Heating homes in different regions of Great Britain

A study on locational costs of electricity and gas network infrastructure

Citizens Advice
[Final version]

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Date of issue: 22/08/2023

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Contents

Glossary

£	Great British Pound/GBP
£M	GBP million

B

BSP	Bulk Supply Point

C

CAPEX	Capital expenditure
CCC	Climate Change Committee
CCS	Carbon capture and storage

D

DESNZ	Department for Energy Security and Net Zero
DLUHC	Department for Levelling Up, Housing and Communities
DSR	Demand Side Response

E

EFV	Excess Flow Valve
ENA	Energy Networks Association
EPC	Energy Performance Certificate

F

FEED	Front End Engineering Design
FES	Future Energy Scenario

G

GB	Great Britain
GWh	(unit) 10^9 Watt-hour

H

HDD	Heating Degree Days
HH	Half-hourly
HP	Heat pumps

I

IMRRP	Iron Mains Risk Reduction Programme

K

km	(unit) 10^3 meter
kW	(unit) 10^3 Watt
kWh	(unit) 10^3 Watt-hour

L

LA	Local authority

M

MHCLG	Ministry of Housing, Communities & Local Government

N

NG ESO	National Grid Electricity System Operator
NHH	Non Half-hourly

T

TNUoS	Transmission Network Use of System charges
TWh	(unit) 10^{12} Watt-hour

U

UK	United Kingdom

V

V2G	Vehicle-to-Grid

1. *Executive Summary*

This report will show that decarbonisation of domestic heat will vary significantly across different regions of GB. The costs of different technology pathways and government and regulatory policy needs to take this into account when considering impacts on consumers.

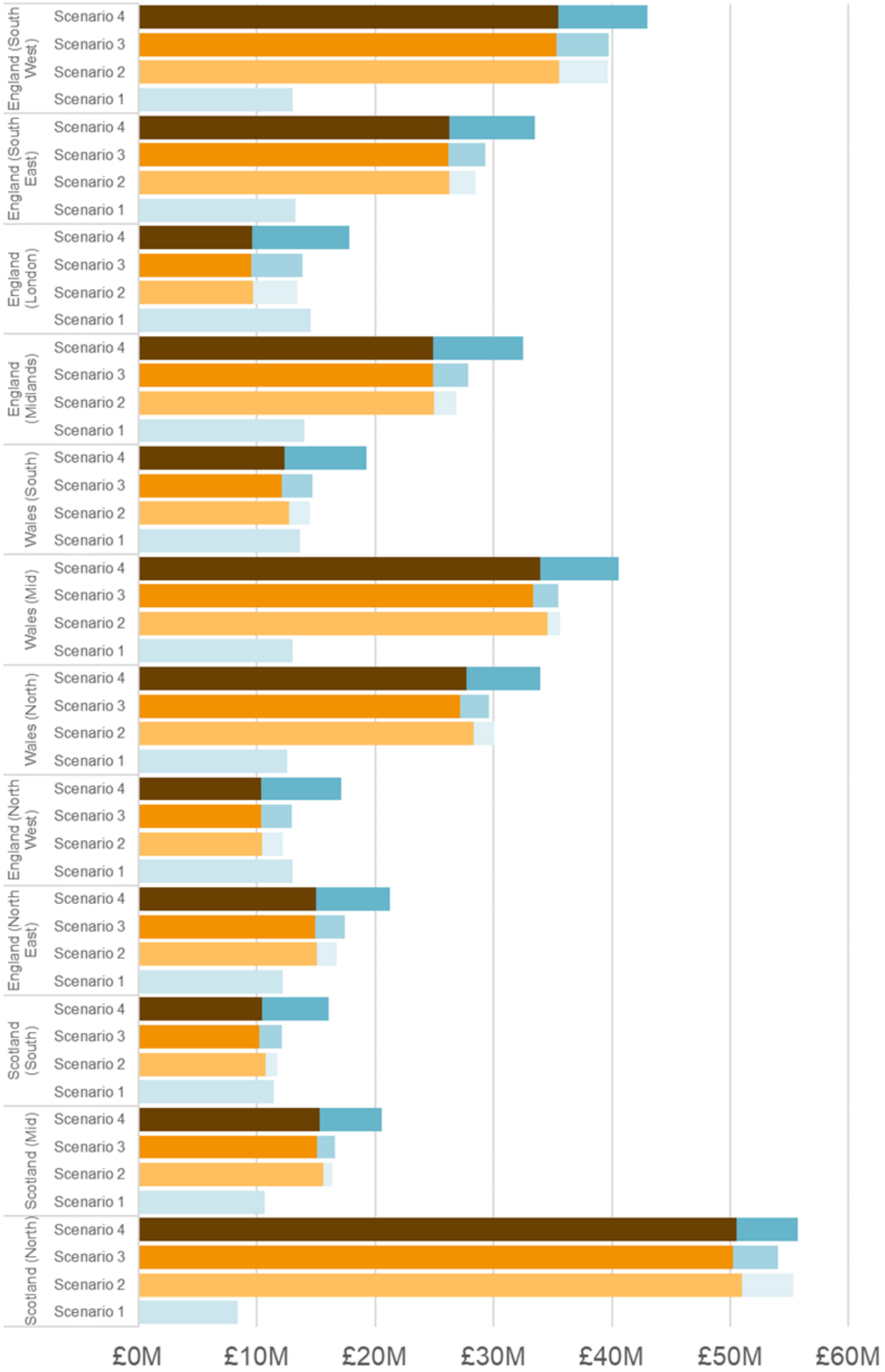
In this report we present a comparison of the total reinforcement and upgrade costs to both the electricity grid and the gas networks, looking at both distribution and transmission. Central points to our analysis:

- **The need for a locational approach** to decarbonising domestic heat in Great Britain (GB). Our methodology is centred on assessing the costs for different GB regions. We assert that this approach provides valuable insight to policy makers and that locational factors are essential considerations when assessing new infrastructure developments.
- **Electricity network** costs are dominated by distribution reinforcement. Transmission network reinforcement costs vary by archetype. However distribution network costs show consistently high costs across GB regions (Scenario 1).
- **Gas network** upgrades are similarly dominated by distribution upgrade work and are premised on ultimately switching to 100% hydrogen for use in hydrogen boilers (scenario 2) or hybrid heat pumps that run on both electricity and hydrogen (scenario 3). When determining the total upgrade costs to the networks hydrogen storage costs are particularly significant. As there is debate regarding whether or not this should be included as a network cost, we present results that clearly identify these costs as separate from upgrade work to pipes to enable a clear cost comparison.

Network infrastructure costs per household are, on average likely to be much higher for hydrogen than for electrification. Network infrastructure reinforcement costs vary significantly by location for both electricity and gas network reinforcement. The variation between different regions is more pronounced for gas than electricity.

1.1. Key findings from the analysis

Figure 1: Total archetype reinforcement costs for each scenario excluding hydrogen storage costs for each archetype.



*Costs are relevant to 5,000 dwellings (electricity network = blue shaded bars, gas network = orange shaded bars)

- **Gas networks:** The significant variation is due to some regions including large land areas but low housing densities, which pushes up the cost per household. Transmission costs are primarily differentiated by the distance from hydrogen storage sites, although these costs are a smaller proportion of the total.
- **Electricity networks:** The proportion of properties already using electricity to heat their homes has a significant impact here. Regions with a high level of electric heating will experience a smaller increase in electricity demand as existing grid infrastructure is already present. For archetypes with lower levels of electric heating, reaching 100% electrification results in much higher costs.

1.2. Recommendations for Policy makers

For DESNZ

- DESNZ should adopt a locational approach that considers existing infrastructure and heating technologies as well as specific costs to reinforce or upgrade networks in different GB regions. When developing key policies on hydrogen readiness and electrification of heat, solutions should be tailored to location instead of applying a blanket approach.
- DESNZ should carefully consider the extent to which not adopting a regional approach and instead favouring full consumer choice has the potential to lead to less optimal outcomes.
- If it is possible for DESNZ to determine specific regions where hydrogen is not suitable earlier than 2026, this would provide clarity for those areas sooner and enable them to start working on alternative solutions more quickly.
- Network companies need clarity regarding the level of investment required for upgrade and reinforcement work to accommodate low carbon heating technologies that will be deployed.

For Ofgem

- Locational differences in cost need to be considered to ensure the energy transition is fair. This includes consideration of different network users.
- Ofgem needs to provide clarity regarding how decisions of strategic importance will be made regarding the decarbonisation of domestic heating.
- Ofgem need to consider how they will ensure sufficient network planning and investment is provided for the electricity grid to cope with mass electrification of domestic heat.
- If the gas distribution network continues it is likely that it will do so at a reduced size and scale. Consideration is needed as to how and when relevant sections are decommissioned and who will pay for this.

2. Background/context

Heating in the UK accounts for almost one third of the UK's annual carbon footprint and in 2019 17% of heating emissions from buildings came from homes. There are 29 million homes that need to be upgraded to low carbon heating systems to meet net zero targets.

Decarbonisation of heat will rely on a range of different low carbon options to be deployed in the future. To achieve full decarbonisation of UK buildings by 2050, it will be necessary to completely phase out natural gas and fossil fuel heating systems and replace them with appropriate low-carbon alternatives. However, there is no one-size-fits-all solution. At present, the two key technologies being considered are electric heat pumps, hydrogen boilers and hybrid heat pumps.

The UK Government has set a target of 600,000 heat pumps to be installed per year by 2028. Although take up is currently slow, heat pumps have seen significant growth throughout large parts of Europe. Therefore it is expected that this market will continue to grow in the UK. Hydrogen, by comparison, is not a technology currently used to heat homes in the UK or Europe. There is a small domestic trial underway in the Netherlands, one in the construction phase in Scotland and decisions regarding further trials in the UK are expected from government later this year. The UK government is expected to make a strategic decision on its future use in 2026. The Climate Change Committee (CCC) has stated that "*Full hydrogen conversion is unwieldy due to the low system efficiency…On this basis we do not recommend planning on a full hydrogen conversion…It could also play a supporting role through targeted regional gas grid conversion, where there is public support and an underlying technical case.*" [1]

The UK Government's Heat and Buildings Strategy (2010 sets out the government's plan to ensure as many homes as possible achieve an Energy Performance Certificate rating of C and phase out natural gas for heating by 2035. The CCC has recommended that the UK government consider a locational approach to heating decarbonisation, including identifying areas which are suitable or unsuitable for hydrogen, so that unsuitable areas can move forward by prioritising other heating sources.

This project aims to contribute to this evidence gap by better understanding the reinforcement and upgrade infrastructure costs involved in these locational choices; costs which will ultimately be paid for by either energy users or taxpayer. The project's outputs will be used by Citizens Advice to advocate in consumers interests across a range of government and regulatory decisions needed to decarbonise heat at least cost to consumers.

3. Methodology

This section outlines the methodology used within the project, including the literature review, consulting with an expert panel and how an approach to calculations was developed through the project.

3.1. Research objectives

What are the total costs for transmission and distribution network conversion/ reinforcement costs in different GB regions for each of the four heat decarbonisation scenarios?

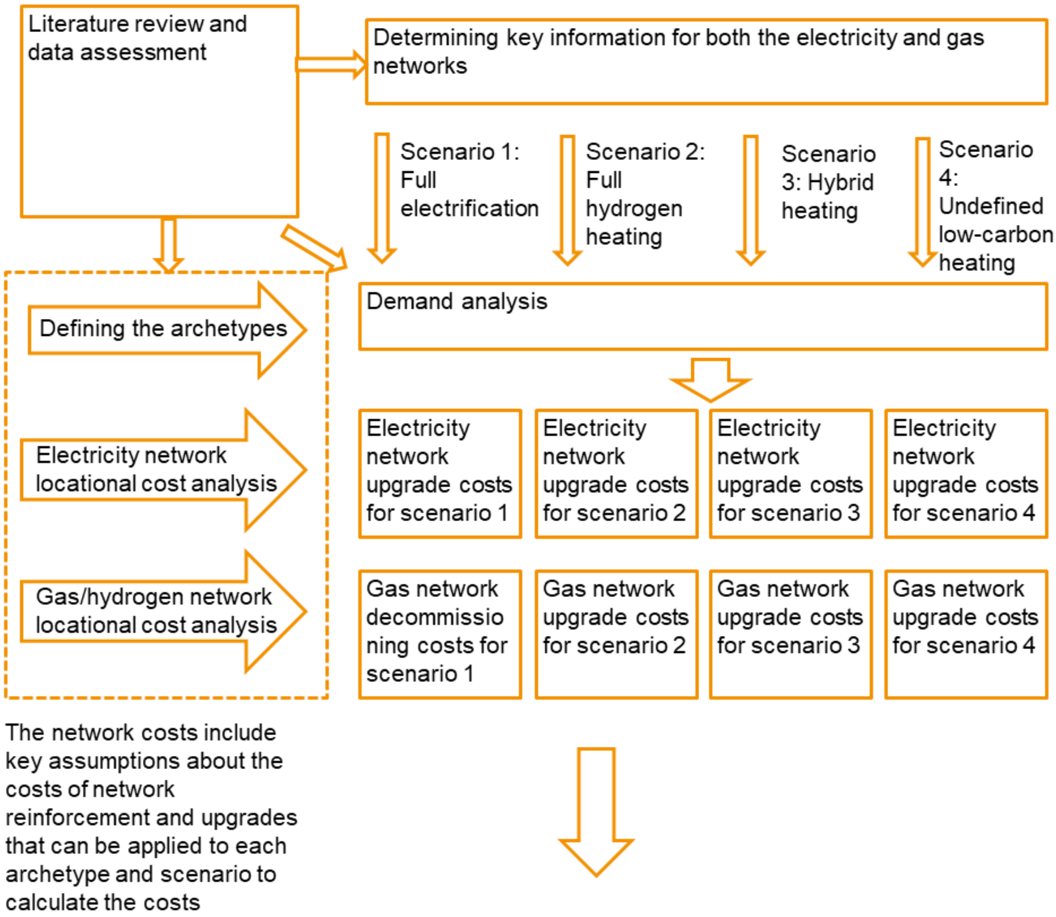
- How do infrastructure costs vary between different geographical locations and network areas?
- How do distribution and transmission network costs compare when considering the total cost for each region?
- How do gas network upgrade costs vary if located closer or further away from hydrogen storage?
- How do electricity upgrade costs vary if located closer or further away from areas with significant renewable electricity generation capacity?

3.2. Overview of our approach

The methodology used to determine reinforcement costs can be split into two parts:

- The electricity network reinforcement costs: distribution and transmission
- The gas network reinforcement costs: distribution and transmission

This is expanded in more detail in the diagram below.



3.3. Scenarios

The table below outlines the four scenarios used within this study. The first two scenarios represent the core choices between electrified heating or hydrogen for heating in all dwellings. Therefore, in scenario 1 there are no upgrade costs for the gas network for domestic heating, as we assume everyone is using ASHPs to heat their homes. In scenario 2, the only upgrades to the electricity network are for those not on the gas network as everyone who can is heating their homes using hydrogen. Scenarios 3 and 4 represent variations of the two core scenarios.

In scenario 3, hybrid heat pumps use electricity as the primary fuel and hydrogen during peak times. This would be when the outside temperature is low and there is less renewable energy generation than usual. As the gas distribution network is only used to provide domestic heating, 100% of these costs still need to be upgraded, even though less hydrogen is being used compared to scenario 2. The gas transmission network upgrades will be utilised by other sectors, such as industry and power. Therefore, a reduced % of the costs of this upgrade work are attributed to domestic heat in scenario 3. As electricity is unlikely to be used to heat homes during peak times, scenario 3 has a lower level of reinforcement for the electricity network. Our assumption is that hybrid heat pumps will run on electricity 80% of the time and hydrogen 20% of the time. The use of hydrogen will therefore reduce demand for electricity as a fuel at times of peak demand. The electricity network will still need to be reinforced, but only meet a new, consistent baseload. Therefore, the electrification reinforcement cost scenario 3 are lower, as the peak demand will be met by hydrogen instead. Scenario 3 has a 10% electricity reinforcement cost to account for additional baseload demand.

Scenario 4 similarly has reduced quantities of hydrogen use for domestic heating, but the whole gas network still requires upgrading. As the exact split between electric and hydrogen heating cannot be determined a mid-range (50%) reinforcement of the electricity network and 50% of the gas transmission costs is assumed. As the technology option is not defined in scenario 4, the exact level of reinforcement or upgrade cannot be known. Therefore two sensitivities have also been included to ensure a 100% level of network costs is always reached:

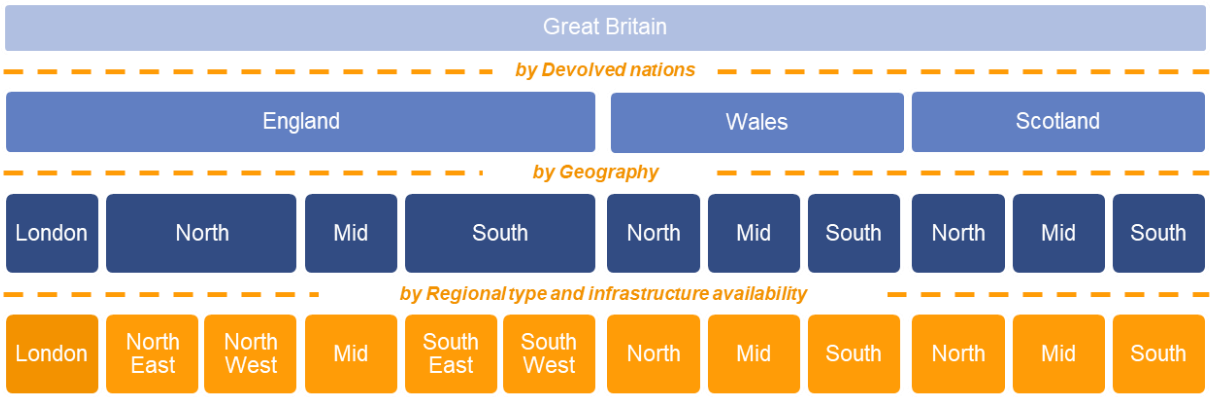
1. Lower (25%) electricity reinforcement and higher (75%) gas upgrade work and;
2. Higher (75%) electricity reinforcement and lower (25%) gas upgrade work.

Scenario	Scenario description for domestic heating	Heating tech	Proportion of Electricity Network reinforcement required for heat	Proportion of Gas Network upgrade required for heat	Assumptions on network reinforcement
1	Full electrification of domestic heat	ASHPs	100%	0%	Only reinforcement costs specifically required to meet domestic heat demand included. Additional reinforcement due to increased demand from EV's excluded.
2	100% hydrogen boilers	Hydrogen boilers	Variable - dependent on % of regional archetype off the gas network	100%	Only dwellings already on the gas grid included (consistent with CCC).
3	Hybrid heating	Hybrid heating system	10% of properties on gas network + % of regional archetype off the gas network	100% of distribution + 20% of transmission costs	Hybrid heat pumps will run on electricity 80% of the time and hydrogen 20% - thereby reducing the pressure on the electricity network at peak times.
4	Undefined low-carbon heating	Choice of the three tech options above	50% of properties on gas network + % of regional archetype off the gas network	100% of distribution + 50% of transmission costs	Uptake of different heating technologies is uncertain so reinforcement/upgrade of both networks required.

3.4. Archetypes Methodology

The project divided Great Britain (GB) into 12 archetypes that have different locational characteristics according to the steps shown in Fig. 1. The archetypes developed are intended to ensure a wide range of locational characteristics could be assessed and ensure multiple considerations are included within the analysis. This includes regional differences from across the devolved nations and locational typologies – which are captured as industrial, rural, and urban.

Figure 2 Methodology used to determine the 12 archetypes used in this study.



3.4.1. Devolved nations

We focused on countries that are situated in GB, i.e., England, Wales, and Scotland, excluding Northern Ireland from the research scope.

3.4.2. Geography

We developed the archetypes by dividing each country into several regions. Segregating Scotland and Wales using this approach was acceptable, as each geographic sub-region (North, Mid, and South) has distinct characteristics in terms of population density, urbanisation level, infrastructure availability and distance to electricity/gas production or storage sites. England is larger both in terms of land area and population density, so we determined a total of six regions were required to ensure the archetypes were sufficiently representative of locations which have different characteristics.

3.4.3. Regional type and infrastructure availability

We divided South England into Southeast England, Southwest England, and London since each of these sub-regions have very distinct characteristics. London is extraordinary in terms of having the highest population density in England and being an urban centre, hence London stands alone as a separate archetype. Most areas in both the Southeast and Southwest of England are rural areas, however Southwest England has a much lower percentage of dwellings connected to the gas network compared to Southeast England. North England is composed of two archetypes. Northeast England represents the industrial/coastal part of England that is located near existing or future hydrogen and renewable electricity production sites. Northwest England represents an urban part of the region.

Sub-regional Scottish and Welsh archetypes were also classified based on their regional types, i.e., urban/rural/industrial and share of dwellings connected to the gas network. North Scotland and Mid Wales are both very distinct rural archetypes, with 100% of both regions being classified as rural areas by the ONS. Both regions also had a high percentage (more than 60%) of households not connected to the gas grid. The Mid Scotland archetype is mostly a coastal area which has several major industrial sites, e.g. St Fergus Gas Terminal in Aberdeenshire which acts as one of the major gas terminals connecting the UK and mainland Europe. South Scotland hosts the biggest Scottish population with major urban cities like Glasgow and Edinburgh. Although mostly still rural, we categorize North Wales as an industrial archetype due to announced plans for renewables development in the area. We then have South Wales representing the most urban part of the region with major cities such as Cardiff and Swansea.

We understand that in the real world, a sub-regional archetype can possess various characteristics, e.g., Northeast England not only boasts well-known industrial clusters but also includes urban cities. For simplicity, we focused on the most predominant regional type within each archetype for this study (approximated by area size following the 2022 Urban Audit VII by the Office of National Statistics), as indicated in Table 1. As a result, the results of our calculations in this study generally provide a representation of all archetypes, even though the actual figures might differ due to the extent of differences present.

Table 1: Archetype's regional type.

No	Archetype	%Rural	%Industrial	%Urban	Final regional type
1	Scotland – North	100%	-	-	Rural
2	Scotland – South	5%	15%	80%	Urban
3	Scotland – Mid	15%	83%	2%	Industrial
4	England – Northeast	20%	70%	10%	Industrial
5	England – Northwest	20%	30%	50%	Urban
6	Wales – North*	25%	60%	15%	Industrial
7	Wales – Mid	100%	-	-	Rural
8	Wales – South	30%	15%	55%	Urban
9	England – Midlands	30%	25%	45%	Urban
10	England – London	-	-	100%	Urban
11	England – Southeast	60%	15%	25%	Rural
12	England – Southwest	90%	5%	5%	Rural

*assumed based on 2021 North Wales Energy Strategy and Framework for the future of manufacturing in Wales

3.4.4. Specifying the archetypes' locations

We selected a Local authority (LA) / Council / Borough / Electoral ward located in each of the archetypes that best represents the corresponding archetype. For consistency, we tried to select locations in each archetype that each have 5000 dwellings based on public datasets from Energy Performance of Buildings Data: England and Wales, Scotland Dwellings per Hectare and Scotland Land Area based on 2011 Data Zones. However, it is important to note that only a few locations had close to 5000 dwellings. In most cases, the areas were either much more densely or sparsely populated. In such cases, we determined the area size for the corresponding location with 5000 dwellings by using the ratio of the actual number of dwellings in the area to its actual size.

3.5. Archetype heat demand for hydrogen

The methodologies used to calculate costs for the electricity and gas networks are specific to each system. The below describes how hydrogen demand for each archetype has been calculated which was used to assign a proportion of the total upgrade costs of the gas network to demand for domestic heat.

Using weather data from BizEE Degree Days Weather Data for Energy Saving we identified each regional archetype's unique outside temperature profiles for throughout the year. Assuming all dwellings will maintain an inside temperature of 18 ºC, we estimated the baseline thermal energy demand for each archetype dwelling based on the corresponding outside temperature and annual heating degree days (HDD) at 18ºC. Heating degree days are a measure of how much (in degrees), and for how long (in days), the outside air temperature was below a certain level. HDD value gives an indication of how much energy is needed to bring a property's inside temperature to a certain point, which in this case is determined as 18 ºC.

We assumed that housings across all archetypes to have Energy Performance Certificate (EPC) level C. EPC is a document that provides information about how energy-efficient a building is, taking account of the building's insulation, construction materials, and energy equipment's efficiency. The EPC rates the building's energy efficiency from A to G, with A being the most efficient and G being the least efficient. A building with lower EPC level will require more amount of thermal energy (or heat demand) to heat the building interior, consuming more energy and may result in higher heating cost. The average potential EPC level across all UK regions were found to be EPC C based on Energy Performance of Buildings Data: England and Wales and Domestic Energy Performance Certificates – Dataset to Q1 2023.

Furthermore, the key assumptions to calculate the residential heat demand are shown in the table below.

Category	Value	Unit	Remarks
Natural gas or hydrogen boiler efficiency	90	%	LCP Delta Heat Service assumption

Heat loss for avg EPC C housing	56	W/m^2	Strathclyde Uni heat demand profile
Total area per housing	118	m^2	Strathclyde Uni heat demand profile

We calculated the baseline heat demand and the equivalent of hydrogen required in energy terms based on the assumed equipment efficiency for each archetype, assuming there will be 5000 dwellings in each archetype's exact location. The calculation results are summarized in Table 4. The amount of hydrogen required for heating at all archetypes is different due to the varying outside temperature.

Table 2: Hydrogen demand for 5000 dwellings in each archetype.

No	Archetype	Regional type	Hydrogen demand (GWh/year)
1	Scotland – North	Rural	136.90
2	Scotland – South	Urban	111.97
3	Scotland – Mid	Industrial	122.70
4	England – Northeast	Industrial	112.75
5	England – Northwest	Urban	103.43
6	Wales – North	Industrial	100.21
7	Wales – Mid	Rural	89.01
8	Wales – South	Urban	93.28
9	England – Midlands	Urban	105.48
10	England – London	Urban	89.29
11	England – Southeast	Rural	93.75
12	England – Southwest	Rural	87.97

3.5.1.Hydrogen vs Natural Gas

As explained in the previous section, we calculated the amount of hydrogen needed for heating purely based on the heating equipment efficiency, which in this case would be hydrogen boilers. However, we found out that the efficiency for both traditional natural gas boilers and hydrogen ones are the same, at 90%. In a glance, this would look like we'll end up needing the same amount of hydrogen and natural gas to have the same heating output. However, hydrogen has a higher calorific value than natural gas, while also having a significantly lower density. This means that to achieve the same energy (heating) output, we will require more volume of hydrogen compared to natural gas. An example based on one housing archetype in London is given below, showing that we'll need 3.65 times the volume of hydrogen compared to natural gas. This does not affect the reinforcement costs but it does impact the amount of storage required for hydrogen compared to natural gas.

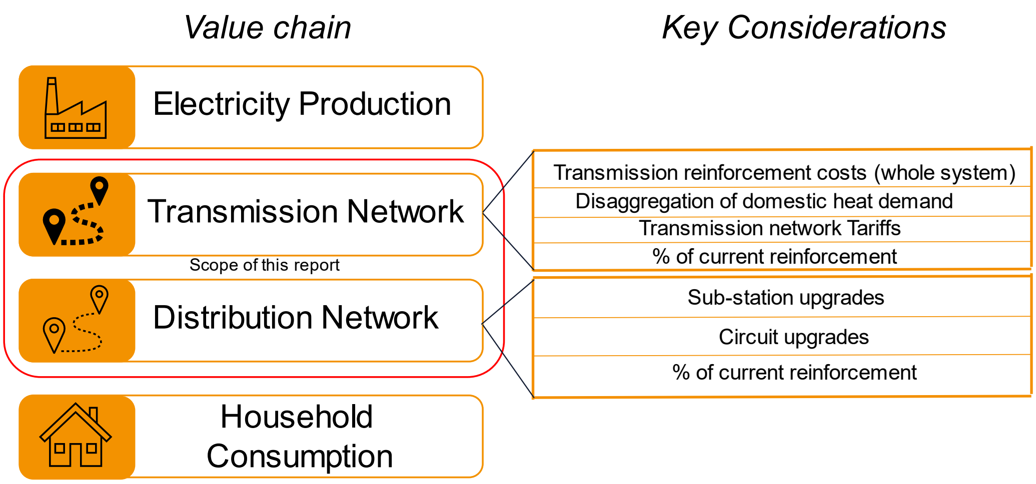
A	Annual thermal energy demand	kWh/year	16,072
B	Gas boiler efficiency		90%
C = A/B	Annual gas demand	kWh (heat)/year	17,858
D	Gas lower heating value (LHV)	kWh (heat)/kg	13.1
E = C/D	Annual gas demand	kg/year	1,363
F	Gas density	kg/m^3	0.777
G = E/F	**Annual gas demand**	**m^3/year**	**1,754**
H	Hydrogen boiler efficiency		90%
I = A/H	Annual hydrogen demand	kWh (heat)/year	17,858
J	Hydrogen lower heating value (LHV)	kWh (heat)/kg	33.33
K = I/J	Annual hydrogen demand	kg/year	536
L	Hydrogen density	kg/m3	0.08375
M = K/L	**Annual hydrogen demand**	**m^3/year**	**6,397**

To note, all price calculations for hydrogen gas demand are based on the £/kWh of hydrogen.

3.6. Overview of Electricity Networks Methodology

To calculate electricity network costs, this research split transmission and distribution results to give overall results for each archetype and scenario. This research focused on the reinforcement costs of meeting 100% electrification for domestic heating.

1. **Distribution Network**: sub-station infrastructure and circuit wiring upgrades were considered for each urban, rural and industrial archetype. Urban and Industrial areas considered the same infrastructure to be reinforced (sub-stations and underground circuit wiring), whilst Rural considered a different infrastructure criterion (substations and overhead circuit wiring). The number of houses already using electrified heating were also considered in this research and are reflected in its overall reinforcement costs.
2. **Transmission Network**: this research approached transmission costs by understanding the overall projected cost of transitioning the grid to net-zero. To do this, peak demand would be disaggregated to understand future domestic heat demand. TNUoS tariff data was applied to weight the regional cost variation of each archetype. Similarly to the distribution network approach, the number of houses already using electrified heating were also considered.
3. **Key Consideration**: **Proportion of dwellings already using electricity as a heat source**. Approximately 15% of properties nationally are already using electricity to heat their homes. This varies widely by location with a higher proportion of properties in rural locations using electricity due to an absence of the gas grid. Therefore electricity distribution reinforcement is assumed to be lower in these areas as the infrastructure is already meeting significant thermal demand.

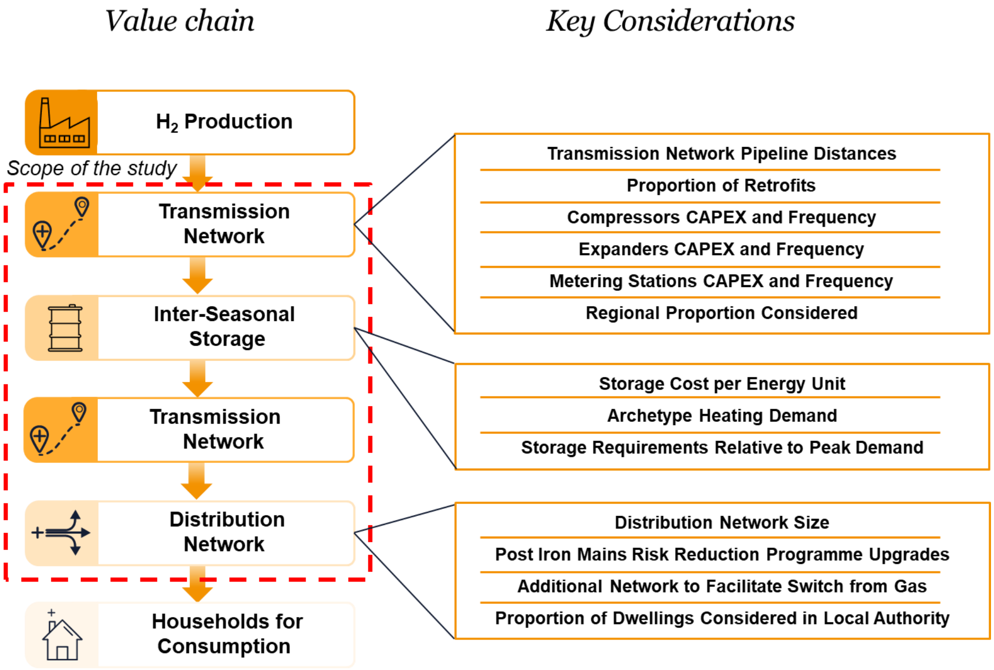


3.7. Overview of Gas Networks Methodology

The methodology to calculate the total network costs for each scenario splits the overall calculation into two distinct, yet interconnected, components: the distribution and transmission network. The sum of these two components represents the total network costs for each archetype and scenario. This approach provides a comprehensive understanding of the network costs by considering the intricacies and unique cost factors associated with each segment of the GB gas network. The segments can be split into the following:

1. **Distribution Network:** This element of the calculation is focused on the localised network of pipelines that distribute gas to individual consumers — residential, commercial, and industrial. For the purpose of this calculation the distribution network only considers distribution to residential properties where hydrogen is used for heat. The distribution network's cost factors include the costs of new pipeline installation and upgrading or replacing existing pipelines to facilitate the transition to a hydrogen network. As it is not recommended to extend the gas distribution network, no costs for achieving this have been included. It is crucial to consider factors such as the number of homes connected to the gas grid, the total road length, the proportion of dwellings in a local authority, and the length of pipeline required from the transmission network to the archetype location, and additional safety measures that are required to be installed.
2. **Transmission Network:** The transmission network cost calculation encompasses the larger, high-pressure pipelines that transport natural gas from production sites and storage (inter-seasonal large scale and localised smaller scale storage) to the distribution networks. Note that while we estimate the cost of storage of hydrogen, we do not use this for comparison with the electricity network, as our focus of the study is on those costs infrastructure costs that vary with the location of heat demand (i.e. the network reinforcement costs). The costs associated with the transmission network include new pipeline construction, the retrofitting of the existing gas network, compressor station costs, storage facilities, and any other infrastructure necessary for the safe and efficient transportation of gas over long distances. Key factors in this segment are the total

length of the transmission network, the costs associated with converting parts of the network to carry hydrogen, the proportion of existing pipeline retrofits and the costs of connecting the transmission network to the distribution network for each archetype.



3. **Key Considerations for gas networks**

a. **Distance from hydrogen storage**. To meet peak demand through the winter, hydrogen storage will be crucial. GB locations with suitable geology for hydrogen storage have been identified. Areas located further away from these sites will require more upgrade work.

b. **Proportion of dwellings already using gas as a heat source**. Only properties already on the gas network and using gas heating are considered candidates for hydrogen heating. This is akin to the CCC assumptions for the conversion of the gas grid. Therefore, additional reinforcement will be needed of the electricity network to ensure all dwellings within each archetypes and scenarios are upgraded to a low-carbon heating solution. These costs are included in the calculations for each scenario.

3.8. Literature Review and Data Collection

A range of literature was reviewed in this study. The tasks below were used to collect valuable sources of information to understand the localised heating factors of the four scenarios outlined in Section 1.5.

1. **Desk-based research**: this research identified key electrification and gas case studies within the United Kingdom. Sources suggested by Citizens Advice were reviewed first to understand the clients focus areas. This informed what additional literature should be reviewed in this study. The desk-based study gathered key information, data and assumptions from both public and private sector sources.

This yielded valuable insight into national, regional, and localised case studies, as well as examples of modelled costs associated with reinforcing the electricity grid and decarbonising the gas network by adopting hydrogen.

2. **In-house expertise**: LCP Delta experts provided key electrification and gas decarbonisation literature review sources. In particular for the gas networks, the experts also provided key considerations on how to factor reinforcement and flexibility. Thorough datasets were also shared by LCP Delta consultants to provide Transmission and Distribution network data to apply to each archetype area. Furthermore, our inhouse experts provided internal data to factor key differentiators between archetype areas across the UK. By leveraging these internally identified sources, we were able to supplement data with additional information, thereby enriching our literature review.
3. **Expert workshop(s)**: two workshops incorporated the views of expert stakeholders. This provided an opportunity for stakeholders to steer the project and provide further literature sources or key data sets that could give insight to understanding the costs in decarbonising domestic heating according to the four scenarios and archetypes in Great Britain. This also provided an opportunity for the stakeholders to challenge any assumptions in the approach used by the project team, including the initial findings based on the desk-based research. Furthermore, the experts provided unique insights and information that may not be readily available in public sources, and/or were initially missed in the identification of data sources. The information gleaned from these workshops allowed us to further refine and enhance our data set. The two workshops were held on the 7th of June 2023 and 12th July 2023 and they included the following attendees:

Table 3: Workshop attendees

Workshop 1 – 7th June 2023	Workshop 2 – 12th July 2023
Rachel Lee – Head of Safety Gas Network Conversions, DESNZ	**Hilary Hill** – Senior Strategy Advisor Hydrogen, Ofgem
Marcus Shepherd – Lead analyst for decarbonisation at CCC	**Marcus Shepherd** – Lead analyst for decarbonisation at CCC
James Walker – Head of Hydrogen Strategy, Ofgem	**James Earl** – Director of Gas, ENA
	Goran Strbac – Professor of Electrical Energy Systems at Imperial College, London
	Fareed Ahmad – Manufacturing, DESNZ

During the workshop, the expert panel presented insights and highlighted several challenges on the methodology. This included:

- Initially, the electricity transmission calculations were set to be based on the National ESO NOA £27.9 billion reinforcement costs (with the majority of these costs being calculated up to 2030). This, however, would only consider the investment of connecting generation capacity. It was therefore recommended this research applied the Electricity Network Strategic Framework reinforcement values to calculate transmission costs in Great Britain.
- The expert panel were conscious to understand how the methodology considered the Iron Mains Risk Reduction Programme (IMRRP). To account for their comments the methodology was updated to consider the ongoing IMRRP to be an already costed project and therefore this cost is not considered in the final methodology; however, there will be a further requirement to replace some existing pipelines to ensure the entire network is hydrogen ready and it is this aspect which is considered in the methodology.
- The initial methodology to calculate the pipeline length was initially driven by the location of production facilities for green and blue hydrogen which were assumed to be located close to or within industrial clusters. However, challenges from the first expert workshop it was clear this methodology would be problematic due to several reasons: green hydrogen production is more likely to be located near large-scale renewable energy production rather than near or within industrial clusters. A further consideration is that there is the potential for offshore green hydrogen production co-located with offshore wind electricity generation which is currently unproven. The hydrogen economy also remains in the early stages of development meaning the expected split in production from blue and green hydrogen is currently uncertain. When combined there is a significant amount of uncertainty in determining the locations of hydrogen production for heating applications. Finally, the project team confirmed with the experts that a mass switchover to hydrogen gas for domestic heating would not be feasible without large-scale storage facilities to sustain demand through the winter. As a result, the methodology was updated to consider key storage locations as the driver of the transmission network length to each archetype with an average figure determining the distance from a production location to the storage facility.
- The proportion attributed to domestic heat applications presented another challenge in the second workshop. While this was initially considered in the storage costs, it was not considered in the other transmission network costs. As a result, the methodology was updated to include this factor and exclude costs which would be attributed to other hydrogen-consuming sectors such as power generation, industrial applications, and transportation.

Overall, our data collection approach was comprehensive, utilizing a variety of sources to ensure a robust and complete data set. This approach allowed us to capture broad views on the subject, enhancing the accuracy and depth of our analysis. The data collection process from the data sources was structured and thorough, considering several key considerations for each data source. A summary of the approach and the key information recorded is below:

- **Document Title:** The title of each source was noted to provide a quick reference for the type of information it contained.
- **Publisher:** The publisher of each source was recorded to understand the origin and credibility of the information.
- **Year:** The publication year was noted to gauge the timeliness and relevance of the data.
- **Aims:** The aims or objectives of each source were considered to understand the context and intention behind the data presented. This informed the relevance and possible key information the source contains.
- **Methodology:** The methodology used in each source was analysed to understand how the data was collected and processed, providing insights into its reliability and repeatability.
- **Key Variables:** Important variables or factors presented in the sources were identified to understand what aspects they were addressing, and which scenario is most applicable to the research conducted as part of this study.
- **Assumptions:** Any key assumptions made in the sources were recorded to understand the basis on which the data was presented and to identify any potential biases or limitations. This aspect was key to highlighting information which had the potential to be incorporated into this study.
- **Key Result(s):** The main findings or results from each source were extracted to capture the essential information they provided.
- **Sensitivities (if relevant):** Any sensitivity analyses or considerations were noted to understand how changes in the variables could affect the results.
- **Comments:** Any additional observations or remarks about the sources were recorded in the comments section which may be useful to highlight for further consideration.

Overall, this comprehensive approach ensured a thorough review and evaluation of each data source, allowing for a robust and reliable dataset for analysis. In the following sections key sources used are highlighted for both the electricity and gas workstreams.

Table 4: Archetype Literature Sources

Category	Scope	Publisher	Source	Year
Region types (urban/rural)	Nationwide	Office for National Statistics	Urban Audit Full Extent Boundaries in the UK	2016
Dwelling stock	England	DLUHC and MHCLG	Live tables on dwelling stock, Table 100: England	2023
Dwelling stock details, including exact	England and Wales	DLUHC	Energy Performance of Buildings Data: England and Wales	2023

location, current and potential EPC rating				
Dwelling stock	Scotland	Scottish Government	Dwellings per Hectare and Land Area based on 2011 Data Zones	2022
Dwellings' current and potential EPC rating	Scotland	Scottish Government	Domestic Energy Performance Certificates – Dataset to Q1 2023	2023
Share of property on/off the gas network	Nationwide	A BEIS project delivered by Kiln	The non-gas map	2015
	Scotland	SP Energy Networks	SP Distribution Heat Maps for Scotland – Mid and South	2023
	Scotland	SSEN	SSEN Network Maps for Scotland - North	2023
For calculating heat demand and required fuel power				
Heat demand calculator		University of Strathclyde	Heat demand profile	2018
Heating degree days (HDD) – input for heat demand calculator		BizEE Software	Degree Days Weather Data for Energy Saving	2023

Table 5: Electricity Network Literature Sources

Source	Author	Year	Use
Accelerated Electrification of the GB electricity system	CCC	2019	Reinforcement costs of infrastructure
Distribution Network Options Assessment Feb 2023	National Grid	2023	Constraint factors in the UK
Review of published energy scenarios and associated methodologies	National Grid	2021	Case study examples of energy scenarios
Electricity Networks Strategic Framework	BEIS & Ofgem	2022	Projecting the peak demand of heat
Electricity Networks Strategic Framework – Appendix 1	BEIS	2022	Projecting onshore transmission costs in the UK
National Grid Final TNUoS Tariffs for 2022/23	National Grid ESO	2022	Valuing transmission costs regionally

National Grid ESO Network Options Assessment 2021/22 Refresh	National Grid ESO	2022	Constraints and reinforcement in the UK
Net Zero South Wales 2050	Regen	2020	How each scenario was applied to model net zero
Distribution Future Energy Scenarios: Regional Review	WPD	2020	How each FES scenario was applied to a regional case study
Future Energy Scenarios 2022	National Grid ESO	2022	Different scenarios of the energy sector
Sixth Carbon Budget	CCC	2020	Sector pathway to net-zero

Gas Networks Literature Sources

A range of sources provided key insights into the decarbonisation of gas networks in Great Britain to transition to 100% hydrogen. These sources provided a comprehensive view of the various strategies and technologies involved, as well as the associated costs, infrastructure requirements and policy considerations. The approach focused on costs for new infrastructure and upgrade work to existing infrastructure to facilitate the shift to hydrogen for both the gas transmission and distribution networks. Key data sources are provided below:

Table 6: Gas Network Literature Sources

Source	Author	Year	Use
Pathways to Net-Zero: Decarbonising the Gas Networks in GB	ENA	2019	Average distance of a hydrogen molecule travelled in the system. CAPEX assumptions of transmission pipelines, compressors, metering stations.
Future Energy Scenarios	National Grid	2023	Used to calculate the proportion of hydrogen heating demand to total hydrogen demand
The role of renewable hydrogen and inter-seasonal storage in decarbonising heat – Comprehensive optimisation of future renewable energy value chains	Applied Energy	2019	CAPEX assumptions of transmission pipelines, compressors, expanders, and metering stations.
Spatially Resolved Optimization for Studying the Role of Hydrogen for Heat Decarbonization Pathways	American Chemical Society	2018	Details on existing distribution grid retrofits.

Source	Author	Year	Use
Heat Street: Scenarios to assess the impact of decarbonisation of heat on UK Power Networks' electricity network to 2030	Element Energy	2021	Details of large-scale storage locations
Planetary boundaries assessment of deep decarbonisation options for building heating in the European Union	Energy Conversion and Management	2023	Details on storage requirements.
Hydrogen Net Zero Investment Roadmap	HM Government	2023	Information regarding current projects (production and storage) and locations.
European Hydrogen Backbone	EHB	2023	To determine transmission pipeline costs and sizes.
Hydrogen Transportation and Storage Infrastructure Assessment of Requirements up to 2035	Frazer-Nash Consultancy, Cornwall Insight prepared for BEIS	2022	To identify inter-seasonal large-scale storage locations.
H21 North of England	H21, Northern Gas Networks, Equinor, Cadent	2018	Used to determine the storage requirements for domestic heating demand

3.9. Detailed Methodology – Electricity Networks

To understand the total costs for each scenario and archetype area, the overall transmission grid was considered. This is because the grid operates as a whole. 'Slicing' the grid to understand regional cost differences was avoided in this research, as electricity can be carried from one archetype region to another (and through other regions) and could therefore be double counted. To understand the transmission costs, the following data was collected.

1. **Reinforcement costs**: The Electricity Networks strategic framework[1] highlighted that significant levels of investment were required to support the expected increase in peak demand. This source suggested that the onshore network (excluding offshore) could require £100-240 billion of investment by 2050. Of this investment, £60 billion of investment was considered for onshore transmission network alone[2]. The £40-60 billion figure quoted in the study is additional investment above a baseline investment that is needed by 2050 to meet current demand of 65GW. The baseline cost equalled £60 billion, Low carbon zero equalled £100 billion (i.e., £100 billion - £60 billion = £40 billion additional cost to meet 125GW), and high net zero equalled £120 billion (i.e., £120 billion - £60

billion = £60 billion additional investment required to meet 185GW). This study is focused on the additional costs as this is what is being compared across the scenarios isolating the reinforcement needed to meet domestic heat demand.

2. **Peak heat demand**: To further disaggregate the £60 billion transmission infrastructure cost, the peak demand projections were reviewed for heating. The Electricity Networks Strategy Framework[3] suggested that the demand from electrified heating is expected to increase the peak demand by between 50-90 GW by 2050, therefore contributing to between 40-50% of the total system peak. This research considered 50% total system peak to understand the maximum network cost. To further disaggregate heating demand to domestic heating demand, it was suggested that 55.5% of heating demand would be generated for domestic users[4].
3. **Archetype data**: as this study focused on 5,000 dwellings, the UK dwelling population was projected for 2045. This was calculated by understanding the population increase percentage and applying the same increase to the current housing stock. This would give more representative costs, by considering the percentage 5,000 dwellings has of the UK's housing stock.
4. **Transmission Network Use of System (TNUoS)[5]**: Demand tariff costs (Table 1) were used in this study to understand the varying transmission costs of regions in Great Britain. TNUoS charges are designed to recover the cost of installing and maintaining the transmission system in the UK and offshore. The costs are location specific, with regions closer to renewable energy generation having lower TNUoS charges (these costs are based on current TNUoS tariffs, and any future changes will impact the archetype transmission costs). Three TNUoS tariff costs were taken as data for this study. Each of the tariffs (below) can be found in Table 5.
    a. Half Hourly Demand Tariff
    b. Non-Half Hourly Demand Tariff
    c. Embedded Export Tariff

Table 7 – Demand tariffs (Source: National Grid)

Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
Northern Scotland	27.446662	3.558626	0
Southern Scotland	35.465718	4.395158	0
Northern	44.681931	5.280945	0
Northwest	51.407508	6.382111	0
North Wales & Mersey	53.406721	6.460609	0
Midlands	57.193871	7.145603	2.676619
South Wales	58.461967	6.630234	3.944715
Southeast	60.199079	8.057826	5.681827

London	63.687789	6.457749	9.170537
Southern	62.263662	7.854326	7.746409
South Western	63.747665	8.671244	9.230413

*****_Those with £0 Embedded Export Tariff costs do not have any costs for embedded generators_

3.9.1.Electricity Distribution Data Collection

To understand the reinforcement each archetype area will require for each scenario, data was collected for both infrastructure costs and its current electricity heating demand.

1. **Infrastructure upgrades**:
    a. Sub-station upgrades: to understand the necessary upgrades to the distribution grid, the following pricings were estimated for each sub-station 1. Bulk Supply Point (BSP) – Urban: (£~9m) Rural: (£7.5m)[6], 2. Primary transformer – Urban and rural: (£840,000[7]) (this figure was also inflated to a 2023 price) and 3. Distribution transformers – Urban and rural: (£27,000[8]) (also inflated).
    b. Circuit reinforcement: low voltage lines (11V) data was used to understand the costs of distribution. Costs were split between Urban / Industrial and Rural archetypes due to the use of underground and overhead lines[9]. Rural: £38,000 per kilometre, Urban / Industrial: £118,000 per kilometre.

2. **Archetype's current electricity heat demand**
    a. Each archetype's percentage of heating already provided by electricity was taken from the Office for National Statistics[10] (Table 2). This provided information to understand the rate of electric heating in the area and how much reinforcement is needed to reach 100% electrification.

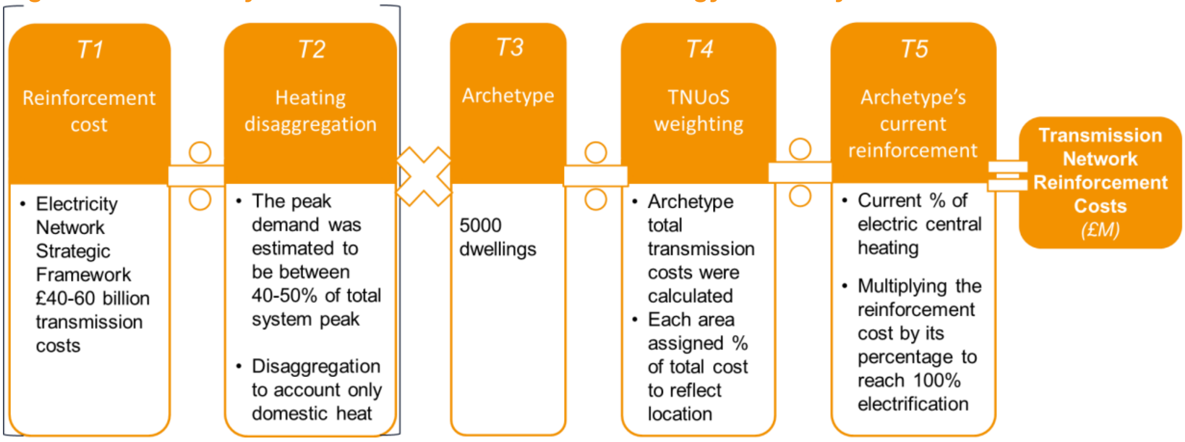
Table 8: Percentage of current electrification of each archetypes heating demand.

Archetype	Area categorisation	% of current Electrification
Scotland – North	Rural	19
Scotland – Mid	Industrial	9
Scotland – South	Urban	9
England – Northeast	Industrial	9.6
England – Northwest	Urban	8
Wales – North	Industrial	12.2
Wales – Mid	Rural	5.6
Wales – South	Urban	10.4

England – Midlands	Urban	4.4
England – London	Urban	10.5
England – Southeast	Rural	6
England – Southwest	Rural	11.9

3.9.2.Electricity Transmission network calculations

Figure 3 - Electricity Transmission network methodology summary



- **Reinforcement costs**: the Electricity Network Strategic Framework[11] suggested that total onshore transmission costs were estimated to be between £40-60 billion. This research considered the maximum cost of reinforcement, therefore £60 billion was calculated.
- **Domestic heating disaggregation:** as peak demand was already considered in the Electricity Network Strategic Framework Onshore Transmission costs; it did not need to be disaggregated. The share of domestic heat did however need to be disaggregated from industrial and services demand. Here, we considered 55.5% of all heating demand to be for domestic properties[12].
- **Archetype dwelling**: to understand each archetype's 2045 share of the UK, a 4.8% population increase was projected. It was considered that the UK's dwelling population would increase by the same figure, meaning there would be 25.84 million dwellings in the UK by 2030. Each archetype therefore presented 0.0193% of UK dwellings. The total disaggregated reinforcement costs were then divided to each archetype area.
- **TNUoS weighting**: to understand how the costs altered between archetype regions, TNUoS data was taken to weight each cost. This was calculated by totalling Half Hourly Demand Tariffs, Non-half Hourly and Embedded Export Tariff data and associating a percentage to the overall cost to each zone. All twelve archetypes disaggregated reinforcement costs were totalled, then assigned their TNUoS zonal percentage, giving a localised cost variable.
- **Archetype's current reinforcement**: this final step factored the infrastructure already established in each archetype region. To do this, the archetypes current percentage of electrification was deducted from the overall transmission costs (e.g., if an archetype had 4% of current reinforcement, 96% of the transmission

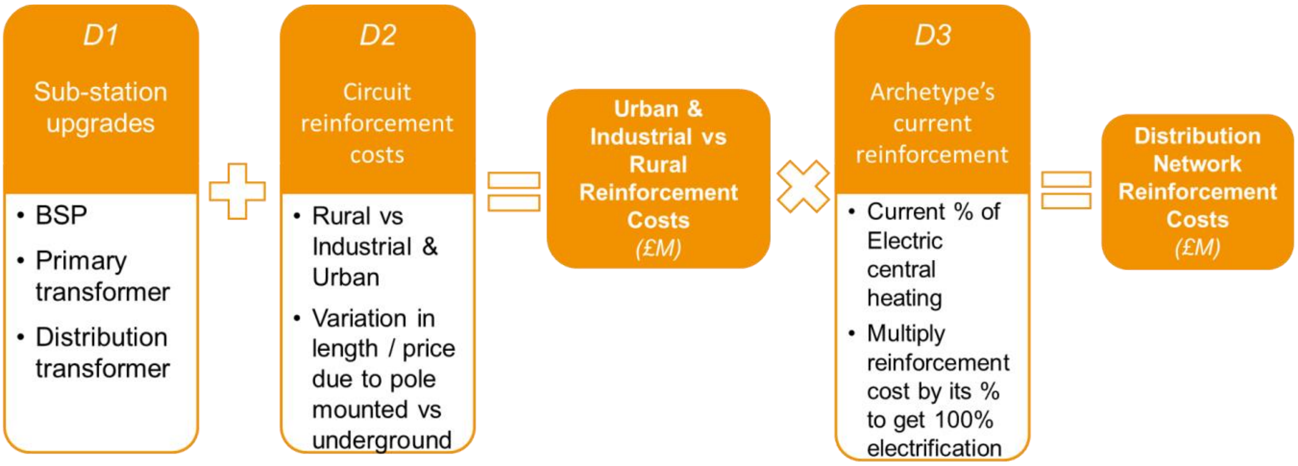
cost would be calculated) as that percentage is already reinforced to meet today's demand. This is because the number of houses using electric heating is already included in the £40-60 billion predicted cost of reinforcement. Our method apportions the required amount of reinforcement in each area by understanding its current domestic heating demand supplied by electrification.

The method above was selected to give locational costs for electrifying domestic heating across GB. When developing this methodology, other factors were considered, however, this study found that the data / focus would give inaccurate results. These included:

- **Import / export areas**: although there is data on import and export regions within the UK, there was no correlation in how to use this data and apply it to our 5,000 dwelling archetypes. This is because electricity travels between multiple zones to reach its final usage point, therefore assigning pricings for its transfer was troublesome.
- **Transmission boundaries**: this study avoided measuring the distance of the transmission line to each archetype's zonal boundary. This is because values would only be assigned to specific areas of the network and not the overall cost in that zonal area.
- **Proximity from large renewable energy sites**: this study avoided measuring the distance of renewable energy sites to archetype areas. This is because the method would only focus on specific transmission lines and infrastructure (and not the whole transmission network) which would not accurately represent how the electricity transmission system works.

3.10. Electricity Distribution network calculations

Figure 4 - Electricity distribution network methodology



- **Substation upgrades**: to understand the costs of the distribution network, Rural and Urban / Industrial archetype costings were split due to varying infrastructure considerations. To facilitate 5,000 dwellings, we assumed the archetypes would be served by infrastructure that would be able to meet its demand. This required:

  - a fifth of a BSP (a variable price for rural and urban/industrial areas),
  - one primary sub-station and,
  - fifteen distribution transformers.
  - The costs gave each rural and urban / industrial archetype area a 'base' infrastructure costing to meet demand.

- **Circuit reinforcement costs**: to understand the typical costs of urban / industrial and rural archetypes, two variables were highlighted as important cost consideration.
  - Urban / Industrial – firstly the length of circuit line was assumed to be underground cables and 40 kilometres in length.
  - Rural – it was assumed these archetypes circuits measured 100 kilometres in length and were pole mounted lines.
  - Phase 3 upgrades (from the distribution network to each dwelling) is excluded from this research as each cost will be variable, depending on the current demand of each dwelling. This is therefore deemed to be a consumer cost, not a network cost.
  - Electric Vehicle (EV) infrastructure considerations were excluded from this research. The most likely effect of including EV upgrades would be to achieve economies of scale when completing infrastructure upgrade work. This would mean that the total costs are lower, therefore the costs are not reduced as a result of excluding EV infrastructure.
- **Archetype's current reinforcement**: once combining both the substation upgrades and circuit reinforcement costs, each archetype is multiplied by its percentage to reach 100% electrification of domestic heat. This is a key variable when considering the overall cost of the distribution network. The data collected from the Office of National Statistics[13] gave a considerable variation in similar archetypes as the rural Northern Scotland Archetype is 19% electrified (81% increase required to reach 100% electrification) whilst the rural England (South East) archetype is 6% electrified (a 94% increase required to reach 100% electrification) (Scottish archetype rates were sourced using Scottish Government statistics[14]).

Similarly to this research's transmission methodology, other factors were considered in developing the distribution methodology, however, this study found that the data / focus would give inaccurate results. These included:

- **Distribution network length**: as this study did not have the total distribution network length data for each archetype, the typical distribution length for urban / industrial and rural archetypes were assumed. This assumption was based on guidance from our internal experts (at LCP Delta), who suggested that a typical circuit length would measure 40km in urban archetypes and 100km in rural archetypes.
- **Distribution transformers**: as multiple transformers would be included within an archetype; each upgrade could significantly affect the performance

of another. Therefore, a whole approach was taken, to estimate how many distribution transformers would be found to meet demand. This was then applied to each archetype area to ensure consistency with our methodology as a maximum cost.

3.11. Detailed Methodology – Gas Networks

The methodology to calculate the total network costs for each scenario splits the overall calculation into two components: the distribution and transmission network. The sum of these two components represents the total network costs for each archetype. This approach provides a comprehensive understanding of the network costs by considering the intricacies and unique cost factors associated with each segment of the GB gas network. The segments can be split into the following:

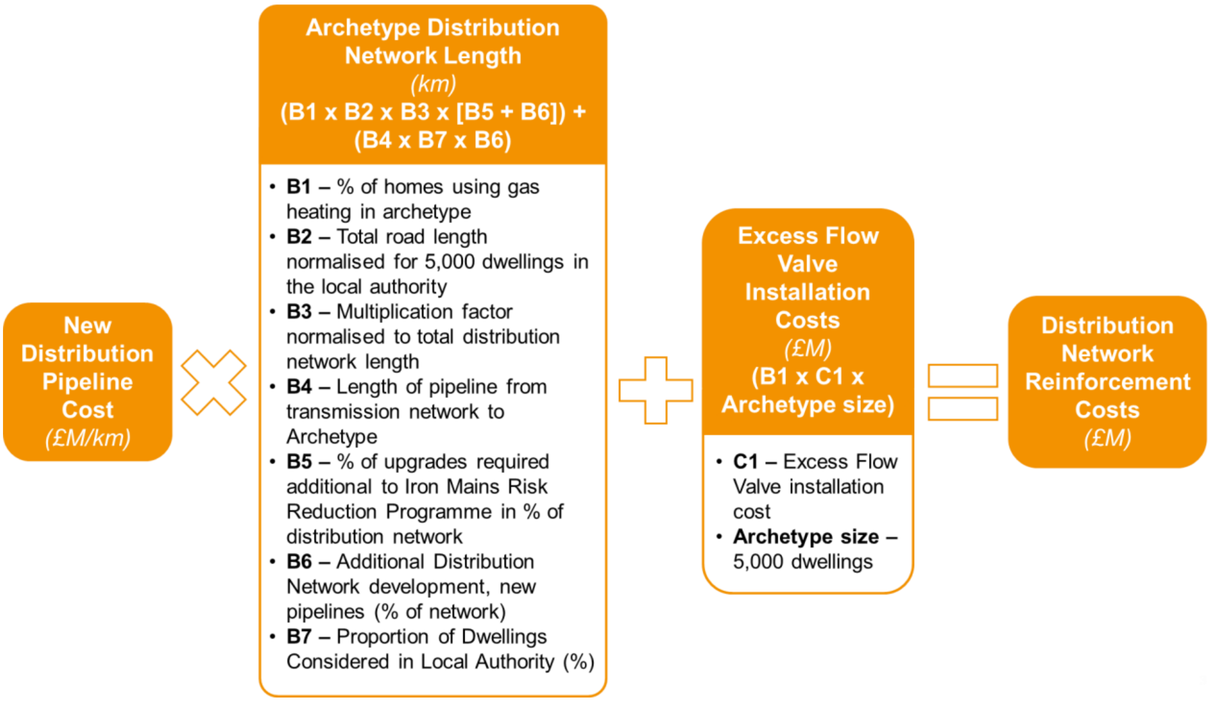
1. **Distribution Network:** This element of the calculation is focused on the localised network of pipelines that distribute gas to individual consumers — residential, commercial, and industrial. For the purpose of this calculation the distribution network only considers distribution to residential properties where hydrogen is used for heat. The distribution network's cost factors include the costs of new pipeline installation and upgrading or replacing existing pipelines to facilitate the transition to a hydrogen network. As it is not recommended to extend the gas distribution network, no costs for achieving this have been included. It is crucial to consider factors such as the number of homes connected to the gas grid, the total road length, the proportion of dwellings in a local authority, and the length of pipeline required from the transmission network to the archetype, and additional safety measures that are required to be installed.
2. **Transmission Network:** The transmission network cost calculation encompasses the larger, high-pressure pipelines that transport natural gas from production sites and storage (interseason large scale and localised smaller scale storage) to the distribution networks. The costs associated with the transmission network include new pipeline construction, the retrofitting of the existing gas network, compressor station costs, storage facilities, and any other infrastructure necessary for the safe and efficient transportation of gas over long distances. Key factors in this segment are the total length of the transmission network, the costs associated with converting parts of the network to carry hydrogen, the proportion of existing pipeline retrofits and the costs of connecting the transmission network to the distribution network for each archetype.

By separately calculating the costs associated with the distribution and transmission networks, we ensure a detailed and thorough examination of all potential capital cost factors for each archetype.

Distribution Network Costs

The methodology to calculate the total costs of reinforcement for a gas distribution network is based on three central components: the ***New Distribution Pipeline Costs (A)***, which is a known input value; the ***Distribution Line Length to Install (B)***, which requires several calculations for its determination and therefore it varies between each archetype, and the ***Costs to install an Excess Flow Valves (C).*** The method of calculating these costs is displayed below:

Figure 4: Distribution Network Costs Calculation



New Distribution Pipeline Costs (A) represents the cost to install one kilometre of new distribution pipeline. This is a predefined value and is determined using literature sources and it includes the costs of materials, labour, and other resources required to install the pipeline. The assumption for this value, in addition to other assumptions and data sources are outlined below.

The Distribution Line Length to Install (B) is a more complex calculation, and requires several calculations:

- **Initial Length Calculation:** The first step is to calculate the initial length of the distribution network within each archetype. This is done by multiplying together:
  - **The proportion of homes using gas heating (B1).** This reflects the reach of the distribution network within each archetype. This is calculated using ONS connectivity data which is provided down to a sub-local authority granularity. The location of the archetype is matched to the area within the local authority it is found in to determine this value.
  - **The total road length (B2).** This provides a baseline for how long the distribution network is within each archetype. The philosophy behind this is that gas distribution networks commonly run alongside the GB road network and this has been used in published studies on the topic.[15] This data is obtained on a local authority level as reported by the UK Government Department of Transport.
  - **The Distribution Network Normalisation Factor (B3)** is a crucial component in our calculations. It is used to adjust the total road length to align with the proportion between the total road length and the total length of the gas distribution network across GB; however, it is important to note that

this normalisation cannot be individually tailored for each archetype. This limitation arises from the constraints on the availability of distribution network data. Currently, this data is only publicly accessible at the national level for GB, and as such, it does not permit a breakdown for specific archetypes. Consequently, the normalisation factor used is uniform across all archetypes.

LCP Delta notes the above methodology has been used in the literature reviewed; however, the methodology outlined improves on the methodology outlined in literature to include the additional normalisation factor (B3). It is noted this methodology has been deemed appropriate and reasonable following interactions with experts in the field and the participants in the first expert workshop for this project.

Further to the initial distribution network length calculation, this value must be adjusted to include the consideration of additional distribution pipeline length for the following aspects:

- **Distribution pipeline length required for upgrades and development:** This is done by adding together the percentages of the network that need to be upgraded through:
    - **Works additional to the Iron Mains Risk Reduction Programme (B5).** This takes into consideration the need for upgrading the existing network to meet safety standards in the distribution network not included under the programme. To estimate this, data was obtained for the level of work estimated to be completed by the programme end in 2032 for the gas distribution network operators (DNOs) at a regional level. Remaining requirements from non-mandatory pipeline replacement for iron pipelines were also included in the estimation of this value, which will ultimately ensure the distribution grid is hydrogen ready (with exception to safety measures detailed below).
    - Initially this methodology did not consider the Iron Mains Risk Reduction Programme (IMRRP) which is currently replacing 'at risk' iron gas mains (i.e., those pipes within 30 metres of buildings) which consequently have a higher risk of injuries, fatalities, and damage to buildings. To account for this consideration the methodology was updated to consider the ongoing IMRRP to be an already costed project and therefore this cost is not considered in the final methodology in this study; however, there will be a further requirement to replace some existing pipelines to ensure the network is hydrogen ready and it is this aspect which is considered in the methodology.

      The development of new distribution pipelines (B6) to enable the transition from the consumption of natural gas to 100% hydrogen must also be considered. As was apparent in the research any transition away from gas consumption towards 100% hydrogen is most likely going to be gradual and the rate of which is dependent on the overall implementation strategy:
    - Initially the strategy is expected to incorporate some blending of natural gas with hydrogen, but there will be a critical point where no more hydrogen content can be blended with natural gas due to compatibility issues with metering points (i.e., the existing gas-boilers in homes). As a result, all

boilers must be replaced with hydrogen ready boilers in preparation for the switch to hydrogen. However, when the switch to 100% hydrogen for heat arrives, there will be limitations on the number of installers available to complete modifications on hydrogen ready boilers to ensure compatibility.

- Furthermore, and perhaps more importantly, production levels of green and blue hydrogen will be ramped up over time which is not sufficient to replace natural gas at a single point in time. Therefore, when combining these key points in addition to other factors such as capital costs, consumer acceptance etc. the gas grid will likely take a step-by-step approach in a similar fashion to the conversion from town gas to natural gas. This will see sectorisation whereby smaller distinct areas of the low-pressure gas distribution network will one-by-one switch from gas to hydrogen.
- The archetype location will determine additional infrastructure requirements to facilitate this. This assumption varies depending on the type of archetype (i.e., urban, industrial, or rural) as the sectorisation (the division of the gas distribution network into distinct segments or sectors which enhances control, efficiency, and safety) of the low-pressure distribution network will vary between location type.

- **Additional length of the distribution network from the existing transmission network:** This must be considered to account for the distance between the transmission network and the archetype location. This value is determined by the **product** of the following:
    - **Distribution Pipeline length from the transmission network to the distribution network of an archetype (B4)**. The distance is calculated using the shortest distance by road between the transmission network and the archetype distribution network, assuming the pipeline is an existing pipeline in the absence of detailed data on the distribution networks.
    - **The development of new distribution pipelines (B6)** as outlined above to enable the transition from gas to 100% hydrogen. This value, expressed as a percentage, is required to outline what additional pipelines, **B4**, requires reinforcement. This is important to consider since the existing pipeline length does not need to be completely replaced or reinforced.
    - **Proportion of dwellings considered in the local authority (B7).** Each archetype size is set to be 5,000 dwellings and using Government data the proportion of dwellings considered is calculated.[16] This is an important consideration because the distribution pipeline from the transmission network to the archetype will be used to supply gas to the rest of the local authority.
- ***Excess Flow Valve Installation Costs (C)*** is the costs associated for the installation of additional safety measures in the form of an EFV. As discussed previously, it has been proposed in pilot trials that each metering point should contain an EFV where the service pipe connects to the grid to prevent accumulations of hydrogen gas in properties. The cost for this was determined using several factors as follows which were multiplied together:

- **The proportion of homes connected to the gas grid (B1).** This reflects the reach of the distribution network within each archetype. This is calculated using ONS connectivity data which is provided down to a sub-local authority granularity. The location of the archetype is matched to the local authority it is found in to determine this value.
- **The number of dwellings in the archetype** (i.e., 5,000 dwellings) to determine the number of dwellings which require an EFV.
- **The cost of a EFV installation (C1)** which is determined using estimations and ranges of costs from gas service providers. It should be noted the low range of estimations were taken as the assumption for the calculation due to economies of scale of installation.

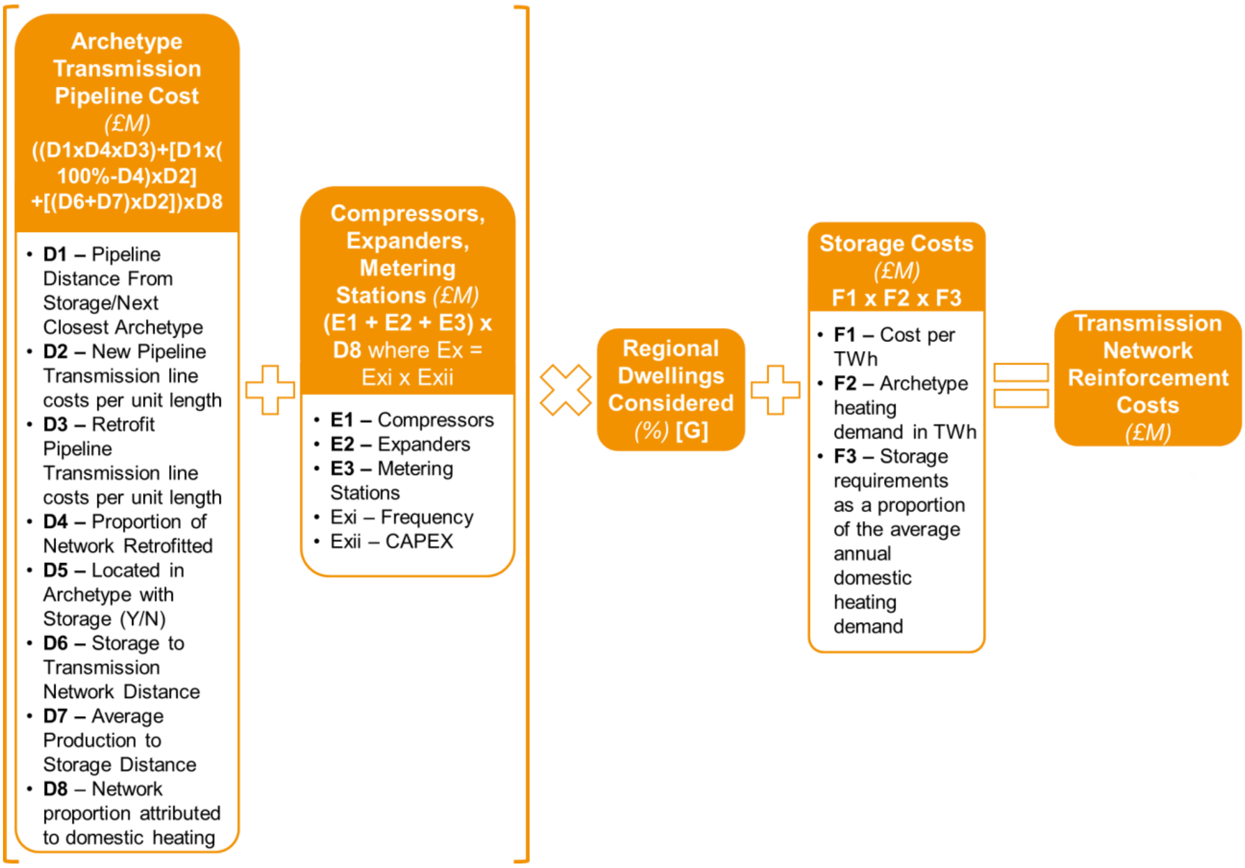
This methodology provides a detailed and comprehensive approach to estimate the total costs of reinforcement costs for a gas distribution network. It considers key factors which drive clear distinctions between archetypes.

Transmission Network Costs

The calculation for the cost of the required GB gas transmission network in each archetype and scenario involves a series of steps and factors. It is broken down into three major components:

- **Transmission Pipeline Costs (D)**
- **Costs for Compressors, Expanders, and Metering Stations (E)**
- **Storage Costs (F)** storage costs are included and are clearly identified in the results as a separate cost to the upgrade work so their contribution to the total cost is clearly understood.
- Each component is calculated separately and then they are summed up, before being multiplied by the **proportion of dwellings considered in the archetype region (G)** to get the final total transmission reinforcement cost.

Figure 5: Gas Transmission Network Costs Calculation



The **transmission pipeline costs (D)** is a complex calculation and requires several calculations. The calculation is made as shown above and as follows, into three separate calculations which are then summed up and adjusted by the proportion of network which can be attributed to the domestic heat applications.

- **Calculation 1:** The pipeline distance from storage or the next closest archetype (D1) is multiplied by the proportion of the network that is assumed to be retrofitted (D4) and the retrofit pipeline transmission line costs per unit length (D3).
- **Calculation 2:** the pipeline distance from storage or the next closest archetype (D1) is multiplied by the remaining proportion of the network that does not require retrofitting in the future (100% - D4) and the new pipeline transmission line costs per unit length (D2).
  - Calculation 1 and 2 collectively account for the full transmission network. The transmission network pipelines are either retrofitted or replaced with new pipelines.
- **Calculation 3:** The sum of the storage to transmission network distance (D6) and the average production to storage distance (D7) is multiplied by the new pipeline transmission line costs per unit length (D2).
- Calculations 1, 2, and 3 are summated and this value is then adjusted by the Proportion Attributed to Domestic Heat Applications (D8).

The individual components D1-D8 are described as follows:

- **Pipeline Distance from Storage/Next Closest Archetype (D1):** This is a measure of the distance in kilometres between the storage site within the archetype region (or in the case where storage in not located within the archetype region, a reference point from which additional transmission pipelines will be required to transport hydrogen from a neighbouring archetype region) and the location where the pipeline is being laid. An example of which would be the Scotland North region where there are currently no expectations of storage being located within the region. As such the distance from the next closest archetype, which is located towards storage, Scotland South, is considered.
  - It should be noted that the archetype is a predetermined geographic location, as outlined in previous sections. The distance D1 was calculated using geographical transmission pipeline information provided by National Gas.
  - The initial methodology to calculate the pipeline length was initially driven by the location of production facilities for green and blue hydrogen which were assumed to be located close to or within industrial clusters. However, following feedback from the first expert workshop it was clear this methodology would be problematic due to a number of reasons: green hydrogen production is more likely to be located near large-scale renewable energy production rather than near or within industrial clusters. A further consideration is that there is the potential for offshore green hydrogen production co-located with offshore wind electricity generation which is currently unproven. The hydrogen economy also remains in the early stages of development meaning the expected split in production from blue and green hydrogen is currently uncertain. When combined there is a significant amount of uncertainty in determining the locations of hydrogen production for heating applications. Finally, the project team confirmed with the experts that a mass switchover to hydrogen gas for domestic heating would not be feasible without large-scale storage facilities to sustain demand through the winter. As a result, the methodology was updated to consider key storage locations as the driver of the transmission network length to each archetype with an average figure determining the distance from a production location to the storage facility.
- **New Pipeline Transmission Line Costs Per Unit Length (D2)** is the cost in £M to construct a new pipeline transmission line per kilometre. This cost includes the expenses for materials, labour, machinery, engineering, permitting, safety measures, and other associated costs. The cost is determined from literature sources, which themselves are supported by the opinions of key stakeholders as determined in the expert workshops. It is important to note that this cost may vary depending on the specific sizing of the pipeline in addition to the geographical location. A single pipeline size and cost is considered for this study.
- **Retrofit Pipeline Transmission Line Costs Per Unit Length (D3):** This is the cost in £M to retrofit a kilometre of the pipeline. This cost includes the costs of materials, labour, machinery, and other expenses that go into retrofitting the pipeline. The cost

is determined from literature sources, which themselves are supported by the opinions of key stakeholders as determined in the expert workshops. It is important to note that this cost may vary depending on the specific sizing of the pipeline in addition to the geographical location. A single pipeline size and cost is considered for this study and the costs for a retrofitted pipeline is linked to a proportion of costs for a new transmission line (D2), which is described below.

- **Proportion of Network Retrofitted (D4):** This is the percentage of the existing gas network that will be require retrofitting in the future to safely ensure the transport of hydrogen at high pressure to facilitate the transition to 100% hydrogen consumption for all applications (industry, heat, power generation etc.). This assumption was obtained through conversations from experts in the field, with the value outlined in Table 9. It is clear from a cost perspective the intention is for the networks to be repurposed as much as possible; however, there will be parts of the transmission network where new pipelines will be required to support the development of the hydrogen network. This value is subject to volatility as it largely depends on the Government's hydrogen strategy which is set to be further defined in the coming years, particularly with the expected decision to be taken on how significant a role hydrogen will have in decarbonising domestic heat in 2026.
- **Archetype Located in Region with an Inter-Seasonal Storage Facility (D5):** This is a simple yes or no term which is used to inform the calculations outlined above and therefore does not directly influence the results.
- **Storage to Transmission Network Distance (D6):** This is the distance in kilometres between the battery limit of the nearest inter-seasonal storage facility and the nearest point on the transmission network. This value is only applicable for archetypes which are considered to contain inter-seasonal large scale hydrogen storage in their region. This measurement is needed to estimate the length of pipeline necessary to connect the storage facility at its battery limit, i.e., the boundary point of responsibility between the storage facility and the network, to the network where applicable. This distance was determined using geographical transmission pipeline information provided by National Gas. All pipelines that fall within the storage facility battery limits and are therefore not the responsibility of the transmission network operator to manage, are excluded from this analysis. The pipeline distance, D6, is assumed to be a new pipeline due to the absence of existing pipelines. In some instances, existing storage facilities are expected to be repurposed and they are already connected to the transmission grid. Therefore, the value D6 equals zero for these repurposed facilities.
- **Average Production to Storage Distance (D7):** This is the average distance in kilometres between the sites of hydrogen production and the storage facility for each archetype region. This value is estimated using an average total distance that a hydrogen molecule travels in the transmission network. A weighted average distance between selected storage locations and the distribution networks is calculated at the archetype level and this value is subtracted from the total distance a hydrogen molecule is anticipated to travel to calculate the average distance from production to storage.

- **The Proportion Attributed to Domestic Heat Applications (D8):** This factor captures costs which would be attributed to other hydrogen-consuming sectors such as power generation, industrial applications, and transportation. It was estimated by using the National Grid ESO Future Energy Scenarios 2023 data which provides a breakdown of hydrogen consumption by sector and the proportion of domestic heat attributed to hydrogen and electricity. The system transformation scenario was used to develop this value because it considers the greatest proportion of hydrogen heating of all FES scenarios. The value was determined using the 2050 energy consumption which considers the full switch to hydrogen from natural gas and therefore the transmission network is used to supply only hydrogen. The proportion accounts for the level of hydrogen heating demand in each of the scenarios comparing this to total consumption in energy terms.

The **Compressors, Expanders, and Metering Stations Costs (E)** calculation can also be split into three parts: **Compressors (E1), Expanders (E2),** and **Metering Stations (E3).** The costs for each of these elements are obtained by multiplying the frequency of each element per kilometre (E1i, E2i, E3i) by their respective CAPEX (£M) (E1ii, E2ii, E3ii) and the sum of the pipeline distance from storage or the next closest archetype (D1), the storage to transmission network distance (D6) and the average production to storage distance (D7). This value is then adjusted by the proportion of network which can be attributed to the domestic heat applications (D8). The costs for each element are then summed up.

Storage Costs (F) are calculated by multiplying together:

- **The cost per terawatt-hour (TWh) of storage (F1)** is determined by literature sources for the cost of adding a set amount of hydrogen storage capacity.
- **Archetype heating demand in TWh (F2).** This calculation is described in further detail in the archetype section above (Section 1.5.1).
- **Storage requirements as a proportion to average annual demand (F3)** is determined by considering the average annual heating demand from gas, the heating demand from a 1-in-20-year demand scenario, and the relative storage required to be able to meet the peak demand from a 1-in-20-year demand scenario. Using these three values, the storage requirements as a percentage of overall heating demand can be calculated.

Total costs as determined by the transmission pipeline costs (D), the costs for compressors, expanders, and metering stations (E), are then multiplied by the **proportion of dwellings considered (G)** of the archetype in the region (i.e., North Scotland, London, North-West England etc.) which are obtained using Government data for number of dwellings for each local authority.[1] The value is then added to the storage costs (F).

[1] GOV.UK (https://www.gov.uk/government/collections/dwelling-stock-including-vacants), accessed 06 July 2023, and Scottish Government (https://statistics.gov.scot/data/dwellings-type), accessed 06 July 2023.

This methodology provides an in-depth and systematic way to calculate the reinforcement costs for a gas transmission network, considering key factors such as retrofitting costs, storage costs, and the proportion of dwellings involved.

Table 9: Gas Network Assumptions.

Assumption	Units	Gas Network Segment Use	Value
New Distribution Pipeline Costs	£M/km	Distribution Network	1.53[17]
Homes Using Gas Heating	%	Distribution Network	Dependent on archetype location (i.e., sub-local authority level).[18]
Distribution Network Upgrades - Iron Mains Replacement Programme Level of Completion of Total Distribution Networks	%	Distribution Network	Dependent on archetype location (i.e., DNOs regional split)[19]
EFV Installation Cost per Dwelling	£	Distribution Network	590[20]
Storage Locations		Transmission Network	See Table 10.
Storage to Transmission Network Distance	km	Transmission Network	Dependent on Archetype Location[21]
Transmission Network Distance to Archetype	km	Distribution Network	Dependent on Archetype Location[21]
Transmission Network Distance to Archetype/Next Closest Archetype (distance different from above)	km	Transmission Network	Dependent on Archetype Location[21]

Average Distance of H2 molecule travelled in transmission network	km	Transmission Network	300[22]
Average Distance from Production to Storage	km	Transmission Network	108[23]
Archetype Road Length	km/5000 dwellings	Distribution Network	Dependent on Archetype Location[24]
Distribution Network Normalization Factor (accounting for distribution network size vs. national total road length)	%	Distribution Network	83%[24,25]
Transmission Network Average Pipeline Diameter	Inches	Transmission Network	36[26]
New Transmission Line CAPEX	£M/km	Transmission Network	2.2[26]
Retrofit Costs	% of new pipeline costs	Transmission Network	23%[27]
Compressor CAPEX	£M	Transmission Network	10.45[28]
Expander CAPEX	£M	Transmission Network	17.3[28]
Metering Station CAPEX	£M	Transmission Network	0.7[22]
Compressor and Metering Station Frequency	km^{-1}	Transmission Network	0.0096 (Metering station required with every compressor)[22]
Expander Frequency	km^{-1}	Transmission Network	0.0030[28]

Distribution Network New Pipeline Requirement[29]	% of network	Distribution Network	20% (Rural)* 15% (Urban)* 17.5% (Industrial)*
Transmission Network New Pipeline Requirement	% of network	Transmission Network	25%[30]
Storage Cost	£/kWh	Transmission Network	0.5[31]
Storage requirements as a percentage of average gas demand for domestic heating.	%	Transmission Network	16.1%[32]
Proportion of domestic heating applications relative to total hydrogen consumption[33]	%	Transmission Network	32% (Scenario 2) 9% (Scenario 3) 19% (Scenario 4 – Base Case) 26% (Scenario 4 – Sensitivity 1) 11% (Scenario 4 – Sensitivity 2)

Storage Locations

The assumptions about storage locations are shown in Table 10 below. The locations are based on the most likely scenarios according to the information available in the data sources and insights from the LCP Delta hydrogen expert and workshop expert inputs. It should be noted there are several different possible storage facility types for hydrogen: salt caverns, liquified hydrogen, as ammonia following conversion via the

* These values were determined following discussions with LCP Delta's Hydrogen Expert supported by the range of European strategies being undertaken to ensure gas distribution networks are 100% hydrogen ready. The consensus is that there are high levels of repurposing existing assets at approximately 80%, therefore there is little requirement for new pipelines. This value increases as urbanisation increases where there is increased sectorisation of the network (i.e., the network is split into more areas) which results in less additional infrastructure to facilitate the switch from natural gas to 100% hydrogen.

Haber-Bosch process, and the saline aquifer/depleted gas reservoirs which remains unproven at this stage for hydrogen.

Research identified that salt caverns and the saline aquifer/depleted gas reservoirs are the most likely locations for inter-seasonal hydrogen storage due to their higher capacity in comparison to other storage facilities. The locations chosen each have hydrogen storage projects in early stages or they are currently being used to store natural gas.

It is likely additional storage facilities will be required to provide GB with sufficient storage quantities under a full hydrogen heating scenario; however, due to the early stages of development for the use of hydrogen for heat and hydrogen storage facilities LCP Delta did not speculate on the location of additional sites.

Table 10: Large-Scale Gas Network Storage Location Assumptions.

Location	Source
Holford Brinefield, Cheshire	https://www.kgsp.co.uk/
Aldbrough, East Riding of Yorkshire	https://www.equinor.com/
Rough gas field, East Riding of Yorkshire	https://www.centrica.com/
Humbly Grove, Hampshire	https://www.humblyenergy.co.uk/
Hornsea Storage Installation, East Riding of Yorkshire	https://www.ssethermal.com/
Teeside, North Yorkshire	https://hydrogen-uk.org/
Portland Port, Dorset	https://www.offshore-energy.biz/

3.12. Limitations of the Methodology

The methodology for calculating the reinforcement costs while comprehensive is subject to several limitations and caveats. The data used in this analysis, although collected from reliable sources, has some limitations on granularity or may not fully represent the entire gas or electricity networks due to its scope. Additionally, the methodologies used for certain calculations are based on assumptions which could potentially vary, and this variability could have implications on the results. Furthermore, the evolving nature of the energy sector introduces an element of uncertainty, especially in the context of long-term projections. These factors should be taken into consideration when interpreting the results of this analysis. The main limitations and caveats for the network reinforcement calculations are as follows:

- **Electricity transmission costs**: The overall transmission cost of £60 billion, taken from the Electricity Networks Strategic Framework only accounts for onshore transmission. As offshore wind is expected to supply a substantial amount of electricity demand for domestic heat, this study does not account for the infrastructure costs to get electricity onshore. This was considered outside of the scope for this research, as we are considering only the costs that are required to reinforce the grid to deal with peak demand (i.e. load related expenditure), not to connect generation.
- **Electricity storage:** as hydrogen storage is an essential component for meeting demand through winter, we have included the CAPEX costs for hydrogen storage in the total network upgrade costs. However, the electricity network does not operate in this way, so there is likely no comparable need for large scale, inter-seasonal storage to ensure domestic heat demand is met. There may be a need for Long Duration Energy Storage (LDES) of 1-2 weeks to ensure periods of low wind and high demand can be bridged. LDES could come from a new of potential technologies, such as pumped storage, compressed air, or using hydrogen as a storage medium for conversion back into power – costs of which range considerably. This study has focused on the network costs, and so we show the cost comparison between electrification and hydrogen without the use of storage. For a full comparison, storage, generation, and costs in the home would all need to be included.
- **Archetype costs:** As this research calculated the archetypes percentage of the UK dwelling population, our calculation based the 2045 housing stock increase on the UK population growth (4.8%). This does not influence the reinforcement costs for each archetype because the number of dwellings is fixed.
- **TNUoS weighting:** The values assigned to each archetype are dependent on current TNUoS tariff costs. These will change in the future when the electricity infrastructure evolves. The results therefore suggest an outlook from today's transmission costs.
- **Archetype's current reinforcement:** Although the heating mix was provided by councils, each archetype figure collected may account for more than the 5,000 dwellings in our criteria. Moreover, the data collected was also sliced into geographic areas, therefore our 5,000 dwellings may have split into two areas in the Office of Statistics datasheet. The location of our archetype's most populated area was therefore considered. This is not anticipated to have any material implications on the findings of the evidence base.
- **Sub-stations costs**: Primary and distribution substation costs were taken from other reports and inflated to 2023 prices[34]. Our BSP costs however, were taken from our associates and therefore do not reference a report where we have collected this data from.
- **Circuit costs**: The circuit costs calculated in this report have been calculated on a typical basis. This therefore does not give great variation between Urban and Industrial areas due to the same methodology and costs being applied to both. This approach was taken due to a lack of circuit line data that could be applied to each archetype's calculations.

- **Circuit lengths:** As data was not available to gather location specific distribution circuit lengths, urban and industrial archetypes considered the same costs.
- **Archetype's current reinforcement:** Similarly to this study's transmission, the same data was applied in the distribution methodology. Therefore, although the percentage of houses using electric heating is accurate in the council area, the exact percentage may differ for the 5,000 archetypes within the council.
- **Gas Network Extension:** Any costs associated with extensions to the existing gas distribution network, intended to supply all dwellings in the archetypes, are excluded from this calculation. Both LCP Delta and the expert panel believe it is unreasonable to assume any extension to the existing network, given the significant costs involved in providing a relatively small number of homes with a gas network connection, which would ultimately skew costs significantly for archetypes located in rural areas. If these gas network extension costs were included it would increase the gas network reinforcement costs significantly.
- **Iron Mains Risk Reduction Programme (IMRRP) Completion Level**: The level of completion of the IMRRP is a limiting factor. The available information on this programme's progress, including tier 1 pipeline replacement requirements, is only reported at a regional level which depends on how the DNOs split regions. As such the regions have different boundaries to the regions assumed in this study with Scotland assumed to be a single region. Therefore, only a single assumption can be made for all three Scottish archetypes. Other regions, such as London is split into North and South with different DNOs being responsible for each part of London. Additionally, Wales and West Utilities have not reported on the distribution network size and their network split by material type. Therefore, for England (South West) and for Wales an average value is taken using the other archetypes values; however, there is a small range in the level of completion and no deviation from these levels are expected given the length of time this project has been progressed. As a result, no significant impact is expected on total costs for reinforcing gas distribution networks for these archetypes.
- **Road Length Statistics:** There was a lack of detail for some local authorities. As a result, county-level road length was used in two instances, which may not represent a highly accurate value for the archetype due to the consideration of rural, industrial, and urban areas into a single value. This has potential to reduce archetype gas distribution network reinforcement costs largely.
- **Gas Distribution Network Normalisation Factor:** Due to the lack of publicly available data on the distribution network pipeline lengths regionally or at local authority level, a GB-wide normalisation factor was used. This will not fully represent regional variations in the distribution network. There is potential for gas network reinforcement costs for each archetype to be lower or greater. Due to the lack of data, LCP Delta are unable to quantify the materiality of this limitation.
- **Gas Storage:** The assumptions about storage locations are based on the most likely scenarios according to the information available in the data sources and insights from the LCP Delta expert and workshop expert inputs. It is noted there could be numerous potential locations for large-scale storage and the lack of specific location information for localised low-level storage is another limitation. This

information would depend on the uptake level of hydrogen for heating in each archetype region and in Great Britain as a whole. As such a cost per demand has been considered in this study using a theoretical cost based on available literature. This has the potential to increase or decrease storage costs a small amount due to the extent of research conducted in this area.

- **Gas Storage Requirements:** A limitation of the study lies in the consideration for storage requirements and the influence of the line packing ability of the network. Storage requirements are dependent on the level of production. During periods of high production, there may be excess hydrogen that needs to be stored for future use. Conversely, during periods of low production, or more likely where demand is heightened significantly due to a particularly bad winter storm, greater quantities of hydrogen will need to be retrieved from storage to meet demand. The balance between production levels and storage directly impacts the efficiency and cost-effectiveness of the gas transmission network. Furthermore, line packing allows the network to essentially act a large, dispersed storage facility. However, the capacity of the network for line packing is not easily quantifiable as it relies on numerous factors such as pipe pressure, diameter, and the variability and timing of gas demand. The ability to line pack my reduce the storage level required and further work is required to determine this impact. Line packing is not anticipated to have any material impact of the costs in this evidence base.
- **Gas Storage Costs:** These costs will also change depending on the type of storage:
  - Salt caverns – the cheapest type of storage facility.
  - Liquified hydrogen – here there are significant losses in regeneration process, therefore requiring recompression from boil-off losses which increases the CAPEX.
  - Storage as ammonia – here there will be further losses from production/cracking back to ammonia which increases CAPEX.
  - Saline aquifer/depleted gas reservoirs – these facilities are unproven at this stage.
  - Cushion gas CAPEX for some of these storage solutions also depends on the cost of hydrogen which at this current stage is not well-defined due to the early uptake of the technology.
  - There is a small potential for costs to decrease if it is proven alternative storage types are cheaper to operate; however, based on the research this appears unlikely.
- **Average Distance from Production to Storage for Hydrogen:** The lack of information about the distance between hydrogen production facilities and storage locations necessitated the use of an average value. This factor itself is contingent on the split of green and blue hydrogen production. Blue hydrogen is likely to be produced at industrial centres while green hydrogen production can be located near renewable energy generation and therefore has the additional potential of being located offshore, connected to wind turbines. This adds a level of uncertainty and mandated an average value across the archetypes. Further research is needed to determine the split of blue/green hydrogen production and their potential locations

in Great Britain to inform this evidence base and facilitate a regional split in the assumptions. This has limited impact on the costs of gas network reinforcements due to the scale of transmission network costs compared to the distribution network.

- **Gas Pipeline Capacity:** The capacity differences between individual transmission pipelines were not considered due to a lack of information available about each pipeline in the transmission network. This has potential to influences the capacity level required for compressors, expanders, and metering stations, and could potentially affect the accuracy of the CAPEX estimates. The CAPEX assumed comes from a high capacity (assumed to be of infrastructure capable of processing a maximum of 1,513MW) and therefore is at the top of the range of CAPEX values. As a result, there is the potential to reduce costs slightly for transmission network reinforcement.
- **Regional Gas Pipeline Cost Differences:** Differences in regional costs were not considered due to a lack of regionally differentiated cost information in the literature. This limitation could potentially affect the accuracy of the CAPEX estimates for each archetype; however, these differences are not expected to be substantial.
- **Gas Network Decommissioning costs:** These costs are not included in this study scope and therefore further work is required for all scenarios. The level of decommissioning will depend on the level of pipeline retrofitting and the level of electrification. The cost associated with decommissioning in theory could be substantial and therefore this could vastly increase costs for the electrification scenario.
- **The Use of Hydrogen by Sector:** A notable limitation in this study pertains to the estimated use of hydrogen for heating applications. The study considers hypothetical scenarios in the future and therefore there is a level of uncertainty of total hydrogen consumption in GB and in particular what level of consumption there will be by other sectors. Further studies are ongoing as the hydrogen strategy is being more well-defined and the incorporation of these when available will improve on this assumption. This will have little material impact on total gas network reinforcement costs due to the magnitude of costs relative to the distribution network.

4. Results

This section outlines the results. Each of the four scenarios is presented with the results for each of the 12 archetypes. Where appropriate additional detail regarding the electricity and gas networks is also included.

4.1. Results – Archetypes

The table below shows the final description for the 12 archetypes. All archetypes consist of 5,000 dwellings and are consistent for both the electricity and gas networks.

Figure 6: Map showing current dominant heating technology for each regional archetype, hydrogen storage locations and areas with electrical headroom availability.

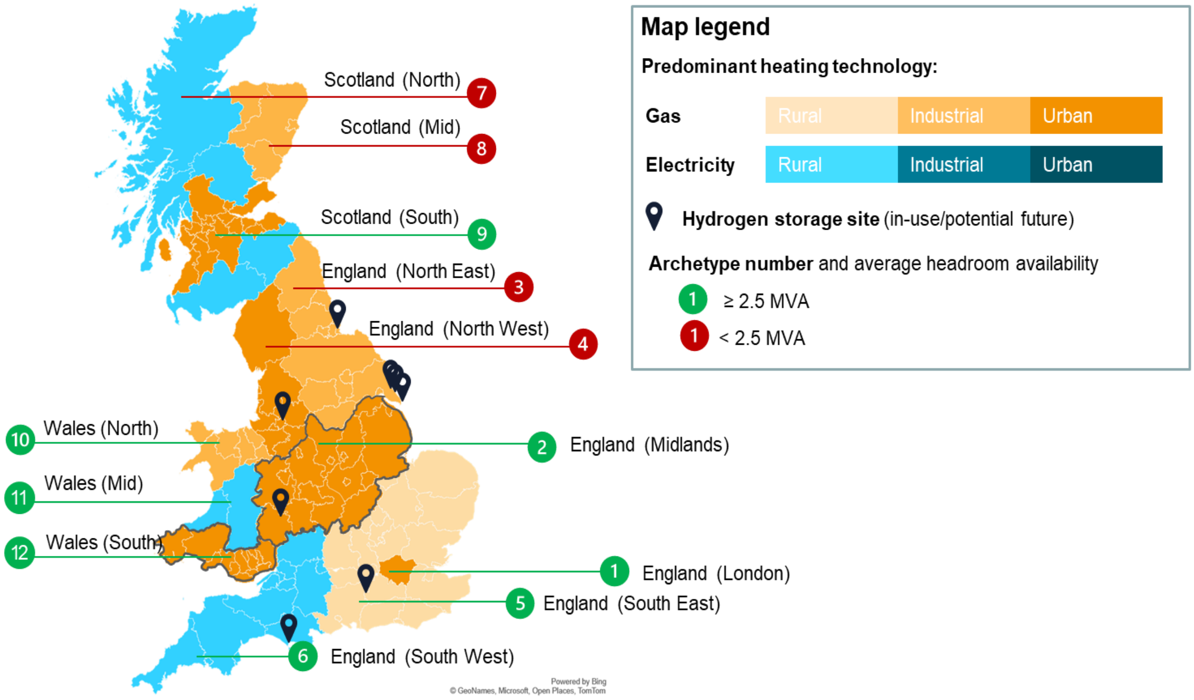


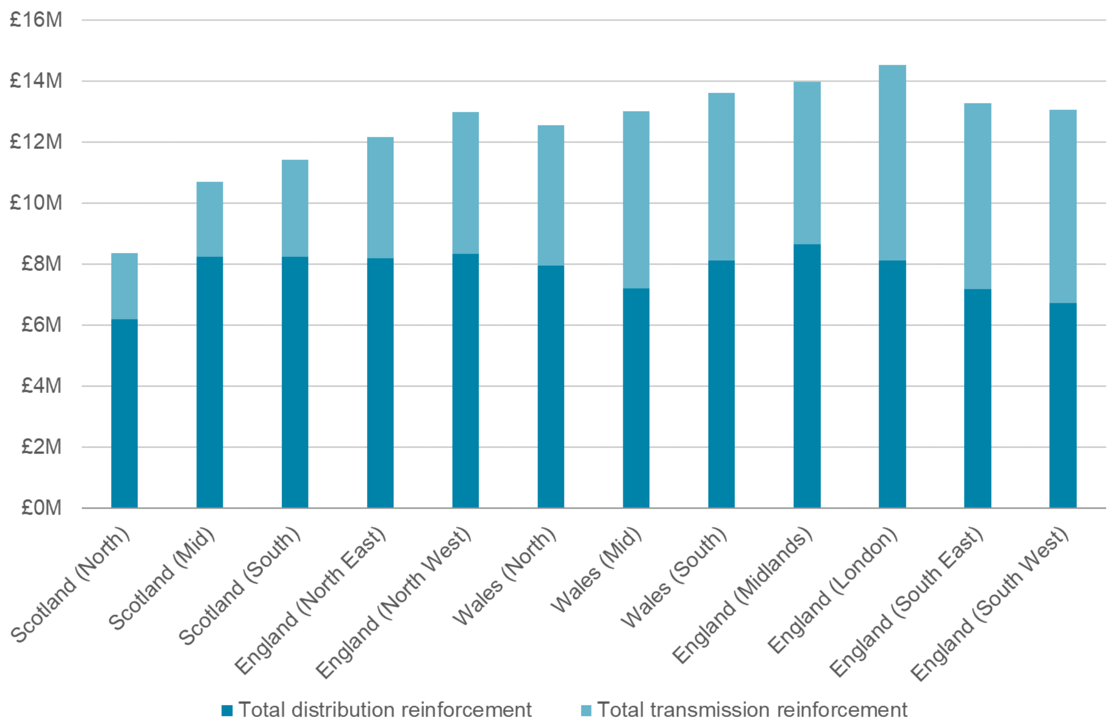
Table 11: Archetypes details.

No	Archetype name	Regional type	Archetype detail
1	Scotland – North	Rural	Rural area with most dwellings (approximately > 60%) off the gas network
2	Scotland – Mid	Industrial	Close to an existing industrial site that will likely be involved in future hydrogen and renewable electricity production
3	Scotland – South	Urban	Urban area within a densely populated Scottish city
4	England – Northeast	Industrial	Residential area nearby to an industrial site
5	England – Northwest	Urban	Sub-urban area close to a city
6	Wales – North	Industrial	Residential area nearby to an industrial site and potentially to future hydrogen and renewable electricity sites
7	Wales – Mid	Rural	Rural area with most dwellings (approximately > 60%) off the gas network
8	Wales – South	Urban	Urban area within a densely populated Welsh city
9	England – Midlands	Urban	Sub-urban area close to a city
10	England – London	Urban	London borough
11	England – Southeast	Rural	Rural area with most dwellings (approximately > 60%) off the gas network
12	England – Southwest	Rural	Rural area with most dwellings (approximately > 60%) off the gas network

4.2. Results – Scenario 1: 100% Electrification of domestic heat

The first scenario only shows costs for the electricity network as it involves 100% of homes using electrified heating. Therefore, there are no costs to upgrade the gas network.

Figure 7: Scenario 1 - 100% electrification of Domestic Heat Costs for Each Archetype



The key points to note from the results are as follows:

- **England (London) has the highest electricity network reinforcement costs**. This archetype's transmission costs were significantly higher than other urban archetype costs; £6.4M compared to the next highest urban cost being £5.5M in Wales South (a 16% difference). England (London) has high costs due to its urban infrastructure needed for future demand (underground cables and 40-kilometre circuit length), it entails high TNUoS tariff costs and has an electrification rate of 10.5% (the number of homes already receiving electricity for their heating supply).
- **Scotland (North) has significantly lower overall costs than all other archetypes**. Both its distribution and transmission costs are the lowest compared to all other archetypes. This is because the archetype requires rural infrastructure (overhead cables and 100-kilometre circuit length), entails low TNUoS tariff costs (to maintain the transmission infrastructure) and has a high current electrification rate of 19%.
- **Urban archetypes have the highest costs associated with electrifying domestic heat**. Although distribution costs were similar to Industrial archetypes, transmission costs were considerably higher in England (London) and Wales (South). This ranges from £3.2 million (in Scotland (South)) to 6.4 million (in England (London) (a 100% difference).
- **Overall costs of electrification are similar across Industrial archetypes.** The overall costs range between £10.7M (Scotland (Mid)) and £12.6M (Wales (North)) (an 18% difference). Transmission costs give the greatest variable and range between £2.5M (Scotland (Mid)) and £4.6M (Wales (North)) (an 84% difference).

- **The rural archetypes England (South East), England (South West) and Wales (Mid) all had similar total costs**. Scotland (North) had the lowest overall cost of £8.4M. This is because Scotland (North) had significantly lower transmission costs of £2.2M (£5.8M in Wales (Mid)) being the next lowest for rural archetypes) because of its low TNUoS tariff costs and high electrification rate compared to the other rural archetypes.
- **Distribution network costs are notably higher than transmission costs in all archetypes.** Overall, each archetype had higher distribution costs than transmission costs. Distribution costs have ranged from £6.2M in Scotland (North) to £8.7M in England (Midlands) (a 40% difference). It is apparent in the results that the rural archetypes have lower costs overall than that of urban and industrial. BSP and 11V cabling are the infrastructure cost variables (please see approach in the methodology), which contribute to Rural and Urban / Industrial archetypes cost differences.
- **Transmission network costs varied significantly from archetype to archetype.** Archetypes in similar locations have similar transmission costs. There is no correlation between archetype categories (Rural, Industrial and Urban). The data taken from TNUoS gave the greatest variation of locational Transmission network costs. This is because the combined Half Hourly Tariff, Non-Half Hourly Demand Tariff and Embedded Export Tariff price combined varies between archetypes. As a result of this, Scottish archetypes have lower transmission costs, whereas archetypes located in the South of England have the highest.

Table 12: Scenario 1 results for each archetype.

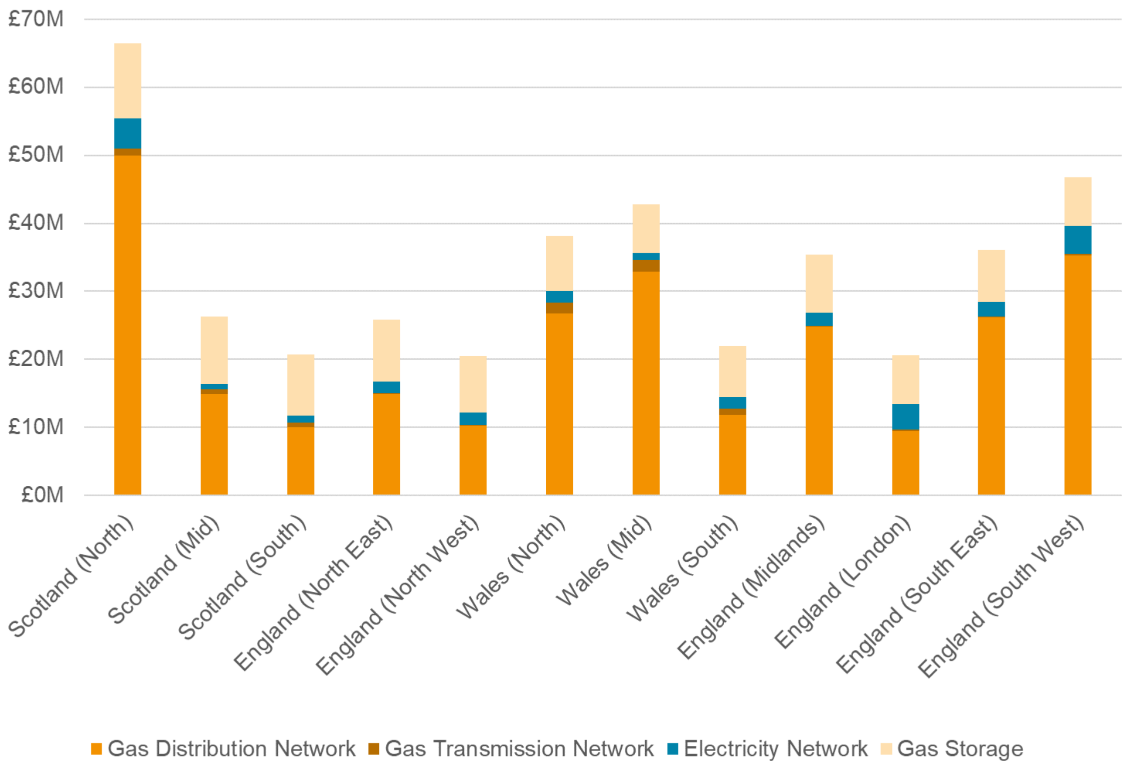
No	Archetype name	Regional type	Distribution costs (£M)	Transmission costs (£M)	Total costs (£M)	Total cost per dwelling (Thousand/£)
1	Scotland - North	Rural	6.2	2.2	8.4	1.7
2	Scotland - Mid	Industrial	8.2	2.5	10.7	2.1
3	Scotland - South	Urban	8.2	3.2	11.4	2.3
4	England – North East	Industrial	8.2	4.0	12.2	2.4
5	England – North West	Urban	8.3	4.7	13.0	2.6
6	Wales - North	Industrial	8.0	4.6	12.6	2.5

7	Wales - Mid	Rural	7.2	5.8	13.0	2.6
8	Wales - South	Urban	8.1	5.5	13.6	2.7
9	England - Midlands	Urban	8.7	5.3	14.0	2.8
10	England - London	Urban	8.1	6.4	14.5	2.9
11	England – South East	Rural	7.2	6.1	13.3	2.7
12	England – South West	Rural	6.7	6.3	13.1	2.6

4.3. Results – Scenario 2: 100% uptake of hydrogen boilers for those already on the gas network

For scenario 2 full adoption of hydrogen, there are two aspects to the calculation: the reinforcement of existing gas networks for those in the archetype currently using gas heating, and an additional requirement for electricity reinforcement for those dwelling that use alternative means of heating to gas. This is required because the scenario assumes that no new gas network is built and those currently not on gas must therefore electrify even in an area that receives hydrogen. This results in a small electrification reinforcement cost in addition to gas networks reinforcements. The results from this added cost are shown below.

Figure 8: Scenario 2 100% gas grid conversion reinforcement costs including gas storage costs and electricity reinforcement costs for each archetype.



When combining electricity network and gas networks **(excluding gas storage CAPEX costs)**, there are several key results as follows. A more detailed explanation follows the key results which outlines the impact of inputs into the calculations.

- **Gas reinforcement costs excluding storage costs form a significant amount of reinforcement costs,** ranging from a minimum of 72% of costs in London, and rising to 97% in Wales (Mid), due to reinforcement costs for gas making up the majority of heating source for each urban archetype, while in more rural areas the cost to reinforce the gas network is generally larger due to the size of the distribution networks.
- **Rural areas tend to have a greater reinforcement cost** when excluding gas storage costs**,** and this is exemplified by the archetype with the highest

total cost being Scotland (North), with a total cost of £55.4M. This is due to a significant cost in gas (£51.0M) network reinforcement with a smaller proportion of electricity (£4.4M) network reinforcement. This is followed by another rural archetype, England (South West) with a total cost of £39.6M. This is attributed to the characteristics of the rural archetypes and Scotland (North) incurs the highest total cost due to the archetype being the most rural which results in a greater gas distribution network size and therefore a greater cost.

- **In terms of the Urban archetypes, the reinforcement costs when excluding gas storage costs are generally lower than other types of archetype** with exception to England (Midlands) which has total reinforcement cost of £26.9M, primarily driven by gas network costs (£25.0M). The primary reason for lower costs in urban areas is the lower size of the gas distribution network.
- **The lowest total reinforcement costs are observed in Scotland (South)** in the Urban area type, totalling £11.7M, followed by England (London) at £13.4M when excluding gas storage costs.
- **England (London) has the lowest total gas network reinforcement costs** when excluding gas storage costs due to the high density of dwellings which therefore results in the lowest distribution network size; however, this is more than offset by Scotland (South) having a smaller requirement for electricity network reinforcement due to a high level of dwellings using gas heating in the archetype compared to England (London).
- **Among the Industrial archetypes, Wales (North) has the highest total cost (£30.0M) almost doubling Scotland (Mid), the lowest (£16.4M) cost** when excluding gas storage costs**.** This archetype generally has costs in between the urban and rural archetypes with characteristics closer to that of the urban archetypes (i.e., dwelling density and high gas heating use).
- **In terms of electricity reinforcement costs only, the archetype with the highest total cost is Scotland (North)** when excluding gas storage costs in the rural archetype, with a cost of £4.35M, followed closely by England (South West), another rural archetype with a cost of £4.08M; however, the results indicate that electricity reinforcement costs can vary significantly between different areas and archetypes, with no clear correlation between archetype and cost.
- **Gas network transmission reinforcement costs are between 5-86 times higher when storage costs are included,** leading to an increase in total costs and costs per dwelling using gas heating in all areas. This is explained by the high level of CAPEX required for hydrogen storage, and the distance to a storage facility from the archetype.
- **Gas network transmission costs a small compared to gas distribution network reinforcement costs,** forming between 0.3% and 6.9% of gas network reinforcement costs when storage is excluded. This is a result of the relatively small network size of the transmission network when compared to the distribution network, in addition to the transmission network

costs being spread over a greater number of dwellings and other end uses of hydrogen such as industry and power generation.

Table 13: Scenario 2 100% gas grid conversion reinforcement costs excluding storage costs for each archetype.

No	Archetype	Regional type	Gas Distribution Network Reinforcement Costs (£M)	Gas Transmission Network Reinforcement Costs (£M)	Electricity Network Reinforcement Costs (£M)	Total Costs (£M)
1	**Scotland - North**	Rural	49.9	1.1	4.4	55.4
2	**Scotland - Mid**	Industrial	14.9	0.8	0.7	16.4
3	**Scotland - South**	Urban	10.1	0.7	1.0	11.7
4	**England - Northeast**	Industrial	14.9	0.1	1.7	16.7
5	**England - Northwest**	Urban	10.3	0.1	1.7	12.2
6	**Wales - North**	Industrial	26.7	1.6	1.7	30.0
7	**Wales - Mid**	Rural	32.9	1.7	1.0	35.6
8	**Wales - South**	Urban	11.9	0.9	1.8	14.5
9	**England - Midlands**	Urban	24.8	0.1	1.9	26.9
10	**England - London**	Urban	9.5	0.2	3.7	13.4
11	**England - Southeast**	Rural	26.2	0.1	2.2	28.5
12	**England - Southwest**	Rural	35.3	0.3	4.1	39.6

4.3.1.Gas Networks - Distribution Reinforcement Costs

Distribution network reinforcement costs are much larger than the transmission network reinforcement costs (up to 4.7 times the cost of the transmission network reinforcement costs even when storage costs are considered). The primary reason for this is due to the relative network sizes in GB. The transmission network comprises of approximately 7,630 km, whereas the distribution network is approximately 280,000 km.[35] Additionally, the study assumes a significant proportion of the transmission network will be retrofitted which aligns with expectations from those working in the industry due to the lower cost impact from using existing infrastructure, reducing the impact to the end consumer from undue costs. This offsets the impact of the greater cost of new build, larger pipelines in the transmission network compared to new distribution network pipelines. Furthermore, it should be noted the transmission reinforcement costs are adjusted to consider the supply to the whole archetype region, rather than just the local authority in the case of distribution costs which results in smaller costs for the archetype.

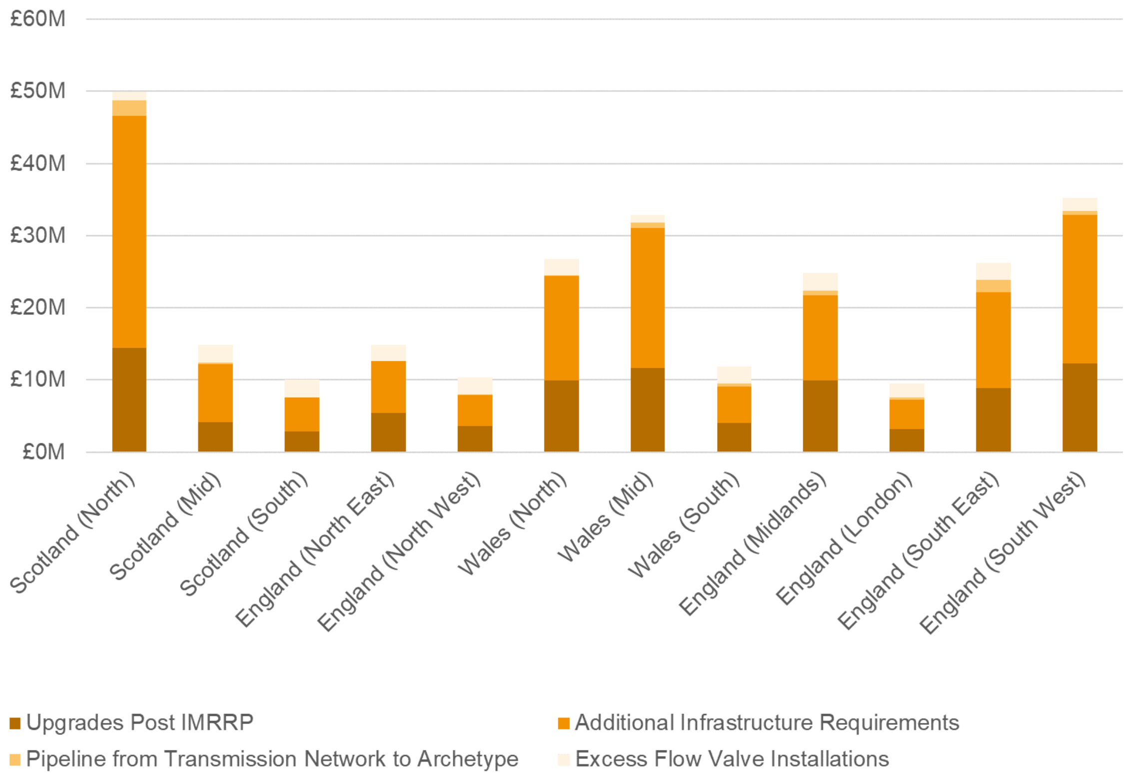
Table 14: Split of Scenario 2 reinforcement costs by cost type and cost per dwelling for each archetype.

No	Archetype	Regional Type	Total Gas Distribution Network Reinforcement Costs (£M)	Total Gas Transmission Network Reinforcement Costs (£M)	Total Gas Storage Costs (£M)	Total Gas Costs (£M) [value includes storage costs]	Cost per Dwelling Using Gas Heating (Thousand £/dwelling using gas heating) [value includes storage costs]
1	**Scotland - North**	Rural	49.9	1.1	11.0	51.0 [62.1]	26.5 [32.2]
2	**Scotland - Mid**	Industrial	14.9	0.8	9.9	15.7 [25.5]	3.7 [6.0]
3	**Scotland - South**	Urban	10.1	0.7	9.0	10.7 [19.8]	2.6 [4.8]
4	**England - Northeast**	Industrial	14.9	0.1	9.1	15.1 [24.2]	3.9 [6.2]
5	**England - Northwest**	Urban	10.3	0.1	8.3	10.4 [18.8]	2.6 [4.7]
6	**Wales - North**	Industrial	26.7	1.6	8.1	28.3 [36.4]	7.5 [9.6]
7	**Wales - Mid**	Rural	32.9	1.7	7.2	34.6 [41.8]	18.9 [22.8]
8	**Wales - South**	Urban	11.9	0.9	7.5	12.7 [20.3]	3.3 [5.2]
9	**England - Midlands**	Urban	24.8	0.1	8.5	25.0 [33.5]	6.0 [8.1]
10	**England - London**	Urban	9.5	0.2	7.2	9.7 [16.9]	2.9 [5.1]
11	**England - Southeast**	Rural	24.3	0.1	7.6	26.3 [33.8]	6.7 [8.6]
12	**England - Southwest**	Rural	32.6	0.3	7.1	35.6 [42.7]	11.7 [14.1]

The additional works required to the distribution network post IMRRP completion and the additional infrastructure to facilitate the switching from gas to 100% hydrogen are both dependent on the total distribution network size. This has the greatest influence on the distribution networks costs, and it is primarily determined by the road length within the archetype. The total road length in the archetype depends highly on the level of urbanisation and density of dwellings of the archetypes, with archetypes with high levels of urbanisation and larger dwelling density in general showing the smallest road length and therefore total distribution network size. This is highlighted by England (North West) and London having the lowest road length within the archetype, at 28.53 km and 31.79 km respectively. Meanwhile, Scotland (North) and Wales (Mid), the most rural areas in the study have the largest archetype road network length at 329.59 km and 208.96 km respectively. Industrial archetypes, such as England (North East) tend to be more urbanised and therefore the road network length is more closely correlated to urban archetypes, resulting in gas distribution network reinforcement costs which fall between the urban and rural archetypes but far closer to the urban archetype reinforcement costs.

One exception to this trend is England (Midlands) which is considered an urban archetype. Here, the total road length within the archetype is 75.56km, more than double that of the London archetype, more akin to the rural area in England (South East). This larger road length directly translates into a greater distribution pipeline length associated with the archetype. As noted in the methodology limitations section, the road length data is not reported on a local authority level for some counties and therefore this lower granularity will increase the road length of the archetype by including more rural locations. Therefore, in reality, gas distribution costs for the England (Midlands) archetype are anticipated to be lower than the results presented here.

Figure 9: Scenario 2 distribution reinforcement costs for each archetype



The distribution network reinforcement costs associated with the distribution network pipeline that connects the existing transmission network to the archetype are small compared to other costs, accounting for up to 4.4% of total distribution costs. The absolute costs range from £0 - £2.2M and the costs attributed to urban and industrial areas remain small compared to rural locations. The primary reason for this is the current location of the existing transmission network, which passes close to many urban and industrial centres. Therefore, the distance between the transmission network and archetypes is small compared to some rural archetypes. Additionally, the pipeline is assumed to be able to provide hydrogen to the whole local authority and therefore the cost is normalised by the number of dwellings in the local authority. For more rural local authorities there are fewer dwellings compared to urbanised areas and therefore costs are split to a lesser extent. When combined this results in lower costs for industrial and urban archetypes.

For England (North East) there is zero cost associated with the transmission network to the distribution pipeline. This is due to the archetype, being located nearby a designated storage facility with an existing transmission pipeline running through the archetype. Therefore, no additional pipeline length needs to be considered beyond the existing archetype distribution network.

The Excess Flow Valve (EFV) installation costs for each archetype vary from between £1.1M to £2.5M between the archetypes. EFV installations will be installed where the service pipe (i.e., the pipe that deliver gas to each individual property and meter from the distribution network) connects to the grid and therefore the cost range for this aspect is governed by the proportion of dwellings that use gas heating. A greater number of dwellings using gas heating results in a larger cost for EFV installations. The Scotland (Mid) archetype has the largest proportion of dwellings using gas heating of any archetype at 85% of dwellings which results in the largest cost, whereas Wales (Mid) has the lowest value at 37%.

Generally, there is little difference in the proportion of dwellings using gas heating between urban and industrial areas and in some more urbanised rural areas such as England (Midlands) which is close to the transmission network. This is generally for the following reasons: both industrial and urban areas are typically well-connected to the main gas distribution network, both areas have substantial energy needs which has justified the development of infrastructure to both industrial and urban areas.

When the archetype becomes highly rural, there are fewer dwellings using gas heating. Due to the costs associated with other aspects, EFV installation costs, while not ranging significantly, contribute to between 2-24% of total distribution network reinforcement costs for the archetypes. The proportional contribution is greater in urban and industrial archetypes where there is a smaller network size for the archetype.

In summary, the level of urbanisation has the greatest influence on the distribution costs due to the increased density of dwellings and therefore lower road network length within the archetype. Industrial archetypes are generally relatively urbanised areas and therefore the distribution costs are much closer to urban locations compared to rural locations, which generally have the highest cost level. Archetype distance from the transmission network is a secondary influence and it is also influenced by urbanisation level because of the transmission network already passing close to large population centres. Industrial areas also have a small archetype distance from the transmission network due to the need of large gas quantities for industrial purposes and therefore are co-located to transmission network pipelines. Lastly, EFV installation costs depend on the proportion of dwellings using the gas grid which is also correlated to the level of urbanisation. When combined, urban archetypes tend to have the lowest reinforcement costs, closely followed by industrial areas, while rural areas appear to have the largest costs, with highly rural areas showing by far the largest costs.

4.3.2.Gas Networks - Transmission Reinforcement Costs

Storage costs make up more than 80% of all transmission network reinforcement costs when included, while in some archetypes it makes up almost all network reinforcement costs such as England (Midlands) and England (North East). These costs, when considered, are determined by the level of hydrogen heating demand of each archetype, which is discussed in greater depth in Section 1.7. As a result of the defined variables, location has a large impact on heating demand and therefore storage costs. Archetypes that are located further north show a greater heating demand and cost, exemplified by the Scottish archetypes and the North East of England having the four greatest storage costs of all archetypes.

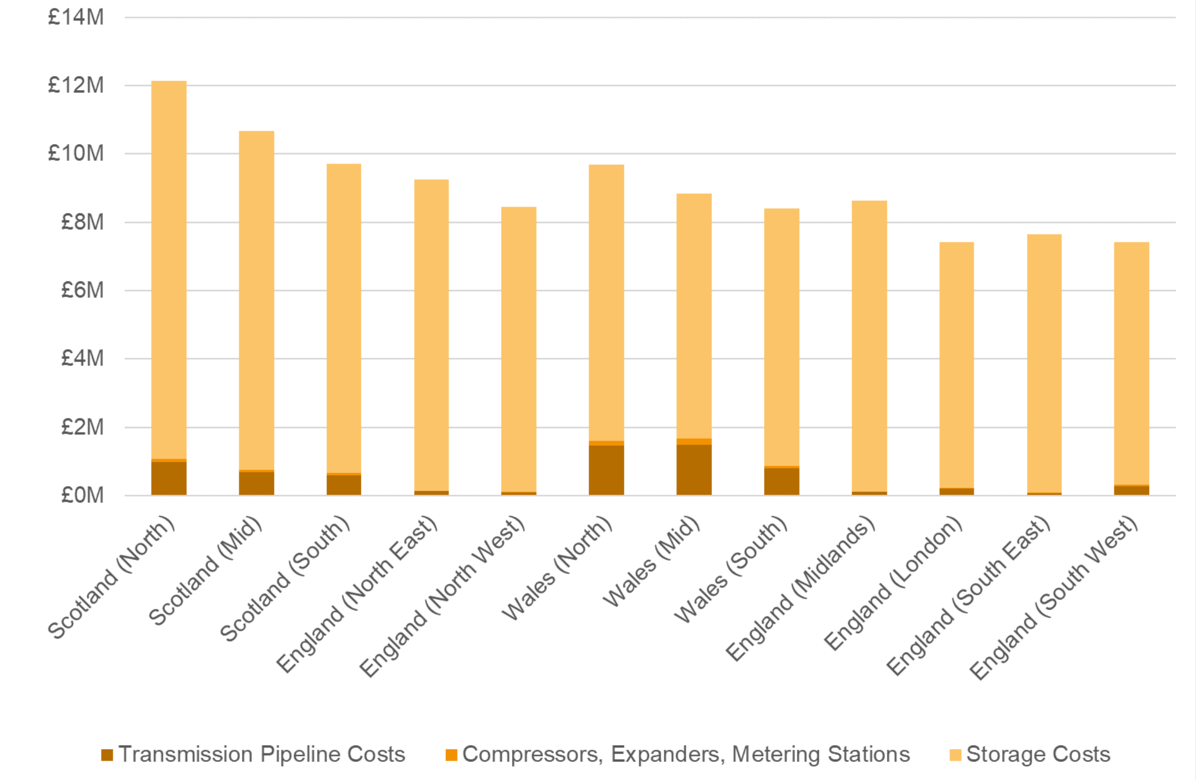
Transmission pipeline costs are the next most influential consideration for transmission network reinforcement costs, accounting for £0.1M - £1.5M of reinforcement costs per archetype. This accounts for between 1% (England (North West), England (Midlands) and England (South East)) to 17% of total archetype transmission costs in the most rural areas of Wales (Wales (Mid)). There are several reasons for these variations:

- **The distance from the closest storage facility:** This distance is the largest contributor to the transmission pipeline costs and it is itself dependent on the inter-seasonal storage locations even when excluding storage costs. Archetypes with storage facilities located within their region (i.e., England (North East), England (North West), England (South East), and England (South West)) have a short transmission pipeline distance from the storage location to the archetype, whereas other archetypes locations have an increased distance from storage. Overall, this means archetypes further away from storage requires the hydrogen to pass through a greater distance of the transmission network which results in larger costs. Due to hydrogen being supplied from other regions to Scotland (Mid), Scotland (South), Wales (Mid), Wales (South), and London, there is a greater distance to travel to reach the archetypes.
- **Distance between the storage and transmission network:** This only applies to archetypes located in the same region as inter-seasonal storage facilities and with the exception of England (South West) does not contribute substantially to the pipeline costs. This is due to the close location to the transmission network and/or the storage facility which is expected to be repurposed for hydrogen and is therefore already connected to the transmission grid.
- **The average distance from production to storage:** This also attributes some additional cost considerations; however, this distance is an average for all archetypes (108km, as outlined in Section 1.12) and remains constant for each archetype. Therefore, this value does not influence the costs.
- **The proportion of dwellings considered in the archetype region:** The total costs for the transmission pipeline length required are assumed to be able to provide hydrogen to the whole region the archetype is in due to the sectorisation of GB in regions in the study. Therefore, the costs are normalised by proportion of dwellings considered in relation to the total number of dwellings in the region (i.e., Archetype dwellings [5000] / Total

dwellings in the archetype region). This results in an inversely proportional relationship where a greater number of total dwellings considered results in a lower normalisation factor. Some regions such as those located in Scotland and Wales consider a lower number of total regional dwellings which leads to a greater proportion of dwellings considered in the archetype and therefore a higher overall cost when compared to those located in England.

These factors when combined result in the English archetypes typically showing lower costs associated with the transmission pipelines themselves, which can be attributed to a larger number of total dwellings in the archetype region which ultimately sees costs split more. Archetypes in Scotland are the next largest group, whereas those in Wales have a larger cost because they consider the greatest proportion of regional dwellings. There is no apparent correlation between urbanisation and cost level when looking at each country split by archetype category.

Figure 10: Scenario 2 transmission reinforcement costs including storage costs for each archetype



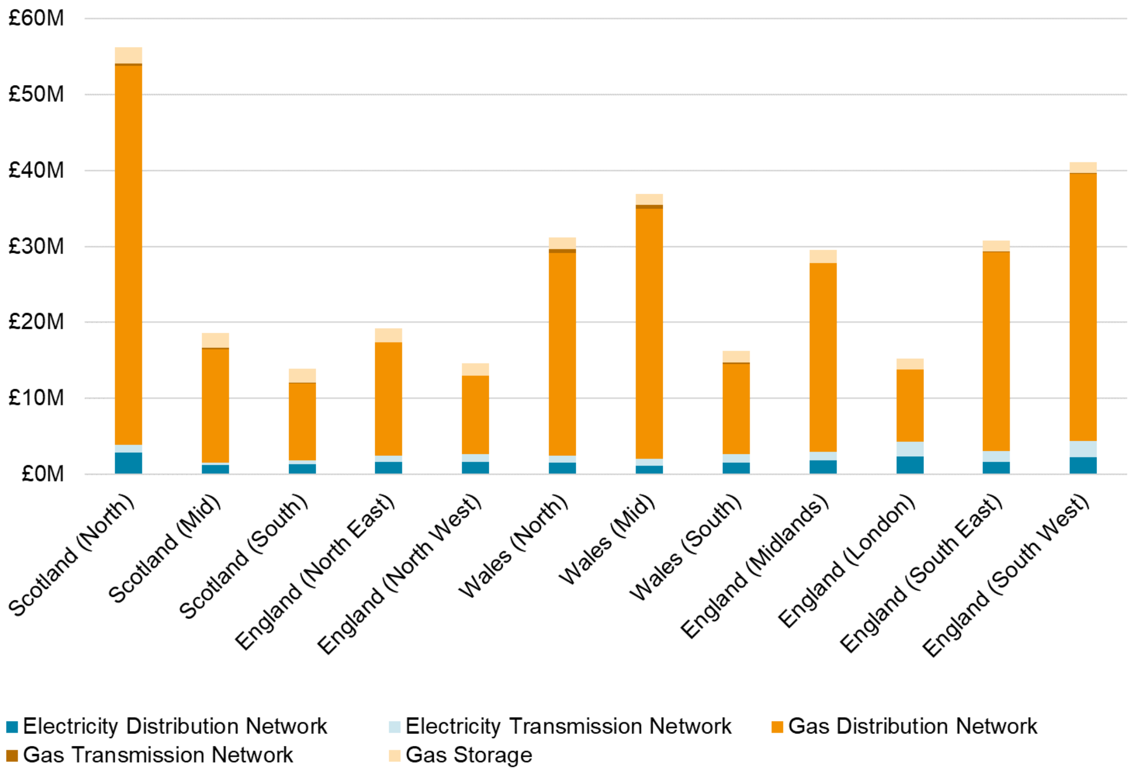
The transmission pipeline costs and the costs for compressors, expanders, and metering stations are inherently proportional to each other. This is due to the compressor, expander, and metering station requirements being determined by a frequency per distance. Therefore, results for this aspect follow those detailed above.

4.4. Results – Scenario 3: 100% uptake of hybrid heat pumps which use both electricity and hydrogen as fuel

In scenario 3, the primary fuel is electricity, but some hydrogen is used to heat homes during peak times, when the outside temperature is low and there is less renewable energy generation than usual. Our assumption is that hybrid heat pumps will run on electricity 80% of the time and hydrogen 20% of the time. This means that the electrification reinforcement cost for the network would be lower compared to scenario 1, as the peak demand would be met by hydrogen instead. Therefore, a 10% reinforcement cost was calculated for electrification under this scenario.

As a result, scenario 3 considers both the reinforcement of existing gas networks for those in the archetype currently using gas heating, and an additional requirement for electricity reinforcements. The results from this addition are shown below.

Figure 11: Scenario 3 Total Costs for each archetype



The key results to Scenario 3 **excluding gas storage costs** unless specified are identified below:

- **Scotland (North) has the highest costs associated with hybrid heating (£54.1M).** England (South West) has the second highest costs (£39.7M), with Wales (Mid) third (£35.5M). The gas distribution costs are high in these archetypes because the archetypes are sparsely populated. This means a larger distribution grid is required to supply the archetypes.
- **Scotland (South) has the lowest costs associated with hybrid heating (£12.1M).** England (London) has the second lowest costs associated (£13.8M) and England (North West) have the third lowest costs (£14.2M).

The gas distribution costs are lower in these archetypes because the areas are densely populated. This means a smaller distribution network is required to supply the archetypes.

- **Urban archetypes generally have the lowest costs of all archetypes.** All three of the archetypes with the lowest costs are urban (mentioned above). England (Midlands) does show variation however as its costs are substantially more (£27.8M) (a 130% difference). This is because the gas distribution costs are generally lower, because the archetypes are densely populated. England (Midlands) costs are higher however, because it is more sparsely populated.
- **Industrial archetypes demonstrate a high range of overall costs.** The archetypes cost ranges from £16.6M (in Scotland (Mid)) to £29.6M (in Wales (North)) (a 78% difference). The industrial archetypes costs vary because of alterations in its population sparsity. Scotland (Mid) for example, is more densely populated than Wales (North).
- **Rural archetypes have the highest associated costs.** All three archetypes with the highest cost are rural archetypes (mentioned above). The overall costs range from £29.3M (in England (South East)) and £54.1M (in Scotland (North)) (an 85% difference). The gas distribution costs are higher in rural archetypes because the area is sparsely populated. A larger distribution network is therefore required to supply the archetypes.
- **Gas network reinforcement costs are significantly greater than electricity network reinforcement costs.** Gas network reinforcement is considerably more costly in each archetype. This ranges between 70%(in Scotland (North)) to 94% (in Wales (Mid)). This is due to the high costs associated of heating a sparsely populated area.
- **Gas transmission costs are less costly than its distribution costs.** Although gas distribution costs are high, the highest cost of transmission upgrades is £400,000 (within Wales (North) and Wales (Mid)). This however is only 1.5% of the overall Gas network cost (with Distribution accounting for 98.5% of the cost). This is because the transmission network will need upgrading, however at a lesser cost than upgrading larger distribution networks.
- **Gas storage costs are not substantial when reinforcing the gas network.** These costs range between £1.4 million in Wales (Mid) (accounting for 4% of total costs) to £2.2 million in Scotland (North) (also 4% of the archetype's overall costs). However, these costs are significantly lesser than the cost of upgrading the gas distribution network.
- **Electricity reinforcement costs are only higher in urban areas.** Electrification contributes most in urban archetype costings (31% of the cost in England (London)). This decreases to as low as 7% of the overall cost in the rural archetype Scotland (North). This is because electricity reinforcement costs are high in urban and southern archetypes (when comparing electricity results (Scenario 1)), however the archetypes entail low gas network distribution costs (when comparing gas results (Scenario

2), because it is densely populated (and requiring a smaller distribution network).

Table 15: Scenario 3 Hybrid heating total network reinforcement costs excluding gas storage costs for each archetype.

No	Archetype	Regional type	Gas Network Reinforcement Costs (£M)	Electricity Network Reinforcement Costs (£M)	Total Costs (£M) (rounded)
1	**Scotland - North**	Rural	50.2	3.8	54.1
2	**Scotland - Mid**	Industrial	15.1	1.6	16.6
3	**Scotland - South**	Urban	10.2	1.9	12.1
4	**England - Northeast**	Industrial	15.0	2.5	17.4
5	**England - Northwest**	Urban	10.4	2.6	14.2
6	**Wales - North**	Industrial	27.2	2.5	29.6
7	**Wales - Mid**	Rural	33.4	2.1	35.5
8	**Wales - South**	Urban	12.1	2.6	14.7
9	**England - Midlands**	Urban	24.9	3.0	27.8
10	**England - London**	Urban	9.6	4.3	13.8
11	**England - Southeast**	Rural	26.2	3.1	29.3
12	**England - Southwest**	Rural	35.3	4.4	39.7

4.4.1.Electricity results

The electricity costs for Scenario 3 are outlined below.

- **England (South West) and England (London) have the highest electricity network reinforcement costs.** Both archetypes had high costs associated (£4.4M and £4.3M) respectively. Both entail high electrification inputs under Scenario 2 (22.9% in England (London) and 15.5% in England (South East)). The electricity costs also show no correlation between archetype areas (e.g. the two highest cost archetypes are Urban and Rural). Interestingly, transmission and distribution costs, are split fairly evenly when assessing the overall cost.
- **Scotland (Mid) has the lowest electricity network reinforcement costs.** Scotland (Mid) transmission costs were significantly reduced (under scenario 3's electrification input (10%)), contributing to its low overall cost. Scotland (South) also had low reinforcement costs. When comparing both, each have low Scenario 2 electrification inputs (6% for Scotland (Mid) and 8% for Scotland (South)).
- **Urban archetypes demonstrate variation in reinforcement costs.** As mentioned, England (London) has the second highest reinforcement costs (£4.3), but also the second lowest cost with its archetype Scotland (South)

(£1.9M) (a 126% difference). This shows little correlation in the urban archetype's costs.

- **Industrial archetypes demonstrate low reinforcement costs.** Scotland (Mid), an industrial archetype has the lowest reinforcement costs, but Wales (North) and England (Northeast) both have costs under £3M. Each archetype is generally on the lower cost scale when comparing each to Urban and rural archetypes.
- **Similarly to urban archetypes, rural archetypes show great variation in reinforcement costs.** As mentioned, England (South West) has the highest reinforcement costs (£4.4M), however Wales (Mid) has the third lowest reinforcement costs (£2.1M) (a 110% difference). Scotland (North) also has high reinforcement costs (£3.8M) due to its high electrification increase percentage in scenario 2 (42%). Therefore, the rural archetype's costs are location specific and not necessarily higher because it is rural.
- **Distribution costs are generally the most expensive to reinforce.** These costs are highest in Scotland (North) (£2.8M) because of its high electrification increase percentage in scenario 2 (42%). On the other hand, Wales (Mid) has the lowest distribution costs (£1.2M) due to its low electrification percentage in scenario 2 (7.4%).
- **Transmission costs range significantly between archetypes.** Scotland (South) entails the lowest transmission reinforcement costs (£0.5M). England (North West) and England (South West) have the highest costs, valuing £2.1M (a 320% difference). This is because of the lower TNUoS values in Scotland, when comparing to England's archetypes.

4.4.2.Gas Networks

The key results for the gas network reinforcement costs for scenario 3 are as follows:

- **In comparison to scenario 2, scenario 3 sees lower gas transmission reinforcement costs when gas storage costs are excluded.** This is due to the lower proportion of costs attributed to heating applications, because of lower hydrogen heating demand. In this case other applications of hydrogen, namely industry and power generation make up a greater proportion of total demand.
- **Similarly, there is a significant reduction in storage costs in scenario 3, resulting in decreased total costs for all archetypes (and per dwelling).** This is linked directly to the lower heating demand of hydrogen in the scenario compared to scenario 2.
- **Distribution costs remain the same when compared to scenario 2.** This is because delivering hydrogen to hybrid heating appliances requires the same amount of distribution network as serving appliances that uses 100% hydrogen**.**
- **For scenario 3, the general trends for gas network costs observed in scenario 2 remain the same.**
- **The highest total cost still lies with Scotland (North)** (£50.2M without storage costs, £52.4M with storage costs), over 5 times greater than the

lowest cost archetype, England (London). It also has the highest cost per dwelling using gas heating (£26.1k without storage costs, £27.2k with storage costs). The difference in total costs between Scotland (North) and other archetypes in terms of total costs is smaller in scenario 3 compared to scenario 2.

- **England (London) has the lowest total costs (£9.6M without storage costs, £11.0M with storage costs).** However, it does not represent the urban archetype with the lowest cost per dwelling using gas heating, which is attributed to Scotland (South) (£2.5k without storage costs, £2.9k with storage costs).
- **Urban archetypes have lower costs per dwelling using gas heating compared to rural and industrial areas,** with costs ranging between £2.5k-£6.0k without storage costs, and £3.0k-£6.4k with storage costs.
- **Wales (North) has a total cost that is 70% – 80% greater than other industrial archetypes** (£27.2M without storage costs, increasing by 6% to £28.8M with storage costs) and cost per dwelling (£7.2k without storage costs, £7.6k with storage costs). Storage costs therefore
- **Rural archetypes have the highest costs per dwelling using gas heating**, particularly in Scotland (North) (£26.1k without storage costs, £27.2k with storage costs) and Wales (Mid) (£18.2k without storage costs, £19.0k with storage costs).
- **The inclusion of storage costs in transmission reinforcement costs results in a modest increase in total costs** and costs per dwelling using gas heating in all areas.

Table 16: Scenario 3 Hybrid heating gas network reinforcement costs for each archetype.

No	Archetype	Regional type	Total Distribution Reinforcement Costs (£M)	Total Transmission Reinforcement Costs (£M)	Total Storage Costs (£M)	Total Costs (£M) [Value includes storage costs]	Cost per Dwelling Using Gas Heating (Thousand £/dwelling using gas heating) [Value includes storage costs]
1	**Scotland - North**	Rural	49.9	0.29	2.2	50.2 [52.4]	26.1 [27.2]
2	**Scotland - Mid**	Industrial	14.9	0.21	2.0	15.1 [17.1]	3.6 [4.0]
3	**Scotland - South**	Urban	10.1	0.18	1.8	10.2 [12.0]	2.5 [2.9]
4	**England - Northeast**	Industrial	14.9	0.04	1.8	15.0 [16.8]	3.8 [4.3]
5	**England - Northwest**	Urban	10.3	0.03	1.7	10.4 [14.0]	2.6 [3.0]
6	**Wales - North**	Industrial	26.7	0.43	1.6	27.2 [28.8]	7.2 [7.6]
7	**Wales - Mid**	Rural	32.9	0.45	1.4	33.4 [34.8]	18.2 [19.0]
8	**Wales - South**	Urban	11.9	0.24	1.5	12.1 [13.6]	3.1 [3.5]
9	**England - Midlands**	Urban	24.8	0.03	1.7	24.9 [26.6]	6.0 [6.4]
10	**England - London**	Urban	9.5	0.06	1.4	9.6 [9.8]	2.9 [3.3]
11	**England - Southeast**	Rural	26.2	0.02	1.5	26.2 [27.7]	6.7 [7.1]
12	**England - Southwest**	Rural	35.4	0.08	1.4	35.3 [36.8]	11.7 [12.1]

4.5. Results: Scenario 4 – Undefined low-carbon heating technology

Scenario 4 represents an undefined low-carbon heating scenario which considers the choice of the technologies in this study: ASHPs, hydrogen boilers, and hybrid heating systems. Therefore, the uptake of the different heating technologies is uncertain, and reinforcement/upgrade of both electricity and gas networks is required.

Three cases are presented that consider different proportions of reinforcement requirements for both the gas and electricity networks. The three cases are:

- **Base Case:** 50% of the gas transmission network relative to Scenario 2 is attributed to domestic heating demand, and 50% electricity network reinforcement relative to Scenario 1 is required under this scenario;
- **Sensitivity 1:** 75% of the gas transmission network relative to Scenario 2 is attributed to domestic heating demand, and 25% electricity network reinforcement relative to Scenario 1 is required under this scenario;
- **Sensitivity 2:** 25% of the gas transmission network relative to Scenario 2 is attributed to domestic heating demand, and 75% electricity network reinforcement relative to Scenario 1 is required under this scenario.

In these sensitivities other end use demand for gas (i.e., industry, power generation, etc.) are fixed. This impacts the gas transmission network costs only as domestic heat will require the use of the gas distribution network and therefore all the costs for that network still need to be included. The other end use demand for electricity (I.e., industry, power generation, etc.) are not included in this calculation as it has already been disaggregated through our methodology.

Figure 12: Scenario 4 Total Costs including gas storage costs for each archetype

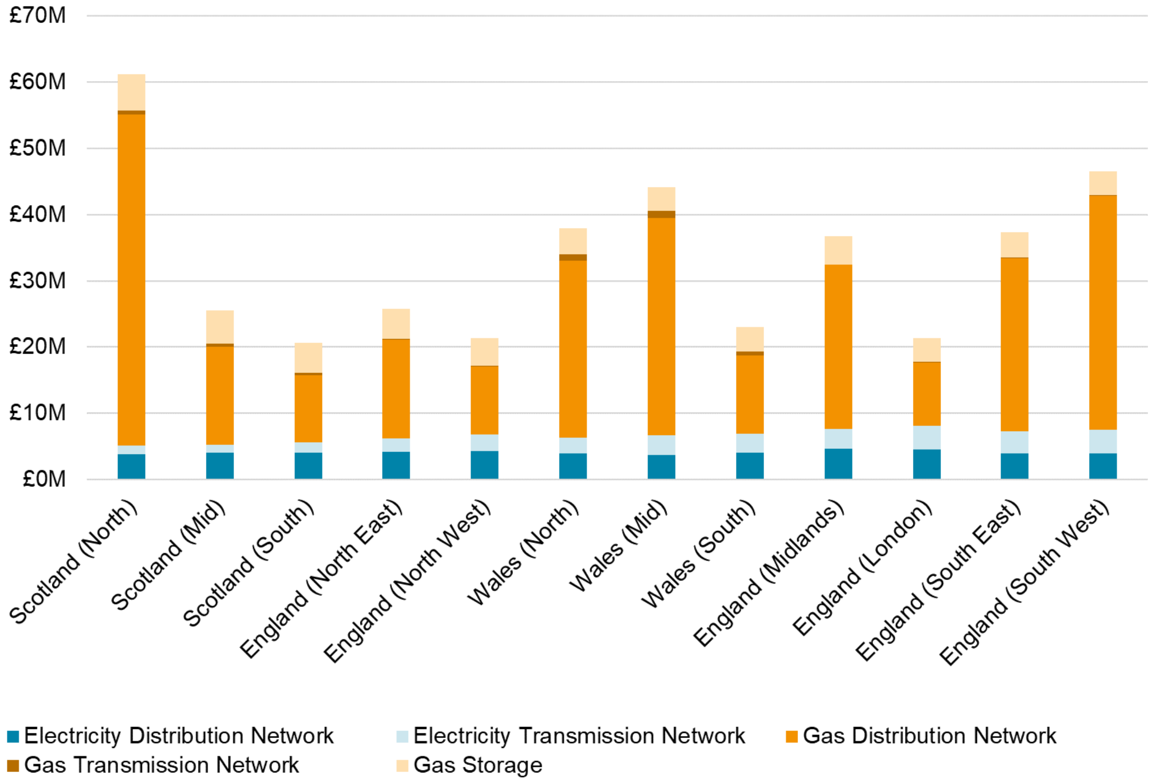
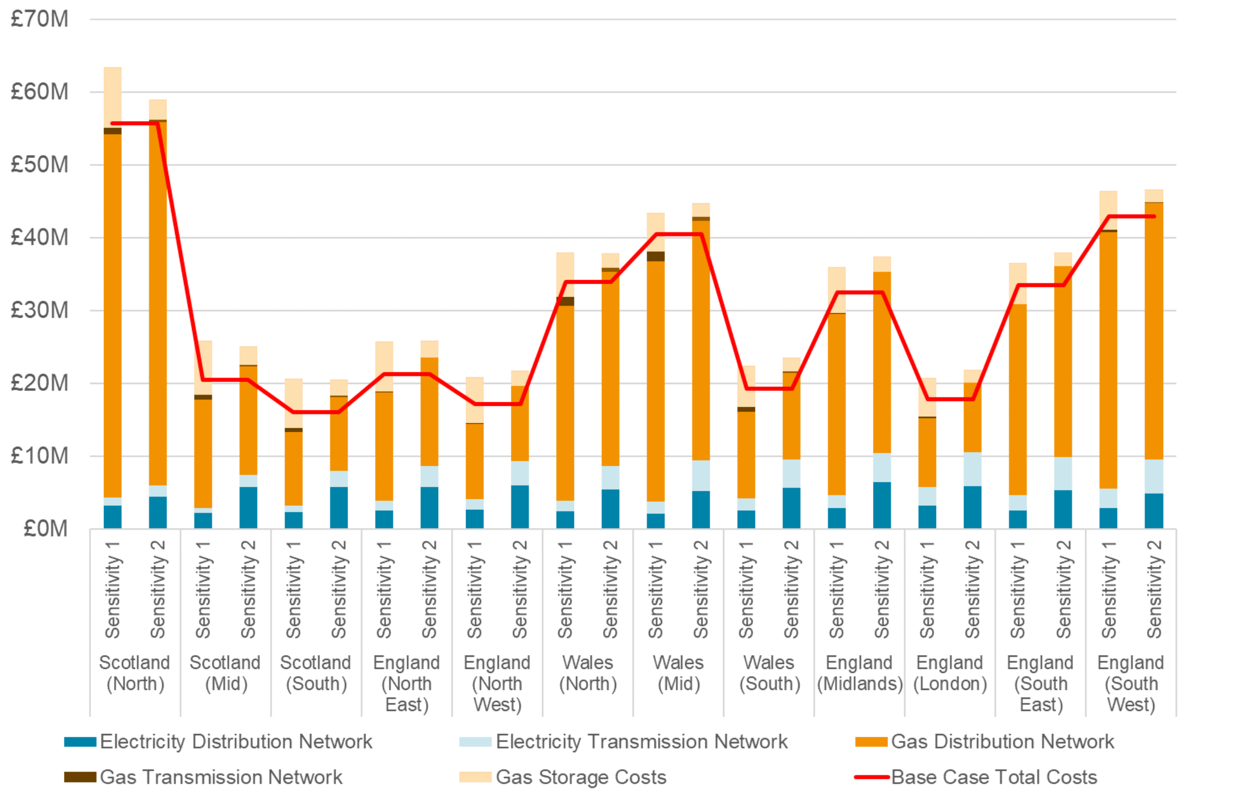


Figure 13: Scenario 4 Sensitivities including gas storage costs for each archetype



The key results for the total reinforcement costs for scenario 4 are summarised below for the base case and each of the sensitivities. The individual contributions from the gas and electricity network reinforcement costs are discussed in Section 1.18.1 and Section 1.18.2. The key results are as follows for the base case and **exclude** gas storage costs for comparison purposes:

- **The reinforcement costs for scenario 4 are consistently greater than any other scenario** due to a greater requirement of electricity reinforcement compared to scenario 3. Cost increases compared to scenario 3 range from 3% for Scotland (North) to 33% for Scotland (South), with differences in electricity reinforcement accounting for the vast majority of the increase.
- **Scotland (South) has the lowest reinforcement cost for scenario 4** at £16.1M, closely followed by England (North West) and England (London) at £17.2M and £17.8M, respectively. Each of these archetypes have low gas network reinforcement costs, which is offset somewhat by higher electricity network reinforcement costs relative to other archetypes.
- **Scotland (North) has the highest reinforcement costs** at £55.7M or 3.5 times the cost of the lowest cost archetype Scotland (South). This occurs due to a high cost associated with the gas network which is only marginally offset by the archetype having the lowest electricity network reinforcement costs of any archetype alongside Scotland (Mid). Gas network reinforcement costs account for 90% of total costs for the archetype.

- **Urban archetypes are generally the lowest cost to reinforce**, ranging from £16.1M to £19.3M when excluding England (Midlands) archetype. In these cases, the electricity network reinforcement costs contribute to more than 35% of total reinforcement costs.
- **Rural archetypes are generally the highest cost to reinforce**, ranging from £33.5M to £55.7M. The gas networks are the greatest contributor to total reinforcement costs in these archetypes at 78-91% of costs. There is a greater spread in reinforcement costs for rural archetypes due to dependence on the gas network and dwelling density.
- **Industrial archetypes reinforcement costs sit between rural and urban archetypes.** Within industrial archetypes, electricity reinforcement costs are relatively consistent, whereas gas network costs vary to a greater extent due to a range of dwelling densities in archetypes.

When considering scenario 4 with different sensitivities there are several key observations:

- **Total reinforcement costs decrease for all archetypes when considering the high hydrogen uptake case (sensitivity 1).** The total cost decreases between 1% (Scotland (North)) to 15% (England (North West)) with greater impact on urban archetypes which have a greater proportion of total costs attributed to electricity network reinforcement costs. This is attributed to a larger fall in electricity reinforcement costs that more than offsets the increase in gas network reinforcement costs.
- **The opposite effect occurs for the low hydrogen uptake case (sensitivity 2) compared to the base case.** The total cost increases between 1% (Scotland (North)) to 15% (England (North West)). There was a greater impact on urban archetypes as costs from electricity network reinforcement increases to a greater extent than the fall in gas network reinforcement costs.

Table 17: Scenario 4 consumer choice total network reinforcement costs excluding storage costs for each archetype.

	Archetype name	Region type	Gas Network Reinforcement Costs (£M)			Electricity Network Reinforcement Costs (£M)			Total Costs (£M)		
			Base Case	Sensitivity 1	Sensitivity 2	Base Case	Sensitivity 1	Sensitivity 2	Base Case	Sensitivity 1	Sensitivity 2
1	Scotland - North	Rural	50.6	50.8	50.3	5.2	4.3	6.0	55.7	55.1	56.3
2	Scotland - Mid	Industrial	15.3	15.5	15.1	5.2	2.9	7.5	20.5	18.4	22.6
3	Scotland - South	Urban	10.5	10.6	10.3	5.7	3.3	8.0	16.1	13.9	18.3

4	England - Northeast	Industrial	15.0	15.0	15.0	6.3	3.9	8.6	21.3	18.9	23.6
5	England - Northwest	Urban	10.4	10.4	10.4	6.8	4.2	9.4	17.2	14.6	19.7
6	Wales - North	Industrial	27.7	28.0	27.3	6.3	3.9	8.7	34.0	31.9	35.9
7	Wales - Mid	Rural	33.9	34.3	33.5	6.6	3.8	9.5	40.5	38.1	42.9
8	Wales - South	Urban	12.4	12.6	12.2	6.9	4.2	9.6	19.3	18.9	21.7
9	England - Midlands	Urban	24.9	24.9	24.9	7.6	4.7	10.5	32.5	29.6	35.4
10	England - London	Urban	9.6	9.7	9.6	8.2	5.7	10.6	17.8	15.4	20.2
11	England - Southeast	Rural	26.3	26.3	26.2	7.3	4.7	9.9	33.5	30.9	36.1
12	England - Southwest	Rural	35.4	35.5	35.4	7.5	5.6	9.5	43.0	41.1	44.9

4.5.1.Electricity Networks

The key results are as follows for the base case:

- **England (London) has the highest reinforcement costs.** It was calculated that the archetype would cost £8.2M. The urban archetype has high transmission costs (£4.6M) due to its transmission TNUoS weighting and high distribution costs because of the urban infrastructure required to be upgraded (£3.6M).
- **Scotland (North) and Scotland (Mid) have the lowest reinforcement costs**. Both archetypes have reinforcement costs of £5.2M. Both have similar transmission costs due to its TNUoS weighting (£1.3 and £1.2M, respectively). Interestingly, both have similar distribution costs (£3.8M and £4.0M) as each consider different distribution infrastructure (rural and industrial).
- **Urban archetypes are generally the most expensive to reinforce.** The two most costly archetypes, England (London) and England (Midlands) (£8.2M and £7.6M, respectively), are both urban archetypes. Scotland (South) has significantly lower costs (£5.7M) due to its low transmission costs (£1.6M) (compared to England (London) (£4.6M)).
- **Industrial archetypes demonstrate consistency in reinforcement costs.** England (North East) and Wales (North) entail the same reinforcement costs of £6.3M. However, Scotland (Mid) has a lower cost (£5.2 million) (a 21% difference), due to its low transmission costs (£1.2 million).
- **Similarly to Urban archetypes, Rural archetypes have a significant range in reinforcement costs.** England (Southwest) has the highest cost

of rural archetypes (£7.5M and the second highest of all archetypes). Scotland (North) has the lowest cost associated (£5.2M) meaning a 44% difference for rural archetypes.

- **Distribution costs are higher than distribution costs across all archetypes.** Its costs range from £4.7M (England (Midlands)) to £3.7M (Wales (Mid)) (a 27% difference). Urban infrastructure costs are generally most expensive due to the infrastructure upgrades and the current electrification percentage of each archetype. Rural archetype costs are generally lower due to their less expensive infrastructure.
- **Transmission costs are variable but show no correlation between archetypes.** England (London) has the highest transmission costs of £3.6M, whilst Scotland (Mid) has the lowest transmission costs of £1.2M (a 200% difference). This gives a significant range of £2.4M due to TNUoS tariff weighting and the current electrification of each archetype.

4.5.2.Gas Networks

The key results for the gas network portion of these results are summarised below for the base case and each of the sensitivities. The key results are as follows for the base case:

- **The gas distribution reinforcement costs are the same for scenario 4 as they are for scenario 2 and scenario 3.** However, the transmission costs with or without storage costs differ resulting in a different total reinforcement cost.
- **The storage and transmission reinforcement costs are between 40% - 50% smaller compared to scenario 2.** This again results in a lower cost for all archetypes (and per dwelling) when storage costs are considered when compared to scenario 2; however, there are higher costs when compared to scenario 3.
- **Consistent with scenario 2 and 3, Scotland (North) has the highest total cost** (£50.6M without storage costs, £56.1M with storage costs). It also maintains the highest cost per dwelling using gas heating (£26.3k without storage costs, £29.1k with storage costs). It remains the highest cost archetype due to the region being the most rural archetype which results in a greater distribution network size and ultimately greater cost.
- **Consistent with scenario 2 and 3 England (London) has the lowest total costs** due to its high dwelling density and low distribution network size (£9.6M without storage costs, £13.2M with storage costs), 5 times smaller than costs for Scotland (North). In line with the previous scenarios, England (North West) is the urban archetype with the lowest cost per dwelling using gas heating (£2.6k without storage costs, £3.7k with storage costs).
- **In urban archetypes, costs per dwelling using gas heating are generally lower compared to rural and industrial areas**, ranging between £2.6k-£6.0k without storage costs, and £3.7k-£7.1k with storage costs. This is a direct result of low reinforcement costs and a high proportion of dwellings using gas for heating.

- **Among industrial archetypes, Wales (North) has a significantly higher total cost** (£27.7M without storage costs, £31.7M with storage costs) and cost per dwelling using gas heating (£7.3k without storage costs, £8.4k with storage costs).
- **Incorporating storage costs into transmission reinforcement costs results in an increase in total costs** and costs per dwelling using gas heating in all areas by a maximum of 11%; however, costs remain smaller than the distribution network due to the relatively small network size of the transmission network when compared to the distribution network, in addition to the transmission network costs being spread over a greater number of dwellings and other end uses of hydrogen such as industry and power generation.

In summary, under scenario 4 gas network reinforcement costs for urban archetypes are generally lower per dwelling using gas heating compared to rural archetypes, which have the highest costs per dwelling. Industrial archetypes show a range of costs. Storage costs contribute to a noticeable increase in overall costs and costs per dwelling across all areas.

When considering scenario 4 with different sensitivities there are several key observations:

- **There is little impact on total gas network reinforcement costs when considering the high hydrogen uptake case without storage costs when compared to the base case.** The total cost increases between 0.07% (England (South East)) to 1.56% (Wales (South)) with greater impact on those archetypes which have a greater proportion of total costs attributed to transmission network reinforcement.
- **There is larger increase on total gas network reinforcement costs when considering the high hydrogen uptake case with storage costs when compared to the base case.** The total cost increases between 4.73% (England (South West)) to 16.06% (Scotland (South)). The larger increase in costs is due to the high CAPEX associated with storage and the greater the heating demand in an archetype, the greater the influence of these costs are.
- **There is once again little impact on total gas network reinforcement costs when considering the low hydrogen uptake case without storage costs when compared to the base case.** The total cost decreases between 0.1% (England (South East)) to 1.9% (Wales (South)) with greater impact on those archetypes which have a greater proportion of total costs attributed to transmission network reinforcement.
- **There is larger decrease on total gas network reinforcement costs when considering the low hydrogen uptake case with storage costs when compared to the base case.** The total cost decreases between 4.77% (England (South West)) to 16.27% (Scotland (South)). The larger fall in costs is due to the high CAPEX associated with storage and the lower heating demand in an archetype, the greater the influence of these costs are.

- **There is the greatest variation when comparing the high case to the low case,** with the difference increasing to a greater extent when storage costs are considered. This is a result of the largest difference in transmission and storage costs that are attributed to domestic heat demand (i.e., a 50% difference between the 75% of the gas transmission network assigned to heating demand relative to Scenario 2 in the high case and 25% of the gas transmission network assigned to heating demand relative to Scenario 2 in the low case).

Table 18: Scenario 4 Consumer choice gas network reinforcement costs for each archetype.

No	Archetype name	Regional type	Total Distribution Reinforcement Costs (£M)	Total Transmission Reinforcement Costs (£M)			Total Storage Costs (£M)			Total Costs (£M) [Value includes storage costs]			Base Case Cost per Dwelling Using Gas Heating (Thousand £/dwelling using gas heating) [Value includes storage costs]
				Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	
1	**Scotland - North**	Rural	49.9	0.6	0.9	0.4	5.5	8.3	2.8	50.6 [56.1]	50.8 [59.1]	50.3 [53.0]	26.4 [30.7]
2	**Scotland - Mid**	Industrial	14.9	0.5	0.6	0.3	4.9	7.4	2.5	15.3 [20.3]	15.5 [22.9]	15.1 [17.6]	3.7 [5.4]
3	**Scotland - South**	Urban	10.1	0.4	0.5	0.2	4.5	6.8	2.3	10.5 [15.0]	10.6 [17.4]	10.3 [17.4]	2.6 [4.2]
4	**England - Northeast**	Industrial	14.9	0.1	0.1	0.0	4.5	6.8	2.3	15.0 [19.6]	15.0 [21.9]	15.0 [17.2]	3.9 [5.6]
5	**England - Northwest**	Urban	10.3	0.1	0.1	0.0	4.2	6.3	2.1	10.4 [14.6]	10.4 [16.7]	10.4 [12.4]	2.6 [3.7]
6	**Wales - North**	Industrial	26.7	1.0	1.3	0.5	4.0	6.1	2.0	27.7 [31.7]	28.0 [34.1]	27.3 [29.3]	7.4 [9.0]
7	**Wales - Mid**	Rural	32.9	1.0	1.4	0.5	3.6	5.4	1.8	33.9 [37.5]	34.4 [39.7]	33.5 [35.3]	18.7 [21.7]
8	**Wales - South**	Urban	11.9	0.5	0.7	0.3	3.8	5.6	1.9	12.4 [16.1]	12.6 [18.2]	12.2 [12.5]	3.2 [4.6]
9	**England - Midlands**	Urban	24.8	0.1	0.1	0.0	4.3	6.4	2.1	24.9 [29.2]	24.9 [31.3]	24.9 [14.0]	6.0 [7.6]
10	**England - London**	Urban	9.5	0.1	0.2	0.1	3.6	5.4	1.8	9.6 [13.2]	9.7 [15.1]	9.6 [11.4]	2.9 [4.0]
11	**England - Southeast**	Rural	26.2	0.1	0.1	0.0	3.8	5.7	1.9	26.3 [30.0]	26.3 [31.9]	26.2 [28.1]	6.7 [8.1]
12	**England - Southwest**	Rural	35.4	0.2	0.3	0.1	3.5	5.3	1.8	35.4 [39.0]	35.5 [40.8]	35.4 [37.1]	11.7 [13.5]

5. *Analysis*

This section provides a detailed analysis of the costings laid out in the results section. We assess which scenario and archetype has the highest and lowest costs and delve into the reasons why this is the case.

5.1. Analysis: Cross-comparison between scenarios

Table 19: Summary of suitability of hydrogen/electricity by region based on reinforcement costs only for each archetype.

No	Archetype	Regional type	Suitability for hydrogen heating	Suitability for electric heating	Explanation
1	Scotland - North	Rural	●	●●●●	Costs to upgrade for hydrogen are very high. Costs for upgrading the electricity network are extremely low making this a better option.
2	Scotland - Mid	Industrial	●●	●●●●	Costs to upgrade for hydrogen are slightly better than average, while costs for upgrading the electricity network are low, making this a better option.
3	Scotland - South	Urban	●●●●	●●●●	Costs to upgrade for both hydrogen and electricity network upgrades are low and comparable.
4	England - Northeast	Industrial	●●	●●●●	Costs to upgrade for hydrogen are average for this archetype, while costs for upgrading the electricity network are low making this a better option.
5	England - Northwest	Urban	●●●●	●●●	Costs to upgrade for hydrogen are very low for this archetype making this a better option, while costs for upgrading the electricity network are better than average.
6	Wales - North	Industrial	●	●●●	Costs to upgrade for hydrogen are extremely high for this archetype, while costs for upgrading the electricity network are better than average making this a better option.

7	Wales – Mid	Rural	●	●●●	Costs to upgrade for hydrogen are extremely high for this archetype, while costs for upgrading the electricity network are better than average making this a better option
8	Wales - South	Urban	●●	●●●●	Costs to upgrade for hydrogen are close to average for this archetype, while costs for upgrading the electricity network are much lower making this a better option.
9	England - Midlands	Urban	●	●●●	Costs to upgrade for hydrogen are high for this archetype, while costs for upgrading the electricity network are lower making this a better option.
10	England - London	Urban	●●●	●●	Costs to upgrade for hydrogen are low for this archetype, better than costs for upgrading the electricity network, making hydrogen a slightly better option
11	England - Southeast	Rural	●	●●●	Costs to upgrade for hydrogen are extremely high for this archetype, while costs for upgrading the electricity network are lower than average making this a better option.
12	England - Southwest	Rural	●	●●●	Costs to upgrade for hydrogen are extremely high for this archetype, while costs for upgrading the electricity network are better than average making this a better option.

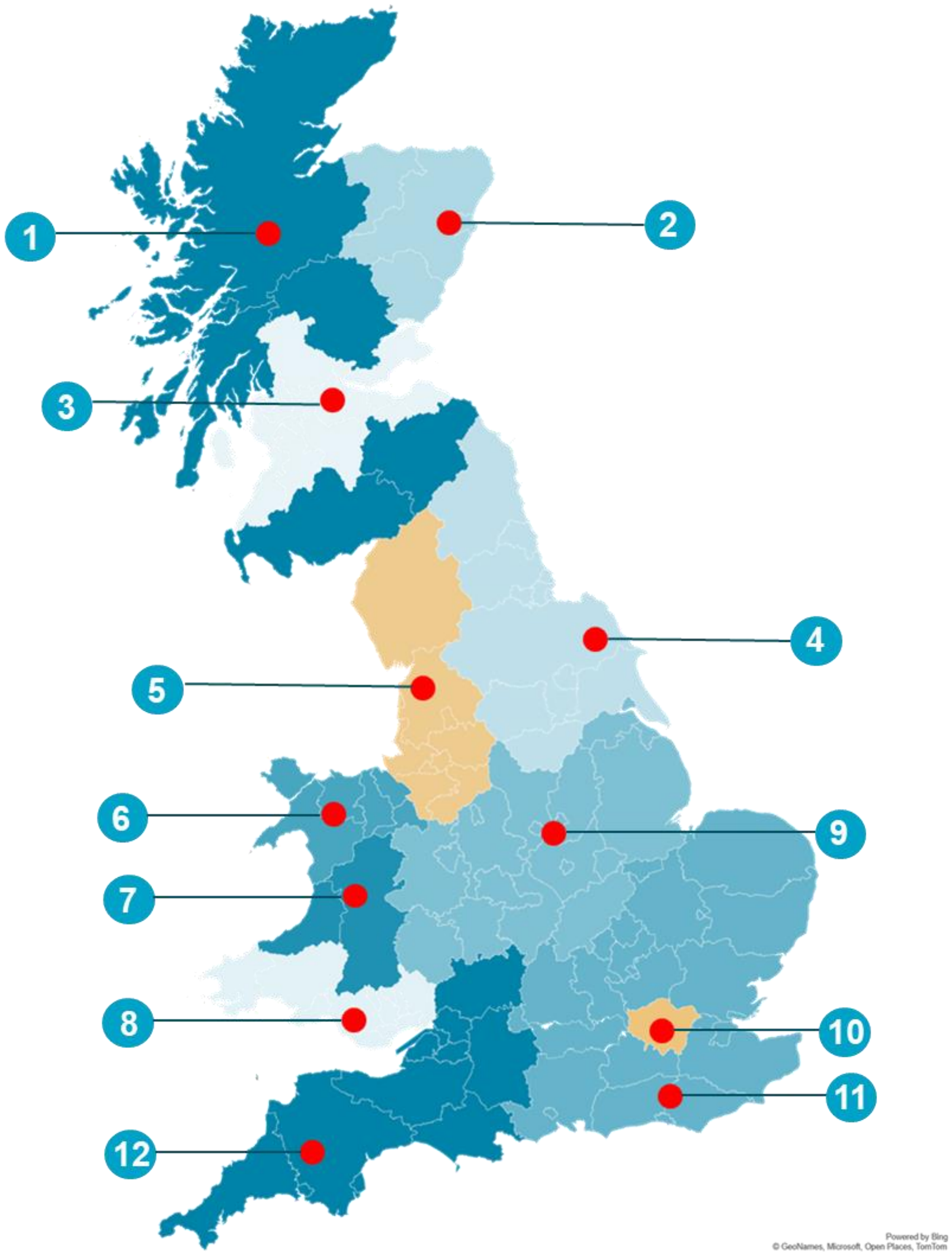
Suitability Scoring Key:

●	●●	●●●	●●●●
Poor	Average	Good	Very Good

The below figures provide a comprehensive illustration of total network reinforcement costs split into the natural gas and electricity networks to achieve net-zero heating across various scenarios.

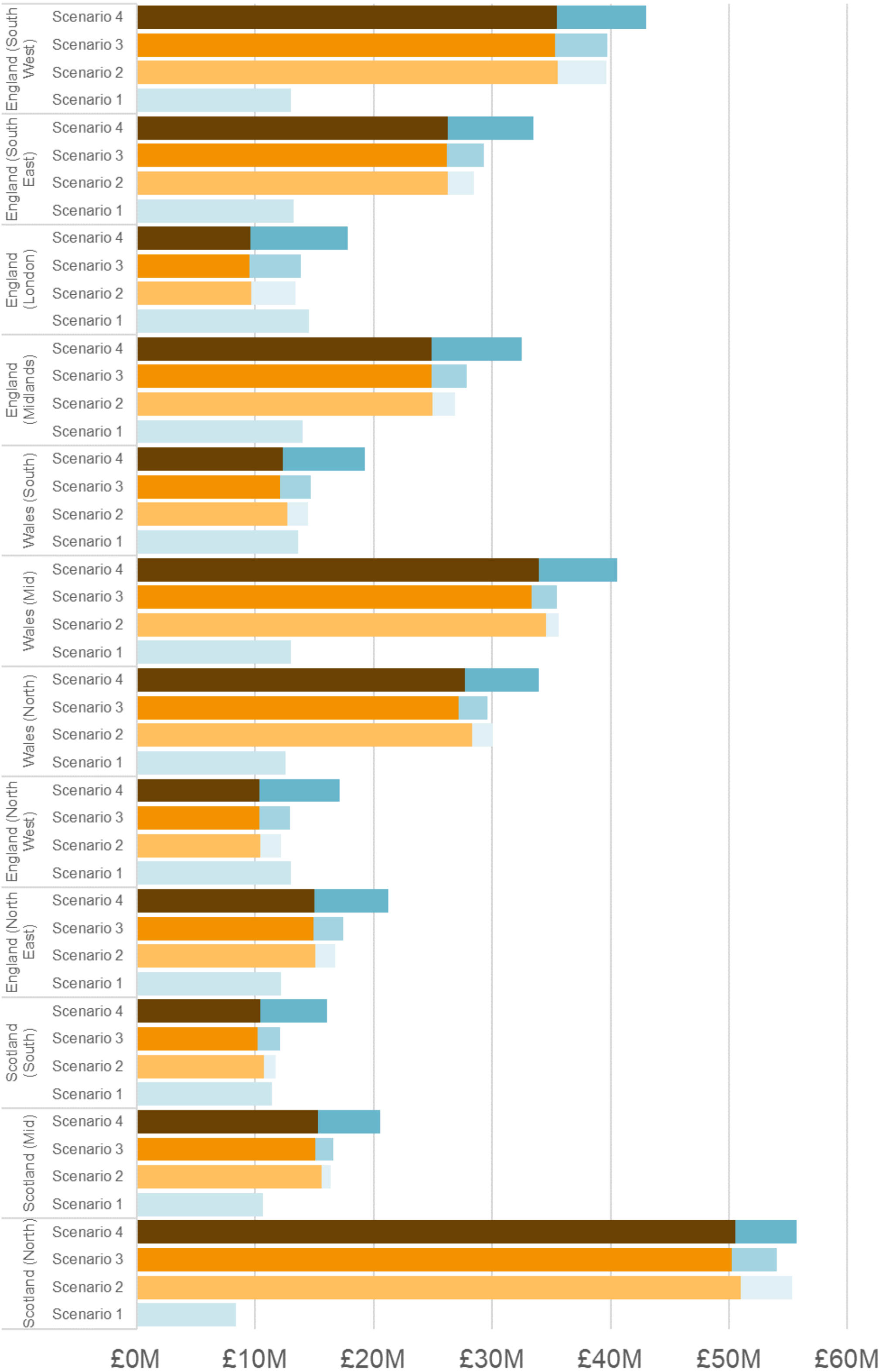
The below graphic is designed to enable easy and simultaneous cross-comparison between different scenarios and geographical archetypes which forms the basis of discussion. The respective network reinforcement costs for Scenarios 1 and 2 are shown in this analysis.

Figure 14: Map of GB highlighting the lowest costs for full electrification (Scenario 1) and 100% hydrogen boilers (Scenario 2) for each archetype within each region



* Archetypes represented by large red dots

Figure 15: Total reinforcement costs for each scenario excluding hydrogen storage costs for each archetype



*Costs are relevant to 5,000 dwellings (electricity network = blue shaded bars, gas network = orange shaded bars)

The summary of the cross-comparison analysis and key implications of the gas and electricity reinforcement costs going forward are:

Electricity Networks

- Rural areas are most suited to electrifying 100% of its domestic heating demand. The archetypes demonstrate the lowest network reinforcement costs overall. This suggests that the technology roll-out should be considered a low / no regret decision in Scotland (North), England (Southeast) and Wales (Mid).
- Industrial archetypes where electrification costs are significantly lower (e.g. Wales (North) and England (North East)) should also be considered a low / no regret decision for the technology rollout. This should be followed by the Scotland (South) archetype where a hybrid approach should be considered, where costs are more comparable.
- Urban areas provide the highest costs for electrifying 100% of domestic heating demand. This suggests that the archetypes should be upgraded last.

Gas Networks

- When considering only network reinforcement costs, urban areas are most suitable for switching the existing gas grid to hydrogen. These areas show the lowest network reinforcement costs of all archetypes and therefore are the area with regrets. The analysis suggests that the first regions where hydrogen should be implemented is in England (North West) and Scotland (South), followed by England (London), and then Wales (South).
- The analysis suggests that the switch to hydrogen in industrial archetypes (England (North East) and Scotland (Mid)), which have the next lowest cost base, would also be an area of lower regret. However, the reinforcement costs for hydrogen in these archetypes is more expensive than electrification.
- There is low suitability to repurpose the gas network for hydrogen in rural locations, the largest cost base and therefore under a 100% hydrogen boiler scenario these areas are likely to be a high regret.

Electricity and Gas Network Preference

- There are two urban areas where there is a small cost preference for prioritising hydrogen heating over electrification – England (London), and England (North West). Gas network reinforcement costs for these archetypes were 8%, and 6% lower than electricity network reinforcement costs, respectively. Therefore, based on this analysis it is more likely that hydrogen heating could be implemented for these archetypes.
- Reinforcement costs in Scotland (South) are comparable between scenario 1 and 2, with scenario 1 (full electrification) reinforcement costs being less than 3% lower than the gas reinforcement costs.
- All other archetypes show a preference for electrification over hydrogen heating. The preference generally becomes larger as dwelling density falls, from urban to industrial and then rural areas. Therefore, rural areas show a

far greater preference for electrification. This is demonstrated by Scotland (North), England (South West), and Wales (Mid) where electricity network reinforcement costs are 15%. 33%, and 37% of gas network reinforcement costs, respectively.

- High gas network reinforcement costs are attributed to the distribution network, as described more in Section 1.21. Due to the high costs, we will likely see a contraction of the gas distribution network to exclude these high-cost areas which will need to be electrified instead.

Implications of Scenarios

- Scenario 1 and 2 – a switch to 100% hydrogen boilers for all archetypes is unreasonable due to the large cost associated with reinforcement in more rural archetypes. Similarly, there and regions where electrification reinforcement costs (Scenario 1) are larger than for hydrogen heating (Scenario 2). It is therefore likely that there will be prioritisation in selecting which heating technology is implemented in each archetype.
- Scenario 3, where a hybrid heating scenario is employed, has a higher cost base compared to the lowest cost from either scenario 1 or scenario 2. Therefore, it is even more unrealistic to assume all archetypes will have hybrid heating. In some cases, the cost difference is not significant, such as England (London) and Scotland (South). A consultation will be required to set priorities for which areas this may be a plausible solution and not end up costing a significantly greater amount in reinforcement costs.
- Scenario 4, undefined low-carbon heating, yields the greatest costs of all scenarios for all archetypes and does not appear to be a cost-effective solution. Costs for the gas network do not change significantly between scenarios and therefore there will be greater costs from reinforcing both the gas and electricity networks to a greater extent.

5.2. Electricity Networks analysis

The network operators' approach to reinforcement

There are numerous approaches network operators could take in order to reinforce the grid to facilitate domestic heating in the UK.

- Areas with the lowest share of electrification – firstly network operators could prioritise areas with a low share of electrification. This research found that the rate of electrification shows little correlation per archetype area type. (For instance, Scotland (North) has a current electrification rate of 19%, whereas England (Southeast) has a reinforcement rate of 6%). Using this approach, network operators would target archetypes to upgrade by turning their attention to those that require the greatest transition to electrification first.
- Addressing areas first with the highest costs associated – this would require a different approach for network operators to target suitable areas to reinforce first. For example, England (London) has the highest reinforcement costs associated (£14.5M) in scenario 1, however, England

(Southwest) has the highest costs in scenario 3 (£4.4M). This approach would target the most expensive areas to reinforce first, depending on what scenario the network operator follows.

- Addressing the lowest cost areas first – network operators could target those archetypes with the smallest reinforcement cost associated first. Again, this would vary depending on which scenario the network operator would take, for example Scotland (North) would be reinforced first under scenario 1's assumptions, whereas Scotland (Mid) would be prioritised for Scenario 3.

Archetype trends

From an urban perspective, this research suggested that scenario 3 (Electricity / Hydrogen hybrid) or scenario 1 would generally be the preferred approach for network operators. The urban archetypes with lower gas and electrification costs (England (London)) contribute to low total costs for scenario 3. However, archetypes with high gas and electrification costs (England (Midlands)) suggest scenario 1 is better suited for reinforcement investment.

In industrial archetype areas, scenario 1 (100% electrification) appears to be best suited financially to reinforce for network operators (costings ranging from £10.7M to £14M). This is similarly the case for rural archetype areas, which are also significantly less expensive (range in costs between £8.4M to £13.3M).

Distribution and Transmission factors

As our reinforcement costs consider distribution and transmission factors, different decisions have to be made between policy makers and network operators to electrify domestic heating.

Distribution

As reinforcing distribution infrastructure is more expensive than transmission infrastructure, network operators need to strongly consider which areas to reinforce first.

Scenario 1, for example, entails the highest distribution reinforcement costs of £8.1M (in England (London)). The same archetype has £2.4M costs when following the Electric / Hydrogen hybrid approach (Scenario 3). This could therefore save the grid operator £5.7M per 5,000 dwellings instead of electrifying its entire network.

As highlighted, this research's reinforcement costs provide assumptions of high-end infrastructure costs. These can be reduced if DSR and energy storage are applied effectively to the grid network. Cohesion between policy makers and network operators will have an important role to play in reducing reinforcement costs overall. This is because household storage can play an influential part in the future, however it will be essential that the technology's roll-out is integrated into the network operator's reinforcement plans. If there is cohesion between both stakeholders planning, this can reduce the peak demand on the network and therefore reduce reinforcement costs.

Transmission

This research has found that transmission costs for reinforcement can he highly variable across different archetypes. This should be a consideration for policy makers. When using TNUoS in our calculations, Scotland has less expensive transmission network costs to that of Southern England. For instance, Scotland (North) transmission costs are £2.2M compared to £6.3M in England (Southwest) (both rural archetypes). Therefore, a regionally based planned approach should be developed by policy makers, to highlight which areas to reinforce first.

As large renewable energy sites and interconnector plans are developed and expand the grid's capacity, long-term planning cohesion should be enacted between policy makers and network operators. This will therefore mitigate the risk of peak demand affecting the headroom of primary transformers and bulk supply points. This is also an important factor to consider when assessing the cost of reinforcing the current grid infrastructure.

Reinforcing the electricity network in scenario 3 (Electric / Hydrogen hybrid) demonstrates the most cost-effective approach when considering electrification alone (£1.9M reinforcement costs in scenario 3 compared to £6.4M in scenario 1 for (England (London)). This suggests that gas networks meeting peak demand may be an effective approach for network operators (in some areas).

Table 20: Electricity transmission network reinforcement costs for all scenarios and each archetype.

No	Archetype	Regional type	Total Transmission Reinforcement Costs (£M)			
			Scenario 1: Electrification	Scenario 2: Hydrogen	Scenario 3: Hybrid Heating	Scenario 4: Consumer Choice
1	**Scotland - North**	Rural	2.2	1.1	1.0	1.3
2	**Scotland - Mid**	Industrial	2.5	0.2	0.4	1.2
3	**Scotland – South**	Urban	3.2	0.3	0.5	1.6
4	**England - Northeast**	Industrial	4.0	0.5	0.8	2.0
5	**England - Northwest**	Urban	4.7	0.6	0.9	2.4
6	**Wales - North**	Industrial	4.6	0.6	0.9	2.3
7	**Wales - Mid**	Rural	5.8	0.5	0.9	2.9
8	**Wales - South**	Urban	5.5	0.7	1.1	2.8
9	**England - Midlands**	Urban	5.3	0.7	1.1	2.9
10	**England - London**	Urban	6.4	1.6	1.9	3.6
11	**England - Southeast**	Rural	6.1	1.0	1.4	3.3
12	**England - Southwest**	Rural	6.3	2.0	2.1	3.7

Electricity storage

Hydrogen storage is an essential component for meeting demand through winter; it is for this reason that we have included the CAPEX costs for hydrogen storage as a key gas network upgrade costs within each scenario. The electricity network does not operate in the same way, so there is not comparable need for large-scale, inter-seasonal storage to ensure domestic heat demand is met. Ensuring there is sufficient electricity to meet domestic heat demand requires several things:

- Renewable generation – this ensures there is sufficient electricity generated across GB to meet demand from all sectors including domestic heat.
- Peaking plants – the grid must remain in balance at all times to prevent a fault developing. The challenge to match supply and demand is constant and when there is insufficient renewable power to meet demand, peaking plants are essential to making up the shortfall.
- Storage – there are many different types and scales of storage that use different technologies. All storage supports the grid in maintaining balance within the network.

Reinforcing the grid has previously been the only option available to both the transmission and the distribution network operators to ensure fluctuations in supply and demand are maintained. Storage provides the network operators a way to improve the efficiency of the energy system by reducing the need for more generation as well as reducing the need for peaking plants. This is because energy that would otherwise be curtailed, can be stored for later use at times of increased demand. Instead of requiring peaking plants, energy previously stored can be used instead. In practice, more storage will also mean that less reinforcement is needed as storing electricity for later use reduces peaks on the network.

The costs included in our results are based on the maximum reinforcement cost anticipated by DESNZ to ensure the grid is kept in balance. It is not currently known where future storage will be incorporated into the network, but any increase in costs due to investing in storage will be followed by a decrease in the total investment needed in grid reinforcement due to the efficiencies provided by the storage. Therefore, storage costs are not an additional cost that need to be added to the total reinforcement as investment in storage will mean less being spent on reinforcement. We are confident that the total costs we have presented here are the upper end of the cost that will need to be paid by consumers or taxpayers.

Decommissioning the gas infrastructure

Gas distribution network decommissioning costs – in scenario 1, where 100% of properties are heated with electricity the gas distribution network would need to be safely decommissioned in its entirety. This would add significant cost to network operators, if following this approach and should be considered when reinforcing archetype areas with gas pipe infrastructure (more likely urban areas than rural areas). Our method focuses on all twelve regions. This means that if the gas use decreases in an area, the entire network will still need to be increased.

There could be an option to adopt a regional approach, where the entire network is not upgraded, but only some regions are instead. Therefore, only some regions would be decommissioned, which is a cost that would need to be considered as part of an electrification scenario. The consumer however would have to pay for this decommissioning. This was considered outside of our scope in this research.

5.3. Gas Networks analysis

In the upcoming section, we explain the reasons behind the observed variations in the gas distribution and transmission network reinforcement costs across the different scenarios and what this means going forward for considerations to upgrade the gas network, offer consumer choice or electrify archetypes.

5.3.1. Gas Distribution Reinforcement Costs

There is a distinct difference between the reinforcement costs of the gas distribution network for Scenario 1: full electrification, where there are zero reinforcement costs, and the remaining scenarios, where there is a consistent cost across the scenarios.

This is explained by scenario 1 showcasing no requirement for a gas network for heating application due to all dwellings in the archetypes being switched onto electrified heat. While there would be an expected cost for decommissioning in the scenario, these costs are not part of the scope of the evidence base calculation and therefore have not been included, as outlined in Section 1.20 above.

Scenarios 2 (gas network conversion for use of 100% hydrogen boilers), 3 (hybrid heating), and 4 (undefined low-carbon heating) have the same reinforcement costs. This is because delivering hydrogen to hybrid heating appliances requires the same amount of distribution network as serving appliances that uses 100% hydrogen.

Looking beyond this, each scenario has a different hydrogen heating demand assumed for each archetype. Therefore, it is plausible this may lead to a small potential of reducing the additional infrastructure requirements to facilitate the switching process from natural gas to 100% hydrogen in GB archetypes where heating demand is lower (i.e., a larger part of the distribution network in the archetype area can be switched at one time). However, this will ultimately depend on the growth rate of total hydrogen production volumes in GB, which itself will be dependent on the UK Government strategy to use hydrogen for heating applications. Therefore, LCP Delta has assumed that varying heating demand in an archetype will lead to no difference in additional infrastructure required for switching to 100% hydrogen for scenarios 2, 3, and 4.

5.3.2. Transmission Reinforcement Costs

There is again a distinct difference between the reinforcement costs of distribution network for Scenario 1: full electrification, and the remaining scenarios due to there being no requirement for any gas network to serve heating purposes in scenario 1.

When storage costs are considered, there is a greater variation in transmission network reinforcement costs across scenarios 2, 3, and 4. Scenario 2: full hydrogen adoption shows the largest cost with Scenario 3: hybrid heating showing the lowest transmission reinforcement costs.

The costs associated with storage are directly proportional to the heating demand from hydrogen and that required from electrified heat. LCP Delta notes for an optimised hybrid heat pump that 20% of the heat will be generated by hydrogen and therefore storage costs associated with scenario 3 are 20% of the costs for the 100% hydrogen boiler scenario. Similarly, Scenario 4: undefined low-carbon heating base case assumes 50% of the hydrogen heating demand in Scenario 2 to enable consumer choice and are therefore 50% of the value of Scenario 2 costs.

When storage costs are excluded scenarios 2 (full hydrogen adoption), 3 (hybrid heating), and 4 (undefined low-carbon heating) all have low transmission reinforcement costs. Scenario 3 has the lowest cost ranging from £0.03M-0.45M, with the value associated with each archetype sitting at 27% of the costs for that of scenario 2. Scenario 4 sits between scenario 3 and 2 in absolute cost terms, with costs ranging from £0.1M-1.0M with the value associated with each archetype sitting at 60% of the costs for that of scenario 2.

The transmission reinforcement cost differences between scenarios can again be explained by the hydrogen heating demand and the proportion of total hydrogen demand. As the hydrogen domestic heating demand falls in scenario 4 and then further in scenario 3, this results in a lower total hydrogen demand and therefore a smaller proportion of total hydrogen demand attributed to domestic heating decreases, while it simultaneously increases for other sectors. Assigning a greater proportion of costs to other end-use sectors therefore decreases the transmission reinforcement costs for heat calculated in this study.

It should be noted that each of the scenarios require a transmission network of the same size to be in place to ensure all consumers in the archetype already using gas heating have access to hydrogen. The same proportion of retrofitting pipelines has been assumed for the scenarios due to a lack of understanding of how a different heating demand for hydrogen will impact the ability to retrofit the existing network. Further study is required in this area to develop this understanding and this presents a limitation to the study. LCP Delta has also assumed the transmission pipeline diameter is also kept constant in the scenarios due to the likelihood the pipeline diameter will remain the same. This is probable due to lower capital costs from retrofitting pipelines versus the cost of installing new, more expensive pipelines with smaller diameters, and the extra infrastructure measures needed to facilitate the transfer of gas into different sized pipelines.

Table 21: Gas transmission network reinforcement costs for all scenarios for each archetype.

No	Archetype	Regional type	Total Transmission Reinforcement Costs (£M) [Value includes storage costs]			
			Scenario 1: Electrification	Scenario 2: Hydrogen	Scenario 3: Hybrid Heating	Scenario 4: Consumer Choice
1	**Scotland - North**	Rural	0	51.0 [62.1]	50.2 [52.4]	50.8 [59.1]
2	**Scotland - Mid**	Industrial	0	15.7 [25.5]	15.1 [17.1]	15.5 [22.9]
3	**Scotland – South**	Urban	0	10.7 [19.8]	10.2 [12.0]	10.6 [17.4]
4	**England - Northeast**	Industrial	0	15.1 [24.2]	15.0 [16.8]	15.0 [21.9]
5	**England - Northwest**	Urban	0	10.4 [18.8]	10.4 [12.0]	10.4 [16.7]
6	**Wales - North**	Industrial	0	28.3 [36.4]	27.2 [28.8]	28.0 [34.1]
7	**Wales - Mid**	Rural	0	34.6 [41.8]	33.4 [34.8]	34.4 [39.7]
8	**Wales - South**	Urban	0	12.7 [20.3]	12.1 [13.6]	12.6 [18.2]
9	**England - Midlands**	Urban	0	25.0 [33.5]	24.9 [26.6]	24.9 [31.3]
10	**England - London**	Urban	0	9.7 [12.0]	9.6 [11.0]	9.7 [15.1]
11	**England - Southeast**	Rural	0	26.3 [33.8]	26.2 [27.7]	26.3 [31.9]
12	**England - Southwest**	Rural	0	35.6 [42.7]	35.3 [36.8]	35.5 [40.8]

5.3.1. Gas Network Scenario Cross-Comparison Summary

The summary of the analysis and key implications of the gas network reinforcement costs are as follows.

Gas Distribution Network

- The IMRRP are classed as a sunk cost in this analysis, and should the networks be deemed obsolete due to electrification then this cost effectively becomes a poor investment by the network operators. The operational lifetime of the new installed pipelines will far exceed the length of time they are required to supply natural gas. This raises a question of whether it is better to complete the upgrades and switch to hydrogen to ensure the investment becomes valuable or completely write this off the costs as a bad investment. There is potential that the gas networks could continue for longer under a scenario that involves blending hydrogen with natural gas. However as this would not achieve net zero this option has not been considered in the analysis.
- There were challenges from gas network operators on the cost level for the distribution networks. They believed the costs were too high compared to other estimates of work required to distribution networks to facilitate a 100% hydrogen for domestic heating scenario. While these costs have been

outlined, the sources and methodology used in calculating the reinforcement cost were not publicly available and therefore we were unable to consider this in evaluating the distribution network costs.

Gas Transmission Network

- Upgrading the transmission network forms a small part of the total reinforcement costs and it is clear the transmission network will be upgraded to some extent regardless of the extent of use for domestic heating. Bearing this in mind the transmission network costs can be largely assigned to other demand end uses. However, further input will be required in the future to understand precisely what proportion of transmission network reinforcement costs can be attributed to domestic heating. Work has already started in this area, and it is under consideration in Project Union but remains in the early stages (i.e., pre-FEED) and therefore the strategy to facilitate the switch from natural gas to hydrogen is not well defined.

Limitations

- The evidence presented here only takes into consideration the gas distribution and transmission costs. Further considerations such as energy costs for hydrogen and electricity, costs to install hydrogen boilers, and hydrogen production costs, need to be considered to determine the overall suitability of hydrogen heating against electrification. The inclusion of these considerations may change the suitability of each technology in each archetype and therefore further work must be completed to address this.
- The costings focus on the distance from hydrogen storage sites due to the importance of storage in meeting winter demand. There is potential for a small number of dwellings situated close to an industrial cluster to note require storage if year-round hydrogen demand can be met directly by the cluster. This would result in lower transmission costs, but our analysis confirmed these are a lower proportion of the total cost so this is unlikely to have made a significant difference to the final results.
- The additional gas infrastructure required for each scenario, both for the distribution and transmission pipelines, pose a limitation to the analysis. This is due to each scenario having an indicative hydrogen heating demand that is specific for each archetype, whereas the total hydrogen demand and strategy for repurposing the existing network will dictate the level of new transmission pipelines required. This potentially leads to either over- or under-estimating the necessary additional infrastructure requirements to facilitate the switchover from natural gas to 100% hydrogen. The UK Government strategy for use of hydrogen for heating and the availability of installers to switch the network to hydrogen means this is difficult to quantify.
- The England (Midlands) total road length within the archetype is 75.56km, more than double that of the London archetype, more akin to a rural area e.g. England (South East). This larger road length directly translates into a greater distribution pipeline length associated with the archetype. As noted

in the methodology limitations section, the road length data is not reported at the local authority level and therefore this reduced granularity will increase the road length of the archetype by including more rural locations. This will likely reduce the gas network reinforcement costs of the archetype to an approximate minimum value of 50% of costs identified in this analysis, therefore providing a limitation to the results and analysis.

6. Conclusions and Recommendations

In this section, we offer our final conclusions based on the results and analysis of the project. We detail our recommendations for how reinforcement for domestic heating within the different regions of GB should be approached to ensure value for money for consumers.

6.1. Key findings from the analysis

Network infrastructure costs per household are, on average double for hydrogen (£5,016 per household) compared to electrification (£2,496 per household) for the archetypes in this evidence base. Network infrastructure reinforcement costs vary significantly by location for both electricity and gas network reinforcement. The variation between archetypes is more pronounced for gas networks cost than electricity network costs.

- The gas networks cost differences are primarily driven by distribution costs per household. The significant variation is due to some regions including large land areas but low housing densities, which pushes up the cost per household. The transmission costs are primarily differentiated by the distance from hydrogen storage sites, although these costs are a smaller proportion of the total.
- The electricity network costs are also primarily driven by the distribution costs per households, which accounts for two-thirds of all reinforcement costs. The proportion of properties already using electricity to heat their homes has significant impact here. Regions with a high level of electric heating have lower reinforcement costs as existing grid infrastructure is already present to meet significant demand. For archetypes with lower levels of electric heating, reaching 100% electrification results in substantially higher costs.

Just three out of the 12 archetypes have comparable gas and electricity network costs. These areas are more likely to be economically viable for hydrogen for heating. In such areas, other costs beyond network upgrades will become more important in determining whether hydrogen for heating is economically viable for the consumer. Industrial areas are more closely located to long-term hydrogen storage and are also more likely to be close to hydrogen production. Therefore, transmission costs in these areas are comparatively low to other archetypes. However, with developments underway for the new H2 backbone for use by multiple sectors, such as industry, the costs savings for domestic heat applications are not significant. Distribution network reinforcement costs are more significant and therefore being close to industrial clusters does not matter as much as how appropriate the residential area is for upgrading the network to run on hydrogen. This is based on the proportion of the network that needs upgrading and the housing density in the area.

In other areas, electricity network costs are significantly lower. Rural areas entail significantly lower costs than urban archetypes, particularly at the distribution level due to above average usage of electric heating. Notably, archetypes located in Northern Scotland have lower transmission costs than those in Southern England because of its proximity to large renewable energy production sites.

Providing upgrades to the gas grid infrastructure in all parts of GB to allow consumers to choose if they want hydrogen or electrified heating will place a significant extra cost onto consumers. A locational approach to low-carbon heating would mean that gas network is only upgraded to hydrogen in certain regions where it makes financial sense to do so.

6.2. Recommendations for Policy makers

For DESNZ

- The first step for DESNZ should be to adopt a locational approach when it is developing its key policies on hydrogen readiness of gas boilers and heat pump deployment. Our analysis is a valuable first step towards a more comprehensive mapping of GB regions to determine which are more suitable for hydrogen use in domestic heating and which are not. For example, our analysis has identified rural areas as most suitable for electrification of heat, particularly the North of Scotland and South West of England.
- If it is possible for DESNZ to determine specific regions where hydrogen is not suitable, the next step would be to share this insight to provide clarity for those areas sooner and enable them to start working on viable alternative solutions more quickly.
- Working with Ofgem through the adoption of a locational approach will help enable network companies to make firmer plans regarding the level of investment required for upgrade and reinforcement work to accommodate low carbon heating technologies.
- DESNZ should carefully consider the extent to which not adopting a regional approach. While it may be tempting to favour a blanket approach to network upgrades and reinforcement across GB to enable full consumer choice, our analysis in scenario 4 clearly shows this will lead to higher costs. Additional factors such as consumer appetite for ASHPs vs hydrogen boilers are difficult to gauge as gas heating is still available and consumers are currently receiving mixed messages regarding low-carbon heating options. A regional approach will ensure consumers are given clear signals regarding the choices they will have in the future.

For Ofgem

- Locational differences in cost need to be considered to ensure the energy transition is fair. This includes consideration of different network users. A first priority for Ofgem is to provide clarity regarding how regional system planners and the Future System Operator (FSO) will be able to determine the key characteristics of locations. This is necessary for these organisations to assess key data, as presented in this research, at the appropriate granularity so that local decisions can be made for the decarbonisation of domestic heating. Similar levels of transparency are needed from the networks to enable appropriate assessments to be made to further progress work.
- Secondly, Ofgem needs to consider how they will ensure sufficient network planning and investment is provided for the electricity grid to cope with mass electrification of domestic heat. Our analysis shows only a small number of areas will be potentially suitable for hydrogen.
- It is likely that if the gas distribution network is to continue, it will do so at a reduced size and scale from what is currently in place. Therefore lastly, Ofgem need to give consideration as to how and when relevant sections are decommissioned and who will pay for this.

6.3. Limitations of the study and further work

There are many additional aspects that could have been included in this work that were beyond the scope of the project. Some key limitations are outlined below:

The project looked at 12 archetypes only. The project does not attempt to map out the whole of GB comprehensively. The findings are representative of 5000 dwellings per region, which is only a fraction of the ~24 million dwellings in GB.

High level calculations. The calculations are therefore deliberately high level:

- Transmission costs for electricity networks are difficult to capture without detailed modelling, as infrastructure costs are related to generation connections and other areas of demand beyond domestic heat. It has therefore not been possible to provide a specific breakdown of transmission costs, for example the reinforcement costs associated with offshore wind transmission. However, we are confident in our findings that even with more detailed modelling, the total costs for transmission associated with domestic heat would still be much lower than the costs for distribution.
- The location of electricity generation is a factor that has not been accounted for in the results. Significant amounts of transmission infrastructure are required to connect, primarily, offshore wind generation, which is located far from demand. This is particularly relevant for the electrified heating scenario. However, it also has implications for the 100% hydrogen scenario if a significant proportion of hydrogen is generated from electrolysis which will require large quantities of renewable energy.
- Head room within the electricity network for our distribution calculations were based on assumptions from the literature. Although we considered this

generally, specific archetype headroom is not accounted for. Headroom is substation specific so some areas of GB will have higher levels of headroom and will thereby require less reinforcement, whereas others have lower levels of headroom and will require more reinforcement.

- Reinforcement costs might change largely for each region, particularly natural gas networks, if alternative archetypes in each region are selected. The regions selected contain a range of rural, semi-urban, urban, and industrial areas and their attributes such as dwelling density and dwelling using gas heating will collectively influence the network reinforcement costs.
- However, the 12 archetypes selected in this evidence base are representative of all possible archetypes in GB. The archetypes consider a range in the proportion of dwellings using gas heating ranging between 37% to 85%, representing the upper and lower boundaries for archetypes connected to the gas grid. A case could be made to include an archetype that is not connected to the gas grid, but this would not highlight any gas network reinforcement costs. The electricity results also take into account the proportion of households currently using electric heating. This ranges between 4% to 19% across our archetypes. If the archetype area moves to a council with a high percentage of electric domestic heating, this would reduce the costs of reinforcement considerably as it would consider these areas to have reinforced the grid already.

Scope. Aspects that fell outside the scope of this work:

- The uptake of EV's and the additional electricity demand associated with this technology is not included. EV's will also result in significant need for reinforcement of the electricity network but it was not possible to disaggregate this need from domestic heat. However, electricity reinforcement work is completed to meet total increases in demand that are not load specific. Therefore, there will be cost savings due to economies of scale associated with reinforcing to meet additional demand from EVs as well domestic heat.
- Electricity grid flexibility is also not considered within our scenarios as there is no suitable dataset that would enable us to do this. It is highly possible that significant advances in flexibility mechanisms, particularly at the distribution level, could lead to reduced need for infrastructure upgrades but it is not currently possible to pinpoint this with certainty to a specific location.
- Decommissioning of gas network would incur greater costs for regions that convert fully to electricity for domestic heating. We were unable to identify a reliable data source for what the total cost for this would be, or indeed what it would be for different GB regions.

This study identifies the need to greater clarity regarding the best locations for where hydrogen can best contribute to decarbonisation of domestic heat. We hope this study supports thinking in this area regarding future policy development, including government funding for hydrogen infrastructure and electrification of heat in the future.

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