee for hydrogen, assuming that some storage would be needed to allow for temporal differences in hydrogen production and demand. We assume the same on-site storage fee as Christensen (2020). We do not explicitly account for the cost of seasonal hydrogen storage, which could potentially be needed as we expect the heating demand for hydrogen to occur mainly in the winter. We expect that utility companies and pipeline operators would charge a fee for the use of pipelines to distribute hydrogen, and we assume that this fee would be the same as present-day UK distribution fees for natural gas. We estimate a typical current natural gas mark-up fee including distribution and grid fees by comparing current UK retail and wholesale prices for natural gas (European Commission, 2020; UK Department for BEIS, 2020).

For the hybrid heating scenario, we assume that the hydrogen needed for the auxiliary boiler would be transported via truck to the residence, so there would be no pipeline retrofit. We assume that hydrogen would be transported in liquid form as that is more cost-effective than transporting it as compressed gas over long distances (Yang & Ogden, 2007). We take a liquefaction fee, which is similar to the cost of present-day natural gas liquefaction, from Babarit et al. (2018) and per-tonne-km trucking costs from Yang and Ogden (2007). We assume that SMR would take place in Leicester, the geographic center of the United Kingdom weighted by population, and the liquid hydrogen would travel by truck to London, a population center.

RESIDENTIAL HEATING TECHNOLOGY AND COST

We assess four scenarios for heating single-family houses in the United Kingdom: 1) boiler using hydrogen; 2) fuel cell using hydrogen, plus an auxiliary hydrogen boiler for cold spells; 3) hybrid heat pump using 100% renewable electricity and an auxiliary hydrogen boiler for cold spells; 4) heat pump used to meet all heating demand. In the fuel cell and hybrid heat pump scenarios, we assume that an auxiliary hydrogen boiler will be needed to supplement the primary heating technology during cold spells, when the fuel cell or the heat pump will reach maximum heating capacity. It is not clear whether it will be necessary to supplement a heat pump or fuel cell with an auxiliary hydrogen boiler given that with climate change, it is possible that in 2050 there will not be enough cold spells in the United Kingdom to justify purchasing and maintaining an auxiliary boiler in residences. We do not include a fuel cell-only scenario because the capital cost of the fuel cell and the hydrogen required to fuel it makes up the majority of the cost of this pathway, so removing the auxiliary boiler does not have a large impact on the cost compared with other pathways.

We retrieve household space heating demand in 2015 and the projected number of households in the United Kingdom in 2050 from Fleiter et al. (2017). To estimate future household heat demand, we multiply 2015 residential space heating demand by the percentage reduction in demand between 2015 and 2050 across the 14 EU member states included in the Fleiter et al. study. This amounts to a 25% reduction in demand in 2050 compared with 2015 assuming that average demand changes across the European Union are reflective of those in the United Kingdom. This 25% reduction represents efficiency improvements in residential heating, using data from the European Building Stock Observatory, which assumes, for example, that building codes are improved and that there are structural improvements in residences like refurbishing windows and doors.

Hydrogen boiler efficiency, heating capacity, CAPEX, operating expenses (OPEX), and 40-year lifetime are from Sadler et al. (2016). We include a yearly maintenance fee for the boiler from Kozarcanin, Hanna, Staffell, Gross, and Andresen (2020). For heat pumps, we retrieve CAPEX, variable and fixed OPEX, and 20-year lifetime from Popovski, Fleiter, Santos, Leal, and Fernandes (2018), and Strbac et al. (2018). In all scenarios, we assume that CAPEX is annuitized based on the lifetime of the heating technology.

The conversion efficiency of heat pumps depends on outdoor temperatures and can be represented by a variety of measures. We choose to use the seasonal performance factor in our assessment because it represents an average performance in a specific location, based on the outdoor temperatures throughout the year. The seasonal performance factor we use is 3.19, from Staffel et al. (2012), which is modeled based on temperatures in central England.

We assume that an auxiliary hydrogen boiler is used the same amount of time per year in both the fuel cell and hybrid heat pump scenarios because the maximum heat output of the fuel cell micro CHP system, which ranges from 11 kilowatt-thermal (kWth) to 13 kWth, is comparable to that of a typical heat pump, or 5kWth to 14kWth (Sansom, 2014). In both of these scenarios, we assume that the CAPEX of the hydrogen boiler would be half that of the scenario using just a hydrogen boiler as it would be used only as an auxiliary unit.

To determine the time that an auxiliary hydrogen boiler would be needed to supplement either a heat pump or fuel cells, we conduct an analysis of daily average temperatures; we utilize typical meteorological year data in central England for 1983–1996 published by the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (2001). We add 1°C to the average temperature of each day to predict possible temperatures in 2050 based on the IPCC's Special Report: Global Warming of 1.5°C (Allen et al., 2018). We employ a heating asset profile to determine whether and how much an auxiliary boiler would be used to heat a typical household on each day of the year (Honoré, 2018). We calculate that a heat pump or fuel cell could be used to meet 79% of the heating needs in a year in the United Kingdom and that an auxiliary boiler would be needed to supply the remainder.

For fuel cells, we derive CAPEX and OPEX from Strbac et al. (2018), while efficiency is derived from Sadler et al. (2016). We assume that the lifetime of fuel cells in 2050 will be 20 years (Staffel et al., 2019). Fuel cells require hydrogen of high quality because contaminants like carbon monoxide and hydrogen sulfide can impede electrode charge transfer, and ammonia can form cations that inhibit proton conduction. SMR plants might produce hydrogen of the purity required in fuel cells, but given that hydrogen can become contaminated during transport in pipelines, we assume a purification cost for a household using a fuel cell (Ohi et al., 2016). We assume PSA will be used to purify the hydrogen as it is the most commercially ready purification technology (Melaina, Antonia, & Penev, 2013). We note that while PSA may be cost-prohibitive if purifying hydrogen from low blends in natural gas, it becomes cost-effective when purifying hydrogen that is already nearly pure.

It is important to note that fuel cells generate more electricity than heat, so we assume that this electricity would be used to supply the electricity needs of the residence.

We derive electricity demand for residences in 2050 from Klaus, Vollmer, Werner, Lehmann, and Müschen (2010), assuming that heating demand in German residences will be similar to those in the United Kingdom. We subtract the demand from electric heat pumps from total electricity demand. We assume that excess electricity production, beyond this household electricity demand, would be sold back to the grid at the average wholesale price for renewable electricity in that country in 2050.

We use the same renewable electricity price as Christensen (2020) for the cost analysis of the heat pump scenarios and for the price of selling electricity back to the grid for the fuel cell scenarios. We apply the mid-range scenario in the National Renewable Energy Laboratory's model for future costs for solar, onshore wind, and offshore wind electricity generation, using national-level capacity factors for each technology. For the retail cost of renewable electricity, we add taxes and grid fees, assuming these costs are the same as for 2015 but slightly increasing the grid fees to account for the greater balancing and distribution costs that can be expected with greater penetration of variable renewable electricity sources, following an analysis by Agora Energiewende (Fürstenwerth, Pescia, & Litz, 2015). We describe this approach in Searle and Christensen (2018).

FINDINGS

PRIMARY RESULTS

Figure 1 compares different technology options for heating a UK household for one year in 2050. Our analysis shows that heat pumps are the most cost-effective option. Both heat pump scenarios, one where only an air-source heat pump is used and the other where a heat pump and an auxiliary boiler are used, cost less than the hydrogen-only technologies. We find that the cost of the heat pump-only scenario is 50% less than the scenario in which a boiler using SMR + CCS hydrogen is used, and in the case that an auxiliary boiler is needed, we find that the cost of the hybrid heat pump scenario using SMR + CCS hydrogen in an auxiliary boiler is still 30% less expensive than using a boiler alone. A hybrid heat pump using electrolysis hydrogen is about the same cost as a hydrogen boiler using SMR + CCS hydrogen. A hydrogen boiler using SMR + CCS is around 30% less expensive than one using electrolysis hydrogen from zero-carbon electricity. We find that fuel cells using SMR + CCS hydrogen are almost six times more expensive than using heat pumps with renewable electricity and almost three times as expensive as using a hydrogen boiler with the same kind of hydrogen.

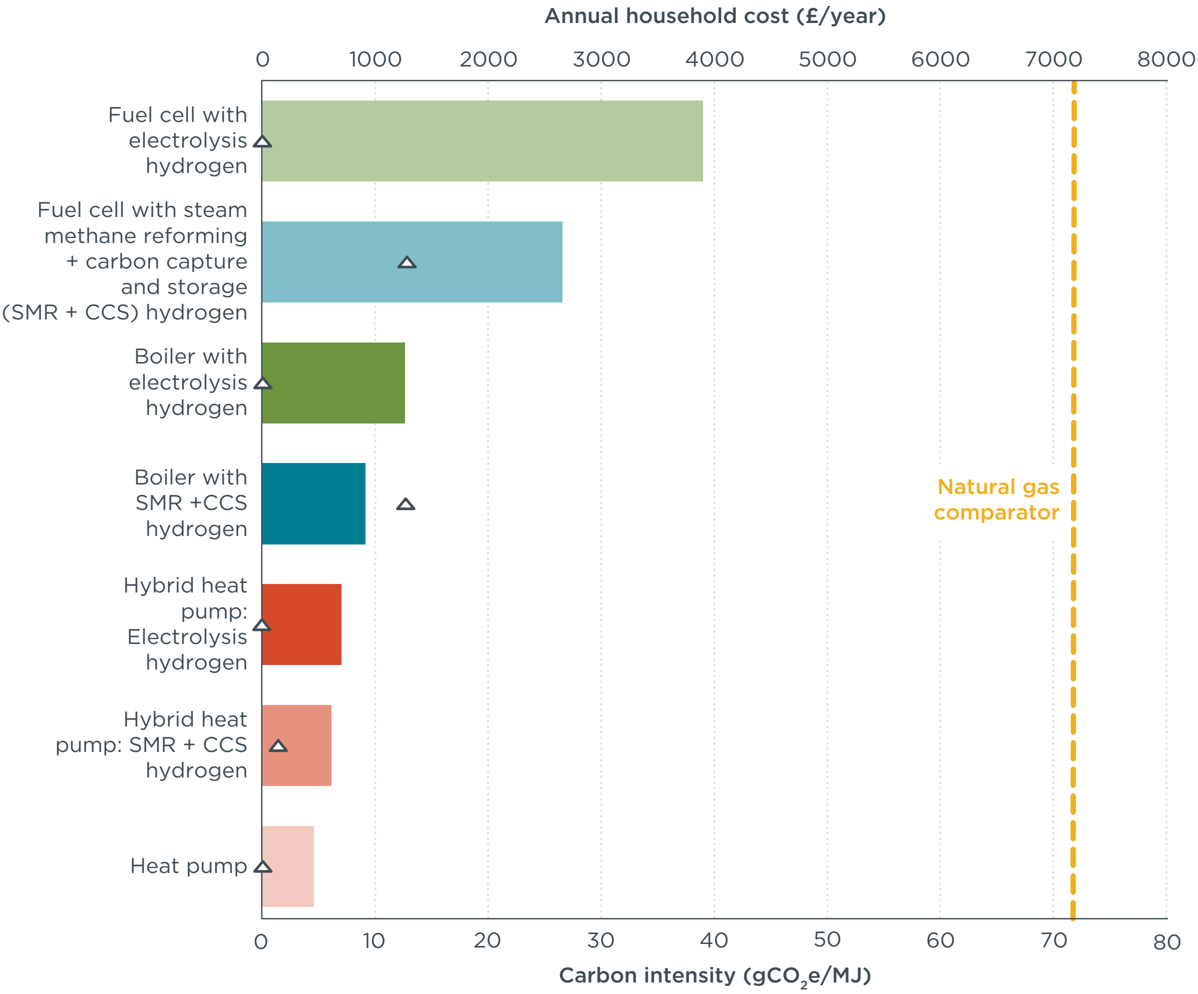

Figure 1: Cost comparison and carbon intensities of different technology options for heating a household for one year in the United Kingdom in 2050. Triangles represent the carbon intensity of the different pathways along with a natural gas comparator.

GREENHOUSE GAS PERFORMANCE

Currently, literature estimates for the carbon intensity of hydrogen from SMR + CCS range from 28 gCO$_2$e/MJ to 42 gCO$_2$e/MJ (Dufour, Serrano, Gálvez, Moreno, &

González, 2011; Salkuyeh et al., 2017; Verma & Kumar, 2015). This translates to GHG savings of 42%–61% compared with fossil gas, assuming a carbon intensity of 72 gCO_2e/MJ (Giuntoli, Agostini, Edwards, & Marelli, 2017). Some of the GHG emissions from SMR + CCS hydrogen production result from the use of fossil fuels to power the process, such as combusting natural gas without CCS for process heat and power. We imagine that in 2050 there may be policies in place to prevent such CO_2 emissions, so we calculate a carbon intensity assuming that some of the hydrogen produced by SMR + CCS is then used for process heat and power. This results in a range of 5–22 gCO_2e/MJ and an average carbon intensity of 13 gCO_2e/MJ, which equates to a 69%–93% GHG reduction compared with fossil gas (Figure 1). This range reflects different assumptions on the CO_2 capture efficiency of the CCS process and on the upstream methane leakage rate of the natural gas used. As for renewable electricity used in heat pumps, we assume this electricity is produced from wind and solar installations with zero carbon intensity (Edwards et al., 2014). Accordingly, we assume that electrolysis hydrogen produced from wind and solar electricity has a carbon intensity of zero (Wang, 2017).

COST COMPONENTS

When considering the total cost of hydrogen produced from SMR + CCS, as noted in the Methodology section, we assume that some of the hydrogen that is produced is consumed as energy in the process, reducing the GHG intensity of the overall hydrogen production process. This raises the price of hydrogen production by 17% compared with using natural gas as process fuel. While we used the best available evidence to assess the various heating options, it is difficult to predict exactly what energy prices will be in 2050, and our analysis is sensitive in particular to these inputs. Natural gas and renewable electricity costs make up a large portion of the final costs of heating in our scenarios. Figure 2 shows a breakdown of the cost components making up the price of SMR + CCS and electrolysis hydrogen, which includes the price of natural gas or electricity, CAPEX, OPEX, and CCS in the case of SMR. The price of natural gas alone is responsible for nearly half of the cost of SMR + CCS hydrogen production, while the cost of electricity makes up more than three-quarters of the cost of electrolysis hydrogen.

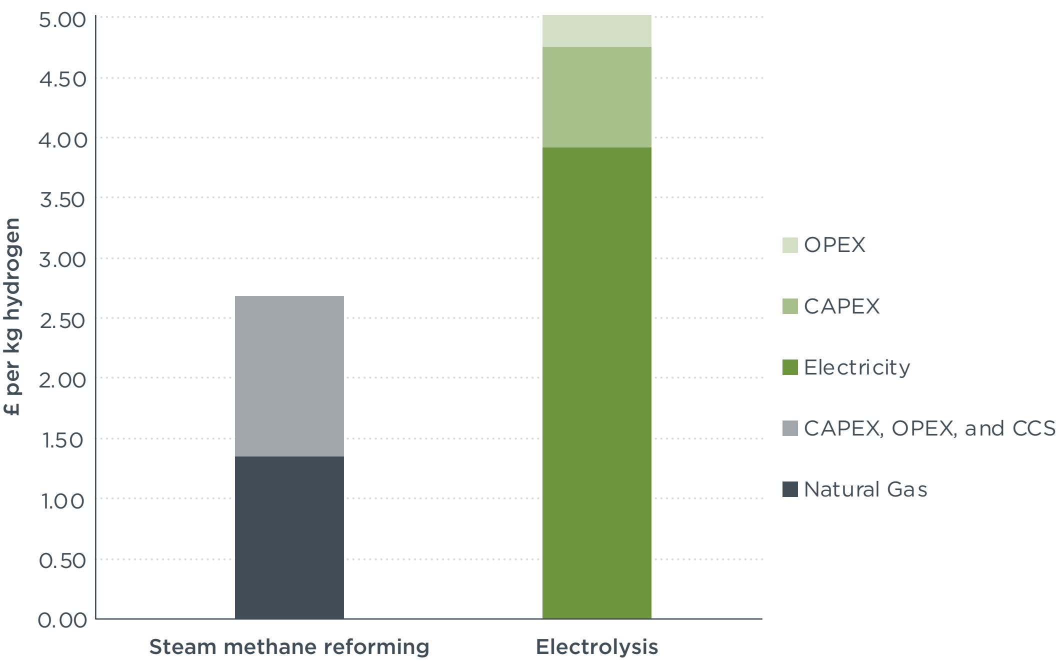

Figure 2: Cost components of SMR + CCS and electrolysis hydrogen prices in the United Kingdom in 2050.

Figure 3 shows a breakdown of cost components for the different heating pathways—the cost of renewable electricity or hydrogen as well as CAPEX and OPEX. For the pathways using hydrogen, the hydrogen is from SMR + CCS. The fuel cell scenario includes revenue from selling excess electricity to the grid. It is clear that the fuel in each heating technology accounts for the majority of overall cost. For the heat pump only, hybrid heat pump, and fuel cell scenarios, CAPEX represents the second-largest cost component, while for the hydrogen boiler, OPEX is larger than CAPEX. This is because hydrogen boilers are relatively inexpensive but require annual maintenance.

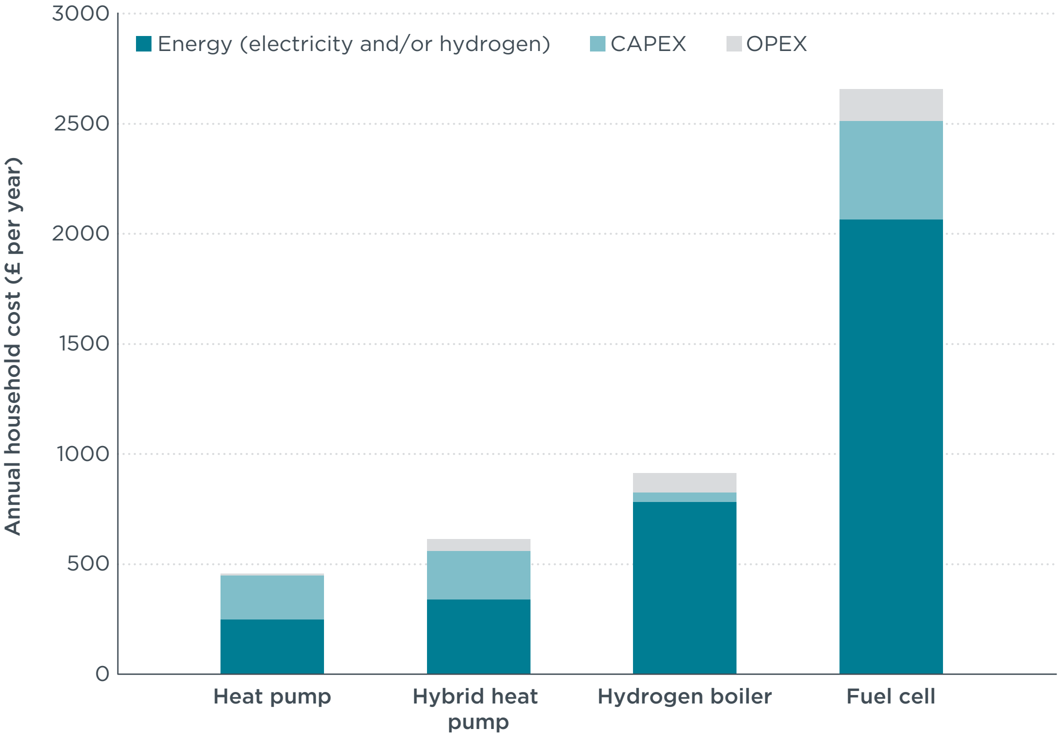

Figure 3: Cost components of heating pathways. Note: The cost of energy for the fuel cell scenario is net of excess electricity generation that is sold to the grid. For the pathways using hydrogen, the hydrogen is from SMR + CCS.

SENSITIVITY ANALYSES

To assess how changing energy prices would affect our results, we conduct a sensitivity analysis (Figure 4). The error bars show the range of results we find when varying the natural gas wholesale price, gas distribution cost, and renewable electricity price by 50% in 2050. Since 2005, EU gas prices have varied by as much as 70%, so our sensitivity analysis may not capture the full range of possible outcomes in 2050 (European Commission, 2020). We find that varying the costs of these major inputs changes our cost estimates for the heat pump, hybrid heat pump, and boiler scenarios by 20%–30%.

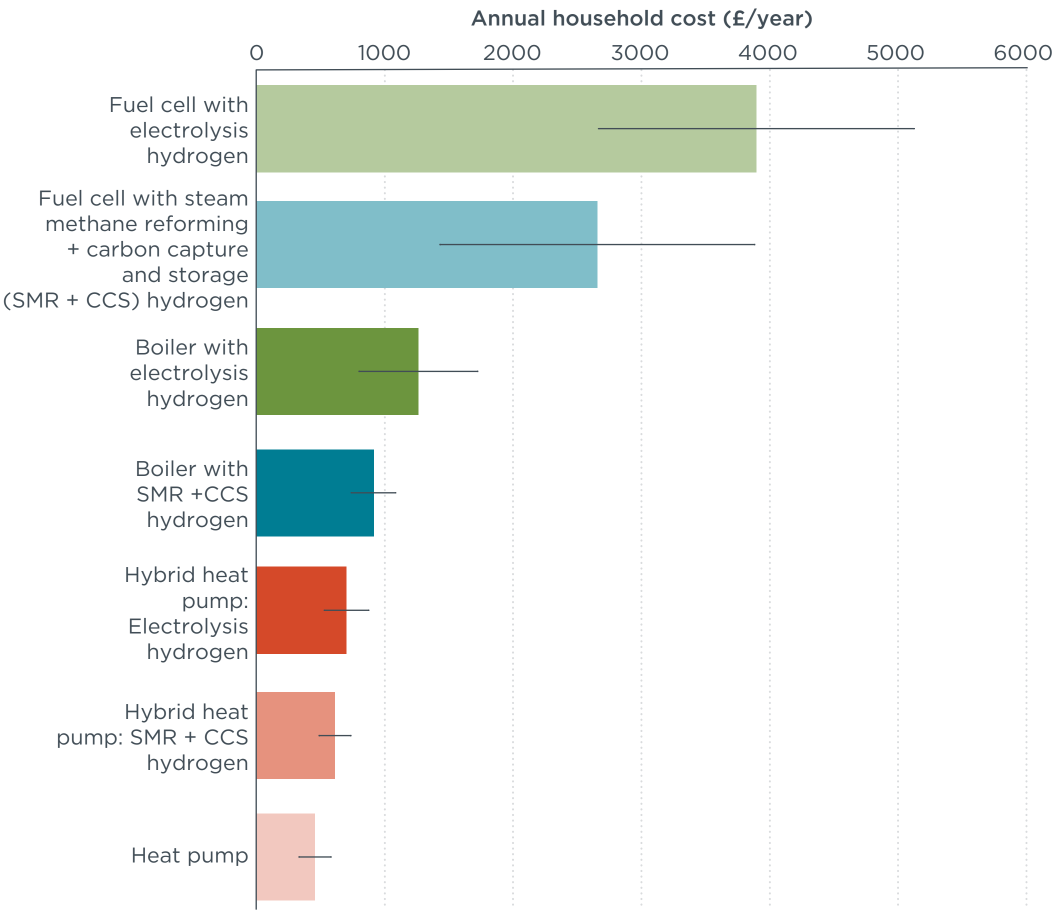

Figure 4: Sensitivity analysis on the cost of household heating. Error bars show the impact of varying the energy inputs (natural gas prices and renewable electricity prices) by 50%.

If renewable electricity prices were 50% lower than our central assumption, we find that a boiler with electrolysis hydrogen could become cost competitive with a boiler using SMR + CCS hydrogen, a fuel cell with electrolysis hydrogen could become cost competitive with a fuel cell using SMR + CCS hydrogen, and the cost advantage of the heat pump and hybrid heat pump scenarios over the SMR + CCS options would increase. If natural gas prices and gas distribution fees were 50% higher in 2050 than our central assumption, the cost advantage of heat pumps would increase as well.

Conversely, if natural gas prices and gas distribution fees were 50% lower than our central assumption, using a heat pump alone or a hybrid heat pump plus auxiliary boiler would still be a more cost-effective option than an SMR + CCS hydrogen boiler. Even if renewable electricity prices were 50% higher and natural gas prices and gas distribution fees were 50% lower than we assume, a heat pump would still be the most cost-effective option. However, it is not certain that a heat pump could supply all the energy needed during periods of high heat demand.

The cost of household heating using a fuel cell depends greatly on electricity prices. Fuel cells generate three times as much electricity as heat (Sadler et al., 2016). We presume that households would sell excess electricity to the grid, and the total cost of using hydrogen fuel cells for heating depends greatly on the amount of that revenue. For fuel cells using electrolysis hydrogen, the upper bound of the sensitivity analysis represents a case where gas distribution fees and renewable electricity prices are both 50% higher than our central assumptions. Because the higher electricity prices increase household revenue from selling electricity to the grid, we find that the household would pay only 30% more for heating than in our central scenario. Similarly, when we halve our assumed costs for renewable electricity and gas distribution, the hydrogen cost would be 40% lower, but households would also receive less revenue from selling electricity, and the lower bound of the sensitivity analysis for fuel cell heating cost using electrolysis hydrogen would therefore be only 30% lower than in the original scenario. There is particularly high uncertainty in the household cost of using fuel cells with SMR + CCS hydrogen. The cost of this heating method can be 50% higher or lower than in our central scenario if there is a combination of high natural gas prices and low renewable electricity prices or lower natural gas prices and higher renewable energy prices.

Another consideration influencing the cost of hydrogen is transportation. In the heat pump scenario with an auxiliary hydrogen boiler, we assume that hydrogen would be produced in Leicester, the UK geographical population center; liquefied; and then transported by truck to London. We conduct a sensitivity analysis on how the cost of hydrogen would change with a reduced trucking distance. According to Yang and Ogden (2007), transporting liquid hydrogen over a shorter distance incurs a higher per km cost, reducing the cost benefit of a shorter transportation distance. Thus, if the trucking distance in our central scenario is reduced from 164 km to 50 km, the total annual household cost for operating auxiliary hydrogen boilers declines by only £5 in 2050. The cost of liquefaction and trucking represents 5-7% of the total annual cost in the hybrid heat pump scenario depending on whether SMR + CCS hydrogen or electrolysis hydrogen is used.

DISCUSSION

Among the low-GHG heating options that we assess, we find that it will be most cost-effective for a single-family UK home in 2050 to use either a stand-alone heat pump or heat pump plus auxiliary hybrid boiler for cold days. Heating via hydrogen boilers using SMR + CCS is more expensive than with heat pumps in our analysis but is less expensive than using electrolysis hydrogen. We find that fuel cells using either type of hydrogen are more expensive than the other options.

The cost of the input energy makes up a large portion of the final costs in all heating scenarios—50% for natural gas and 75% for renewable electricity. In our sensitivity analysis, changing the renewable electricity price, natural gas price, and gas distribution fee by 50% affects the overall costs for most of the heating scenarios by 20%–30%. The cost of household fuel cell heating using SMR + CCS hydrogen depends greatly on electricity prices and natural gas prices, leading to the greatest uncertainty for this heating option. In all cases in our sensitivity analysis, a heat pump is still the most cost-effective option.

We find that using SMR + CCS hydrogen with natural gas as process fuel provides at best a 42%–61% reduction in GHG emissions compared with fossil gas. When renewable electricity and some of the hydrogen is used to fuel the SMR process instead, the GHG performance of SMR + CCS hydrogen improves, providing a 69%–93% reduction compared with fossil gas. In all cases when using natural gas as a feedstock for hydrogen production, upstream methane leaks will lead to GHG emissions, and the carbon capture process cannot be 100% efficient. Our carbon intensity for low-GHG SMR + CCS hydrogen (13 gCO_2e/MJ, Figure 1) is a median value of a range of carbon intensities, where we assume upstream leakage rates of 0.5%–2%. However, it is possible that leakage rates could be higher. A previous ICCT study illustrates how small changes in methane leakage can significantly reduce or reverse the climate benefits associated with a pathway (Baldino, Pavlenko, & Searle, 2018). In contrast, heat pumps and electrolysis hydrogen pathways use zero-carbon energy inputs and provide high GHG savings with greater certainty. These differences in carbon intensity are an important consideration for policymakers assessing the costs of different heating pathways. For example, although we find that heating a home using a hybrid heat pump with an auxiliary boiler burning electrolysis hydrogen would cost about the same as doing so with a boiler using SMR + CCS hydrogen, the boiler-only scenario clearly has a higher carbon intensity, even with CCS and other measures to reduce GHG.

Our cost findings differ from those in other recent studies of low-GHG heating options for Europe and the United Kingdom. Bloomberg New Energy Finance finds in *Hydrogen: The Economics of Space and Water Heating* (BNEF, 2019b) that using heat pumps in 2050 would provide a lifetime cost advantage of 40% over hydrogen boilers employing electrolysis hydrogen, using the median of their fuel costs and assuming "medium heat demand," which is not defined in the paper. But we find a greater advantage—that operating a heat pump will be almost two-thirds less expensive than a boiler with electrolysis. Similarly, we find that the lifetime of heating via fuel cells using electrolysis hydrogen will be 1.5 times. the cost of using a hydrogen boiler, while BNEF estimates that fuel cells could achieve a lifetime cost similar to that of hydrogen boilers. The difference in results between our study and BNEF (2019b) may largely be in the estimated cost of producing electrolysis hydrogen. The BNEF study projects a global average price of hydrogen delivered to the end user of $2–$4/kg in 2050, with the United Kingdom falling in the middle of that range at around £2.16/kg. This is less than half our estimate of £5.35/kg for the final delivered cost of electrolysis hydrogen. Most likely because of this significant difference, BNEF concludes that using an air-source heat pump does not offer much of a cost advantage over electrolysis hydrogen for heating (2019b).

The BNEF (2019b) study and a sister publication on electrolysis hydrogen production (BNEF, 2019a) provide few details on cost assessment methodology and assumptions. Some assumptions appear to be optimistic. For example, BNEF (2019a) assumes that electrolyzers made in China could be 50% cheaper than those manufactured in other parts of the world, without providing evidence or justification. BNEF (2019b) does not include pipeline construction costs and does not detail or provide a data source for assumed hydrogen network costs. BNEF (2019b) does note that retail electricity prices will play an important role in determining the cost competitiveness of the different technologies in 2050, in agreement with one of our findings.

Our findings also differ from those of an Imperial College London (ICL) study (Strbac et al., 2018), although we use some of the same data inputs. The difference in results is most likely due in part to methodological differences: The ICL study conducts society-wide cost optimization modeling, while our analysis is on a household level. Differences in assumptions may also play a role, and we cannot compare all of these as Strbac et al. do not provide all of them.

Similarly to our study, the ICL report concludes that electric heating using heat pumps or resistive heating is less expensive than heating with hydrogen, either from electrolysis or autothermal reforming + CCS). That study determines that hydrogen is the least energy-efficient heating option and finds cost savings in investing in renewable electricity infrastructure but not in hydrogen grid infrastructure (Strbac et al., 2018). However, contrary to our findings, Strbac et al. (2018) conclude that a hybrid scenario using electricity plus low-carbon hydrogen or biomethane during cold spells is the most cost-effective solution for the United Kingdom, even less expensive than a heat pump-only option. The researchers find that this option would cost society nearly 30% less than their hydrogen scenario. One reason the ICL report offers for this finding is that the electricity infrastructure in the hybrid scenario would not need to be as high-capacity as it would in the electricity-only scenario. We do not consider the impacts of heat demand on large-scale electricity infrastructure in our analysis. A recent Fraunhofer study found that electricity grid infrastructure does not respresent a significant obstacle to using heat pumps (Gerhardt et al., 2020).

Another reason Strbac et al. (2018) give for their finding is that they believe there is no need to replace gas appliances in the hybrid scenario, as biomethane can readily be used in natural gas boilers. We consider this to be an unrealistic assumption as our previous research has shown that the cost-viable potential for biomethane in the United Kingdom is very low (Baldino, Pavlenko, & Searle, 2018). For illustrative purposes, we calculate the cost of using renewable methane directly in gas boilers as a heating alternative and find the cost would be much higher than for heating a home with hydrogen. Using renewable methane would cost a single-family UK home £1,630 in 2050, compared with £910 when SMR + CCS hydrogen is used in a boiler, and £1,260 when electrolysis hydrogen is used. For this calculation, we assume a renewable methane cost of £1.59/kg, which is the cost at which a substantial amount of renewable methane could become cost viable but still not nearly enough to replace all gas demand (Baldino, Pavlenko, & Searle, 2018).

In addition, Speirs et al. (2017) assess the costs and carbon impacts associated with using renewable gas, including hydrogen, in heating. They find that SMR + CCS hydrogen costs roughly £0.60/kg less than our analysis, which would translate to a household cost of 15% less than our analysis using the same assumptions as our hydrogen boiler scenario. This difference in hydrogen cost is partly because their study does not include the cost of upgrading gas infrastructure to be hydrogen-ready. Although Speirs et al. (2017) don't say so, it is also possible that Speirs et al. (2017) assess the cost of SMR + CCS hydrogen using natural gas as process fuel, which would lead to a higher carbon intensity than the pathway in our study.

Our analysis focuses only on single-home costs in 2050 and does not consider the potential for district-wide heating, where a single source provides heating for multiple buildings using a network of insulated pipes. David, Mathiesen, Averfalk, Werner, and Lund (2017) estimate that district heating could cover 50% of heating demand in Europe and that 25%–30% of district heating needs could be met with large-scale electric heaters. Our analysis suggests that using heat pumps at a district scale could be more cost-effective than using hydrogen, but it is difficult to draw a concrete conclusion because heating at this scale may incur lower hydrogen infrastructure costs. Gerhardt et al. (2020) argue that district-wide heating needs could best be met with large-scale heat pumps and that combined heating and power (CHP) with hydrogen should be used only when it is not possible to use heat pumps. The researchers write that district-wide CHP would provide a cost advantage compared with fuel cells in individual homes.

The heating demand that we estimate for a typical UK residence in 2050 takes into account efficiency improvements compared with buildings today (Fleiter et al., 2017). However, it is important to compare the cost of heating a home using hydrogen or renewable electricity with the cost of reducing heating demand from installing various efficiency measures. Connolly, Hansen, and Drysdale (2015) analyze the cost of a number of energy-efficiency measures in the United Kingdom. They find (Figure 10 of the study) that a typical UK home could reduce its heating needs by around 15% with measures that would be less expensive than the per-heat-unit cost of our heat pump scenario (£0.08/kWh). Based on this comparison, using energy efficiency measures to reduce heat demand would be a more cost-effective strategy for achieving GHG reductions than any of the low-GHG heating pathways we assess. One should thus keep in mind the importance of continuing to support efficiency improvements in homes by 2050. The UK Green Building Council (2020) notes that policy measures to improve insulation in UK homes have stalled, highlighting that this is an important issue to address.

While we present a sensitivity analysis in Figure 4, we do not believe that all of these energy price scenarios are likely in 2050. Given the current policy trajectory, it seems unlikely that the United Kingdom will have lower natural gas prices and higher renewable energy prices than presently predicted. Therefore, we consider it unlikely that the lower bound of our sensitivity analysis for fuel cells using SMR + CCS hydrogen will be reached. The results from the sensitivity analysis illustrate how a carbon tax or other policy measure could have a significant influence on supporting heat pumps over hydrogen technologies, or vice versa.

In addition, this analysis includes only a short-term storage cost for both SMR + CCS and electrolysis hydrogen, representing approximately the cost of storing the amount of hydrogen produced via electrolysis in a single day. We do not include long-term, seasonal storage of hydrogen, which could be a significant issue, particularly for electrolysis hydrogen produced using wind and solar electricity. In particular, seasonal supply and demand of solar-powered electrolysis hydrogen would be deeply mismatched, with the greatest hydrogen production in the summer and highest demand for heating in the winter. The amount of wind power generation is difficult to predict on a seasonal timescale (Lledó, Torralba, Soret, Ramon, & Doblas-Reyes, 2019). Thus, the feasibility and cost of storing hydrogen, which may fluctuate throughout the year, is an important consideration for policymakers planning for 2050, particularly for the heating sector, where demand peaks at one point in the year.

At present, technologies for long-term storage of hydrogen exist, but few have reached large-scale, commercial maturity. Salt cavity storage of hydrogen is already used industrially, but it is limited to certain regions. All storage options, besides simply liquefying or compressing hydrogen, are still at relatively early stages of development, so Andersson and Grönkvist (2019) note that it is not possible to compare the costs of different storage technologies. Nascent storage technologies include converting hydrogen into energy-carrying molecules with better storage density, such as chemical hydrides, methanol, liquid organic hydrogen carriers, and ammonia, but all of these options would come with significant efficiency losses.

CONCLUSIONS

As UK government officials work to decarbonize the building sector by 2050, they must make key decisions regarding infrastructure and policies to support renewable energy sources. As they make these decisions, it is important that they consider how end users will be affected. Therefore, in this assessment, we estimate the cost to heat households in 2050 using zero-carbon or low-carbon renewable electricity, hydrogen, or a combination of both.

We find that both stand-alone and hybrid heat pumps are lower-cost solutions than hydrogen-only technologies. Our analysis shows that stand-alone heat pumps are 50% less expensive than using a boiler with SMR + CCS hydrogen, and the cost of hybrid heat pumps with auxiliary hydrogen boilers using SMR + CCS is still 30% less expensive than using a boiler alone. We find that hydrogen boilers using SMR + CCS are around 30% less expensive than those using electrolysis hydrogen from zero-carbon electricity. In our analysis, fuel cells using SMR + CCS hydrogen are six times more expensive than using heat pumps with renewable electricity and almost three times as expensive as using a boiler with the same kind of hydrogen.

It is important to consider the relative carbon intensities of the different heating options as well. SMR + CCS hydrogen cannot completely decarbonize heating because there will always be upstream natural gas leakage and carbon capture is never 100% efficient. We calculate that SMR + CCS hydrogen today has 39%–58% of the GHG emissions of fossil gas, and even in a scenario where zero-carbon energy is used to fuel the SMR process, this pathway would still emit 7%–31% of the GHG emissions of fossil gas. In contrast, the use of wind and solar power for heat pumps and electrolysis hydrogen would be fully zero-carbon.

At the same time, these conclusions come with uncertainties. Energy prices for 2050 are unknown and will have a large impact on the cost-competitiveness of these heating options. Further, there are uncertainties regarding the impacts that hydrogen storage will have on the gas grid and the impact renewable electricity will have on the electricity grid. All of these factors will influence the costs of heating in 2050 in ways that are difficult to predict.

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