Department for
Energy Security
& Net Zero

Hydrogen Transport and Storage Cost Report

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Contents

Acronym glossary

Name	Abbreviation
American Society of Mechanical Engineers	ASME
Capital expenditure	CAPEX
Composite overwrapped pressure vessels	COPV
Compressed gaseous hydrogen	CGH2
Development expenditure	DEVEX
European Agreement concerning the International Carriage of Dangerous Goods by Road	ADR
First of a kind	FOAK
Heavy goods vehicle	HGV
Liquefied hydrogen	LH2
Liquid natural gas	LNG
Liquid organic hydrogen carriers	LOHCs
Methylcyclohexane	MCH
National Transmission System	NTS
Operating and maintenance	O&M
Operating expenditure	OPEX
Standard temperature and pressure	STP
Submerged Arc Welded	SAW

Introduction

Low carbon hydrogen will be vital for meeting our legally binding commitment to achieving net zero by 2050. Hydrogen transport and storage will be a critical enabler for the necessary growth of the hydrogen economy. An understanding of the available hydrogen transport and storage technologies, and the technical and cost characteristics of these technologies is a fundamental part of energy market analysis and is needed to analyse and design policy to make progress to net zero.

This report, produced by the Department for Energy Security and Net Zero (referred to hereafter as 'the Department'), presents technoeconomic characteristics of hydrogen transport and storage technologies. The report aims to consolidate existing evidence on hydrogen transport and storage into a single reference point for ease of use and to provide cost estimates for use within the Department, other government departments and externally. It follows a similar report for Hydrogen Production Costs published in 2021[1], which presented estimates of the costs and technical specifications for different production technologies. However, due to the more nascent nature of hydrogen transport and storage technologies, there is less available cost data compared to hydrogen production.

This report does not attempt to be an exhaustive assessment of the technoeconomic considerations of all existing, or potential, hydrogen transport and storage technologies. Nor does the report consider all factors, for example, regulation and funding, that will interact with the technoeconomic factors to influence the growth of hydrogen transport and storage and the hydrogen economy. It is expected that this report can be used for the following:

- To inform policy analysis supporting the design of hydrogen transport and storage business models[2].
- To act as a baseline for understanding first-of-a-kind (FOAK) project costs for proposed transport and storage projects, as well as hydrogen production projects that include plans for limited transport and storage solutions.
- To provide relative hydrogen transport and storage costs for comparison to alternative energy vectors.
- To inform assumptions and inputs into energy system modelling to analyse strategic energy decisions.
- To inform impact assessments and monitoring and evaluation of future hydrogen projects.

The report is structured as follows:

- Section 1 gives an overview of the methods used to produce this report.
- Section 2 provides an overview of the different hydrogen forms.
- Section 3 describes the technical and cost characteristics of storage technologies.
- Section 4 describes the technical and cost characteristics of transport technologies.
- Section 5 provides a brief conclusion on the report.

[1] https://www.gov.uk/government/publications/hydrogen-production-costs-2021 (Accessed November 2023)
[2] Although cost estimates in this report will be used as inputs into analysis for hydrogen policy design, it is important to note that the levelised costs do not indicate costs that will be used to determine payments under future business models.

- Lastly, the Annex includes additional underlying data for the figures presented in this report and provides additional data on levelised costs from published literature.

We acknowledge that the evidence base is fast-moving and through producing this report we have a better understanding of the gaps in our knowledge. We invite views on this report to continue to improve our collective understanding. To provide your views and any new evidence, please email hydrogenevidencebase@energysecurity.gov.uk. We will continue to monitor and update cost estimates as new evidence becomes available.

Section 1: Methodology

Overview

Using published literature and market intelligence, we have identified existing and potential hydrogen transport and storage technologies and subsequently the necessary potential hydrogen forms (Section 2). The technologies included in this report are unlikely be exhaustive – they represent technologies discussed in existing literature, or in planned projects. Novel technologies for both hydrogen transport and storage could emerge as the market develops.

In Section 3 and Section 4 respectively we have identified which hydrogen technologies are likely to be utilised with which hydrogen form and provided a brief overview of the technical characteristics of these technologies. We researched published data on hydrogen transport and storage technology costs with the aim to present a range of levelised cost estimates for different technology/form combinations.

Levelised costs

The intention of a levelised cost metric is to provide a simple cost comparison between different types of technologies. The levelised cost of a hydrogen transport and storage technology is the ratio of the total costs (£) of an archetypal technology relative to the amount of hydrogen to be transported or stored over the technology's lifetime. For hydrogen transport and storage, this is usually measured in kilograms. By archetypal technology we mean an illustrative example, e.g. trailers, as the costs for individual trailers and projects will vary hugely, depending on a range of factors, some of which are discussed in this report.

Although there are published estimates for the levelised costs of hydrogen transport and storage for a range of technologies and forms in different external literature, most publications do not provide sufficient detail on the method used to derive those costs to make fair and direct comparisons with other sources. For example, the levelised cost of transporting hydrogen (presented in £/kg) will apply to a specific distance covered, which is often not stated. The same applies to the literature on storage costs, where there is often little detail on the number of cycles (how often the store fills and empties) used to derive the levelised cost estimates.

In the following section we discuss different 'hydrogen forms' which could be transported or stored. To transport or store hydrogen, hydrogen may need to be compressed (to more compressed gas) or converted to another form (e.g. ammonia). While conducting research for this report, we encountered challenges in discerning how to separate the costs associated with compression and/or conversion from those related to hydrogen transport and storage and have identified this as a key evidence gap. An important avenue for further work is to improve our understanding of the potential emerging end-to-end archetypes, covering production plants, any transport and storage required, and end-use. Improving our knowledge of the potential end-to-end process will be key to understanding the total compression/conversion costs.

Without this, it is difficult to understand where to attribute any potential compression/conversion costs to hydrogen transport and storage technologies. For example, hydrogen may already be compressed to a suitable pressure for some transport technologies when released from the production plant. Or, depending on the end-to-end process, hydrogen may be compressed/converted several times between the producer and end-user.

During our research we found limited cost data which had sufficient detail on the method to calculate levelised costs and their assumptions on compression/conversion for us to present a comparable range of the levelised cost estimates from different sources. Although we used a wide range of published evidence and literature to form the basis of the technoeconomic considerations and conclusions drawn in this report, the levelised cost estimates presented here are from DNV's 2019 publication on the hydrogen in the electricity value chain[3][4]. Based on our research, this report provided the most detail on their methods, including information on cost drivers. We have converted the levelised cost estimates produced by DNV into GBP and adjusted for inflation to present these in 2023 prices. In compiling this report, we viewed other data on levelised costs, both published and unpublished, and the trends presented here, e.g. the ranking of costs from lowest to highest by technology, are consistent with other literature sources. A summary of the levelised cost data from other published sources is included in the Annex. We had sufficient input data for road transportation of gaseous hydrogen to produce our own cost calculator to derive levelised costs of transport. The outputs of this calculator are presented in Section 4 and a summary of the method is included in the Annex.

The transport and storage technologies presented in this report are not an exhaustive view of all existing, or potential, technologies. We have focused on technologies where there is published evidence on the technical characteristics and costs, and those where there are projects, or proposals for projects, which plan to use these transport and storage technologies. Although some of the technologies presented in this report could be used for international transport of hydrogen, we have tried to view this from a UK domestic lens, to narrow the scope and provide a more meaningful technoeconomic view relevant to the early years of hydrogen economy growth. As the hydrogen market grows, we anticipate new hydrogen transport and storage technologies will develop and we can revise our evidence base as needed.

In this report, we consider hydrogen transport and storage technologies separately. However, we acknowledge that there are some overlaps. For example, a trailer used to transport hydrogen could also be used to store hydrogen prior to transportation. Like with compression/conversion costs, a more detailed understanding of the potential end-to-end movement of hydrogen will be key to understanding the dual role of some technologies.

[3] https://www.dnv.com/Publications/hydrogen-in-the-electricity-value-chain-225850 (accessed November 2023)
[4] Although this report is from 2019, we still think these are the best public cost estimates and have updated these figures to account for inflation. We anticipate a step-change in the quality of transport and storage cost estimates, as projects start applying for government support, and complete funded feasibility studies. Until then, the majority of cost estimates and their assumptions and input data will be theoretical.

Uncertainty

There is inherent uncertainty when estimating current and future costs of hydrogen transport and storage because technologies are not yet deployed at scale; some technologies are still in research phase, and cost data for existing technologies has been difficult to obtain because it is commercially sensitive. The costs presented here consider archetypal projects, and the actual costs of a project will vary, depending on many factors. Where possible, we have described the key cost drivers and their relative importance in Sections 3 and 4.

In addition to the specific drivers of costs for respective transport and storage technologies, there are other cost drivers that will affect all infrastructure projects. For example, the price of components may differ between buyers depending on their project size and the supplier's confidence that their project will go ahead, and long delivery times will drive up costs as producers add cost inflation to cover uncertainty in the price of raw materials. Location may also be a driver of cost differences, for instance the wage differential across the country will affect the labour costs for projects building in different locations.

Metric definitions

- In this report, the levelised costs of hydrogen transport and storage are presented as £/kg. Using the Higher Heating Value (HHV)[5] to express kWh, the energy content of 1kg of hydrogen is 39.4 kWh.
- The levelised costs presented for storage technologies are relevant for a specific pressure, or range of pressures. In this report, we present pressure in in the bar unit.
- In this report, we discuss CAPEX and OPEX costs and their relative impacts on the levelised costs of transport and storage. Examples of capital expenditure (CAPEX) includes spend on physical assets, for example tube trailers. Operating expenditure (OPEX) includes spend on operating costs, for example, fuel and labour costs.

[5] The HHV refers to the total amount of heat liberated during the combustion of a unit of fuel, including the latent heat stored in the vapourised water. Lower heating value (LHV) refers to the total amount of heat available from a fuel after the latent heat of vaporisation is deducted from the HHV.

Section 2: Hydrogen Forms

Table 1 provides an overview of the technical characteristics that we have termed different hydrogen 'forms' relevant for hydrogen transport and storage applications. Hydrogen will be produced as a gas from production plants, with the outlet pressure dependent on the production technology. Because hydrogen has a low volumetric energy density, further compression of hydrogen, or converting it into a different form, will usually be required to transport and store hydrogen economically.

This report does not consider the end-uses of hydrogen but some hydrogen 'forms' may be used directly by end-users without any changes to compression and/or conversion between forms. Most hydrogen transport and storage technologies can transport, or store, hydrogen in different 'forms'. These combinations have different technoeconomic considerations and trade-offs, discussed in Sections 3 and 4.

Table 1: Overview of Hydrogen 'Forms'

Hydrogen (STP)	Hydrogen is a gas at standard temperature and pressure (STP). Standard temperature and pressure are defined as 0 °C (273K) and 1 atm (1.013 bar), respectively. Compared to other forms of hydrogen, the low volumetric energy density of hydrogen at STP makes it less practical to be used in transport and storage applications.
Compressed gaseous hydrogen (CGH2)	CGH2 can be used to describe hydrogen compressed to a range of pressures and to transport and store hydrogen it would be compressed to around 300-700 times atmospheric pressure. Compressed gaseous hydrogen (CGH2) is the least energy dense form of hydrogen we consider as a hydrogen form in the technologies considered in this report.
Liquefied hydrogen (LH2)	Converting hydrogen to liquid requires refrigeration to -253^{o}C and compression, and then regasification to convert back to gaseous hydrogen. Liquefied hydrogen (LH2) is more energy dense than compressed hydrogen gas and liquid organic hydrogen carriers, but less energy dense than ammonia. Liquid hydrogen has high boil-off losses compared to compressed gas. The benefit of storing hydrogen as a liquid is that, once converted and containerised, it can be transported and stored in higher volumes (of energy) than gas.
Ammonia	Hydrogen can be combined with nitrogen to form ammonia. Like hydrogen, ammonia is a gas at atmospheric pressure and room temperature. To store ammonia, it must be either compressed to 10 times atmospheric pressure or cooled to -33^{o}C. Apart from metal hydrides, ammonia is the most energy dense form of hydrogen we consider in this report. However, ammonia is corrosive and potentially toxic so needs careful consideration when storing and transporting. There is also a need

	to prevent any nitrous oxide emissions and ammonia leakage which would be environmentally harmful. Because there is an established ammonia trade in the UK, storage and transport technologies are already tested, making ammonia a promising option for transporting and storing hydrogen. In the energy sector, ammonia could be transformed back into hydrogen or used directly for fuel.
Liquified organic hydrogen carriers (LOHCs)	Hydrogen can be bound to more complex molecules to form liquid organic hydrogen carriers (LOHCs), such as the hydrogenation of toluene to form methylcyclohexane (MCH), and can later be released from LOHCs. LOHCs are more energy dense (in terms of volumetric density) than forms of compressed hydrogen gas but not as dense as liquid hydrogen or ammonia. Leaks are less likely than ammonia, and unlike LH2 and ammonia, no pressurisation is needed as LOHCs are liquid at normal conditions. LOHCs can potentially be stored in overground tanks and transported by truck or ship to other LOHC production sites for dehydrogenation. The chemical components can then be reused. Like with ammonia, care must be taken when storing and transporting LOHCs due to their toxicity. For example, MCH is classed as "very toxic to aquatic life with long lasting effects"[6]. While the hydrogen forms above are already transported and stored at scale in the UK (although not in the energy sector), LOHCs are a more novel technology.
Metal hydrides	Gaseous hydrogen can be absorbed into the crystalline structure of solid metal powders to form a stable metal hydride. This can be stored in specialised storage tanks and later extracted through desorption. This form of hydrogen storage is the most energy dense. It is also very heavy, so is more likely to be used as a storage technology, rather than for hydrogen transportation. Additional considerations include the fact that metal hydrides can be very flammable. Equipment for purposes such as hydrogen-drying can be needed in cases where the hydride burns well in the presence of water. Like, LOHCs, metal hydrides are a more novel storage technology, not proven at scale.

It is important to distinguish the difference between volumetric energy density and gravimetric energy density. Volumetric energy density refers to the amount of energy that can be stored in a given volume (kWh/dm^3), while gravimetric energy density refers to the amount of energy per unit of mass (kWh/kg). Hydrogen has a high gravimetric energy density, approximately 33.33 kWh/kg (~2.2 times the energy density of natural gas per unit mass). However, the volumetric energy density of hydrogen at standard temperature and pressure (STP) is just 0.003

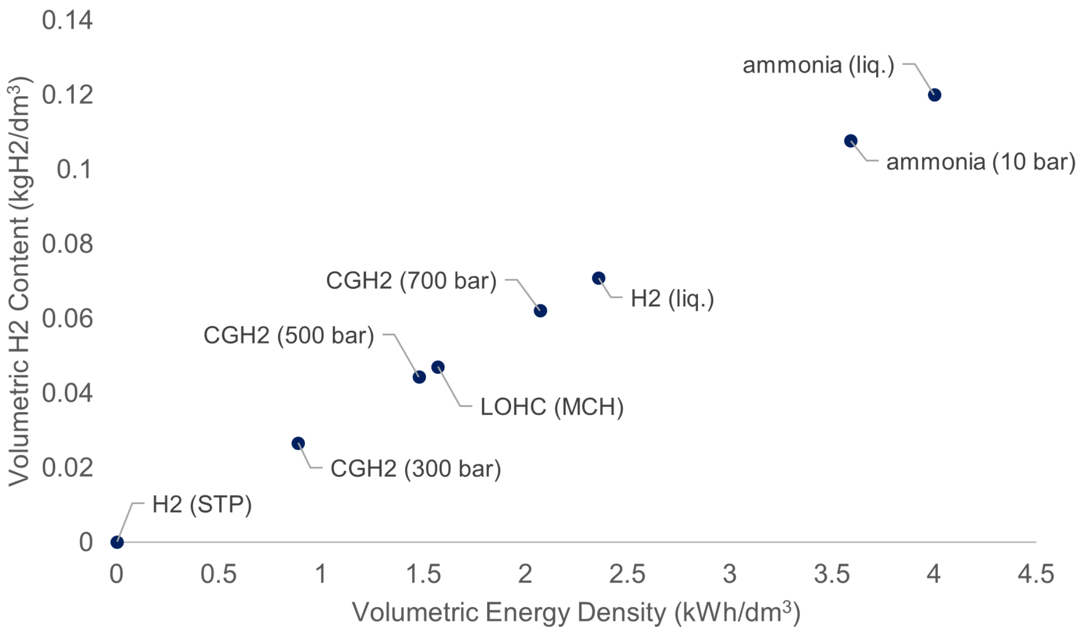
[6] https://www.merckmillipore.com/GB/en/product/msds/MDA_CHEM-806147 (accessed November 2023)

kWh/dm³. Because hydrogen is so much light, ~3 times the volume of hydrogen compared to natural gas is required to get the same amount of energy.

In terms of real-world applications, such as hydrogen storage (e.g. tanks and vessels), the available volume is often more constrained than the available mass. Therefore, it is more practical to consider the energy density of a hydrogen 'form' in terms of its volumetric energy density.

Figure 1 displays the energy density of given hydrogen 'forms' as a function of volumetric hydrogen content (see Table A1 for figures behind this graph). From this chart we can see that compressing hydrogen from 1 bar to 700 bar (under standard temperature conditions) results a in volumetric energy density increase from 0.003 kWh/dm³ to 2.1 kWh/dm³. It is also possible to convert hydrogen into other forms, such as liquid hydrogen, liquid organic hydrogen carriers (e.g. methylcyclohexane) and ammonia. Of these converted hydrogen forms, liquid ammonia has the highest volumetric energy (4.0 kWh/dm³). However, it is important to note that while these various forms may increase the volumetric energy density of hydrogen, the processes involved (i.e. compression and/or conversion) are often constrained by highly intensive energy requirements.

Figure 1: Energy Density vs Volumetric H2 Content of Hydrogen Forms



Section 3: Storage

Storage technologies

The hydrogen storage technology market is a rapidly growing sector, with the global hydrogen energy storage market estimated to grow from USD 11 billion (GBP 9bn) in 2023 to USD 197 billion (GBP 161bn) by 2028[7]. This growth is driven by the rising demand for low-emission fuels, advancements in electrolysers for sustainable hydrogen production, and the scalability and affordability of renewable energy systems.

Hydrogen storage technologies can be categorised based on hydrogen forms (described above in Section 2) and technology. These storage forms include solid, liquid, and gas and involve the use of compression, liquefaction, and material-based storage. Table 2 outlines the feasibility of storing different forms of H2 using various storing methods.

It is important to note that the storage technologies listed in this section are unlikely to be exhaustive and may not capture the entirety of the innovative strides being made in this area. As the hydrogen market continues to expand, novel storage technologies may emerge, reshaping the landscape.

[7] https://www.marketsandmarkets.com/PressReleases/hydrogen-energy-storage.asp (accessed November 2023)

Table 2: Feasibility of Storing Different Forms of H2 by Storage Technology[8]

Technology	CGH2	LH2	Ammonia	LOHC	Metal hydride
Underground Salt caverns (new or repurposed from natural gas storage)	£				
Depleted oil or gas field (newly depleted, or repurposed from natural gas storage)	£				
Aquifer (new)	£				
Rock cavern (new)					
Tank/vessel (new)	£	£			

Currently used in the UK
Theoretically possible
Not likely to be a storage technology/hydrogen form combination
£ - levelised cost data presented in this report

Technical characteristics

In this section, we first present a summary of the technical characteristics of different hydrogen storage technologies, and following this, present the levelised costs for some storage technology/form combinations.

Tanks and Storage Vessels

All forms of hydrogen discussed in this report can be stored in above-ground tanks or pressurised storage vessels.

Compressed gaseous hydrogen (CGH2) is stored in pressurised tanks. Broadly there are four types of storage tank: types I and II are primarily of steel construction and cheaper but heavier; types III and IV are composite overwrapped pressure vessels (COPV) which are more expensive but lighter in weight. These tanks are not currently used for large-scale fixed

[8] Line-packing is a well-established practice in the natural gas transmission system for addressing imbalances in entry and exit volumes. However, the UK hydrogen strategy does not recognise line-packing as a viable method for managing short-term imbalances in hydrogen supply and demand because of the lower energy density of hydrogen.

storage, rather as small-scale storage tanks which can be stored statically or transported on HGVs. They can be filled and emptied quickly, for example for refuelling small-scale end-users such as hydrogen-fuelled vehicles. Storing hydrogen in a tank offers an additional advantage: the gas maintains a high level of purity. This characteristic enhances its suitability for a range of end-users, including road transport and fuel cell applications, where there will likely be demand for high-purity hydrogen. Small, compressed gas cylinders have a capacity of 1 m^3, and those that can be transported by trailer have a capacity of between 40 m^3 and 1,000 m^3. Already in use in the UK, technological readiness of tank storage for compressed gas hydrogen in small volumes is high. However, there are no examples in the UK of larger overground compressed gas storage on the scale required if it were to make up a substantial share of the predicted hydrogen storage capacity required to support a growing hydrogen economy. Current limitations include uncertainty around the regulations required for large volumes of overground storage, and the large amount of space required.

Liquified hydrogen (LH2) can be stored in large overground cryogenic tanks at a temperature of –253 °C, similar in design to liquid natural gas (LNG) storage tanks but built specifically for hydrogen. Storing hydrogen as liquid in a tank requires extensive conversion processes (liquification and regasification), however, the hydrogen retains a high level of purity. Already in use in the UK, technological readiness of tank storage for liquid hydrogen is high, although like CGH2 storage in tanks, this has not been demonstrated at a larger scale. The capacity of liquid hydrogen storage tanks varies from 1,200 m^3 for a bullet tank, to between 10,000 m^3 and 180,000 m^3 for a purpose-built flat-bottomed concrete tank.

Ammonia needs careful management due to its toxicity and potential pollution issues and is therefore currently stored in pressurised tanks at specialised storage sites, for example, where ammonia is produced at ports for export. It can be stored in 1,000 m^3 bullet tanks or 50,000 m^3 concrete tanks, for weeks or months. Storing hydrogen in the form of ammonia requires conversion into ammonia, and potentially conversion back to hydrogen depending on the demand for end-use products. Although the process of synthesising ammonia (the Haber-Bosch process) is well used in the UK, ammonia is not currently used for creating hydrogen and therefore converting ammonia back into hydrogen (cracking) is not a process yet used on an industrial scale. However, the technical readiness of ammonia storage combined with its property as a high energy density form for hydrogen, makes it an attractive theoretical option for transporting hydrogen long distances by shipping.

LOHCs (other than ammonia) are also stored in tanks. Extensive chemical processes are required to transform hydrogen into and out of liquid organic hydrogen carriers. However, their relatively high energy density (higher than compressed hydrogen gas, but lower than ammonia and liquid hydrogen) makes LOHCs a potentially more attractive storage option than gaseous hydrogen, and the fact that LOHCs do not need to be cooled to be in a liquid state and have no risk of gas leaks, overcomes some of the limitations of liquified hydrogen and ammonia. An additional benefit is that once extracted from the carrier, the hydrogen could retain a high level of purity. LOHCs are an emerging technology, and as such there is limited data and a high level of uncertainty around the volumes that could be stored in overground tanks and the costs involved.

Metal hydrides present a promising solution for stationary hydrogen storage, due to their high volumetric energy densities and safety advantages. These materials can store and release large amounts of hydrogen in a relatively safe and controlled manner, making them ideal for energy storage applications. The hydrogen storage occurs through adsorption or absorption processes within the metal hydride, which allows for mostly loss-free and long-lasting storage. Nevertheless, when compared to alternative storage technologies, such as compressed hydrogen gas tanks, the cost of implementing a metal hydride storage system tends to be notably higher. This increased cost is attributed to the materials used and the inherent complexity of the system. Furthermore, the relatively heavier weight of metal hydride storage systems should be considered in applications where weight is a critical factor, like transportation. Despite these challenges, metal hydride storage is an emerging technology, and ongoing research and technological advancements could lead to cost reductions and wider adoption of metal hydride hydrogen storage in the future.

Salt Caverns

Salt caverns are a well-established technology for storing natural gas, but the utilisation of these caverns for hydrogen storage is limited. There are four designated hydrogen salt cavern storage sites in the world today: three in the USA (Clemens Dome, Spindletop, and Moss Bluff) and one in the UK (Teesside). The Teesside facility consists of three caverns, each capable of storing approximately 70,000 m^3 of hydrogen, with a total combined energy storage capacity of 25 GWh[9]. Although the design of caverns is influenced by operational needs and geological considerations, the overall geotechnical requirements for hydrogen storage salt caverns closely align with those for natural gas storage.

The UK's salt deposits have undergone detailed analysis by The British Geological Society[10]. In certain UK locations, there are options to repurpose existing natural gas storage caverns for hydrogen use or construct new salt caverns. The construction process of a salt cavern involves several key stages: site selection, solution mining, infrastructure installation, testing, and the commissioning phase.

Site Location: An ideal site must feature a substantial and deep salt layer suitable for creating a cavern. This salt layer should be free from of geological faults and fractures to ensure adequate structural integrity of the cavern. The salt layer should also contain few mineral impurities which could react with hydrogen.

Solution Mining: This involves drilling a well into the salt layer and injecting water. The water dissolves the salt, creating a brine that is then pumped back to the surface. This process is then repeated until a cavern of desired size and shape is formed. The brine that is produced during solution mining can be treated and disposed, or alternatively, repurposed for use in various industrial processes.

[9] https://www.gaffneycline.com/sites/g/files/cozyhq681/files/2022-07/gaffneycline_underground_hydrogen_storage_article.pdf (accessed November 2023)
[10] https://ukccsrc.ac.uk/wp-content/uploads/2020/05/John-Williams_CCS-and-Hydrogen.pdf (accessed November 2023)

Installation of Infrastructure: After the cavern has been created, infrastructure for storing and retrieving hydrogen is installed. This includes compressors and piping for injecting and extracting hydrogen, as well as safety systems to monitor and control the operation of the cavern.

Testing: Before the cavern can be used for hydrogen storage, it must be tested to ensure its integrity and safety. This involves filling the cavern with a test gas, such as nitrogen, and monitoring the pressure in the cavern over time. If the pressure remains stable, this indicates that the cavern is sealed and ready for use.

Commissioning: The cavern is filled with a 'cushion gas'[11] and the working gas (e.g. hydrogen) under pressure. The pressure in the cavern can be adjusted to match the required demand, allowing for flexible cycling operations. While the pressure can be adjusted, it is within certain limits to ensure the stability and integrity of the cavern structure.

In considering options for hydrogen storage, repurposing existing natural gas storage caverns and the construction of new salt caverns through solution mining are recognised as viable options. However, these approaches face limitations, with a notable constraint being the uneven distribution of suitable salt deposits across the UK. Regions whereby hydrogen storage in salt caverns have been identified include the northwest (Chesire Basin), the northeast (East Yorkshire), and the south coast (Wessex Basin)[12]. Factoring in this geographical constraint suggests that prospective hydrogen users beyond these regions, such as industry in Scotland or South Wales, may lack convenient access to nearby onshore salt cavern storage facilities.

Salt caverns are regarded as an effective way to ensure hydrogen purity and hermetic storage. However, gaseous hydrogen is highly diffusive and bacterial activity can disturb the cavern impermeability and the purity of the stored gas. For instance, microbial impurities in salt caverns could lead to hydrogen loss and limit the applications of extracted hydrogen unless thorough purification measures are implemented. Microorganisms present in salt caverns, such as sulfate-reducing bacteria, can consume hydrogen, leading to losses and potential production of toxic hydrogen sulfide. The extent and rates of microbial hydrogen consumption under high-saline cavern conditions are not yet fully understood[13]. Processes to purify the hydrogen at the cavern outlet could therefore be necessary and contribute to additional cost in the construction of hydrogen ready salt caverns.

Depleted Gas and Oil Fields

Depleted gas and oil fields are underground formations of porous permeable rock from which the hydrocarbons (oil or gas) have been removed. They could potentially be used for large-scale storage of compressed gaseous hydrogen (CGH2).

[11] A 'cushion gas' (sometimes referred to as a 'base gas') is a volume of gas permanently stored in a storage facility. Various gases can serve as the cushion gas, including N_2, CO_2, CH_4, amongst others. The purpose of this gas is to maintain sufficient pressure in the cavern to allow for adequate injection and withdrawal rates, as well as uphold the structural integrity of the cavern. For salt caverns, the required amount of cushion gas is approximately one-third of the total cavern volume.
[12] https://www.sciencedirect.com/science/article/pii/S2352152X22011100 (accessed November 2023)
[13] https://www.nature.com/articles/s41598-023-37630-y (accessed November 2023)

Use of depleted oil and gas fields for storing hydrogen are at an earlier stage of technology readiness than salt and rock caverns - in the UK there are currently no depleted oil and gas field sites storing hydrogen. However, it is a well-established technology for storing very large volumes of natural gas in the UK and worldwide (the Rough depleted gas field in the North Sea has a capacity of 3.3bn m^3), and as such is considered also theoretically possible for hydrogen. Depleted oil and gas fields could be repurposed from natural gas storage to hydrogen, or a hydrogen store could be built new from a depleted gas or oil field.

Despite the UK's geographical advantage with many oil and gas field sites in the North Sea, and the size of storage that a depleted field would offer, there are limitations. Depleted oil and gas fields are geographically constrained due to the location of geological formations and past oil and gas exploration. Furthermore, not all depleted oil and gas fields will have the geological properties required to contain hydrogen without it leaking. As with other forms of underground storage, purity of hydrogen due to bacteria is a further constraint. In a depleted gas field, stored hydrogen will also likely mix with pre-existing natural gas, meaning extracted hydrogen will need to be used as mixed gas, or treated to create pure hydrogen. Contamination of hydrogen in a depleted oil field is likely to be even higher, making depleted oil fields a less appealing option for storing hydrogen than depleted gas fields. In addition, current evidence indicates that cycle rates will be limited because the porous rock structure limits the injection and withdrawal rates that are possible. We anticipate that depleted oil and gas fields would therefore be more suited to long term seasonal storage.

Like salt caverns, depleted oil and gas fields require a proportion of cushion gas so the working volume of gas is likely to be between 50% and 60%[14] of the overall cavern volume. In addition, oil and gas field sites offer significant potential for storing carbon (CCS), which may limit availability of sites for hydrogen storage, although research indicates that the optimal sites for hydrogen and carbon storage may differ.

Aquifers

Aquifers are like depleted oil or gas fields in that they are underground formations of porous permeable rock, but water is removed rather than hydrocarbons. They could potentially be used for large-scale storage of compressed gaseous hydrogen. Aquifer technology is an established storage technology for natural gas. In theory, if used as a store for gaseous hydrogen, they have the advantage over depleted oil and gas fields of there being no risk of mixing hydrogen gas with hydrocarbons.

However, aquifers are not currently used for gas storage in the UK so using aquifers for hydrogen storage would therefore require creating one from scratch, and would likely require more innovation than e.g. depleted gas fields, which have already been used for natural gas storage in the UK. This storage would be geographically constrained due to the location of geological formations and require considerable exploration to identify whether the site was suitable for storing hydrogen.

[14] https://www.sciencedirect.com/science/article/pii/S2352484721014414 (accessed November 2023)

Rock Caverns

Rock cavern storage for hydrogen is an emerging technology involving the storage of hydrogen in underground rock formations. The caverns are created through rock excavation, and a sealing layer is applied to the cavity to prevent leaks, ensuring secure storage.

In the UK, while there is substantial potential for hydrogen storage in salt caverns and depleted oil and gas fields, rock cavern storage presents itself as an alternative with geological adaptability. This makes it a viable option in specific locations where salt caverns or depleted oil and gas fields are unavailable due to geological constraints.

However, the use of rock caverns for hydrogen storage will likely come with higher costs compared to other forms of underground storage. For rock caverns, the construction process is more intricate and expensive. Unlike salt caverns formed through the dissolution of rock salt, rock caverns require intensive excavation, often involving drilling and blasting. In addition, these caverns must be lined to prevent leaks and ensure safe hydrogen storage, incurring additional costs for both procurement and installation.

Despite the higher construction and operational costs, rock caverns offer geographical adaptability and could serve as a practical solution if large-scale hydrogen storage is required where alternative options are unavailable. For example, a FOAK lined-rock cavern facility is currently being piloted in Luleå (Sweden) for hydrogen storage[15], which could provide valuable insights that could inform similar projects in the UK. Nevertheless, further research and development will be required to comprehensively understand the potential and challenges of implementing this storage technology in the UK.

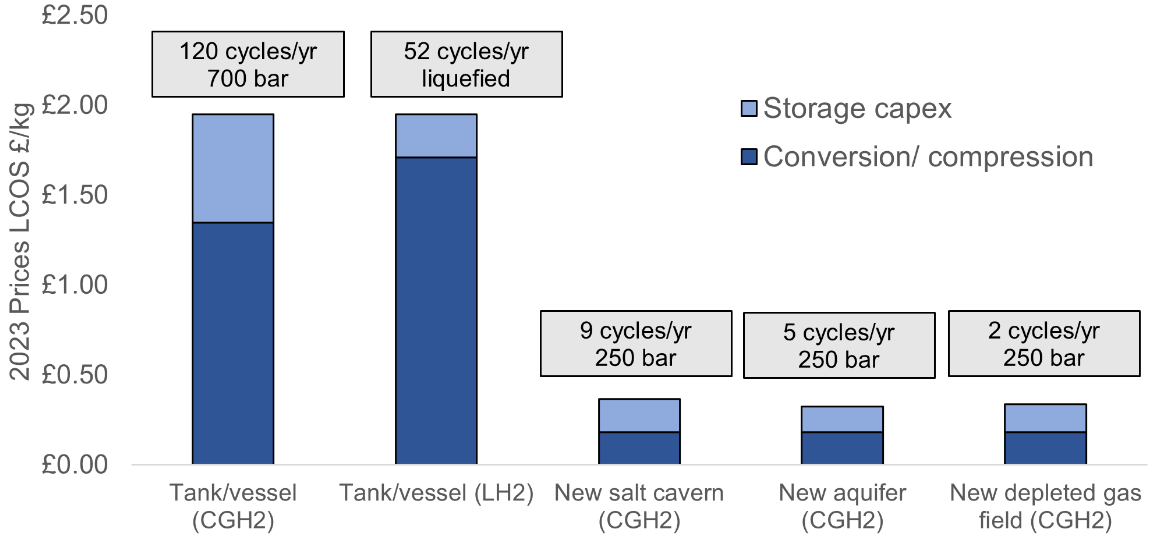
Levelised costs

Based on our literature review, the publication which presents the most detailed levelised costs of storage technologies is DNV's 2019 report on Hydrogen in the Electricity Value Chain[16].

Figure **2** below presents the levelised costs of storage by some hydrogen form/technology combinations and separates out compression/conversion costs. In the annex we present a table with the figures behind this graph, and as discussed in the Methods section, the annex also includes a comparison with the levelised costs of storage published in other literature.

[15] https://www.smart-energy.com/industry-sectors/storage/underground-rock-cavern-hydrogen-storage-facility-inaugurated-in-lulea/amp/ (accessed November 2023)
[16] NB: this was also the input data Frazer-Nash decided was most appropriate to use to calculate the T&S requirements in 2035 in this publication: https://www.gov.uk/government/publications/hydrogen-infrastructure-requirements-up-to-2035

Figure 2: Levelised Cost of Hydrogen Storage (£/kg) by Technology, adjusted for £2023



NB: the cost estimates presented in the above table will be more uncertain for technologies not yet deployed at scale, particularly aquifers and depleted gas fields.

For storage in a vessel, liquefaction costs are higher per unit of hydrogen than compressing hydrogen for use in a tank. The costs of compressing gas for storage underground (salt caverns, aquifers, and depleted gas fields) are lower per unit of hydrogen, as hydrogen does not need to be compressed as much to be stored underground. For tank/vessel storage, levelised costs are based on a cycle rate of once every three days (I.e. 120 days per year) for pressurised storage and once every week (I.e. 52 days per year) for liquid storage. Due to the lower storage capacity of pressurised vessels, more load-unload cycles (I.e. more than once a week) are required to make this storage method viable in terms of costs and efficiency.

Levelised costs for the three underground storage technologies are similar. Although we anticipate that depleted gas fields would have a larger capacity than salt caverns and aquifers, the economies of scale will not necessarily be realised, as depleted gas fields are not likely to have as many cycles per year as salt caverns. We anticipate that economies of scale will be realised within other storage technologies, for example a larger salt cavern which can achieve the same number of cycles as a smaller salt cavern would likely have a lower cost of storage per unit of hydrogen. The theoretical maximum cycling rates will be driven by the technical characteristics of a storage site, including, for example the shape of a cavern. However, the actual cycling rates will be driven by demand for the storage facility and the types of producers and users the facilities are supporting. Through compiling this report, we have identified cycling rates as a key evidence gap, and improved evidence on this would better our storage cost estimates.

For underground storage, another driver of cost differences will be driven by the geology of the site. A site with lots of smaller caverns which share the same above-ground infrastructure (compressors, for example), will be more expensive than a site with one larger cavern as more complicated excavation will be required for the smaller caverns. Additionally, the shape and depth of the salt cavern, aquifer, or depleted gas field, will affect overall costs, because CGH2 will need to be compressed to different levels. In addition, the flow rate (how much hydrogen you can get in and out of the store) will differ depending on the size and depth of the cavern, a lower flow rate will reduce the theoretical cycling rate of the store, and therefore the amount it can be utilised.

This report has not considered development expenditure (DEVEX) in much detail as there is limited evidence on DEVEX costs. However, we can predict that the DEVEX costs for aquifers and rock caverns would be higher than for e.g. salt caverns, as these are unproven technologies for hydrogen storage.

Levelised costs of hydrogen storage vs storing other fuels

Storage costs for hydrogen are likely to always be more expensive than for natural gas. As a compressed gas, hydrogen takes up three to four times as much space as natural gas. In other forms, although hydrogen energy density is greater, the costs involved in transforming the hydrogen (liquification, cracking, etc) are greater.

A key benefit of hydrogen storage is being able to store electricity as hydrogen when there is an excess of electricity generated through renewable sources (wind, solar), to be converted back to electricity when energy demand peaks. Because the technology has been tested, this makes hydrogen a feasible option for long-term energy storage. However, there are clearly draw-backs in terms of the costs involved and the energy required in producing and storing hydrogen and re-converting to electricity. Storing excess (curtailed) electricity on a large scale is a challenge currently being investigated using other technologies, for example, pumped-storage hydropower, compressed air storage, mechanical gravity storage and chemical batteries. In the long term it will be important to consider and monitor which technology or technologies are most cost effective at storing electricity at scale.

Summary

There are a number of feasible, and theoretical hydrogen storage technologies available. Based on the trade-offs between the technoeconomic characteristics of different storage technologies, we have considered the viability of uses of different technologies in the emerging hydrogen economy. These are based on evidence to date and may change as the market develops. As with everything presented in this report, we welcome feedback on these conclusions.

We anticipate that storage as LH2 will only be preferable if hydrogen will need to be transported over a long distance, and transport by pipeline is not suitable, or available. Conversion costs for LH2 are very high, and storing hydrogen above ground as LH2 will require space above ground, including space to build facilities for liquefaction.

Storage of CGH2 in a tank/vessel will likely be preferable if you need a small amount of storage soon, prior to other storage facilities (e.g. salt caverns) being available and accessible. These technologies are easy to build/buy, can be operated flexibly, and can be distributed by trailer (see discussion on road transportation of CGH2 in Section 4).

Rock caverns might be the only solution for storing larger volumes of hydrogen if there is limited space overground, and there is not the right geology for salt, depleted oil or gas fields or aquifers (e.g. most of onshore mid/south England or Scotland). The advantage, if these are built, is that the hydrogen could be purer than that stored in other larger-scale stores, so could be a promising solution where the end-use requires hydrogen of a high purity.

For larger-scale storage, salt caverns have the best advantage in terms of a higher flow rate (compared to depleted gas fields). Based on the technoeconomic evidence, aquifers do not appear to bring any advantages above those of salt caverns and depleted gas fields, unless in the future we find that there are aquifers located in locations where hydrogen storage is needed and there are no alternative large-scale storage options, e.g. salt caverns.

Aside from storing CGH2, the three hydrogen forms – LH2, ammonia, and LOHCs all offer similar benefits of being high-energy dense methods for transporting hydrogen, but all have some drawbacks. Ammonia carries more safety risks, liquid hydrogen has the highest boil-off losses, and although LOHCs overcome both of these limitations, they are less well developed. Before these hydrogen forms are suitable for hydrogen transportation, which they may be if conversion/compression costs drop, or hydrogen needs to be transported longer distances (e.g. for international import/export), we predict that we are not likely to see hydrogen stored in these forms.

We think the best approach to assess storage needs will be to focus on emerging demand for hydrogen, including purity requirements and locations relative to potential larger-scale underground storage.

Section 4: Transport

Transport Technologies

This section describes the technoeconomic characteristics of two hydrogen transport technologies – road transportation and pipelines. Like for storage, and as discussed in the methods section, this is not an exhaustive list of potential transport technologies. Hydrogen could also be transported by rail and newer solutions for hydrogen transportation will likely emerge as the market develops. In addition, this report is focused on domestic hydrogen transport and storage, and therefore excludes shipping, which could be used in the future for hydrogen import and exports. The potential combinations of transport technologies and hydrogen forms are summarised in Table 3 below.

Table 3: Feasibility of Transporting Different Forms of H2 by Technology

Technology	CGH2	LH2	LOHC	Ammonia	Metal hydride
Road transportation	£			**For use as a feedstock*	
Pipeline	£				

Currently used in the UK
Theoretically possible
Not likely to be a transport technology/hydrogen form combination
£ - levelised cost data presented

Road transportation

A hydrogen trailer is a specialised road vehicle designed for transportation of hydrogen from point of production or storage to end-user. Hydrogen trailers could be used to transport hydrogen in all five of the hydrogen forms described in Section 2 – gas, liquid, ammonia, LOHCs, and metal hydrides.

Converting hydrogen to LH2, ammonia, LOHCs or a metal hydride increases the energy density of hydrogen, meaning more could theoretically be transported per trailer. However, conversion adds significant costs due to the considerable amount of energy required. Furthermore, for liquid hydrogen, cryogenic conditions (very low temperatures) are required during transportation, further increasing costs. If hydrogen needs to be transported greater distances, for example, domestic transport in countries larger than the UK, or international transport, then the benefits of being able to transport larger quantities of hydrogen could make these forms more economical.

In addition, some of these forms of hydrogen could become more commercially viable with the introduction of newer technologies into the market. One such notable example is the FOAK metal hydride solid-state hydrogen storage and distribution trailer developed by Hydrexia Energy Technology[17]. This trailer utilises a magnesium-based alloy for hydrogen storage, with a solid-state capacity of 1 tonne, a high hydrogen storage density of 6.4%wt, and operates at a low pressure of under 12 bar.

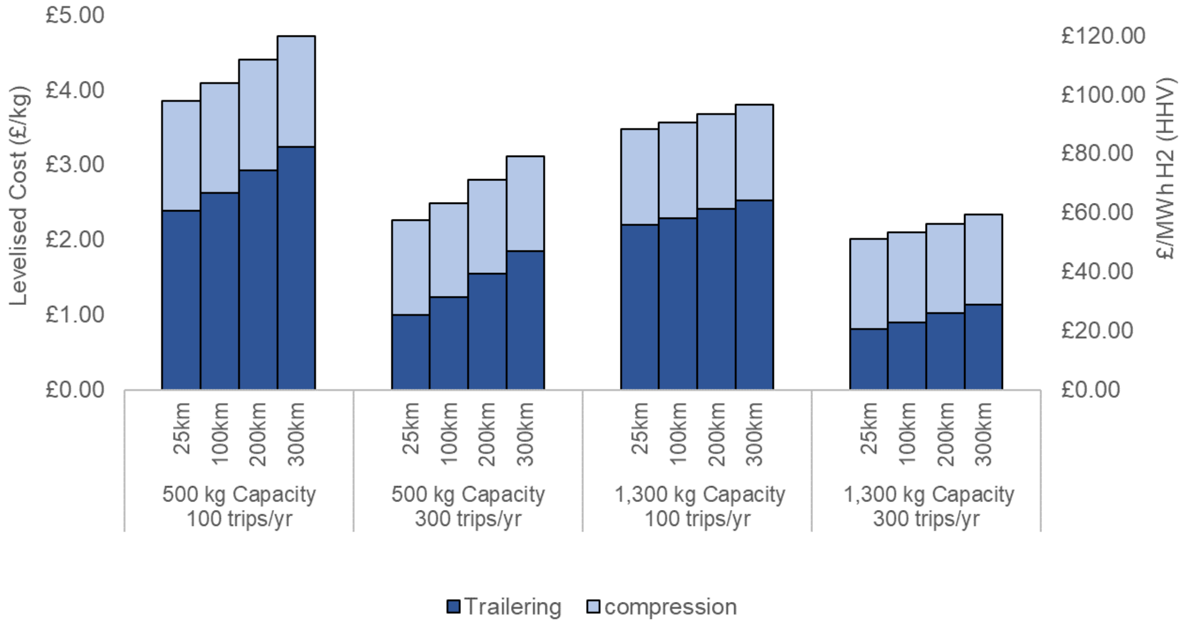
Compressed gas tube trailers

Based on the technoeconomic evidence, we anticipate that composite-based (type IV) compressed gas tube trailers will be used for domestic road transportation of hydrogen in the UK in the early years of hydrogen economy growth. We have produced a calculator to provide bottom-up estimates of the levelised costs of road transportation of compressed gaseous hydrogen (CGH2) in type IV trailers at 500 bar. While the exact service lifetime for a truck-trailer for CGH2 transportation varies across different reports (e.g. 10-30 years), we have based our analysis on a project lifetime of 15 years as this allows for a comprehensive analysis of the costs and benefits over a significant period. However, it is worth noting that potential technological advancements and changes in market conditions could impact the cost over such a period.

Our analysis enables us to understand the cost drivers, and make informed comparisons, such as those based on trailering carrying capacity and number of trailer journeys. Figure 3 presents a summary of the outputs from the cost calculator, along with a description of the technical characteristics of compressed gas tube trailers. For more information on the assumptions in the cost calculator, please refer to the Annex (Table A4).

[17] https://hydrexia.com/ (accessed November 2023)

Figure 3: Levelised Costs of Hydrogen Transport by Type IV Compressed Gas Tube Trailers



The levelised costs of transporting CGH2 are higher from smaller trailers, in part because of the lower carrying capacity. Our analysis suggests that increasing the carrying capacity of a CGH2 trailer from 500kg to 1,300kg results in a 10-25% reduction in levelised cost. The extent of this reduction is dependent on factors such as the number of trailer trips and the distance travelled.

This cost reduction stems from the ability to spread fixed costs, including those associated with the trailer and equipment, across a larger volume of hydrogen transported. Essentially, the economies of scale tied to the transportation of greater hydrogen volumes outweigh the impact of operational costs, such as labour, fuel, and compression expenses, on a per unit basis. This highlights the economic benefits of transporting larger quantities of CGH2 using high-capacity trailers.

It is evident that across each trailering scenario, the cost of compression accounts for a significant portion of the levelised cost of CGH2 transportation. As shown in Figure 3, the cost of compression was calculated to be 30-60% of the overall transportation cost. However, the high cost of compression can be offset by increasing trailer capacity and subsequent hydrogen payload per trip. A sensitivity analysis was carried out to examine compressor capex and opex on the levelised cost of transporting CGH2 by road trailer. The results are presented in Table A11 and Table A12 in the annex.

Technical characteristics

Tube trailers are articulated lorries that consist of multiple high-pressure vessels manifolded together. The pressurised gas cylinders are made from either steel or composite materials. Compressed hydrogen gas tube trailers (referred to herein as 'tube trailers') are constructed using high-pressure cylinders, also known as tubes, which are made from either steel or composite materials. These materials are chosen for their strength, durability, and ability to withstand high pressures.

Steel Cylinders (Type I): These are all-metal construction vessels, generally made from steel. Historically, Type I cylinders have held more than 90% of the tube trailer market[18]. Steel cylinders are commonly used for lower pressures, typically around 200 bar.

Composite Cylinders (Type III and Type IV): These cylinders are made from a combination of metal liners (usually aluminium) and composite materials such as carbon fibre and advanced polymers. The composite materials are wound around the liner to provide additional strength and durability. Type III cylinders have a metal liner and a composite overwrap, while Type IV cylinders have a plastic liner and a composite overwrap. These cylinders are often used for higher pressures, such as 500 bar or higher.

Hydrogen is a compressible gas, therefore storing and transporting hydrogen at higher pressures increases the amount of hydrogen that can be transported ('payload'). Table 4 shows the typical operating pressures and hydrogen payloads for type I and type III/IV tube trailers. In the UK, a typical steel (Type I) tube trailer would be filled to 228 bar and carry around 300 kg of hydrogen[19]. Recent advancements in composite storage vessel designs have increased the capacity to transport larger hydrogen payloads. Newer tube trailers fitted with composite cylinders (Type III/IV) can transport >1000 kg of hydrogen at 500 bar working pressure or higher.

Table 4: Tube Trailer Types, Pressure, and Payload

Tube trailer type	Pressure (bar)	Payload (kg)
Type I	228	300
Type III/IV	500	>1000

It is worth noting that carrying capacity onboard a tube trailer is not primarily limited by its operating pressure. Instead, their capacity is constrained by road weight restrictions, which are enforced to protect road infrastructure and ensure safety.

[18] https://www.compositesworld.com/articles/composites-end-markets-pressure-vessels-2023 (Accessed November 2023)
[19] https://www.fuelsindustryuk.org/future-vision/hydrogen/ (accessed November 2023)

In the United Kingdom, the maximum gross weights for goods vehicles are set out in the Road Vehicles (Construction and Use) Regulations 1986[20] and the Road Vehicles (Authorised Weight) Regulations 1998[21]. The maximum weight limits for different types of vehicles vary depending on the number of axles. The maximum gross weight for vehicles with six axles is 44 tonnes. These restrictions directly impact the carrying capacity of tube trailers. For example, a steel (Type I) tube trailer with a hydrogen payload of 300 kg is limited by the weight of the steel tubes. This is because the weight of the steel tubes, combined with the vehicle weight and hydrogen payload, must not exceed the road weight restrictions.

Composite materials used in Type III and IV cylinders are lighter than the steel used in Type I cylinders. This results in a lighter overall weight of the trailer, allowing for more hydrogen to be transported within the same weight restrictions. Composite tube trailers are generally more expensive than steel tube trailers due to the advanced materials and manufacturing processes involved. However, the higher cost of composite tube trailers can be offset by their increased capacity and efficiency. For example, Spanish-based Calvera Hydrogen announced they had developed the largest capacity tube trailer on the international market[22]: designed to transport 1,300 kg at an operating pressure of 517 bar. The carrying capacity of this trailer is over four times that of a conventional Type 1 tube trailer.

Moreover, a study has found a linear relationship between the deliverable payload and the capital cost of a composite tube trailer[23], suggesting that the cost per kilogram of hydrogen transported decreases as the payload increases. This indicates that while the upfront cost of composite tube trailers may be higher, they could be more cost-effective in the long run, especially for larger payloads and longer transportation distances. Moreover, the increased capacity can lead to more efficient transportation of hydrogen, as more hydrogen can be transported per trip.

In the UK, the transportation of hydrogen by road is regulated under various legislative frameworks and guidelines. The European Agreement concerning the International Carriage of Dangerous Goods by Road (ADR) classifies hydrogen as a dangerous good and sets specific requirements for its transportation. Hydrogen is classified as a dangerous good under Annex 5 of the ADR. Hydrogen transport is excluded through ten tunnels in the UK, based on its ADR classification. Drivers transporting hydrogen must be appropriately trained and hold an ADR training certificate specific for hydrogen transportation, which can increase the operating costs for hydrogen transportation by road.

Pipeline Transportation

Hydrogen can be transported by pipelines in gaseous or liquid form, or as ammonia. Transporting liquified hydrogen and LOHCs by pipeline is theoretically possible, but based on

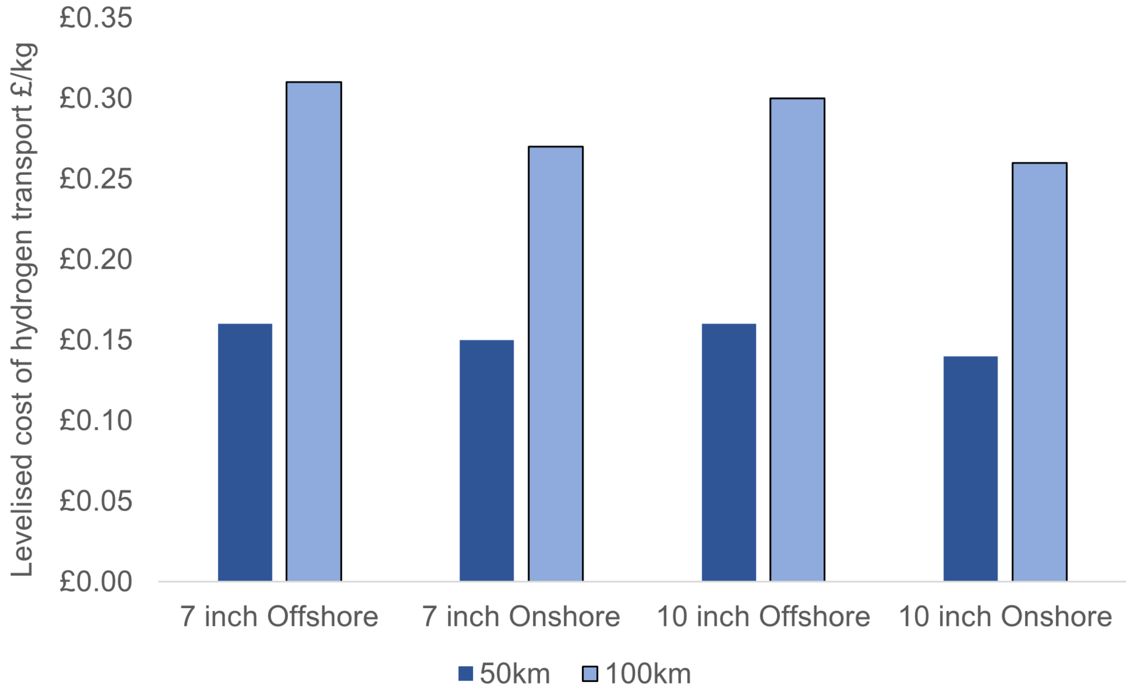
[20] https://www.legislation.gov.uk/uksi/1986/1078/contents/made (accessed November 2023)
[21] https://www.legislation.gov.uk/uksi/1998/3111/contents/made (accessed November 2023)
[22] https://www.calvera.es/calvera-hydrogen-develops-the-largest-ever-hydrogen-transport-tube-trailer-model-for-shell-hydrogen/ (Accessed November 2023)
[23] https://www.osti.gov/biblio/1461439 (Accessed November 2023)

existing evidence, this is not currently in use. Because ammonia is used widely as a feedstock for fertilisers, there is a high level of maturity in transport technologies – ammonia pipelines exist in the US, for example. Based on our literature review, there is little/no cost evidence on transporting liquid hydrogen or LOHCs by pipeline. There is some evidence comparing the cost of transporting compressed gas by pipeline vs ammonia. However, this evidence covers distances that would be larger than domestic transport in the UK, so have been excluded from this report. Most of the literature for UK domestic transport of hydrogen by pipeline focuses on transporting hydrogen as a compressed gas. This technology/form is therefore the focus of this next section.

Levelised costs

We do not have sufficient data on the inputs into the levelised costs of pipeline transport to produce a bottom-up calculator, like for road trailer transportation of gaseous hydrogen. Based on our literature review, the publication which presents the levelised cost of pipeline transport broken down by the most drivers is DNV's 2019 report on Hydrogen in the Electricity Value Chain[24]. Figure 4 below presents DNV's levelised costs of transport broken down by pipeline diameter, onshore or offshore, and length of pipe. In the annex to this report, other quantitative estimates of transportation by gaseous hydrogen are included. See Table A5 for the figures behind this graph. Although not directly comparable to other cost estimates in the literature because of differences in the method, the magnitude of levelised costs for gaseous transport of hydrogen is similar.

Figure 4: Levelised Costs of Hydrogen Transport (£/kg) by Pipeline



[24] NB: this was also the input data Frazer-Nash decided was most appropriate to use to calculate the T&S requirements in 2035 in this publication: https://www.gov.uk/government/publications/hydrogen-infrastructure-requirements-up-to-2035

Offshore pipelines are likely to be more expensive primarily because CAPEX costs are predicted to be higher, as more materials are required. Pipelines with a larger diameter would have slightly higher CAPEX costs, but here this is outweighed because higher capacities can be transported, lowering the levelised costs. In DNV's analysis, the biggest driver of differences in costs is the length of the pipeline, with a doubling in distance (50 to 100km) increasing levelised costs by just less than half.

Technical characteristics

A gas pipeline is a system of pipes used to transport natural gas or other gases from one location to another. Pipelines are an essential part of the UK energy infrastructure, providing a convenient, efficient, and economic mode for mass transportation of gases over long distances. Pipelines can be broadly classified into three categories: gathering lines, transmission lines, distribution lines.

Gathering pipelines are the initial stage in the gas supply chain, collecting gas from various wells and production facilities. They transport the gathered gas to central processing plants, where it is cleaned, processed, and compressed for transmission through larger pipelines. These gathering pipelines can vary in size and pressure levels, depending on the specific requirements of the production area.

Transmission lines are responsible for moving large quantities of natural gas or other gases over long distances. They are the backbone of the gas distribution system, connecting gas production fields to distribution centres, industrial facilities, and even export terminals. Transmission pipelines are typically large in diameter and operate at high pressures to ensure efficient mass transportation of gas. The National Transmission System (NTS), operated by National Grid, is a network of 7,630 km of high-pressure pipelines, that supplies natural gas directly to around 40 power stations and larger industrial users in Great Britain. The NTS also supplies gas to distribution networks who then supply natural gas to commercial and domestic users.

Distribution pipelines are the final stage in the gas supply chain, delivering natural gas from transmission pipelines to end-users, such as residential, commercial, and industrial consumers. These pipelines have a smaller diameter and operate at lower pressures compared to transmission pipelines. They are designed to transport gas safely and efficiently over shorter distances to homes and businesses.

Gas pipelines are typically constructed from materials such as steel, although newer pipelines may use materials like plastic or composite materials. They are equipped with various safety features, including pressure-regulating stations, control valves, and safety valves to ensure the safe and reliable transportation of natural gas.

Like natural gas, gaseous hydrogen can also be transported using pipelines. However, the current state of hydrogen pipeline infrastructure in the UK is still in the early stages of development. The UK currently has around 40 km of dedicated hydrogen pipeline networks that are owned and operated by two chemical companies[25]. While there are plans and projects underway to build new pipelines and repurpose existing gas pipelines for hydrogen transportation, there are no operational 100% hydrogen pipelines at scale in the country yet.

The construction of hydrogen pipeline infrastructure in the UK will involve significant planning, engineering, and investment. Although transmission of hydrogen via pipeline has many similarities with that of natural gas; hydrogen pipelines come with their own set of challenges.

In terms of materials and construction, hydrogen pipelines can experience issues with permeation and leaks due to the unique properties of hydrogen and the challenges associated with pipeline design and maintenance. Some of the key constraints for hydrogen pipelines include:

- **Hydrogen permeation through pipeline walls**: Hydrogen molecules can permeate through the walls of the pipeline. This phenomenon is a result of the small size of hydrogen molecules and the various processes involved in hydrogen permeation, such as adsorption, dissociation, diffusion, and desorption.
- **Hydrogen embrittlement of pipeline materials**: Hydrogen can cause embrittlement in certain materials, including metals like steel, which are commonly used in pipeline construction. This embrittlement can lead to cracks and ruptures in the pipeline, increasing the risk of leaks.

Material costs make up around 26% of the total expenses for building pipelines on average[26]. Therefore, reducing the thickness of the pipeline walls, can significantly cut down on the overall costs. Nowadays, natural gas transmission pipelines are usually made from higher strength steels, such as X70, which allows for thinner walls without compromising the pipeline's integrity. However, these high strength steels are more vulnerable to hydrogen permeation and embrittlement, making them potentially unsuitable for hydrogen pipelines. Instead, hydrogen pipelines are typically made from lower grade steel with thicker walls, which are more resistant to hydrogen embrittlement. Consequently, the use of more material in the construction of a hydrogen pipeline naturally increases the cost. Studies have found that pipelines designed specifically for carrying hydrogen can be up to 68% more expensive[27] than those for natural gas, depending on factors like pipe diameter and operating pressure. Work is ongoing to understand the technoeconomic considerations of converting natural gas pipelines in the UK to carry 100% hydrogen. If repurposed pipelines could be used to transport hydrogen, this would be at a lower cost compared to constructing new pipelines. Research conducted by ACER reviewed published literature on repurposing costs and concluded that the costs of repurposing pipelines is estimated at around 10-15% of the cost of constructing new pipelines[28].

The specific type of steel used for hydrogen pipelines in the UK may vary, and the development of hydrogen pipeline materials is still ongoing. However, the following is an

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[25] https://www2.deloitte.com/content/dam/Deloitte/uk/Documents/energy-resources/deloitte-uk-energy-resources-investing-in-hydrogen.pdf (accessed November 2023)
[26] https://escholarship.org/content/qt2gk0j8kq/qt2gk0j8kq_noSplash_cfbe115e54fba9e62c107c7ac2f3ef17.pdf (accessed November 2023)
[27] https://www.sciencedirect.com/science/article/abs/pii/S036031991501575X?via%3Dihub (Accessed November 2023)
[28] https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure_Overview%20of%20studies.pdf (Accessed November 2023)

example of some of the steel grades that have been used or are being developed for hydrogen pipelines.

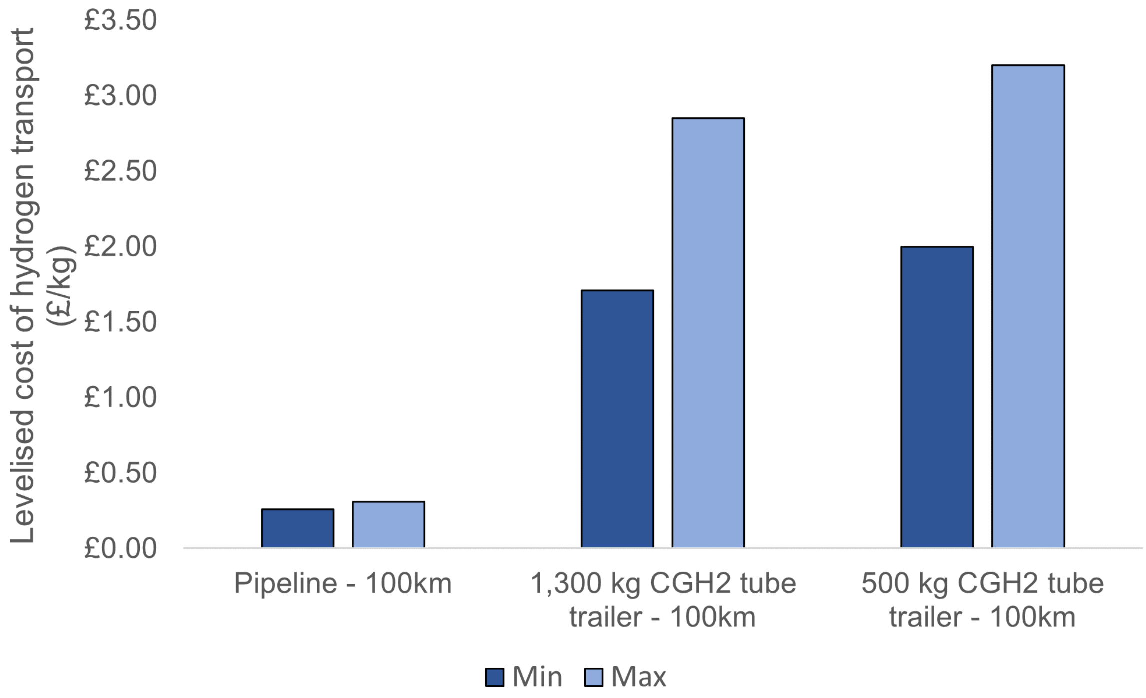
Submerged Arc Welded (SAW) Steel: Liberty Pipes Hartlepool has successfully passed trials to become the first UK producer of pipelines for safe transportation and storage of hydrogen. Physical testing by Element Materials Technology confirmed that Liberty's 42" SAW steel line pipe meets international requirements for hydrogen pipelines set by the American Society of Mechanical Engineers (ASME)[29].

[29] https://libertysteelgroup.com/liberty-pipes-hartlepool-becomes-first-uk-producer-of-hydrogen-pipeline-material-one-of-only-a-handful-globally/ (Accessed November 2023)

Summary

Although hydrogen is and can technically be transported by a variety of different hydrogen technology/form combinations, based on the technoeconomic characteristics, existing literature, and market intelligence, we anticipate that road transportation and pipeline transport of CGH2 will be the two main technologies emerging in the early years of the hydrogen economy. A comparison of the costs for these technologies, and a summary of the pros and cons of the technical characteristics follows. Figure **5** compares the maximum and minimum levelised costs of transporting CGH2 100km by pipeline or trailers presented in this report (see Table A6 for figures). The methods used to derive these cost estimates differ so will not be directly comparable. However, the costs of transporting a kg of CGH2 by road transportation will likely be more than the costs of transporting a kg of CGH2 by pipeline.

Figure 5: Minimum and Maximum Estimates of the Levelised Cost to Transport CGH2 100km, by Technology



Transport Technology	Pros	Cons
Road transportation – CGH2 tube trailer	• Easier infrastructure setup and maintenance cost • Composite storage vessels have been developed that have capacities of 500–1,300 kg of hydrogen per trailer • Lower cost compared to liquid hydrogen trailers • Faster refuelling times	• Lower energy density compared to liquid hydrogen trailers • Limited carrying capacity • Higher energy consumption for compression • High storage pressures require significant investment and incur increased operating costs

		• Safety concerns with high-pressure storage
Pipelines – CGH2	• Low cost option for delivering large volumes of hydrogen • Existing pipelines can be repurposed for hydrogen transport	• High initial capital costs of new pipeline construction • Converting existing natural gas pipelines to deliver pure hydrogen may require more substantial modifications • Technical concerns related to pipeline transmission, including the potential for hydrogen to embrittle the steel and welds used to fabricate the pipelines, need to control hydrogen permeation and leaks, and need for lower cost, more reliable, and more durable hydrogen compression technology

Levelised costs of hydrogen transport vs transporting other fuels

Like storage, the costs of transporting hydrogen are likely to always be more expensive than for natural gas because of its low volumetric energy density. Given transporting gas, including hydrogen, through pipelines is usually cheaper than transporting electricity, building hydrogen networks, or converting natural gas networks to hydrogen has the potential to reduce overall energy system costs[30]. However, there will be trade-offs across the energy system that will need to be considered before making decisions around network development, whether hydrogen or electricity.

[30] Cost of Long-Distance Energy Transmission by Different Carriers: https://www.sciencedirect.com/science/article/pii/S2589004221014668 (Accessed November 2023)

Section 5: Conclusions

As set out in the introduction, this report has collated existing evidence on transport and storage into a single reference point. Through compiling this report, we have identified several evidence gaps which would better our understanding of hydrogen transport and storage technologies, particularly:

- Improved understanding of the potential emerging end-to-end archetypes, covering production plants, transport and storage required, and end-use, which will be key to understanding the compression/conversion costs necessary for transport and storage.

- Improved understanding of the theoretical cycling rates for storage technologies, and the likely cycling rates based on demand for the storage facility to better our understanding of storage costs.

Because hydrogen transport and storage technologies have not yet been deployed at scale, much of the evidence on potential costs is theoretical. As hydrogen projects apply for business model support and projects conduct more feasibility studies, we will obtain more up to date data on the predicted costs of transport and storage technologies which can be used to refine our evidence base.

Annex

Underlying data

The following tables present the data included in Figures throughout this report.

Table A1: Comparison of Selected Hydrogen Forms[31]

Properties	Units	H2 STP	CGH2	Liquid H2	MCH	Ammonia
State	-	gas	gas	liquid	liquid	liquid
Density	kg/m^3	0.09	26.6^a 44.4^b 62.1^c	70.8	770	610^d 680^e
Volumetric H2 content	kgH_2/m^3	0.09	26.6 44.4 62.1	70.8	47.1	107.7 120
Volumetric energy density^f	kWh/dm^3	0.003	0.9 1.5 2.1	2.4	1.6	3.6 4.0
Gravimetric H2 content	wt%	100	100	100	6.1	17.65
Gravimetric energy density^g	kWh/kg	33.33	33.33	33.33	2.0	5.8

^{a}At 0°C and 300 bar. ^{b}At 0°C and 500 bar. ^{c}At 0°C and 700 bar. ^{d}At 20 °C and 10 bar. ^{e}at –30 °C. ^{f,g}Values are the corresponding hydrogen energy densities, calculated based on the LHV of hydrogen (LHV_{H2} = 33.33 kWh/kg).

Table A2: Levelised Costs of Hydrogen Storage[32]

Hydrogen technology/form	Levelised cost (£/kg)			Cycles (per year)	Pressure (bar)
	Total	Conversion/ compression	Total less conversion/ compression		
Tank/vessel (CGH2)	£1.39	£0.96	£0.43	120	700
Tank/vessel (LH2)	£1.39	£1.22	£0.17	52	n/a
New salt cavern (CGH2)	£0.26	£0.13	£0.13	9	250
New aquifer (CGH2)	£0.23	£0.13	£0.10	5	250
New depleted gas field (CGH2)	£0.24	£0.13	£0.11	2	250

[31] https://pubs.acs.org/doi/10.1021/acsenergylett.1c02189 (accessed November 2023)
[32] https://www.dnv.com/Publications/hydrogen-in-the-electricity-value-chain-225850 (accessed November 2023)

Table A3: Levelised Costs of Hydrogen Transport by Type IV CGH2 Tube Trailers – 100 Trips/yr

Distance Travelled/trip (km)	Levelised cost							
	500 kg Capacity				1,300 kg Capacity			
	Trailering		Incl. compression		Trailering		Incl. compression	
	£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh
25	2.39	61	3.86	98	2.20	56	3.47	88
100	2.62	67	4.09	104	2.29	58	3.56	90
200	2.93	74	4.40	112	2.41	61	3.68	93
300	3.24	82	4.71	120	2.53	64	3.80	97

Table A4: Levelised Costs of Hydrogen Transport by Type IV CGH2 Tube Trailers – 300 Trips/yr

Distance Travelled/trip (km)	Levelised cost							
	500 kg Capacity				1,300 kg Capacity			
	Trailering		Incl. compression		Trailering		Incl. compression	
	£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh
25	1.00	25	2.26	57	0.81	21	2.01	51
100	1.23	31	2.49	63	0.90	23	2.10	53
200	1.54	39	2.80	71	1.02	26	2.21	56
300	1.85	47	3.11	79	1.14	29	2.33	59

Table A5: Levelised Costs of Hydrogen Transport (£/kg) by Pipeline

	Levelised Cost (£/kg)			
	50 km Pipeline		100 km Pipeline	
	7” Pipeline Diameter	10” Pipeline Diameter	7” Pipeline Diameter	10” Pipeline Diameter
Onshore	0.15	0.14	0.27	0.26
Offshore	0.16	0.16	0.31	0.30

Table A6: Minimum and Maximum Estimates of the Levelised Cost to Transport CGH2 100km, by Technology

	Levelised Cost (£/kg)	
	Minimum	Maximum
Pipeline	0.26	0.31
1,300 kg CGH2 Trailer	2.10	3.56
500 kg CHH2 Trailer	2.49	4.09

Additional levelised cost data from published sources

In the main body of this report, we presented the levelised cost data from DNV's 2019 publication and cost data on trailering based on internal analysis. In this section of the annex, where available we have provided costs estimates from other published sources for the technologies presented in this report[33]. Comparing these cost estimates allows us to have a useful insight into the potential ranges and uncertainty of the levelised cost of transport and storage technologies. However, the following estimates should not be used for direct comparisons as the methods used to produce levelised costs will differ, and variations in the methods may drive some differences, rather than revealing true cost differences between the technologies.

Table A7:Levelised Cost of Trailering Compressed Hydrogen Gas, adjusted for £2023 prices, by external source

	Levelised Cost (£/kg)		
	Gas	Incl. Compression Cost	Description
Deloitte[34]	0.15	0.76	-
Royal Society[35]	-	1.88	-
H2 Council[36]	0.79	-	-
DNV[37]	-	1.48	350 bar

[33] For some storage technologies – aquifers and depleted gas fields – we found no other published data on the levelised costs of these technologies.
[34] https://www2.deloitte.com/content/dam/Deloitte/uk/Documents/energy-resources/deloitte-uk-energy-resources-investing-in-hydrogen.pdf (accessed November 2023)
[35] https://royalsociety.org/-/media/policy/projects/green-ammonia/green-ammonia-policy-briefing.pdf (Accessed November 2023)
[36] https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf (November 2023)
[37] https://www.dnv.com/Publications/hydrogen-in-the-electricity-value-chain-225850 (accessed November 2023)

Table A8:Levelised Cost of Transporting Compressed Hydrogen Gas via Pipelines, adjusted for £2023 prices, by external source

	Levelised Cost (£/kg)		
	Gas	Incl. Compression Cost	Description
Deloitte	0.12	0.74	Distribution
	0.33	0.95	Transmission
Royal Society	0.83	-	1,400km
H2 Council	0.4	-	Distribution

Table A9: Levelised Cost of Hydrogen Storage Technologies, adjusted for £2023 prices, by external source

Storage Technology	External Source	LCOS £/kg £2023 Prices
CGH2 tank (700 bar)	Deloitte (2020)	0.74
Ammonia Tank	Deloitte (2020)	1.88
Salt Cavern	Frazer Nash (2022)	0.27
	Aurora (2021)	0.27
	Deloitte (2020)	0.72

CGH2 trailers: Levelised Costs Calculations

The following section outlines the assumptions used to calculate the levelised costs of road transportation of hydrogen via CGH2 tube trailers presented in Section 4 over a 15-year period.

Assumptions: Compression

The capital cost of a hydrogen compressor can vary significantly based on factors such as size, efficiency, and construction materials. Our findings indicate that the typical cost of a hydrogen compressor ranges from £40,000 to £120,000, with the possibility of exceeding this range for large compressors[38]. For our calculations, we assume an average cost of £80,000 for a hydrogen compressor. It is important to note that this assumption is specific to our calculations.

Additionally, we estimate the annual fixed operating and maintenance (O&M) cost to be 5% of the hydrogen compressor's capital expenditure. Actual maintenance costs may vary depending

[38] https://pureenergycentre.com/hydrogen-products-pure-energy-centre/hydrogen-compressor/ https://pureenergycentre.com/hydrogen-products-pure-energy-centre/hydrogen-compressor/ (accessed November 2023)

on factors such as the compressor's reliability, operational frequency, and specific maintenance practices.

The energy required to compress hydrogen is a significant cost factor. The required compression energy depends on the thermodynamic compression process. Two thermodynamic processes are considered: adiabatic compression, and isothermal compression[39]. For adiabatic compression, the energy consumed in the compression process is given by:

$$W = \left[\frac{\gamma}{(\gamma - 1)}\right] p_0 V_0 \left[\left(\frac{p_1}{p_1}\right)^{(\gamma-1)/\gamma} - 1\right]$$

Where, W is the specific compression work (J/kg), p_0 is the initial pressure (Pa), p_1 is the final pressure (Pa), V_0 is the initial specific volume (V_0 = 11.11 m^3/kg for hydrogen), and γ is the ratio of specific heats (γ = 1.41 for hydrogen).

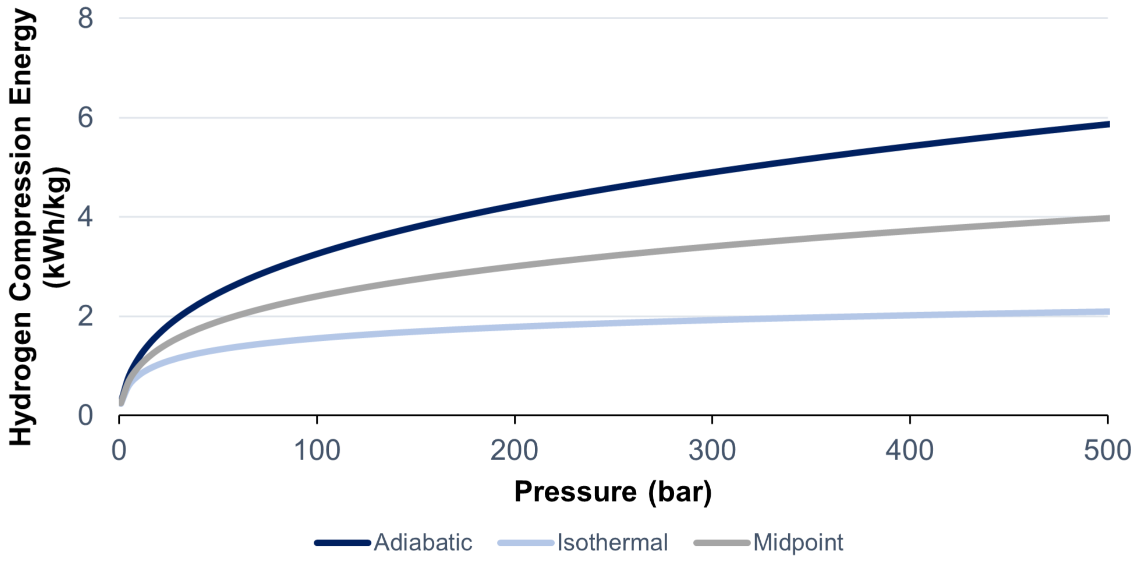
For isothermal compression, the required energy is then given by:

$$W = p_0 V_0 \ln\left(\frac{p_1}{p_0}\right)$$

Figure A1provides a comparison of the energy requirements associated with adiabatic and isothermal compression methods. Achieving ideal isothermal conditions is currently unattainable with existing compressor technology. Instead, the use of multi-stage compressors with intercoolers allows compression to operate within a range between these two limiting curves. In our analysis, we assume a midpoint compression profile between the adiabatic and isothermal limiting curves as an illustrative example of the energy requirements of a multi-stage compressor.

[39] https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf

Figure A1: Adiabatic vs. Isothermal Compression Energy



It is presumed that the compression energy is sourced from electricity. As of 2022, the average cost of electricity in the UK was 27p/kWh[40]. Using the midpoint compression energy profile depicted in Figure A1 we can calculate the cost of compressing hydrogen to 500 bar. Moreover, we assume a typical outlet pressure of 30 bar from an electrolyser, resulting in an overall compression energy requirement of 2.41 kWh/kg of hydrogen. This equates to a compressor operating cost of £0.68/kg of hydrogen.

Assumptions: CGH2 Trailers

The primary factors that contribute to hydrogen delivery costs include capital costs of tube trailers, driving distance, driver labour, diesel fuel expenses, and O&M costs. On average, the capital cost of composite tube trailers is approximately £1,046 per kilogram (price converted into GBP and adjusted for inflation to 2022 prices) of deliverable hydrogen payload[41]. We assumed an annual operational and maintenance cost of 5% of the trailer's capital expenditure. For a comprehensive understanding, we have detailed some key assumptions related to tube trailer delivery of hydrogen in Table A10 which were used to produce the cost estimates presented in this report.

[40] https://energyguide.org.uk/average-cost-electricity-kwh-uk/ (accessed November 2023)
[41] https://www.sciencedirect.com/science/article/abs/pii/S0360319918300843 (accessed November 2023)

Table A10: General Tube Trailer Assumptions

Tube Trailer Capacity (kg)	500	1,300
Capital Cost[42]	£520,000	£1,360,000
Operating Pressure (bar)	500	
Trailer loading time (hr)	3	
Trailer unloading time (hr)	1	
Fuel efficiency[43] (mpg)	7.9	
Average trailer speed (km/hr)	50	
Labour[44] (£/hr)	16.85	
Fuel cost (£/L)	1.60	
O&M Cost (annual)	5% trailer capex	

Transporting hydrogen by compressed gas tube trailer involves several potential losses, including leakage and residual gas. For our analysis we estimate leakage volume to be in the range of 0.1 to 1% of the trailer's capacity.

Residual gas losses occur when the remaining pressure in the trailer is not sufficient to push the remaining hydrogen out of the trailer after delivery. While exact percentages for residual gas losses in tube trailers will vary, we have assumed here that residual gas left behind after delivery to be 0.5 to 2% of the trailer's capacity.

Sensitivity Analysis

Multiple assumptions have been made in our calculations to derive levelised cost estimates. We decided to conduct sensitivity analysis on the cost of compression, as this plays a significant role in the levelised cost calculations and there was little publicly available data to cross-reference this with. Consequently, we carried out sensitivity tests to examine how levelised costs is affected by: (a) compressor capital cost, and (b) compression energy requirements.

We chose to examine how a £40,000, £80,000, and £120,000 compressor effected the levelised costs of transporting hydrogen by CGH2 tube trailer. These price points were selected based on search results for the cost of a hydrogen compressor45. Note that in our calculations the annual O&M cost is 5% of the compressor capital cost. The results from this analysis are displayed in Table A11.

[42] Capital Cost (£) = £1,046/kg of deliverable hydrogen payload (price converted into GBP and adjusted for inflation to 2022 prices)
[43] https://assets.publishing.service.gov.uk/media/5bc75808e5274a1219d54a18/env0104.ods (accessed November 2023)
[44] https://uk.indeed.com/career/tanker-driver/salaries (Accessed November 2023)
[45] https://pureenergycentre.com/hydrogen-products-pure-energy-centre/hydrogen-compressor/
https://pureenergycentre.com/hydrogen-products-pure-energy-centre/hydrogen-compressor/ (accessed November 2023)

Table A11: Sensitivity analysis examining compressor capex on the levelised cost of transporting CGH2 by tube trailer

	Distance travelled (km)	Levelised Cost							
		Trailering		Trailer + £40k compressor		Trailer + £80k compressor		Trailer +£120k compressor	
		£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh
500kg trailer 100 trips/yr	25	2.39	61	3.70	94	3.86	98	4.02	102
	100	2.62	67	3.93	100	4.09	104	4.25	108
	200	2.93	74	4.24	108	4.40	112	4.56	116
	300	3.24	82	4.55	116	4.71	120	4.87	124
500kg trailer 300 trips/yr	25	1.00	24	2.21	56	2.26	57	2.31	59
	100	1.23	31	2.44	62	2.49	63	2.55	65
	200	1.54	39	2.75	70	2.80	71	2.86	73
	300	1.85	47	3.06	78	3.11	79	3.17	80
1,300kg trailer 100 trips/yr	25	2.20	56	3.41	87	3.47	88	3.53	90
	100	2.29	68	3.50	89	3.56	90	3.62	92
	200	2.41	61	3.62	92	3.68	93	3.74	95
	300	2.53	64	3.74	95	3.80	97	3.86	98
1,300kg trailer 300 trips/yr	25	0.81	21	1.99	50	2.01	51	2.03	51
	100	0.90	23	2.07	53	2.10	53	2.12	54
	200	1.02	26	2.19	56	2.21	56	2.23	57
	300	1.14	29	2.31	59	2.33	59	2.35	60

The energy required to compress hydrogen is a considerable cost factor. We based our assumptions of compression energy requirements on theoretical calculations. As shown in Figure A1 we defined the midpoint curve as a reasonable assumption for the real-life energy cost to compress hydrogen (standard compression energy cost). By assuming a typical pressure outlet of 30 bar from an electrolyser, we calculated that the energy required to further compress hydrogen to 500 bar is 2.41 kWh/kg (£0.68/kg)

As a sensitivity test, we examined how increasing and decreasing compression energy requirements affected the levelised cost of transporting hydrogen by CGH2 tube trailers.

- **High compression energy cost**: a secondary midpoint curve was calculated between the primary midpoint curve and upper adiabatic curve. The energy required to further compress hydrogen from 30 bar to 500 bar is 3.36 kWh/kg (£0.94/kg)
- **Low compression energy cost**: a secondary midpoint curve was calculated between the primary midpoint curve and lower isothermal curve. The energy required to further compress hydrogen from 30 bar to 500 bar is 1.47 kWh/kg (£0.41/kg)

The results from this analysis are presented in Table A12.

Table A12: Sensitivity analysis examining compressor operating costs on the levelised cost of transporting CGH2 by tube trailer

	Distance travelled (km)	Levelised Cost							
		Trailering		Standard compression cost		High Compression Cost		Low Compression Cost	
		£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh	£/kg	£/MWh
500kg trailer 100 trips/yr	25	2.39	61	3.86	98	4.31	109	3.41	87
	100	2.62	67	4.09	104	4.54	115	3.64	92
	200	2.93	74	4.40	112	4.85	123	3.95	100
	300	3.24	82	4.71	120	5.16	131	4.26	108
500kg trailer 300 trips/yr	25	1.00	25	2.26	57	2.71	69	1.81	46
	100	1.23	31	2.49	63	2.94	75	2.04	52
	200	1.54	39	2.80	71	3.25	83	2.35	60
	300	1.85	47	3.11	79	3.56	91	2.66	68
1,300kg trailer 100 trips/yr	25	2.20	56	3.47	88	3.92	100	3.02	77
	100	2.29	58	3.56	90	4.01	102	3.11	79
	200	2.41	61	3.68	93	4.13	105	3.23	82
	300	2.53	64	3.80	97	4.25	108	3.35	85
1,300kg trailer 300 trips/yrs.	25	0.81	21	2.01	51	2.46	62	1.55	39
	100	0.90	23	2.10	53	2.55	65	1.64	42
	200	1.02	26	2.21	56	2.67	68	1.76	45
	300	1.14	29	2.33	59	2.79	71	1.88	48

This publication is available from: www.gov.uk/government/publications/hydrogen-transport-and-storage-cost

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