Hydrogen Transportation and Storage Infrastructure

Assessment of Requirements up to 2035

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Executive Summary

Hydrogen is set to play a key role in the decarbonisation of the UK's energy system. Starting with some initial applications in local transport and industry, its use is expected to grow significantly in the 2030s, playing a significant role in broader industrial decarbonisation, provision of flexible power generation and potentially nationwide transportation such as Heavy Goods Vehicles (HGVs). Hydrogen could potentially play a role in the decarbonisation of the gas network, either in the short to medium term by blending up to 20% hydrogen with natural gas, or in the longer term by full conversion of the natural gas network to 100% hydrogen. Blending could also help support the growth of hydrogen production, as an early/reserve offtaker whilst transport and storage infrastructure develops and the number of end users grows. There is also significant interest in the role of liquid hydrogen and hydrogen carriers (ammonia or synthetic fuel) to decarbonise shipping and aviation, which could see large scale deployment post 2030. To meet all these sector demands, the government has set a target ambition for up to 10GW of low carbon hydrogen production capacity by 2030.

This emerging hydrogen energy system will require supporting infrastructure in hydrogen transportation (via either new and repurposed pipelines or transport by road, rail or ship) and hydrogen storage (as surface storage in tanks or longer-term storage in salt caverns). Whilst there is increasing certainty around the applications for hydrogen and also how this will be produced, to date there has been limited investigation of this supporting infrastructure. Frazer-Nash and our partner Cornwall Insight have been asked by BEIS to develop the evidence base on hydrogen transport and storage infrastructure. This study uses five structured work packages to predict the requirements and costs of hydrogen transport (pipelines and trailering) and hydrogen storage (salt caverns and surface storage) up to 2035. It also considers the *commercial configurations* that could be used to develop the hydrogen transport and storage infrastructure, drawing on relevant existing commercial arrangements from other industries. Finally, it identifies barriers to investment for this infrastructure.

Methodology

Figure 1 shows the process and work packages used in this study.

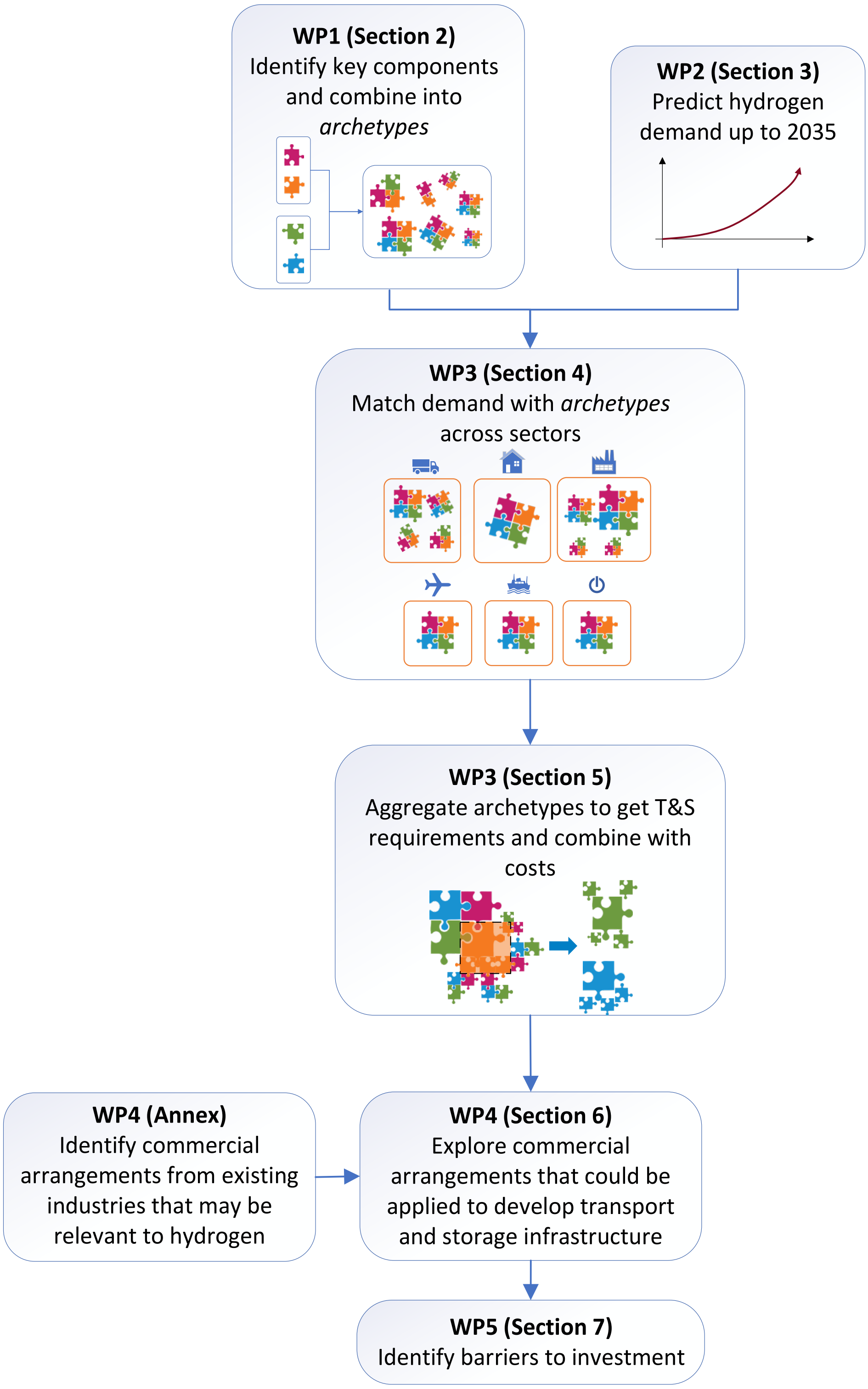


Figure 1: Overview of process and work packages in this study

In Work Package 1 (WP1) the key components of the hydrogen economy are identified and combined into a series of *archetypes* where these technologies work together.

In Work Package 2 (WP2) predictions for demand are prepared for 2030 and 2035. These predictions are split into the following sectors; industry, transport (including road, regional aviation, and small ferries), buildings, power, shipping, and aviation.

In Work Package 3 (WP3) the demand predictions and *archetypes* assigned to each sector are combined to give estimated hydrogen Transportation and Storage (T&S) requirements. These are then used to predict the cost of hydrogen T&S.

In Work Package 4 (WP4), commercial arrangements are explored that apply to the hydrogen T&S infrastructure. It was found that, for this purpose, the *archetypes* group into three different types of *commercial configurations*. These are outlined in Figure 2, and are used to explore potential commercial arrangements.

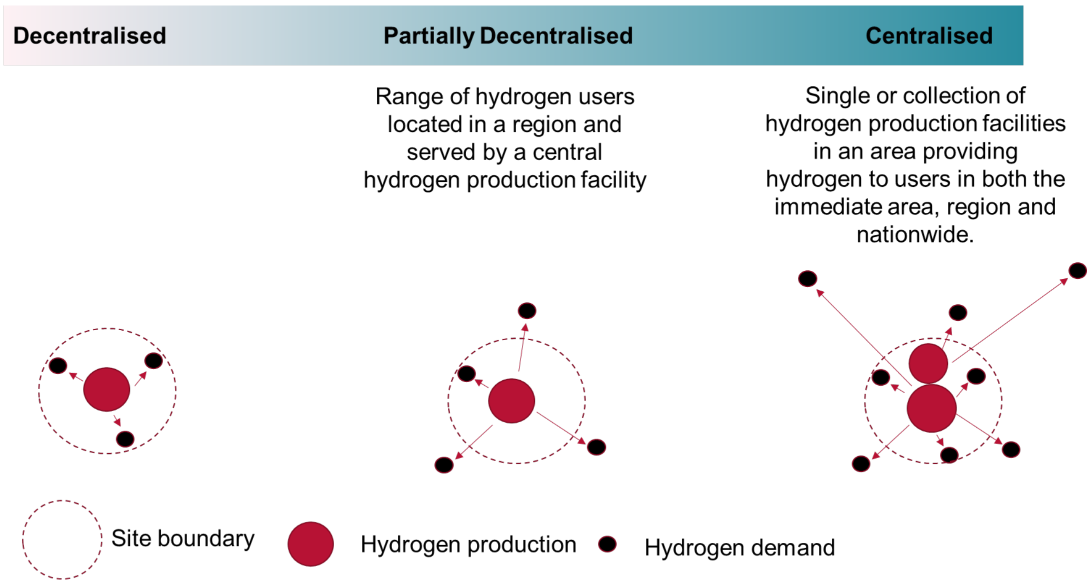


Figure 2: Explanation of *Commercial Configuration* used to explore the commercial arrangements relevant to *archetypes*

In Work Package 5 (WP5), barriers to investment are outlined based on the findings of earlier work packages.

Based on our assumptions, what are the requirements for hydrogen transport and storage up to 2035?

Transport: By 2030 there is a predicted requirement of between 100km and 1,000km of pipeline. The large range in this requirement is mainly driven by uncertainty in the role of hydrogen in power. By 2035, the demand for hydrogen pipeline is expected to increase significantly (to between 700km and 26,000km of pipeline – with approx. 24,750km of this maximum relating to hydrogen demand in buildings[1]), due to growth in the use of hydrogen for power and potentially in domestic buildings (including regional heating), as well as introduction into shipping and aviation markets. Trailering of hydrogen is also expected to play a significant role in hydrogen delivery in 2030 and 2035, serving small users without on-site hydrogen production (*archetypes* 3 and 7).

[1] In this study, it has not been estimated how much of this pipeline length will be new vs. repurposed. An assumption has been made, to aid cost estimates, that pipeline for buildings can be repurposed.

Storage: Storage will be required to balance hydrogen production and demand. In this study, it is assumed that storage will be needed to ensure consistent hydrogen supply from production and also as reserve for the use of hydrogen in flexible power production. In reality, the storage capacity required will depend on the different end users, and consistent supply from production might not be necessary for all end uses. Electrolytic hydrogen production has inter-day and seasonal variability which it is estimated will require, respectively, storage capacity of around 1% and 10% of average annual hydrogen production. CCUS-enabled hydrogen production will require an estimated 0.4% to 5% average annual production in storage depending on the distribution of production plant downtime through the year. The demand for hydrogen in industry and transport is likely to be fairly unform across the year but hydrogen demand for flexible power will be considerably more variable and this will be a key driver for storage. Storage for flexible power is predicted to be between 3% and 5% of average annual demand.

Hydrogen demand for heat is seasonal and is broadly correlated with electrolytic hydrogen production driven by wind (it is generally windier in the winter). In this study, we make the simple assumption that no storage is required as a reserve for heating. However, if hydrogen demand for heat increases significantly after 2035, then we predict that much more storage will be required for heat, depending on the proportion of electrolytic hydrogen in the hydrogen production mix.

Overall, it is predicted that between 0.02 – 0.9 TWh of surface storage will be required in 2030, rising to between 0.04 – 2.3 TWh in 2035. It is predicted that between 0.2 – 3.1 TWh of salt cavern storage is required by 2030 and between 0.6 – 13.2 TWh by 2035.

What is this transportation and storage infrastructure likely to cost?

The estimated levelized costs for transport and storage of hydrogen are summarised as follows.

Year	Costs from levelized hydrogen transport costs (£/kg) and annual demand (kg)			
	Pipeline (£M)		Trailering (£M)	
	Minimum	Maximum	Minimum	Maximum
2030	39	129	28	133
2035	239	636	64	357
	Costs from levelized hydrogen storage costs (£/kg) and annual demand (kg)			
	Cost of surface storage (£M)		Cost of salt cavern storage (£M)	
	Minimum	Maximum	Minimum	Maximum
2030	0.3	13.2	1.2	20.4
2035	0.6	35.5	5.4	86.9

These cost predictions are based on the assumptions in this study. Overall, there is significant uncertainty in the cost predictions for transport and storage infrastructure out to 2035. This is the result of the combination of 3 individual factors:

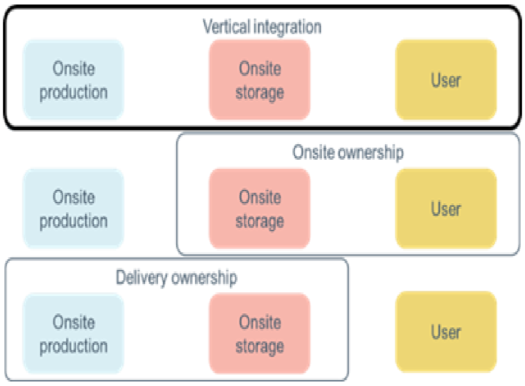
- Variability in the overall demand for hydrogen in 2030 and 2035;
- Difficulty in accurately predicting the required transport and storage requirements on an individual *archetype* level;
- Variability in the unit costs of storage (£/kg) and transport (£/kg, £/km for capex).

The latter two factors could be improved as follows:

- Hydrogen storage: Further explore how the requirements for hydrogen storage may change with different types and quantities of wind power.
- Hydrogen transport: Further investigate the distances between large producers and users that will require pipelines.

What *commercial configuration* could be used to develop this infrastructure and what commercial challenges are there?

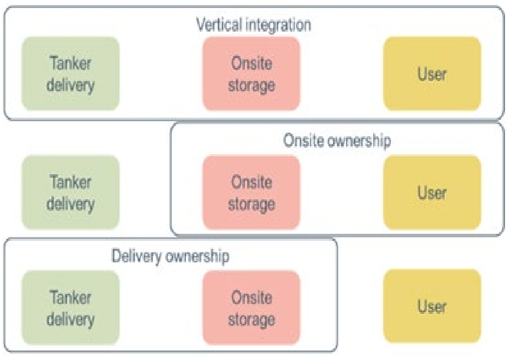
Decentralised configuration: Vertical integration, where the entire site is owned by a single entity – such as a joint venture, is likely to be the most efficient structure in the first instance, but this would require amendment to regulatory arrangements. It is expected that parties will come together to form a Special Purpose Vehicle (SPV) to operate a site or sites and thereby simplify contractual arrangements and risk management. This is a simple contracting arrangement with no commercial barriers other than price. However, on public access sites (for example at hydrogen refuelling stations), there is less certainty of end-user demand and as the market for hydrogen and a potential network develops, decentralised arrangements may not be cost-effective.



Partially Decentralised configuration: Commercial arrangements may either be vertical integration, onsite ownership (comprising onsite storage and users) or delivery ownership (tanker delivery and onsite storage).

Pipeline connected sites are possible, but it is considered tanker deliveries will be more likely.

The flexible nature of contracting and remote delivery by tanker lends itself to a highly competitive market, provided that there a number of parties offering delivery services. However, it does not provide high security of supply, as there is no guarantee of deliveries being made available from fuel suppliers. For early development sites, some form of take-or-pay contract guaranteeing the volume and price of regular deliveries and thus investment in tanker delivery services, at the recipient's financial risk, may be suitable. Potential barriers are seen in sizing of storage and limitations to number of trailer delivers allowed by local planning considerations, but these could be resolved with amendments to regulations to support larger trainer receptacles to reduce frequency of deliveries.



Centralised configuration (hydrogen production centres): These are expected to be more commercially complex configurations than the decentralised and partially decentralised configurations as they will have multiple producers, using different technologies, and multiple consumers, located at each site. In this case the considerations are different for each party:

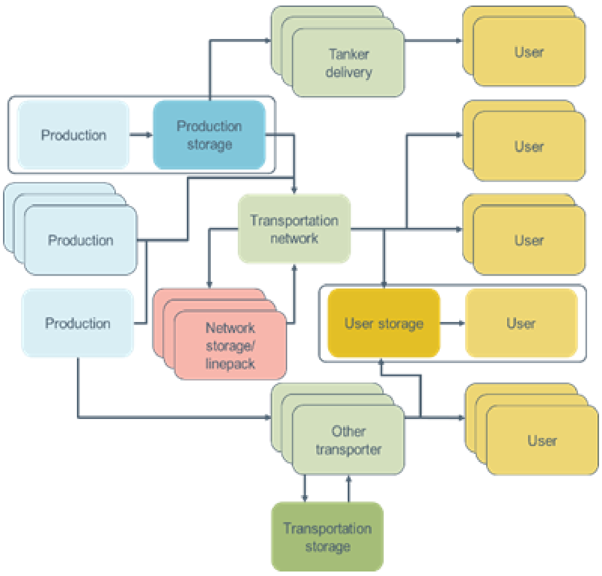
- Producers will aim to maximise economic production and sell direct to consumers or intermediaries, or to inject into storage assets.

- Networks and storage owners/operators will aim to recover the correct economic costs of the long-term investment in their assets.
- For consumers, the primary concern is for security of supply and being able to receive hydrogen at an affordable cost.

Given that there is a network, there is also a need for a system operator role, which would have responsibility to keep the physical system safe and operating within guidelines and commercial arrangements. This system operator role may also apply to the partially decentralised *commercial configuration*, and this would depend on the scale and efficiency seen and how this develops over time. The key differentiator here is whether the network owner and the network-connected storage asset are single or multiple parties. This study suggests that either vertically integrated or independent commercial arrangements could be feasible.

Consultation with industry highlighted that a Regulated Asset Base (RAB) model might be most suitable for both pipeline networks and storage, although for storage cap-and-floor arrangements or other methodologies might be equally suitable, as long as they delivered certainty on the level of revenue over the initial investment period (around 15 years). However, a contract with a sufficiently creditworthy counterparty was also considered viable by a significant minority of users.

The development of the centralised *commercial configuration* is largely dependent upon the presence of hydrogen storage of multiple durations (within-day, monthly, seasonal, and multi-seasonal) although storage types of this nature could also be part of a partially decentralised *commercial configuration*. These storage sites are likely to be geological in structure, for example salt caverns or depleted gas fields, and are cost-effective when compared to multiple compressed hydrogen storage tanks. However, market signals are unlikely to be sufficient for this long-duration storage to emerge organically, particularly given the lack of a liquid market in hydrogen. Furthermore, the government's plan for publishing a business model for hydrogen storage in 2025 creates a timeline which will deliver storage in the early-mid 2030s. Potential storage investors or operators have highlighted that the build-times for geological storage assets – which can be as short as 4–5 years, but which are more typically 6–8 years – do not align with the planned release date for the storage business model and the start of requirement for large-scale storage of hydrogen. This is therefore mismatched with the need to make investment decisions on the size of hydrogen gas processing infrastructure that fits both near and longer-term requirements. A solution that bridges the gap with an early or interim funding model may overcome this.



The market barrier to the development of larger-scale hydrogen storage is insufficient certainty on a return on an investment. Without an incentive (in the form of long-term revenue certainty) it is extremely unlikely that any operator would choose to invest capital into the necessary equipment. This risks undermining the emergence of large-scale hydrogen projects and consequential learnings from early projects to be passed down to subsequent projects, for example in terms of supply chains and operations. Third party access to grid scale storage assets is an enabler to growing the hydrogen economy and storage providers can aid this by providing sufficient and timely information as to the availability of storage capacity both in the near and long term.

Overall, the following actions are proposed to develop the commercial arrangements for hydrogen transport and storage infrastructure:

- Review the rules for the transport of hydrogen by road and the storage of hydrogen in surface tanks (if they have not been already) to check if they are fit for purpose for the more widespread use a hydrogen economy would entail.
- Develop an early, interim or innovation funding model for trial grid-scale salt cavern storage projects.
- Accelerate the deployment of hydrogen blended into the current gas network, including in respect of issues such as the permitted percentage blend and how this percentage blend will change over time (e.g., starting at 5% then increasing to 20% within five years).

Glossary

Term	Description	Example
Archetype	An *archetype* is a group of technologies that work together to support a hydrogen use case, from production to use.	Production via PEM electrolysers attached to a wind farm, salt cavern storage, blending at 20% via national gas pipelines, to be used in heating for homes in a specified region
CCUS-enabled hydrogen production	Hydrogen production from natural gas, where the carbon dioxide outputs are captured and stored.	
Commercial configuration	This is a characteristic of an *archetype*. There are 3 *commercial configurations* considered in this study. The *commercial configuration* describes the commercial framework in which an *archetype* works best.	**Centralised** – This is where a large producer of hydrogen is connected via a network to multiple users. The system works across the UK, connecting all possible users to a hydrogen producer. **Partially decentralised** – This is somewhere between a fully centralised or decentralised system. An example could be where small to medium size hydrogen producers are connected to multiple users, not co-located on the same site. **Decentralised** – This is where small producers are directly connected to a user. It is localised and does not require a transport network.
Complementary technology	This is a technology that is normally, but not necessarily required in an *archetype*. These will fall into the category of storing or transporting hydrogen.	Salt cavern as a storage technology of hydrogen. Gas pipelines in the national gas network as a hydrogen transport technology.
Electrolytic hydrogen production	Hydrogen production via electrolysis. In this study (up to 2035), this is assumed to be powered from renewable electricity, principally wind power.	
Hydrogen Production Centre	Large-scale hydrogen production connected to multiple users within a geographical boundary (potentially distinct from currently recognised UK industrial clusters).	
Load Factor (LF)	The energy (or hydrogen) produced in a year divided by the peak power output (or hydrogen production rate) if operating at peak output all year.	

Term	Description	Example
Production (technology)	A specific technology that produces hydrogen.	A PEM electrolyser as described above. A large steam methane reformation (SMR) plant with carbon capture and storage (CCS) capability. Note this example is not considered a 'storage' technology for the purpose of this project, as it is not being used to store the hydrogen.
Required technology	This is a technology that is required in an *archetype*. These will fall into the category of producing hydrogen, or using hydrogen.	A small PEM (Proton Exchange Membrane) electrolyser as a hydrogen production technology for a fleet of hydrogen powered refuse collection vehicles (RCVs), as a hydrogen using technology.
Storage (technology)	A specific technology whose purpose is to store hydrogen. Hydrogen stored temporarily in pipelines, for example, is not a storage technology.	Surface storage tank, at 10MPa.
Transport / Distribution (technology)	A specific technology that is used to distribute or transport hydrogen, from a producer to a user or storage location. Note this is not a technology that uses hydrogen to transport other goods or people.	Gas pipelines in the national gas network.
Use (technology)	A specific technology that uses hydrogen, considered as demand in the hydrogen economy.	A fleet of hydrogen powered Refuse Collection Vehicles (RCVs).

Contents

1 Introduction

1.1 Background

The government's UK Hydrogen Strategy in 2021 [1] highlighted the importance of hydrogen for decarbonising hard-to-abate sectors. It set out how hydrogen has the potential to decarbonise industry, provide greener, flexible energy in the power sector, how it could play a significant role in road transport and heat, and how longer term it is likely to be used to decarbonise shipping and aviation. It included an ambition of up to 5 GW of low carbon hydrogen production capacity by 2030 and included analysis suggesting hydrogen demand is likely to increase significantly in the 2030s. The UK Hydrogen Strategy was followed up in 2022 by the British Energy Security Strategy [2], recognising that hydrogen can provide a key role in providing resilient and secure energy security. This strategy doubled the UK's target for low carbon hydrogen production capacity from 5 GW to up to 10 GW by 2030, with an aspiration that at least half of this will come from electrolytic hydrogen.

Whilst the future role of hydrogen in the UK energy system is becoming clearer, hydrogen is still a nascent industry in the context of decarbonisation. Small independent hydrogen ecosystems are developing for specific hydrogen applications, where production and demand are co-located. At larger scale, hydrogen production centres are forming to consolidate hydrogen demand from different industrial processes. The next five years will see deployment of hydrogen projects of different forms and sizes and the industry is likely to start accelerating out to 2035. The diversity of applications for hydrogen and its ability to be transported and stored will mean that hydrogen is likely to become a traded commodity, and the different end-users and producers will become progressively more interlinked.

The development of the hydrogen energy system will require supporting transport and storage infrastructure. Hydrogen will need to be transported by either pipeline or road trailer from production facilities to end-users, and storage will be needed to balance production and demand. Whilst there is increasing certainty over the uses of hydrogen and how it will be produced, there is currently significantly less certainty on the requirements for this supporting transport and storage infrastructure and developing this evidence has been the premise of this study. Some knowledge can be transferred from existing industries such as Oil & Gas or natural gas distribution to homes and businesses. However, much of the emerging hydrogen energy system, including the commercial arrangements, will need to be developed. This will need to be scalable and adaptable as the hydrogen energy system evolves over the next few decades up to 2050 to support the UK's net zero ambitions [1].

1.2 Aims and Objectives

This study has sought to predict the requirements and costs of hydrogen transport and storage infrastructure up to 2035 and explore potential commercial arrangements and investment barriers. It has been structured in five Work Packages (WP) as follows:

- WP1: Identify the key components of the hydrogen economy (production, demand, transport and storage) and how these will combine into *archetypes* that form the basis of hydrogen infrastructure.
- WP2: Predict how hydrogen production and demand are expected to grow up until 2035.
- WP3: Assess how the *archetypes* will combine to meet the demand for hydrogen and use this to predict the requirements and costs for hydrogen transport (pipelines and trailering) and hydrogen storage (salt caverns and surface storage[2]).
- WP4: Explore commercial arrangements that could be used to develop the hydrogen transport and storage infrastructure.
- WP5: Identify barriers to investment in transport and storage infrastructure.

1.3 Approach

This study follows a structured approach as shown in Figure 3. In WP1 (Section 2), the key technology components of the hydrogen landscape; production, demand, transport, and storage are compiled and characterised based on scale. These components are then combined into *archetypes* that group technologies together to support a hydrogen use case. *Archetypes* are conceived primarily by matching the scale of production and demand, but also evaluating variability in supply and demand, geographical constraints, and stakeholder requirements.

In WP2 (Section 3), hydrogen demand predictions are presented, focussing on two key dates 2030 and 2035. Data has been derived from various publicly available sources and combined to develop a picture of UK-wide demand. In Section 4 the *archetypes* are aggregated to meet hydrogen demand, calculating the number of each *archetype* required to meet demand in 2030 and 2035.

In WP3 (Section 5), the transport and storage requirements are estimated for each individual *archetype* and these are then multiplied up by the number of *archetypes* in 2030 and 2035 to predict the total transport and storage required. In turn, these requirements are used to predict the cost of transport and storage infrastructure in 2030 and 2035[3].

WP4 (Section 6) explores potential commercial arrangements that may be suitable for the new hydrogen transport and storage infrastructure, drawing on commercial arrangements from other existing infrastructure (Annex). Finally, in WP5 (Section 7), the findings from the infrastructure cost predictions and commercial mechanisms assessment are used to investigate enablers and barriers to investment.

[2] While there are more transport and storage technologies (e.g. transport via shipping, storage in depleted gas fields), this report only considers pipelines and trailering for transport, and surface-based and salt caverns for storage. This is because these are the technologies that are expected to be deployed by 2035, based on current and planned hydrogen projects in the UK. In particular, this study only considers a relatively small demand for hydrogen for heat in buildings by 2035. If hydrogen is deployed more widely for heat in buildings post 2035, then depleted gas fields may become more necessary as a storage technology.

[3] The requirements for transport and storage are based on demand estimates, rather than production targets or estimates. If demand estimates for 2030 and 2035 increase, then this would in turn increase the requirements and costs of hydrogen transport and storage.

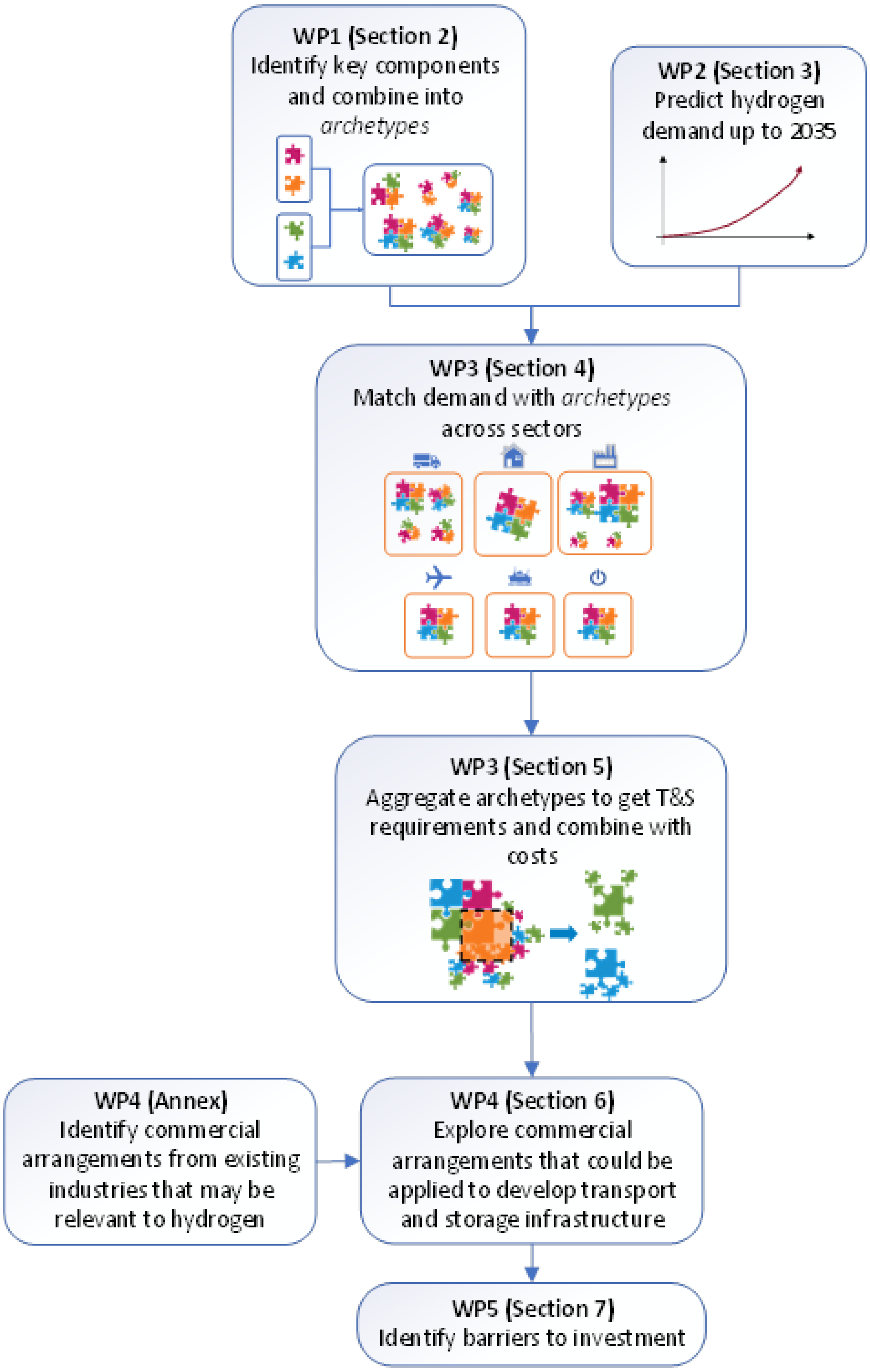


Figure 3: Structured approach to study comprising five work packages

2 WP1: Key Components and *Archetypes* of the Hydrogen Economy

This section introduces the key individual components of the developing hydrogen economy and investigates how they combine into *archetypes* that will form of the basis of the hydrogen infrastructure up to 2035. In this context, an *archetype* is a group of key components that work together to deliver a hydrogen use case from production through to demand. Four types of key component are considered as follows:

- Production technologies (which produce hydrogen, acting as a supply),
- Consumer technologies (which use hydrogen, acting as demand)
- Storage technologies (either surface storage[4] or salt caverns)
- Transport (of hydrogen) technologies (pipelines and trailering).

Production and consumer technologies are required technologies, as they must both be present in an *archetype*. Storage and transport (of hydrogen) technologies are complementary technologies, as while they are often part of an *archetype*, they do not necessarily need to be. For example, an *archetype* could comprise small-scale hydrogen production facility with a single end-user for the hydrogen. As the hydrogen is produced and consumed at the same location, this eliminates the need for a transport technology (greater than a very small pipeline[5]), but not necessarily storage.

These key components are then combined using a structured process to form *archetypes* as shown in Figure 4.

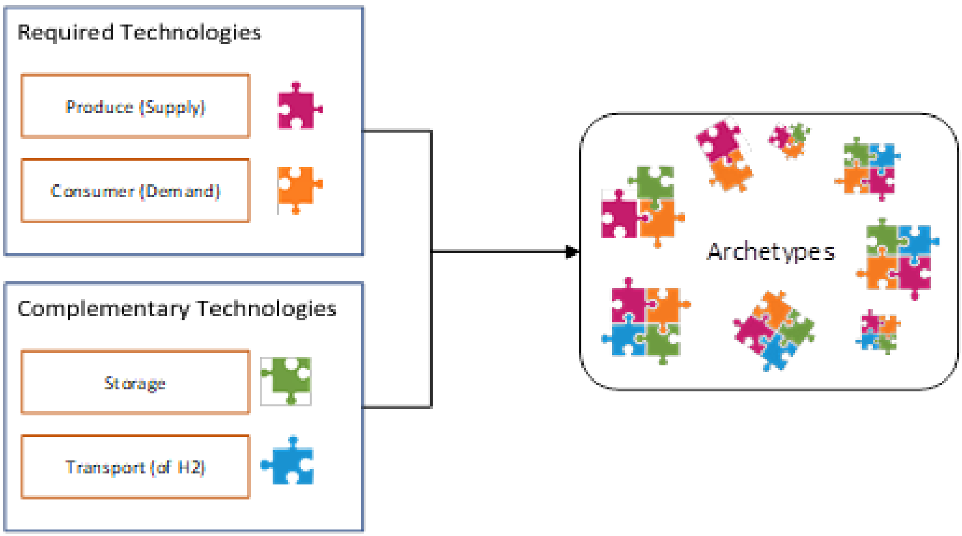


Figure 4: Combination of key components ingo *archetypes*

[4] Note that "surface storage" is likely to comprise pressurised tanks of hydrogen gas, although it is recognised that it may also be stored in solid state form (e.g., metal hydride) or as liquid hydrogen.

[5] Transport requirements and associated costs for co-located archetypes are not included in the requirement and cost estimates as these are negligible on the national infrastructure scale. This is described more in Section 2.2.5 onwards.

2.1 Key Components

The key components considered are presented in Table 1. These are categorised by their function as Production, Storage, Transport, or Demand technologies. This list was collated from a broad review of industry literature and then tested with stakeholders to ensure full coverage of relevant technologies. Each key component is assigned a typical scale in terms of annual production, demand, transport or storage with notes or examples used to justify these.

Table 1: Key components of the hydrogen economy - technologies

Function	Technology	Typical Scale (Annual production / demand / capacity unless specified)	Notes / Examples for illustration
Production	Electrolysis - small	10 GWh	5 MW onshore wind farm (at a LF of 0.25) [3]
	Electrolysis – medium	100 GWh	50 MW onshore wind farm (at a LF of 0.25) [3]
	Electrolysis – large	> 1 TWh	> 200 MW offshore wind farm (at a LF of 0.57) [3]
	CCUS enabled (SMR, ATR)	3–30 TWh	Equivalent to plants of 350MW – 3.5 GW [4] (at a LF of 0.95) [3]
	Bio-energy with CCS (BECCS) – Medium	0.8 TWh	100 MW plant (at a LF of 0.95) [3]
	Bio-energy with CCS (BECCS) – Large	4 TWh	500 MW plant (at a LF of 0.95) [3]
	Hydrogen from waste	0.8 TWh	Unknown but assumed to be similar to small bio-energy plant (0.8 TWh). LF assumed to be 0.95 [3]
	Imported - Ammonia	0.7 TWh (per shipment)	Based on a ship being able to transport 60,000t of ammonia [5]
	Imported - LH2	3.5 GWh (per shipment)	Based on a ship being able to transport 1,250m^3 of liquid hydrogen [6]
Demand	Cars (or light commercial vehicle)	4 MWh	Annual hydrogen demand of a single vehicle based on fuel consumption 0.01 kgH_2/km [7] and 10,000 km per year [8]
	HGVs (Heavy Goods Vehicles)	200 MWh	Annual hydrogen demand of a single vehicle based on fuel consumption 0.08 kgH_2/km [9] and 60,000 km per year (assumed)
	RCVs (Refuse Collection Vehicles)	200 MWh	Assumed to be similar to HGV
	Buses	100 MWh	Annual hydrogen demand of a single vehicle based on fuel consumption 0.06 kgH_2/km [10] and 40,000 km per year (assumed)
	Aviation - regional aviation	0.5 TWh	Based on consumption of 10,000 tonnes per year [11]
	Aviation - large aviation	10 TWh	Based on consumption of 300,000 tonnes per year [11]
	Ferry – small	10 GWh	Based on analysis of Scottish intra-island ferries, 400 tonnes per year

Function	Technology	Typical Scale (Annual production / demand / capacity unless specified)	Notes / Examples for illustration
	Ferry – large	0.1 TWh	Based on analysis of Scottish inter-island ferries, 3,650 tonnes per year
	Combined Cycle gas Turbines (CCGT) for high utilisation power generation	1 TWh	400 MW gas turbine running on 100% hydrogen with a LF of 0.4 [12]
	Open Cycle Gas Turbines (OCGT) peaker plants (100% hydrogen)	50 GWh	25 MW gas turbine running on 100% hydrogen with a LF of 0.2 (assumed)
	Industry – Small	5 GWh	Based on hydrogen demand for a distillery (1.3MW electrolyser at an assumed LF of 0.5) [13]
	Industry - Medium	100 GWh	Based on hydrogen demand for a food manufacturing plant (40MW electrolyser producing 9,000kg per day) [14]
	Industry – Large	2 TWh	Based on a typical ammonia plant [5]
	Heating – regional hydrogen network (conversion of town or city near an industrial cluster to 100% hydrogen)[6]	45 TWh	Equivalent to heat demand from approximately 3 million homes (see Section 3.6).
Transport (of hydrogen)	Road – trailer liquid hydrogen	60 GWh	Annual transportation based on trailer capacity of 8,000 kg of liquid hydrogen. 200 trips per year [15]
	Road- trailer high pressure gas	7 GWh	Annual transportation based on trailer capacity of 900 kg of gaseous hydrogen. 200 trips per year [15]
	Pipeline – local	0.2 TWh	Based on 3,100 kgH2/hr for a 10” onshore pipeline [16] to service a local area. Pipeline assumed to be in use for 25% of year
	Pipeline – national	>1 TWh	Assumed based on annual gas demand. [17] A national hydrogen pipeline is not expected to be in use by 2035, and so is not considered further in this study
Storage	Surface storage tanks	10 GWh	Based on 250 tonnes of hydrogen. Surface storage tanks can be combined at a single site. However, it will take up considerable space and have safety implications. 50 tonnes of hydrogen is the threshold for top-tier COMAH site [18]
	Salt caverns	3 TWh	Typical aggregated capacity of salt caverns in a single area. Based on Inovyn project in Runcorn, UK [19]

[6] 100% hydrogen for heating (outside regional or hydrogen towns) is not considered in this study, as it is not expected to be in place by 2035.

2.2 Combining Key Components into *Archetypes*

In this study, *archetypes* are groups of technologies that work together to deliver a hydrogen solution from production through to demand. This section briefly outlines the process taken to form the *archetypes* from the individual key components and the final boundary set of *archetypes* obtained. Four different approaches were used to combine the key components into *archetypes*.

2.2.1 Data-Driven

Key components were compared by characteristics such as capacity, variability, and geographical restrictions. These comparisons allowed groupings to be identified containing elements from each technology type (producer, storage, transportation, consumer) with matching characteristics. *Archetypes* were built from these groupings.

An example of this method is shown in Figure 5, where the components are plotted approximately by size/capacity, and variability (varying from hourly variability to annual or seasonal). In this example, four groupings appear, which roughly translate into heating based, domestic transport, large transport and heavy industry-based groupings. In this example, these four groups were used to form *archetypes.* These *archetypes* were added to through further analysis as outlined in the following sections.

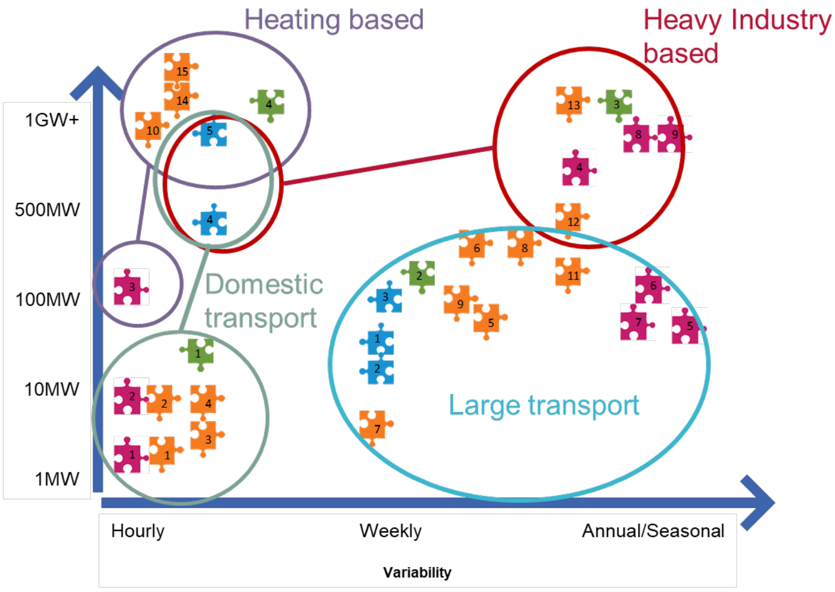


Figure 5: Data driven *archetype* formation – graph showing *archetype* formation via plotting of size and variability.

2.2.2 Producer Centric and Consumer Centric

With technologies separated into categories as per Table 1 (producer, storage, transportation, consumer), a producer or consumer technology was chosen as a starting point, and other technologies matched to it.

This process is illustrated in Figure 6, with key component technologies arranged in their groupings (producer, consumer, transport, storage) around the outside, and selected components moved into the *archetype* central box. The example shows a consumer centric approach, where a consumer component is used as the starting point, and the most obvious relating technologies combined with it to form the *archetype.* Any context relating to the *archetype* is also added.

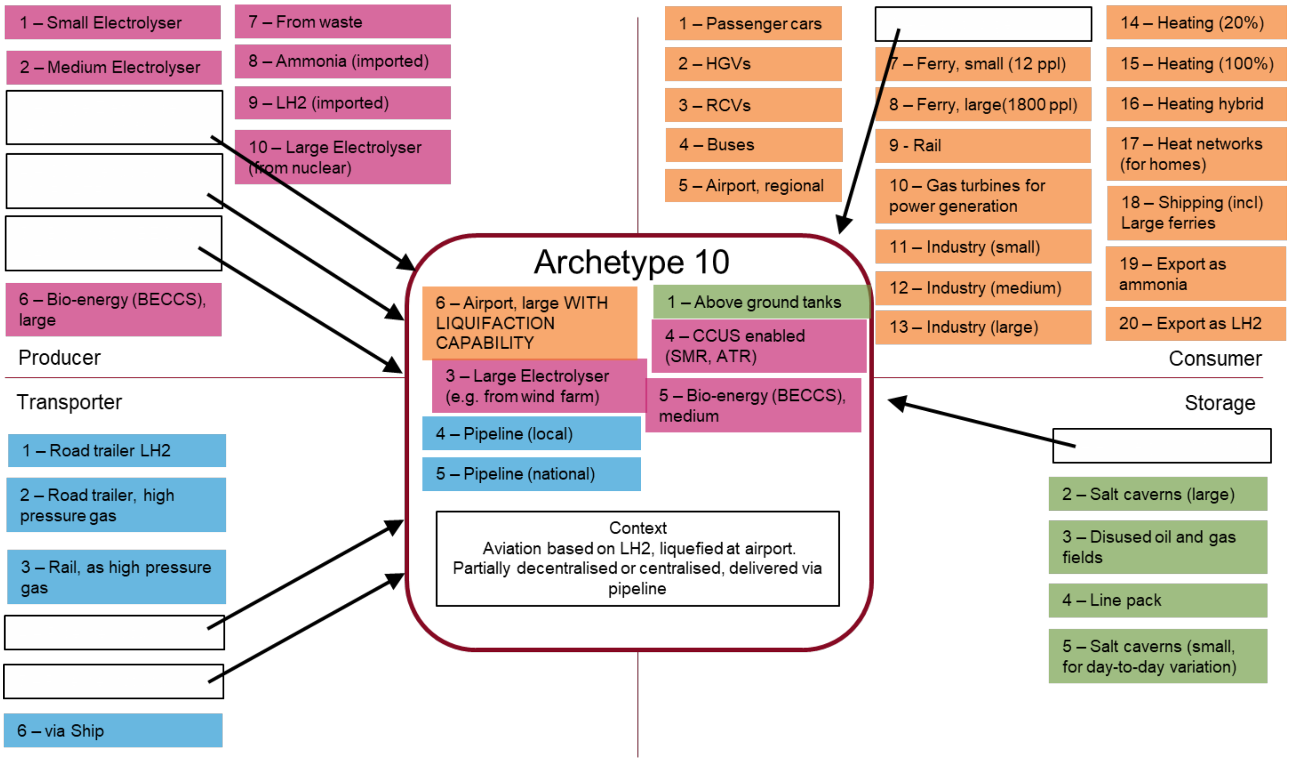


Figure 6: Example of producer or consumer centric *archetype* formation. Key components are arranged around the outside, the central box contains the selected technologies for the *archetype.*

2.2.3 Stakeholder Questionnaire

Some *archetypes* were identified through responses to a stakeholder questionnaire issued as part of this study. For example, where a producer was expecting hydrogen to be used by particular consumers. Some hydrogen users identified how they currently use and would like to use hydrogen in the future. One example combined hydrogen delivered by trailer for multiple local uses, with on-site storage and a view to increase this storage. Another expressed plans to achieve on-site hydrogen production, with on-site storage, for use on site.

This questionnaire was carried out online and contained the following sections:

- Hydrogen and your organisation
- Growth of the hydrogen economy and your business
- Growth of the hydrogen economy in the UK
- Hydrogen technologies and affecting factors
- Specifics (e.g. security of supply, form of hydrogen received)

Stakeholders from trade bodies, energy providers, hydrogen producers, gas networks, gas distributors, hydrogen users, and academia and research were contacted. A total of 48 responses were received for this survey, with a spread across hydrogen producers, users, storage and transport providers. A full list of questions asked is given in Appendix 1 (Section 11).

2.2.4 Combining *Archetypes* and Testing

Using these four different approaches, 44 separate *archetypes* were identified. These were interrogated to look for patterns and commonalities to reach a manageable representation for further analysis; many of the *archetypes* were found to be sufficiently similar that they could be combined, whilst others were determined not to be practicable and so removed. Ultimately this list was reduced to a representative set of nine *archetypes*, which were tested at a stakeholder workshop. Some *archetypes* naturally transition to others as the UK hydrogen economy grows.

The stakeholder workshop was carried out online on Friday 6th May 2022. Questionnaire respondents who showed an interest in contributing further to the study were invited to the workshop. At the event, 23 stakeholders attended from various organisations, excluding those from BEIS, Frazer-Nash and Cornwall Insight. The agenda for the workshop was as follows:

- Problem statement
- Introduction to the developed framework and scenarios
- Test developed *archetypes*.
- Discussion on policy, enablers, blockers etc.
- Discussion on predicted growth.

2.2.5 Final *Archetypes*

The final *archetypes* are introduced in Table 2, with indicative titles or short descriptions. Further detail is given in Sections 2.2.6 to 2.2.14, which describe each *archetype* in depth. In the descriptions below, the characteristics of the *archetypes* are described as definite. These however are all based on evidence collated and assumptions described so far and will not be a completely accurate description of hydrogen growth in the future. The exact nature of the *archetypes* will become clearer as these markets develop. In this study, the *archetypes* provide a framework to estimate infrastructure requirements and costs.

Table 2: Summary table of *Archetypes*

Archetype	Short Description
1	Decentralised, independent unit
2	Decentralised, supporting national (nationwide) system
3	Small user using hydrogen from a medium producer, without a dedicated pipeline
4	Medium size users using hydrogen from a medium producer, connected predominantly via pipeline
5	Large point user as part of a large hydrogen production centre
6	Large, distributed user as part of a large hydrogen production centre
7	Small/Medium user as part of a large hydrogen production centre
8	Alternative fuel production for shipping or aviation sectors, as part of a large hydrogen production centre
9	National hydrogen pipeline network connecting many producers, users and storage facilities

2.2.6 *Archetype* 1 - Decentralised, Independent Unit

The hydrogen demand is relatively small for this *archetype,* allowing the formation of designated and co-located hydrogen production facilities. The hydrogen demand comes from local return-to-depot transport services such as buses, recycling vehicles and gritters, small ferries, or from small industry. This demand is approximately uniform across the year but with daily and potentially weekly minor variability. At this small scale, hydrogen production is electrolytic, potentially powered from a local renewable energy facility which will have daily, seasonal and interannual variability. Co-locating the production and demand removes the need to include hydrogen transportation but there will need to be hydrogen storage to balance the demand and supply. At this small scale, this will be surface storage, most likely compressed hydrogen in tanks.

Producer technologies: Small electrolyser

Demand technologies: RCVs, HGVs, small ferries, small industry

Transport (of hydrogen) technologies: None or assumed to be part of production infrastructure. While some small-scale pipeline could be required, it is not at a scale to be considered in infrastructure estimates later in this study, and so is not included in this *archetype.*

Storage technologies: Surface storage

2.2.7 *Archetype 2* - Decentralised, Supporting National System

This *archetype* covers refuelling stations which act as independent units, although are only useful as part of a national system. As with *archetype* 1, there is local hydrogen production on site, and a need for onsite storage in the form of surface storage, most likely compressed hydrogen in tanks.

This *archetype* supports national transportation such as the use of hydrogen in HGVs, where the need develops for dispersed refuelling stations around the country. This *archetype* would be most likely to materialise where there is not a nearby large hydrogen production facility.

Producer technologies: Small electrolyser

Demand technologies: HGVs, passenger cars, national coaches or buses

Transport (of hydrogen) technologies: None or assumed to be part of production infrastructure

Storage technologies: Surface storage

2.2.8 *Archetype 3* - Small User Using Hydrogen from a Medium Producer, Without a Dedicated Pipeline

This *archetype* covers small users, that use hydrogen from a medium producer.

A medium-sized hydrogen production facility developed in response to increasing demand for hydrogen in a region. The hydrogen demand is not centred at a single location but sufficiently close to allow a partially decentralised model to develop, where hydrogen is produced centrally and trailered relatively short distances to end-users. There will need to be some above-ground storage depending on the variability of hydrogen production, flexibility of the hydrogen demand and the resilience of hydrogen supply required.

It is unlikely that a medium hydrogen producer, once mature, would entirely feed only into this *archetype*, with some pipelines being developed directly to users as maturity and confidence builds – this is covered in *archetype* 4. The split between *archetype* 3 and 4 connecting to a medium hydrogen producer would depend on production technology, split of users, and geographical considerations.

Producer technologies: Medium electrolyser, medium BECCS facility

Demand technologies: RCVs, HGVs, small ferries, small industry, medium industry, regional aviation

Transport (of hydrogen) technologies: Trailer

Storage technologies: Surface storage[7]

2.2.9 *Archetype 4* - Medium Size Users Using Hydrogen from a Medium Producer, Connected Predominantly Via Pipeline

This *archetype* is similar to *archetype* 3 in that it uses hydrogen produced by a medium hydrogen producer. Although the same use technologies appear as in *archetype* 3, in *archetype* 4 they are the primary user of hydrogen for the production facility, and so have a designated pipeline to receive their hydrogen. Incidences of *archetype* 3 could evolve into *archetype* 4 over time.

Hydrogen production could be electrolytic, potentially powered by a local renewable energy plant or could be produced from a Bio-Energy with CCS plant (BECCS).

As the hydrogen demand grows in a particular area it is possible that a pipeline becomes more economic than trailering. For example, initially a regional airport may start using trailered hydrogen but then look to develop a pipeline as demand increases. Therefore, some areas that start as an *archetype* 3, could transition over time to fit *archetype* 4. As production increases, there would be higher storage requirements to alleviate any mismatches in supply and demand, which will be provided by salt caverns.

Producer technologies: Medium electrolyser, medium BECCS facility

Demand technologies: RCVs, HGVs, small ferries, small industry, medium industry, regional aviation

Transport (of hydrogen) technologies: Pipeline

Storage technologies: Large scale storage (salt cavern)

[7] In practice, Archetype 3 could use salt caverns for storage but as the hydrogen is transported by trailer it is assumed to be surface storage.

2.2.10 *Archetype* 5 - Large Point User as Part of a Large Hydrogen Production Centre

Archetype 5 works for large point users as part of a large hydrogen production centre.
Where several industries consolidate their hydrogen demand and form large scale anchor demand, a large hydrogen production centre can form. The large scale of demand is delivered by a combination of CCUS-enabled and electrolytic production.

Hydrogen is distributed to these large users by short pipeline. Industrial hydrogen demand is likely to be relatively uniform throughout the year, but hydrogen use for flexible power will require more significant storage that will be provided by salt caverns. Hydrogen use for flexible power only appears in this *archetype* due to the scale and nature of hydrogen requirements (i.e. in somewhat unpredictable frequency, and high quantities at times), this use will require pipelines supplying hydrogen from large producers, and such only fits within this *archetype.*

Producer technologies: Large electrolyser, large BECCS facility, CCUS enabled

Demand technologies: Gas turbines (for power generation), medium industry, large industry

Transport (of hydrogen) technologies: Pipeline

Storage technologies: Large scale storage (salt cavern)

2.2.11 *Archetype* 6 - Large, Distributed User as Part of a Large Hydrogen Production Centre

Archetype 6 works for large, distributed users (such as in buildings) as part of a large hydrogen production centre. This *archetype* could develop into *archetype* 9 (a national hydrogen network), but this is not definitive, or necessary for deployment of this regional *archetype.* The distributed nature of the user means that much more pipeline is required for hydrogen delivery, i.e. pipeline is not required simply to one 'point' site, but to many sites which are geographically distributed, such as homes across a region. A large hydrogen production centre serving seasonal demand necessitates large scale storage, in a salt cavern.

Producer technologies: Large electrolyser, large BECCS facility, CCUS enabled

Demand technologies: Heating – regional hydrogen network, for example

Transport (of hydrogen) technologies: Pipeline

Storage technologies: Large scale storage (salt cavern)

2.2.12 *Archetype* 7 - Small/Medium User as Part of a Large Hydrogen Production Centre

Archetype 7 works for small/medium users as part of a large hydrogen production centre. Where hydrogen is available from a large production facility and not entirely used up by larger users, smaller users such as council run RCVs and buses, local HGV depots, or small industries may look to utilise the remaining hydrogen. As these users are smaller, they will likely receive hydrogen via trailer. The users in this *archetype* are not likely to use large portions of the hydrogen available in a large hydrogen production centre.

Producer technologies: Large electrolyser, large BECCS facility, CCUS enabled

Demand technologies: HGVs, passenger cars, buses, RCVs, small ferries, regional aviation, small industry, medium industry

Transport (of hydrogen) technologies: Trailer

Storage technologies: Large scale storage (salt cavern) with a small amount of surface storage for day-to-day operations[8].

2.2.13 *Archetype* 8 - Alternative Fuel Production for Shipping or Aviation Sectors, as Part of a Large Hydrogen Production Centre

Archetype 8 supports production of alternative fuels for shipping or aviation, in the form of SAF (Sustainable Aviation Fuel), LH2 (Liquified Hydrogen) or ammonia. This *archetype* will act as a large point user, but will have greater geographical constraints which are tied to the user of the final fuel produced. The exact nature of this *archetype* will become clearer as these markets develop.

Producer technologies: Large electrolyser, large BECCS facility, CCUS enabled

Demand technologies: Alternative fuel production (SAF, LH2, ammonia)

Transport (of hydrogen) technologies: Pipeline

Storage technologies: Large scale storage (salt cavern)

[8] For storage sizing purposes in Section 5 this will be assumed to be all salt cavern storage.

2.2.14 *Archetype* 9 - National Hydrogen Pipeline Network Connecting Many Producers, Users and Storage Facilities

Archetype 9 is linked to nationwide conversion of the gas network; which would likely be dependent on centralised hydrogen production centres for producing the significant scale of hydrogen required. The production facility would need to be connected via pipeline to the National Transmission System (NTS) or Gas Distribution Networks. The seasonality of heat demand would necessitate larger scale hydrogen storage in salt caverns or potentially disused gas wells.

This *archetype* is not considered further in this study, as it is not expected to be in place by 2035.

Producer technologies: Large electrolyser, large BECCS facility, CCUS enabled

Demand technologies: Multiple users connected to a national hydrogen network

Transport (of hydrogen) technologies: Pipeline (national)

Storage technologies: Large scale storage (salt cavern)

2.3 *Archetype* Summary

Developed *archetypes* can then be used as a framework for fulfilling predicted demand in the UK. The following sections of this work rely on the eight *archetypes* developed during WP1 which are relevant up to 2035 *(archetype* 9 is not included as not expected to be in use by 2035). These were developed internally and tested during the stakeholder workshop.

Archetypes have been sized in Table 3 in order to assess transport and storage requirements associated with them. This sizing is based on the hydrogen production technology used within the *archetype*, as follows.

For the initial step in this process, the magnitude of production from each individual *archetype* was estimated. This estimate was based on the size of the production technology identified in the *archetype*, as given in Table 1. Where there was a range of production technologies or sizes of production technologies available to an *archetype*, a reasonable mid-point is assigned. This resulted in three sizes of production assigned across the eight *archetypes*, which depend on whether the production component of the *archetype* is large, medium or small (at 10,000GWh, 500GWh, and 10GWh annual production respectively). This enabled sizing of transport and storage requirements as outlined in the following sections.

The variation in the size of hydrogen production technologies within *archetypes* is explained in Section 4, after the quantity of each *archetype* required to meet demand is calculated, to show how the variation in the size of production is incorporated into the final estimates.

Table 3: Sizing *archetypes*

Archetype	Size/Annual production (GWh)	Description	Production technologies
1	10	Decentralised, independent unit	Small electrolyser
2	10	Decentralised, supporting national system	
3	500	Small user using hydrogen from a medium producer, without a dedicated pipeline	Medium electrolyser, medium BECCS facility
4	500	Medium size users using hydrogen from a medium producer, connected predominantly via pipeline.	
5	10,000	Large point user as part of a large hydrogen production centre	Large electrolyser, large BECCS facility, CCUS enabled
6	10,000	Large, distributed user as part of a large hydrogen production centre	
7	10,000	Small/Medium user as part of a large hydrogen production centre	
8	10,000	Alternative fuel production for shipping or aviation sectors, as part of a large hydrogen production centre	

3 WP2: Sector Specific UK Hydrogen Demand Up to 2035

3.1 Introduction

This section explores how the UK demand for hydrogen introduced in Section 2 could develop in the period up 2035. It presents demand predictions for the key sector specific use cases for hydrogen, focusing on two milestones; 2030 and 2035. The *archetypes* that would support hydrogen in each end use are also described. In Section 4, these demand predictions will be combined with the individual *archetypes* to calculate the quantity of each *archetype* required up to 2035 and the implications for transport and storage infrastructure. The hydrogen demand predictions have been obtained from a literature review. Future hydrogen demand is highly uncertain and the figures here are used to illustrate the potential scale of demand. However, it is recognised that these figures could change depending on how the hydrogen economy develops.

3.2 Predicted Hydrogen Demand Up to 2035

Current UK hydrogen production and use is heavily concentrated in chemicals and refineries [20]. This hydrogen is largely produced from natural gas (without carbon capture) or as a by-product of other industrial processes. It is used as a feedstock, or input, into making other chemicals and plays a variety of roles in refineries to convert crude oil into different end products [1]. It is generally all made locally at the point of use and so there is limited need for hydrogen transportation either by pipeline or road trailering.

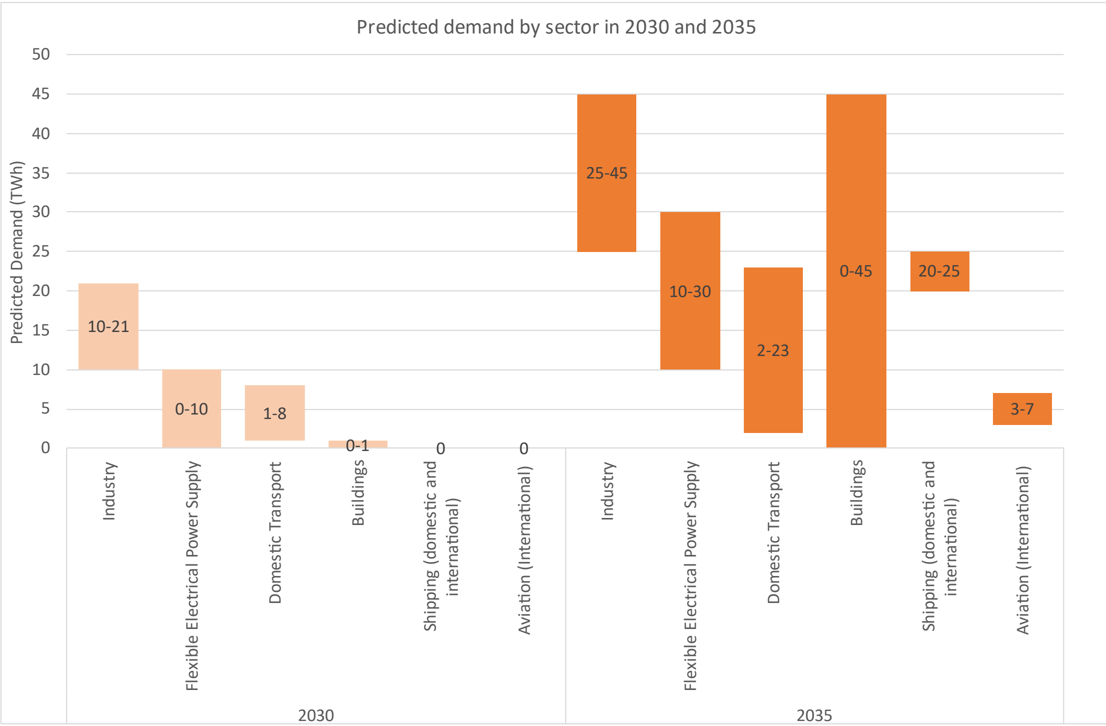


Figure 7: Predicted demand for Hydrogen by sector, for 2030 and 2035[9]. [21]

[9] This is based on modelling undertaken for the UK Hydrogen Strategy [1], the 6th Carbon Budget [21] and other sources for emerging hydrogen demand in shipping and aviation as referenced in Sections 3.3 - 3.9.

Going forward, hydrogen is likely to play a much broader role in the energy system. The UK Hydrogen Strategy [1] sets out how hydrogen will increasingly be used to decarbonise heavy industry and provide greener, flexible energy across power, transport and potentially heat. Predictions in the Hydrogen Strategy show that in the period up to 2030, switching from fossil-fuels to low carbon hydrogen for industrial applications is likely to provide the main demand but post 2030 the use of hydrogen in power, road transport and potentially in buildings will rise rapidly. Estimates of hydrogen demand in 2030 and 2035 are shown in Figure 7.

The following sections describe the key demand sectors for hydrogen. For each sector, the relevant *archetypes* developed in Section 2 that will deliver this hydrogen demand are presented.

3.3 Industry

Applications for low carbon hydrogen in industry will include those that currently rely on hydrogen, as well as new applications in iron and steel manufacturing, glass production and other chemicals. The Climate Change Committee's (CCC) 6th Carbon Budget [21] highlights that hydrogen will play a key role in decarbonising boilers and steam production, power production and Combined Heat and Power (CHP) and large stationary and mobile machinery that is currently powered by fossil fuels.

Latest analysis by BEIS for the UK Hydrogen Strategy highlighted that by 2030, demand from industry for low carbon hydrogen as a fuel could range from around 10 TWh per year if supply is limited to clusters, or up to around 20 TWh per year if some dispersed sites are connected to pipelines [1]. Furthermore, to meet the 6th Carbon Budget, the UK Hydrogen Strategy predicts that industrial demand for low carbon hydrogen would need to continue to grow, up to a maximum of 45 TWh by 2035 [1]. The majority of this demand is expected to be from industrial clusters but there will be other industrial processes such as food production that are not located at an existing cluster and will require hydrogen to be transported in or produced locally. The use of hydrogen in industry is included in *archetypes* 1, 3, 4, 5 and 7, described in Section 2.2.

3.4 Flexible Electrical Power Supply

Unabated natural gas-fired generation is currently widely used in Great Britain to provide flexible capacity and match electrical demand and supply and as the proportion of intermittent renewable power on the grid increases, the need to align supply and demand will only increase. The government has also committed to a zero-carbon electricity system by 2035 [22], subject to security of supply, and flexible hydrogen fuelled electricity generation is likely to become a key part of this system balancing. The UK Hydrogen Strategy highlights that low carbon hydrogen can play an important role in providing flexible power generation such as through rapid operating 'peaker' plants and larger scale but less flexible Combined Cycle Gas Turbines (CCGTs) [1].

The UK Hydrogen Strategy predicts that by 2030, demand for hydrogen in power will be between 0 – 10 TWh, increasing to between 10 – 30 TWh by 2035 [1]. Similarly the CCC's 6th Carbon Budget highlights that by 2035 hydrogen gas plants could use 30 TWh of hydrogen per year for electricity generation, meeting 5% of electrical demand. The use of hydrogen for flexible power is supported by *archetype* 5.

3.5 Domestic Transport

'Domestic transport' for the purpose of this study, includes road transport, ferries and regional aviation, but excludes domestic shipping. Domestic shipping is covered under 'shipping' alongside international shipping, as these will likely work alongside each other in practical terms, sharing ports and infrastructure.

There is considerable uncertainty over the role of hydrogen in decarbonising road vehicles, with cars and light duty transport expected to be electrified. Even with Heavy Goods Vehicles, the CCC highlights that there is doubt over the most cost-effective and feasible decarbonisation option [23]. To mitigate this uncertainty, the government has launched the Zero Emission Road Freight (ZERFT) programme [24] to demonstrate leading zero emission technology options for HGVs. Based on the findings of this and other research, the government aims to make a decision on policy enablers by the mid-2020s.

One of the early adopters of hydrogen in the UK has been for depot-based transport including buses, recycling trucks and other municipal vehicles. These vehicles, with energy density or high utilisation requirements is compatible with centralised refuelling infrastructure rather than requiring distributed fuelling facilities. The UK Hydrogen Strategy [1] expects depot-based hydrogen transport to form the bulk of hydrogen demand in the 2020s but envisages that by 2030 hydrogen could be in use across a range of transport modes, including HGVs, buses and rail. The step-up from depot-based to national hydrogen vehicles will require significantly more refuelling infrastructure, though it is possible that a small set of appropriately spaced hydrogen refuelling stations will allow for a test bed in prescribed transport routes. Additional analysis by Element Energy for the CCC [25] highlights that hydrogen uptake could be relatively quick, reaching 77% of larger HGVs by 2035 and 99% by 2040 [25].

The UK Hydrogen Strategy [1] suggests that there could be up to 6 TWh demand for low carbon hydrogen in transport in 2030 and 45 TWh by 2035. These figures included shipping but omitted aviation due to the relative immaturity of technology and lack of evidence when the report was published. The hydrogen demand for domestic transport (between 1 – 8 TWh in 2030 and between 2 – 23 TWh in 2035) has therefore been calculated by subtracting the hydrogen demand for shipping (0 TWh in 2030 and between 20 – 25 TWh in 2035, given in Section 3.7) and adding the demand for regional aviation (between 1 – 2 TWh in 2030 and between 2 – 3 TWh in 2035, given in Section 3.8) from the Hydrogen Strategy's [1] transport predictions. There is interest in using hydrogen in domestic ferries (e.g., inter-island ferries) but overall this is expected to provide a relatively low demand by 2030 and 2035 and is assumed to be included in the UK Hydrogen Strategy's transport demand estimates.

The use of hydrogen for domestic transport is included in *archetypes* 1, 2, 3, 4 and 7.

3.6 Buildings

The route to decarbonising heat use in homes and businesses is also still unclear. Given the diversity of buildings and consumers' needs, no single solution can provide the best option for everyone. However, 100% hydrogen for heating is not yet an established option and further work is required to understand the feasibility, costs, benefits and other impacts of using hydrogen instead of natural gas to heat buildings in the UK [26]. The Government is working with industry, regulators and others to deliver a range of research, development and testing projects to help establish the evidence required to inform a strategic decision on the role of hydrogen in heating in 2026. These projects include:

- A Neighbourhood hydrogen trial by 2023
- A larger-scale hydrogen village by 2025
- A potential hydrogen town by 2030 (at most 1 TWh) contingent on 2026 decisions

Accordingly, the UK Hydrogen Strategy has highlighted a small hydrogen demand for buildings of at most 1 TWh of hydrogen by 2030 [1]. Based on a typical household gas consumption of 13,600 kWh/year [27], this would equate to around 70,000 homes or a typical UK town. By 2035, it is possible that hydrogen towns develop and the UK Hydrogen Strategy highlights that there could be up to 45 TWh of hydrogen demand for heat in buildings, although the lower bound of zero TWh by 2030 and 2035 is also a possible scenario [1]. Based on similar scaling, 45 TWh of hydrogen corresponds to approximately 3 million homes.

The use of hydrogen for buildings is supported by *archetype* 6.

3.7 Shipping

As an international and highly cost sensitive industry, shipping is likely to be one of the later industries to be decarbonised. Analysis by the CCC for the 6th Carbon Budget [21] suggests that by 2035 the majority of fuel in shipping will still be fossil-fuel with around a third coming from zero-carbon fuels.

Hydrogen can be used to decarbonise ships directly through combustion or in fuel cells and there is interest in the use of hydrogen for small-scale maritime [28]. However, ammonia and methanol are predicted to be more cost-effective than using hydrogen directly, resulting in hydrogen being used as a feedstock rather than a fuel itself. Frontier Economics has investigated a range of scenarios for decarbonisation of shipping and all scenarios show a competitive advantage of ammonia with hydrogen as a feedstock [29].

Demand for ammonia in domestic and international shipping is only likely to start after 2030 with 20 – 25 TWh[10] demand by 2035 [29]. It is assumed that ammonia use in shipping is likely to be produced centrally in large industrial clusters positioned sufficiently close to ports to allow the ammonia to be transported by pipeline. The use of hydrogen for shipping is included in *archetype* 8. For the purposes of the cost estimates, ammonia pipelines for shipping are assumed to be the same cost as hydrogen pipelines.

3.8 Aviation

While there are technological challenges to overcome before hydrogen is used in aviation, interest from the aviation industry is significant. Compressed hydrogen gas is already being trialled for short-haul aviation [30] and liquid hydrogen is being actively considered for long-haul aviation [31]. Additionally, hydrogen can be used as a feedstock for Sustainable Aviation Fuels (SAF). Low carbon hydrogen can be combined with carbon-based gases extracted from the atmosphere to produce synthetic aviation fuel that has similar properties to existing jet fuel [32]. As an alternative to hydrogen, there is also developing interest in the role of biofuels for long distance aviation [33]. There is uncertainty over which of these will become the main fuel type, or if short and long-haul will use different fuels. However, both liquid hydrogen and hydrogen-based SAF have similar requirements from an infrastructure perspective and need very large, centralised facilities for their production.

Total demand for hydrogen in short and long-haul aviation (whether used in liquefied form or used as feedstock for SAF) could be between 1 – 2 TWh by 2030 and around 5 – 10 TWh by 2035 [34]. In the short term it is assumed this hydrogen is likely to be used for regional aviation in gaseous form (this demand is included in the domestic transport category in Section 3.5) before demand increases for SAF or liquid hydrogen later on. This hydrogen demand is therefore assumed to be split between regional aviation (gaseous hydrogen, which is included in Section 3.5) and international aviation (SAF or liquid hydrogen), where demand from international aviation is predicted to be 0 TWh in 2030 and between 3 – 7 TWh in 2035.

[10] Note: Hydrogen for shipping is likely to be in the form of hydrogen-based fuels such as ammonia. Approximately 1 TWh of hydrogen is required to produce 1 TWh of ammonia [61].

Recent analysis by Fly Zero suggests that liquefied hydrogen is initially likely to be produced and liquified off-site and then supplied by road tanker to the airport [34]. This approach could be readily applied to SAFs too. As demand increases and tankering becomes unviable, liquified hydrogen may need to be produced locally at the airport with hydrogen gas piped from the hydrogen production facility to the airport. SAF is potentially different in this context as unlike liquified hydrogen it can be transported by pipeline so could still be produced centrally away from the airport.

Hydrogen for regional aviation is included in *archetypes* 3, 4 and 7 whilst international aviation is included in *archetype* 8.

3.9 Blending Hydrogen into the Gas Grid

Although not an end-use application directly, hydrogen may be blended into the natural gas grid in the short to medium term as a route to transporting hydrogen to end-use applications. Blending has the potential to support the growth of hydrogen production by acting as a reserve offtaker whilst hydrogen transport and infrastructure develops, and demand grows. Under the Gas Safety (Management) Regulations 1996, hydrogen content in the gas networks is currently limited to 0.1 % by volume [35]. However, subject to changes to legislation, hydrogen may be blended into the gas network at up to 20% by volume with, in principle, minimal changes to either the network itself or end-use applications such as domestic boilers [36]. This could be either an initial step on a nationwide conversion of the gas network to 100% hydrogen, or an end-state prior to a long term move to electrified heating. Evidence suggests that blending above 20% would require new appliances and so it is highly unlikely that there will be an intermediate blending step between 20% and 100% hydrogen. The role of blending is being actively investigated by the HyDeploy project [37].

Hydrogen has a lower energy density by unit volume to natural gas so blending 20% hydrogen by volume only provides approximately a 7% carbon saving [38]. However, blending also offers security for production investment by reducing commercial risks for hydrogen producers [39]. If hydrogen is blended into the gas distribution networks that are currently transporting, for example, 450 TWh of natural gas then this would require approximately 35 TWh of hydrogen a year (as blending is not a specific sector end-use, these figures are not included in Figure 5 above). The government acknowledges that it is unlikely that this maximum potential will be reached by 2030, as the actual amount blended will depend on market conditions and how hydrogen use evolves across other sectors. The government aims to provide a final policy decision on whether to enable blending in the distribution networks by 2023 once evidence on safety and value for money has been assessed [39].

3.10 Hydrogen Production Ambitions

The UK Hydrogen Strategy provided an ambition of up to 5 GW of low carbon hydrogen production capacity by 2030 [1]. This ambition was increased in the British Energy Security Strategy [2] to up to 10 GW, with an aspiration that at least half of this will come from electrolytic hydrogen production. The amount of hydrogen produced in a year is dependent on the load factor (LF) of the production method. CCUS-enabled hydrogen production is predicted to have a high LF of 0.95 [3]. For electrolytic hydrogen production, the LF depends on the variability of the electricity supply. Grid connected electrolysis would also have a high LF, whilst electrolysis from designated renewables could vary from approximately 0.25 (curtailed renewables) to 0.57 (designated offshore wind farm)[11] [40]. 10 GW of production, split equally between CCUS-enabled

[11] higher load factors could be possible if a producer has, for example, a power purchase agreement with multiple offshore wind sites, or a mix of renewable technologies. However, for the purpose of this study we have used the load factor assumptions for 2030 (dedicated offshore and curtailed electricity) published in BEIS' Hydrogen Production Costs report [40].

and electrolytic would provide between 52 and 66 TWh hydrogen[12] This is greater than the predicted total demand in 2030 of up to 40 TWh. Blending could be used as an additional source of hydrogen demand to enable production to develop and this is discussed in Section 5. The hydrogen transport and storage requirements for 2030 and 2035 have been calculated based on the estimated demand estimates, not on targets for hydrogen production.

The government has not currently set a hydrogen production ambition for 2035 and transport and storage requirements are similarly based on hydrogen demand estimates.

[12]The lower estimate of 52 TWh assumes all electrolytic production is from curtailed renewables, and the higher estimate (66 TWh) assumes all electrolytic production is from designated renewable power.

4 Aggregations of *Archetypes* to Match Demand

This section determines the quantity of each *archetype* (based on the production volumes ('sizes') described in Section 2.3) required to meet the hydrogen demand predictions for 2030 and 2035. Initially, the hydrogen demand for each sector is apportioned between the eight *archetypes* to quantify the end-use demand for hydrogen within each *archetype*. Which *archetypes* are relevant for each sector is shown in Table 4. The number of each *archetype* required to meet total demand in that sector and total hydrogen demand in 2030 and 2035 is then calculated. Ar*chetype* 9 is not considered further in this study as it is not expected to be in place by 2035, as set out in Section 2.2.14.

This process is shown in Figure 8, where industry sector is used as an example.

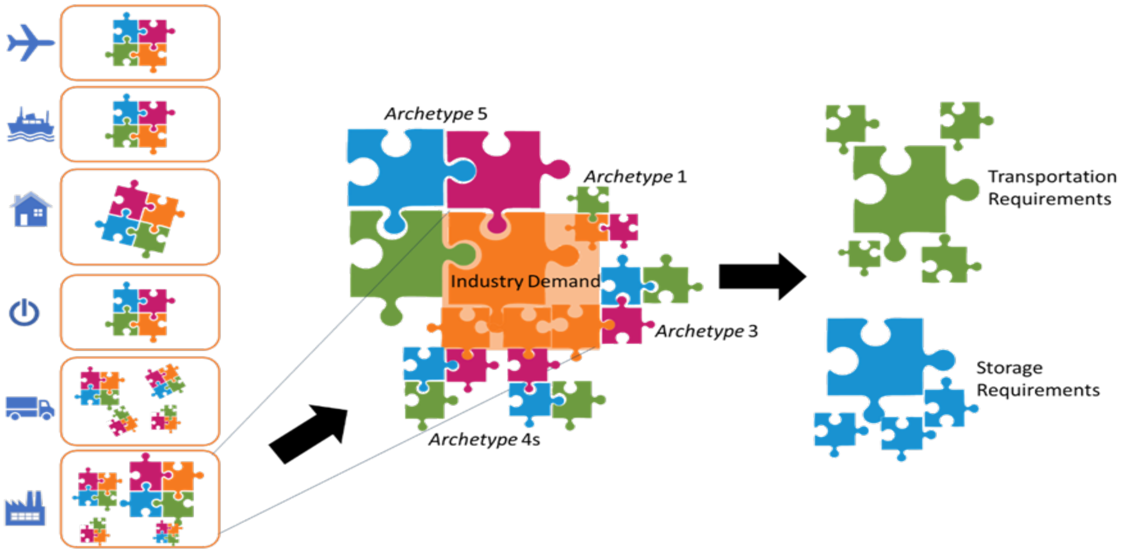


Figure 8: Process of aggregation of *archetypes* to extract transport and storage requirements

Table 4: Matching *archetypes* to sectors. Crosses indicate where *archetypes* service sector hydrogen demand[13]

Archetype	Sector					
	Industry	Flexible Electrical Power Supply	Domestic Transport	Buildings	Shipping	Aviation
1	x		x			
2			x			
3	x		x			
4	x					
5	x	x				
6				x		
7			x			
8					x	x

4.1 Sector Split into *Archetypes*

The hydrogen demand for the end-use sector is now apportioned to the 8 *archetypes* as shown in Table 5. For flexible power, heat, shipping and aviation the entire sector demand is assigned to a single *archetype*[14]. For industry and domestic transport (road transport, ferries and regional aviation), the hydrogen demand is split across multiple *archetypes* and the rationale for this is explained in Sections 4.1.1 and 4.1.2. Only the transport sector has a change in *archetype* split between 2030 and 2035. All others have the same split in 2030 and 2035.

[13] Rationale for the assignment in this table is given in Section 3.

[14] Although power generation could be a point or distributed user, it is assumed that by 2035, it will be dominated by individual sites which do not require large amounts of pipeline to serve them. Therefore, this sector is served entirely by *archetype* 5 in both 2030 and 2035.

Table 5: Apportioning demand per sector to the eight *archetypes*

Archetype	End-Use Sector[15]						
	Industry	Flexible Electrical Power Supply	Domestic Transport		Heat	Shipping	Aviation
	2030 & 2035	2030 & 2035	2030	2035	2030 & 2035	2030 & 2035	2030 & 2035
1	5%		60%	20%			
2				40%			
3	5%		20%	20%			
4	20%						
5	70%	100%					
6					100%		
7			20%	20%			
8						100%	100%
TOTAL	100%	100%	100%	100%	100%	100%	100%

4.1.1 Industry – *Archetype* Split Assumptions

As highlighted in Section 3.3, the UK Hydrogen Strategy predicts that annual hydrogen demand for industry will be between 10 – 21 TWh in 2030. It states that annual hydrogen demand could be 10 TWh per year if limited to clusters, or up to 20 TWh if some dispersed sites are connected to pipelines. At the upper demand prediction (21 TWh), approximately 50% of hydrogen demand is therefore likely to come from large industrial sites.

The Industrial Decarbonisation Strategy [41] suggests that the total current CO_2 output of dispersed industry such as food and drink is comparable to larger industry such as refineries, chemicals and iron and steel in clustered sites. Whilst CO_2 output and uptake of hydrogen are not necessarily strongly correlated it suggests that 50% of industrial hydrogen demand coming from large industry is a reasonable assumption. For simplicity, it is assumed that this 50:50 split in hydrogen demand (large industry: small/medium industry) also applies at the lower industrial hydrogen demand prediction of 10 TWh. It is further assumed that this proportion also applies to 2035 (both lower and upper hydrogen predictions).

Further subdividing the remaining 50% industrial hydrogen demand between small and medium-sized industries is difficult due to lack of evidence. For the purposes of this study, it is assumed that in general medium-sized industry will be able to adopt hydrogen more readily than small industry and the split between small and medium industries is therefore assumed to be 4 : 1.

- Small industry – 10%, even split between *archetypes* 1 and 3.

[15] Greyed out boxes indicate that the archetype is not relevant for the sector, as per Table 4.

- Medium industry – 40%, even split between *archetypes* 4 and 5.
- Large industry – 50%, *archetype* 5.

However, it is recognised that this is highly uncertain and as such in Section 5 a sensitivity test is undertaken where all industry hydrogen demand is instead provided by *archetype* 5. Attributing all industry hydrogen demand to *archetype* 5 will mean that hydrogen is therefore entirely used at (or transported in from) a hydrogen production centre, with no local hydrogen production. This will maximise the amount of hydrogen transport required. As the production is at a large hydrogen production centre it will also maximise the amount of large-scale storage in a salt cavern that is required.

4.1.2 Domestic transport – *Archetype* Split

The demand for domestic transport (covering road transport, ferries and regional aviation) is predicted to be between 1 – 8 TWh in 2030 and between 2 – 23 TWh in 2035. Hydrogen use in ferries is expected to be relatively small and included in this demand estimates.

2030

- In 2030, regional aviation demand is expected to be between 1 – 2 TWh (Section 3.8), this equates to around 20% of transport demand in 2030 and is attributed to *archetype* 7.
- Demand for decentralised refuelling stations is assumed to be low in 2030 and so *archetype* 2 is not included in the 2030 split.
- As set out in the UK Hydrogen Strategy [1], the government expects hydrogen vehicles, particularly depot-based transport including buses, to constitute the bulk of potential 2020s hydrogen demand from the transport sector. As it is predicted that there will be only four industrial clusters by 2030, it is assumed the majority of depot-based transport will be serviced by independent production facilities (e.g. *archetype* 1), with a smaller portion served by clusters (*archetype* 3). The remaining 80% of the 2030 hydrogen transport is therefore assumed to be split 60%:20% between *archetypes* 1 and 3.

2035

- As highlighted in Section 3.8, regional aviation demand is predicted to be between 2 – 3 TWh in 2035 so 20% is attributed to *archetype* 7. The remaining hydrogen demand is assumed to be evenly split between depot-based transport (*archetypes* 1 and 3) and national refuelling transport (*archetype* 2). Therefore, 20% of the transport demand is attributed to *archetypes* 1 and 3 and 40% to *archetypes* 2.

Similar to the assumptions for apportioning industry demand to the *archetypes* in Section 4.1.1, it is recognised that splitting the transport hydrogen demand is very uncertain. In Section 5 a sensitivity test is therefore undertaken where all transport hydrogen demand is attributed to *archetype* 7. This will maximise the amount of hydrogen transport required and also maximise the amount of salt cavern storage required.

4.2 Required *Archetype* Quantities

The hydrogen demand for the 8 *archetypes* is calculated by combining the individual sector hydrogen demands (summarised in Section 3.2) with the apportionments of the sector demands to each *archetype* (Table 5). The quantity of each *archetype* is then calculated by dividing the *archetype* demand by the size of the *archetype* and these are presented in Table 6. The size of the 8 *archetypes* (in GWh) is based on production volumes, as described in Section 2.3, and has been determined based on the typical scales highlighted in Table 1.

Some large production facilities will support multiple sectors via multiple *archetypes*. As the size of an *archetype* is set by the size of production technology included within it, this can lead to fractions of *archetype*. Figure 9 shows how this could work for a 10TWh hydrogen production facility supporting a mixture of *archetypes* 5, 6 and 7. For this example, the fractions could be described as 0.8 *archetype* 5, 0.1 *archetype* 6, and 0.1 *archetype* 7.

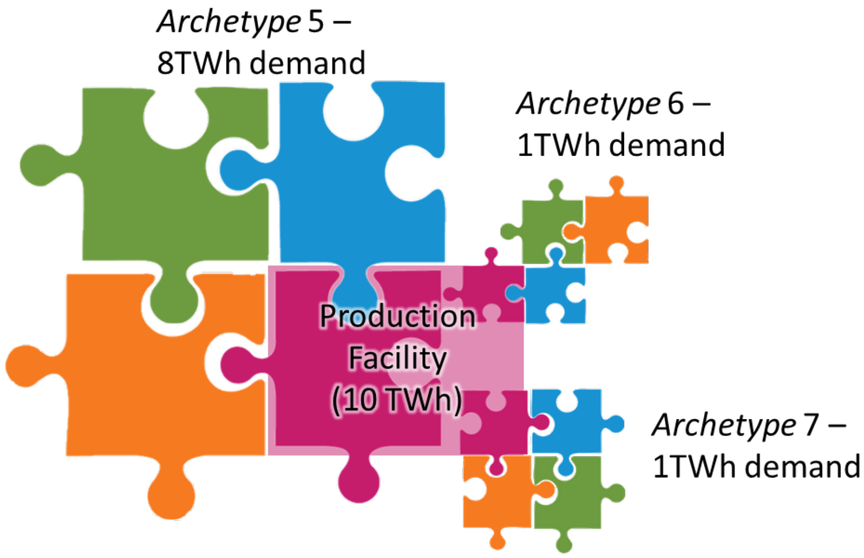


Figure 9: Example combination of large *archetypes* making shared use of a large hydrogen production facility

The minimum and maximum number of *archetypes* is calculated for each *archetype* based on the lower and upper hydrogen demand of the different sectors presented in Section 3. The calculation has been undertaken for both 2030 and 2035.

Table 6: Quantity of *archetypes* required to match 2030 and 2035 demand estimates

Archetype	Size (GWh)	Description	Total estimated quantity of *archetype*			
			2030		2035	
			Min	Max	Min	Max
1	10	Decentralised, independent unit	110	585	165	685
2	10	Decentralised, supporting national system	0	0	80	920
3	500	Small user using hydrogen from a medium producer, without a dedicated pipeline	1	5	3	14
4	500	Medium size users using hydrogen from a medium producer, connected predominantly via pipeline.	4	8	10	18
5	10,000	Large point user as part of a large hydrogen production centre	0.7	2.5	2.8	6.2
6	10,000	Large, distributed user as part of a large hydrogen production centre	0	0.1	0	4.5
7	10,000	Small/Medium user as part of a large hydrogen production centre	0.02	0.16	0.04	0.5
8	10,000	Alternative fuel production for shipping or aviation sectors, as part of a large hydrogen production centre	0	0	2	3
		Total number of large hydrogen production centres (*archetypes* 5-8)	**1**	**3**	**6**	**15**

Table 6 shows that a maximum of 3 large production centres in 2030, and 15 large production centres in 2035 are required. These are made up of a combination of *archetypes* 5-8, as described in Section 2.3. This is based on a nominal size of 10TWh (annually) for each large hydrogen production centre. In reality (and in line with the key components outlined in Section 2.1) the size of these centres could vary between 1TWh and 30TWh. In practice, this means that there could be fewer hydrogen production centres of a larger size, or a greater number of hydrogen production centres of a smaller size.

Having estimated the number of *archetypes* and hydrogen production centres required, the associated T&S infrastructure requirements and costs can be estimated.

5 WP3: Predicted Transport and Storage Infrastructure Required to Support Hydrogen Development

This section develops requirements and cost predictions for transport (trailering and pipelines) and storage (surface and salt caverns) infrastructure in 2030 and 2035. While there are other technologies capable of storing hydrogen on a large scale (such as depleted oil and gas fields), these are not expected to be developed by 2035, which is the focus of this study. For this reason, only salt cavern storage is considered hereafter for large scale hydrogen storage. Initially, the transport and storage requirements are calculated for the individual *archetypes* (developed in Section 2.2) and these are then aggregated up, based on the number of *archetypes* required to meet the overall demand in 2030 and 2035 (Section 4).

5.1 Hydrogen Storage Infrastructure

Hydrogen storage will be required to balance hydrogen production and demand. On the production side, both electrolytic and CCUS-enabled methods will have variability. CCUS-enabled production has high utilisation but there will be times when the plant output is reduced for maintenance or due to fault. Hydrogen storage will then be required to meet constant demand. Electrolytic hydrogen production will also have downtime for maintenance but in this case the variability of electricity supply is likely to be the dominant requirement for storage, particularly when it is provided by wind or solar energy. Electrolysers can ramp-up and down in response to the electrical supply (load follow), but unless there is battery storage upstream of the electrolyser, the hydrogen produced will be subject to the variability of the electricity supplied. For the purposes of this study, we have estimated storage required to enable constant supply from all production, assuming self-contained archetypes are likely to dominate to 2035. It is recognised that less small-scale storage may be required post 2035.

On the demand side, hydrogen for industry and transport applications is assumed to be largely uniform across the year in line with current fossil fuel use in these areas. There may be variability in offtake (particularly associated with trailering), at the individual site level, but this is likely to be small compared to the variability in hydrogen production and so storage requirements for industry and transport offtakes have not been estimated. In this study, it is assumed that storage is required to ensure consistent supply from production. In reality, the storage capacity required will depend on the end use, and consistent supply from production might not be necessary for all end uses.

Hydrogen demand for heat will have a large seasonal variation, with hydrogen demand up to four times greater in the winter than summer [42]. However, this demand is broadly correlated with electrolytic hydrogen production driven by wind (it is generally windier in the winter). A small hydrogen demand for heat may therefore reduce the storage requirements slightly as it will reduce the need to balance out some of the seasonal electrolytic hydrogen production. In this analysis it is assumed that no storage is required for heat, although the degree to which electrolytic hydrogen production and seasonal heat demand are correlated would warrant further investigation. This is discussed further in Section 5.1.7.

Hydrogen use for flexible power will be variable as this will need to respond to balancing requirements in the electricity system. Storage for hydrogen use in flexible power is therefore included in this model.

For the purposes of initial sizing, three modes of hydrogen storage are considered:

- Mode 1: Smoothing out electrolytic hydrogen production
- Mode 2: Smoothing out CCUS-enabled hydrogen production
- Mode 3: Enabling hydrogen use in flexible power

The implications for hydrogen storage on the use of hydrogen for heat and in blending are discussed in Section 3.9.

5.1.1 Storage Mode 1: Smoothing out Variability in Electrolytic Hydrogen Production

In the period up to 2035, the electricity to drive electrolytic hydrogen production is likely to come from wind generation. The wind power could be obtained from the grid (e.g. via a power purchase agreement) in which case the aggregation of sites across the country (and potentially internationally via interconnectors) could mean the power supply to the electrolysers is largely uniform. Equally, the wind power may come from a designated wind farm in which case it will be subject to the local variability of wind power. The power could also be provided from curtailed wind (that would otherwise be wasted) which would be subject to both the electricity system balancing requirements and the contractual arrangements for curtailing.

For the purposes of this study, electrolytic hydrogen production is assumed to be powered from designated wind farms, which is variable at different temporal scales[16]:

- On a day-to-day level it can vary considerably over the course of a few hours.
- It is seasonal; the wind tends to be stronger in the winter than summer. On a monthly average basis, electricity production from wind can be up to twice as much in winter months than summer [42].

Smoothing out the variability in electricity and hence hydrogen production requires different levels of storage as shown in Figure 10. Inter-day variability can typically be averaged out with a few days of average annual production. However, balancing out seasonal variability in wind generation requires significantly more storage, and this can be up to 10% of annual production [42]. In this initial sizing, it is assumed that electrolysers are able to load follow the variable renewable power production and that 10% hydrogen storage is sufficient to smooth out both inter-day and seasonal variability of intermittent renewable energy to provide a constant supply of hydrogen.

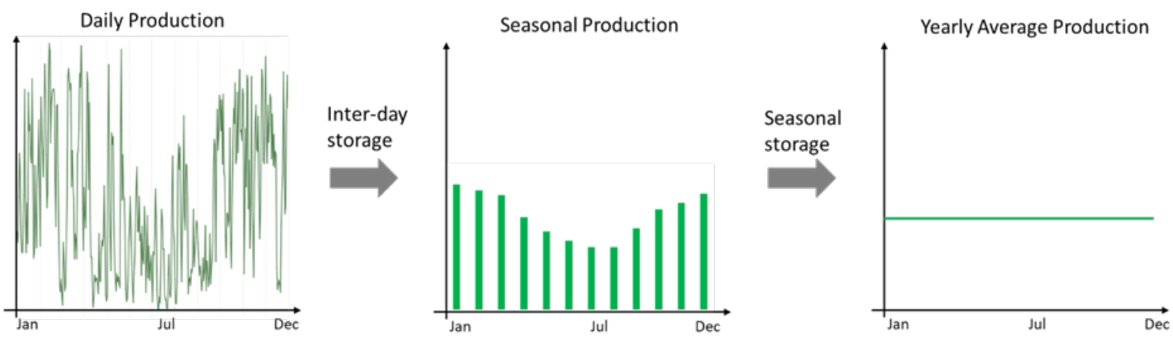


Figure 10: Wind power is variable on a day-to-day and seasonal level

Wind and solar can be combined to reduce the seasonality of power production. Solar energy is greatest in the summer and this can be combined with wind power to provide a more uniform electricity production across the year. For the UK, however, it is envisaged that wind power will provide the majority of power for electrolytic hydrogen production and so hydrogen storage will be required to even out the seasonal power production.

16 In practice, wind also has an inter-annual variability. The average power produced in any given month is different year-on-year. For the purposes of this initial sizing calculation, inter-annual variability has been omitted but this would benefit from further analysis.

5.1.2 Storage Mode 2: Smoothing out CCUS – Enabled Production

Up to 2035, CCUS-enabled hydrogen production is likely to be from Steam Methane Reformation (SMR) with carbon capture. These plants are designed to work at full utilisation for long periods of time with short outages for planned preventative maintenance and less frequent longer outages for larger intrusive work. The load factor for new SMR plants with carbon capture and storage is expected to be 0.95 [3], equivalent to 18 days downtime a year. The distribution of this downtime has implications for the amount of hydrogen storage required as shown in Figure 11:

- If the 18 days of plant downtime is split evenly across 12 months (1.5 days per month) then only 1.5 days of storage (0.4% of annual average production) would be required in storage.
- Conversely, if the plant is fully offline for 18 days sequentially then 18 days (5% of average annual production) would be required.

The storage requirements for CCUS-enabled production have been estimated by calculating how much storage is required to ensure there is a consistent source of hydrogen production, equivalent to that from 95% of the maximum production capacity.

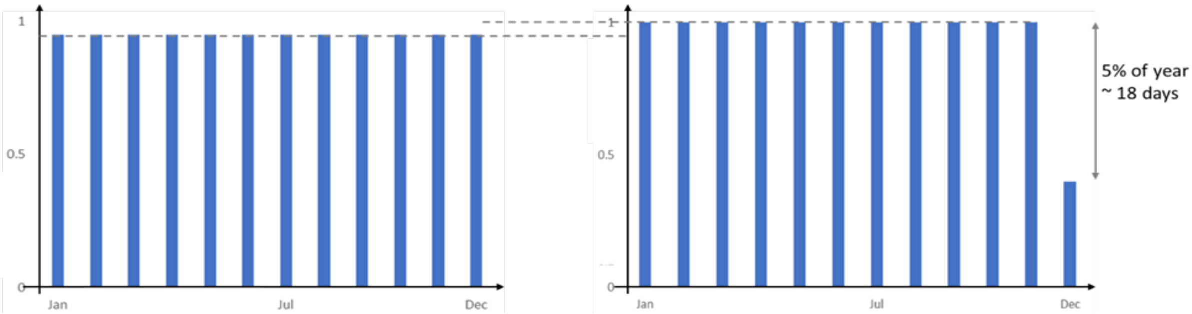


Figure 11: Bounding amounts of hydrogen storage required for CCUS-enabled hydrogen production with a load factor of 0.95 (equivalent to 18 days offline per year). Left: the 5% unavailability is split evenly across 12 months so that 1.5 days of average annual production is required in storage. Right: the 5% unavailability is within a single month so the full 5% (18 days) of average annual production is required in storage.

5.1.3 Storage Mode 3: Enabling Hydrogen Use in Flexible Power

Hydrogen to power applications are predicted to provide balancing services for the electricity system. Currently natural gas-powered gas turbines are used to balance electricity demand and supply, either as high utilisation base load (using Combined Cycle Gas Turbines) or as peaker plants to manage short term mismatches. Analysis of demand for natural gas in current natural gas turbines [43] suggests that gas demand can double from the yearly average demand for up to 10 – 20 days, equivalent to around 3 – 5 % of the annual gas demand. This suggests that 3 – 5 % of average annual hydrogen demand will be required in storage to service the gas turbines.

The variability of hydrogen demand for power production may be very different from the current use of natural gas. In particular, as the proportion of renewable energy in the energy system increases, there may be a shift towards short-term peaker plants. However, 3 – 5 % of annual hydrogen demand is used as an initial estimate for the hydrogen storage required to meet the demand for flexible power.

5.1.4 Summary of Storage Requirements

To calculate the storage requirements for the eight individual *archetypes*, minimum and maximum levels are set for the three storage modes and these are summarised in Table 7.

Table 7: Storage requirements for electrolytic and CCUS-enabled hydrogen production and the use of hydrogen in flexible power

Storage Mode		% of average annual production/ demand	Justification
1. Smoothing out Variability in Electrolytic Hydrogen Production	Min	1	Inter-day variability (based on 4 days of average annual production)
	Max	10	Seasonal variability of wind power [42].
2.Smoothing out CCUS – Enabled Production	Min	0.4	Plant operating with monthly short periods of downtime (1.5 days per month)
	Max	5	Plant operating with a long single downtime period (18 days)
3.Enabling Hydrogen Use in Flexible Power	Min	3	Doubling of average annual gas demand for 10 days.
	Max	5	Doubling of average annual gas demand for 20 days.

5.1.5 Storage Requirements for *Archetypes*

The three modes of storage given in Table 7 have been applied to the eight individual *archetypes* to calculate their storage requirements and the results are shown in Table 8. The applicability of the three storage modes to each *archetype* is in the table below and the % storage requirement for each is then multiplied by the size of the *archetype* (annual GWh of energy use, Section 2). For each *archetype* minimum and maximum requirements for storage are provided based on the lower and upper % bounds provided in Table 7.

- For *Archetypes* 1 – 4, hydrogen production is 100% electrolytic (no CCUS-enabled production) and none of the hydrogen is used for flexible power. Consequently, only the electrolytic storage levels are applied to the whole *archetype* (storage requirement is 10% of 10 GWh; 0.1 GWh).
- *Archetypes* 6 – 8 use a combination of electrolytic and CCUS-enabled production and have no storage requirement for power[17].
- *Archetype* 5 has electrolytic and CCUS-enabled production, as well as hydrogen demand for power. Consequently, all of the storage modes are applied to this *archetype*[18].

[17] It is assumed that the split is 50:50 between electrolytic and CCUS-enabled production as this provides an approximately 50:50 split between electrolytic and CCUS-enabled hydrogen overall. This is because Archetypes 5 – 8 are responsible for the majority of the hydrogen production.

[18] The demand for hydrogen for flexible power is approximately 25% of the total demand for the archetype and so the storage demand for power is applied to 25% of the archetype annual energy demand (i.e. 2,500 GWh).

Table 8: Storage requirements for the eight individual *archetypes*[19].

Archetype	Size (GWh)	Need for Storage			Type of Storage (Surface/ Salt Cavern)	Storage Requirement (GWh)	
		Electrolytic production	CCUS-enabled production	Flexible Power demand		Minimum	Maximum
1	10	Y	-	-	Surface	0.1	1
2	10	Y	-	-	Surface	0.1	1
3	500	Y	-	-	Surface	5	50
4	500	Y	-	-	Salt cavern	5	50
5	10,000	Y	Y	Y	Salt cavern	145	875
6	10,000	Y	Y	-	Salt cavern	145	875
7	10,000	Y	Y	-	Salt cavern	70	750
8	10,000	Y	Y	-	Salt cavern	70	750

For *archetypes* 1 and 2, a storage requirement of 0.1 GWh is equivalent to approximately 2.5 tonnes of hydrogen. At the upper end, 1 GWh is equivalent to 25 tonnes of hydrogen. This will be too large to store in surface storage at a small decentralised facility and in practice it will be necessary to manage the hydrogen demand so that it is more in line with seasonal electrolytic hydrogen production. However, in this analysis it is still included this as the maximum estimated surface storage for these *archetypes*.

Archetypes 4 – 8 will require access to salt caverns as the requirements will be too high for surface storage. For example, the lower prediction for *archetypes* 3 and 4 is 5 GWh, which is equivalent to around 125 tonnes of hydrogen. However, these *archetypes* will require some additional surface storage for short term reserve and also to manage the demand from trailers. The surface storage requirements for *archetypes* 4 – 8 have not been quantified here as they will be highly case specific. Therefore, in this analysis, it is assumed all the amount of storage required for these *archetypes* is met by salt cavern storage.

The storage requirements for the eight individual *archetypes* are aggregated up based on the number of *archetypes* required to meet the hydrogen demand predictions for 2030 and 2035. *Archetypes* 1 – 3 use surface storage and *archetypes* 4 – 8 use salt cavern storage. The results are shown in Table 9 (surface storage) and Table 10 (salt cavern). Minimum values are obtained by multiplying the minimum storage requirement for each *archetype* (Table 10) by the lower estimated quantity of each *archetype* (Table 6). Maximum storage values are obtained by multiplying maximum storage requirement and maximum estimated quantity of *archetype.*

Table 9: Predicted surface hydrogen storage requirements in 2030 and 2035

Year	Predicted Surface Storage Requirement (TWh)	
	Minimum	Maximum
2030	0.02	0.85
2035	0.04	2.29

[19] The application of the three storage modes (smoothing out variability in electrolytic production, CCUS-enabled production and flexible power demand) for each of the *archetypes* are noted with a Y.

Table 10: Predicted salt cavern hydrogen storage requirements in 2030 and 2035

Year	Predicted Salt Cavern Storage Requirement (TWh)	
	Minimum	Maximum
2030	0.18	3.09
2035	0.82	13.17

There is significant uncertainty in the requirements for both surface and salt cavern storage. This is due to the variability in both the storage requirements for the individual *archetypes* and the quantity of *archetypes* required to meet the hydrogen demand.

A sensitivity test has been undertaken (described in Sections 4.1.1 and 4.1.2) where all hydrogen demand is assumed to be at hydrogen production centres; industry hydrogen demand is attributed to *archetype* 5 and all transport hydrogen demand to *archetype* 7. This completely removes the need for surface storage but increases the salt cavern storage. The max requirements for cavern storage increase to 3.4 TWh in 2030 and 14.6 TWh in 2035.

Overall, the storage predictions are consistent with those reported elsewhere. National Grid's Future Energy Scenarios 2022 predict that between 1 – 2 TWh of hydrogen storage will be required by 2030 and between 2 – 10 TWh by 2035 [44][20].

5.1.6 Effect of Blending Hydrogen into the Gas Network on Storage Requirements

Blending has not been included as a hydrogen demand, but the ability to inject hydrogen into the gas distribution network could provide a reserve offtake for hydrogen that could reduce the demand for hydrogen storage. This section briefly explores the effect of blending on the requirements for storage in 2030.

As highlighted in Section 3.10, the government has targeted 10 GW of hydrogen production by 2030. The amount of hydrogen this could produce annually (in TWh) depends on the load factor of production but at 50% CCUS-enabled (with a load factor of 0.95) and 50% electrolytic powered by offshore wind (with a load factor of 0.57) this could provide 67 TWh of hydrogen per year. The upper 2030 hydrogen prediction in Section 3 is 40 TWh so in principle there is the potential to inject 27 TWh of hydrogen into the gas network[21].

Under the assumption that blending is only likely to be available to large hydrogen production facilities, it only applies to *archetypes* 5 – 8. The combined hydrogen demand for *archetypes* 5 – 8 is 27 TWh, so blending 27 TWh of hydrogen represents a doubling of demand for these *archetypes.* Storage has been sized based on variability on production, and not on demand, but this additional demand could be very flexible. If seasonal hydrogen demand and electrolytic hydrogen production trends are well matched, then the ability to blend surplus hydrogen could reduce the requirement for inter-seasonal storage discussed in Section 5.1.1. It could also enable the co-location of hydrogen production and demand without the need for local large-scale storage required in *archetypes* 5 – 8.

In practice blending rates will have geographic and operational constraints, and will depend upon the seasonal variations of both demand and production. The ability of blending to act as a flexible demand for

20 Based on three of the four Future Energy scenarios (Consumer Transformation, System Transformation and Leading the Way) but omitting the lower predictions for the Falling Short scenario (0 TWh in both 2030 and 2035).
21 At a blend of 20% hydrogen, the distribution network could accept 35 TWh of hydrogen per year.

hydrogen will also depend on contracting arrangements and whether they are flexible across the year or have monthly targets. This is discussed in more detail in Section 3.9.

Blending could also reduce the requirements for salt cavern storage in 2035 but the relative benefit of this will be less if blending is a smaller proportion of the overall hydrogen demand.

5.1.7 The Role of Heat for Buildings in reducing Storage Requirements

This analysis has provided simple predictions for hydrogen storage out to 2030 and 2035. It has highlighted that the storage requirements are particularly sensitive to the variability of wind power and this would warrant further detailed exploration, particularly around the implications of large offshore wind power deployment, and the use of curtailed wind power that could have a very different distribution to the use of a single or collection of designated farms. It would also be useful to explore the level of correlation between seasonal heat demand and the seasonality of electrolytic hydrogen production.

5.1.8 Summary of Costs

The initial estimates for storage requirements have been combined with levelised costs for surface hydrogen storage and salt cavern storage:

- Surface stored compressed hydrogen (350-700 bar): £0.61/kg [45][22]
- Salt cavern storage: £0.26/kg [46] [16][23]

Both these levelized costs include compression/preparation of the hydrogen for storage.

Surface stored compressed hydrogen levelized cost has been taken from [45] which considers 350-700 bar storage, as it is likely that stationary storage will occur below 700 bar. It is, however, recognised that the pressure of surface storage will differ depending on quantities required, site safety and cost. Many sources include only 700 bar storage, with large variability with costs ranging from £0.10/kg (without compression) [45] up to €6.37/kg (£5.43/kg) [46].

Salt cavern storage costs are based on new salt cavern storage, and do not consider re-purposing of old salt caverns, or the specific geological circumstances - which can have an impact on costs. As with surface storage costs, there is much variation within the literature, with costs varying from €0.27/kg (£0.23/kg) in [46] (p18), to £0.64/kg in [45]. Further work specific to UK sites and the most likely locations of hydrogen storage, would be useful to improve these estimates. More specific information was not available from stakeholders at the time of this study.

Further work to better understand these costs in the UK would be useful, as current cost estimates are sensitive to such variations. The estimated costs are summarised in Table 11.

[22] Mean value taken across three scenarios on p23(/40), including conversion and storage [45].
[23] Mean value taken from p18(/29) of [46] and p14(/64) of [16], converted from €/kg to £/kg.

Table 11: Estimated costs for hydrogen storage infrastructure based on levelized costs, annual demand, and *archetype* requirement

	Surface storage (£M)		Salt cavern storage (£M)	
	Minimum	Maximum	Minimum	Maximum
2030	0.3	13.2	1.2	20.4
2035	0.6	35.5	5.4	86.9

5.1.9 Salt Cavern Timescales and Related Costs

From interviews with key stakeholders in this area, it is expected to take between 4 and 7 years to prepare a salt cavern for hydrogen storage (from new). While some opportunities to accelerate the introduction of salt cavern storage have been identified, these come at extra cost.

Key factors in salt cavern preparation include permits (application and allowed volume at discharge point), and time for leaching (which is somewhat linked to permits). Leaching (sometimes referred to as solution mining) is the process whereby water is pumped into the initial well, dissolves salt, and is pumped out as brine. This process can vary in duration, but a reasonable estimate is 2.5 years. Limiting factors on leaching come from permit limits and equipment availability.

For salt caverns to be built in parallel (a technique for accelerating development) there is a significant capital cost for equipment - both for the initial drill phase, and for the leaching process. This means that there is a greater upfront capital cost, as more equipment is needed to be bought. If caverns are built in series, then the equipment can be re-used for later builds.

This should be considered alongside the predicted salt cavern requirements and costings. For illustration, if the maximum salt cavern storage requirement in 2030 of 2.4 TWh was to be held in caverns of a similar size to that proposed for HySecure [47] (approx. 0.5 TWh per salt cavern), this would give a requirement for 5 salt caverns by 2030 and over 20 by 2035. With a build time of 5 years, this would require significant acceleration of salt cavern build in the UK, with parallel processing.

5.2 Transport Infrastructure

To build single data points for very high-level comparison of scenarios, levelized costs for trailering (1.23 £/kg from [48][24]) and pipeline (0.17 £/kg[25] [16][26]) have been used, which are multiplied by the amount of hydrogen demand associated with each *archetype*, and the number of that *archetype* required. This gives a cost associated with annual requirement estimated for each *archetype*, based on levelized costs. These costs are shown in Table 12.

[24] In [48] levelized trailering costs are given with the breakdown of elements such as the cost of hydrogen production, and of refuelling station. Hydrogen production and refuelling station costs were excluded from the costs used in this study, and averaged over the 2020 and 2030 data points.

[25] Levelized costs vary significantly across available sources, up to a factor of 10. The value used has been taken from a source considered most relevant to the application in this study.

[26] Mid range data point used from source, no distinction between repurposed or new pipeline in source, assumed to be new pipeline.

Table 12: Estimated costs for hydrogen transport infrastructure based on levelized costs, annual demand, and *archetype* requirement

Archetype	Transport costs, based on levelized costs of transport (£/kg) and annual demand (£M)[27]							
	2030				2035			
	Trailering		Pipeline		Trailering		Pipeline	
	Lower (£M)	Upper (£M)	Lower (£M)	Upper (£M)	Lower (£M)	Upper (£M)	Lower (£M)	Upper (£M)
1	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-
3	22	83	-	-	52	214	-	-
4	-	-	8.6	18	-	-	22	39
5	-	-	30	107	-	-	119	265
6	-	-	0	4.3	-	-	0	194
7	6	50	-	-	12	144	-	-
8	-	-	-	-	-	-	99	138
Totals	**28**	**133**	**39**	**129**	**64**	**357**	**239**	**636**

5.2.1 Capex costs for Pipeline

As pipeline levelized costs are dominated by capex [16] and with pipeline capex data available, the capex costs for pipelines have been projected. Costs of pipelines are affected by many aspects such as the size and location of the pipeline (onshore / offshore). However, the overall dominating factors are length, and whether a pipeline is repurposed or built as new. For the purpose of these calculations, all pipelines are assumed to be onshore, and medium diameter. Length and the nature (new or repurposed) of the pipeline have been projected in line with the *archetype* requirements.

Archetypes 4, 5, 6 and 8 utilise hydrogen pipelines. Other *archetypes* either need limited transportation (and estimates for this aren't included) or use trailering. Transport in *archetypes* 1 and 2 is assumed to be very small and linked to the production sites, it has therefore not been included in these calculations. Therefore, only *archetypes* 4,5,6 and 8 are included in this section.

The levelised costs of transport are based on a £/kg transport cost estimate and don't assume anything about the length of the pipeline. The capex costs below, do make assumptions about pipeline length (Table 13) and whether the pipeline is new or repurposed (Table 14). Length of pipeline per *archetype* and reasoning is given in Table 13. These lengths are multiplied by cost per km (1.53 Million £/km for new [49] [50][28], 0.339 Million £/km for repurposed [49][29]), to give the capex costs in Table 14.

[27] Cells containing '-' indicate where the archetype does not utilise the transport technology.
[28] Converted from €/km to £/km, average across two sources.
[29] Converted from €/km to £/km.

Table 13: Pipeline lengths per *archetype* and distinction of repurposed/new pipeline

Archetype	Length of pipeline per archetype (km)	Reasoning
4	7.5	Length of pipeline based on assumed linear relationship between annual hydrogen production and length of pipeline. Extrapolated from [51] and [52], giving an upper estimate of 15km/TWh. This based on new pipeline, and so new pipeline is associated with this *archetype*. The size of the *archetype* as defined in Section 2.3 (in TWh) is multiplied by this upper estimate of 15km/TWh to give the required pipeline length.
5	150	As for *archetype* 4.
6	5,500	Length of distribution network per household nationally [53], applied to a 70,000 household town (in accordance with calculations set out in Section 3.4). This gives a distribution pipeline of 550km per 1TWh town. For a 10TWh *archetype*, this gives a pipeline of 5,500km. This *archetype* is assumed to be able to use repurposed pipeline. However, it is noted that there may also be additional needs for new pipelines for a transitional period. To improve this assumption, further investigation is required to improve understanding around pipeline requirements when building or converting an area to hydrogen heating.
8	150	As for *archetype* 4.

Table 14: Estimated capex costs for pipeline for relevant *archetypes* for 2030 and 2035

Archetype	Capex costs (£M)							
	2030				2035			
	Repurposed pipeline		New pipeline		Repurposed pipeline		New pipeline	
	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper
4	-	-	46	96	-	-	110	210
5	-	-	160	570	-	-	630	1,410
6	0	190	-	-	0	8,400	-	-
8	-	-	-	-	-	-	530	730
Totals	**0**	**190**	**206**	**666**	**0**	**8,400**	**1,270**	**2,340**

5.2.2 Transport Requirements Summary and Conclusion

It is predicted that small users will be largely reliant on trailering as a method of hydrogen transport out to 2035. Commercial considerations relating to this are considered as part of Section 8. Section 9 explores the impact of regulations in the area of transport of hydrogen via trailer. In order to fully understand costs and impacts on affected users and industries, further work is required looking into the cost components of hydrogen transport via trailer in the UK, as this information is not readily available currently.

The *archetype* approach used for this study suggests that the equivalent of between 6 and 15 large hydrogen production centres sized at 10TWh annual production will be required to meet demand in 2035, with between 1 and 3 required in 2030. Based on our predictions, this highlights the importance of anchor loads and decarbonising large industry between 2030 and 2035.

As part of large hydrogen production centres, it is predicted that up to 6% of the hydrogen produced is utilised by small users such as transport depots or small industry, with the rest utilised by large users including large industries, regional heating, power and alternative fuels in shipping and aviation. Based on these assumptions, it is concluded that most hydrogen produced in large hydrogen production centres will likely need to be distributed via pipeline, which is both more cost effective, and avoids an impractical numbers of trailer journeys.

The distance of large users from producers of hydrogen or large scale storage, will have a significant impact on the amount of pipeline required to serve them. For improved estimates of pipeline requirements and associated costs, further work to gather understanding on these distances would be of benefit.

Use of hydrogen for heating has large implications on pipeline requirements, due to the distributed nature of the users. In this study it has been assumed that repurposed pipeline would be used, but it is also possible that some new pipeline could be required for a transitional period. This would increase costs further. A better understanding of factors influencing pipeline length, and any intermediate steps would improve cost estimates in this area.

The estimated costs for hydrogen transport and storage produced in this study, could be improved on in future work through greater breakdown of costs, particularly for hydrogen transportation via trailering, and for salt cavern capex where there are many unknowns not available publicly or from stakeholders. Costs in this study have been based generally on levelized costs, where breakdown into e.g., capex and opex was not generally available. For improved insight and breakdown of costs, further work is required to establish cost breakdown.

Similar to the storage calculations, a sensitivity test has been undertaken (described in Sections 4.1.1 and 4.1.2) where all hydrogen demand is assumed to be at hydrogen production centres with no distributed sites; industry hydrogen demand is attributed to *archetype* 5 and all transport hydrogen demand to *archetype* 7. This removes *archetypes* which do not need transportation of hydrogen as production and demand is co-located, and thus increases both trailering and pipeline requirements and associated costs (note this is entirely in new pipeline, as opposed to repurposed pipeline) by approximately 10%.

6 WP4: Potential Commercial Arrangements for Hydrogen T&S Infrastructure

By reviewing the developed *archetypes* through a commercial arrangement lens, it became clear to both Frazer-Nash and Cornwall Insight that the nine arrangements fitted into three *commercial configurations* as shown in Figure 12. In the UK, process companies, located in industrial regions are forming clusters to consolidate demand mostly centred around large CCUS-enabled hydrogen production. At the other end of the size spectrum, there are small, decentralised facilities with co-located hydrogen demand and production. In-between these two, a third, partially decentralised option is starting to develop where the hydrogen demand is more spread out but sufficiently close that it can be supported by a central production hub.

This section identifies and discusses the types of commercial arrangements that could be used to deliver the three types of *commercial configurations*: decentralised, partially decentralised, and centralised. In each case, considerations around production, storage, transport, and demand are explored in the context of both transport and storage infrastructure. A SWOT assessment (Strengths, Weaknesses, Opportunities and Threats) is provided for each *commercial configuration*.

Further discussion is provided at the end of this section on the potential extension of the centralised *commercial configuration* to allow for hydrogen for heat on a regional basis. Although full nationwide hydrogen-based heat is not expected to be implemented (if at all) until after 2035, the commercial challenges are still relevant for the adoption of localised hydrogen for heat in towns and cities near industrial clusters or hydrogen production centres.

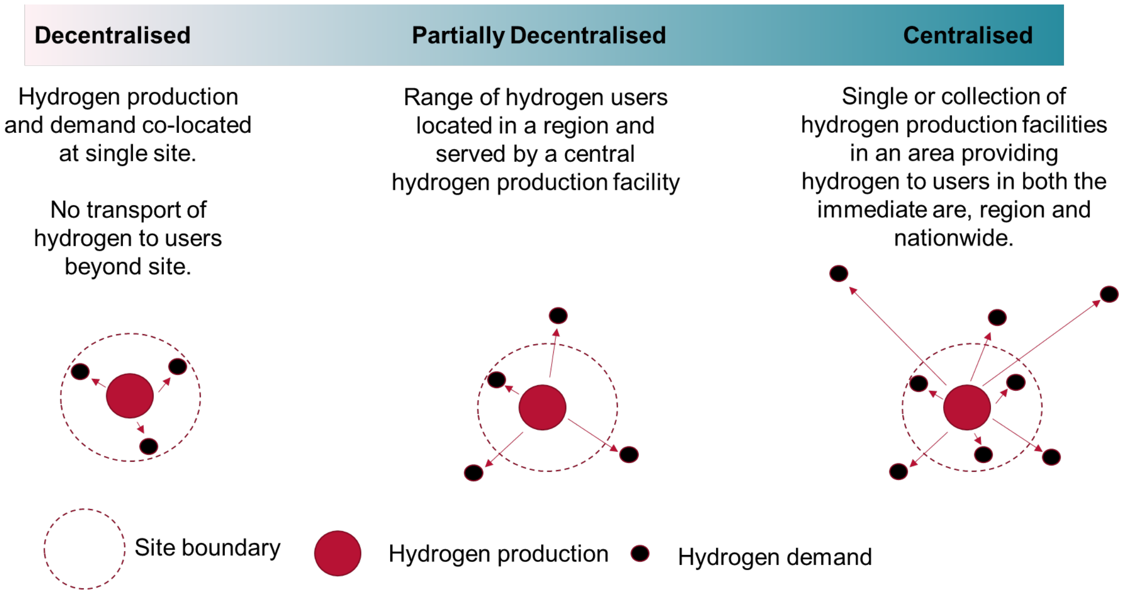


Figure 12: The *archetypes* derived in this study are grouped into three *commercial configurations*; decentralised, partially decentralised and centralised.

The following subsections describe the *archetypes* that fit within the three c*ommercial configuration*s.

6.1 Decentralised *Commercial Configuration* – Small, Decentralised users

The hydrogen demand for each user is relatively small and this allows the formation of designated and co-located hydrogen production facilities. Initially, the hydrogen demand comes from either local return-to-depot transport services such as buses, recycling vehicles and gritters, small ferries or rural train refuelling (*archetype* 1). This demand is forecast to be approximately uniform across the year but with minor daily and potentially weekly variability. At this small scale, hydrogen production is electrolytic, powered from a local renewable energy facility which will have daily, seasonal and interannual variability. Co-locating the production and demand reduces the requirement for hydrogen transport to onsite arrangements, but there will need to be storage to balance the demand and supply. At this small scale, this will be surface storage, most likely compressed hydrogen in tanks.

Although initial demand is likely to be return-to-depot transport applications, this model may also support the development of national transportation such as the use of hydrogen in HGVs where the need develops for dispersed refuelling stations around the country (*archetype* 2). It is also possible that if the hydrogen production facilities can be scaled-up and new hydrogen demand materialises nearby, but not at the same location, then this model could gradually evolve into the partially decentralised *commercial configuration.*

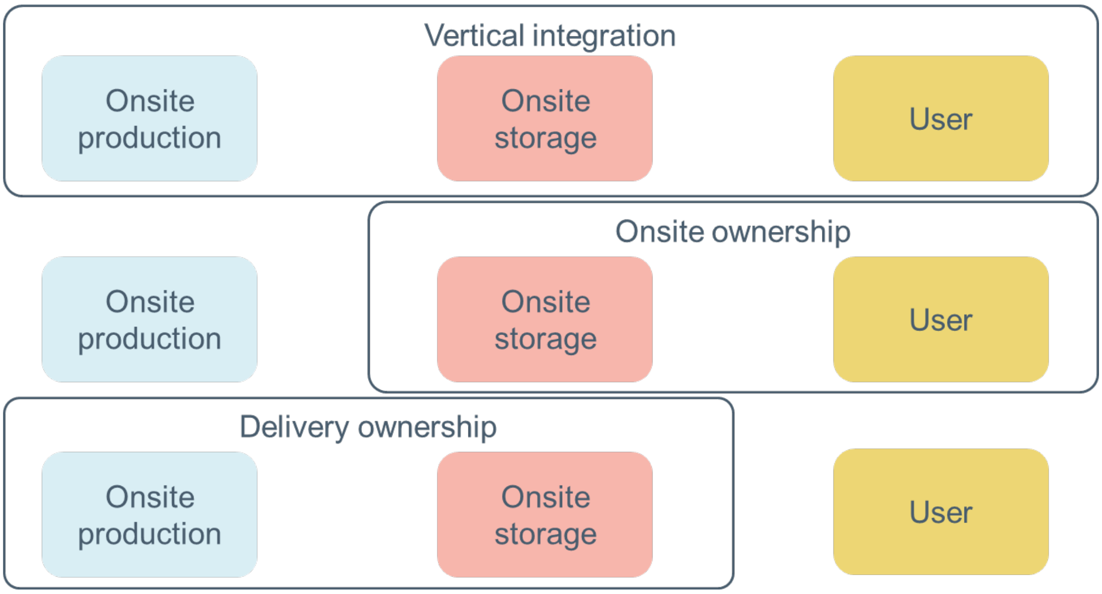


Figure 13: Ownership models, Decentralised *Commercial configuration*

The case of vertical integration, where the entire site is owned by a single entity – such as a joint venture, is likely to be the most efficient structure which simplifies commercial arrangements and risk management, leading to optimisation as a unit and to higher overall site efficiency. While a case can be made for various parties having more experience in providing, for example, electrolysers, hydrogen fuelling systems, customer management and billing etc, in practice it is expected these parties to come together to form a special purpose vehicle (SPV) to operate a site or sites and thereby share contractual, commercial, and operational risks. It is therefore anticipated that contractual arrangements would include (not exclusively) price, service levels, availability/ up-time of both transport and storage assets and responsibility for site management, maintenance, and operation.

In case of two parties locating onsite, the most directly comparable model in other industries might be a private electricity network in which a generator is owned by a different party from the demand and/or network assets. The model can also be compared to existing motor or small-scale maritime fuel models, where a transportation company delivers fuel to a storage asset for sale to consumers (for example, a petrol station forecourt). This model sees small, onsite transport assets (likely low-pressure pipeline) which may be owned by the various parties operating the site. This transportation would be necessary on any site, and commercial arrangements would only need to adherence to prevalent health and safety protocols.

6.1.1 Production Considerations

Production on a small site would likely be electrolyser-based, with the producer operating to minimise electricity import costs or maximise use of any onsite generation resources. Due to the investment requirements associated with such a development and the site-specific nature of any asset, both the producer and user would both need certainty that their partnership would be in place for an extended period. This therefore implies a 10 to 15-year arrangement and may include take-or-pay provisions on the level of demand, along with guarantees on level of fuel availability/ production up-time. These arrangements are common on private electricity networks, but an important difference is that the off-taker can refuse an unfavourable contract to instead import power from the public network. This highlights the importance of Third Party Access (TPA) rules, to prevent users being captive customers of the local producer and manage potential monopoly detriment.

TPA rules would be a set of guidelines and protocols that clearly defines the process that local producers follow that allows users to seek good faith access to production in a transparent and non-discriminatory basis. These would include, but not limited to publication of non-discriminatory T&Cs, timely reporting of production capability against nameplate capacity, anti-hoarding mechanisms and recourse processes should the user and producer not reach an agreement. Such TPA arrangements are seen in gas storage, although it is noted that gas storage operators could seek exemptions under minor facilities clauses present in the Gas Act.

Pricing would be agreed in this enduring contract bilaterally between parties. Both parties are likely to require certainty on level of pricing, but this may be difficult to agree as the costs of production will vary over the lifetime of the arrangement, for example as the price of electricity to power electrolysers changes. Where a producer has access to onsite electricity generation, this may stabilise electricity prices; alternatively, a long-term Corporate Power Purchase Agreement (CPPA) deal could have the same effect[30].

Alongside pricing, there are also whole system considerations. Reduction of electrolytic electricity demand in response to high electricity demand or reduced electricity supply scenarios would increase commercial efficiency. Market based arrangements, in the form of wholesale electricity pricing or Demand Side Response is one avenue. Alternatively, or in addition, this aspect could be built into any production policy support mechanism envisaged.

Other arrangements seen in liquid markets (e.g., electricity trading) for long-term pricing include a discount to an index price; this would be difficult to achieve in a hydrogen market without an index price for a fungible fuel. For example, in the early days of gas competition, oil indexation was used. As such, a situation could occur in which hydrogen is indexed to electricity and/or gas until a suitable price benchmark is established. A cost-plus model, which includes the cost of raw materials for hydrogen production plus an allowance to cover the capital and operational cost of the electrolyser, could be possible.

From a regulatory and permitting point of view two sets are required – planning permission and health and safety requirements. Due to the small scales discussed here, the Local Authority process under the Town and Country Planning Act applies and an Environmental Impact Assessment must be completed in accordance with the Town & Country Planning (Environmental Impact Assessment) Regulations. Planning

[30] Though still leaving the producer exposed to changes in network and policy costs.

would also include securing electricity network connections though may be challenging in some locations. These issues are discussed further in the appendices.

6.1.2 Transportation Considerations

This model, which sees all hydrogen produced and consumed on a single site, only has need for onsite transportation (e.g. from production unit to storage vessel, or storage vessel to an industrial user) which is likely to be in pipeline form. For operators active on multiple sites, this would see standard terms and conditions across sites.

For the Vertically Integrated case contractual arrangements would include service levels, maintenance, and operation; since it is owned by the same entity all parties would be sharing these operational and financial risks. This would also be true for the aspects that are owned by single entities in the Onsite and Delivery ownership cases.

In the case of two parties located on the same site the arrangements would need to specifically define access conditions and penalty clauses for non-compliance for the transportation assets connecting the two systems. For example, with the Onsite case a connections agreement stating permitted delivery rates and quality standards with curtailment clauses for non-compliance. This is analogous to a gas connection agreement seen between a gas reception terminal operator and gas transporter.

6.1.3 Storage Considerations

We do not consider it likely that a third-party would be able to provide storage services practically or commercially on this kind of site, given the small scale and short-term nature of storage, as well as comparable arrangements seen elsewhere in industry. There is also the possibility of a site that does not require any storage with the production and demand centres flexing to meet individual needs, but this is outside the scope of this study. Such examples where no onsite storage is required that have alternative back-up connections are covered in the Centralised *commercial configuration* (Section 6.3).

The refined petroleum sector is the closest comparator to this model. The analysis of the refined petroleum sector carried out as part of this study and presented in the annex indicates that both the provider of fuel and the demand user frequently have their own storage assets – the former to ensure security of availability and the latter to ensure security of supply. Therefore, both the producer and user of hydrogen are considered to be equally likely and valid storage operators, with contractual arrangements driving which party will be likely to own the storage asset. In the vertically integrated case, since all elements are owned by the same entity the site is likely to be optimised to meet either production or user requirements.

- The producer would find storage useful to maximise production during low electricity cost periods, for example overnight or when there is excess renewable generation. It would store this hydrogen to sell later, improving margins by minimising production costs.
  - In this case, the producer would control the amount of hydrogen in the storage vessel, and contracts with the user should specify availability, which the producer would meet with production and reserves – effectively taking on the security of supply risk and hedging responsibility.
- Alternatively, the user may wish to take on the security of supply risk and hedging by operating its own storage asset, buying from the producer to manage its level of reserves according to forecast demand and according to prices set by the producer.

In either case, the two parties will need to work closely together in order to maintain supply, for example by sharing demand forecasts. As the situation evolves into the Partially Decentralised *commercial configuration* and deliveries of hydrogen begin to arrive on site, either in discrete quantities by road or on a continual basis by pipeline, the user would be more likely to require its own storage assets to manage supply, in addition to any on the production site.

Storage of more than two tons of hydrogen is restricted by the HSE through COMAH and requires more permits than conventional fuel storage. This requirement implies that locating hydrogen forecourts in residential and commercial districts – where petrol forecourts are currently found – may be difficult if large stores are required. Operators have told us that around 500kg of hydrogen is the minimum daily sales target for a viable site, which suggests that the two-tonne limit will not immediately be a barrier, but – given that petrol forecourt tanks range from around 60,000 litres (44,400kg) to over 1mn litres (740,000kg) – may be a blocker to growth over time.

For other types of sites, such as hydrogen generation units, supply to airports and similar, the two tonne limit is likely to be restrictive. However, these sites already have considerable experience in managing large volumes of fuel, and so are likely to be able to navigate the health and safety considerations and permitting requirements to establish fuel depots.

6.1.4 Demand User Considerations

A demand user selling hydrogen to end consumers or using the hydrogen as industrial feedstock will require a stable source of fuel. However, these demand users are not necessarily guaranteed supplies, and this means that risk driven by security of supply is economic (missed sales) and reputational (an image of unreliable fuel supplies would not support industry growth) rather than bound by contract.

The exception is return-to-depot fuelling of fleets, where a requirement to deliver fuelled vehicles to the roads following re-fuelling periods represents an additional contractual requirement to deliver fuel and thus helps to mitigate security of supply concerns.

This *commercial configuration* does not permit third party access[31]. This means that there is no option for competitive pressures to be applied – although in time, competition between different suppliers of fuel will likely emerge, as it has in the fossil transport fuel space in petrol and diesel, and is expanding in the EV charging, CNG and LPG markets.

[31] Strictly, it does permit this, but third-party access would convert it into a different *archetype*, as discussed in the introduction.

6.1.5 Decentralised *Commercial Configuration* – SWOT Assessment

Strengths	Weaknesses
Commercial barriers other than price are limited Simple configuration, with flexibility from different ownership models Small size simplifies some permitting and planning considerations	No certainty of end-user demand (on public-access sites) As market develops, may not be competitive Requirement for electrolysers to provide flexibility and resilience services to grid may restrict onsite production – or increase costs to electricity system
Opportunities	**Threats**
Potential large range of suitable sites to implement solution on merchant level (with suitable subsidy in place) Electricity flexibility revenues could become an additional revenue stream, reducing costs/ need for subsidy Return-to-depot fuelling for hydrogen vehicles	Concerns on planning due to HSE requirements and Environmental Impact Assessments regarding storage Security of supply for production/ pricing Initial two-party sites could have complex arrangements, but these are likely to ease as familiarity of them and/or standard terms develop
Unanswered questions	
What will the production/ consumption subsidy business model be? How will this be structured to cover unintended impacts on electricity and gas markets? How will HSE, EIA and planning guidelines change?	

The simplicity of this model lends itself to a straightforward *commercial configuration* with the only barrier being the delivered price of hydrogen. Early developmental support to reduce the price of hydrogen to levels of competing fuels would be welcome, with clarification on how this support would interact with providing flexibility and energy network resilience services and minimising the costs to input energy, to maximise efficiency.

6.2 Partially Decentralised *Commercial Configuration* – Small, Partially Decentralised Users with Deliveries

These *archetypes* cover small users that use hydrogen from a central regional hydrogen production hub as described by *archetype* 3 (Section 2.2.8) and *archetype* 4 (Section 2.2.9).

A small to medium-sized hydrogen production facility develops in response to increasing demand for hydrogen in a region (*archetype* 3). The hydrogen demand is not centred at a single location but sufficiently close to allow a partially decentralised *configuration* to develop where hydrogen is produced centrally and then trailered relatively short distances to end-users. This is between sites where a pipeline is not economically viable. There will need to be some surface storage depending on the variability of hydrogen production, flexibility of the hydrogen demand and the resilience of hydrogen supply required.

Over time, this enables additional users in industry and potentially regional airports (*archetype* 4). Hydrogen production is electrolytic, powered by a local renewable energy plant although hydrogen could potentially also be produced from a BECCS plant. The hydrogen demand is likely to be relatively uniform throughout the year with some daily or weekly variations. As the hydrogen demand grows in a particular area it is possible that a pipeline becomes more economic than trailering. For example, initially a regional airport may start using trailered hydrogen but then look to develop a pipeline as demand increases.

This is similar to the previous *commercial configuration*, except that some or all production is offsite, with hydrogen trailered or piped to the site. In the case of the use of trailers, this implies a greater need for storage as there is no option for continuous production / delivery of supply as is the case is in the onsite production and pipeline delivery instances. This brings the model closer in line with the petrol forecourt paradigm, and in line with that option there is a requirement for small-scale storage onsite to manage intermittent or slow-rate delivery. This issue in relation to fossil fuel sector is discussed in the appendix.

Potential sources of hydrogen range from medium-sized assets, specified primarily for production and regional (or, later, national) export to consumers, or large assets developed as part of offtake centres which have spare capacity that can be exported to these smaller users.

Though this is described in Section 6.1 as a potential development of the decentralised *commercial configuration*, according to our research both are developing in parallel[32].

As with the previous *commercial configuration*, under this model there are three main ownership options, set out in Figure 14.

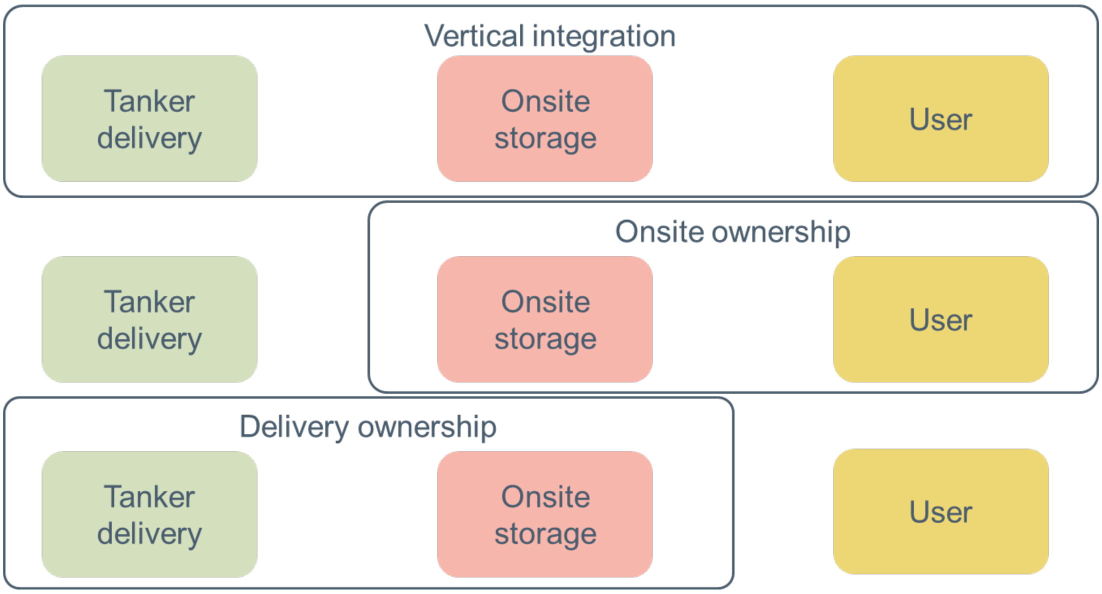


Figure 14: Ownership models, Model 2

6.2.1 Transportation Considerations

There are two primary routes for hydrogen to arrive onsite: pipelines and tankers. As an observed rule, the transport of liquid fuels by the existing fossil fuel industry, such as petroleum and diesel, shows that pipelines directly connecting to retail sites are unnecessary or uneconomical, with major airports and ports

[32] One producer/ distributer noted that minimum viable scale for distribution was 500kg/day, whereas minimum viable production was 5t/day. It therefore is trailering product to distribution sites to maximise its breadth of site acquisition and development, with the intention of scaling up each site over time.

being the exceptions. A separate report has been submitted which contains more commentary on existing arrangements. However, if a regional hydrogen pipeline were to be in development for a range of other users, it would be possible for the fuel site to connect with such an asset. Such regional pipelines are discussed in Section 6.3.

We consider tanker deliveries to be the more likely approach to providing hydrogen onsite, and this model is already being applied to a number of innovative and commercial hydrogen projects through vertically integrated business models – i.e., the producer is trailering hydrogen in its own vehicles to its own sites. Permitting for hydrogen by tanker is through the International Carriage of Dangerous Goods by Road Regulations (ADR) and further details are found in the annex. Typically, a producer will seek to own a range of hydrogen end-use sites in order to provide diversity of demand and to match efficient end-use demand with efficient production volumes.

In established fossil fuel markets, however, tankers tend to be owned by third-parties or by large fuel producers. Contractual models either rely on buying or leasing tanker fleets (bringing transportation in-house), or purchasing fuel on a delivered basis. As the market expands, the role of independent transporters may expand as it has in fossil fuel delivery, increasing competition for delivered supply.

6.2.2 Production Considerations

Offsite production may be at a site dedicated to road fuel production or be excess production at a producer which is providing hydrogen to another user or range of users. If the latter, quality standards may be an important contractual consideration, noting that SMRs may not provide fuel of sufficient purity for use in vehicle fuel cells – implying the need for quality or composition standards.

In either case, the range of usage sites and likely greater scale of production suggests that for the producer, security of demand will be more certain[33]. There is also a new storage role created at the production site, in order to allow the producer to maximise its production efficiency. This is likely to be met by the producer itself with relatively small-scale surface storage tanks.

Pricing for production under this model might see development of a semi-liquid market, with several producers potentially competing to meet demand in all but the most nascent development situations. As with Model 1, guaranteed supply to final end-users is not a given – although there are financial and non-financial incentives to deliver reliable supply. As such, echoing current practices for road and maritime fuel providers, short-term agreements for fuel supplies may be suitable contracts for supply, as price-changes can be passed through to end-users.

6.2.3 Storage Considerations

The key difference between the Decentralised and Partially Decentralised *commercial configurations* is that production is carried out offsite in the latter, where producers would own storage on their production sites rather than the consumption site, as per the Decentralised *commercial configuration*. Storage on the consumption site would then be owned by the consumer. This allows supply to multiple use-sites from a single production site, aligning to the models seen in the market currently both for industrial hydrogen and fossil fuel distribution businesses. Storage considerations are thus seen as broadly similar to the Decentralised *commercial configuration* (see Section 6.1.3).

We note that the two-tonne limit on local hydrogen storage explained in Section 6.1.3 may be of increased significance for sites without directly connection production facilities. This restriction may require multiple

[33] The reverse may be true for users, if there is high competition for offtake, particularly during early years of market when options for procuring fuels are limited.

tanker deliveries per week for busy sites, which could result in additional costs and disruption to operations, as well as being considered in the planning permission process.

6.2.4 Demand User Considerations

The flexible nature of contracting and remote delivery by tanker lends itself to a highly competitive market developing, provided that there a number of parties offering delivery services. However, it does not provide high security of supply, as there is no guarantee of deliveries being made available from fuel suppliers. In the fossil fuel transport industry this does not generally present a problem – other than during instances of "panic buying", for example during September 2021 – but with a smaller range of hydrogen sellers, at least in the early days, it is likely that deliveries may be less reliable or flexible, with regards to dates or volume of delivery.

This suggests for early development sites, some form of take-or-pay contract guaranteeing the volume and price of regular deliveries, at the recipient's financial risk, may be suitable, while latter users may be more willing to accept security of supply risk based on a range of producers/transporters being available.

6.2.5 Partially Decentralised *Commercial Configuration* – SWOT Assessment

Strengths	Weaknesses
No barriers other than price Simple configuration	As market develops, may not be competitive Current planning restrictions on storage may require multiple weekly tanker deliveries
Opportunities	**Threats**
Potential large range of suitable sites to implement solution on merchant level (with suitable subsidy in place) Amendments to ADR to support larger receptacles will reduce frequency of deliveries	Concerns on planning due to HSE requirements and Environmental Impact Assessments Security of supply for production/ pricing

Unanswered questions
How and when will HSE, EIA and planning guidelines change?

This *commercial configuration*, as per the decentralised *commercial configuration*, lends itself to a simple commercial set up with hydrogen pricing seen as the main barrier and so any support to bring the cost of the fuel to compete with similar fuels would be welcome. Additionally, steps towards support in the adoption of larger tanker receptacles will help to lower transportation costs and mitigate concerns on the need for multiple tanker deliveries.

6.3 Centralised *Commercial Configuration* – Centres of Medium and Large Users

Several industries consolidate their hydrogen demand and form large scale anchor demand (*archetype* 5). The large scale of demand is delivered by a combination of CCUS-enabled and electrolytic production. Hydrogen is mostly distributed to the individual industrial processes by short pipeline, with some trailering to smaller users. Industrial hydrogen demand is likely to be relatively uniform throughout the year, but hydrogen use for flexible power will require more significant storage that will likely be provided by salt caverns.

Local conurbations near centralised facilities may also provide a demand source for hydrogen for the decarbonisation of heat; converting domestic boilers and other gas fired appliances to hydrogen (*archetype* 6). This may be with or without the further extension to any nationwide conversion of the gas network. Secondary smaller users may also develop in the wider region including other industries, regional airports or refuelling for developing nationwide HGVs (*archetype* 7).

Further afield, the use of ammonia in shipping and either liquid hydrogen or SAF will be served by these centralised facilities (*archetype* 8). Finally, any nationwide conversion of the gas network; will be dependent on the centralised hydrogen production centres for producing the significant scale of hydrogen required (*archetype* 9). The production facility will need to be connected via pipeline to the National Transmission System (NTS) or Gas Distribution Networks, either re-purposing existing pipelines or building new. The seasonality of heat demand will necessitate larger scale hydrogen storage in salt caverns or potentially disused gas wells, although the latter are unlikely to be available before 2035.

The majority of initial deployment of large-scale low-carbon hydrogen production and consumption will be deployed in industrial clusters. Pipelines across these clusters and sizable storage assets are expected, along with multiple producers, using different technologies, and multiple consumers, located at each site. This creates a much more complex situation than the previous *commercial configurations*.

As the options for producers and consumers to own and operate their own small scale storage assets have been covered, they are not considered these further in this section. Options have also been reviewed in a different format, looking at the different relationships and contractual models possible between the remaining four types of party. Figure 15 shows an advanced hydrogen production centre operational model, with multiple producers, multiple consumers, a regional pipeline network, and other transportation providers (which could include tankers, private pipelines, ships, and ferries[34]) to users not connected to the pipeline.

[34] Note that only estimated costs of trailering are used in this analysis, though these other options may become available as the hydrogen economy evolves.

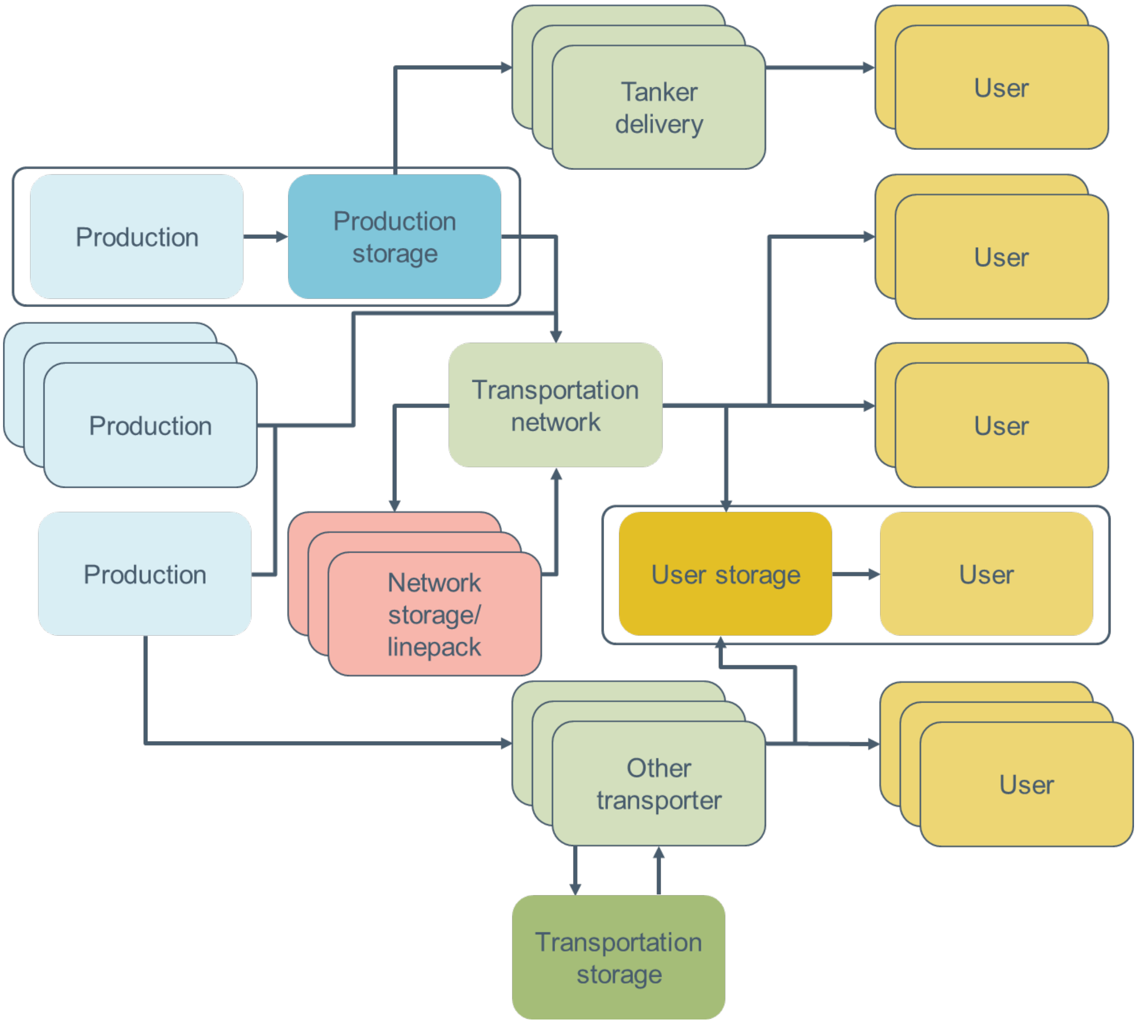


Figure 15: Hydrogen production centre operational model, centralised *commercial configuration*.

From the producer perspective, the main consideration is to maximise economic production, either to sell direct to consumers or intermediaries, or to inject into storage assets. For networks and storage operators, the key considerations are to recover sufficient revenue for the costs of the long-term investment in their assets. However, the storage operator may have some flexibility to deliver commercial optimisation (e.g., arbitraging hydrogen prices), whereas network operators are simply meeting demand.

For consumers, the concern is for security of supply, and being able to receive sufficient hydrogen at an affordable cost. Given that there is a network, there is also a need for a system operator role, which would drive efficient operation of the system.

We therefore discuss options for relationships between network operators and storage operators, relationships between producers/consumers and network operators, and relationships between producers/consumers and storage operators, and a potential role for storage operators in creating liquid markets.

In all cases the communication protocols and IT infrastructure between parties are key enablers and consideration on their timely delivery should be made.

6.3.1 Network to Storage Provider Relationship Options

The key differential is whether the network operator and a storage asset connected to the network are single or multiple parties, and what the relationship between these parties should be. In this section, both options are discussed, with reference to lessons learned from other sectors.

6.3.1.1 Integrated transport and storage

This model would see the network operator also owning storage, taking on the system operator role, and having responsibility for security of supply from both network and commodity availability perspectives. There are comparators for this arrangement:

- In the electricity sector, license requirements for unbundling (between network operators and storage, which is treated as a generator) mean that this kind of arrangement cannot exist. Some aspects were seen when UK Power Networks trialled implementation of a storage asset in place of network reinforcement, but this is now blocked, and they are required to procure services from third parties.
- Gas network licenses are different, with The Gas Act requiring onshore gas storage operators to have a gas transportation licence to convey gas via pipeline unless they meet exemption criteria. The Gas Act also requires gas storage operators to be independently owned from entities that are also network operators and although exemptions can be requested for small-scale activity and where this would benefit storage operational efficiency, the scale of this operation may not be deemed as small. An exemption might be required from this segment of the license to permit this behaviour; this could be time-limited or subject to capacity / volume restrictions to set end-conditions for exemptions.
- Water companies provide these integrated services naturally, with the integration of production elements also. They also provide a single commodity price to consumers, incorporating network, storage and production costs (though significant network costs are collected as standing charges). Similarly, hydrogen pricing could be informed by prices for production submitted by third party producers and the cost and forecast future value of hydrogen in the storage asset.

In terms of commercial arrangements seen, this model could work in the following ways:

- As monopoly service providers, both the network and storage operators would need to be price controlled and funded by connected users, probably via a Regulated Asset Base (RAB) model.
  - Network charges would recover capital costs of both assets from all users, based on standing and volumetric charges (potentially seasonally weighted), although the number of users and volumes may be insufficient to recover costs economically, during the growth phase, pointing to a need for out-of-market support.
  - Costs of operating storage in terms of fuel costs could be recovered by loss factors. For example, when producers create more hydrogen than required by consumers, this could be submitted to the storage asset with the network operator/ storage operator then extracting the necessary fuel component and subsequently storing the remainder. The producer's storage inventory is credited with this remaining volume for later disbursal.
- For the case where production centres are connected via a pipeline and storage, a Cap and Floor arrangement similarly used for interconnectors is a possibility. However, these arrangements are usually used where there are liquid commodity markets and price differentials between ends of the pipeline. This is not envisaged within the timeline of this study.
- The system operator role would accept physical notifications from all system members and balance the network from the storage asset, with users incentivised to remain in balance with their notified positions by imbalance prices.

- The imbalance / settlement period would need to be shorter than the gas balancing period (1 day) due to the relatively small scale of a potential early hydrogen network compared to the GB gas network, with lower possibility for variation to be automatically manage due to linepack in the network and thus a greater need for active management by participants.

- Matching the GB electricity settlement period, half hourly, might be sensible, given that much production will be driven by electricity price.

- The model has some issues with price discovery and contracting for storage injection / withdrawal over the seasonal duration. Where no seasonal duration or long term price signals exist a system of bilateral agreements featuring interruptible capacity products and Use-it-or-Lose-it (UIOLI) provisions could support price discovery, although such arrangements are potentially very complex. With contractual UIOLI provisions, is it recognised that any previously bought capacity that is subsequently underutilised by the user could be re-sold by the operator to other users without compensation. With interruptible products the operator could reasonably oversell capacity ahead of time and then, within contractual lead times curtail this capacity to within available operating parameters. When taken together, UIOLI provisions and interruptible capacity products can help to maximise utilisation. This could improve the economic efficiency of the facility, and through the activity of selling interruptible capacity, aid price discovery. For example, a potential user of interruptible storage capacity could be an operator of a hydrogen electrolyser that relies on the availability of spare electricity that would have otherwise been curtailed.

- Under this integrated model, in the future as the system expanded, storage, transporter and system operator roles could be unbundled to increase competition and could also incorporate independent storage providers.

6.3.1.2 Independent transport and storage

With separate parties for network operation and storage operation, there are a number of options for establishing an entity to serve the system operator role. These include a major producer, the network, a major storage operator, or a fully independent party. Cost efficiency, investment control, regulatory and monopoly considerations should inform this decision.

Regulation could be based on the existing gas network licenses – only relatively small adaptations being necessary. Network assets (hydrogen transport) would be monopoly price regulated to guarantee cost recovery, e.g., through a RAB. It is noted that some network assets, for example heat networks, are not managed by price controls, but where they have monopoly market power this risks consumer detriment and slowing market growth as consumers may be reluctant to join a market where they are exposed to excessive market power. In heat networks, this awareness has led to ongoing introduction of regulation.

Storage assets could potentially be supported by a business model e.g., RAB or cap-and-floor arrangements. Another option is that storage assets operate as “fully merchant”, meaning they are unsubsidised and earn money through wholesale market trading and participating in grid services. However, evidence from stakeholders indicates that storage assets cannot operate as “fully merchant” initially because there isn’t sufficient certainty on return from investments. Therefore, for storage assets to be deployed, business models and certainty around the design of these will be required. Potential storage operators interviewed for this project have told us that – given the long design and build times of storage assets, of 4 to 5 years – the current timeline for issue of the storage business model (2025) is not believed to be sufficient to enable First-Of-A-Kind projects – such as HyNet – to go ahead on the correct timeline to meet expected demand.

For both integrated and independent setups, innovation of products and services in line with both producer and end-user requirements will be a key enabler in developing the hydrogen economy. A process that enables open discussion and sharing of product needs and ideas should be encouraged across production centres to ensure the market develops as a sector and not just as individual production centres.

6.3.2 Producer / Consumer and Network Relationship

Networks act as monopolies, as consumers are reliant on the single available network provider. Large monopoly networks are therefore regulated to ensure efficiency and value for money for consumers in the absence of competition. A potential hydrogen sector regulator could develop price controls based on a view of efficient costs, though it is noted that the process of setting price controls is lengthy and expensive and may not be suitable for small-scale networks.

Network charges for small networks are generally regulated on a benchmark basis against their larger regional counterparts, with rates capped accordingly. This is unlikely to be possible for hydrogen networks, as there are no comparable larger-scale hydrogen networks. Given the similar characteristics of natural gas networks to hydrogen networks, it may be possible to cap charges at the level of regional natural gas networks.

This would be aligned to the process for licensed independent gas, power and water networks. If hydrogen network costs are higher, a multiplier could be used to compensate for this. This is likely as gas networks are established infrastructure assets with economies of scale that early hydrogen networks will not have. This does have drawbacks in those industries – particularly as developers can “cherry pick” profitable networks to retain, while passing the more expensive to the regional incumbent to socialise costs.

Whether the network is independently operated or integrated with storage, network charges should be recovered via a combination of fixed and volumetric charges, with such approach having been applied during the GB’s post-privatisation era for gas and electricity. There may also be a case for out-of-market support during the growth phase, while network utilisation increases to cover costs at an economically viable level.

Long-term certainty of charges would be attractive to users, and this may inform the use of a RAB model setting allowed revenues for a given period, possibly with an allowance for sharing emerging cost-efficiencies between the network operator and network users, to promote increasing efficiency over time. However, it is noted that established network RABs may restrict investment and cause a step change in charges when they refresh. This latter point may be mitigated through the use of an enduring charging framework with rates set on an annual basis in a manner similar to the current gas and electricity network charging controls.

In addition to these concerns, network users will require security of supply, with the introduction of guaranteed standards of performance for the network operator potentially providing an element of confidence to these users. In early networks, commercial agreements may be sufficient to provide surety, but over the long-term standard terms through licensing and network codes may be required to facilitate network growth.

6.3.3 Producer / Consumer and Storage Relationship

If the storage asset is independently operated, then relationships will have to be established with producers and users as well as the network. There are two main models for trading: capacity and arbitrage. The former lends itself well to arrangements such as RAB and cap-and-floor, while the latter could support these but is more optimised for merchant operation:

- Capacity models would auction the right to inject, withdraw or store in the asset. This could be based on flows rates or on volumetric capacity, or a combination of both.

    – This model would probably see auctions for capacity held regularly.

- Arbitrage models would see the operator act both as a hydrogen user (purchasing low-cost hydrogen when available and injecting into storage), and a producer (withdrawing hydrogen from the store and onto the system when it is high cost).
    – An arbitrage model could see investment support if storage assets were required by the system to dispatch injection and withdrawal in certain patterns to support the system – this could be linked to hydrogen prices, energy prices for hydrogen production, available production or consumption demand, or similar metrics.

6.3.4 Centralised *Commercial Configuration* SWOT Assessment

Strengths	**Weaknesses**
Large, multi-user joined up system Could lead to liquid commodity market for hydrogen	Could restrict competitive pressures, especially on seasonal value of hydrogen Requires complex agreements between parties which are difficult to bootstrap into place
Opportunities	**Threats**
Could provide a viable anchor system to expand from over time Could support trailering out hydrogen to create regional hydrogen economy	Lack of a large underground storage provider may prevent hydrogen production centres from safe and efficient operation Timely delivery of communication protocols and IT infrastructure required

Unanswered questions
Which party should be responsible for system operation and how will they be incentivised? What is the preferred subsidy model for hydrogen production, consumption and storage? What are the key decision factors for future unbundling networks, storage, system operation?

The relationships between the parties, whether via vertical integration or through numerous independent entities, will be complex and the commercial arrangements will mirror this. For regulated price-controlled assets RAB is the preferred option across many equivalent sectors, with some having elements of profit-share to encourage innovation and efficient operations. A RAB model could be simplest to set up, given the industry need to timely develop business models, in particular with vertical integration. However, moving away from this as the market transitions to enduring arrangements may be a challenge. A cap-and-floor arrangement could encourage innovation; development of products and services to enable parties to hit cap limits and perhaps enable a quicker transition to an enduring market design.

For independent parties, clear rules and procedures on how each interact, both commercially and physically will require development and existing comparable sectors all have examples of best practice. Without a liquid market price for hydrogen, either in certificate or commodity form, long-term revenue certainty sufficient to enable investment is unlikely without a subsidy incentive or other out of market payment to provide this.

In encouraging development of this model, government should consider bringing forward the decision on hydrogen storage business models to allow for timely investment in grid scale storage assets. Alongside this, setting up a task force or Working Group mechanism that encourages collaboration between parties to consider whole system thinking on commercial arrangements and to find ways to simplify structures may be an easy step forward. This will help to ensure all relevant parties have scope to share insights, learnings and perhaps develop opportunities to reduce overall costs and potential supply chain challenges.

6.4 Extending Centralised *Commercial Configuration* to Consider the wider Gas Network

This section examines options for blending hydrogen into the national natural gas networks at penetrations of 20% or greater. For blending at lower volumes, the commercial considerations discussed here may not be required. There are additional considerations if hydrogen for heating and other uses is transported via national networks, as this could contribute to developing a liquid market for hydrogen and thus a market value for the price of storage. This in turn could enable the emergence of merchant hydrogen storage and the end of subsidy or stability support from government.

While national adoption of 100% hydrogen for heating is not likely until post 2035 (if at all) and thus excluded from this study, there is the potential for delivery of 20% blending of hydrogen into the existing gas networks, providing approximately 35TWh/year of hydrogen demand. Blending this volume of hydrogen would imply the need for a mechanism for existing gas suppliers to continue to offer services to maintain a level of competition between suppliers, requiring gas suppliers to meet a certain threshold in the fuel mix provided to customers.

There is precedent for such an approach, with options including a certificate scheme along the lines of the Renewables Obligation (RO) or Road Transport Fuel Obligation (RTFO), or a requirement to trade for hydrogen injected into gas networks.

The physical solution necessitates the establishment of a liquid market for hydrogen (whether certificates or physical fuel). Given the number of customers involved gas network licenses, safety regulations and price controls would also need to be updated to account for this change.

Storage and network operations would therefore remain largely unchanged, although with an incentive for obligated parties (most likely suppliers given parallels with the RO) to fund sufficient storage assets and injection to deliver the required blend over the course of the year. This itself may not provide sufficient investor confidence in terms of long-term revenue certainty for storage assets but will provide support to a potential revenue stream and could help storage projects to reach positive final investment decisions.

Depending on the duration of the settlement period for a blended scheme, this could drive greater or lesser demand for storage. For example, if the scheme was assessed over the course of a year, then there would be relatively little need for storage as higher production in summer (due for example to excess solar) may make up for lower production in winter. If the scheme was assessed monthly, then there would be a higher need for storage. It is noted that the longer the assessment period the greater the role and perhaps cost to the system operator of ensuring the correct level of hydrogen blend to maintain grid integrity and safety protocols.

Looking beyond 2035 and considerations for a 100% hydrogen network, a liquid market for the commodity may not be entirely necessary. However, without one the necessary volume of gas storage capacity may not be operable on a merchant basis in the future. Certainty on a 100% hydrogen network would decrease the investment risk for storage assets and a lower threshold of revenue certainty for storage (e.g., via a subsidy) may be sufficient to enable investment.

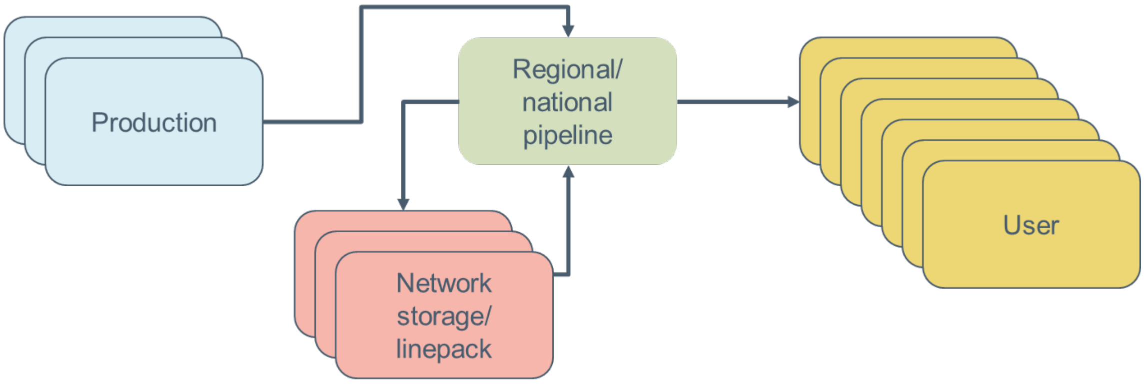


Figure 16: Hydrogen network via pipeline, at 20% (blended into the gas network) or 100% - Extended Centralised *Commercial Configuration*

6.4.1 Production Considerations

A government commitment to blending of hydrogen at 20% in the gas grid, implies the need for correspondingly high volumes of hydrogen production (35TWh/year). The market structures required to verify that suppliers have met targets will provide considerable certainty of demand for producers, whether subsidy measures are in place or not.

There are two primary options for measuring compliance with such a hydrogen scheme – a certificate-based scheme akin to the RO or RTFO, or the embedding of a requirement for suppliers to trade hydrogen as part of their gas mix.

Under either requirement, suppliers could create long-term agreements with hydrogen producers to acquire necessary volumes, with the market likely to develop structures for top-up and sale to meet final demand, as has happened in electricity and gas wholesale trading. For example, suppliers may set out their Fuel Mix Disclosure based on their purchasing of Renewable Energy Guarantee of Origins (REGOs), even though the actual mix of electrons received by the consumers may differ from this. If hydrogen similarly does not have a strict matching requirement, the actual physical delivery of volumes of fuel to individual consumers would be less relevant.

Suitable structures include the Power Purchase Agreement (PPA)/ Gas Purchase Agreement (GPA) model, which broadly relies on relating prices to an independent liquid index price (usually at a discount), or the CPPA model, which broadly sets a fixed price for the commodity at contract commencement. A further structure might be cost-plus, with electricity (or gas and carbon storage) elements and a capital / operational element stacked to create a price.

Given hydrogen is a physical commodity, a certificate validity period of several days or perhaps weeks could be developed. Hydrogen storage would have a role in elongating validity. This would – across the year – result in additional scarcity value for hydrogen during periods of higher demand and support the economics of storage assets. If a wholesale approach was taken, existing structures for trading biomethane, LNG and storage assets may be suitable for replication.

6.4.2 Transportation Considerations

To enable blending existing gas networks would need some new infrastructure. If the existing gas network is used to transport 100% hydrogen, assets will need to be repurposed and some new build may also be required for last-mile supply to domestic and small non-domestic customers. Where new build pipeline is necessitated, depending on the size of the requirement there could be scope for competition and tendering in developing such a network.

This would mean that existing industry rules would need to be adapted for hydrogen gases, including the transporter license, storage license, monopoly price controls, and GSMR. The main consideration would be for calorific values (CVs) to be updated – a particular concern for blending, where varying levels of hydrogen would be present in the gas mix and therefore CVs change over time.

The Future Billing Methodology [54] is currently working to implement in-network assessment and measurement of CV. This is primarily for the purpose of enabling a broader biogas mix in the network, but could over the long-term support the use of variable levels of hydrogen in the network as well.

As explained in Section 6.3.4, a RAB mechanism is the preferred option for many equivalent sectors involved in the transportation of commodity by pipeline to wide groups of consumers with low individual bargaining power. Future work needs to explore how a RAB mechanism for hydrogen transport could interact with the current natural gas RAB.

6.4.3 Storage Considerations

Requirement for storage depends greatly on the target level of hydrogen in the network (the main options under consideration being 20% or 100%) and the period over which this is assessed. The current pattern of gas demand sees much higher consumption during the winter – two to three times higher demand than the summer. With an annual 20% target, a relatively high share of hydrogen during the summer months could result in meeting the annual threshold without the need for storage. However, evidence on blending so far indicates that hydrogen blended in the gas grid should not exceed 20%, so having an annual target where the amount of hydrogen injected could exceed 20% at certain times is not likely to be viable. Daily, monthly or seasonal target assessment for blending would require considerable storage, in particular the need for inter-seasonal storage.

Under a certificate scheme, obligated parties (anticipated to be gas suppliers, as stated) would need to purchase certificates from producers to match the required share of gas supply. The prices of these certificates would be driven by availability, and on an intra-year scheme basis would therefore be expected to increase during high demand periods, i.e. winter months.

If the obligation period was less than annual, then providing storage assets with the possibility to purchase certificates in line with the hydrogen which they take out of the network into storage, and to sell certificates in line with the hydrogen which they put into the network, would enable transfer of certificates from period to period. This would incentivise storage to provide inter-seasonal capacity and operate in the hydrogen market to provide this service to suppliers.

Likewise, under a wholesale hydrogen trading scheme, storage would be incentivised similarly to arbitrage the value of the wholesale gas across the year in the emerging liquid market for hydrogen. In either case, existing gas network storage would be able to store a gas mix from the network but would be incentivised to contract with hydrogen producers to access a higher hydrogen mix in order to maximise value (as storing hydrogen would likely have higher net benefits than storing natural gas).

As well as providing commercial storage services, storage assets may have a role in balancing the network over the short term. Given the national scale of the system and the presence of multiple parties connected to it, this role may be less significant on a national system than on a local system, subject to any specific local balancing issues which may occur.

In terms of support for hydrogen storage developers, signalling a policy decision for the large scale use of hydrogen for heating may ease long term revenue certainty concerns. A policy decision to maximise blending at 20% could also increase long term revenue certainty. However, both these decisions in itself may not provide the level of investor certainty nor the volume of storage capacity required. As explained in Section 6.3.4, a RAB model for storage capacity could be easiest to develop but a cap-and-floor mechanism is also suitable. Any cap-and-floor model would need to see some continuing value retention for investors over the cap, in order to encourage continuing operation of the asset subsequent to the cap (and availability targets) being reached.

It was noted through our discussions with storage developers that the cost of gas processing infrastructure is most efficient when it is sized to the eventual volume requirement rather than through periodic incremental investment. A timely signal on hydrogen for heating could help to plan larger storage capacity deployment and engage wider supply chain support to lower overall infrastructure costs.

6.4.4 Demand User Considerations

In this *commercial configuration*, energy suppliers are the end-users (their customers do not have a choice about the gas mix provided to them through the national system). Their engagement with the market may be driven by policy requirements or by customer demand[35]. For non-domestic customers, any additional costs can be passed through to consumers. Therefore, while they will seek to remain price competitive and hence seek to trade for gas and certificates accordingly, their own direct exposure to price movements may be limited.

However, in the domestic space, Ofgem's default tariff cap methodology [55] may need to be updated to include the costs of hydrogen policy elements (depending upon when such costs come into effect and the ongoing application of the cap) and this will impact suppliers' trading behaviour.

Suppliers, particularly small suppliers, may also trade differently depending on whether they are buying certificates alongside wholesale hydrogen (or there is no certificate scheme, and they are only trading for wholesale hydrogen) or buying certificates independently of / instead of hydrogen. A number of suppliers contract out their shipper functions to a third party, meaning that the addition of a requirement to consider hydrogen share would increase the cost and complexity of this role.

Larger suppliers and / or those if suitable credit standing may be able to deliver long-term contracts along the model of GPAs. This is a type of contract currently synonymous with green gas (biomethane) producers and based in part on electricity PPAs. Such a structure would help to provide both long-term certainty on route to market and value for the hydrogen producer and certainty on availability and costs for the energy supplier.

[35] For example, customers willing to pay for a more expensive tariff in order to secure (nominally) higher shares of hydrogen in their gas mix, much as customers currently do for green electricity and green gas.

6.4.5 Extended Centralised *Commercial Configuration* SWOT Assessment

Strengths	**Weaknesses**
Very large scale of system will lead to liquid market in hydrogen Model can accept many producers, storage operators and consumers and is large enough to balance itself	Potentially high costs Low energy density of hydrogen may require running networks at higher pressures or expanding network assets
Opportunities	**Threats**
Replication of contractual structures from other sectors (e.g. GPA) High decarbonisation potential without requiring customers to take active decisions Reduces stranded asset risk for gas network, particularly distribution elements	Very large-scale targets for hydrogen provision risks not being met, particularly with no decision on future heating until mid-decade Existing gas assets might not be physically capable of carrying hydrogen and current gas appliances might not be able to safely use blends of hydrogen over 20% (and up to 100%).

Unanswered questions
What level of hydrogen will be required in networks? Will a certificate system be introduced? What settlement/ assessment period will be used?

A liquid price for hydrogen could develop through a certification scheme with mechanisms on its longevity helping to develop grid scale storage capacity and a liquid market price for hydrogen. Suppliers would use the certificate scheme to prove compliance, allowing for consumers to adopt to the use of hydrogen within existing domestic fuel supply arrangements. For blending, this relies on a number of decision points: implementation of the Future Billing Methodology to enable more variable calorific values of gas in the networks, implementation of new safety rules, and possibly the implementation of a production or consumption subsidy to reduce the impact of higher gas prices on consumers. Moving to a 100% hydrogen mix over time would require further reform of safety rules and a decision to re-purpose the gas networks to hydrogen.

7 WP5: Barriers and Enablers to Investment

This section examines the enablers and barriers to investment from a transport and storage viewpoint identified in our analysis and engagement activities. The main barriers are set out and explained below.

Table 15: Summary of Barriers and Enablers to Investment

Barrier or Enabler	Detail
Transport business model (7.1)	The viability of delivering hydrogen by road has been demonstrated by distributors of grey hydrogen, though this could be more efficient. However, a decision on the model for cost-recovery of pipelines is still needed and regulation / licencing for this model implemented.
Lack of demand certainty (7.2)	A fundamental barrier to investment in hydrogen production is a lack of certainty of demand, over the investment time-horizon, at an appropriate price. This is itself partially driven by uncertainty on availability of supply. It is unlikely – at least initially, before costs decrease – that this can be compensated without subsidy support and specifically not before a decision on the role of hydrogen for heat, which is expected in 2026.
Uncertainty on asset reuse (7.3)	Research is ongoing into whether natural gas network assets and appliances can be easily used for hydrogen blends and / or repurposed for 100% hydrogen. Until complete, it is difficult to take decisions on future heating technology and hydrogen transportation.
Storage business model publication (7.4)	The timeline for the storage business model publication and subsequent asset-build does not align to the need for large-scale first-of-a-kind projects proposed for development in government identified priority clusters. An innovation or early-stage storage model could bridge this gap.
Factors affecting business models (7.5)	Currently, the production Hydrogen Business Model subsidises the models based on the merchant price of delivered grey hydrogen product. Continuing this commoditised production arrangement seems beneficial, but unbundling roles (production, transportation, storage) could help different classes of investor to enter the industry to invest in different asset classes.
Building clusters (7.6)	Hydrogen clusters appear to be structured around specific partnerships, to deploy large-scale infrastructure. Structuring these to expand over time to enable new producers and consumers to come on board would enable a hydrogen economy to grow out from these locations.
Road and rail transport of hydrogen (7.7)	Rules and regulations for the road and rail transport of hydrogen need updating to reflect the greater understanding of hydrogen that now exists. This includes enabling long-distance and high-volume transport.
Licensing the industry (7.8)	Expanding the current industry's health and safety regulations to a licencing regime in the interests of providing consumer protections and common standards. This could be based on a new regime, or an adaptation of existing natural gas regulations.
Certifying green hydrogen (7.9)	A certificate scheme is one route to providing additional value to low-carbon hydrogen, above grey hydrogen, including seasonal value (which could support storage).
Ownership and operation under centralised *configuration* (7.10)	The level of independence of system operators is under examination in several markets (gas, electricity distribution and transmission). This will also be a key question for a growing hydrogen market.
Third party access (7.11)	Setting arrangements to enable parties to store and retrieve hydrogen may be important to enabling growth. Third party access arrangements can help to minimise the market power of storage providers.

7.1 Summary of *Commercial Configuration* Requirements

As with other fuels, the price of hydrogen will be influenced by its relative competitiveness against other fuels, the demand and supply of the fuel itself, and the potential for legislative and / or regulatory change in the sector. The nature of the wider energy systems – particularly the electricity system – with intermittent renewable energy sources and a requirement for network resilience creates a need for hydrogen production to be flexible. This implies that any medium or large production of hydrogen will require development of grid scale storage solutions with corresponding integrated transport and distribution. The absence of such a coordinated approach risks harming the growth of the sector and confidence in the availability of hydrogen on a consistent basis.

The growth of the decentralised and partially decentralised *commercial configurations* do not envisage the presence of such issues, but it is with the centralised *commercial configurations* and particularly the extended centralised *commercial configuration* that consideration of large-scale storage assets is required.

7.1.1 Decentralised and Partially Decentralised *Commercial Configurations*

We do not see any fundamental barriers to the Decentralised and Partially Decentralised *commercial configurations*. The relevant commercial and physical arrangements are currently being tested and are based on experiences from comparable sectors and / or industrial experience. The relatively short duration of storage required means that development of the long-term business case is not immediately required. However, it is noted that as a bulk fuel for general use[36], hydrogen remains more expensive than the comparator, natural gas. This is the case at all stages of the value chain, with higher costs in production, transportation and storage. Therefore, there is a case for subsidy of hydrogen to deliver growth, during the period that these higher costs apply.

The primary considerations are therefore in respect of production (a need to reduce and de-risk the investment in production equipment) and on the consumption side (e.g. on fuel suppliers to provide a certain amount of hydrogen or on vehicle operators to operate a number of hydrogen vehicles). Ensuring the latter would provide additional certainty over market size and growth, particularly in the emerging context of economic uncertainty.

Beyond *commercial configurations*, growth of the industry will be aided by clarity on the regulatory approach and structure, with issues which have been identified to us including:

- ADR rules on the road transport of hydrogen fuel, including the standards for containing vessels, size restrictions, and distance restrictions. Updates to the rules on tunnel use could also be useful, and restrictions on fuel types for tractor units could be reviewed
- Planning and health and safety guidelines for above ground and small underground storage tanks should be reviewed and, to the extent that this is possible while maintaining safety, brought into line with rules for natural gas, propane, LPG and fossil petrol/ diesel rules, acknowledging that industry understanding of the physical characteristics and technologies for safe storage of fuel has improved

7.1.2 Centralised *Commercial Configuration*

The development of the Centralised *commercial configuration* is largely dependent upon the presence of long-duration and / or seasonal hydrogen storage – particularly if hydrogen is used for heating. However, insufficient market signals are likely to emerge for this long-duration storage to emerge organically, particularly given the lack of a liquid market in hydrogen.

[36] i.e., beyond specialist uses of hydrogen as a feedstock and in transport applications.

The main barrier to the development of larger scale hydrogen storage is insufficient certainty on returns on their investment. Without an incentive (in the form of long-term revenue certainty), then it is extremely unlikely that any operator would choose to invest capital into the necessary equipment. This risks undermining the emergence of large-scale hydrogen projects and consequential learnings. Furthermore, the government's plan for publishing a business model for hydrogen storage in 2025 creates a timeline which will deliver storage in the early-mid 2030s, and which is mismatched with the ambition to create large-scale hydrogen trials such as regional-scale HyNet project and the hydrogen village and potential hydrogen town trials during the 2020s.

There also appear to be no fundamental barriers to the creation of hydrogen pipelines at the local scale, with the assumption that the business case is present for hydrogen production and use between local parties, for example across the emerging hydrogen production centres. However, it is noted that the fundamental business case for switching to hydrogen may need out-of-market support during development phases. Clarification of the rules on operating hydrogen networks could be adopted from the gas regulatory regime, with a light-touch regime in the early days of the market potentially advantageous - as has been seen in independent / unlicensed networks in gas, electricity, water and heat.

In order to drive growth, particularly to the domestic market, introducing additional regulatory controls over time may be useful and – given the monopoly nature of networks and the fact that these will be, for most customers, replacing mains gas – the existing regulatory model from the electricity and gas sectors could be usefully transposed to hydrogen with only minor amendments. De-risking (and therefore reducing the cost of capital for) early network investments will require clarity on how future regulatory regimes will be implemented on these assets.

Government may wish to consider implementing powers to create "hydrogen zones", similar to the "heat network zones" which are under consideration to drive growth in that market. Hydrogen zones would allow creation of a requirement for users across industry, transport and, potentially, heating to switch to hydrogen fuel, although price guarantees or other support might be necessary to enable fuel switching, depending on the level of hydrogen price support and consequential end-user prices for hydrogen. This could also provide clarity for gas network operators on future network use, and storage operators on where they should consider locating new storage sites.

7.2 Lack of Demand Certainty

The most fundamental obstacle to the expansion of the existing hydrogen industry is lack of certainty as to the scale of future hydrogen demand. While there is certainly confidence that low-carbon hydrogen will be needed to achieve net zero, this is mostly centred on industrial applications, aviation fuel and marine fuel. Key areas of uncertainty are:

- **Hydrogen use in power stations** – while some gas-fired power stations will seek to incorporate a hydrogen blend, switch over to hydrogen or be built to use it from the ground up, the extent of this is unclear, with Cornwall Insight's modelling suggesting that under some scenarios hydrogen in power generation may be transitory and a means to support the conversion to a fully renewable, nuclear and storage-based electricity system.
- **Blending into the gas network** – the existing gas network may be adapted to incorporate hydrogen injection. However, this will not be confirmed until 2023, nor the level of potential blending as discussed in Section 6.4.1 (indicated to be up to a maximum of 20%, but potentially lower).
- **Demand for domestic heating** – linked to the above, hydrogen is unlikely to have a significant role to play in domestic heating as a standalone fuel during the current decade, as a decision is not due until

2026 [56]. However, the government is currently pursuing projects like developing a “hydrogen town” and hydrogen is likely to play a role in domestic heating in at least some locales and property types.

- **Demand for vehicle fuel** – it is widely accepted that hydrogen use for road transport will be limited to heavier vehicles due to the efficiency of electrification for smaller vehicles. However, HGV demand is similarly uncertain, with hydrogen potentially remaining niche if battery HGVs become widespread, or coming to the forefront if these are less cost-effective.

Together, these elements make it hard to judge the size of the future hydrogen market, and in turn are likely to restrict hydrogen investment in the immediate term to specific clusters where investors can have high confidence of the level of hydrogen demand. Sole dependence on one or more of the aforementioned markets may therefore be seen as too high risk an investment in the absence of a guaranteed demand base, government policy certainty and/or subsidy support.

7.3 Uncertainty On Asset Reuse

Similar to the above, there is also considerable debate as to the extent to which existing gas assets can be adapted to use hydrogen. Re-use of pipelines, compressors and storage would considerably reduce the cost of switching to hydrogen, whereas if these are not available other solutions such as electrification may be more attractive. This will especially be the case for demand users. The key issues are:

- Hydrogen has a lower density than natural gas, which means approximately three times the volume of gas must be flowed to equal the delivered energy of natural gas. This has implications for compression in networks and pipework at power stations and industrial sites.
- Hydrogen embrittles iron and steel, making it more liable to cracking. Evidence is still being gathered on embrittlement rates and there is still no consensus, ranging from suggestions that it would necessitate complete replacement of pipework, to reducing asset life, to being manageable with mitigation.
- Sulphate-reducing bacteria (SRB) is known to influence corrosion in steel pipe when exposed to hydrogen to form hydrogen sulphide. The use of corrosion inhibitors in the oil and gas industry is a well-established process although a system of continuous pipeline testing and monitoring ensures pipeline integrity. As part of its project to develop hydrogen storage, one stakeholder interviewed is looking to set up a live test to develop the necessary process, protocols and procedures to ensure all developers work to the required standard to maintain pipeline integrity.

Safety and logistical issues mean that the ability to re-use existing infrastructure is unclear, especially in the absence of a consistent body of evidence and case studies to which developers may refer. Trial projects such as HyNet are testing existing assets and building knowledge, but the prospect for wide-scale rollout is unknown.

7.4 Storage Business Model Publication

Potential storage investors / operators have informed us in interviews that given the build-times for large-scale salt cavern storage assets – which can be as short as 4 to 5 years, but which are more typically 6 to 8 years – do not align with the planned release date for the storage business model and the start of requirement for large-scale storage of hydrogen. Even for companies which are enthusiastic about GB hydrogen economy, and which wish to make investments, the scale of cost means that without clarity on further income streams for assets, the likelihood of such investments being undertaken is low.

Trial projects such as Hynet are hoping to commence in the latter part of the decade but have told us that they will struggle to do so on a useful scale without storage. However, as a decision on storage business models is not expected until 2025, assets will not be able to accept injections until the early 2030s at earliest.

This risks delaying the growth of the hydrogen economy significantly and missing government targets. There is hence a need for early-stage/ demonstration business models for hydrogen in advance of the 2025 decision on enduring models in order to allow investment, which will include ordering long lead time items like steel pipe and compressors for specific projects.

The Centrica owned and operated Rough storage asset has recently been brought online again. Centrica are proposing to use the site for hydrogen storage by the late 2020s, working from a 2023–24 start-date – indicated to us that it will not proceed with the investment without clarity from the government on business models and support.

7.5 Factors Affecting Business Models

Current grey hydrogen business models are based around a merchant, fully delivered product which works at small scale and can successfully be translated to larger scales, with added economies of scale (exemplified by the Decentralised and Partially Decentralised *commercial configurations*). As the scale increases - both in volume terms and geographic footprint of the operation, whether linked via pipelines or tankers - the relationships between the stakeholders change. It is considered that the simplest business model is one with commoditised delivered product due to the reduced number of counterparties, contractual relationships, and potential points of failure.

This is seen in the water industry, where the network operator also provides the commodity and acts in the supplier role, whereas for natural gas the supplier is simply a point of contact for a non-vertically integrated value chain. In water the joined-up risk of delivery is handled by a single entity - leading to initial cost efficiencies and thus the best opportunity for the economy to grow. In an emerging market such as hydrogen, individual stakeholders (producers, network and storage operators) may not be willing to take the risk of stranded assets unless the burden can be amicably shared, particularly in the absence of a separate supplier role which would absorb some of the risk.

A focus on risk allocation and the setup of a coordinated approach to distribute the risk across all the stakeholders is key. Business models invariably look to tackle specific pinch-points, whereas a holistic approach – at least in the development phase of the market – should avoid the pitfalls of previous regimes, e.g., under investment in gas storage.

A production-based support policy does not encourage the development of transportation and storage services in itself, unless the producer is bound by other factors as a requirement for securing policy support. This could be by means of minimum production load factors, subject to other provisions – for example, providing gas or electricity system resilience services or developing “delivered” whole year-round products, with appropriate security of supply to consumers. This ensures a level of storage utilisation and thus the booking of storage capacity or an oversizing of production capacity to manage winter use. Economically, it may well be cheaper to book long-term storage then over size production capacity.

An alternative is for the consumer to have a quota which encourages year-round low-carbon fuel use. Such an approach would see hydrogen suppliers develop services as described above and/or for end-users to seek other non-hydrogen-based solutions, such as electrification. For storage business models, without a liquid market price for hydrogen, the value of hydrogen storage cannot be calculated other than the lost production value, for example through the use of “cheap” renewable electricity for electrolysis. For hydrogen producers, optionality is key, i.e., the ability to curtail production when the price of input energy is high and to maximise production when the input energy price is low each time using storage to buffer end-user demand. For storage operators to sell access on an ad hoc basis is not sustainable, and therefore storage developers are looking for revenue certainty.

In terms of the form of support which would be required to deliver investment in storage at the scale required for a Centralised *commercial configuration* regional network (around £600mn-650mn), stakeholders have expressed that a RAB model might be most suitable, although cap-and-floor arrangements or other methodologies might be equally suitable, as long as they delivered certainty on level of revenue over the initial investment period (around 15 years). However, a contract with a sufficiently creditworthy counterparty was also considered viable by a significant minority of users.

There was also a strong preference expressed for third parties to operate and manage both transportation and storage assets, rather than for these to be under the control of producers or end-users. Some potential storage operators noted that they saw RAB and cap-and-floor models as too low-return for their required investment profile. They suggested however that they would be able to construct assets and sell to long-term operators, taking their reward at the point of sale, after construction and commissioning risks have elapsed, with the enduring operator then achieving its regulated returns. This is not unlike existing project finance models, where assets are re-financed following commissioning to deliver a lower ongoing cost of capital and thus lower total asset costs.

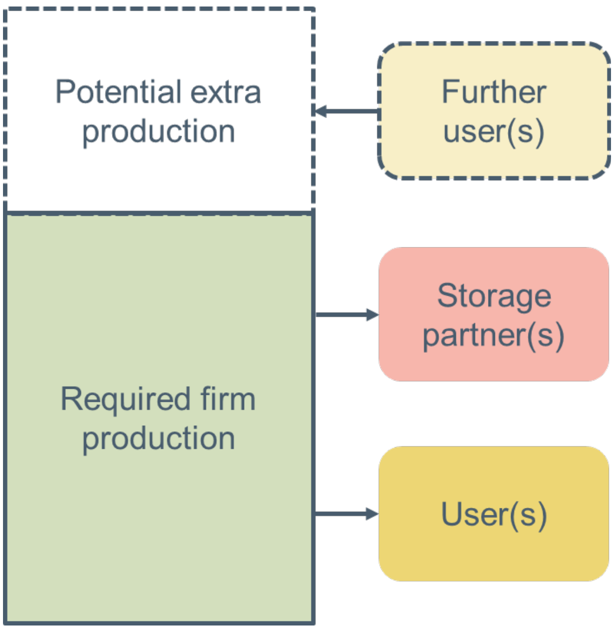
In terms of implementing a storage model, it is recognised that implementing a long-term state-aid approved mechanism for support is a time-intensive endeavour, requiring considerable consultation and legislative approval. However, given the level of practical learning which could be achieved through the design and build of one or more large-scale hydrogen storage facilities in the UK, and the significant de-risking (and thus reduction of cost) which could be delivered, there is a strong case that one or more early-stage projects should be funded under innovation funding streams.

7.6 Building Hydrogen Production Centres

The barriers discussed above are all currently best addressed through the deployment of hydrogen in production centre focussed on large demand sources with local hydrogen production. This aligns also to the production and usage paradigm seen currently in GB, which is concentrated on large industrial sites. This mitigates the uncertainty over offtake for the producer and achieves economies of scale through shared assets. The deployment of hydrogen could therefore be supported by making it simpler to develop hydrogen production centres of supply and demand. This could be facilitated by the subsidy mechanism process. Figure 17 illustrates this process, described below:

- A producer, seeking a subsidy, has secured users to offtake some or all of its planned output.
- Subsidy rules require it to advertise any additional production which could

Figure 17: Hydrogen production centre building



be delivered onsite to potential users looking for production in the region.

- Further users come onboard, expanding the project.
- This could be under a take-or-pay arrangement, to guarantee offtake.
- If demand exceeds production capacity, a local auction (for capacity or volumes) could be used to prioritise those offering higher prices.
- Details of any unsuccessful users could be retained for further regional auctions.

7.7 Transport and Distribution of Hydrogen

Provisions for transport of dangerous goods by road are standardised in the Agreement concerning the International Carriage of Dangerous Goods by Road (ADR). Hydrogen is treated like other flammable gases and no recommendations for change of the existing legal and administrative framework are made in this. Equally, no change is proposed to the requirements covering construction, testing, type approval and certification of hydrogen transportation equipment

However, the standards for compressed hydrogen receptacles have been developed for a relatively small market volumes and short delivery distances. New materials and production technologies are available for increasing storage volumes on vehicles, increasing the payload of hydrogen trailers and allowing hydrogen delivery at larger scales. Therefore, the existing standards need to be revised and adapted. This also applies to smaller portable cylinders and distribution to dispersed customers. In particular, the complexity and requirements for vehicle and H_2 storage equipment adherence under ADR is a barrier, as the threshold at which full ADR compliance is required is relatively low.

7.8 Licensing the Industry

Existing hydrogen operators have noted that they have been producing, trading, storing and consuming hydrogen as a fuel and an industrial chemical without a formal licensing process, but subject to health and safety regulations. These issues are discussed further in the appendices. However, they acknowledged that the expansion of the industry to the mass market would likely require regulation, from – at a minimum – a customer protection angle.

The main options for licensing would be to either bring production and supply hydrogen fully under the Gas Act and associated licenses (shipper, supplier, transporter, network operator) and codes, or to create a new regime for hydrogen production, transportation and storage. Creating a new set of licenses would enable licenses to take account of all of the idiosyncrasies of hydrogen as a fuel and a commodity and may enable a regime of increasing regulatory oversight (of relevant areas of the market) over time as it develops.

However, a separate regime would be more expensive and take longer to develop, requiring new primary legislation. It would also need to be operated in parallel with natural gas licenses for the long-term, as the existing regulatory regime is likely to remain relevant at least until 2050 and likely beyond. Changes to the natural gas regime would also be required to account for fuel mixing in local and national transportation systems, and in delivery to consumers.

The existing regime also has well-developed regulation and processes for protecting customers, maintaining the physical integrity of the gas system, settling gas consumption and apportioning network and system operational costs across the full range of potential user types.

The optimum licensing regime is therefore likely to be a hybrid of amendments to the Gas Act to bring supply of hydrogen through pipeline delivery systems under the existing regime, with a series of class exemptions to enable demonstration and trial projects, off-network supply, and small project, to go ahead without the burden of excessive regulation. To protect investor confidence, making clear the end-conditions for exemptions – for example, an end-date or a maximum size threshold – will also be of importance.

7.9 Certifying Low Carbon Hydrogen

One route to providing extra value for low carbon hydrogen is to institute a certificate scheme. Schemes exist in GB to reflect value in the electricity (ROC and REGO), green gas (RGGO) and road fuel (RTFO) areas. Some are legislated (ROC, REGO and RTGO), and some require purchase by suppliers of certificates to discharge an obligation (ROC and RTFO). The latter effectively creates a subsidy to producers from suppliers, while non-obligation scheme simply provide a revenue.

The government published the UK Low Carbon Hydrogen Standard in June 2022 [57]. This standard defines what constitutes low carbon hydrogen at the point of production, and how producers should calculate emissions associated with hydrogen production. The British Energy Security Strategy (April 2022) [2] committed to setting up a hydrogen certification scheme by 2025

Certificates are generally tradable independently from the wholesale energy which they were produced alongside, to simply trading and pricing arrangements. The CertifHy project is creating an EU certificate scheme for hydrogen. It is not yet clear whether the UK will create its own system or adopt this, and whether the UK scheme will be compatible with the EU scheme. This latter may be important when considering the flow of hydrogen through gas interconnectors to and from Europe.

In GB, the Granular Energy project launched a trial of a new hourly-matched certificate for renewable generation. This is much more granular than the existing REGO scheme, which tracks generation and consumption on an annual basis. For hydrogen, it is unlikely that an hourly scheme would be beneficial as the fuel takes time to flow through networks; however, a weekly, monthly or seasonal matching period could help to provide seasonality to value and therefore provide revenue to storage providers as the price of certificates changes across the year, in line with availability and demand.

7.10 Ownership and Operation under Centralised *Commercial Configuration*

A specific consideration to the licensing arrangements described in Section 7.8 is asset ownership and what this means for the role of system operator as opposed to network operator which manages the pipeline network.

Under the decentralised and partially decentralised *commercial configurations* the small scale of the system means the operation can be managed through existing HSE regulatory arrangements. The complexity of a hydrogen production centre under the centralised *commercial configuration* requires a system operator role, especially where a large integrated system is seen with multiple producers and end-users to coordinate between the peaks and troughs of production, demand, pipeline and storage use. Unlike the large gas national transmission and distribution systems where linepack may be used to provide a degree of flexibility and thus can be managed with daily system balancing, this may not be available at a cluster scale with the movements of gas through storage and pipelines intertwined to maintain network safety protocols, and at a sub-daily balancing regime.

In the early stages of market development, operational aspects would be easier if ownership of the pipeline and storage is aligned ensuring a high level of system operatorship and cost efficiencies i.e., a system operator. The owner should anticipate future unbundling, either through a system of Chinese Walls or divestment, when developing, for example IT, and finance reporting systems. The alternative, i.e., independent pipeline and storage ownership is to clearly define the duties and commercial arrangements of each and installing a system operator that ensures the system is operated efficiently and safely.

7.11 Third Party Access

Current pipeline network systems in similar sectors have defined access protocols and hydrogen network would need to develop their own to ensure continued market development and growth. Access to, and development of tanker loading and unloading systems, should not be unduly prevented.

Access to large hydrogen storage facilities is therefore no different, especially considering the limitations of suitable sites for grid scale storage. During the early years of operation and whilst the market is nascent, it is accepted that the demand for third party access may be limited, but this should not prevent processes like auctions to determine price and open seasons to determine the scale of demand.

Initial capacity allocations may well support storage operators with certainty of use and revenue streams, for example helping producers to maximise production sizing, and provide end-users a degree of security of supply, but these should be timebound with regular reporting of unsold capacity to inform new entrants. Other mechanisms include upper limits to single owner use of capacity, interruptible products, and a system of UIOLI to prevent capacity hoarding and aid market development.

Any operator seeking policy support should see these as minimal requirements, although not necessarily from project inception, and any operator seeking merchant use may well take the exemption route available under the Gas Act. Given the possibility of price arbitrage of hydrogen certificates third party access may well develop earlier than otherwise.

8 Conclusions

Using a set of *archetypes* as building blocks for the emerging hydrogen economy, this study has explored and quantified predicted requirements, costs and commercial arrangements for hydrogen transport and infrastructure in 2030 and 2035.

Initially, the key components of the hydrogen economy have been identified and combined into a series of *archetypes* to explore how the hydrogen landscape may develop. These have been combined with demand predictions at 2030 and 2035 to predict the requirements, and ultimately costs for transportation and storage. To meet hydrogen demand in 2035, the equivalent of between 6 and 15 large hydrogen production centres sized at 10TWh annual production are predicted to be required, with between 1 and 3 predicted in 2030. As part of large hydrogen production centres, up to an estimated 5% of the hydrogen produced could be utilised by small users such as transport depots or small industry, with the rest utilised by large users including large industries, regional heating (buildings), power and alternative fuels in shipping and aviation. This means that most hydrogen produced in large hydrogen production centres will likely need to be distributed via pipeline as users are large and/or distributed. Decentralised and partially decentralised hydrogen facilities with co-located production and use will also be important in the period up to 2030 to enable the use of hydrogen for industry and depot-based transport.

Hydrogen storage will be required to smooth out hydrogen production (both electrolytic and CCUS-enabled) as well as to support hydrogen use for flexible power. It is predicted that both surface storage and salt cavern storage will be required by 2030 to support decentralised and centralised facilities and by 2035 the requirement for salt cavern storage will increase significantly. Grid scale salt-cavern storage is key to the success for a hydrogen economy at the macro level - allowing producers to maximise production and ease security of demand concerns, and for end-users to alleviate security of supply fears. The build out of grid scale storage needs to occur ahead of, or in tandem with, production to ensure production is maximised.

Blending of hydrogen into the gas distribution network could provide a flexible use case for hydrogen to promote the development of production and end-use applications. It could also help reduce the demand for salt cavern storage to a small extent, but this will depend on the flexibility of the blending arrangements on a month-by-month basis.

In terms of potential commercial arrangements, the route to transition from interim rules and regulations to an enduring model should be set early and not deviated from, in order to provide certainty to investors. A model of providing exemptions to projects established before a certain date or limited to a certain size or customer type would seem optimum. The operation of the UK's statutory independent gas networks demonstrates that the current gas rules are able to accommodate physically discrete networks that are served by tanker, have their own storage, and use a different gaseous fuel from the rest of the network. This suggests that a similar approach could be very suitable for early hydrogen networks. However, these networks are an exception rather than the rule, so it is recognised that utilising a similar framework once hydrogen represents a substantial portion of gas use may risk unintended consequences and distortions. For large hydrogen production centres (or industrial clusters), consultation with industry highlighted that a Regulated Asset Base (RAB) model might be most suitable for both pipeline networks and storage, although for storage cap-and-floor arrangements or other methodologies might be equally suitable, as long as they delivered certainty on level of revenue over the initial investment period (around 15 years).

9 Recommendations

Overall, there is significant uncertainty in the cost predictions for transport and storage infrastructure out to 2035. This is the result of the combination of 3 factors:

- Variability in the overall demand for hydrogen in 2030 and 2035;
- Difficulty in accurately predicting the hydrogen transport and storage requirements on an individual *archetype* level;
- Variability in the unit costs in storage (£/kg) and transport (£/kg, £/km for capex).

The latter two factors could be improved as follows:

- **Hydrogen transport and storage requirements:** Explore how the requirements for hydrogen storage may change with different types and quantities of renewable electricity used to produce hydrogen. Hydrogen storage is particularly sensitive to the variability of wind power used for electrolytic hydrogen production. It would be beneficial to explore the role of curtailed wind (rather than a designated wind farm) on the requirements for storage. Curtailed wind power could vary depending on the wider demand for electricity in the energy system, the volume of installed wind and commercial mechanisms.
- **Investigate the distances between large producers and users that will require pipelines:** The estimated costs for hydrogen transport and storage produced in this study could be improved through greater breakdown of costs, particularly for hydrogen transportation via trailering, and for salt cavern construction costs where there are many unknowns not available publicly or from stakeholders.

To develop the commercial mechanisms for hydrogen transport and storage infrastructure the following is proposed:

- Review the rules for the transport of hydrogen by road and the storage of hydrogen in surface storage tanks (if they have not been already) to check if they are fit for purpose for the more widespread use in the hydrogen economy.
- Consider an early, interim or innovation funding model for trial large-scale salt cavern storage projects.
- Accelerate the deployment of hydrogen blended into the current gas network, including in respect of issues such as the permitted percentage blend and how this percentage blend will change over time (e.g., starting at 5% then increasing to 20% within five years).

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11 Appendix 1 – Questionnaire

11.1 Hydrogen and your organisation

In this section we are gathering information on the general role of your organisation. If your organisation represents a number of different types of business or stakeholder, please select the answers you see as most applicable to them.

1) If you are happy to do so, please provide the name of your organisation.
   ……………………………………..
2) How much does your organisation currently consider hydrogen in its energy planning?
   a. Not at all
   b. Sometimes
   c. Frequently
   d. Very frequently
3) How much does your organisation consider hydrogen for future energy planning?
   a. Not at all
   b. Sometimes
   c. Frequently
   d. Very frequently
4) In a hydrogen context, will your organisation be involved primarily as a …
   a. Producer
   b. Storage provider
   c. Transporter
   d. Consumer
   e. Other
   (Please select all that are applicable)

5) Does your organisation have a net-zero strategy?
   a. Yes
   b. No
   c. Prefer not to say
   If yes, is hydrogen part of that strategy?
   ………………………………

11.2 Growth of the hydrogen economy and your business

You are now in Section 2. You are approximately 15% of the way through this questionnaire.

Some of the questions in this section may not be applicable to your organisation. If so, please leave these questions blank or reply with N/A.

1) In 5 years time how much hydrogen does your organisation plan to be producing, transporting, using, or storing? If known, an estimate of kg per day would be valuable.
   ……….

2) In 10 years time how much hydrogen does your organisation plan to be producing, transporting, using, or storing? If known, an estimate of kg per day would be valuable.
   ……….

3) In 15 years time, how much hydrogen does your organisation plan to be producing, transporting, using, or storing? If known, an estimate of kg per day would be valuable.
   ……….

4) What are your current main barriers to adopting hydrogen and related technologies for your organisation? (these could include: financial, legislation, availability, decarbonisation, public opinion)
………..

5) What are the main motivations for your organisation to use hydrogen and related technologies? (these could include: financial, legislation, availability, decarbonisation, public opinion)
…………

11.3 Growth of the hydrogen economy in the UK

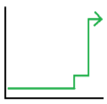
You are now in Section 3. You are approximately 25% of the way through this questionnaire.

Some of the questions in this section may not be applicable to your organisation, or you may not have the information available. If so, please leave these questions blank or reply with N/A.

1) How would you characterise the current frequency of your supply requirements? If you are a hydrogen producer, please answer this for how you supply your hydrogen to users.
    a) Continuous pipeline (>=18 hours of supply/day)
    b) Variable pipeline supply (>=8 hours but <18 hours/day)
    c) Infrequent/batched pipeline supply (<8 hours/day)
    d) Continuous supply from onsite storage (<18 hours of supply/day)
    e) Variable supply from onsite storage (>8 hours but <18 hours/day)
    f) Infrequent supply from onsite storage (<8 hours/day)
    g) Onsite storage used as required
    h) None of the above

    How do you anticipate this to change in 5, 10 and 15 years' time?
    ……….

2) In 2035 what percentage of the UK's overall energy needs do you believe will be served by hydrogen?
……….

3) The hydrogen economy is expected to grow significantly by 2050. Do you believe that this growth will be:
    a. initial adoption and fast growth 
    b. steady development 
    c. just in time adoption 

4) Setting your organisation's perspective to one side, what do you believe are the main barriers to adopting hydrogen and related technologies for the UK as a whole? (e.g. financial, legislation, availability, decarbonisation, public opinion)
………

5) Please put the following hydrogen technologies in the order in which you think they will be deployed at significant scale in the UK. Please provide estimate year if you can.
    a. Aviation
    b. Domestic heating
    c. Flexible power generation
    d. Heavy duty road transport
    e. Industrial processes

   f. Shipping
   g. Other

11.4 Hydrogen technologies and affecting factors

You are now in Section 4. You are approximately 40% of the way through this questionnaire.

Some of the questions in this section may not be applicable to your organisation. If so, please leave these questions blank or reply with N/A.

Please answer the following questions from the perspective of your organisation.

1) What elements of the emerging hydrogen economy are most important for your organisation? (these could include: refuelling, green hydrogen production, etc.)
   ……….

2) What are the biggest unknowns of the emerging hydrogen economy that affect your organisation?
   ……….

3) Are there any technical limitations which could stop you interfacing with other hydrogen services?
   ……….

4) Are there any key hydrogen technology barriers which are limiting your organisation?
   ……….

5) Do you have geographical constraints regarding hydrogen adoption?
   ………..

6) Are there any policy decisions you think are needed to enable a hydrogen economy? If so, what are they?
   ………..

7) Do you think hydrogen generation will be:
   a. Centralised (large central hubs providing hydrogen across the UK)
   b. Partially decentralised (local production hubs supplying multiple users)
   c. Fully decentralised (hydrogen made where it is used)
   d. Combination of the above, affected by geographical factors

8) What hydrogen technologies do you think would be involved in a centralised system?
   ……….

9) What hydrogen technologies do you think would be involved in a de-centralised system?
   ……….

10) Are you aware of any geographical areas which are likely to become hubs for hydrogen production and use? If so, please list them below.
    ……….

11) If hydrogen were to be blended with natural gas (up to 20%) in the national gas network, and/or the national transmission network, how would this affect your organisation?
    ………

12) If the national gas network were to be repurposed for 100% hydrogen delivery, how would this affect your organisation?
……..

11.5 Specifics

You are now in Section 5. You are approximately 70% of the way through this questionnaire. This section tries to capture specific and technical information which will be useful for future planning.

This is the longest section of the questionnaire, but it is likely some of the questions are not applicable or the information unavailable. If so, please leave these questions blank or reply with N/A.

1) If your organisation currently uses, or plans to use, hydrogen, how would you characterise the nature of the supply?
    a. high pressure gas (hundreds of bar)
    b. low pressure gas (tens of bar)
    c. liquified
    d. hydrogen carrier (e.g. ammonia)

2) If your organisation currently uses, or plans to use, hydrogen, how is it transported/received? (this could include: pipeline/trailer/made on site etc.)
…………

3) In the future, which hydrogen delivery, storage or transport system do you believe would best suit your needs?
………..

4) Does your hydrogen production/throughput/demand vary with time?
…………….
If so, on what timescale (hrs, days, months, seasonal, yearly etc.)?
…………….
What is the size of this variability? Please provide upper/lower bounds.
……………

5) For producers, how does your organisation intend to manage variations in demand?
……………

6) How many passenger transport vehicles does your organisation own/operate? If this number varies, please provide upper and lower bounds.
……………

7) What other vehicles does your organisation own/operate (e.g. light or heavy goods transport, tankers, municipal or emergency services vehicles)? Please give details of the nature and number of vehicles where available.
……………

8) If your organisation currently uses or produces hydrogen, are there any specific quality specifications or limitations to your requirements?
If so, how is any out of specification volume managed?
…………….

9) What are the consequences of receiving/producing out of specification hydrogen (where a site outage is required include the outage duration in days, as upper and lower bands)?
…………….

10) How would a variable availability of feedstock (if you are a producer) or of supply (if you are a user) affect your transition or plans to increase the use of hydrogen?
Does your answer to the above change if the variability becomes intermittent and/or seasonal? Please, explain your answer.
…………….

11) Would you pay a premium for a security of supply (if you are a user) or a security of demand (if you are producer)? Please, explain your answer.
…………….

11.6 Additional comments and future communication

You are now in Section 6. You are approximately 90% of the way through this questionnaire.

This section is an opportunity for you to add any extra information or comments, and to pass on your preference for future communications. This is the last section of the questionnaire.

1) Would you like to provide more information or detail? If so, please use the space below.
…………….

2) Are there areas not covered by this questionnaire which you think are important or would like to see considered?
…………….

3) Would you be open to follow up conversations or questions regarding your answers in this questionnaire? If yes, please provide a contact name, and email or telephone number.
…………….

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