Heat GB

Calculating the network costs for low carbon heating

citizens advice

October 2023

Executive summary

28 million homes will need to be using low carbon heating systems by 2050 in order to meet net zero targets. The Climate Change Committee reports that progress on heating is already falling behind[1]. The UK Government has recently indicated that the majority of homes will use electrically powered heat pumps and strategic decisions about the role of hydrogen for domestic heating are expected in 2026.

The Climate Change Committee (CCC) has challenged the UK Government on the need to set a clear direction on the future technology mix for low carbon heat, with heat pumps and heat networks described as no-regrets options in many cases and to identify regions with high, low or no potential to use hydrogen for home heating[2].

We commissioned LCP Delta, as leading experts on the energy transition, to explore one of the key cost factors: the cost to upgrade the electricity wires and gas pipes depending on which heating technology is used, and where it is used.

Citizens Advice is the statutory energy consumer advocate. We actively engage in the processes to regulate monopoly energy network companies, to ensure that the costs consumers pay are appropriate.

Network costs already make up the second highest portion of a household consumer's energy bill after wholesale costs, and network upgrades will certainly be needed across GB to deliver low carbon heating. However, there has been a lack of evidence of these costs on an area-by-area basis which the CCC is clear is essential to UK Government decision making.

The research explores the costs in 12 different location archetypes across GB to deliver four different heat decarbonisation scenarios for households:

1. full electrification
2. full conversion of the gas network to 100% hydrogen
3. the use of hybrid heat pumps, and
4. where no technology is specified.

The research does not consider industrial or non-domestic heat.

Findings

In **10 out of the 12** archetypes, **electrification** has the lowest network costs, with hydrogen having the lowest costs for the remaining 2 archetypes.

Electrification is the lowest cost option in all **rural and industrial** archetypes by between 27% and 84%.

Distribution upgrades are the **key influence** for overall costs in all archetypes and scenarios.

Where **electrification** has the lowest cost this is, on average, **44% below the next lowest cost scenario**. Where hydrogen has the lowest it is, on average, 5% lower when hydrogen storage costs are not included.

Not specifying a technology (scenario 4) more than **doubles the network costs** on average as it requires large scale upgrades of both electricity and gas networks.

Citizens Advice would like to thank stakeholders from the Department for Energy Security and Net Zero, Climate Change Committee, Ofgem, Imperial College London, and the Energy Networks Association for their contributions in the two expert workshops held as part of this research.

Recommendations

1. Decisions about decarbonising heat at lowest cost must reflect local network costs and be on an **area-by-area basis.**

2. The UK Government should **make low-regrets decisions** about heat decarbonisation options **as soon as possible** in areas where evidence suggests they are, or are not, suitable. Based on this report and the CCC's expectations of fuel costs we recommend:

   - Ruling out hydrogen in rural areas before 2026 and pursuing electrification
   - Pursuing the strategy recommended by the CCC to push forward with electrification as the default choice where it is feasible. Our findings have not identified where the full hydrogen scenario is low-regrets and hybrid heating costs may be comparable or lower overall.

3. The UK Government should **rule out** options in locations which require **both** the electricity and gas networks to undergo extensive upgrades to be ready for low carbon home heating as this is prohibitively costly to consumers.

4. The UK Government should publish an **assessment of future wholesale costs** of electricity and hydrogen. This will be a key factor in further defining no and low-regrets decisions that can be made.

5. In locations where electrification of heat is low-regrets, clarity must be provided by the UK Government to consumers and supply chains. Policies should ensure consumers have the **information, protection and support needed**.

6. The UK Government **should not implement** a GB-wide hydrogen-ready boiler mandate.

The challenge

Around 78% of homes use gas boilers for heating while 12% use some form of electric heating, 5% use oil, and 5% use a mix of solid fuel, gas fires, portable heaters and district heating. In order to meet the country's Net Zero targets all 28 million homes will need to be heated by low carbon technology by 2050. Currently there are only a small number of technologies considered to be able to deliver this:

- A range of electrically-powered appliances, with the majority likely to be air source heat pumps
- Boilers powered by 100% hydrogen
- Hybrid heat pumps which combine both appliances
- Heat networks which can be powered by low carbon energy

The Climate Change Committee (CCC) is the independent, statutory body who advises the UK and devolved governments on emissions targets and reports on progress made. In their Progress Report 2023, the CCC highlighted that progress in decarbonising buildings is *"broadly insufficient to ensure the buildings sector reaches zero emissions by 2050"*.

They advised the UK Government that the rate of consumers installing low carbon heating technologies is too slow, with heat pump installations well below what is required and needing to rise nine-fold in six years.

They identified what they describe as *"systemic uncertainty"* around the future roles of electrification and hydrogen for heat in buildings, which they say is holding back investment in the infrastructure to produce, store and transport electricity and hydrogen.

Although the UK Government is due to take a strategic decision on the role of hydrogen for heating in 2026, the CCC has recommended that the scope of the strategic decision is narrowed prior to 2026 by taking a number of actions including:

- Affirming that electrical heat is the default option in all new buildings and existing properties off the gas grid
- Setting out clear routes for other properties or areas where electrification or heat networks represent low-regret options

The CCC recommends that those locations already known to be suitable for heat networks should proceed with them.

In locations where heat networks have not already been identified, decision makers at all levels of Government need to assess where electrification or hydrogen represents a low-regrets option and implement policies and provide clear direction of how heat decarbonisation will progress in different locations.

Why this matters for consumers

Any decisions regarding heating technologies must be informed by safety, affordability, consumer acceptability, disruption, practicality, energy security and resilience and, as highlighted by the CCC, the necessary rate of emissions reduction.

We commissioned LCP Delta, as leading experts on the energy transition, to explore a key cost factor: the cost to upgrade the electricity cables and gas pipes depending on which heating technology is used, and where it is used.

Network costs make up the second highest portion of a consumer's energy bill at between 20% and 25%. Understanding these costs is therefore essential to deliver the necessary changes at the lowest cost to consumers.

This report is intended to provide independent evidence to support the UK Government to make decisions as early as possible and inform further work in this area.

Consumer-first energy transition

The net zero transition must be affordable, fair and centred around consumers.

Optimising costs and ensuring consumers have clear and consistent information, protection and support will therefore be fundamental to net zero and to decarbonising heat.

Narrowing the scope of the strategic decision prior to 2026, taking the actions recommended by the CCC, and providing greater clarity will enable government at the UK, devolved and local level to develop the right policies and incentives to encourage consumers to adopt technologies that are right for their homes.

There are four key risks that are playing out in real time:

1. **Consumers and landlords install heating technologies which may not be compatible with the heat decarbonisation solution in their area** - purchasing decisions being made now will have a 10-20 year lifecycle or could even leave people facing scrappage costs. Consumers should not be expected to change technologies multiple times.
2. **Regulatory decisions about gas and electricity network investment could lag behind need or be inaccurate** - resulting in extra costs for consumers.
3. **Heating technologies continue to be used which contribute towards greenhouse gas emissions for a longer period of time** - slower progress from reducing emissions from home heating will require faster progress in other emissions areas.
4. **A lack of certainty creates barriers to commercial decisions for supply chains and the generators and producers of electricity and hydrogen** - further jeopardising progress and increasing costs to consumers.

Methodology: Archetypes and scenarios

We have considered **four scenarios** in this research. Each scenario assumes that a proportion of domestic households are using a particular heating technology mix in order to understand how that need would be met by the electricity and gas networks. The technologies in these scenarios align with the main technologies considered by the CCC. Only heat networks are anticipated to play a key additional role.

This report also assumes that no new gas distribution network will be built, as recommended by the CCC. There is therefore a distinction in the technologies used in scenarios 2-4 between homes already connected to the gas grid and those that are not.

	Heating technologies	Fuel used	% of domestic households using the heating technology
Scenario 1	Air source heat pump	electricity	**100%** of homes
Scenario 2	Hydrogen boiler	100% hydrogen	**100%** of homes **already connected** to the gas distribution network
	Air source heat pump	electricity	**100%** of homes **not connected** to the gas distribution network
Scenario 3	Hybrid heat pump	100% hydrogen + electricity (in same appliance)	**100%** of homes **already connected** to the gas distribution network
	Air source heat pump	electricity	**100%** of homes **not connected** to the gas distribution network
Scenario 4	Air source heat pump	electricity	Technology mix is unknown. The base case assumes the following for heating: • 50% of the electricity reinforcement required in scenario 1 • 100% of the gas distribution costs required in scenario 2 • 50% of the gas transmission costs required in scenario 2
	Hydrogen boiler	100% hydrogen	
	Hybrid heat pump	100% hydrogen + electricity (in same appliance)	

Archetypes

This research considers the above scenarios in a **set of 12 archetypes** across GB: 3 each in Scotland and Wales, and 6 across England. Each archetype is a real location with different characteristics which influence network costs. To ensure consistency and comparability, each archetype contains 5,000 domestic dwellings.

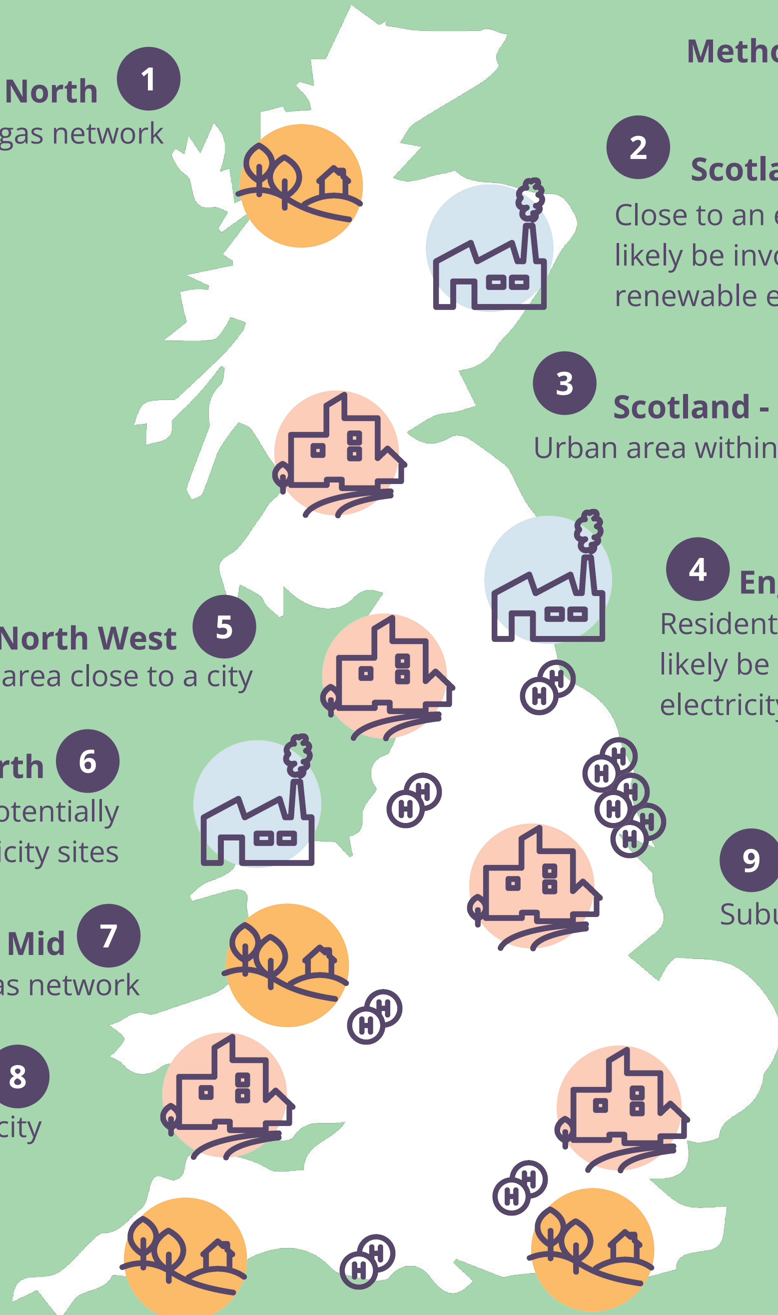
Characteristics such as **dwelling density** and **geographical location** are key factors. The **proportion of homes using each heating appliance**, based on whether they are already connected to the gas distribution network or not, also influences the costs.

For example, a rural location would require longer pipes and wires between each dwelling and, in the case of electricity, would most likely be served by overhead wires. By contrast, in a densely populated city, the pipes and wires would have less distance to travel between dwellings but are more likely to be installed underground. A further example is that the location, whether urban or rural, may require differing lengths of transmission infrastructure based on geographical location.

The archetypes do not consider industrial or non-domestic heat.

These archetypes are not intended to be representative of any of the much larger regions or countries in GB. However, findings would be broadly representative of other locations which share similar characteristics.

- Rural
- Industrial
- Urban
- Hydrogen storage location (current/potential)



1 Scotland - North
Rural area with most dwellings (~ 60%+) off the gas network

2 Scotland - Mid
Close to an existing industrial site that will likely be involved in future hydrogen and renewable electricity production

3 Scotland - South
Urban area within a densely populated Scottish city

4 England - North East
Residential area nearby to an industrial site that will likely be involved in future hydrogen and renewable electricity production

5 England - North West
Suburban area close to a city

6 Wales - North
Residential area nearby to an industrial site and potentially to future hydrogen and renewable electricity sites

7 Wales - Mid
Rural area with most dwellings (~60%+) off the gas network

8 Wales - South
Urban area within a densely populated Welsh city

9 England - Midlands
Suburban area close to a city

10 England - London
London borough

11 England - South East
Rural area with most dwellings (~ 60%+) off the gas network

12 England - South West
Rural area with most dwellings (~ 60%+) off the gas network

Methodology

The methodology used in this research calculates the distribution and transmission costs for both the gas and electricity networks according to the 4 scenarios and 12 archetypes, producing 48 different final outputs for comparison.

A literature review was conducted by LCP Delta to develop the methodology and source key inputs and variables for the calculations. It is an important part of this research that sources were drawn from publicly available reports and are deemed to be robust and independent. LCP Delta's report lists the key data sources and their use, most of which are governmental, from official statistics agencies, academic institutions, National Grid ESO, the Climate Change Committee and network companies.

These inputs include peak heating demand, the required fuel to meet demand, the proportion of properties connected to the gas distribution network, road lengths, and overall geographical distances.

The literature review also revealed what types of network upgrades are required, how these vary by the demand they need to meet and how the costs vary. For example, this includes electricity sub-station upgrades, transformers and circuit reinforcement; and gas pipeline retrofit, new gas pipeline, compressors, expanders, metering stations and excess flow valves which are needed for safety reasons[3].

For all four cost components - gas distribution, gas transmission, electricity distribution, and electricity transmission - the methodology disaggregates the costs so that outputs are associated with heating demand only.

The methodology considers the proportion of homes in each archetype which are already using a form of electric heating. As there must already be adequate network capacity to serve these homes, all electricity network calculations reflect the upgrades needed to bridge the gap between current capacity and what would be needed under each scenario.

To understand electricity transmission network costs the methodology starts with the overall projected cost of transitioning the onshore grid to net zero set out by the UK Government's Electricity Networks Strategic Framework[4]. A proportion of this is considered for heat and to ensure that outputs were able to reflect differences between archetypes, electricity transmission costs have been apportioned according to the new electricity demand that could not be met currently.

The cost apportionment also uses Transmission Network Use of System tariffs (TNUoS). These charges are paid by consumers to recover the costs of building and operating the transmission network. They vary across GB, reflecting a range of locational factors such as being lower when closer to renewable energy generation, such as in Scotland, and higher in southern areas of GB where they are furthest from generation. These factors are expected to broadly remain the same in the future and so have been used to indicate potential variation. Any significant changes to the locational signals of TNUoS would affect the findings.

This research considers the costs to establish hydrogen storage sites and to transport the gas for each archetype and scenario. Input from our expert panel indicated that supporting hydrogen for home heating on a significant scale would not be feasible without large-scale hydrogen storage facilities which can meet demand through the winter. Results are presented with and without these figures to enable different comparisons as electricity storage costs have not been considered.

The storage locations are based on the most likely scenarios according to the information available in the data sources, insights from the LCP Delta hydrogen experts, and input from the workshop experts. The locations chosen each have hydrogen storage projects in early stages or they are currently being used to store natural gas. It is likely that additional storage facilities would be required to provide GB with sufficient storage quantities, particularly under scenario 2. However, due to the early stages of development LCP Delta did not speculate on the location of additional sites.

Assumptions

The methodology assumes no expansion of the gas distribution network as recommended by the CCC. In each of the scenarios where a proportion of homes use hydrogen for heating (2, 3 and 4) there is therefore a cost associated with electricity network upgrades for homes not connected to the gas distribution network. This cost is included in the total costs presented.

The Iron Mains Risk Reduction Programme (IMRRP) is currently replacing 'at risk' iron gas mains (i.e. those pipes within 30 metres of buildings) and is due to be completed in 2032. This research assumes this programme is already completed so the costs are not included in the methodology. The methodology does, however, include the costs to replace the iron pipes which are not currently considered for mandatory pipeline replacement within the scope of the IMRRP but would be needed to achieve the transportation of 100% hydrogen. The lack of detailed information publicly available means some assumptions have had to be made. However, only a small range in the level of completion has been observed across GB so this is not expected to have a material impact.

In the three hydrogen-use scenarios (2, 3 and 4) the same gas distribution reinforcement cost has been assumed for each archetype because each of them require a network of the same size to ensure consumers have access to hydrogen even if the heating demand varies.

In scenario 3 (where hybrid heat pumps would be used) and scenario 4 (where no technology is specified) this research has made some plausible assumptions. For scenario 3 we have assumed that a hybrid heat pump runs as a hydrogen boiler 20% of the time and as an air source heat pump 80% of the time. In scenario 4, we cannot predict the choices that consumers might make regarding their preferred heating technology. We have therefore presented findings from a base case and two sensitivities which are explained in the findings section.

To calculate gas distribution and transmission costs the methodology must account for how much of the network can be repurposed for hydrogen and how much new network may be required to facilitate hydrogen for heating. An assumption is applied to the transmission network and for the distribution network different assumptions have been used in the rural, urban and industrial archetypes.

This research assumes that all homes have an Energy Performance Certificate (EPC) level C, which is found to be the average potential EPC score in each archetype region. If progress on energy efficiency substantially increases then costs may be lower.

Existing electricity network headroom describes the amount of capacity that is not being utilised at each substation on the electricity distribution network. Where there is greater headroom, it will take a greater additional electricity demand before reinforcing is required.

However, if this is small then it will take a smaller additional demand before upgrades are required. As headroom is specific to each substation it was not possible to account for this for each archetype and is therefore based on assumptions.

As data was not available to gather location-specific electricity distribution network lengths at the lowest voltage level, urban and industrial archetypes are calculated with the same length which is assumed to be installed underground while in rural areas a shorter length is assumed but is assumed to be installed overhead as pole-mounted cables.

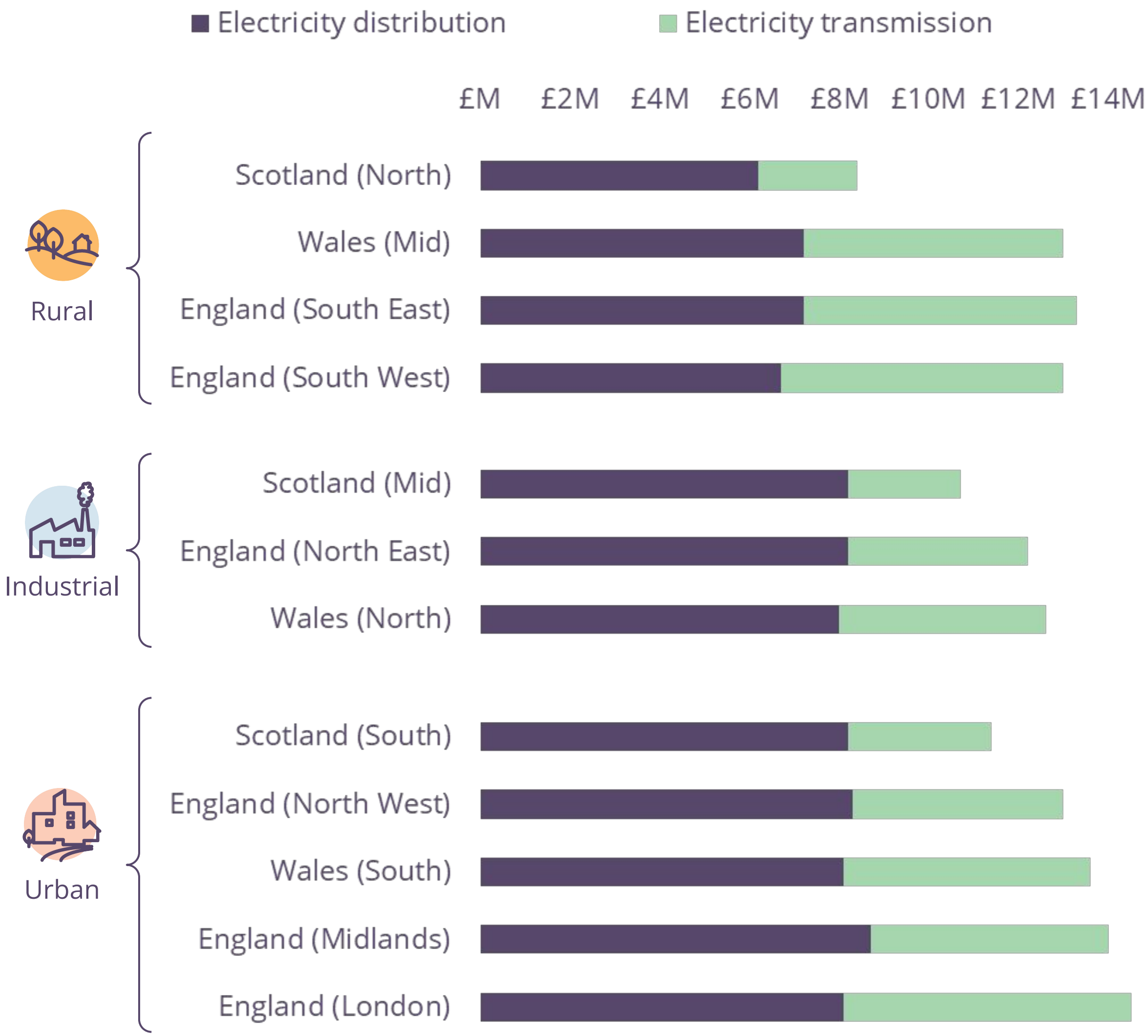
Expert workshops

In developing this methodology and some of the key assumptions, LCP Delta held two expert workshops with stakeholders from DESNZ, the Climate Change Committee, Ofgem, a leading academic from Imperial College London, and the Energy Networks Association. In these workshops the expert panel challenged assumptions, provided feedback on initial findings and provided unique insights and further data sources. LCP Delta tested and refined the methodology in response to this feedback. In a range of areas the methodology was improved. Areas include the scale of electricity transmission investment required, how the Iron Mains Risk Reduction Programme (IMRRP) was considered, and the use of storage instead of production to calculate hydrogen transmission costs. Citizens Advice would like to thank all stakeholders for their valuable contributions.

For further detail on the methodology please read the report produced by LCP Delta for Citizens Advice.

Findings

Scenario 1: Full electrification



* Costs are relevant to 5,000 dwellings

In this scenario, the research assumes that all homes use electrified heat and only the costs to upgrade the electricity network are included.

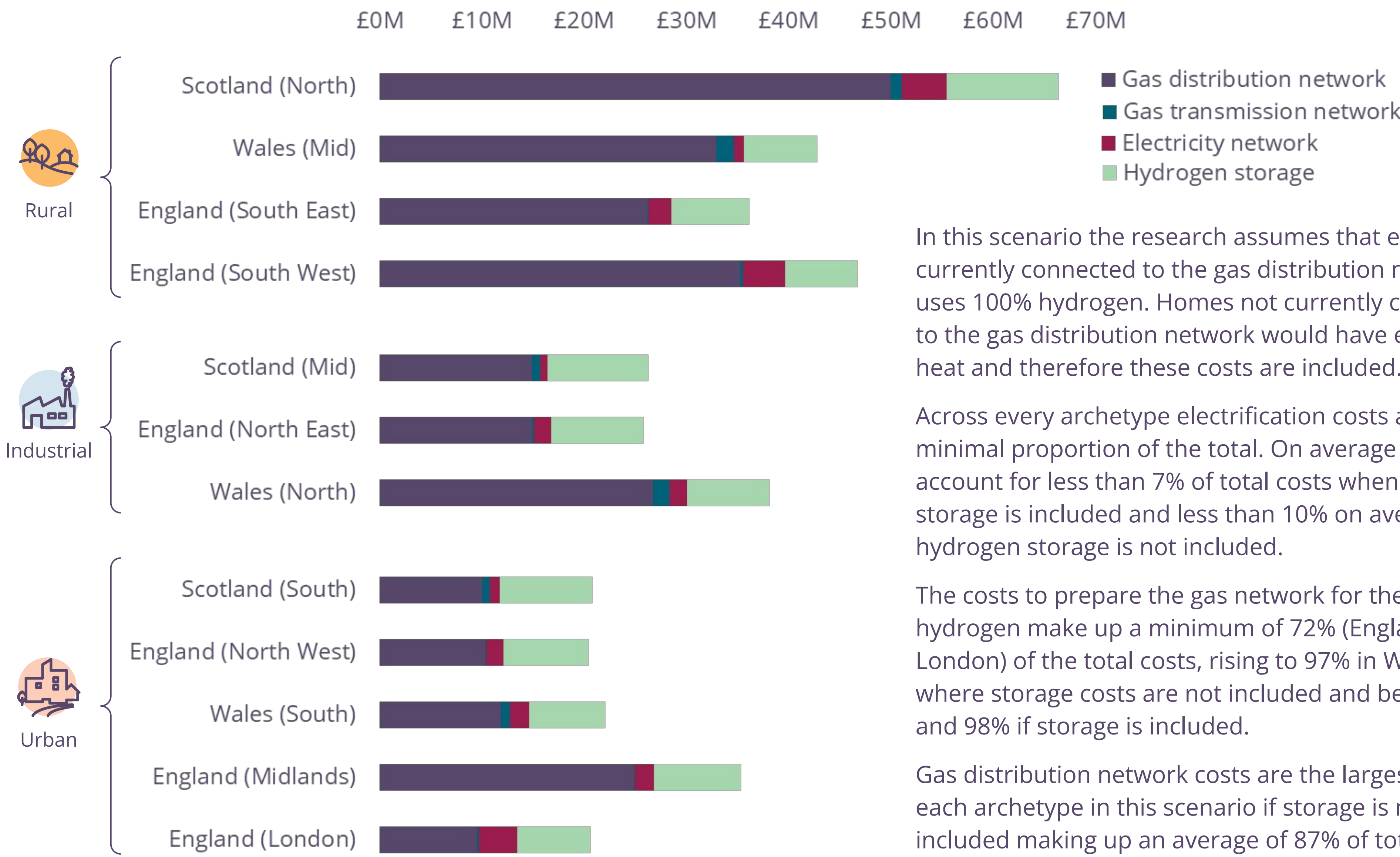
England (London) has the most expensive electricity reinforcement costs and Scotland (North) has the lowest. The differences between the two archetypes are driven mainly by higher transmission costs in England (London) and very low transmission costs in Scotland (North).

There isn't a significant difference in the costs at the distribution level in each location, although across the archetypes they account for between 51% and 76% of total upgrade costs.

Only in rural areas do we see lower distribution costs relative to urban and industrial areas. This is driven by the lower costs of cables being installed overhead on poles in rural areas while being more expensive where they need to be laid underground in more urbanised areas. In Scotland (North) lower costs can also be seen due to nearly a fifth of homes already using electric heating.

The general trend for transmission costs is that they are lower in the North and higher in the South.

Scenario 2: 100% hydrogen



In this scenario the research assumes that every home currently connected to the gas distribution network uses 100% hydrogen. Homes not currently connected to the gas distribution network would have electrified heat and therefore these costs are included.

Across every archetype electrification costs are a minimal proportion of the total. On average they account for less than 7% of total costs when hydrogen storage is included and less than 10% on average if hydrogen storage is not included.

The costs to prepare the gas network for the switch to hydrogen make up a minimum of 72% (England, London) of the total costs, rising to 97% in Wales (Mid) where storage costs are not included and between 82% and 98% if storage is included.

Gas distribution network costs are the largest cost in each archetype in this scenario if storage is not included making up an average of 87% of total costs.

* Costs are relevant to 5,000 dwellings

It is also the largest cost when storage is included with the exception of (England, London) and Scotland (South), where costs are just less than half of the total costs at 46% and 49% respectively. This is driven primarily by the level of urbanisation.

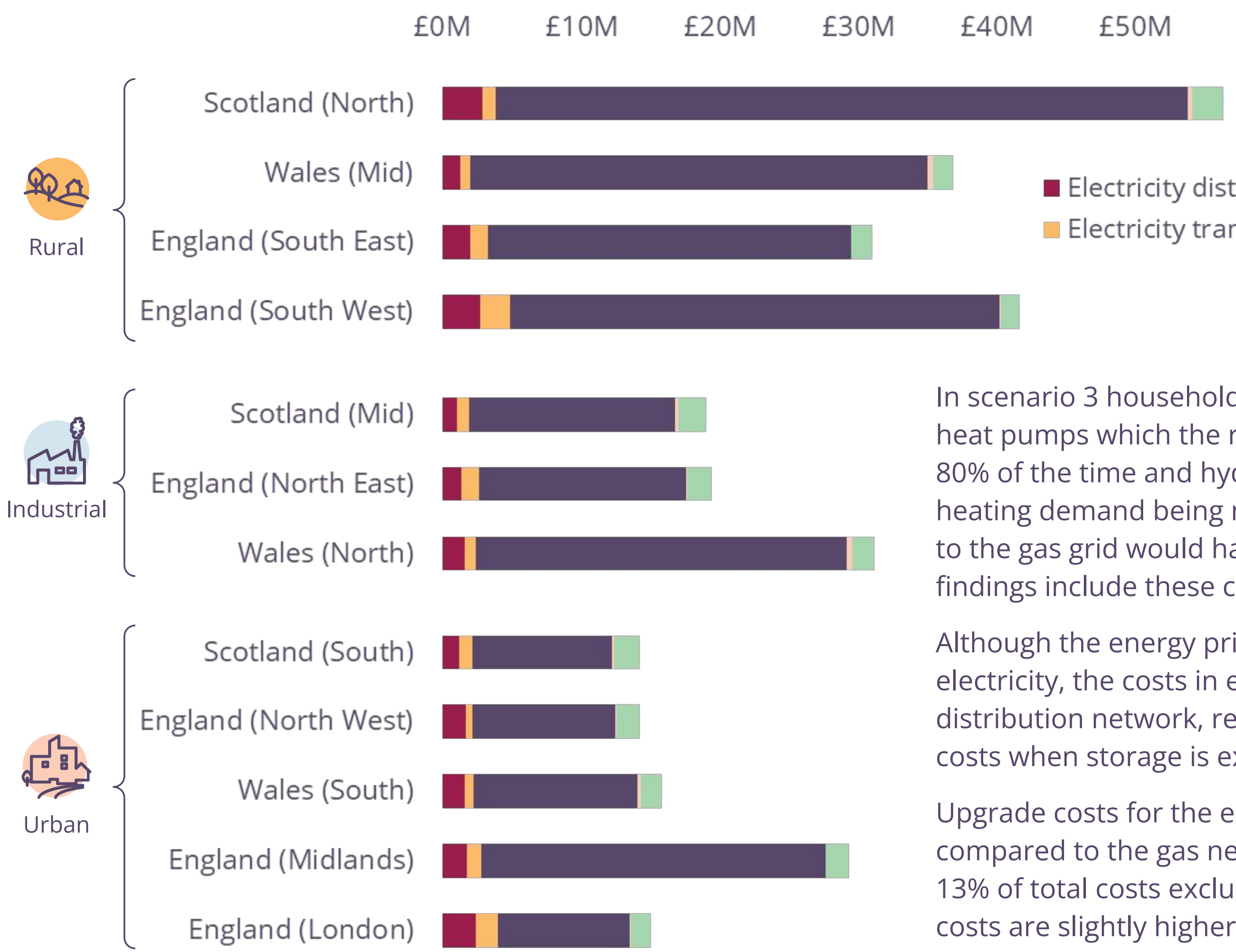
Rural archetypes have the highest gas reinforcement costs due to the lower density of dwellings and therefore larger size of the distribution network required. Costs for urban archetypes are generally much lower due to the smaller size of the distribution network. Costs for industrial areas are more similar to urban areas due to similar levels of urbanisation and proportions of homes connected to the gas grid. However, there is variety among industrial archetypes with Wales (North) having costs that are 47% higher than England (North East) even with storage costs included.

A key finding is that hydrogen storage associated with domestic heating increases transmission costs by between 5-86 times and location is a key factor. Firstly, gas transmission costs on their own are very small because of the relatively small size of the network making up between 0.4% and 7% of gas network costs without storage. The other reason is due to the capital costs of hydrogen storage. Scottish archetypes and the North of England (North East) have the four most expensive storage costs.

In England (North East) the archetype is industrial and is located nearby to a designated storage facility. However, if storage costs are included, these represent a significant proportion of the total costs at 35% (the 4th highest proportion of the 12 archetypes).

Scenario 3: Hybrid heat pumps

14.2 – 56.2 **Scenario 3 range of costs** (£millions)



In scenario 3 households connected to the gas grid use hybrid heat pumps which the research assumes will run on electricity 80% of the time and hydrogen 20% of the time, with peak heating demand being met by hydrogen. Homes not connected to the gas grid would have entirely electrified heat and the findings include these costs.

Although the energy primarily used by homes in this scenario is electricity, the costs in each archetype are dominated by the gas distribution network, representing between 69% and 93% of all costs when storage is excluded.

Upgrade costs for the electricity networks are generally low compared to the gas network costs making up an average of 13% of total costs excluding storage. Electricity network upgrade costs are slightly higher as a proportion of total costs for Scotland (South), England (North West), Wales (South), and England (London).

* Costs are relevant to 5,000 dwellings

Urban locations generally have the lowest overall costs. England (Midlands) is an exception though gas distribution costs will be overstated here due to data availability, as explained in more detail in the limitations section. There is a range in costs for industrial locations with a 78% difference between Scotland (Mid) and Wales (North).

Rural locations have the highest costs overall. This is consistent with scenario 2 as this scenario requires the same gas distribution network upgrades even where the gas demand is much lower. As in scenario 2, these locations have relatively longer pipe lengths and lower dwelling density.

In this scenario, the lower hydrogen demand means that transmission and hydrogen storage costs represent a consistently small proportion of overall costs. While hydrogen transmission would still be required, a lower proportion of the cost is attributed to domestic home heating. Similarly, a lower hydrogen demand results in lower storage costs. Combined, they represent an average of 8% of total costs, while the highest proportion is only 14% (Scotland (South)).

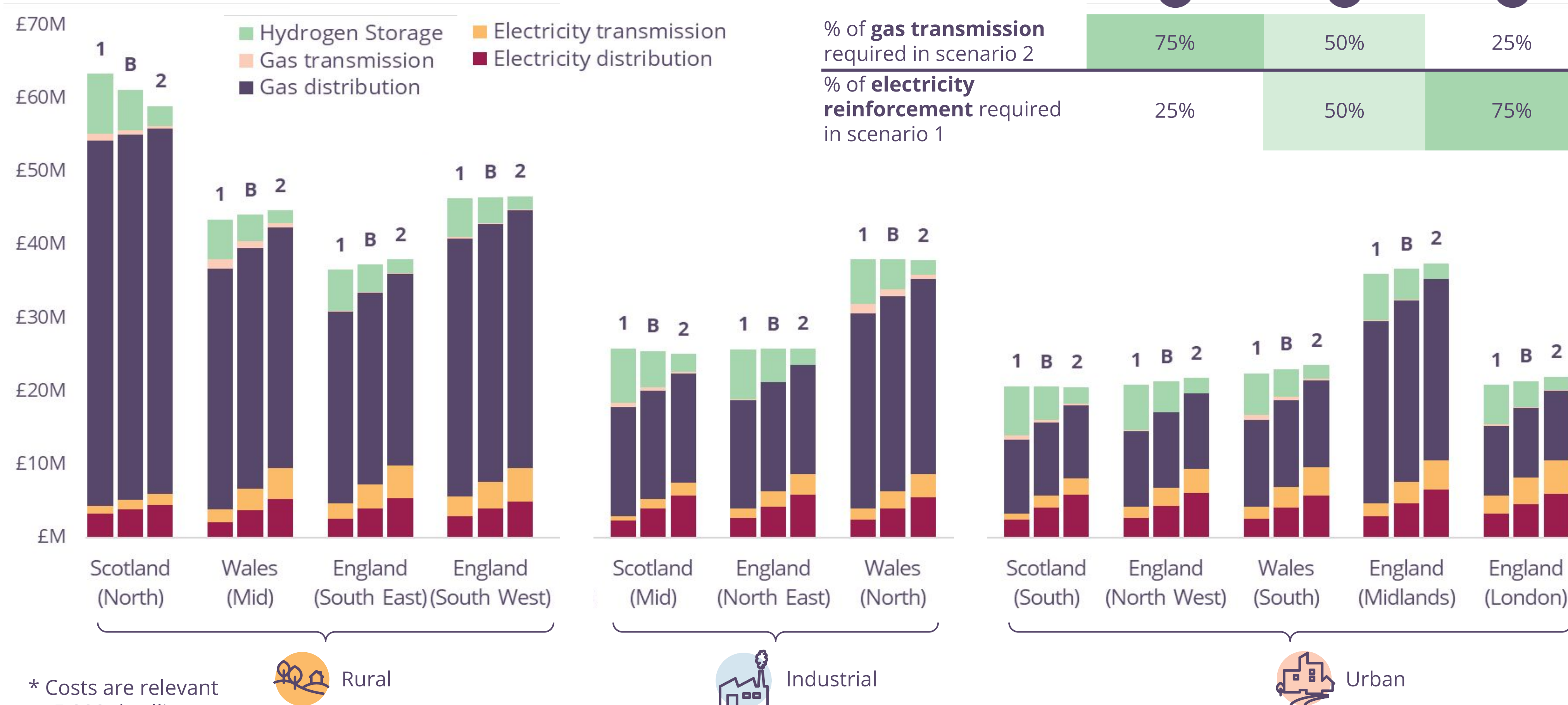
Scenario 4: Unspecified technology

20.6 – 63.4 **Scenario 4 range of costs** (£millions)

In scenario 4 no heating technology has been specified in each archetype. The technology mix is therefore driven by consumer choice of heat pumps, hybrid heat pumps with hydrogen, and 100% hydrogen boilers. As uptake is uncertain, upgrades would be needed for both the gas and electricity networks and so this scenario includes a base case and two sensitivities.

Like scenarios 2 and 3 the same gas distribution network upgrades would be required and so this does not vary. The remaining costs vary as shown in the table.

	Sensitivity 1 (high hydrogen) 1	Base case B	Sensitivity 2 (high electrification) 2
% of **gas transmission** required in scenario 2	75%	50%	25%
% of **electricity reinforcement** required in scenario 1	25%	50%	75%



* Costs are relevant to 5,000 dwellings

Urban archetypes generally have the lowest network costs in this scenario. Although England (Midlands) is an exception, data availability means that gas distribution costs, in reality, are likely to be lower. Rural areas have the highest costs and both findings are consistent across the base case and both sensitivities. As in scenarios 2 and 3, gas networks contribute the vast majority of costs in rural archetypes representing between 67% and 81% on average across all 12 archetypes. As in the other hydrogen scenarios, gas network costs represent a lower proportion in England (London) than in other archetypes.

When excluding storage costs, sensitivity 1, with greater hydrogen demand, results in lower costs (by between 1% and 15%) compared to the base case. Sensitivity 2, with higher electricity demand, results in higher costs (by between 1% and 15%) across all 12 archetypes when excluding storage costs.

If hydrogen storage costs are included then the impact of the sensitivities are smaller but more mixed. In some instances the higher hydrogen case in sensitivity 1 increases the costs for example in Wales (South) but lowers them in England (London). The same is true of sensitivity 2 where differences are minor and with some costs increasing like England (London) and decreasing Scotland (North).

Overall we see average changes to costs decreasing by 8% (sensitivity 1) and increasing by 9% (sensitivity 2) compared to the base case when storage is not included and changing by less than 1% in either direction if storage costs are included.

The base case therefore represents the lowest cost option within scenario 4 if storage costs are not included and when storage costs are included the lowest cost option is dependent on location though the differences are relatively minor.

Scenario comparison

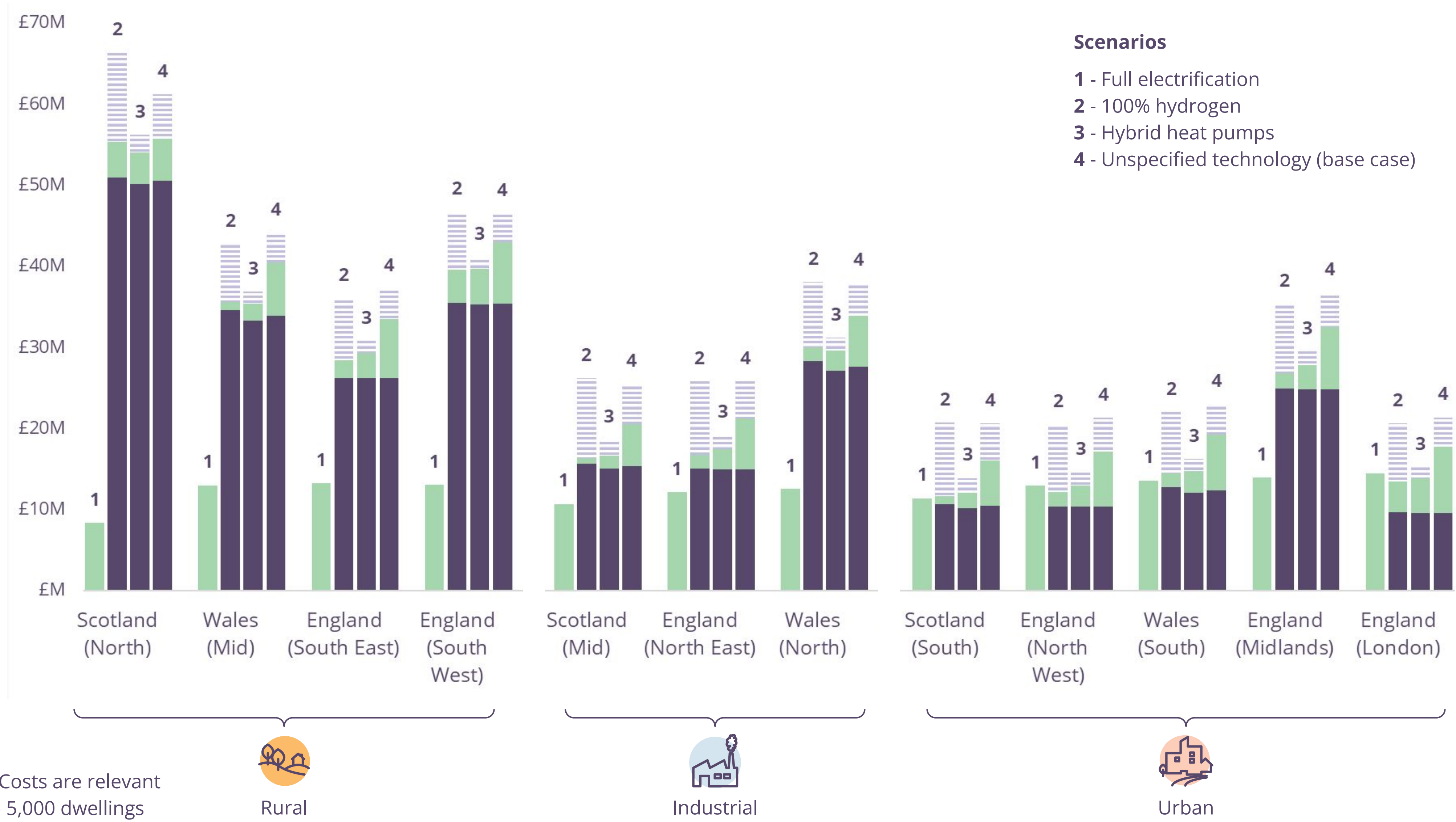
These findings are based on the total costs of each scenario and are presented to enable costs to be compared with and without hydrogen storage.

Cost breakdown

- Hydrogen storage
- Electricity network
- Gas network

Scenarios

1 - Full electrification
2 - 100% hydrogen
3 - Hybrid heat pumps
4 - Unspecified technology (base case)



* Costs are relevant to 5,000 dwellings

Headline

For 10 of the 12 archetypes across GB, the lowest network cost option is electrification (scenario 1). Two archetypes show hydrogen (scenario 2) as having the lowest network costs.

Rural trends

Electrification is overwhelmingly the lowest network cost option for all four of the rural archetypes. It is between 53% and 84% cheaper than the next lowest cost option. In England (South East) and England (South West) the next cheapest option is hydrogen (scenario 2), however in Scotland (North) and Wales (Mid) the next cheapest is hybrid heat pumps (scenario 3).

These rural areas have a number of things in common, though to different degrees: relatively higher rates of already electrified heating, less gas distribution network and longer lengths of gas distribution pipeline. They therefore have the highest costs for supporting hydrogen for heat while also the lowest costs for electricity upgrades due to the lower cost of overhead network infrastructure in rural areas.

Industrial trends

Electrification has the lowest network costs in all three of the industrial archetypes. It is lower by 27% in England (North East), by 35% in Scotland (Mid), and by 57% in Wales (North) compared to hydrogen or hybrid heat pumps.

This is particularly notable as a key geographical feature of all three industrial archetypes is their close proximity to either existing or future production sites for hydrogen or renewable electricity. The findings indicate that for the hydrogen scenarios, being close to industrial clusters is not a key influence and that gas distribution network costs, as in other areas, remain the most important factor to cost.

Urban trends

Of the five urban archetypes the electrification scenario has the lowest network costs in three of them and it is here where hydrogen is the lowest cost in the other two archetypes.

In Scotland (South) and Wales (South) electrification is the lowest cost by 3% and 6% respectively. In England (North West) hydrogen is the lowest cost option by 6% compared to electrification in scenario 1. In England (London) where hydrogen is also the lowest cost it is lower by 3% compared to the second lowest network cost option which is scenario 3.

In England (Midlands) scenario 1 may be up to half the cost of scenario 2, though data availability means that the gas distribution costs are likely to be lower in reality.

Variation

The findings also show that electricity upgrade costs in scenario 1 do not vary significantly, while the costs for scenario 2, 3, and 4 vary significantly by archetype.

Hybrid heating

In four archetypes which are a mix of industrial, rural and urban areas, the second lowest network cost option is scenario 3 where homes use hybrid heat pumps.

Across all 12 archetypes the findings show that the difference in network costs between scenario 3 and the full hydrogen scenario are generally small. There is an average difference of less than 3% with the exception of England (North West) where scenario 3 costs 16% more.

Unspecified technology

In scenario 4 where no technology is specified, network upgrades must meet varying and potentially unpredictable consumer demand from the range of technologies considered in this research. As a result, costs are significantly higher than the lowest cost option and are not cost effective. Choosing scenario 4 would increase network costs by between 32% and 563% across all 12 archetypes.

Storage effects

The findings above do not include hydrogen storage costs. If these costs are included it would make electrification the lowest cost option in all 12 of the archetypes. It also makes scenario 3 with hybrid heat pumps the next best option in all 12 archetypes. This is because the lower gas demand in scenario 3 requires much smaller levels of storage relative to the full hydrogen scenario.

Among Scotland (South), England (North West), Wales (South) and England (London) where the margins in favour of electrification or hydrogen are 6% or less, the impact of hydrogen storage costs makes electrification the lowest cost option in all four locations compared to hybrid heating by between 16% and 18%, except for England (London) where the margin is just under 5%.

Recommendations

1. Decisions about decarbonising heat at lowest cost must reflect local network costs and be on an area-by-area basis.

   This is the key driver of costs in each scenario and archetype.

2. The UK Government should make low-regrets decisions about heat decarbonisation options as soon as possible in areas where evidence suggests they are or are not suitable. Based on this report and the CCC's expectations of fuel costs we recommend:

   - Ruling out hydrogen in rural areas before 2026 and pursuing electrification.
   - Pursuing the strategy recommended by the CCC to push forward with electrification as the default choice where it is feasible. Our findings have not identified where the full hydrogen scenario is low-regrets and hybrid heating costs may be comparable or lower overall.

3. The UK Government should rule out options in locations which require both the electricity and gas networks to undergo extensive upgrades to be ready for low carbon home heating as this is prohibitively costly to consumers.

4. The UK Government should publish an assessment of future wholesale costs of electricity and hydrogen.

   This will be a key factor in further defining no and low-regrets decisions that can be made.

5. In locations where electrification of heat is low-regrets, clarity must be provided by the UK Government to consumers and supply chains.

   Policies should ensure consumers have the information, protection and support needed.

6. The UK Government should not implement a GB-wide hydrogen-ready boiler mandate.

   Any mandate should be targeted to locations only where there is clear evidence that hydrogen is anticipated to be overall least cost option for heat.

Limitations

This research has not accounted for a number of factors which would affect an overall assessment of the lowest cost network option to decarbonise heat. Some of these are limitations to the methodology where data is not available. For others these factors are out of scope.

Methodology limitations

Storage

There are some limitations to the hydrogen storage methodology. For example, where further storage and production might be located is not known and is particularly the case for green hydrogen. If homes are reasonably close to hydrogen production and can be reliably supplied without storage this would reduce storage costs significantly.

However, as distribution costs outweigh storage and transmission costs significantly, this is, on its own, unlikely to alter the findings. The extent to which the transmission network could be used for line packing (where the network is effectively used as a storage facility) is also not assumed. Costs of storage are also variable depending on the type. Costs are therefore presented with and without hydrogen storage costs.

The research does not consider the costs associated with electricity storage as LCP Delta determined that there is not the same comparable need for large-scale inter-seasonal electricity storage to meet domestic heat demand. Where there will be costs for storage LCP Delta considers that this is likely to support meeting peak demand, therefore reducing the network reinforcement required. LCP Delta have determined that they are confident that the total costs presented for electricity networks costs are therefore at the upper end and that costs in reality are likely to be lower.

Headroom

Headroom describes the amount of capacity that is not being utilised at each substation on the electricity distribution network. Where there is greater headroom, it will take a greater additional electricity demand before reinforcing is required. However, if this is small then it will take a smaller additional demand before upgrades are required. Also, if a different electrical solution was adopted, other than heat pumps, this could also affect when headroom is used up. Other actions such as deploying flexibility can also delay reinforcement as discussed below. As headroom is specific to each substation it was not possible to account for this for each archetype and is therefore based on assumptions. As headroom can vary by location this would likely result in a greater variation in the findings presented for upgrading the electricity distribution network.

Road length

The data required to determine total road length within the England (Midlands) archetype was not available at the required level. The reduced granularity increases the road length by including more rural locations than is likely to be the case for the urban archetype. The road length and therefore gas distribution costs are therefore likely to be higher in the findings than in reality.

Out of scope

Offshore Electricity Transmission

The costs included in this methodology only account for onshore transmission and not the costs for infrastructure to get electricity onshore from offshore wind farm generators. These costs may be significant, however they would impact across all four scenarios presented in this research. While these costs would be necessary to directly meet a high electric heating demand like scenario 1, they would also be required indirectly in order to produce green hydrogen by electrolysis on a suitably large scale to meet a high hydrogen scenario such as scenario 2.

Reinforcement for electric vehicle charging

It is well known that the electricity network will have to be upgraded in order to have sufficient capacity to charge electric vehicles. However, this research only seeks to understand the network costs associated with home heating so has not considered these costs.

As network companies would be carrying out upgrades for the combined demand from heat and transport at the same time, there would most likely be cost efficiencies. In simple terms, networks would dig up and replace a wire once, not twice.

The findings of this research for electricity network costs therefore represent a maximum cost which, in reality, will be lower.

Impact of flexibility

In times when there is not enough electricity supply from generators to meet the demand from consumers, the Electricity System Operator (ESO) has a number of options available. It either requires demand to be reduced or for generation to increase supply. Historically the ESO has relied more on paying generators to provide more supply. However, a key pillar of the net zero transition at lowest cost is the other option - reducing demand. The ESO's Future Energy Scenarios 2023 expect that up to 60 GW of flexibility by 2050 could be provided from consumer demand side response, electric heat flexibility, vehicle to grid at peak times and smart charging[5].

In practice this will mean consumers, both domestic, commercial and large industry, adjusting the time that they consume electricity. We already see tariffs offered by some suppliers to support this and research to further understand the flexibility potential of heat pumps[6].

The more flexibility that is in the electricity system, the lower the demand peak will be. Crucially for the topic of this report, this means that less upgrades need to be made to the electricity network, which will deliver cost savings.

This research does not account for flexibility and the savings this would bring. It is our expectation, and the expectation of our expert panel, that flexibility would also reduce the electricity network costs compared to the analysis in this report so the findings for electricity network costs are, again, likely to be lower in reality.

Decommissioning

In this research we have focussed on the network costs which enable heating technologies to be adopted. Therefore, we have not considered the costs of decommissioning the gas network.

There will be costs to decommission at least some of the gas network under all four of the scenarios considered in this research. What work is required, whether the network can be repurposed for other uses, what the costs are and how these costs are recovered are important questions for government and Ofgem to consider but were deemed out of scope for this research.

Heat networks

Heat networks will play a crucial role in decarbonising heat, particularly in more densely populated areas but also in areas because of their geography, such as proximity to industrial processes or geothermal sources. The CCC expects around 5.5 million homes to be connected to heat networks by 2050[7].

The CCC advises that heat networks in locations, which are already mostly known to be suitable, should proceed. This research has not considered if and where heat networks would be located, how they would be powered, and what impact this has on network costs.

Nevertheless, our expectation is that in locations that are served partly by electrically-powered heat networks, the overall size of any electricity network upgrades for heat would be lower than presented in this research.

For hydrogen, an electrically-powered heat network may mean there is no longer a need for the gas distribution network in that area or that a different configuration may be needed if powered by hydrogen. Generally speaking we would not expect gas and electricity network costs to increase as a result of heat networks but, more likely, decrease.

Further considerations

This research has not attempted to consider all factors involved in the heat decarbonisation decision process and, importantly, the consumer experience of it.

There are a number of further considerations which must be considered by decision makers. Here we outline some of these:

Appliance costs - The cost of buying, installing and maintaining a heat pump, hydrogen boiler, hybrid heat pump or other electric heating device must be taken into account. These costs may change over time as demand increases and from government subsidisation policy. Their proportion of the overall cost must also be carefully considered.

Fuel costs - The future costs of electricity and hydrogen must be taken into account when assessing the overall least-cost solution. Timing is also critical here. As fuel costs are likely to change over time, this could impact if and when a solution becomes least-cost which may not align with the necessary rate of decarbonisation.

Based on the findings in this report, if hydrogen wholesale costs are expected to be similar or cheaper than electricity this would strengthen the case for hydrogen in the two locations where it is the least-cost network solution, and may mitigate the higher network costs in others to some extent.

If hydrogen wholesale costs are expected to be more expensive than electricity it would further strengthen the case for electricity in the 10 archetypes where the network costs are cheapest. It may also mean that, overall, electrifying heat is also the lowest cost solution in the two areas where electricity network costs are marginally higher than hydrogen.

The CCC suggests that the running costs of hydrogen boilers *"will remain more expensive than heat pumps"* and that *"electrical heat (powered by renewables) should be cheaper than any fossil gas or hydrogen option"* though they note that policy choices and energy market arrangements mean this is not currently the case[8].

Based on the CCC's expectations that it is likely that wholesale costs would be lower for electricity than hydrogen, then based on the findings in this research, and the expectation that electricity network costs are likely to be lower in reality, this may indicate that electrification is the lowest cost option for all 12 of the archetypes based on network and wholesale costs.

Property changes - All technologies will come with some disruption and fabric energy efficiency improvements, like insulation, are essential in all homes and under any scenario. For heat pumps some households may need to upgrade to larger radiators. For homes that may already be charging EVs at home, the additional demand may require an upgrade to the property's fuse which comes with a cost.

For hydrogen boilers, it may require the home's internal pipework to be changed as well as a change to the meter used to measure gas.

Current meters (including smart meters) are not compatible with hydrogen. Ventilation also needs to be considered[9]. Overall the potential experience for consumers between different technologies must be better understood.

Implementation - To install a heat pump, consumers have a reasonable level of control over the timing of such a change and the switchover can happen on an individual house-by-house basis. Incentives such as banning natural gas boilers may change this timing but would also provide a clear signal to consumers.

The transition to a boiler powered by 100% hydrogen is unlikely to be possible on a house-by-house basis. Unless a parallel network is built to enable hydrogen to flow in one pipe and natural gas in the other, the switchover process for homes would have to be coordinated as part of a group of properties within a location. This would also require suitable support for consumers in vulnerable circumstances[10] and would require all homes within a certain boundary to already have hydrogen-ready boilers in advance of a switchover date.

Hydrogen is shown as potentially the lowest network cost option in the most densely populated archetypes in this research. In these types of areas the practicality of how a switchover would be implemented would need to be considered.

Consumer trust - The change in the way we heat our homes and the costs and processes involved are significant. It is essential that consumers have trust in such changes and that they have adequate and clear information, protection and support. This will require a proactive strategy from all levels of government and will most likely require tailoring to the locational choices that will have to be made. It also requires clear and consistent policy making in order to send the appropriate signals to empower consumers to make decisions.

Minimum viability and choice - As highlighted in this research a key difference between electricity and gas network infrastructure is in the options available to network operators and planners. Electricity networks have options on the size and capacity of the infrastructure they install in order to meet demand because flexibility can provide an alternative. More flexibility can lessen the amount of upgrades needed.

However, gas networks have less flexibility. This is why the gas distribution costs are consistent throughout scenarios 2, 3 and 4 as shown in the findings and this may have implications.

If scenario 2 is selected for an area and the gas distribution network is converted for hydrogen, it is possible that not all consumers who could use hydrogen actually choose to use it. They may, instead, opt for an electric option. If this were to happen and it meant upgrades were also subsequently required for the electricity network then the costs assumed under scenario 2 could look more like they do for scenario 4 which this research indicates would not be cost-effective. Another implication is that the costs of the gas network upgrades would have to be recovered from a smaller number of customers than might have been assumed.

There is therefore a critical policy question for government - should there be a minimum viable customer base using hydrogen for heat in any location at the distribution level to prevent costs per customer increasing or the need for subsidisation?

This poses an important question regarding what choices consumers will be able to make while minimising costs overall. Public engagement that is tailored by location will be essential to improve understanding of low-carbon heat and the choices which can be made.

Citizens Advice has previously carried out research[11] into this question and found three key lessons:

1. Early communication will be vital if choices are restricted
2. Government is expected to mitigate risks if low carbon heat options are mandatory
3. Consumers will want to retain control in some areas and need extra reassurance about cost and quality

Supply chains - It is our recommendation that decisions about decarbonising heating at an optimised cost for consumers should be made on an area-by-area basis.

Making these choices as early as possible will give greater clarity to the supply chains and installers of both heat pumps and those currently in the gas boiler market. This will enable businesses to make the necessary investments and give a clear direction on whether staff re-training will be needed. Clear and early signals on skills and training will ensure that current heating engineers of any technology are at the forefront of what will need to be a very significant installer market of any heating appliance. It will also ensure that there will be enough supply to meet consumer demand. In the case of heat pumps, the number of installers is significantly off track, putting Government deployment targets at risk.

It is clear that any heat decarbonisation option will have significant economic benefits as a result of the need to significantly scale up manufacturing, training and the number of installers. The next step for the UK and devolved governments is therefore to take low and no-regrets decisions on the most efficient route to decarbonise heat in the interests of consumers, and to make these decisions without delay.

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