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Evidence review for hydrogen for heat in buildings

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May 2021

DOI: https://doi.org/10.7488/era/1239

Executive summary

Project aims & context

The Scottish Government has set ambitious climate change targets to reduce greenhouse gas (GHG) emissions by 75% by 2030, 90% by 2040 and to net-zero emissions by 2045. To support achieving these targets, the Scottish Government needs to understand the potential role for using hydrogen to heat buildings in Scotland and its contribution to the decarbonisation of heat. Hydrogen is one of only a handful potential heat decarbonisation routes that offers a mass-market solution.

This project was commissioned to help build a clear evidence base, using existing literature, relating to all aspects of the use of hydrogen to heat buildings, including supporting infrastructure and costs. Lessons gained thus far from key projects (H100, Acorn, Hy4Heat and others[1]) have been synthesised along with a wide range of evidence sources on aspects such as technical feasibility, safety and costs. The review focused on drawing out relevant lessons for Scotland from evidence across Scotland, the wider UK and further afield (where appropriate). A four-step methodology was applied, details of which are presented in the report annex.

[1] H21 Leeds City Gate, H21 North of England, Aberdeen Vision, HyDeploy, HyNet North West, Project Methilltoune. The complete list of the reports used as references for this evidence review can be found on page 43.

Key findings

Key findings on hydrogen for heat within buildings

	20% hydrogen blend	100% hydrogen
Safety	• For a 20% hydrogen blend with natural gas, existing heating appliances can continue being used without modifications or replacements.	• In the case of 100% conversion to hydrogen, appliances will need to be replaced with hydrogen ready ones, as the appliances are not designed to run on this fuel. Piping in buildings will highly likely also need replacement, to avoid the risk of embrittlement.
Costs	n/a	• The total cost of converting a property to 100% hydrogen is estimated to be £3,000 - £4,000. This range includes the costs for appliances (mainly heating systems), piping and installation. For the hydrogen boiler itself, existing literature suggests a price range of £700 - £2,500 for the end customer, without the installation costs included (in comparison, new natural gas boilers will generally range between £600-£2000). • Limited evidence was uncovered on fuel cost; it suggests that the retail prices of fuel might increase under both blending and full conversion. Based on limited existing literature, maintenance costs for 100% hydrogen heating systems are estimated to be ~£120 per year, which is slightly higher than the maintenance costs associated with existing natural gas boilers today.
Technical	• According to available evidence, a 20% hydrogen blend can be safely used in domestic appliances without the need of upgrade or replacement. Therefore, no significant technical amendments will be needed to accommodate up to a 20% hydrogen blend in buildings.	• For 100% hydrogen conversion, some of the internal components of existing natural gas boilers (e.g. valves, burners, control systems) are not suitable for use with hydrogen. Hence, existing gas appliances will need to be replaced with hydrogen ready ones.

Key findings for hydrogen at the system level (infrastructure beyond the building)

Costs	• Several sources consider hydrogen production via methane reformation[2] and carbon capture to be the lower cost option for large scale hydrogen production in the UK (vs electrolysis[3]).

[2] Methane reformation involves producing hydrogen from methane often through the use of high temperature steam.
[3] Electrolysis is the process of using electricity to split water into hydrogen and oxygen.

	• Only one source, BEIS, projects and compares the capital costs (CAPEX) and operational (OPEX) costs of hydrogen production via reformation and electrolysis and suggests that by 2050, electrolysers will be cost competitive with reformers on a CAPEX basis (this limits the visibility of total system level implications, given the significant impact range of OPEX). • There is limited but robust evidence on costs relating to the transmission and distribution of hydrogen via pipelines. For the establishment of a purpose-built hydrogen transmission network that would become part of the regulated asset base, costs are estimated to be £1 million to £1.46 million per kilometre of pipeline. • Cost assumptions for replacing or reinforcing the distribution network (iron and steel pipes) to carry hydrogen vary according to pipe diameter. • Little evidence was found on hydrogen storage costs. The costs will be influenced by the storage type which can be centralised (inter-seasonal) or distributed (for intra-day). • Above ground hydrogen storage facilities – a viable centralised storage option for Scotland – can be grouped into high pressure and medium pressure. High pressure storage (of ~42.5 Megapascal pressure units) is currently over 4 times more expensive than medium pressure storage (of ~5 Megapascal pressure units), due to the cost of the high-pressure cylinders, and the additional requirement for compression.
Technical	• Methane reformation without carbon capture is a well-established technology. However, the economical or technical feasibility of this hydrogen production type with carbon capture is not proven at scale. • Large scale production of hydrogen via electrolysis technology is unproven and considered unfeasible today due to high capital and operational costs. • There is disagreement on whether steam methane reformation (SMR) or auto-thermal reforming (ATR) is the best technology to deploy today. While SMRs are a mature technology and widely used across the refining and petrochemical industries, ATRs are less established but with a potentially higher efficiency. • In a model where pure hydrogen is transmitted via pipelines, a new purpose-built pipeline will likely need to be constructed. • Transporting pure hydrogen in distribution networks requires polyethylene pipes. Hydrogen blends up to 20% require minimal changes. • Scotland has very limited salt cavern resources available for hydrogen storage, but other geological features for storage are being explored. A proposed solution for Scotland is to store hydrogen at scale as ammonia. • The reduced energy content per unit volume of hydrogen compared to natural gas means additional pipeline will be required to store the same amount of energy in the distribution network (i.e. additional linepack).

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1. Project aims and methodology

Project aims

The research identifies, collates and assesses the current evidence base for using hydrogen for heating buildings in a Scottish context using a systematic literature review. In-depth review explores:

(a) The technical feasibility, costs and safety implications of using hydrogen to heat buildings
(b) Costs and technical considerations with regards to hydrogen production, capabilities and challenges of distributing hydrogen around current networks and types of hydrogen storage
(c) Roles and responsibilities of key actors including Governments, regulators, network companies and commercial organisations

Methodology

The literature review follows a four-step methodology, described in some detail below. A full methodology description can be found in the report annex.

Step 1: Gathering literature

- Use the defined research questions and sub questions to formulate search terms.
- Carry out the initial search for literature using the various search terms to establish a long list of sources.
- Use simple criteria to limit the breadth of literature gathered at this stage.

Step 2: Literature screening [1. Filter]

- Use specified criteria to include or rule out literature sources to establish a short list.

Step 3: Mapping & describing

For each piece of literature that passes the screening stage, we:

- Provide a short paragraph summary of the scope of the study.
- Pull out relevant key findings that are contained within the Executive summary, Abstract or Introduction.
- Map which parts of the value chain the source covers at the system level and/or building level.
- Capture whether the source covers safety, cost, or technical aspects.

Step 4: Quality & relevance appraisal [2. Filter]

Following the mapping & describing above, we then prioritise the literature short list using specified criteria. The sources making it through this filter constitute our 'Final evidence base'.

Final evidence base

Table 1 below lists and summarises the final evidence base. Research Questions 1, 2 and 3 were answered using evidence extracted from these sources.

Table 1: Final evidence base for evidence review

Ref. no.	Evidence source	Author / owner	Date	Type	Research questions (RQ)
1	Hydrogen supply chain evidence base	BEIS (UK Government Department for Business, Energy & Industrial Strategy)	2018	Government	1, 2
2	What is needed to deliver carbon-neutral heat using hydrogen and CCS?	Sunny et al, 2020	2020	Independent	1
3	Acorn hydrogen feasibility study	Pale Blue Dot	2019	Independent	2
4	Analysis of Alternative UK Heat Decarbonisation Pathways	Climate Change Committee (CCC)	2018	Government quango	1, 2
5	Hydrogen: Cost to customer	Energy Networks Association (ENA)	2020	Industry	1
6	H21 Leeds City Gate	Northern Gas Networks (NGN)	2016	Industry	1, 2
7	Aberdeen Vision Project	SGN (gas network operator for Scotland and parts of southern England)	2020	Industry	1, 2
8	HyDeploy Project	Cadent, Northern Gas Networks (NGN)	2018	Industry	1, 2, 3
9	Decarbonisation of heat and the role of 'green gas' in the United Kingdom	The Oxford Institute for Energy Studies	2018	Independent	2
10	Future Energy Scenarios	National Grid	2020	Industry	2
11	Cost analysis of future heat infrastructure options	National Infrastructure Commission	2018	Government quango	1, 2
12	Hy4Heat Progress Report	BEIS (UK Government Department for Business,	2019	Government	1, 2, 3

		Energy & Industrial Strategy)			
13	H21 North of England Report	NGN, Cadent	2018	Industry	2, 3
14	HyNet North West: from vision to reality	Cadent	2018	Industry	
15	RIIO GD2 Business Plan Appendix	SGN (gas network operator for Scotland and parts of southern England)	2019	Industry	1, 2, 3
16	Should we inject hydrogen into gas grids? Practicalities and whole-system value chain optimisation	Quarton and Samsatli	2020	Independent	2, 3

At the time of writing this report, there are some highly relevant studies ongoing that will provide additional key evidence. These will address some of the research questions outlined in this report. Delta-EE is aware of the following ongoing studies, where evidence is yet to be published:

- H100 workstream A (Evidence and safety case)
- Hy4Heat work packages:
  - WP4 - Domestic hydrogen gas appliance development
  - WP5 - Commercial hydrogen gas appliance development
  - WP7 - Safety assessment
  - WP8 - Demonstration facilities

2. Key findings by research question

2.1. RQ1: What are the safety concerns, costs and technical requirements associated with hydrogen use for heat at building level?

2.1.1. Summary

This section summarises evidence on the safety aspects, costs implications and technical requirements related to enabling the use of hydrogen for heating in buildings.

Within this section, we consider:

- changes in infrastructure required, focusing on heating appliances (i.e. changes required to existing appliances to be compatible with hydrogen gas and new 'hydrogen ready' appliances) and pipework *within* the building
- operational and maintenance requirements of appliances that use hydrogen
- blending hydrogen with natural gas versus a 100% conversion to hydrogen

The sources of evidence used for this section are outlined in Table 1 in Section 2.

2.1.2. Evidence on the safety aspects with using hydrogen for heat in buildings

Below, we summarise the key conclusions from existing evidence around the safety aspects of using hydrogen for heat in buildings, broken down by:

- Appliances
- Pipework
- Operation and maintenance

For each point above, we consider separately the safety aspects around blending hydrogen into the gas grid versus a 100% conversion to hydrogen.

Safety aspects at the appliance level – when blending hydrogen with natural gas

Evidence suggests that a switch to up to a 20% hydrogen blend by volume has no safety impacts on domestic appliances currently operating on natural gas [7].

HyDeploy, a project led by Cadent field trialled 230 appliances in over 130 properties and proved that domestic heating appliances can safely switch to 20% hydrogen blend as all their components continue to operate within their design limitations [8].

The safety of hydrogen blend was also examined across a number of projects by SGN (including Aberdeen Vision, Project Cavendish, H100 and project Methilltoune). Results from these projects show that a 20% hydrogen blend can be safely used in domestic appliances without the need to upgrade or replace them [15].

Safety aspects at the appliance level – 100% conversion to hydrogen

The safety case of heating appliances using 100% hydrogen shows that existing condensing gas boilers cannot safely use 100% hydrogen; they therefore need to be replaced with hydrogen ready appliances [15]. Regulations are currently being developed to support the development and certification of appliances that can use 100% hydrogen to ensure quality standards.

Projects and trials are focusing on supporting the development of the following certification and standards:

Hydrogen Appliances Certification: According to the Hy4Heat project, hydrogen appliances are to be certified under the Gas Appliance Regulation (GAR). This regulation will be aimed at providing guidance on testing and certification of domestic appliances for relevant bodies and appliance manufacturers [12].

In addition, the British Standards Institution (BSI) is working on a new standard for hydrogen appliances which it aims to use on the Hy4Heat project. The PAS4444 standard will form a guide to be followed by appliance manufacturers and other relevant bodies on functionality, safety, installation, operation and maintenance of hydrogen-only and hydrogen/natural gas fuelled or converted appliances [12].

NOx emissions from domestic hydrogen boilers

According to the H21 Leeds City Gate study, the most important driver for the use of hydrogen as a fuel is the low levels of emissions formed during combustion when compared to natural gas. During hydrogen combustion there is no CO_2 produced and the only pollutants created are oxides of nitrogen (NOx) (a modern condensing gas boiler emits < 40 mg of NOx/kWh). NOx occurs as a result of the high flame temperature and the nitrogen content of air, however, with careful engineering this can be minimised or even eliminated. In addition, pure hydrogen boilers completely remove the safety issue presented by carbon monoxide.

Safety concerns at the piping level – 100% conversion to hydrogen

Piping within buildings will almost certainly require refurbishment to accommodate 100% hydrogen use [1] although the PE pipes in the distribution networks are safe for transporting hydrogen [15].

2.1.3. Evidence on the cost implications of using hydrogen for heat in buildings

Below, we summarise the key conclusions from existing evidence around the within-building cost implications of using hydrogen for heat in buildings, broken down by:

- Appliance
- Pipework
- Operation and maintenance
- Retail price

For each point above, we consider separately the cost implications around blending hydrogen into the gas grid versus a 100% conversion to hydrogen. Table 1 presented later at this section summarises the key quantitative evidence available in existing literature reviewed for this study.

Across different studies, it is estimated that the total domestic cost of conversion to hydrogen per property ranges between £3,000-£4,000[4] [5]. Key sensitivities are the heating appliance cost, cost of replacing hobs, ovens or other gas appliances, pipework and labour.

[4] 2020 prices

Costs implications at the appliance CAPEX – when blending hydrogen with natural gas

Evidence suggests that up to a 20% hydrogen blend will have negligible cost implications on existing heating appliances as they can operate as currently.

Costs implications at the appliance CAPEX – 100% conversion to hydrogen

According to current evidence, the cost of a hydrogen boiler is estimated between £700 – £2,500 depending on the volume of hydrogen boilers being manufactured. The higher end of this price range is based on low volumes of hydrogen boilers being manufactured today. BEIS expects hydrogen boiler prices to decrease to the same level as conventional gas boiler prices once manufacturing volumes increase to over 100,000 units per year per manufacturer [1]. Sunny *et al.* and National Infrastructure Commission also support the view that the costs of domestic hydrogen boilers will be comparable to natural gas boilers at higher production scales in the future [2, 11].

Boiler installers / fitters will need extra training on the new hydrogen appliances; hence, additional costs for training should be considered under 100% conversion to hydrogen [1].

Cost implications related to the maintenance of heating appliances – when blending hydrogen with natural gas

Evidence suggests that up to a 20% hydrogen blend will have zero cost implications on the maintenance of existing heating appliances (maintenance will continue to be the same as that for a standard condensing gas boiler)

Cost implications related to the maintenance of heating appliances – 100% conversion to hydrogen

Hydrogen boilers (that run on 100% hydrogen) are expected to have additional servicing requirements compared to standard condensing gas boilers, as some components of the hydrogen boilers, such as the exhaust catalysts, will possibly require regular servicing to ensure their performance standards [1]. Thus, their operation and maintenance (O&M) costs are expected to be higher [1, 4]. The Hydrogen supply chain evidence base by BEIS estimates that the annual maintenance cost of a hydrogen boiler as ~£120, which is around 50% greater than can be expected from a current natural gas boiler [1].

Table 2: Estimation of costs associated with hydrogen conversion of buildings

Hydrogen appliances and actions required	**Estimated cost**	**Source**
'Average' hydrogen boiler price from installers to customers	£700 - £2,500 depending on the volume of hydrogen boilers being manufactured. There is limited evidence for how boiler prices will vary by size of boiler. For the majority of the existing literature, the cost of hydrogen boilers is estimated at £800 - £1,500.	[1, 4, 5, 6, 11]
Pipework	£100 - £500	[1, 5, 6]

Installation costs	£300 - £600 per appliance (boiler or other domestic appliances)	[1, 5]
Maintenance costs	£120/ year	[1]
Other appliances		
Cookers	£300 - £750	[6]
Heaters	£300 - £450	[6]

Evidence suggests that the within-building capital costs for decarbonising heat are higher in the case of heat pumps compared to hydrogen [11, 15]. This is due to the higher appliance costs of heat pumps compared to hydrogen boilers and the extra costs for the changes to the heat distribution systems within homes needed for the heat pump installation (e.g. larger radiators may be needed or changes to the piping) that hydrogen boilers largely avoid. According to CCC, the capital cost of hydrogen heating systems is significantly lower compared to electric heat pumps, at £75/kWth for a hydrogen boiler and £600/kWth for a heat pump [4]. A capital cost comparison table between a hydrogen boiler and a heat pump is presented below [4]:

Table 3: Cost comparison between a hydrogen boiler and an electric heat pump

	Hydrogen boiler	Electric heat pump[5]
Appliance cost	£2,500	£5,000
Conversion costs[6]	£1,500	£1,000
Total costs	£4,000	£6,000

The electric heat pump prices presented on the table above represent a 5kWth system suitable to cover an annual space heating demand of 10MWh. These systems are usually installed in new build properties or well insulated houses with generally low annual demand for heating. Therefore, in properties with higher demands where bigger heat pumps will be installed, the capital cost gap between hydrogen boilers and heat pumps will be greater.

Cost implications for the fuel retail price

Limited evidence was uncovered during the literature review process for this study on the topic of heating running cost implications from hydrogen use. From the final evidence base, we draw on two key sources that provide estimates (the H21 project and Sunny et al. 2020). Evidence from both sources suggest that the retail prices of fuel might increase under both blending and full conversion.

[5] Electric – Heat pump (5kWth) and resistive heating (1kWth), preheating (3.6kWth), thermal storage (1.7 kWth)
[6] Decommission and replacement.

According to the H21 Leeds City Gate project, hydrogen conversion is expected to have an impact on customer bills. The project estimates that for those customers within the area of conversion, the retail price of fuel will be [6][7]:

- 7.3p/kWh (excluding the appliance upgrade)
- 10p/kWh (including the appliance upgrade)

The H21 North of England project[8] estimates that the additional hydrogen unit cost for gas customers will be £3.8/MWh (excluding VAT) and £4/MWh (including VAT), which converts to an additional 0.38 – 0.4 p/kWh. Based on a standard gas bill with a current consumption of 14,200kWh per year, this translates to an additional ~£54 - 57 per year.

According to Sunny et al., by 2050, the cost to consumers can be estimated as 4.8p/kWh, 6p/kWh and 7.1p/kWh under government financing, hybrid regulated asset base (RAB)[9] and private sector cost structures respectively. This would imply running cost increases of 190%, 260% and 320% relative to heat provided from natural gas currently.

2.1.4. Evidence on the technical specifications for using hydrogen for heat in buildings

Below, we summarise the key conclusions from existing evidence around the within-building technical specifications for using hydrogen for heat in buildings, broken down by:

- Appliance
- Pipework
- Operation and maintenance

For each point above, we consider separately the technical specifications around blending hydrogen into the gas grid versus a 100% conversion to hydrogen.

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[7] Key assumptions (H21 Leeds City Gate report): A hydrogen conversion would almost certainly have to be financed through a regulated price control as was the case with the original town gas to natural gas conversion. In the scenario presented, appliances upgrades are included in the regulatory finance. Values presented are on a standalone project only basis. The impact on GVA and the northern economy and subsequent UK economy has not been considered in these evaluations. These costs have not considered the potential for repurposing the Local Transmission System should an incremental hydrogen conversion take place.
For simplicity, all costs have been forecast from 2023 onwards with conversion taking place between 2026 and 2029. In reality, costs will begin slightly earlier for the design/build years of the hydrogen production and HTS systems.
The Expenditure Forecast for Leeds City Hydrogen Project used two options of regulatory finance changing the proportions of fast/slow money: a methodology which shows allowed revenues earlier in the project lifecycle because of the upfront OPEX costs needed; and as an illustration only and not considering other factors such as network financeability – if the £1bn of OPEX costs could be treated as slow money which would spread the funding over 45 years. The impact on the total customer bill has been considered with the biggest gap being a £22 increase to the annual bill in Year 2026/27 under existing regulatory methodologies. The two rollout options presented alongside efficiency savings could be developed with minimal impact on customers overall bills. Charging the costs just to NGN customers significantly increases the bill contribution to the transportation charge. Socialising the costs across all UK customers is the best option to minimise the impact on customer's bill.
[8] H21 North of England is based on steam methane reforming for hydrogen production, a method which is not net zero compliant.
[9] Framework which allows a lower cost of capital for transport & storage of both H2 and CO2 elements, along with private sector financing rates for the production infrastructure.

Technical specifications at the appliance level – when blending hydrogen with natural gas

According to Cadent's HyDeploy project and a number of projects from SGN (including Aberdeen Vision, Project Cavendish, H100 and project Methilltoune), a 20% hydrogen blend can be safely used in domestic appliances without the need of upgrade or replacement [7, 15].

Technical specifications at the appliance level – 100% conversion to hydrogen

Conversion to a network of 20-80% hydrogen will be a challenging step on the pathway to methane's replacement with hydrogen. Natural gas appliances will need to be replaced or refurbished to safely operate on concentrations of hydrogen over 20%, whilst hydrogen boilers will only be able to operate on hydrogen concentrations greater than 80% [15].

According to BEIS [1], refurbishing existing gas boilers to accommodate a 100% (or >80%) hydrogen use is not feasible as different system components will be needed e.g. different internal control systems, valves, burner types etc. This is due to the different calorific values of hydrogen and natural gas (the calorific value of hydrogen is about one third of that of natural gas), different flame speeds and densities; therefore, natural gas and hydrogen cannot be interchangeable in the same boiler burner, so new boilers suitable for hydrogen use will be needed for providing domestic heating and hot water [15].

Boiler manufacturers have already shown interest in developing their hydrogen products portfolio and this effort will likely be further stimulated by a long-term UK national hydrogen heat support plan and relevant policies [6].

The following table summarises the actions required for various domestic appliances under two different decarbonisation scenarios [4]:

Table 4: Actions required for domestic appliances under two different heat decarbonisation scenarios.

Current domestic appliance	**Scenario 1: 100% hydrogen network**	**Scenario 2: Full electrification**
Gas/oil boiler	Boiler will require replacement in order to operate on hydrogen and old boiler decommissioned and disposed of.	If a boiler is already installed, it will require decommissioning.
Gas hob	Evidence suggests that hydrogen cannot operate on open flames. The hob will need to be replaced with an electric hob[10].	If a gas hob is already installed it will require decommissioning and replacing with an electric hob.
Gas oven	Oven will likely require replacement to operate safely on open flame devices. It will be decommissioned and replaced with an electric oven.	If a gas oven is already installed it will require decommissioning and replacing with an electric oven.

[10] Although hydrogen hobs may be an option in the future.

Other gas appliances	Evidence suggests that hydrogen will likely not be able to operate on open flames. Other gas appliances will therefore be decommissioned and replaced with an electric appliance.	If a gas appliance is already installed it will require decommissioning and replacing with an electric appliance.
(Wet) heat emitters	No replacement needed.	Replacing/upgrading may be required to compensate for lower flow temperatures.
Hot water storage	No replacement needed.	Hot water storage will be required; possibly it will be included with the heat pump.

During this literature review, we did not uncover evidence to suggest that hydrogen can operate safely on 'open flame devices', such as hobs and ovens. Evidence on this is currently being gathered to reach a definite conclusion.

The estimated time required for hydrogen switchover of a combi boiler is 6 hours (replacement of existing natural gas boiler); for a traditional boiler system (e.g. sitting room back boiler units) this can be up to 11 hours [6]. The replacement of traditional system boilers is time-consuming, due to the large number of components that they have compared to those used in modern combi boilers [6]. Other sources report that the switch-over of a hydrogen-ready boiler to 100% hydrogen takes approximately 45 minutes.

The efficiency and lifetime of a hydrogen boiler is expected to be similar to that of a natural gas boiler (~94% thermal efficiency, ~12-year lifetime) [1]. However, there is currently limited evidence on this.

Hydrogen Quality Standards: Hy4Heat recommends a minimum hydrogen purity level of 98%[11] to be used by appliance manufacturers when developing prototype hydrogen appliances [12].

Technical specifications at the piping level – when blending hydrogen with natural gas

Evidence suggests that a 20% hydrogen blend can be safely used in existing pipework within buildings, without the need for upgrade or replacement.

Technical specifications at the piping level –100% conversion to hydrogen

The internal pipework of buildings is a crucial (and somewhat overlooked) aspect of a potential shift to hydrogen for heating. In the UK, the building pipework is usually made from copper and is sized to ensure that adequate gas flow rates can be provided to each of the gas appliances in the building, while maintaining acceptable pressure drops along the pipes. The length, sizing and set up of internal piping will vary significantly across buildings and is closely linked with the number of gas appliances. We have not come across studies that explore this in detail.

[11] The purity of delivered hydrogen is based on considerations from existing quality recommendations for natural gas. The hydrogen purity standard aims to address possible impurities from hydrogen production, trace contamination in the pipeline network etc [Hy4Heat Hydrogen Purity report].

Learnings around consumer engagement on hydrogen for heating

Experience from the SGN 'Opening up the gas market' project showed that gaining high levels of consumer involvement can be achieved (approaching 90% active support and < 1% active refusal) but this takes high levels of street-by-street canvassing and skilful public relations; which may increase the cost of hydrogen switchover significantly [6]. The public acceptance of hydrogen conversion is expected to be stimulated by any positive impact on local employment [6].

2.1.5. Limitations and gaps

There is limited evidence around internal pipework and associated technical and safety concerns for pure 100% converted systems.

Due to the limited number of heating appliances running on a hydrogen blend or 100% hydrogen (largely contained in various trials that have been in operation for only 2-3 years), there is little evidence on the impact of hydrogen on the maintenance requirements of heating systems. As the numerous trials in place continue and more trials start, we expect more evidence on this impact to emerge in the next 5 years.

There is little to no evidence covering the cost of other domestic hydrogen heating appliances, such as hybrid heat pump systems, gas driven heat pumps or fuel cell micro-CHPs (there are cost data for the latter, but for systems running on natural gas).

There is very limited evidence on hydrogen heating appliances running costs.

2.2. RQ2: What are the system level costs and technical requirements of hydrogen use for heat associated with 100% conversion?

2.2.1. Summary

This section summarises evidence on the costs and technical requirements at the system level related to enabling the use of hydrogen for heating in buildings.

Within this section, we consider:

- changes in infrastructure at the system level required, focusing on transmission & distribution networks, hydrogen production facilities and storage facilities
- a pure 100% hydrogen system
- comparison of a hydrogen-based system against other decarbonisation options.

The evidence summarised in this section has been extracted from the key sources across our Final Evidence Base outlined in Table 1 in Section 2.

Evidence on the system level cost impacts and technical considerations of using hydrogen for heat in buildings

Below, we summarise the key conclusions from existing evidence around the costs implications and technical considerations at the system level of using hydrogen for heat in buildings, broken down by:

- Production
- Transmission & distribution

- Storage

We consider separately the implications from blending hydrogen into the gas grid versus a 100% conversion to hydrogen (this section refers to 100% only). This is especially relevant for the transmission & distribution networks. Blended systems are considered in more depth in the next section (RQ3).

2.2.2. Production

The two main feasible low carbon hydrogen production options are electrolysis or reformation technology (which needs to be coupled with carbon capture and storage) [1]:

- **Electrolysis**
  - **Proton Exchange Membrane (PEM)**: Hydrogen electrolysis with PEM (Proton Exchange Membrane) offers rapid dispatchability and turn down to follow the energy output from renewables and is therefore ideal for pairing with wind farms for low-carbon hydrogen production or the provision of rapid response to the grid. PEM is a mature technology, which have been tested and proved in operational environments.
  - **Alkaline:** Hydrogen production by alkaline electrolysis is a proven technology with almost 90 years of operational experience. Dispatchability is not as rapid as in a PEM system.
  - **Solid Oxide Electrolyser (SOE):** High temperature solid oxide electrolysis (SOE) is an immature production technology with the potential to be a future large scale production method. The particular advantage of SOE is the ability to make use of industrial sources of waste heat to improve the overall efficiencies. If the energy cost of the waste heat is not included in the calculation, SOE electrical efficiencies can exceed 100%.
- **Reformation technology**
  - **Steam methane reforming (SMR):** Mature technology and widely used across the refining and petrochemical industries.
  - **Auto-thermal reforming (ATR):** Numerous ATRs are in operation worldwide, but most operate as secondary reformers in ammonia plants in collaboration with SMR technology.
  - **Auto-thermal reforming including Gas Heating Reforming (GHR):** GHR has been demonstrated on a semi- commercial scale for over 20 years, although not currently for standalone hydrogen production (methanol).

Evidence on technical system-level scenarios relating to hydrogen production

The Aberdeen Vision Project sought to assess the feasibility of delivering 2% hydrogen blend via the National Transmission System (NTS). The final project report argues that hydrogen would need to be produced at scale via reformation technology today to fulfil the 2% target. This is because electrolyser units that are commercially ready today tend to have hydrogen generation capacity in the region of 1MW. The hydrogen generation requirement for blending 2% by volume into the NTS will be in the region of 200MW. The report also makes the more general observation that deploying enough hydrogen production capacity for the UK to meet its 2050 net zero target[12] would require reformation technology (though the report does not explicitly state the expected amount or capacity needed). They do also recognise that electrolysis will play a (smaller) part in decarbonisation [7].

Producing hydrogen via reformation requires significant volumes of natural gas. The H21 Leeds report notes the amount will be in the region of 1:4 by mass (i.e. to produce one unit of hydrogen, one needs four units of natural gas. This is measured in kilograms.[13]). The study therefore suggests, the reformer site needs to connect to a suitable natural gas source at a suitable pressure. It also notes that it is more practical to locate the hydrogen production facility in close proximity to carbon dioxide storage infrastructure or resources, as this significantly reduces cost and effort for the transportation of the gas[14] [6].

The Oxford Institute for Energy Studies paper[15] says that hydrogen produced from methane, via steam reforming combined with carbon capture and storage is the most viable solution to decarbonising gas demand in the UK. This is mainly due to technical and economic feasibility compared with other low carbon options. It references the UK's long-established expertise in natural gas production as a key driver, along with several advantageous coastal terminals where a steam reformer could be sited. However, it is important to point out the authors also highlights that "Policies for the decarbonisation of heat are therefore likely to have very significant implications for the share of gas in this market", and that electrification will likely play a key role in heat decarbonisation [9].

A report for the National Infrastructure Commission (NIC) also suggests that it is highly unlikely electrolysis could provide sufficient hydrogen for a national rollout of hydrogen heating at reasonable cost. The NIC puts forward steam methane reforming (SMR) as most viable hydrogen production option, with carbon capture and storage (CCS) as pre-requisite[16] [11].].

The paper's most ambitious hydrogen deployment scenario (maximum rollout of hydrogen to all of the on gas network) would require a total SMR capacity of 91.9 GW, resulting in a CAPEX of £18.6 bn, cumulative OPEX of £44.9 bn and cumulative fuel cost of £188.5 bn to 2050 for the UK [11].

The timeline for hydrogen rollout in this scenario sees Scotland, NE England and SE England being the first regions to convert, starting from 2035.

The CCC's Analysis of Alternative UK Heat Decarbonisation Pathways, also concludes that zero-emissions energy system based on domestically produced hydrogen via electrolysis would not be feasible. This is in part due to the constrained availability of

[12] Scotland has set itself a legally-binding target to cut greenhouse gas emissions to net zero by 2045, five years ahead of the date set for the UK as a whole, as well as an interim target of 75% emissions reductions by 2030.
[13] Calorific value natural gas: 13.6 kWh/kg. Calorific value hydrogen: 33.3 kWh/kg. This suggests 54.4 kWh natural gas is required to produce 1kg (33.3 kWh) of hydrogen, or 1 kWh of hydrogen requires ~1.6kWh of natural gas.
[14] For the H21 Leeds City Gate project, delivery points for carbon dioxide have to be assumed as no infrastructure currently exists. It was considered potentially more contentious and costly to build a large CO_2 capture pipeline to the hydrogen production facilities. According to the H21 report, it is more practical to locate the hydrogen production facility close to CCS cutting cost for the transportation of carbon and also planning considerations (no quantitative data presented).
[15] This source predates the UK's adoption of net zero emissions targets by 2050.
[16] This source predates the UK's adoption of net zero emissions targets by 2050.

low-carbon generation resources, as well as significantly higher projected cost compared with hydrogen produced via reforming. CCC sees ATR to be the best reforming method, due to the expected superior performance in terms of cost, energy efficiency and carbon capture rate. However, the study acknowledges that electrolysers will be needed if a strict zero-carbon target is a long-term objective for the energy system (unless emissions from ATRs can be removed entirely) [4].

Hydrogen production via reforming and CCS implies additional cost factors around CO_2 transmission and storage. The National Infrastructure Commission (NIC)'s main hydrogen scenario assumes [11]:

- **CO_2 transmission:** CO_2 transmission pipelines transport the captured CO_2 to shoreline terminals and then to the offshore storage sites. Total CO_2 flows of 81 $MtCO_2$/y are captured by 2050, requiring onshore CO_2 pipelines with CAPEX of £3.9 bn and cumulative OPEX of £0.3 bn to 2050, while for offshore CO_2 pipelines CAPEX of £6.3 bn and cumulative OPEX of £0.9 bn to 2050 is required.
- **CO_2 storage:** Depleted hydrocarbon storage sites and aquifers in the Northern North Sea are used for storing the captured CO_2. This results in a cumulative infrastructure investment of £17.4 bn for a total cumulative storage requirement of 1040 $MtCO_2$.

HyNet North West (which plans to implement a "Hydrogen Production and Carbon Capture" plant) is developing a Autothermal reforming (ATR) plant to produce hydrogen. The study suggests ATR offers increased gas process efficiency compared to steam methane reforming (SMR) and the production of hydrogen at pressure results in reduced compression costs. Two units are planned with a total capacity of 890 MWth [14].

Evidence on cost relating to hydrogen production

The BEIS 'Hydrogen supply chain evidence base' study provides the following cost assumptions for the different hydrogen production options [1].

Electrolysis

Table 5: Electrolysis CAPEX, £/kW installed, base scenario

	2020	2030	2040	2050
PEM	750	400	350	340
Alkaline	600	485	465	455
SOE	1640	1000	800	700

Reformation* (incl. carbon capture plant)

Table 6: Current reformation CAPEX, £/kW, for different capacities (MW)

	100	300	500	1000
SMR	918	700	610	529
ATR		822	697	554
ATR + GHR		790	670	533

Table 7: Future reformation CAPEX, £/kW, for a 1000 MW plant size

	2020	2030	2040	2050
SMR	529	466	410	361
ATR	554	499	430	378
ATR + GHR		480	414	364

Table 8: Reformation OPEX (for all years)

	Fixed OPEX (£/kW/yr)	Natural gas (kWh / kWh H2)	Electricity (kWh / kWh H2)	CO_2 capture rate[17]
SMR	25.38	1.355	0	90%
ATR	24.41	1.197	0.059	95%
ATR + GHR	24.41	1.115	0.042	95.7%

**the figures for ATR assume that its electricity need is met by the grid. It is possible to generate some of the power needs on site with the hydrogen produced, which would slightly increase the CAPEX cost.*

The BEIS study also suggests that the high CAPEX cost of capturing CO_2 from SMR flue gas makes the use of ATR more attractive for "blue" hydrogen production, especially if CO_2 capture rates of greater that 90% are required.

2.2.3. Transmission & distribution

Evidence on technical specifications relating to transmission and distribution (T&D)

The Oxford Institute for Energy Studies points out that the UK is in the process of converting its distribution system to polyethylene pipes. These pipes can carry hydrogen with little or no technical adjustment – avoiding the issue of 'embrittlement' which limits the volume of hydrogen that can be carried through metal pipes [9].

An important system level consideration around hydrogen transmission and distribution, is that transporting hydrogen through pipes requires a greater volumetric flow than natural gas, as the energy content per unit volume is around a third that of natural gas. (Hydrogen has 31% of the energy per unit volume of natural gas). As summarised in the BEIS study, the reduced energy density does not directly translate to requiring a threefold increase in flow to meet a given energy demand, as the very small molecule of hydrogen flows far more easily than methane and can therefore deliver a quicker rate of energy delivery. The energy flow rate for hydrogen is approximately 71% that of natural gas [1]. Three options are discussed to mitigate this:

- a larger diameter pipeline,
- an increase in inlet pressure or
- accepting a larger drop in pressure through the pipeline

The report suggests that it is likely all three options will need to be implemented.

There is limited evidence on the implications and upheaval for end customers that would occur during the actual system conversion from natural gas to hydrogen. The H21 Leeds City Gate project describes its plans at a high level for the city of Leeds. The existing gas network would be segmented and converted from natural gas to hydrogen incrementally through the summer months over a three-year period. This approach should mean minimal disruption for customers during the conversion [6].

In addition, the Acorn feasibility study outlines a similar phased approach by area for Aberdeen. It suggests 100% hydrogen conversion of the low-pressure network would require the phased transition of the distribution network by area from natural gas to hydrogen. Such a conversion to hydrogen would mean that where the network is

[17] This represents the on-site CO_2 capture rate of the CCS plant, not the full chain (including upstream) emissions intensity of the production process.

operating purely on hydrogen, it would need to be isolated from the natural gas system.

Evidence on cost relating to T&D

The Energy Networks Association (ENA) aggregates a range of estimates for the establishment of a purpose-built hydrogen transmission network across GB. A range of £1.0-£1.46m per kilometre of pipeline is identified. The report highlights that assuming a cost of £1.2m per kilometre and a national network length of 7,000km, this equates to £8.4bn for a new GB-wide hydrogen transmission network [5].

The same study provides estimates for the repurposing the distribution network, including the replacement of gas network not covered under the Iron Mains Risk Reduction Program (IMRP). It is assumed that all GB distribution network components must be replaced on a like for like basis at a total cost of £22.2bn. However, there is a very wide range in cost across different sensitivities, depending on the share of iron/steel pipeline that needs replacing, as well as the gas meters and detectors. A range of £7.7 to £26.7bn has been calculated [5].

Therefore, the total estimated cost for the repurposed distribution network and the purpose-built hydrogen transmission network ranges between £16.1bn and £35.1bn for GB as a whole[18].

A separate study (BEIS) considers the potential requirements for network replacement in Scotland. We have summarised the assumptions in Table 9 below [1].

Table 9: Potential network replacement requirements in Scotland

Total Length of All Pipeline Mains in 1999 (km)	13447*
Length of Iron Mains in 1999 (km)	6384
Estimated Iron Mains requiring Replacement after IMRP (km)	319
Length of Steel Mains in 1999 (km)	1043
Estimated Steel Mains requiring Replacement (km)	1043

**the remainder is made up of polyethylene (PE) pipes.*

With regards to pipeline cost, the study (BEIS) provides the following formulae to estimate CAPEX and OPEX.

- The capital cost (CAPEX) of pipeline and compressors are calculated as
  - $Pipeline\ cost\ £m\mathrm{T}km = 0.064\ x\ Pipeline\ diameter\ inches - 0.2799$
  - $Compressor\ cost\ £m = 0.3114\ x\ Compressor\ size\ MW + 1.3869$
- The annual fixed OPEX is calculated as 5% and 15% of pipeline and compressor capital cost respectively.

Two underlying assumptions are that 100% of steel pipeline will require replacement post IMRP, and that 100% of the iron mains requiring replacement are assumed to be within the low pressure tier (i.e. that the IMRP is replacing all iron pipes that are not low pressure) [1].

Below we summarise additional selected cost items found for network replacement or reinforcement (BEIS) [1]:

Table 10: Additional selected cost items for network replacement or reinforcement

[18] Calculated as: £8.4bn (transmission) + £7.7bn (distribution, low end estimate) and £8.4bn (transmission) + £26.7bn (distribution, high end estimate)

Cost of gate metering station with Odourisation (£ / meter)	£ 2.98
Cost of network survey (£ / meter)	£ 1.89
Long-run average total cost for domestic gas meter (£ / meter)	£ 151.43
Long-run average total cost for non-domestic gas meter (£ / meter)	£ 2,477.23
Long-run average total cost for gas detector (£ / detector)	£ 68.34
Cost Gas Meter Fittings (£ / meter)	£ 50.00

Table 11: Pipeline replacement and reinforcement cost assumptions

Pipeline replacement / reinforcement costs	**Cost**	**Assumption**
Cost of replacing/reinforcing Low Pressure Iron / Steel Pipelines (£ / km)	£200,000	Assuming 127mm (5") pipe
Cost of replacing/reinforcing Medium Pressure Iron/ Steel Pipelines (£ / km)	£350,000	Assuming 229mm (9") pipe
Cost of replacing/reinforcing Intermediate Pressure Iron / Steel Pipelines (£ / km)	£400,000	Assuming 268mm (10.5") pipe

Furthermore, BEIS estimates the following 5 cost items to be the most significant for distribution network repurposing (each between 10-15% of total cost, assumed at the reference case of £22.2bn for distribution network upgrade) [1]:

1. Replacing domestic gas meters (excl. installation) - £3,519,494,101
2. Labour and fitting for installation of domestic gas meters - £3,486,179,700
3. Replacing gas detectors (excl. installation) - £3,176,745,981
4. Replacing low pressure steel pipes - £3,109,431,439
5. Additional 7 bar pipeline required due to reduction in line pack energy - £2,450,921,086

2.2.4. Hydrogen storage

Hydrogen storage can typically be grouped into 2 main categories:

- Centralised storage
- Distributed storage

BEIS' Hydrogen supply chain evidence base report summarises the main categories as [1]:

- **Centralised storage** involves very large volumes stored seasonally or strategically
  - For seasonal storage the volume would be filled during months of low demand (summer) and then emptied into the Transmission system during times of high demand (winter). This storage allows the production capacity of the whole hydrogen system to be sized based on the average monthly demand rather than the peak monthly demand.
  - Salt caverns would provide the majority of this storage, and potentially other geological features that are being explored. Imported Liquid Hydrogen could also provide additional storage at Import Terminals (akin to LNG Import Terminals).
- **Distributed storage** would be situated close to the high demand locations to help supply any localised peak demand. This is most likely to be intra-day rather than intra-seasonal.

- Linepack storage in the transmission system*
- Large above ground vessels / tanks
- Line packing in the distribution network

**Linepack refers to the volume of gas that can be stored within the pipes. The amount of storage can be adjusted by changing the compression levels within the pipes.*

As noted within the H21 study, Scotland has very limited salt cavern resources (centralised storage) available for hydrogen storage [13]. The evidence presented here will therefore focus on storage solutions that are viable in Scotland.

Evidence on technical specifications relating to hydrogen storage

For larger scale centralised hydrogen storage, several studies suggest salt caverns are the best solution, as they are extremely gas tight and the salt is suitable for storing hydrogen. They are also expected to be the most cost-effective storage solution. However, Scotland has very limited salt cavern resources available for hydrogen storage (H21). The H21 North of England report proposes ammonia production as a technically viable solution for inter-seasonal hydrogen storage in Scotland (centralised storage). This would involve converting the produced hydrogen into ammonia, (which is easier to store) and re-converted to hydrogen for use for better ease of storage. The authors further suggest that the centralised storage would be located at Dundee to ensure storage was near the largest urban demand centres (Glasgow and Edinburgh) and next to a port for potential export [13].

Across the UK, all three of National Grid's net zero Future Energy Scenarios say hydrogen storage requirements will reach 15 TWh annually (centralised and distributed storage). This level is comparable to energy stored in gas today, but the study notes that due to the lower energy density of hydrogen compared with methane, larger storage volumes will likely be required [10].

In comparison, the CCC estimates a far lower need for hydrogen storage across its main hydrogen scenarios (it is important to note that the CCC's heat decarbonisation scenarios are 'low carbon', compared with 'net zero' in National Grid's scenarios mentioned above and cover whole system scenarios with negative emissions that may offset heat related emissions elsewhere). Their estimates range between ~130 GWh to 330 GWh of hydrogen storage for Great Britain. CCC assumes that Scotland will require hydrogen storage capacity of between 10.1 - 26.1 GWh [4].

Evidence on costs relating to hydrogen storage

Regarding above ground storage (distributed storage) BEIS' Hydrogen supply chain evidence base makes the following observations [1].

- High pressure storage (~42.5 MPa) is currently more than 4 times more expensive than medium pressure storage (~5 MPa). This is primarily due to the additional cost of the high-pressure cylinders, and the requirement for compression.

- The study suggests it is unlikely that the compressed/high pressure would be chosen over the medium pressure option unless the area of demand was a long way from a transmission pipeline.

The table below summarises the cost assumptions presented in that study. The costs vary between a single decant per day (to meet an evening peak, 1 cycle) and two decants per day (to meet morning and evening peaks, 2 cycles). Across all scenarios there is a variable OPEX of 0.0529kWh of electricity demand for each kWh of hydrogen stored.

Table 12: Above ground storage costs, 333MW H2 stored, base scenario

	Capex £/kWh stored	Fixed Opex £/kWh stored	Daily Cycles
Medium pressure	11.45	0.34	2
High pressure	54.75	1.06	1
High pressure	73.85	1.69	2

BEIS' Hydrogen supply chain evidence base suggests there is significant linepack storage (distributed storage) available in the current natural gas transmission system, whereas linepack in the distribution system is limited. There are no specific cost assumptions referenced in relation to linepacking in the study. However, it notes that the cost of building additional pipeline to reach the same level in linepack energy (given the reduced energy density of hydrogen compared with natural gas) will be significant [1].

Across the remaining evidence base, there are no more data that refer to specific cost implications for hydrogen line packing.

2.2.5. Hydrogen system comparison with other decarbonisation scenarios

Across the evidence base identified under this study, three sources were identified that compare decarbonisation of heat scenarios using hydrogen against other energy sources[19]. The comparison mainly focusses on the electrification of heat versus hydrogen use for heating across all studies. Note that these studies do not necessarily model scenarios that are compatible with Scotland's statutory climate change targets, which became law in 2019.

1. **Analysis of Alternative UK Heat Decarbonisation Pathways – CCC [4]**. The study assesses the technical and cost performance of alternative decarbonisation scenarios for low-carbon heating in 2050. The scenarios include: hydrogen pathway, electric pathway, hybrid[20] (electricity & hydrogen) pathway.

   The Hybrid pathway is identified as the most cost-effective decarbonisation pathway, although the costs across all the low carbon pathways are relatively similar (the cost difference is within 10%). The table below summarises the system level costs (CAPEX & OPEX) for different levels of CO_2 emissions from heating (in million tonnes, MT).

[19] These sources predate the UK's adoption of net zero emissions targets by 2050.
[20] The hybrid pathway is based on the application of combining the use of gas and electric heating systems, i.e. hybrid heat pumps.

Table 13: CCC - system level costs for different levels of CO_2 emissions, £bn / year

	30 MT CO_2 emissions	**10 MT CO_2 emissions**	**0 MT CO_2 emissions**
Hybrid	£81.6 bn	£84.8 bn	£88.0 bn
Electric	£87.8 bn	£89.5 bn	£92.2 bn
Hydrogen	£89.6 bn	£90.2 bn	£121.7 bn*

**In Scotland's case, the country will effectively require zero carbon heat in buildings, due to its ambitious and legally binding greenhouse gas emissions targets.*

The key reason why the zero-emission hydrogen pathway (0MT) is much higher in cost, is the hydrogen production method required (there is a shift from ATR to electrolysers). At this stage, electrolysis is a much more expensive production option. Therefore, the study argues the cost-effective decarbonisation of heat may require electrification. The study also suggests that unless carbon capture rates involved in the production of hydrogen via gas reforming can reach close to 100%, then decarbonising via hydrogen would require significant investment in zero-carbon electricity generation in order to produce hydrogen via electrolysis, which increases the costs of hydrogen scenario significantly above hybrid and electric pathways.

CCC also make a point that importing low-cost hydrogen could potentially make the hydrogen pathway cost competitive against electrification pathways; Imports of hydrogen could also reduce the need for UK based hydrogen storage.

2. **Cost analysis of future heat infrastructure options – National Infrastructure Commission [11]**. The study presents an analysis of the cost of decarbonising the UK's heat infrastructure, specifically space heating and hot water. The different pathways include electrification of heat, decarbonisation of the gas grid with biomethane and repurposing of the gas grid to deliver low carbon hydrogen, or a combination of these approaches.

   The table below summarises the annualised CAPEX and OPEX costs across the different pathways. The Hybrid gas-electric pathway includes the use of biomethane injection (up to 67 TWh per year, but the authors note that there is significant uncertainty around actual availability).

Table 14: Annualised CAPEX and OPEX costs across the different pathways, £bn / year

	Electrification (heat pumps)	**Electrification (direct electric)**	**Hybrid gas-electric**	**Hydrogen grid**
Annualised costs in 2050: CAPEX	£21bn	£5bn	£15bn	£8bn
Annualised costs in 2050: OPEX	£19bn	£33bn	£25bn	£28bn
Annualised costs in 2050: Total	£40bn	£38bn	£40bn	£36bn

The study concludes that re-purposing the gas grid to deliver low carbon hydrogen is the lowest cost option under most scenarios studied if this option can be delivered safely and at scale. However, the authors note that there is greater uncertainty over the hydrogen pathway compared with the electrification and hybrid options. Cost-effective hydrogen heating is highly likely to be reliant on carbon capture and storage (CCS), which the authors say is also as yet unproven, and carries substantial cost uncertainty.

3. **Decarbonisation of heat and the role of 'green gas' in the United Kingdom – The Oxford Institute of Energy Studies [9].** This study draws on a number of published studies of the economic and technical feasibility of 'green gas' and seeks to draw out overall conclusions.

   The main hydrogen scenarios considered in this study look at a 100% hydrogen system that involve the use of hydrogen produced from methane, via steam reforming combined with carbon capture and storage (CCS). Therefore, when the authors reference 'green gas' they are referring to hydrogen in this case. They conclude that the costs of this option are at any rate not clearly worse and could be significantly lower than the electrification option. This also factors in the relevant storage and other costs, and the cost of upgrading the housing stock.

   However, the study also suggests that there are significant uncertainties on the cost implications of a hydrogen system that is based on methane reforming and CCS. The authors argue that although hydrogen production takes place on a wide scale today, the distribution of hydrogen to residential consumers, and the capture of the CO_2 generated in hydrogen production have not been tested at scale. Similarly, although CO_2 capture takes place at many locations in the world today, large scale CO_2 capture from fossil fuel combustion is less well understood.

   The main challenge therefore does not lie with the individual technologies, but by the fact that they have not been tested and demonstrated in combination at scale.

To summarise, the studies above all suggest that a pure hydrogen system based on reformed hydrogen production from methane, coupled with CCS ('blue' hydrogen) may be cost competitive with an electrified system. There are, however, two important elements to consider.

- There are significant uncertainties and sensitivities around the economics of 'blue' hydrogen production at scale. There is very little evidence today on the use of CCS technology alongside methane reformation, which bear operational and economic uncertainties.
- A pure hydrogen system based on current 'blue' hydrogen production technology can only guarantee a (significant) partial emissions reduction. The evidence above suggests that **to achieve a zero emissions system via the use of electrolysis to produce the hydrogen would significantly increase the system costs**.

Pursuing a 'low carbon' 'blue hydrogen pathway would therefore carry policy and economic implications with regards to statutory net zero targets, as remaining emission reductions would be required to come from other sources.

2.3. RQ3: What are the system level costs and technical requirements of hydrogen use for heat associated with blending?

2.3.1. Summary

This section summarises evidence on the costs and technical requirements at the system level related to enabling the use of hydrogen for heating in buildings.

Within this section, we consider:

- changes in infrastructure at the system level required, focusing on transmission & distribution networks
- a blended hydrogen system
- hydrogen production and storage are covered in section 2.2. (RQ2)

The evidence summarised in this section has been extracted from the key sources across our Final Evidence Base outlined in Table 1 in Section 2.

Evidence on the system level cost impacts and technical considerations of using hydrogen for heat in buildings

Below, we summarise the key conclusions from existing evidence around the costs implications and technical considerations at the system level of using hydrogen for heat in buildings. Hydrogen blending is looked at in more detail in this section.

2.3.2. Transmission & distribution

Evidence on technical specifications relating to T&D

In their model of UK energy systems, Quarton and Samsatli [16] found that gas grids are ready for partial hydrogen injection now. They suggest this is especially likely for the distribution networks, which operate at lower pressure levels. However, certain types of compressor on the transmission networks may need replacing to accommodate hydrogen's lower energy density [16].

Quarton and Samsatli [16] highlight a particular challenge in blended gas systems around metering. Currently, gas meters measure the gas by volume. As natural gas flowing through pipes today has a consistent energy content, this has not been a challenge. However, as hydrogen blended with natural gas reduces the energy delivered per unit volume, this method will no longer be viable, as the exact proportion of natural gas and hydrogen will fluctuate. A possible solution that is being tested is using gas calorific value to measure final consumption.

The HyDeploy demonstration project seeks to establish the level of hydrogen that can be safely blended with natural gas for transport and use in a UK network. The project aims to establish a maximum permissible hydrogen concentration in a blend, and it is expected that a blend concentration between 10 and 20% by volume will be possible. A key milestone of the project is that the HSE made an exemption to the hydrogen requirements of the Gas Safety (Management) Regulations to allow 20% hydrogen to be injected into the grid at Keele University campus. Two key observations that were made are that [8]:

- the network and components, such as control valves, would likely maintain operational integrity throughout the blended trial
- relating to operational procedures of the gas network, no major changes would be required to accommodate the blend

Within its latest business plan, SGN highlights three main reasons why blending 2% hydrogen into the National Transmission System would be possible and desirable.

- It burns like natural gas and domestic consumers will not notice the difference.
- Only minor, if any, changes to combustion systems for most industrial and commercial users will be required.
- A 2% blend provides stimulus for both Hydrogen and CCS at strategic hubs

SGN's plan also notes that while it may be possible to operate a transmission system with different hydrogen blends, this has not yet been proven. They say that increasing the concentration of hydrogen in the Local Transmission System needs to be investigated carefully, as transporting gas blends rich in hydrogen would be very different from transporting natural gas. And the higher the pressure in the pipes, the greater the difference from natural gas.

SGN note that a possible solution to address the transportation of hydrogen/methane blends within the existing 36 UK gas system is to "de-blend" (i.e. separate) the mixed gas streams at scale on a regional basis. There is no proof yet if this concept would be technically and economically feasible [15].

Evidence on cost relating to T&D

We found very limited evidence on the cost implications for introducing hydrogen blending into a fully natural gas based system. While many sources suggest that gas networks will require little to no upgrades for a hydrogen blend (typically, up to 20%), there were no definitive statements uncovered.

The paper by Quarton and Samsatli [16] highlights that the assumption that blending hydrogen into a gas network will be less costly from a infrastructure upgrade point of view than 100% conversion may not necessarily be true (although the authors note that they would not conclude this with high certainty). They argue that while partial injection involves limited upgrades, full conversion assumes lower costs for injection and network monitoring. The examples they highlight are the UK GDN projects HyNet and H21. The HyNet (blending) project was estimated to cost £3.60 per kW of gas grid capacity, while the H21 (full conversion) project was projected to cost £3.40 per kW of gas grid capacity. However, the authors acknowledge that the H21 project assumes the Iron Mains Risk Reduction Programme will have replaced lines with polyethylene (the costs of which are therefore not considered), and it does not include costs for the surveying and safety checks of the pipelines [16].

2.4. RQ4: What are the roles & responsibilities of different stakeholders today in implementing hydrogen use for heat in buildings?

This section considers the different roles and responsibilities that are key to implementing hydrogen deployment.

Before being able to clearly identify these roles and responsibilities, a decision needs to be made on whether or not hydrogen will actually play a role in heating, and if so, at what scale. Further actions are required to enable this decision to be made.

If the decision is made that hydrogen will be used for heating, then key roles, actions, and timescales for different stakeholders need to be clearly set out to realise deployment. While the focus of this study is on the use of hydrogen for heating, many of the actions and responsibilities described below will link with a wider adoption of hydrogen use across the economy. It is important to note that – unlike the previous sections of this chapter – this section is primarily based on Delta-EE views and opinions, rather than from the literature review. Delta-EE is able to draw on wide experience working and engaging with many of the relevant stakeholders listed below.

Alongside the roles and actions required for implementing hydrogen deployment, we connect these roles and actions to the key stakeholders that would be responsible. Finally, we draw out and describe some important roles and responsibilities of Scottish Government.

Deciding whether hydrogen should play a role in heating

Before rolling out hydrogen for heating, a point must be reached to allow a decision on whether hydrogen should indeed play a role in heating – taking into account safety, economic, environmental and societal factors and more. To do so, Scottish and UK Governments need to work with and engage a wide range of stakeholders.

Much research must be carried out to provide Governments with enough certainty to make a decision on hydrogen use for heat. A lot is already happening in the UK. BEIS' Hy4Heat programme is delving into the opportunities, challenges and risks associated with hydrogen for heating – a scheme that is being closely watched internationally. The UK gas network operators are exploring key aspects on the transmission and distribution of hydrogen through trials and studies, concerning its feasibility, safety and cost. But there are many more stakeholders that will also be crucial for providing input and research efforts for Government:

- Consumers
- Local authorities
- Public bodies (e.g. HSE, universities, Innovate UK, Citizen's Advice, Ofgem, GEMA)
- Associations (e.g. HHIC, SHFCA, ENA)
- Appliance manufacturers, kit and infrastructure suppliers
- Energy suppliers
- Network operators

And if hydrogen will indeed be used for heating buildings, the scale at which it will be deployed is another key consideration; ranging from a regional, low volume scale, over large pure hydrogen hubs to a national rollout. The timing and scale of hydrogen deployment will likely vary by region and Nation across the UK.

Roles and responsibilities of different stakeholders involved in implementing hydrogen for heating

In this section it is assumed that a decision has been made to go ahead with hydrogen rollout for heating to some degree. In the table below, we summarise roles and responsibilities of different stakeholders who would be involved in realising hydrogen for heating.

Table 15: The roles and responsibilities of the different stakeholders involved in hydrogen for heating

Roles and actions for implementing hydrogen deployment for heating	Responsible stakeholders
Stimulating the hydrogen heating industry **How?** • Introducing policies regulations • Setting visions and targets • Funding innovation and research • Providing financial support **When?** Near-term.	• Scottish Government • UK Government • Local authorities • Ofgem
Ensuring that the industry and consumers are ready for the hydrogen heating transition **How?** • Setting standards • Protecting consumers • Facilitating innovation and dialogue • Informing and educating consumers • Informing and educating industry • Ensuring compliance • Supplying kit and infrastructure **When?** Near-term.	• Local authorities • Public bodies (e.g. HSE, universities, Innovate UK, Citizen's Advice, Ofgem, GEMA) • Associations (e.g. HHIC, SHFCA, ENA) • GDNs and DNOs • Commercial companies
Ensuring that an adequate skills base exists to implement the hydrogen heating transition in Scotland & across UK **How?** • Providing training and incentives • Long-term planning • Facilitating dialogue • Protecting and representing skill areas **When?** Near to medium term.	• Scottish Government • UK Government • Associations (e.g. technicians, installers)

Producing hydrogen – including both the local production of hydrogen as well as the importing of hydrogen. **How?** • Supplying kit and infrastructure • Innovating business models • Funding innovation and research • Providing financial support • Supporting CCUS • Securing energy supply **When?** Near to medium term.	• Commercial companies • Scottish Government • UK Government • Ofgem
Storing hydrogen **How?** • Supplying kit and infrastructure • Providing financial support • Securing energy supply **When?** Near to medium term.	• GDNs • Commercial companies • Local authorities • Scottish Government • UK Government • Ofgem
Transmission & distribution of hydrogen **How?** • Supplying kit and infrastructure • Providing financial support • Securing energy supply **When?** Near to medium term.	• GDNs • National Grid • Commercial companies • Local authorities • Scottish Government • UK Government • Ofgem
Ongoing system operation **How?** • Balancing supply and demand • Regular maintenance • Ensuring safety **When?** Long term.	• National Grid • GDNs • Ofgem

Key roles and responsibilities of the Scottish Government:

Below we draw out actions for Scottish Government that will be crucial for enabling a rollout of hydrogen for heating use.

1. Stimulating the industry - providing stimulus (regulatory and fiscal) by signalling political ambition and commitment. Making funding available to support deployment (as well as for evidence gathering and mitigating financial risks) and introducing clear policies and regulations will be critical.

2. Ensuring that consumers and the industry are ready for the hydrogen heating transition - providing the necessary support mechanisms to the stakeholders (e.g. local authorities, GDNs, installers etc.) responsible for ensuring a smooth transition from the use of natural gas to hydrogen for heating (similar to the transition from town gas to natural gas). Through collaboration with other stakeholders (e.g. local authorities, associations, Citizen's Advice) ensure consumers are protected, informed and educated on the topic.
3. Ensuring an adequate skills base - making sure enough skilled individuals (e.g. installers, technicians, planners) are available to implement a hydrogen rollout. This will involve long term planning and providing suitable training programmes and incentives. Furthermore, Scotland has an advantageous position to leverage North Sea oil & gas engineering competencies for hydrogen production and storage. But some of this skills base will likely require converting and re-training, which will need to be carefully planned and managed.

But before the actions above are implemented, Scottish Government should continue to gather evidence, support research and encourage trials to determine whether hydrogen is suitable and desirable for heating use. Scotland has world leading carbon reduction targets, and the potential for hydrogen to underpin heat decarbonisation must be further defined and quantified. A clearer understanding of comparative costs, safety concerns and impacts on customers and the environment from hydrogen heating will be key to optimising Scotland's journey to net-zero.

3. Conclusions and recommendations

In this project, a wide range of evidence on the use of hydrogen for heat in buildings (from over 100 pieces of literature across various sources) was considered. Sixteen pieces of literature uncovered in this project were deemed to be most relevant and were then prioritised for an in-depth review, upon which the evidence presented in this report was extracted.

Below, we:

- Summarise the headlines findings from the evidence base gathered in this project
- Comment on the availability & quality of evidence and sources found
- Draw out relevant recommendations and lessons for Scotland

As with the previous sections of this report, our conclusions are grouped into building level and system level, and for each level we focus on cost, safety, and technical aspects.

3.1 Headline findings from the evidence base

Building level headlines

Technical specifications

1. According to available evidence, a 20% hydrogen blend can be safely used in domestic appliances without the need of upgrade or replacement. Therefore, no significant technical amendments will be needed to accommodate up to a 20% hydrogen blend in buildings.
2. For 100% hydrogen conversion, some of the internal components of the existing natural gas boilers (such as valves, burners and internal control systems) are not suitable for use with hydrogen. Therefore, existing gas appliances will need to be replaced with hydrogen ready ones.

Cost implications

3. Total cost of converting a property to 100% hydrogen is estimated to be £3,000 - £4,000. This range in costs includes the costs for appliances (mainly heating systems, but also decommissioning and replacing appliances such as gas hobs or ovens), piping and installation. For the hydrogen boiler itself, existing literature suggests a price range of £700 - £2,500 for the end customer, without installation costs included.
4. Limited evidence was uncovered during the literature review process for this study on the topic of heating cost implications from hydrogen use; it suggests that the retail prices of fuel might increase under both blending and full conversion. Maintenance costs for hydrogen boilers are estimated to be ~£120 per year, which is slightly higher than the maintenance costs for existing natural gas boilers today.

Safety

5. For a 20% hydrogen blend with natural gas, existing appliances can continue being used without modification or replacement. Whilst not explicitly stated in the literature, it is generally *assumed* that internal piping (i.e. the piping between the gas meter and the gas boiler) is also safe for use with a 20% hydrogen blend without the need for upgrade or change.

6. In the case of 100% conversion to hydrogen, appliances will need to be replaced with hydrogen ready ones, as the appliances are not designed to run on this fuel. Piping in buildings will highly likely also need replacement, to avoid the risk of embrittlement.

System level headlines

Technical aspects for production of hydrogen

1. Methane reformation *without* carbon capture is a well-established technology today. However, the economic and technical feasibility of hydrogen production *with* carbon capture is not proven at scale.
2. Large scale production of hydrogen via electrolysis technology is unproven and considered unfeasible today, due to high costs.
3. Several sources agree that large scale low carbon hydrogen production via methane reformation with carbon capture is the most optimal solution for the UK[21] However, there is disagreement on whether steam methane reformation (SMR) or auto-thermal reforming (ATR) is the best technology to deploy. The main arguments are:
    a. SMR is a mature technology and widely used across the refining and petrochemical industries.
    b. ATR is expected to display superior performance in terms of cost, energy efficiency and carbon capture rate. However, it is a less mature technology and not proven for large scale production.

Technical aspects for transmission and distribution of hydrogen

4. For the transmission of pure hydrogen, evidence suggests a new purpose-built pipeline needs to be constructed (the ENA suggests this equates to £8.4bn for a new GB-wide hydrogen transmission network).
5. Transporting pure hydrogen in distribution networks requires polyethylene pipes. Hydrogen blends up to 20% require minimal changes.

Technical aspects for hydrogen storage

6. For larger scale centralised hydrogen storage, salt caverns are expected to be the best solution. However, Scotland has very limited salt cavern resources available for hydrogen storage. A proposed solution for Scotland is to store hydrogen at scale as ammonia.
7. The reduced energy content per unit volume of hydrogen compared to natural gas means additional pipeline will be required to store the same amount of energy in the distribution network.

Cost implications for production of hydrogen

8. Several sources consider hydrogen production via methane reformation and carbon capture to be the lower cost option for large scale hydrogen production in the UK, compared with electrolysis. However, there are residual emissions from methane reformation.
9. Only one source, BEIS, projects and compares the CAPEX and OPEX costs of hydrogen production via reformation and electrolysis. Comparisons can only be made between the CAPEX costs (as the study does not forecast electrolyser OPEX costs) and it suggests that by 2050, electrolysers will be cost competitive with reformers on a CAPEX basis:

[21] However, it is important to note that the sources primarily considered the previous emissions reduction targets of 80% (as opposed to net zero by 2050), as this could influence this conclusion.

a. Reforming: CAPEX costs in 2050 range from £361 – 378 / kW
b. Electrolysis: CAPEX costs in 2050 range from £340 – 700 / kW

Cost implications for transmission and distribution of hydrogen

10. There is limited but robust evidence on the costs relating to the transmission and distribution of hydrogen via pipelines. For the establishment of a purpose-built hydrogen transmission network, costs are estimated to be £1 million to £1.46 million per kilometre of pipeline. For the whole of Scotland[22], this would equate to £27.4 - £40.0 billion.
11. Cost assumptions for replacing or reinforcing the distribution network (iron and steel pipes) to carry hydrogen vary according to pipe diameter as outlined in the table below.

Type of pipe	£/km	Cost for whole of Scotland
127mm (5") pipe	£200,000	£5.5 billion
229mm (9") pipe	£350,000	£9.6 billion
268mm (10.5") pipe	£400,000	£11.0 billion

Cost implications for hydrogen storage

12. Little evidence was found on hydrogen storage costs. The costs will be influenced by the storage type, which can be centralised (for inter-seasonal storage) or distributed (for intra-day storage). More research is needed to explore this area further.
13. Above ground storage facilities – which are a viable centralised storage option for Scotland – can be grouped into high pressure and medium pressure. High pressure storage (~42.5 MPa) is currently over 4 times more expensive than medium pressure storage (~5 MPa). This is primarily due to the additional cost of the high-pressure cylinders and the requirements for compression.

High level findings from evidence that compares scenarios for decarbonising heat based on using hydrogen versus fully electrifying heat demand:

- Limited but robust evidence suggests that hydrogen systems based on reformation with carbon capture could compete, or even be more cost effective than systems with a fully electrified heat demand. However, reformation plus carbon capture and storage still has implied carbon emissions and therefore is unlikely to be compatible with Scotland legal climate change targets unless additional abatement can be achieved elsewhere in the economy.
- For a hydrogen system to be zero greenhouse gas emissions, hydrogen would be required to be produced via electrolysis – which evidence suggests would be higher cost by 2050 than the system where heat demand is fully electrified. There could be alternative routes to achieve negative emissions from hydrogen production, for example by using biomass gasification with carbon capture and storage (CCS) to balance residual emissions from fossil fuel reforming.

[22] 17,000 miles of gas network

3.2 Availability and quality of current evidence

At the building level

- We believe the evidence used in this study is high quality and is based on reliable sources (i.e. from Government and public bodies, network companies, peer-reviewed academic studies). It is, however, worth noting that a large share of the evidence base (9 out of 16) is from industry bodies, such as network companies, that have an interest in the hydrogen sector.
- Literature reviewed, in general, aligns well on building level insights. No significant contradictions or differences of opinion were identified. This leads us to believe the evidence and information presented in this study is robust.
- Key gaps identified:
    - In general, little evidence is available that focuses specifically on building level aspects. Many more sources were found that consider the system level – some of which also examine the building level.
    - Very little evidence is available on piping and the respective costs in buildings.
    - Very little evidence is available on the running costs (in particular fuel costs) of hydrogen heating system.
    - Evidence available on hydrogen appliances other than boilers (e.g. gas heat pumps, fuel cells) is limited.

At the system level

- We believe the evidence used in this study is high quality and is based on reliable sources (i.e. from Government and public bodies, network companies, peer-reviewed academic studies)
- Literature reviewed, in general, aligns well on system level insights. Only a few significant contradictions were identified – the contrasting views on hydrogen production methods are highlighted in the key headlines above. This leads us to believe the evidence and information presented in this study is robust.
- Key gaps identified
    - At the transmission and distribution level, most evidence focuses on pure 100% hydrogen conversion. Much less evidence focuses on blending.
    - Little evidence is available on hydrogen storage cost implications and technical requirements.
    - Little evidence is available on transportation of hydrogen outside of pipelines.

3.3 Key recommendations and lessons for Scotland

At the building level

Delta-EE has not identified published literature to date analysing hydrogen conversion at the building level specifically in Scotland. All the evidence found relates to the UK, that report learnings and conclusions from studies, trials and projects in a number of different locations in the UK. No regional differences have been reported in the building stock, heating appliances or pipework between Scotland and the rest of the UK. The currently ongoing H100 project by SGN is expected to provide evidence for hydrogen use at the building level in Scotland in the future.

At the system level

Across the literature studied for this report, Delta-EE has identified some Scotland specific strengths and challenges at the system level value chain. These relate to Scotland's unique position regarding natural resources, skills, and existing infrastructure. They are highlighted in more detail below:

- Scotland's strengths include:
    - Good access to large volumes of natural gas, which is required for large scale production of 'blue' hydrogen (methane reformation with carbon capture)
    - Strategic CO_2 storage capacity offshore to support carbon capture efforts (depleted hydrocarbon storage sites and aquifers)
    - St. Fergus is a key delivery point for gas to the National Transmission System (NTS), which offers country wide hydrogen blending opportunities
    - North East Scotland has a wealth of skills, capabilities and infrastructure from the oil and gas sector that can be leveraged to support hydrogen and renewables development
    - High levels of wind curtailment resource for renewable electricity generation, which in turn can be used for 'green' zero carbon hydrogen production via electrolysis
- Scotland's challenges:
    - Scotland has limited existing centralised hydrogen storage 'resources' (e.g. salt caverns) for intersessional storage. Investments in new infrastructure (above ground storage facilities) or new solutions (converting hydrogen into ammonia) would be required

Final comments from Delta-EE:

In many key areas, Scotland holds a leading position in the deployment of hydrogen at a large scale for heating (and other) uses. Many advanced studies and trials have been carried out in Scotland on 'blue' hydrogen production, alongside carbon capture. Soon, a trial is expected to build evidence on pure 100% hydrogen conversion of a community (H100). As highlighted above, Scotland also has an advantage with regards to resources, skills and infrastructure. All this will provide Scotland with a robust foundation of expertise and evidence, which can be shared and communicated across the country and beyond. This could allow Scotland to showcase its expertise and leading position in the deployment of low carbon hydrogen.

Furthermore, Scotland is in a strong position to explore a key gap identified in this evidence review. There is limited visibility today on the fuel cost implications of using hydrogen for heating. This is in large part due to the absence of real life 'blue' hydrogen production plants and the lack of actual case studies of hydrogen use for heating. By leading the charge on 'blue' hydrogen production, Scotland could be well positioned to lead the evidence building on the potential final cost of hydrogen to end users.

Lastly, the technical and engineering skills base centred in Scotland from the oil and gas sector could be leveraged and converted to hydrogen expertise, which could enable Scotland to become a global leading expert in hydrogen very quickly. Developing the required skills, capabilities and expertise quickly could enable Scotland to be viewed as a global leader in hydrogen.

4. References (Final Evidence Base)

1. BEIS (2018), *Hydrogen supply chain evidence base*
2. Sunny et al (2020), *What is needed to deliver carbon-neutral heat using hydrogen and CCS?*
3. BEIS, Pale Blue Dot Energy (2019), *Acorn hydrogen feasibility study*
4. CCC (2018), *Analysis of Alternative UK Heat Decarbonisation Pathways*
5. ENA (2020), *Hydrogen: Cost to customer*
6. NGN (2016), *H21 Leeds City Gate*
7. SGN (2020), *Aberdeen Vision Project*
8. Cadent, NGN (2018), *HyDeploy Project*
9. The Oxford Institute for Energy Studies (2018), *Decarbonisation of heat and the role of 'green gas' in the United Kingdom*
10. National Grid (2020), *Future Energy Scenarios*
11. National Infrastructure Commission (2018), *Cost analysis of future heat infrastructure options*
12. BEIS (2019), *Hy4Heat Progress Report*
13. NGN, Cadent (2018), *H21 North of England Report*
14. Cadent (2018), *HyNet North West: from vision to reality*
15. SGN (2019), *RIIO GD2 Business Plan Appendix*
16. Quarton and Samsatli (2020), *Should we inject hydrogen into gas grids? Practicalities and whole-system value chain optimisation*

Annexes

Annex 1: Long list of research questions and sub questions

RQ1: What are the safety concerns, costs and technical requirements associated with hydrogen use for heat at building level?

1. What changes are required to convert buildings from natural gas to hydrogen for a blended / 100% hydrogen system?
2. What are the cost implications for end customers of a blended / 100% hydrogen system? Considering:
    a. Internal piping / building upgrades
    b. Different appliance types
    c. Cost of fuel (Retail costs including taxes)
3. How safe is hydrogen for heating end uses in buildings?
4. What is the state of development of hydrogen appliances?
5. What are the potential operational and maintenance issues with hydrogen appliances?
6. What safety issues arise from hydrogen appliances?
7. How many and which types of safety trials / feasibility studies have been carried out on using hydrogen in appliances?
8. How technically feasible is hydrogen heating in buildings?
9. At what levels are consumer awareness and acceptance of hydrogen use for heating?
10. What are the potential timescales?
11. International lessons for Scotland?

RQ2: What are the system level costs and technical requirements of hydrogen use for heat associated with 100% conversion?

1. What infrastructure is required for a 100% hydrogen system?
2. Which technologies, techniques, and energy sources can be used to produce hydrogen (in Scotland)?
3. How can hydrogen be stored (in Scotland)?
4. How ready / technically feasible is a 100% hydrogen system?
5. What are the cost implications of a 100% hydrogen system?
6. Which elements of the existing gas transmission & distribution network can already support a 100% hydrogen system?
7. What upgrades to the existing system are needed to support a 100% hydrogen system? Associated costs?
8. How many and which types of safety trials / feasibility studies have been carried out on conversion to a 100% hydrogen system?
9. Comparison of electrification and hydrogen whole system costs to decarbonise heat
10. What does the actual system conversion entail on the day? (I.e. Street by street? Area? What is the disruption?)
11. What are the potential timescales for a 100% hydrogen system?
12. International lessons for Scotland?

RQ3: What are the system level costs and technical requirements of hydrogen use for heat associated with blending?

1. Which elements of the existing gas transmission & distribution network can already support a blended hydrogen system?
2. What upgrades to the existing system are needed to support a blended hydrogen system?
3. Which technologies, techniques, and energy sources can be used to produce hydrogen (in Scotland)?
4. How can hydrogen be stored (in Scotland)?
5. What are the cost implications of a blended hydrogen system?
6. How technically feasible is a blended hydrogen system?
7. What are the metering implications of a blended hydrogen system?
8. How many and which types of safety trials / feasibility studies have been carried out on conversion to a blended system?
9. Comparison of electrification and hydrogen whole system costs to decarbonise heat
10. What does the actual system conversion entail on the day? (I.e. Street by street? Area? What is the disruption?)
11. What are the potential timescales for a blended hydrogen system?
12. International lessons for Scotland?

RQ4: What are the roles & responsibilities of different stakeholders today in implementing hydrogen use for heat in buildings?

1. Which stakeholders are involved / influence decision making in implementing hydrogen use for heat at the system level?
2. Which stakeholders are involved / influence decision making in implementing hydrogen use for heat at the building level
3. What are the implications of a blended / 100% hydrogen system on the on the skills base required to install, service and operate hydrogen heating systems?
4. Which stakeholders are responsible for ensuring an adequate skills base exists for supporting a hydrogen system?

Annex 2: Literature review methodology

Step 1: Gathering literature

- Use the defined research questions and sub questions to formulate search terms.
- Carry out the initial search for literature using the various search terms to establish a long list.
- Use the following simple criteria to limit the breadth of literature gathered at this stage:
    - Publish date: 2015 or later
    - Geographic coverage: Includes the UK / primarily focuses on the UK
    - Automatically include flagship governmental studies examining hydrogen for heat use in buildings
    - Automatically exclude literature that cover out of scope hydrogen topics, such as transport and industrial demand.
- For all literature found, capture the following high-level information:
    - Title
    - Organisation
    - Date
    - Geography
    - Transparency of methodology / approach
    - Bias / objectivity of source
    - Topic – [*System level, building level or both**]
    - System coverage – [*Does the source cover the whole system or building level value chain*, or just parts of it?]*
    - Scale conversion – [*Does the source consider a blended or pure hydrogen system?*]
    - Scenarios included? – [*Does the source consider different hydrogen for heating scenarios?*]
    - Scenario timeframe – [*If the source considers scenarios, what is the time horizon?*]
    - Comparison with electrification? – [*Does the source compare hydrogen to electrification or other forms of heat decarbonisation?]*

*See page tk for definition of system level and building level value chain

Step 2: Literature screening [1. Filter]

Use the following criteria to **include** or **rule out** literature sources that make the short list. The long list makes up 133 sources.

Criteria applied for inclusion (see table below for summary):

- Geography: include ALL sources that cover Scotland. Include UK sources with the best coverage. See next point.
- Coverage:
    - Include UK source that cover ‘building level’ AND ‘whole’ system coverage
    - Include UK source that cover ‘both’ AND ‘whole’ system coverage
    - Include UK source that compare hydrogen to electrification or other forms of heat decarbonisation
    - Include UK flagship governmental (e.g. BEIS) studies that cover ‘system’ AND ‘whole’
- Recentness: include all source that have been published in 2018 or later.

Geography	Filter	Number of sources	Number of sources published in 2018 or after

Scotland	None	22	14
UK	'Both' AND 'Whole'	15	12
UK	'Building' AND 'Whole'	2	2
UK	Comparison to electrification or other forms of heat decarbonisation	+6 (3 covered above, 9 in total)	+5 (3 covered above, so 8 in total)
UK	Flagship governmental (e.g. BEIS) studies that cover 'system' AND 'whole'	+6 (1 covered above, so 7 in total)	+6 (1 covered above, so 7 in total)
	TOTALS	51	**39**

Step 3: Mapping & describing
For each piece of literature that passes the screening stage, we:

- Provide a short paragraph summary of the scope of the study.
- Pull out relevant key findings that are contained within the Executive summary, Abstract or Introduction.
- Map which parts of the value chain the source covers at the system level and/or building level.
- Capture whether the source covers safety, cost, or technical aspects.

Step 4: Quality & relevance appraisal [2. Filter]
Following the mapping & describing above, we then prioritise the literature short list using the criteria below. The sources making it through this filter constitute our 'Final evidence base'.
The final filter applies a simple scoring system (0 to 4) that is based on the following criteria:

- Coverage of scope & research questions
- Coverage of the building/system level value chain (favouring sources that look at the in-depth research questions)
- Quality (based on robustness of methodology, impartiality and transparency)
- Repetition of similar findings

The following table describes each score in more detail. Sources that score 2 or 3 make it into the 'Final evidence base'.

Score	Description
3 IN	• Very good coverage of scope & research questions (min. 2 aspects of; safety, cost or technical). • Very good coverage of building/system level value chain (covering in-depth questions in detail, specific and unique findings). • High quality, robust, impartial.
2 IN	• Good coverage of scope & research questions (1-2 aspects of; safety, cost or technical). • Good coverage of building/system level value chain (covering in-depth questions in some detail, as well as high level questions. Include unique findings with some repetition). • High quality, robust, may be some bias.
1 CLOSE OUT	• Moderate coverage of scope & research questions. • Limited depth and detail. • Repetition of high-level research questions. • Limited quality and bias.
0 OUT	• Poor/moderate coverage of scope & research questions. • Very limited depth and detail. • Limited quality and bias.

Annex 3: Framework for mapping literature

Building level: Downstream of the Meter Model

Internal piping upgrades

↓

Appliance and controls

↓

Operating & Maintenance

↓

Retail costs including taxes

System level: Hydrogen Value Chain Model

Production

↓

Transportation
(Trucking, shipping, or possible conversion to other energy carriers and then re-conversion [e.g. ammonia])

↓

Storage

↓

Transmission network & Distribution network (inc. metering)

Annex 4: List of tables

Table 1: Final evidence base for evidence review

Table 2: Estimation of costs associated with hydrogen conversion of buildings

Table 3: Cost comparison between a hydrogen boiler and an electric heat pump

Table 4: Actions required for domestic appliances under two different decarbonisation scenarios

Table 5: Electrolysis CAPEX, £/kW installed, base scenario

Table 6: Current reformation CAPEX, £/kW, for different capacities (MW)

Table 7: Future reformation CAPEX, £/kW, for a 1000 MW plant size

Table 8: Reformation OPEX (for all years)

Table 9: Potential network replacement requirements in Scotland

Table 10: Additional selected cost items for network replacement or reinforcement

Table 11: Pipeline replacement and reinforcement cost assumptions

Table 12: Above ground storage costs, 333MW H2 stored, base scenario

Table 13: CCC - system level costs for different levels of CO_2 emissions, £bn / year

Table 14: Annualised CAPEX and OPEX costs across the different pathways, £bn / year

Table 15: The roles and responsibilities of the different stakeholders involved in hydrogen for heating

Glossary

Acorn	Acorn hydrogen feasibility study being led by Pale Blue Dot
ATR	Auto-thermal reforming. This uses oxygen and carbon dioxide or steam in a reaction with methane to produce syngas (hydrogen and carbon monoxide).
Blending	Combining up to 20% hydrogen with natural gas into the mains gas grid.
Blue hydrogen	Hydrogen produced using fossil fuels with Carbon Capture and Storage (CCS)
BEIS	UK Government Department for Business, Energy & Industrial Strategy
CAPEX	Capital expenditure – the funds required to purchase physical goods or assets such as equipment
Cadent	Gas Network Operator for regions of England
CCC	Committee on Climate Change
CCS	Carbon Capture and Storage
DNO	Distribution Network Operator
Electrolyser	A device which creates hydrogen. It uses electrical energy to split water into hydrogen and oxygen.
ENA	Energy Networks Association
GHG	Greenhouse gases
GDN	Gas Distribution Network
GHR	Gas-heated reformer
HyDeploy	A hydrogen demonstration project being carried out by Cadent and NGN.
Hy4Heat	A programme commissioned by BEIS to explore the feasibility of replacing natural has with hydrogen for domestic heating and cooking.
H21	A suite of gas industry projects designed to support conversion of the UK gas networks to carry 100% hydrogen.

H100	SGN project to demonstrate the safe, secure and reliable distribution of 100% hydrogen in their gas network.
NIC	National Infrastructure Commission
NGN	Northern Gas Networks
OPEX	Operating expenses – the ongoing costs of running a system or product
Reformer / reforming	A reformer is a device used to produce hydrogen from methane. Reforming is the chemical process used to do this. The most common types of reforming are autothermal reforming (ATR) and steam methane reforming (SMR).
SGN	The gas network operator for Scotland and parts of southern England
SMR	Steam methane reformation. This reacts methane with steam to produce syngas, which is hydrogen and carbon monoxide.

climate change

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