Department for
Business, Energy
& Industrial Strategy

Hydrogen transport and storage infrastructure

A consultation on business model designs, regulatory arrangements, strategic planning and the role of blending

Closing date: **22 November 2022**

August 2022

Any enquiries regarding this publication should be sent to us at: HydrogenTransportandStorage@beis.gov.uk

Contents

General Information

Why we are consulting

Hydrogen can support the decarbonisation of the UK economy, particularly in ‘hard to electrify’ UK industrial sectors, and can provide greener, flexible energy across power, transport and potentially heat. Hydrogen produced in the UK could create thousands of jobs across the country, and provide greater domestic energy security, lowering our reliance on energy imports. Analysis by BEIS for Carbon Budget 6 suggests 250-460TWh of hydrogen could be needed in 2050, making up 20-35 per cent of UK final energy consumption.

For these reasons, in the British Energy Security Strategy (BESS) government doubled its ambition to up to 10GW of new low carbon hydrogen production capacity by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen production.

Hydrogen transport and storage infrastructure will be critical to enable this 10GW ambition, and related economic benefits. It will connect producers with consumers, and balance misalignment in supply and demand. However, lengthy development lead times, high capital costs and uncertain financial investment returns in a nascent market mean this infrastructure is unlikely to materialise without a supportive policy framework.

For this reason, government committed in the BESS to design new business models for hydrogen transport and storage infrastructure by 2025. This consultation seeks views on design options for these business models in order to meet this commitment and enable the hydrogen economy to delivery its substantial potential carbon and economic benefits. In addition, it seeks views on the need for a strategic planning function for the rollout of hydrogen transport and storage infrastructure, approaches to wider regulation and implications for blending.

Consultation details

Issued: 31 August 2022

Respond by: 22 November 2022

Enquiries to:

Email: HydrogenTransportandStorage@beis.gov.uk

Or

Hydrogen Networks and Markets team
Department for Business, Energy and Industrial Strategy
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Consultation reference: Consultation on business model designs, regulatory arrangements, strategic planning and the role of blending.

Audiences:

This consultation will be of interest to all parties involved in the hydrogen economy:

- Hydrogen producers
- Hydrogen consumers
- Gas transporters
- Gas shippers
- Storage operators
- Investors
- Consumer champions
- Trade associations
- Academics

Territorial extent:

The territorial extent of the consultation is UK-wide, and responses are invited from all parts of the UK. However, certain aspects of the proposals may impact on policy matters that are devolved in Scotland, Wales, and Northern Ireland. BEIS will work with the devolved administrations as we develop the business models in order to ensure that our policies take account of devolved responsibilities. Where proposals are suited to implementation on a UK or GB-wide basis, working with the devolved administrations will facilitate the successful deployment of the business models and consistency with devolved policy.

How to respond

Your response will be most useful if it is framed in direct response to the questions posed, and with evidence in support wherever possible. Further comments and wider evidence are also welcome. When responding, please state whether you are responding as an individual or representing the views of an organisation.

We encourage respondents to make use of the online e-consultation wherever possible when submitting responses as this is the Government's preferred method of receiving responses. However, responses in writing or via email will also be accepted. Should you wish to submit your main response via the e-consultation platform and provide supporting information via hard copy or email, please be clear that this is part of the same consultation response.

Respond online at: https://beisgovuk.citizenspace.com/industrial-energy/hydrogen-transport-storage-consultation

Email to: HydrogenTransportandStorage@beis.gov.uk

Write to:

Hydrogen Networks and Markets team
Department for Business, Energy and Industrial Strategy
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Confidentiality and data protection

Information you provide in response to this consultation, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018 and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential please tell us, but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy.

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the government's consultation principles.

If you have any complaints about the way this consultation has been conducted, please email: beis.bru@beis.gov.uk.

Chapter 1: Introduction

Context – The Hydrogen Economy

Hydrogen can support the deep decarbonisation of the UK economy, particularly in 'hard to electrify' UK industrial sectors, and can provide greener, flexible energy across power, transport and potentially heat. Hydrogen produced in the UK will create new jobs across the country, and secure greater domestic energy security, lowering our reliance on energy imports. Analysis by BEIS for CB6 suggests 250-460TWh of hydrogen could be needed in 2050, making up 20-35 per cent of UK final energy consumption.[1]

In 2021, the UK Government published the Net Zero Strategy, which sets out policies and proposals for decarbonising all sectors of the UK economy to meet our net zero target by 2050.[2] This supports the preceding publications of the Hydrogen Strategy and the Prime Minister's Ten Point Plan, along with other notable publications that set out the development of the UK hydrogen economy as a UK Government priority. Building on the Ten Point Plan and Hydrogen Strategy, the British Energy Security Strategy (BESS) doubled our 5GW low carbon hydrogen production capacity ambition to deliver up to 10GW by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen.[3] These strategies combine near term pace and action with clear, long-term direction to unlock the innovation and investment critical to meeting our energy security and net zero ambitions.

Hydrogen transport and storage infrastructure will be critical enablers for the necessary growth in the hydrogen economy required to meet our 10GW ambition, which could support over 12,000 jobs in hydrogen production, distribution, and storage by 2030.[4] Alongside connecting producers and consumers, a well-developed hydrogen transport and storage network could be especially valuable for system flexibility. Excess renewable electricity can be used to produce hydrogen, which then can be stored over time. Analysis by AFRY estimates that long duration energy storage, supplied predominantly by hydrogen,[5] could provide between £13-24bn savings to the electricity system between 2030 and 2050 – by reducing network constraints and seasonal imbalances emerging from an increasingly weather-driven system.[6] Nonetheless, infrastructure projects may have lengthy development lead times, high capital

[1] Impact Assessment for the Sixth Carbon Budget (2021): https://www.legislation.gov.uk/ukia/2021/18/pdfs/ukia_20210018_en.pdf
[2] Net Zero Strategy: Build Back Greener (2021): https://www.gov.uk/government/publications/net-zero-strategy
[3] British Energy Security Strategy (2022): https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
[4] Internal BEIS analysis based on the Energy Innovation Needs Assessment (EINA) methodology with updated domestic and global scenarios; figures consider jobs linked to hydrogen production, distribution, and storage. EINA methodology provided by Vivid Economics (2019): https://www.gov.uk/government/publications/energy-innovation-needs-assessments
[5] Multiple assets are required to enable hydrogen to power. These include hydrogen production (e.g., electrolysis), hydrogen storage (e.g., salt caverns) and H2 to power generators (e.g., hydrogen CCGTs)
[6] The savings are predominantly driven by reduced fuel costs for generators. The analysis assumes hydrogen storage infrastructure is already built and so does not include the costs associated with this, nor the costs of de-risking necessary technologies. Please refer to the original analysis for details on the methodology: https://www.gov.uk/government/publications/benefits-of-long-duration-electricity-storage

costs, and uncertain financial investment returns in a nascent market, meaning transport and storage infrastructure is unlikely to materialise in the absence of supportive policy and commercial frameworks. For this reason, we also committed in the BESS to design new business models for hydrogen transport and hydrogen storage infrastructure by 2025. This is a clear commitment by government to provide a supportive commercial framework to unlock the significant infrastructure investment that is likely to be required to deliver the future hydrogen economy.

This Consultation

This consultation is the first step in meeting our BESS commitment to design new business models for hydrogen transport and storage infrastructure by 2025. We are seeking stakeholder views on high level business model design options for hydrogen transport and hydrogen storage, as well as whether the options we have identified are appropriate and proportionate for stakeholders, which options stakeholders prefer, and why. We are mindful that an evolutionary approach to the business model designs, and the wider regulatory and market frameworks they will sit within, may be required. This consultation therefore also seeks views on system planning, the regulatory framework, and the potential role of blending to support this wider journey.

Your feedback will enable us to develop informed policy and legislation.

Chapter 2 sets out the general considerations that inform this consultation and seeks views on our overall approach and design principles.

Chapter 3 sets out potential high-level business model design options for hydrogen transport infrastructure. This chapter seeks views on which business model design is most appropriate. There is an initial focus on onshore pipelines transporting hydrogen as a gas but views are sought on other hydrogen transport infrastructure and methods of transport.

Chapter 4 considers the role of hydrogen storage, both within the hydrogen economy and more widely, by providing flexibility across the whole energy system. It considers the types of storage infrastructure that might be deployed, how it is expected to emerge and the market barriers that might deter investment and timely deployment. It concludes by considering how those market barriers might be addressed through the implementation of a business model, with a number of possible options presented for comment.

Chapter 5 considers the need for strategic planning to support the development of hydrogen transport and storage infrastructure, as the UK moves to a decarbonised energy system. It explores different approaches to strategic planning, what factors may need to be considered, interactions with the provision of business model support and whether early support for “low or no-regrets” and systemically important projects is required.

Chapter 6 explores the wider supporting regulatory landscape for hydrogen transport and storage infrastructure (as well as covering production and end use). This chapter asks questions to support BEIS and other bodies to help ensure that both a conducive market framework and industry commercial arrangements, as well as broader non-economic regulatory measures are in place, workable, and optimal for project development.

Chapter 7 seeks to better understand the hydrogen market-building potential of allowing hydrogen blending into the existing gas grid, and how this might affect the economic and strategic case for blending. This includes assessing the scale of any gap between production volumes being ready to come online and large-scale hydrogen transport and storage infrastructure being developed, and blending's potential to bridge this gap. The chapter also explores the potential role of blending to act as a reserve offtaker to help bring forward investment and support delivery of our hydrogen ambitions.

The scope of the consultation is UK-wide, and responses are invited from all parts of the UK. However, certain aspects of the proposals may impact on policy matters that are devolved in Scotland, Wales, and Northern Ireland. BEIS will work with the devolved administrations as we develop the business models in order to ensure that our policies take account of devolved responsibilities. Where proposals are suited to implementation on a UK or GB-wide basis, working with the devolved administrations will facilitate the successful deployment of the business models and consistency with devolved policy.

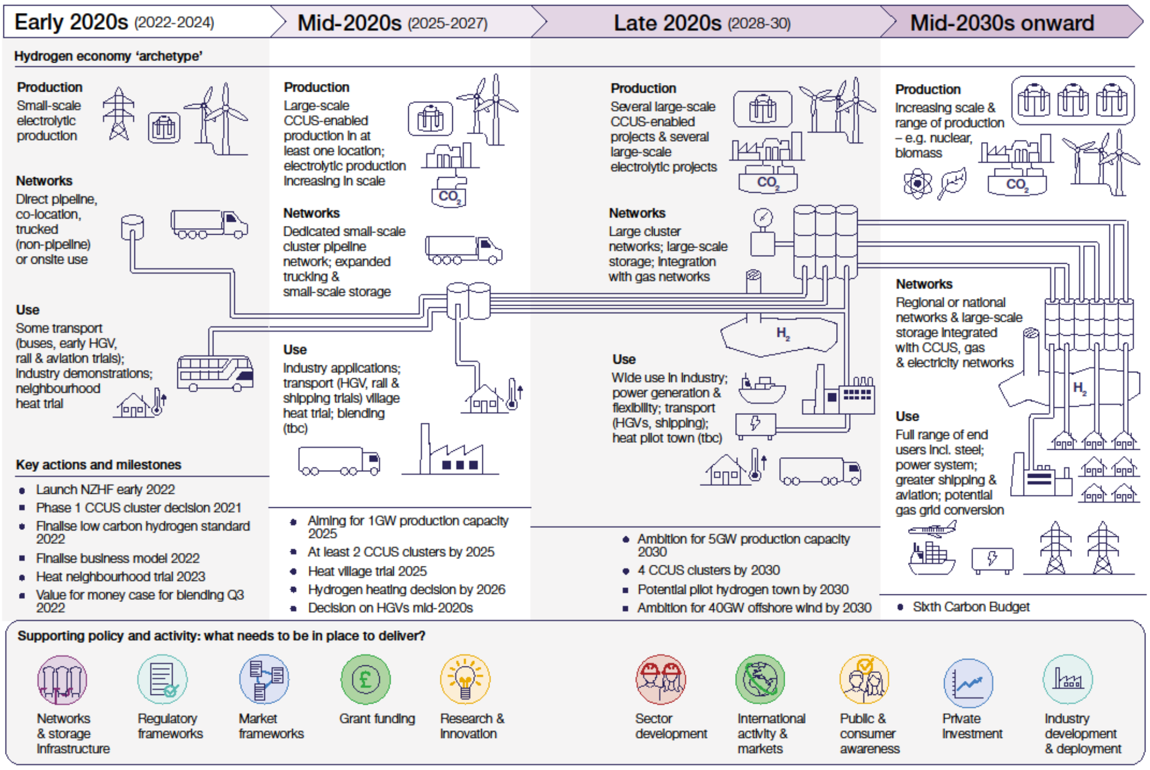
The scope of this consultation is also not limited to the transport and storage of low carbon hydrogen. BEIS intends for new, low carbon hydrogen to provide cleaner energy to meet our decarbonisation ambitions as set out in previous publications. Nonetheless, for security of supply reasons, transport and storage may need to be available to all forms of hydrogen in the event of unintended risks to low carbon hydrogen supplies, and the subsequent need to ensure hydrogen can be transported and stored effectively to avoid risks of disruption of hydrogen supply to consumers.

Chapter 2: General Considerations

The Hydrogen Roadmap

The Hydrogen Strategy included a roadmap which set out our vision for the expected growth of the hydrogen economy in the 2020s and beyond, which was largely based on incremental growth and an increasingly more integrated transport and storage network for low carbon hydrogen. The size and nature of the hydrogen economy and supporting network in 2050 will depend on several factors and policy decisions. This includes the roles of hydrogen across its different potential end uses in industry, power, transport and potentially heat. As summarised in the Hydrogen Economy 2020s Roadmap (Figure 1), we expect the hydrogen economy to reach regional and/or national scale transmission networks supported by both small and large-scale storage from the mid-2030s onwards.[7]

Figure 1: Hydrogen Economy 2020s Roadmap (Hydrogen Strategy)



[7] Hydrogen Strategy (2021): https://www.gov.uk/government/publications/uk-hydrogen-strategy. Note that the British Energy Security Strategy has since updated the hydrogen production capacity ambition for 2025 to 2GW/2030 to 10GW, and the offshore wind capacity ambition up to 50GW by 2030

Our Hydrogen Networks Vision

Our vision for hydrogen transport and storage infrastructure builds on our Hydrogen Strategy roadmap. We aim to reach a large, liquid and competitive hydrogen market enabled by an integrated and resilient network with multiple entry and exit points, connected to several hydrogen storage facilities at various scales. This may begin to materialise from the mid-2030s and beyond.[8] In time, we expect the market to be able to operate free of subsidy, although likely not free of regulation (much like the existing gas networks today).

We consider that business models for both hydrogen transport and storage are required to remove market barriers and stimulate private investment in the necessary supporting infrastructure, to deliver this vision of how hydrogen can play its full role in decarbonising the UK economy. The types of transport and storage infrastructure and examples being considered within this consultation are summarised in Table 1.

Table 1: Types of hydrogen transport and storage infrastructure

Infrastructure type	Examples
Transport	Transmission pressure hydrogen pipelines (new or repurposed) Distribution pressure hydrogen pipelines (new or repurposed) Non-pipeline transportation (e.g. road & rail vehicles, or marine vessels)
Storage	Depleted gas or oil fields Salt or rock caverns Aquifers Containers for compressed or liquified hydrogen Hydrogen carriers Metal hydrides

Given the nascent state of the current UK low carbon hydrogen economy, we anticipate that the journey to our envisaged end state will transition through several phases. Practical project delivery will depend on early decisions to accommodate investment timetables.

- In the **mid-2020s**, we intend for dedicated small-scale pipeline transport for individual producers to pipe hydrogen to users co-located on the same or close industrial sites. We also envisage expanded trucking and small-scale storage, capable of supporting large-scale CCUS-enabled production in at least one location, as well as electrolytic production. This aligns with our expectation that up to 2GW of low carbon hydrogen

[8] Hydrogen Strategy (2021): https://www.gov.uk/government/publications/uk-hydrogen-strategy

production capacity will be in operation or construction by 2025.[9] This will be used for industrial and early transport applications, as well as a village-sized trial of 100% hydrogen heating.

- In the **late 2020s**, we envisage larger within-cluster networks supported by both small and large-scale hydrogen storage, serving a greater number and wider variety of end uses across industry, power generation, transport and potentially for a hydrogen heated town.[10] We may also see some early off-cluster pipelines and storage development centred on electrolytic production, for example, to increase flexibility and efficiency in areas where renewable electricity generation is constrained by the capacity of the electricity grid.
- From the **mid-2030s onwards**, we envisage regional and/or national scale networks to be developing, supported by systemic large-scale storage infrastructure and integrated with CCUS, gas and electricity networks. This could enable a full range of hydrogen production technologies to service a full range of end users (potentially including heat in buildings) via a large, liquid and resilient market, with the potential to further transition to being free of subsidy (if not regulation).

The exact scale of this end state (and the journey leading there) will be significantly affected by a number of factors, for example:

- Geographical location and interactions with producers and end users of hydrogen will be extremely important in determining the need for, and potential value of, both hydrogen transport and hydrogen storage infrastructure. Strategic planning, which this consultation also considers, may be required to account for the locational and systemic design of hydrogen networks, to enable an optimal transition to a well-functioning hydrogen market.
- Wider market developments, including the role of imports and exports, as well as future technological developments, such as hydrogen carriers like ammonia or liquid organic hydrogen carriers (LOHCs).
- Wider policy decisions – for example those covering production and end use markets, including the strategic decisions in 2026 on the role of hydrogen in heat decarbonisation, and the decision on blending hydrogen into the gas distribution networks, which is aimed for 2023. However, we do not anticipate that the overall need for a large, integrated, and resilient hydrogen transport and storage network will be critically contingent on decisions and developments around hydrogen use in heating, especially given hydrogen's wider value for flexibility and as a storage solution. Demand for low carbon hydrogen in industry, power and transport is estimated to reach between 125-285TWh in 2050.[11]

[9] Hydrogen Investor Roadmap: Leading The Way to Net Zero (2022): https://www.gov.uk/government/publications/hydrogen-investor-roadmap-leading-the-way-to-net-zero

[10] In 2026, the Government will take strategic decisions on the role of hydrogen in heating, including whether or not to proceed with delivering a hydrogen heated town

[11] Demand estimates are from the Hydrogen Analytical Annex: https://www.gov.uk/government/publications/uk-hydrogen-strategy. Upper and lower estimates of demand in 2050 (page 10) for industry, power and transport

The ability of each part of the low carbon hydrogen value chain to scale up as the market expands will critically depend on the policy frameworks designed and implemented during the 2020s, as well as its later transition to an integrated, liquid, dynamic and competitive end state from the 2030s onwards.

Question 1

Do you agree with Government's analysis and vision for hydrogen network evolution through the different phases as described? Please explain your answer and provide any relevant evidence.

Support for Transport and Storage Infrastructure

Small Scale Infrastructure

Since the publication of the Hydrogen Strategy, Government has made two important policy decisions that are relevant to small scale hydrogen transport and storage infrastructure.

First, in the April 2022 response to the consultation on a hydrogen (production) business model (HBM),[12] Government stated that it intended to adopt a pragmatic approach when considering whether to support small scale transport and storage costs through the initial HBM contracts awarded. Government stated that factors including necessity, affordability and value for money would be taken into account when assessing whether to support these costs for both CCUS-enabled and electrolytic hydrogen projects. Government also said that consideration would be given to how such infrastructure could be future proofed to enable it to transition as smoothly as possible to a future hydrogen transport and storage network, potentially supported by its own commercial framework.

Second, in the April 2022 response to the consultation on the Net Zero Hydrogen Fund (NZHF), Government stated that where appropriate, support may be available for front end engineering design (FEED) and post-FEED costs for on-site transport and storage infrastructure associated with hydrogen production projects.[13]

In aggregate, these policy decisions mean that some support may be available for the development of initial small-scale transport and storage infrastructure. This initial support could help to overcome some market barriers to stimulate private investment in hydrogen production facilities, and help link-up production and demand on a more localised basis.

have been added together. There is significant uncertainty around estimates of demand for hydrogen. The ranges illustrate our current understanding of the opportunity for hydrogen in each sector, but do not represent a full range of potential outcomes for hydrogen.

[12] Design of a Business Model for Low Carbon Hydrogen (2021): https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

[13] Designing the Net Zero Hydrogen Fund (2021): https://www.gov.uk/government/consultations/designing-the-net-zero-hydrogen-fund

Additionally, electrolytic hydrogen producers whose customers are in the transport sector may be eligible to receive support through the Renewable Transport Fuel Obligation (RTFO),[14] which might provide sufficient support to meet associated transport and storage costs for the hydrogen produced.

Government continues to recognise the importance of small-scale transport and storage infrastructure to producers and end users in the emerging hydrogen economy, as well as on an enduring basis for electrolytic producers and some specific end-user types (for example in the transport sector, or for non-road mobile machinery, such as excavators on construction sites). Consequently, this consultation also seeks the views of stakeholders on the potential suitability of the identified high level business model design options to support investment in small-scale transport and storage infrastructure alongside investment in larger scale infrastructure.

Larger Scale Infrastructure

Crucially, as we look to build out the hydrogen economy, larger scale hydrogen transport and storage infrastructure is likely to play an increasingly important role linking more production facilities with end-users, whilst increasing resilience and security of supply for hydrogen producers and consumers, and enabling the realisation of wider system benefits.

Initial feedback from stakeholders indicates that developers are exposed to a number of market barriers (for example revenue uncertainty) which could delay or prevent final investment decisions (FIDs) being taken on such projects. We are exploring options for dedicated support to address these barriers given the critical role this infrastructure is expected to play in the hydrogen economy in the late 2020s and beyond, its wider system value, and lengthy development lead times.

Key Principles for Business Model Design

For separate transport and storage business models, we propose to apply common key principles to their design and implementation. These follow design principles applied to the HBM.[15]

[14] Renewable Transport Fuel Obligation (2019): https://www.gov.uk/guidance/renewable-transport-fuels-obligation
[15] Design of a Business Model for Low Carbon Hydrogen (2021): https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

Key design principles

Investable: the business model should provide sufficient predictability over revenue and return to investors and mitigate risks which investors are not best placed to bear.

Promotes market development: the business model should incentivise transport and storage providers to optimise the use of their infrastructure.

Compatible: the business model should be compatible with other policies across the value chain and should not result in double subsidisation.

Avoids unnecessary complexity: the business model should avoid unnecessary complexity for government to design, implement, and administrate over time, and for transport and storage providers to understand and comply with over time.

Reduces support over time: the business model should allow for support to reduce over time by being responsive to market conditions, the changing risks as the hydrogen economy grows and by incentivising learning and innovation to drive cost reductions over time.

Suitable for future pipeline: the business model should be fit for purpose for first of a kind (FOAK) projects as well as next of a kind (NOAK) projects.

Value for money: the business model should be effective in achieving its intended purpose at the lowest possible cost to the government and prevent excessive returns to developers.

Question 2

Do you agree with these key design principles for the transport and storage business models? Please explain your answer and provide any relevant evidence.

Chapter 3: Hydrogen Transport Infrastructure

Background

The British Energy Security Strategy sets out government's intention to design a new business model for hydrogen transport infrastructure by 2025. In this chapter, we outline some potential high-level design options for this business model and seek views on the best approach for its design.

This business model sets out to encourage investment in and the development of hydrogen transport infrastructure in the UK. This initially means supporting infrastructure needed in the 2020s to support delivery of the 2030 10GW low carbon hydrogen production capacity ambition (subject to affordability and value for money).[16] This is because increasingly larger transport infrastructure will be needed to link hydrogen producers with consumers (e.g. in industry, power and/or transport) and potentially storage facilities.

As set out in the introduction, and building on the roadmap in the Hydrogen Strategy, our vision for hydrogen transport from the mid-2030s onwards is for a large, integrated, and resilient hydrogen network with multiple entry and exit points within and across regions and/or nationally,[17] the exact scale is yet to be determined. Subsidy may be needed to support the development of hydrogen transport infrastructure in its infancy, although in time, we would expect the hydrogen network to be able to operate free of subsidy, although likely not free of regulation (much like the existing natural gas networks today). Providing the right policy, commercial framework, and regulatory support to infrastructure development in the 2020s will be essential to achieving this.

A range of pipelines could ultimately contribute to supporting the hydrogen economy including onshore pipelines for hydrogen as a gas, liquid hydrogen, a hydrogen carrier and offshore pipelines as well as vehicular transport.[18] Early stakeholder feedback indicates the current focus for producers and consumers is on hydrogen as a gas, that will be used, and initially likely produced, onshore.[19] As such, it is more likely that most pipelines transporting hydrogen as a gas will initially develop onshore to support the hydrogen economy, and is the focus of this consultation.

Some offshore pipelines, transporting hydrogen as a gas, supporting offshore production and storage facilities, could be needed at similar timescales to onshore pipelines. Given most

[16] British Energy Security Strategy (2022): https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
[17] By resilient we mean a network that maintains connectivity for producers and consumers which importantly helps preserve security of supply of hydrogen
[18] Vehicular transport, for the purposes of this chapter, includes transport of hydrogen via road, rail and sea
[19] A sample of potential hydrogen projects across the UK, the majority of which are onshore, was published alongside the Sector Development Action Plan (2022): https://www.gov.uk/government/publications/hydrogen-sector-development-action-plan

consumers are expected onshore, there will likely be a need for onshore pipelines to allow these offshore facilities to connect with a market.

Vehicular transport via road might be favoured in the early phases. However, given the volume of hydrogen that is expected to meet our ambitions, pipelines are estimated to eventually be more cost efficient. Long lead-in times for developing these pipelines mean further clarity on the design of a business model is needed to allow projects to develop in time for demand.

We then expect these onshore pipelines, and pipeline systems, transporting hydrogen as a gas, to eventually join to form a hydrogen network.

In designing a business model, we will consider how the design may need to evolve over time to continue to support the growth of the hydrogen economy in the 2030s and beyond.

Interactions with decision on hydrogen heating in 2026

Government has committed to taking strategic decisions in 2026 on the role of hydrogen for decarbonising heat, which will have important implications for the scale and nature of any hydrogen network. However, as set out in the introduction, we consider that the overall need for a large, integrated, and resilient hydrogen network (supported by storage) to link multiple producers and consumers is not contingent on the use of hydrogen in heating.

Nonetheless, as we design a business model by 2025, we will need to consider whether this business model is suitable for supporting infrastructure development for hydrogen heating, should this be required following the decision on heating in 2026.

Connecting Hydrogen Supply and Demand

In order for hydrogen to play its role in the decarbonisation of the UK, hydrogen has to be able to travel from its place of production to its place of consumption. Hydrogen transport infrastructure would connect producers and consumers of hydrogen and, therefore, enable potential end users in a variety of sectors, including industry, power and/or transport sectors, to switch to hydrogen, as the UK transitions away from high carbon fuels.

The recent doubling of the UK’s hydrogen production ambition, to up to 10GW by 2030, subject to affordability and value for money, also includes a greater focus on electrolytic hydrogen production. This has opened up potential opportunities to export hydrogen from the UK at scale, particularly to continental Europe where hydrogen demand is increasing alongside established energy trading and interconnection with the UK.

In the longer term, we expect UK hydrogen demand to increase significantly during the 2030s. This could lead to a greater role for imports in building resilience and supporting energy security as part of a diverse supply mix. Depending on the volumes of hydrogen traded with other countries, transport infrastructure may be required around export and import terminals, potentially alongside repurposed or additional international pipeline infrastructure.

Benefits of Hydrogen Transport Infrastructure

As set out in the Hydrogen Strategy, we will need to see significant development and scale up of hydrogen network infrastructure for the development of a UK hydrogen economy and for low carbon hydrogen to play its role in contributing towards UK decarbonisation over the 2020s under Carbon Budget 6 and on a pathway to net zero.

Facilitation of a Mature Market

We expect pipelines, and pipelines systems, to eventually form networks as they begin to join. The development of a network will support the growth of the hydrogen economy. Not only connecting producers with consumers to ensure hydrogen can get to a wider market (which vehicular transport could also offer) but also offering greater resilience for producers and consumers. Networks with multiple entry and exit points and multiple producers and consumers offer security of supply and economies of scale in comparison with vehicular transport or even a series of localised pipelines, which are susceptible to production outages and potentially uncompetitive practices by their owners and operators.

Developing these pipelines, and subsequent networks, has the potential to reduce investment risk and related costs for both hydrogen production and end-use projects in centres of supply and demand, whilst also lowering prices through greater competition in the low carbon hydrogen market. This can help to support the market transition from a highly fragmented initial stage to a more integrated, competitive, and transparent end state, where hydrogen can compete against other technologies without support and allow it to form part of an integrated energy system, working alongside and concurrently with electricity and natural gas. This integration across energy vectors will contribute to providing overall energy security in the UK.

We will also look to position the UK so that it is able to seize opportunities to export hydrogen when ready to do so. The development of a network could help grow the export market for hydrogen as producers, not located near a port or an interconnector, may use it to access international customers.

Supporting Decarbonisation of the Electricity System

As set out in the Hydrogen Storage Infrastructure chapter, storage could play an important role as a ‘system balancer’ in the wider energy system. The Net Zero Strategy set out a commitment to deliver a decarbonised power system by 2035 (subject to security of supply).[20] This is supported through a range of measures including the British Energy Security Strategy ambition to deliver up to 50GW of offshore wind capacity by 2030.[16] This aspiration to increase energy from renewable sources makes electrolytic hydrogen especially valuable for power system flexibility, and as a potential form of long duration electricity storage.

Hydrogen to power plants firing low carbon hydrogen fuel can play an essential role in achieving our decarbonisation targets, by providing a form of flexible low carbon electricity

[20] Net Zero Strategy: Build Back Greener (2021): https://www.gov.uk/government/publications/net-zero-strategy

generation to complement intermittent renewable generation, as well as creating a pathway for the decarbonisation of existing unabated gas generation.

The deployment of hydrogen to power plants is critically dependent on the availability and scale of hydrogen network infrastructure to access fuel. The hydrogen network could play a crucial role in the ability and effectiveness of hydrogen storage to provide wider 'system balancer' services to the power sector. For example, allowing hydrogen produced from electricity to be transported to a power plant and converted back into electricity for the grid, or to other areas of demand for direct use as hydrogen.

Hydrogen networks might also allow electrolytic hydrogen produced close to the source of renewable power to be easily transported to hydrogen consumers, particularly important for hydrogen producers located in areas where the offtake market is limited. This has two potential benefits, firstly reducing the need for costly electricity network reinforcements and, secondly, utilising electricity that would otherwise be curtailed, and hence maximising the value of investments in renewable electricity generation.

Given transporting gas, including hydrogen, through pipelines is usually cheaper than transporting electricity, building hydrogen networks or converting natural gas networks to hydrogen has the potential to reduce overall energy system costs.[21] However, there are likely to be trade-offs across the energy system that will need to be considered before making decisions around network development, whether hydrogen or electricity.

As well as supporting hydrogen produced from renewable sources, and the added benefits to the energy system, this consideration will be extended to include nuclear enabled hydrogen. This may become more important given plans in the British Energy Security Strategy to increase deployment of civil nuclear to up to 24GW by 2050, alongside our ambition to achieve up to 10GW of low carbon hydrogen production capacity by 2030.

Lowering the Need for Hydrogen Production and Storage Capacity

A network can also reduce the need for additional production and/or storage in a region to meet localised variations in demand, through the pooling of production/storage capacity. It can thus reduce the overall cost for hydrogen consumers and enable production and storage facilities to have a broader benefit. Again, this brings the potential to improve security of supply of hydrogen, and lower risk and costs for producers and consumers of hydrogen. This is likely a longer term benefit, which could come to fruition with the formation of a network from the mid 2030s.

[21] Cost of Long-Distance Energy Transmission by Different Carriers (2021): https://www.sciencedirect.com/science/article/pii/S2589004221014668

The Development of Hydrogen Transport Infrastructure

Today, hydrogen production and consumption in the UK is typically co-located for use by industry, removing the need for large scale hydrogen transport infrastructure. In cases where hydrogen is transported, production and consumption are usually closely located, only requiring limited infrastructure to transport gas or liquified hydrogen, whether via a direct pipeline or a small number of tube trailers (used for vehicular transport by road).

As the hydrogen economy grows, production and consumption will increase. To realise our ambition, create new markets, and connect production with consumers, hydrogen transport infrastructure will be critical (although the exact scale and location of this infrastructure is still to be determined).

Types of Hydrogen Transport

Hydrogen can be transported through various means. In gas or liquid form, or through a carrier, e.g. ammonia, hydrogen can be transported by pipeline or vehicle, including by road, rail or sea. These are summarised, and expanded upon, in Table 2.

Table 2: Summary of hydrogen transport options

Type of Hydrogen Transport	Description
New pipeline	Purpose built pipeline to transport hydrogen. Most likely as a gas or through a carrier. Suited to transport a range of hydrogen volumes over varying distances, this includes high volumes of hydrogen over regional and national distances as well as smaller volumes of hydrogen over shorter distances.
Repurposed pipeline	Repurposed from existing natural gas pipeline to transport hydrogen. Most likely as a gas or through a carrier. Suited to transport a range of hydrogen volumes over varying distances, this includes high volumes of hydrogen over regional and national distances as well as smaller volumes of hydrogen over shorter distances.
Road	Transporting hydrogen via road. Can be as a gas, a liquid, or through a carrier. Suited to transport a lower volume of hydrogen over short distances.
Rail	Transporting hydrogen via rail. Can be as a gas, a liquid, or through a carrier. Suited to transport a lower volume of hydrogen over medium distances.
Sea	Transporting hydrogen via sea. Most likely through a carrier. Suited to transport a high volume of hydrogen

	over long distances. Using a hydrogen carrier, would need converting back to compressed hydrogen unless being used directly.

The costs of transporting hydrogen via road is estimated to be higher than the costs of transporting hydrogen via pipeline, especially over longer distances. Analysis by BloombergNEF estimates that transporting hydrogen 100km by road could cost a maximum of £1.46/km while transporting hydrogen 100km via a distribution pipeline is expected to cost a maximum of £0.19/km.[22]

The costs for pipelines will be dominated by high capital costs of building the pipeline,[23] while for vehicular transport via road relatively more of the cost will be driven by ongoing operational expenditure. As such, the benefits of lower pipeline costs would only be realised when there is sufficient hydrogen volume to utilise this infrastructure, which requires significant capital investment. The lower capital costs of vehicular transport via road, and its suitability for smaller volumes, could favour transporting hydrogen by road in the early phases of the hydrogen economy.

Although vehicular transport by road may be used initially by industry, given expected volume of hydrogen based on our 10GW production capacity ambition, pipelines are envisaged to become the preferred transport method given the reduction in costs as hydrogen volumes increase. Alongside vehicular transport by road, we are still likely to see pipelines initially, especially within the industrial clusters.

Costs are not the only reason why pipelines or vehicular transport by road may or may not be favoured by producers and consumers. Other factors include regulatory requirements such as health and safety or planning, and hydrogen purity/quality specifications may be factored into the decision as well.

Growth of Hydrogen Transport Infrastructure

The expected growth of hydrogen transport infrastructure is set out in the Hydrogen Roadmap within the Hydrogen Strategy.[24] Infrastructure is expected to go from direct pipelines and vehicular transport via road in the early to mid 2020s, to a large cluster wide network in the late 2020s as the number of consumers in the clusters increase. From there, a regional, or even a national network, could be needed from the mid 2030s as new consumers become more

[22] The maximum estimates of hydrogen transport costs in the 2nd column of figure 4 (up to 100km) have been converted from USD to GBP from BloombergNEF, Hydrogen Economy Outlook: Key Messages (2020): https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

[23] For example, figure 7.2 in the techno-economics of hydrogen pipelines report shows the high proportion of capex costs in pipeline build (2021): https://transitionaccelerator.ca/wp-content/uploads/2021/12/Hydrogen-Pipelines-_30Nov2021-PUBLISH-V2.0-1-Dec-2021.pdf

[24] UK Hydrogen Strategy (2021): https://www.gov.uk/government/publications/uk-hydrogen-strategy

geographically dispersed. To realise this transition in scale of transport infrastructure during the 2020s and beyond, we believe a hydrogen transport infrastructure business model is required.

As set out in the government response to the Hydrogen Business Model (HBM) consultation, initial HBM contracts may include costs for limited transport infrastructure, taking into account a number of factors, including necessity, affordability, and value for money.[25] This could include funding pipelines, as well as vehicular transport by road, to connect to consumers. It should be noted that BEIS's minded to position is for only capex costs to be covered for small-scale hydrogen transport infrastructure, and not opex costs, through the HBM, as set out in the HBM indicative Heads of Terms.[25] We also confirmed that we will consider how these costs are treated in the HBM and, taking into consideration the wider hydrogen economy, how this infrastructure can be future proofed to transition as smoothly as possible to a future hydrogen network, potentially supported by its own commercial framework.

Some early hydrogen producers and consumers may use closed system pipelines, either existing or new, to transport hydrogen. However, this is not an enduring solution for a large and integrated hydrogen economy, and we may see shared pipelines from an early stage, most likely connecting one producer to multiple consumers in the first instance, but also catering to multiple producers soon after. As more producers and consumers come online, increasingly further away from each other, we envisage shared pipelines will be needed, both to provide increased reach for new potential consumers, but also to improve system resilience and increase competition.[26]

As these shared pipelines develop and join, we anticipate hydrogen transport infrastructure to eventually consist of a network with multiple entry and exit points to support the growing number of hydrogen producers and consumers. This network may also include some direct pipelines. In time, these initial networks have the potential to grow into a collection of regional hydrogen networks, or even a national network.

There may be pipelines owned by hydrogen producers supported by the initial HBM contracts, or any other available support. These may become shared pipelines and, in time, part of a shared large-scale network. Alternatively, direct pipelines may become dispensable if alternative shared pipelines, and ultimately a shared network, become available. We recognise that a future business model supporting the development of shared pipelines would need to consider the interactions and interfaces with any pre-existing government support provided in respect of pipelines, such as through the HBM, including in terms of ownership, operation, and regulation. We will provide further guidance on this as the hydrogen transport infrastructure business model is developed.

Government is aiming to reach a policy decision in 2023 on whether to allow blending (up to 20% hydrogen by volume) into the gas distribution networks. If allowed, blending will likely impact, not only the future hydrogen network, but also the existing natural gas network. Some new 100% hydrogen pipelines may be required to connect producers to the existing natural

[25] Government Response to the Consultation on a Low Carbon Hydrogen Business Model (2022): https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen
[26] Shared pipelines are pipelines that can be used by a number of different hydrogen producers and consumers

gas network (especially for electrolysers co-located with renewable power generation, as this may not be close to a suitable injection point for hydrogen into the natural gas network). We have set out questions requesting feedback from stakeholders on the hydrogen market building potential of hydrogen blending, and how this might affect the economic and strategic case for blending, later in this consultation.

Repurposing Existing Pipelines to Transport Hydrogen

Hydrogen pipelines can be developed as new pipelines, purpose-built to transport hydrogen, or pipelines from the existing natural gas network might be repurposed to transport 100% hydrogen.

The ability and safety of natural gas transmission and distribution networks being used for transporting 100% hydrogen is being assessed by National Grid and the Gas Distribution Networks (GDNs). Depending on the outcomes of these assessments, repurposing of existing infrastructure could be possible. Some examples of these assessments are set out below.

FutureGrid is building an offline hydrogen test facility from decommissioned equipment to demonstrate whether National Grid's network can safely transport up to 100% hydrogen.

Local Transmission System Futures is looking at the feasibility of repurposing the local transmission system owned and operated by the GDNs.

H21 is looking at the feasibility of repurposing the distribution network owned and operated by the GDNs.

As well as projects looking at the feasibility of repurposing pipelines, National Grid's Project Union is exploring the development of a UK hydrogen network to connect strategic hydrogen production centres with storage and consumption to support the creation of a UK hydrogen market. As well as building on the feasibility testing from FutureGrid, this project will identify potential pipelines routes, assesses the readiness of existing gas assets, and determine a potential transition plan for some of National Grid's transmission pipelines. The result could see the existing national transmission system repurposed in a phased approach to create a 2,000km hydrogen network for the UK.

While constructing new pipelines or repurposing existing pipelines will both entail potentially substantial costs, repurposing is likely to be of lower cost. Marcogaz interim results exploring the costs of repurposing natural gas infrastructure suggests that repurposing is possible at 20% to 40% of the cost of building a new hydrogen pipeline.[27]

Repurposing pipelines from the existing natural gas network may therefore be a preferable way to develop hydrogen pipelines and, eventually, the bulk of the hydrogen network. However,

[27] Marcogaz (2022), European Gas Technology Conference (viewed 14 June 2022)

new hydrogen pipelines are likely to be required initially so as to not compromise the resilience and functionality of the existing natural gas system while it is still needed.

As the UK begins to transition away from natural gas, there should be more opportunities for repurposing. Currently, repurposing has the potential to contribute hydrogen infrastructure this decade, and we envisage seeing a mix of new and repurposed pipelines making up the UK pipeline systems and network.

These natural gas pipelines are currently owned and operated by private companies regulated by Ofgem. As such, the design of any business model will need to take this into account.

Case Studies

To help understand the considerations, challenges and solutions the design of a business model will have to factor in, lessons can be drawn from those designed for similar infrastructure in the UK and to support hydrogen infrastructure internationally.

Natural Gas Networks in GB

The current GB natural gas network is broken down into one national transmission network and eight regional distribution networks which are defined by area. These networks are natural monopolies owned and operated by private companies under licence. Only those holding a gas transporters licence can convey gas through pipelines to premises or other pipeline systems operated by gas transporters (subject to certain exemptions and exceptions).

One company owns and operates the gas transmission system - National Grid Gas, and four companies own and operate the distribution networks – Cadent, Northern Gas Networks, SGN, and Wales and West Utilities. In addition, there are a number of smaller networks owned and operated by Independent Gas Transporters, located in the areas covered by the regional distribution networks.

The natural gas network is a natural monopoly. The large capital investment required to construct, maintain, and operate a network, mean it is usually more efficient to have one network in a geographical area as this allows for economies of scale and to spread shared and fixed costs over a larger customer base.

This opens the network to monopolistic tendencies, such as excessive charges or poor performance, by its owners and operators. To overcome this, the natural gas transmission and distribution networks are regulated by Ofgem under a Regulated Asset Base (RAB) business model, using the RIIO price control framework.[28]

[28] RIIO: Revenue = Incentives + Innovation + Outputs: https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2021-2028-riio-2

The RIIO price control ensures owners and operators of the network can, through efficient operation, earn a fair return on their activities while controlling the end cost to consumers. Ofgem does this by deriving an 'allowed revenue' the natural gas network companies may collect each year, based on an efficient view of costs, investment, returns, etc. This provides revenue certainty. Ofgem also sets performance targets through RIIO covering customer service, network reliability, environmental performance, and more.

Given the Hydrogen Roadmap expectation that a hydrogen network will develop, and this could form into a series of regional or even one national network from around the mid 2030s, there could be some parallels between our desired end state for hydrogen and parts of the current natural gas network. As such, the regulation for natural gas may provide a useful framework as we approach the design of a business model for hydrogen transport infrastructure, especially in the long-term.

CCUS in the UK

A RAB business model has been proposed for the CO2 T&S infrastructure connected to Carbon Capture, Usage and Storage (CCUS). The government's view is that the CO2 T&S infrastructure, like the natural gas network, is most efficiently run as regional monopolies, which would be best catered for through a RAB.

One of the main differences between the CO2 T&S infrastructure and the natural gas network, is the small user base for the CO2 T&S infrastructure, particularly at the start of the CCUS economy. Under a RAB, owners and operators of the infrastructure usually charge users, both producers and consumers, for the service of transporting gas.

However, for early CO2 T&S infrastructure, the user base will be small. This creates a potential revenue gap between revenue received and costs needed to develop, construct, and operate the infrastructure.

Policy development for the proposed CO2 T&S RAB model, known as the T&S Regulatory Investment Model, discusses several specific measures that could be used to address this issue. Those of most relevance are set out below:

1. Cost mutualised over the available user base, so that the costs covered by the available users for the infrastructure would increase to close the revenue gap. This could create an increase in charges in the short-term. However, as more users join, the quantum of these mutualised charges would decrease. To protect users against excessive mutualised charges, that would be uneconomical for users, these costs are capped.

2. The allowed revenue profile can be shaped to match the expected utilisation profile of the CO2 T&S infrastructure. As such, deferring revenue from the early operational

phase to later in the operational phase. Allowing more of the revenue to be collected from a larger user base. This could be achieved from adopting a non-straight-line depreciation of the Regulated Asset Value.

3. 'Revenue support', sourced through taxpayers, to meet the revenue gap. This can be used in conjunction with capping costs (mentioned above in option 1).

Alongside the T&S RAB model, there is also a capital grant potentially available through the CCUS Infrastructure Fund (CIF). This upfront contribution reduces those costs needed to fund the construction of the infrastructure, and therefore, the costs that need to be recovered through users will be lower.

The hydrogen pipelines, and a subsequent network, will also start with an initial small user base and may benefit from similar mitigations.

Hydrogen in the EU

The EU has ambitions for the use of hydrogen to support decarbonisation. Similar to the UK, these ambitions rely on hydrogen transport infrastructure. At the end of 2021, the EU proposed modifications to the existing regulatory framework for natural gas to support the transition of the existing natural gas network to hydrogen as well as other low carbon and renewable gases.[29]

The EU is an advocate of a user pays principle. Only users of the infrastructure should cover the costs. As such, a separate RAB is needed for natural gas and hydrogen to ensure the value of both assets remain distinct. To allow for repurposing, the financial transfer of an asset from one RAB to the other can be made after a valuation. This avoids cross-subsidisation, so costs cannot be spread across different users.

However, the EU proposals do acknowledge that to stimulate the funding needed for the new hydrogen network, cross-subsidisation may be needed in the initial stages provided it is proportional, transparent, and limited in time. This would mean some hydrogen network costs being socialised between domestic natural gas and hydrogen consumers.

The EU recognised that, although user pays should always be the principal model, cross-subsidisation can contribute to EU decarbonisation objectives and can provide reasonable and predictable tariffs for early network users and de-risk investment for network owners and operators.

[29] The EU proposed legislative changes for gas and hydrogen network regulation (2021): https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en

Given the issues the UK may have with an initial smaller user base, an external funding mechanism may also need to be considered for a new business model.

Hydrogen in Germany

In 2020, Germany published its Hydrogen Strategy. In it, Germany recognised the need to strengthen its hydrogen transport infrastructure to further develop the hydrogen market, and support its production capacity ambitions, as well as enable imports of hydrogen into Germany.

To support their ambitions, the German Federal Government is using the expertise of the existing owners and operators of the natural gas network, or gas transporters, to help deliver this needed infrastructure.

These gas transporters have been planning the network requirements through the Gas Development Network Plan 2020 – 2030.[30] Understanding of the requirements for this Plan is based on demand and supply expected in 2050. This end point is used to develop an initial hydrogen network from early 2020s to early 2030s. This initial network is proposed to predominantly repurpose from the existing natural gas network where parallel gas lines exist, which will minimise the need for newly developed pipelines. Gas transporters can identify pipelines for conversion through the Gas Development Network Plan.

The German Government, through the Gas Development Network Plan, has approved hydrogen pipeline plans from incumbent gas network owners and operators under their current natural gas RAB so work can progress. Costs will need to be accounted for individually so they could be separated into different RABs in the future.

Germany offers an example of how another country is approaching the development of hydrogen pipelines, including thinking around interim measures.

Hydrogen Transport Business Model

Support to hydrogen production projects, via the Net Zero Hydrogen Fund and/or the HBM is expected to encourage new low carbon hydrogen production projects, delivering our ambition for up to 10GW low carbon hydrogen production capacity by 2030 (subject to affordability and value for money). These projects will likely increase the demand for hydrogen pipelines (both new and repurposed), as existing and new producers look to cater to new sources of hydrogen

[30] Information on the Gas Network Development Plan 2020-2030 is set out on Bundesnetzagentur's website: https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/GridDevelopment/Gas/NEP_2020_1/start.html

demand. The development of such pipelines can enable further sources of low carbon hydrogen supply and demand in the future, thus supporting the UK's decarbonisation goals.

Government has been acting on its commitment to undertake a review of systemic hydrogen network and storage requirements. The review so far (of which this consultation forms part), has identified that although we anticipate that the development of hydrogen pipelines, and the subsequent growth of a network, will be essential to the success of the hydrogen economy, significant market barriers are likely to inhibit their widespread deployment.

Market Barriers

Final investment decisions (FIDs) will need to be taken if shared hydrogen pipelines are to be developed. For these FIDs to be made, developers will need to secure investment, either from internal or external sources in order to fund their projects. However, and as detailed in the analytical annex to this consultation, we believe that a number of significant market barriers exist preventing FIDs from being taken. The main market barriers are set out below and additional market barriers for hydrogen pipelines, and a subsequent network, are described in the analytical annex.

- **Demand and supply uncertainty.** The Hydrogen Strategy provided investors with a broad sense of timelines around supply and demand. However, demand and supply of hydrogen at the required detail for investment is likely to be uncertain whilst the hydrogen economy is in its infancy. This uncertainty is likely to impact investor confidence which could be a barrier to the development of pipelines. A pipeline involves large amounts of upfront capital investment. Investors cover these costs in anticipation of receiving a revenue. Sufficient confidence in the long-term revenue is, therefore, important to encourage this investment. Investors need to have confidence in the source of the future revenue stream to provide certainty that costs can be covered, and a steady and certain rate of return is possible. Uncertain demand and supply make this revenue uncertain, as it is unclear how many users there will be of the pipeline. Developers and investors are also likely to be wary of futureproofing this infrastructure and be reluctant to cover costs for additional capacity in preparation for demand to increase in the future, given this future demand is uncertain. However, without futureproofing the network, future growth might be prevented, or greater investment overall could be needed, if this greater demand comes through. This uncertainty also creates a greater risk that these early pipelines become stranded assets. It may be prudent to focus on progressing "no regrets" or "low regrets" pipelines.
- **Limited consumer base to cover costs.** At the start of the hydrogen economy there will be a small number of producers and consumers. As such, there will be a small number of users of these pipelines to cover costs. Given the large upfront capital investment, users could face excessive charges to recover these costs. These potential charges are likely to put off users from accessing the pipeline. If owners and operators of the pipelines cannot recover costs through users, the revenue gap widens, and costs cannot be recovered. This limited revenue may, again, impact investor confidence in investing and developing pipelines. An inability to recover costs through users, could

reduce investment into these initial pipelines, and an eventual network. This reduced investment could also put further pressure on the ability to futureproof pipelines. A large and persistent revenue gap could stop investors from being able to fund projects catering to future demand which may be needed.

- **High cost.** There is currently very limited infrastructure in terms of hydrogen pipelines. This means these pipelines need to be developed, whether newly built or repurposed. This comes with a cost, and for this type of infrastructure, even repurposing, incurs high up-front capital costs. Market-price risk is associated with the market barrier of high cost. With hydrogen transport, we expect that early users will be unable to pay the cost of hydrogen transport as it is likely to be prohibitively expensive, but that this infrastructure would be utilised if available at a lower price.

The market barriers set out above are likely to have an impact on the development of pipelines during a growth phase. These market barriers can deter investment in hydrogen pipelines, due to the uncertain and limited returns.

If these initial barriers are overcome (e.g. through the provision of a business model), and FIDs can be taken, other market barriers may start to materialise as a network starts to form. The main market barrier at this phase, natural monopoly, is set out below.

- **Natural monopoly.** This potential market barrier is usually only experienced for larger infrastructure, so in this case when pipelines begin to merge to form a network. Due to the significant capital costs involved in developing a network, there is a need to pool resources across a larger customer base, in order to have the ability to develop, construct, and operate a network. As such, there is usually only one owner and operator in a geographic area, and the network becomes a natural monopoly. While this may be seen as preferable due to the cost savings linked to economies of scale, a natural monopoly does present market barriers, mainly as a result of the lack of competition. The potential market barriers are set out below.
    - Vertical issues – owners and operators prevent users from joining the network or reduce access to users.
    - Horizontal issues – owners and operators set excessive charges for users.
    - Performance issues – poor handling in terms of customer service, not investing efficiently in the network, and not willing to innovate.

These market barriers appear at different phases in the evolution of a hydrogen network. All may need to be considered as we look to design business models for hydrogen pipelines, and subsequent networks, taking account of their likely materiality as the hydrogen economy moves through its expected phases of evolution. However, with the acknowledgment that a business model may need to focus on the most pressing market barrier being faced at that specific phase.

Question 3

In your view, do you agree we have correctly identified and characterised the market barriers facing the development and operation of hydrogen pipelines and a hydrogen network? Are there any other market barriers we should be considering? Please explain your answer and provide any relevant evidence.

The development of these pipelines will be essential to support government's hydrogen ambitions. To overcome these market failures and to bring forward investment in and development of hydrogen pipelines, and subsequent networks, we consider that a business model for hydrogen transport is likely required to provide the commercial framework used to build, operate, and fund the network.

Business Model Design Options

Government has worked together with industry to design business models to support the build out of infrastructure across the energy system and beyond, which have successfully stimulated investment. For example, a Contracts for Difference has been used to encourage investment in offshore wind farms, and a RAB business model has been used to encourage investment in the electricity grid. The Government has, following public consultation, introduced and passed the Nuclear Energy (Financing) Act 2022 which established the RAB model as an option to finance future nuclear power projects.[31]

The analytical annex to this consultation sets out a design framework for the development of business models. In the following sections we categorise, at a high level, a number of business model design options, and consider how they might support the development of hydrogen transport infrastructure.

Most of the potential business models would require the input of additional participants, such as a delivery body, in order to be implemented. For example, those that fall under the 'regulated returns' category would require an economic regulator. Those that fall under the 'contractual payments' category may require a counterparty to collect levies, make payments, and to manage any compliance issues arising. Those that fall under the remaining categories would require, to a greater or lesser extent, administration activities to be undertaken, including compliance and enforcement action.

Regulated Returns

Regulated Asset Base (RAB)

An owner and operator of a hydrogen pipeline would be allowed to earn a regulated return on costs. This regulated return would be determined by a regulator to provide for the 'allowed revenue' over a specific period. This 'allowed revenue' would be reflective of costs incurred as well as a fair rate of return. This would provide revenue certainty for investors, helping mitigate uncertain supply and demand. A RAB model typically recovers costs from users of the infrastructure. However, given the likelihood of there being a relatively small user base for the

[31] Nuclear regulated asset base (RAB) model: statement on procedure and criteria for designation (2022): https://www.gov.uk/government/publications/nuclear-regulated-asset-base-rab-model-statement-on-procedure-and-criteria-for-designation

network infrastructure initially, it may be necessary for revenues to be subsidised through an external funding mechanism, especially whilst the hydrogen economy is in its infancy. This would enable user costs to remain non-prohibitive. Once a more integrated and extensive network is formed, a RAB is a well-established business model to deal with the market barriers associated with natural monopoly. This is because the 'allowed revenue' aims to ensure only fair and reasonable costs are recovered from users. However, a natural monopoly is unlikely to materialise until a more extensive network has formed.

Cap and Floor

An owner and operator of a hydrogen pipeline would have a revenue cap and floor set by a regulator for a specific period. The floor would be the minimum amount of revenue that the owner and operator could recover. If the floor is not reached, the revenue would be topped up through an external funding mechanism. The cap would be the maximum revenue an owner and operator could recover. If the cap was exceeded, revenue would be transferred to the organisation responsible for the external funding mechanism. Through this, a cap and floor could overcome the market barrier of uncertain demand and supply as well as a small user base.

Contractual Payments

Contracts for Difference

Ordinarily, a contracts for difference (CfD) arrangement is adopted to address price risk through a variable premium which is paid to (or by) an asset owner to top-up (or reduce) regular sales receipts for a commodity. The strike price is the amount that the asset owner is prepared to accept in order to operate the asset, and the premium is paid by an external funding provider, usually via a private law contract. An owner and operator of a hydrogen pipeline could, therefore, receive a subsidy covering the additional cost of transporting hydrogen compared to transporting a high carbon counterfactual fuel, like natural gas. A CfD type model would make transporting hydrogen as competitive as transporting other high carbon counterfactual fuels, such a natural gas. As such, it could be effective at mitigating a price risk. However, the volume risk associated with uncertain supply and demand, as well as a small user base initially, would remain. Additional provisions, such as a sliding scale price support similar to the HBM, could help mitigate the volume risk.

Government as a Long-Term Capacity Booker

Under this arrangement, government would agree to reserve a certain volume of transport capacity for a certain number of years. The owners and operators of pipelines would prioritise the resale of this capacity, but in the event it remained unsold, government would be liable for the costs. The volume of capacity that government would be liable for could reduce the market barriers associated with uncertain demand and supply and a small user base.

Capacity Availability

Under this arrangement, payments would be made to transport owners and operators for providing transport capacity when and where it is required. An owner and operator of a hydrogen pipeline would receive set minimum payments for providing a given amount of capacity. This would reduce the market barriers associated with revenue uncertainty and small user base as payments would not be made on use but rather the existence of the pipeline.

Other Models

Co-investment by Government

Government would choose to co-invest in selected pipelines which it considers to be of strategic importance, for instance through a capital grant. This would lower the costs and, as such, lower the revenue needed to recover the costs, and hence lower investment risk. Co-investment by government would reduce the risk associated with demand and supply uncertainty, as well as issues stemming from a small user base, as the revenue needed to recover costs would be lowered.

Merchant model

The owner and operator of a hydrogen pipeline would not be supported by a business model. All the risk would fall to the owner and operator of the pipeline. Market forces would determine investment into the pipeline. A merchant model would not include an external funding mechanism, only users would pay for the pipeline. However, uncertain demand and supply would remain and, through that, result in a slower development of pipeline and growth of the network as owner and operators wait for certain users before investing.

From our initial intelligence gathered from stakeholder engagement, we consider that a business model is likely to overcome the perceived market barriers mentioned earlier, both in the short and long-term. However, further consideration is required as to whether and what type of a business model might be best suited in the different phases of network evolution.

The options listed above are high-level examples of business models. There are additional possibilities which could be a hybrid of these examples, and there are many additional features that could be incorporated into business model designs. For example, policies with the aim of driving market development and use of transport infrastructure could be incorporated into the business model or delivered alongside a business model. The business model would be designed to overcome the key risks to enable investment whilst additional policies could drive efficiency and value for money by encouraging more use of the infrastructure.

Question 4

In your view, have we set out the main business model design options, or are there others that should be considered? Please explain your answer and provide any relevant evidence.

Our key principles for designing the business model, as set out in the introduction, can feed into a review of these design options.

Existing Support for Hydrogen Transport Infrastructure

A business model for hydrogen transport infrastructure specifically is not currently available to allow for the development of pipelines in these early stages. However, some support may be available to encourage investment in and development of initial pipelines through other means, including those set out below. Early projects may need to use this support to start or continue to progress the development of pipelines to meet initial demand.

Hydrogen Business Model for production

As noted above, the initial HBM contracts awarded may fund transport infrastructure directly linked to hydrogen production projects, taking into account a number of factors, including necessity, affordability, and value for money. This could include funding for the earliest hydrogen pipelines connecting specific early producers and consumers.

However, as set out in the Government Response to the HBM Consultation, the primary focus of the HBM is the production of cost competitive low carbon hydrogen. While government has agreed to adopting a pragmatic approach to the earliest small scale hydrogen transport infrastructure projects where these are necessary for hydrogen producers to access their initial consumers, this is not an enduring solution.

Ofgem RIIO Framework

Under RIIO, Ofgem sets an 'allowed revenue' that owners and operators of gas networks are allowed to recover. This allowed revenue ensures that any revenues recovered by the owners and operators of gas networks for their activities balance the relationship between investment in the network, company returns and the amount that they charge customers for the use of the network. It thus enables the owners and operators to cover their costs and, also, receive a certain rate of return, determined by the regulator, over a set period, to ensure it is in the interest of consumers.

On a case by case basis, Ofgem has previously allowed some of these costs to extend to feasibility studies for hydrogen transport infrastructure. We will continue to work collaboratively with Ofgem to consider what work needs to happen now and what appropriate funding mechanisms could be used to support this, if necessary. Ofgem will work closely with industry partners and Government to address any barriers which prevent the development of this infrastructure in the near-term and ensure a suitable framework is in place to ensure this growth can happen, acknowledging governments commitments in the British Energy Security Strategy including to design new business models by 2025. The current price control or another measure may provide this suitable framework and allow projects to continue in the interim before a hydrogen transport infrastructure business model is available.

Although available, we do not envisage that existing support mechanisms provide an enduring solution to support investment in and the development of pipelines. As such, a business model for hydrogen transport infrastructure is likely needed.

Development Phases

We see the development of these pipelines, and eventual network, to take place in phases, and any design will have to consider these phases, as outlined below.

- Growth phase – development of pipelines to make hydrogen available to potential consumers within and outside of industrial clusters, enable connections with producers (e.g. CCUS enabled and electrolytic) or import terminals, connect to new larger scale storage onshore or offshore, and more generally build connectivity and resilience as a wider network begins to form.
- Steady state phase – maintaining one or several extensive networks with multiple entry and exit points, multiple larger scale storage facilities, and potentially international connections. The Hydrogen Strategy envisages this starting to form from the mid 2030's. Further network changes and investments are made on an incremental rather than transformational basis driven by market conditions.

It is worth noting that these phases may co-exist in practice, particularly in line with the cluster sequencing process, i.e. hydrogen network evolution may be in a growth phase in one region of the UK, in the transition towards a steady state network, while it has already moved into an initial steady state phase elsewhere.

Business Model for a Growth Phase

While existing support may be used for the initial pipeline projects, it may not provide an optimal enduring solution, meaning a separate business model is likely needed to support pipeline and network development through its growth phase.

Hydrogen represents a new energy vector compared to natural gas and is subject to new and distinct challenges as well as market barriers that need to be overcome to drive initial pipeline and subsequent network development. Designing a business model for hydrogen transport using the existing framework for natural gas may therefore not be appropriate, given this framework has been established to support a mature market with a large and mainly captive user base.

The market barriers faced during this growth phase are likely to be different to the ones faced in an eventual steady state phase. We expect the predominant early barriers to be uncertain demand and supply and limited user base to cover the build out costs, although there may be others.

We expect this growth phase to last until we start to see a network form, and the market barriers associated with a growth phase become less consequential, and market barriers, most notably a natural monopoly, associated with a steady state phase become predominant.

Question 5

In your view, do you agree that uncertain demand and supply and limited user base will be the predominant barriers in a growth phase of hydrogen network development? Please explain your answer and provide any relevant evidence.

Question 6

In your view, which business model design options do you consider may be suited to address the barriers in a growth phase? Please explain your answer and provide any relevant evidence.

Question 7

In your view, are there any interim measures that we should be exploring to support the development of early hydrogen pipelines ahead of a hydrogen transport infrastructure business model being available? Please explain your answer and provide any relevant evidence.

Business Model for a Steady State

As set out in the introduction, and building on the roadmap in the Hydrogen Strategy, our long-term vision for hydrogen transport is of a large, integrated and resilient network with multiple entry and exit points potentially across regions, or even nationally. In time, even if a subsidy is needed for a growth phase, we expect the hydrogen network to eventually be able to operate free of subsidy, although likely not free of regulation (much like the existing gas networks today).

In this eventual steady state, the predominant market barrier is likely to be that associated with natural monopoly. A RAB may therefore be the most appropriate business model design, as it is a model typically used in the UK and further afield for monopoly infrastructure such as gas, electricity, and water networks, and is a proven tool to address challenges associated with natural monopolies, as well as to de-risk investment in mature markets.

RABs reduce the cost of capital for investors by guaranteeing fair returns over a longer period, thus giving investors a high degree of certainty on future revenues and the expected return on investment. All investment made is valued and costs are recoverable in accordance with regulation, in order to support infrastructure development and operation, control tariffs, and to pay investors.

At this point, there are clear parallels between the eventual steady state we expect for the hydrogen network and the current natural gas network, particularly with respect to the risks associated with natural monopoly.

For this reason, we consider it likely that a RAB will be the most suitable business model for a hydrogen network in the long-term, especially as it reaches a state of maturity where subsidy, if needed initially, is no longer required and where natural monopoly is the predominant market barrier to address through economic regulation. As such, the regulation for natural gas, including the RAB business model (RIIO price control), may provide a useful guide as we consider the design of a long-term business model for hydrogen transport infrastructure in a steady state.

Question 8

In your view, is a RAB model, based on the natural gas RAB design, likely to be the most suitable business model during a steady state, or would another business model design be more appropriate? Please explain your answer and provide any relevant evidence.

Additional Considerations

With a business model to drive network development through the growth and steady state phases of network evolution, additional factors may need to be taken into account in business model design. For instance:

- **Compatibility with long-term business model for a steady state.** A transitional business model in a growth phase that also works or can seamlessly transition into the desired long-term business model in a steady state phase is likely required.
- **Compatibility with the natural gas business model.** There may be future benefits from compatibility with the natural gas business model given the link between the hydrogen pipelines and natural gas pipelines through repurposing.

These additional considerations focus on compatibility. However, there may be others.

Question 9

In your view, is there a need for compatibility between a business model for a growth phase and a business model for a steady state, and how should this be managed? Please explain your answer and provide any relevant evidence.

Question 10

In your view, is there a need for compatibility between a business model for hydrogen and a business model for natural gas, and how should this be managed? Please explain your answer and provide any relevant evidence.

Question 11

In your view, are there any other considerations we should take into account? Please explain your answer and provide any relevant evidence.

Specific Features within Business Model Design Options

Irrespective of the high-level business model design option selected to support the roll out of hydrogen transport infrastructure, a number of specific design features and wider contextual and institutional factors will need to be considered, noting that not all features and factors will apply equally to all the business model design options.

Ownership Model

There are a variety of ownership models that could work within these business model design options, including government owned, privately owned, or a combination. For example, pipelines could be co-owned by a private company and government.

Infrastructure under a regulated business model, such as a RAB or a cap and floor can be either privately owned or government owned. Under a contractual business model, infrastructure tends to be privately owned. Through government co-funding, infrastructure can be privately owned or co-owned.

Question 12

In your view, what ownership arrangements do you think are likely to be suitable for hydrogen networks? Does this depend on the chosen business model and/or phase of network evolution? Please explain your answer and provide any relevant evidence.

Provision of Business Model Support

The Strategic Planning chapter sets out options in relation to the provision of business models. Questions around this are set out in the Strategic Planning chapter and are also important to business model design.

Costs Covered

Projects have different types of costs at different stages. Devex costs are development costs mainly incurred early in the project. Capex costs are the capital costs associated with construction. Opex costs are ongoing operating costs. This is set out in more detail in the analytical annex. Investors may also require a rate of return, and this may differ depending on a number of factors, including the risk associated with the investment.

One specific design feature to be considered, once a design option has been chosen, is which costs, if any, should be supported.

External Funding Mechanism

A business model may need an external funding mechanism to help overcome the market barriers identified above, especially in a growth phase of network evolution. For example, the market barrier associated with a limited initial user base may require an external funding mechanism to increase revenues while keeping user costs affordable, whilst the market barrier associated with uncertain revenues may require an external funding mechanism to provide some predictability to revenues.

Natural gas currently does not have an external funding mechanism. The business model is paid for through users of the natural gas networks. However, this may not be possible for supporting the development of a hydrogen network, as a new network will not have established economies of scale that can provide services at an affordable rate for users. An external funding mechanism, potentially through a levy or other kind of formalised cross-subsidy from other energy consumers as envisaged in the EU (see case study above) or via another means, such as directly through central government, may be needed to support the development of new pipelines, and a subsequent network.

Question 13

In your view, is an external funding mechanism needed in a growth phase of network evolution? If so, at what stage of market and network evolution might it no longer be required? Please explain your answer and provide any relevant evidence.

Question 14

In your view, if needed, what are your views on possible approaches to funding a potential external subsidy mechanism? Please explain your answer and provide any relevant evidence.

Other Hydrogen Transport Infrastructure

This consultation focuses on a business model for onshore pipelines transporting hydrogen as a gas. However, there are other means of transporting hydrogen. While these are not considered in detail in this consultation, we are keen to understand stakeholder thoughts on how this infrastructure may develop, whether any business model support is likely to be required, and whether and how this might impact on the business model design options considered here.

Other onshore pipelines

We expect the transport of hydrogen around the UK to be as a gas initially, as we expect this will be suitable for early hydrogen producers and consumers. However, there could be a role for onshore pipelines transporting hydrogen in other forms, such as through a hydrogen carrier like ammonia.

As the import and export market for hydrogen develops, we may begin to see the transport of hydrogen through a carrier into and out of the UK, as this might be more cost-efficient over very long distances, including internationally (due to the higher volumetric energy density of hydrogen carriers). Additionally, end-use sectors, such as maritime, may use hydrogen carriers, such as ammonia, as a direct fuel. As such, pipelines may develop to transport hydrogen carriers to and from ports or interconnectors.

However, these pipelines may be met with market barriers that deter investment and their development. These market barriers may be the same or different to the ones applicable to onshore pipelines transporting hydrogen as a gas. As such, a business model may be needed, and it may be possible to extend the business model designed for onshore pipelines transporting hydrogen as a gas for other onshore pipelines, depending on the chosen business model.

Question 15

In your view, how might other onshore hydrogen pipelines, including pipelines transporting hydrogen through a carrier, develop in the UK? Please explain your answer and provide any relevant evidence.

Question 16

In your view, is a business model required for the development of other onshore pipelines for hydrogen and, if so, how might a business model for onshore pipelines transporting hydrogen as a gas be adapted for this? Please explain your answer and set out the specific market barriers that a business model would be required to address as well as providing any relevant evidence.

Offshore pipelines

We anticipate that the future hydrogen economy may include the storage of hydrogen in suitable offshore reservoirs such as salt caverns and/or depleted oil or gas fields, with offshore pipelines connecting offshore storage facilities to an onshore hydrogen network. In addition, HMG's ambition to deliver up to 50GW of offshore wind by 2030, including up to 5GW of innovative floating wind, presents new opportunities for electrolytic hydrogen production projects to be co-located with new and/or existing offshore wind developments. These too will likely require pipelines connecting electrolytic production facilities with offshore storage and/or direct connections to a future onshore hydrogen network.

Given offshore pipelines are expected, and may even be needed around the same time as onshore pipelines (e.g. for demonstration projects), we want to seek stakeholder views on how offshore pipelines may develop and whether a business model may be needed.

There is uncertainty as to how offshore pipelines might develop. For instance, offshore hydrogen pipelines may simply remain individual pipelines connecting specific facilities (production or storage) to the onshore network. However, it may be more efficient, and reduce overall cost, for these pipelines to connect with each other in due course and develop into an offshore network rather than have separate pipelines for each facility, especially in marine areas with several hydrogen assets with similar routes to shore.

The potential development of an offshore network of hydrogen pipelines would need to be considered as part of any marine spatial prioritisation alongside other potential uses of the marine space. Other considerations, for example relating to wider environmental impacts, would also need to be taken into account.

These pipelines may be faced with market barriers that deter investment and their development. These market barriers may be the same or different to the ones applicable to onshore pipelines transporting hydrogen as a gas. As such, a business model may be needed, and it may be possible to extend the business model designed for onshore pipelines transporting hydrogen as a gas for offshore pipelines, depending on the chosen business model.

Alternatively, if these pipelines remain essentially point-to-point connections for specific facilities to the onshore network, then the appropriate business model may be that for the projects themselves (e.g. HBM, a hydrogen storage business model or something else). Using these support measures may be required initially, if a new business model is needed for offshore pipelines, before a new business model is operable, if required.

The **Offshore Transmission Owner (OFTO)** regime has been used to encourage investment in and development of offshore electricity transmission infrastructure. Through the OFTO, a revenue stream underpinned by the OFTO licence provides a stable revenue profile over the life of the asset for the owner and operator. Thus allowing parties, not connected with production, to own and operate this infrastructure. This creates an investment opportunity to encourage the development of offshore electricity transmission infrastructure. This approach has led to individual point to point offshore electricity transmission infrastructure for each offshore windfarm. However, in the context of increasingly ambitious targets for offshore wind, constructing individual point to point connections may not provide the most efficient approach and could become a major barrier to delivery given the considerable environmental and local impacts, particularly from the associated onshore infrastructure required to connect to the national transmission network. BEIS, Ofgem and the ESO are therefore implementing a range of reforms to ensure appropriate coordination of offshore transmission infrastructure.

Question 17

In your view, how might offshore hydrogen pipelines develop in the UK? Please explain your answer and provide any relevant evidence.

Question 18

In your view, is a business model required for the development of offshore hydrogen pipelines and, if so, how might a business model for onshore pipelines transporting hydrogen as a gas be adapted for this? Please explain your answer and set out the specific market barriers that a business model would be required to address as well as providing any relevant evidence.

Vehicular transport

As highlighted in the Hydrogen Strategy Roadmap, vehicular transport via road is likely to develop at the start of the hydrogen economy. This vehicular transport could move hydrogen as a gas, a liquid or through a carrier. Even with the development of onshore pipelines, vehicular transport is likely to play a role in the growth of the hydrogen economy in the 2020s and beyond.

Vehicular transport will be needed for those producers and consumers not yet connected by a pipeline. This may decrease as pipelines and networks develop. Additionally, this may be more prevalent for early electrolytic hydrogen production not based in the industrial clusters. Further, vehicular transport may be needed to deliver hydrogen for use in transport end-use sectors, as these may require higher purity hydrogen.

Even in a mature hydrogen market, vehicle transport is likely to play a role in the transport of hydrogen, especially as, like the natural gas network today, a future hydrogen network is unlikely to be able to cater to all consumers. As the hydrogen economy grows, we may even see a situation similar to how liquid fuel is transported across the UK today with third parties, independent of producers and consumers, providing this service.

Vehicular transport by road is likely to be favoured initially to transport hydrogen. However, this may extend to rail for UK wide distribution. We are also likely to see the need for vehicular transport via sea for the international trade of hydrogen. Transport by sea is more likely to be through a hydrogen carrier, as this may prove more cost-efficient over long distances due to the higher energy density of carriers, for example ammonia.

However, vehicular transport may be met with market barriers that deter investment and development. These market barriers may be the same or different to the ones applicable to onshore pipelines transporting hydrogen as a gas. As such, a business model may be needed, and it may be possible to extend the business model designed for onshore pipelines transporting hydrogen as a gas for vehicular transport, depending on the chosen business model.

Question 19

In your view, how might vehicular transport for hydrogen develop in the UK? Please do include any other vehicular transport we may have missed. Please explain your answer and provide any relevant evidence.

Question 20

In your view, is a business model required for vehicular transport and, if so, how might a business model for onshore pipelines transporting hydrogen as a gas be adapted for this? Please explain your answer and set out the specific market barriers that a business model would be required to address as well as providing any relevant evidence.

Chapter 4: Hydrogen Storage Infrastructure

Background

In this chapter we consider the role that hydrogen storage can play both within the hydrogen economy and more widely by providing flexibility across the whole energy system. This role encompasses the balancing of low carbon hydrogen production and demand, as well as the provision of a store for surplus energy, potentially supporting dispatchable power generation.

Government committed to undertake a review of systemic hydrogen transport and storage requirements in the 2020s and beyond, including the need for funding and economic regulation. An update on the review was provided in the government's response to its consultation on a business model for low carbon hydrogen, in which it announced that some initial support would be made available for transport and storage infrastructure[32] through the hydrogen business model (subject to taking a number of factors into account, including necessity, affordability and value for money) in the absence of dedicated business models for transport and/or storage.

In this chapter, we consider the types of storage infrastructure that might be deployed and how it is expected to emerge, before considering some of the market barriers that are likely to inhibit private investment. We note that whilst the Net Zero Hydrogen Fund (NZHF) and Hydrogen (production) Business Model (HBM) may be able to offer some early investment support, they are unlikely to be sufficient to bring forward investment in the kind of larger-scale storage that we expect will be required in the late 2020s and beyond.

We conclude by considering a number of high-level options for a dedicated storage business model, something which the government committed to designing by 2025 in its British Energy Security Strategy (BESS). By addressing market barriers, a business model would seek to stimulate private investment in hydrogen storage infrastructure and bring about its timely deployment.

Misalignment of Hydrogen Production and Demand

The 2021 Hydrogen Strategy recognised that as the hydrogen economy develops, there will be times when the supply of low carbon hydrogen will not align with demand from offtakers. This will result in periods where there is either a surplus or scarcity of low carbon hydrogen produced, increasing security of supply risks. It noted that a misalignment could occur across a range of timescales, ranging from intra-day to inter-seasonal, and that this could prove problematic for both producers and offtakers of low carbon hydrogen.

[32] Design of a business model for low carbon hydrogen (2021): https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

A misalignment in production and demand is expected to occur for a number of reasons including:

- CCUS-enabled hydrogen production is expected to maintain a largely flat profile, since varying its rate will negatively impact production efficiency. This flat profile is unlikely to always align with the demand profile which can be expected to vary.
- Electrolytic hydrogen production is expected to be intermittent because it will predominantly be powered by electricity from intermittent sources (wind, solar etc).[33] This intermittent production profile is unlikely to wholly align with demand.
- Hydrogen demand may not be particularly responsive to an over- or under-supply of low carbon hydrogen, because offtakers may be unable, or unwilling, to react. An over-supply might occur, for example, when there are favourable conditions for electrolytic production, and/or when there is a fall in demand, both expected and unexpected. An under-supply might occur as a result of planned or unplanned outages in production, or when there is an increase in demand for hydrogen.

Benefits of Hydrogen Storage

Balancing misalignment in hydrogen production and demand

The Hydrogen Strategy identified storage infrastructure as an important option for addressing future imbalances in hydrogen production and demand, providing a temporary sink for excess hydrogen production during periods of low demand, and an additional source of hydrogen during periods of peak demand and/or low production. It envisaged storage as being a key part of future network infrastructure, providing security of supply to offtakers and security of demand to producers as production and use increase, and become more spread out, over time and distance. This contrasts with the natural gas system where an increasing diversity of supply sources over the past 20 years or so - UK Continental Shelf, Norwegian Continental Shelf, onshore production, interconnectors and LNG imports - has led to a fall in demand for storage.

Supporting decarbonisation of the electricity system

Hydrogen storage has the potential to play an important additional role in a future energy system where renewable generation – wind and solar power in particular – play an increasingly dominant role.[34] Within this scenario, excess renewable generation that might otherwise be curtailed during periods of high generation and low demand, or due to localised network

[33] In order for electrolytic hydrogen to receive Hydrogen Business Model (HBM) support it must meet the technical requirements of the UK Low Carbon Hydrogen Standard (LCHS), including that the electrolyser must be powered by electricity from low carbon sources. Further information on the HBM is available at the following URL (2021): https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen. Further information on the LCHS is available at the following URL (2021): https://www.gov.uk/government/consultations/designing-a-uk-low-carbon-hydrogen-standard

[34] The Government's British Energy Security Strategy (BESS), for example, includes an ambition for up to 50GW of offshore wind capacity by 2030 and an expectation of up to 70GW of solar capacity by 2035 (2022): https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy

constraints, would instead be used to power electrolytic hydrogen production ('Power to Gas'), which would be coupled with hydrogen storage. Similarly, when electricity prices are higher, electrolytic hydrogen producers would be incentivised through power markets to turn down production, and thereby provide power system flexibility through 'demand side response'. This would reduce demand on the power system and hence the need for additional generation to be turned on.

The stored hydrogen would subsequently be put to a variety of uses across the hydrogen economy, either locally or further afield, as and when required. These uses could include flexible power generation through rapid operating hydrogen fuelled 'peaker' plants through to larger-scale combined cycle gas turbines (CCGTs). These could provide a flexible source of low-carbon electricity when the wind is not blowing and the sun is not shining, or when demand, and therefore electricity prices, is particularly high. The availability of large-scale hydrogen storage is critical to enabling hydrogen fuelled power generation to operate flexibly, and so provide low carbon capacity to complement intermittent renewable generation.

By providing low-carbon hydrogen for power generation, hydrogen storage has the potential to displace and replace higher-carbon alternatives and therefore contribute to the delivery of the government's commitment for a fully decarbonised power sector by 2035 (subject to security of supply). Government analysis shows that having hydrogen available in the power sector could achieve lower emissions at a lower cost than under corresponding scenarios without hydrogen.[35]

Reducing hydrogen production capacity requirements

Hydrogen storage will enable hydrogen production facilities to optimise their output, meaning they can produce hydrogen when it is most cost effective to do so, even if this does not align with demand. This could reduce overall hydrogen production capacity requirements needed to maintain security of supply.

The Development of Storage Infrastructure

Types of storage

There are a number of approaches that could be adopted for the storage of hydrogen at scale and which could potentially benefit from business model support. These include:

- **Depleted gas or oil fields:** Underground sites of former oil and gas exploitation. Potentially suited to the storage of large volumes of compressed hydrogen, although at an earlier stage of technology readiness compared with salt and rock caverns. Geographically constrained because specific geological formations are required which are not widespread.

[35] Modelling 2050 – Electricity System Analysis (2020): https://www.gov.uk/government/publications/modelling-2050-electricity-system-analysis

- **Salt caverns:** Underground solution-mined cavities created in salt-strata. Potentially suited to the storage of large volumes of compressed hydrogen. Geographically constrained because specific geological formations required which are not widespread.
- **Rock caverns:** Underground caverns which have been lined to make them impervious to hydrogen and which are suited to the storage of large volumes of compressed hydrogen.
- **Aquifers:** Underground porous rock that holds water and which is potentially suited to the storage of large volumes of compressed hydrogen. Geographically constrained because requires specific geological formations which are not widespread.
- **Containerised compressed hydrogen:** Fabricated containers, either stationary or mobile. Potentially suited to the storage of relatively small volumes of compressed hydrogen.
- **Containerised liquified hydrogen:** Fabricated containers, either stationary or mobile. Potentially suited to the storage of relatively small volumes of cryogenic liquid hydrogen, i.e. at temperatures below -253^{o}C.
- **Hydrogen carriers:** Typically ammonia (NH3) but also other liquid organic hydrogen carriers (LOHCs) that are capable of storing hydrogen as a component of another chemical compound but at a higher energy density than compressed molecular hydrogen. Chemical processes are required to put hydrogen into, and out of, hydrogen carriers. Ammonia is an established hydrogen carrier that may be particularly suited to the long-distance transportation of hydrogen or as a fuel in the maritime sector, whilst LOHCs are emerging at scale.
- **Metal hydrides:** Solid metal powders which enable hydrogen to be adsorbed into the crystalline structure to form stable metal hydrides. Hydrogen is typically stored at an energy density that exceeds that of liquid hydrogen. A technology that is emerging at scale.

The above list is unlikely to be exhaustive. These technologies are at different levels of technological maturity and government recognises that novel approaches to hydrogen storage could emerge as the market develops. Government's initial view is that the underground approaches, which are generally larger, less expensive per unit of hydrogen stored and have longer development lead times than the above-ground approaches, could be more likely recipients of a storage business model. However, above-ground approaches could be further developed, or configured, to the extent that they might become competitive with the underground approaches. Therefore, government is currently open minded as to which approaches might be supported by a business model.

It is worth noting that 'line-pack' flex (i.e. increasing within-pipe gas pressures to accommodate more hydrogen) has not been included in the list of potential approaches to hydrogen storage. Whilst we recognise that line-pack flex plays an important balancing role in the natural gas system, we also note that there is less scope for managing hydrogen imbalances in the same way given its much lower energy density.

Question 21

What do you consider to be the key technical barriers associated with the development of particular approaches to storing hydrogen which should be considered? Please explain your answer and provide any relevant evidence.

Anticipated emergence of storage infrastructure

In the BESS, the government announced an extended ambition for up to 10GW of low-carbon hydrogen production capacity by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen. This built on its earlier ambition, set out in the 2021 Hydrogen Strategy, for 5GW of production capacity by 2030.

The Hydrogen Strategy envisaged that together with transportation infrastructure, hydrogen storage infrastructure would be a key part of the future network infrastructure needed to help deliver this ambition. It envisaged that in the early 2020s, storage vessels (e.g. pressurised containers) would likely be the most common storage option, deployed for example at hydrogen refuelling stations coupled to electrolytic hydrogen production. Unlike underground storage facilities (salt caverns, depleted gas fields, etc.), storage vessels can be deployed relatively quickly and at relatively low cost (per vessel) and are not constrained by the availability of suitable geology, a major limiting factor for underground storage. It is anticipated that where early storage needs are limited to above ground storage vessels connected to specific production and use, projects could potentially receive sufficient support from the Renewable Transport Fuel Obligation (RTFO)[36] or the Hydrogen Business Model (HBM) to meet associated storage costs.

In the mid-2020s, the strategy envisaged that CCUS-enabled production for industrial fuel switching would likely be designed to minimise misalignment between production and industrial consumption, i.e. they would both have flat profiles. It noted that the proposed CCUS-cluster projects identified larger-scale underground storage as secondary phase needs. By the late 2020s, however, it envisaged that underground storage facilities could start to become important to the functioning of the hydrogen economy as a town pilot of hydrogen heating (subject to a strategic decision on the use of hydrogen in heating in 2026) and hydrogen-fuelled power generation could increase the need for larger-scale storage. As noted above, the distribution of underground storage will be constrained by the availability of suitable geology.

The government’s ambition for up to 10GW low-carbon hydrogen production capacity by 2030 subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen, seems likely to increase the need for hydrogen storage capacity in the late 2020s and beyond in order to manage likely increased imbalances in production and demand.

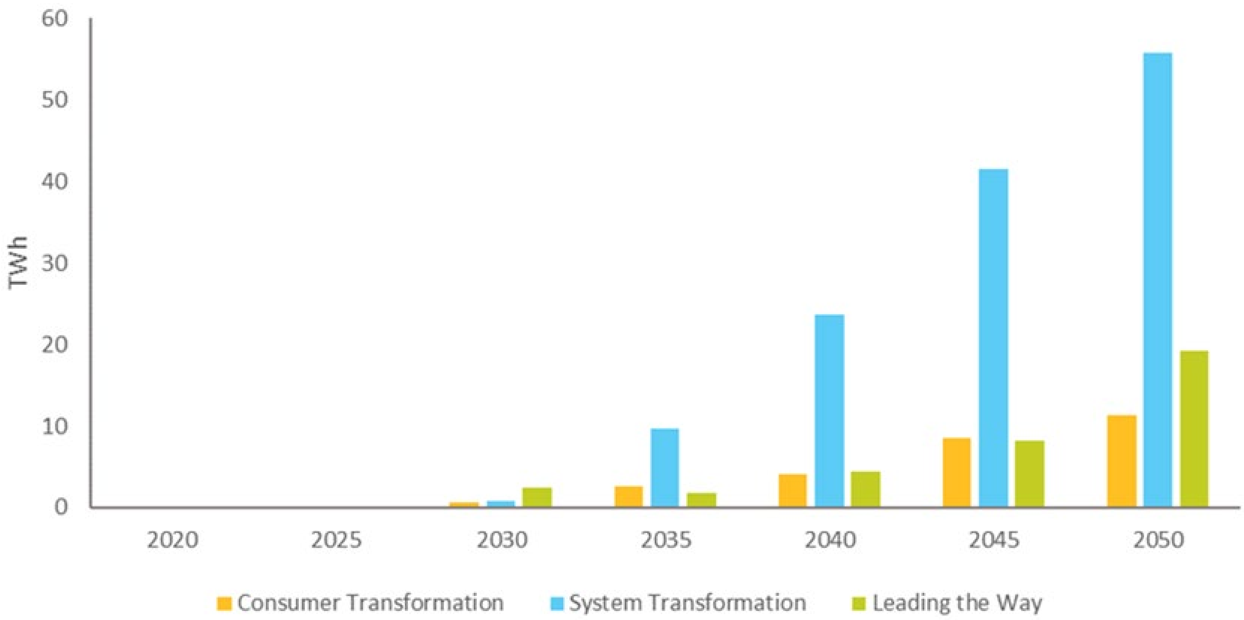
[36] The Renewable Transport Fuel Obligation (RTFO) is a government scheme which stimulates the supply of eligible transport fuels through a system of tradable Renewable Transport Fuel Certificates (RTFCs).

Uncertainty in demand for storage capacity

The Hydrogen Strategy also recognised the challenges in accurately forecasting the transport and storage infrastructure needs of the emerging hydrogen economy. These challenges reflect uncertainty across a range of influencing factors, such as how and where growth of the hydrogen economy might take place, the characteristics of hydrogen production and demand and whether the "end state" will be a national network or a number of discrete regional networks. Questions also remain about the prevalence of hydrogen blending (into the existing gas networks) and the extent of the role that hydrogen might play in heating.

These uncertainties are reflected elsewhere. For example, in their 2022 "Future Energy Scenarios" report, National Grid ESO suggest that up to 2TWh of salt cavern storage could be required by 2030, and that somewhere between 11 and 56TWh of storage could be required by 2050 (Figure 2).[37]

Figure 2: Hydrogen Storage requirements - Future Energy Scenarios 2022, National Grid ESO



Challenges to the roll-out of strategic storage infrastructure

The Hydrogen Strategy also recognised that in order to develop larger-scale hydrogen storage, particularly as a strategic asset (i.e. one that provides benefits to multiple users, as opposed to just a single producer/offtaker combination), a number of significant challenges would need to be overcome. These challenges include:

[37] National Grid ESO - Future Energy Scenarios (2022): https://www.nationalgrideso.com/document/263951/download

- understanding the optimum pace and mix of storage technologies – ensuring that the growing demand for hydrogen storage can be met with appropriate storage infrastructure both when it is needed and where it is needed;
- the lengthy lead times (up to ten years) and complexity of strategic scale storage such as salt caverns and depleted oil and gas fields;
- the need for significant levels of investment (potentially hundreds of millions of pounds of up-front development costs).[38]

These challenges could impact investment decisions in storage infrastructure which, in turn, could impact the growth of the hydrogen economy. Without overcoming these challenges, storage infrastructure investment decisions may be delayed and critical storage infrastructure may not be available when needed in the late 2020s, potentially impacting the government's hydrogen and wider net zero ambitions.

Supporting Investment in Storage Infrastructure

Market barriers

Government has been acting on its hydrogen strategy commitment to undertake a review of transport and storage infrastructure requirements. Whilst this review is ongoing (this consultation forms part of that review) it has already identified that some storage projects have made considerable progress, having undertaken feasibility and FEED studies, as well as making progress towards securing planning permission. These projects are targeting commercial operation in the late 2020s.

In order for development investment to be taken and ultimately final investment decisions (FIDs) to move into construction to be made, developers will first need to secure investment, either from their own balance sheet or third-party investment, in order to fund their projects. However, and as detailed in the analytical annex to this consultation, we consider that a number of significant market barriers exist. The main barriers are set out below.

- **Demand uncertainty.** Whilst there is growing consensus that hydrogen storage infrastructure will play a key role as the hydrogen economy emerges in the 2020s and beyond, uncertainty remains around the capacity and type of storage infrastructure that will be required, as well as where it should be located. These are reflective of ongoing uncertainties about how and where the hydrogen economy will grow, as well as likely patterns of hydrogen production and demand. Collectively, these uncertainties will contribute to volume risk, i.e. the risk that the supply of storage volume, either locally or nationally, will exceed the demand for storage. This could result in storage providers

[38] Figure 21 of the BEIS commissioned report entitled "Supply Chains to Support a Hydrogen Economy" (2022) estimates that the cost of developing salt caverns to meet the 2030 storage capacity requirements given in National Grid's FES scenarios is between £1.2bn and £2.3bn: https://www.gov.uk/government/publications/supply-chains-to-support-a-uk-hydrogen-economy

being unable to recover sufficient revenues through the sale of storage capacity to cover their costs. This volume risk is likely to negatively impact investor confidence.

- **High costs.** The cost of developing larger-scale storage infrastructure is likely to be on the order of hundreds of millions of pounds (or more) per storage facility. This need not be a barrier on its own, but when combined with lengthy lead times and revenue uncertainty (which arises from demand uncertainty) it could make investment on such scales especially risky, impacting investor confidence. Additionally, underground storage facilities require large volumes of “cushion gas” to be injected (to bring facilities up to working pressure) before they can become operational, the costs of which represent a significant portion of overall development costs. Whilst this cushion gas can be retrieved and sold when the facility is decommissioned, this is potentially decades later and there is no certainty what the market value will be that far into the future.
- **Policy and regulatory uncertainty.** There is currently an absence of a clear and consistent long-term policy for hydrogen storage. In addition, while demand uncertainty exists (for example, the role of hydrogen in heating is unclear), storage requirements such as how much is needed, what type is needed and where is it needed, will also remain unclear. The extent (if any) to which the revenue recovery of hydrogen storage facilities will be regulated is unclear. For natural gas, storage facilities operate on a merchant basis and revenue recovery is unregulated. Initial feedback from stakeholder engagement suggests that this arrangement may not be appropriate for hydrogen storage, given the important enabling roles that it is expected to play coupled with demand uncertainty and the associated risk of revenue shortfalls. We therefore seek views through this consultation on a business model for supporting the development of hydrogen storage infrastructure. Whilst revenue uncertainty remains, it may prove difficult for developers to create a business case for, and attract investment in, potential storage projects.
- **Commercial uncertainties.** There is currently little certainty surrounding the industry commercial arrangements which might apply to hydrogen storage, with this consultation being government’s first formal stakeholder engagement on the matter. For example, it is not clear who might own and operate hydrogen storage infrastructure, who might use hydrogen storage infrastructure and what governance arrangements on matters such as access and pricing might best serve the interests of both storage providers and users. As noted above, natural gas storage exists as a merchant activity, meaning that storage providers are fully exposed to all market risks (as well as opportunities). However the natural gas economy is a liquid economy that has been established for a number of years. Consequently, storage providers are aware of, and therefore able to take a view on, the risks and opportunities that storage presents. In any case, if natural gas storage infrastructure fails commercially, it is unlikely to threaten the viability of the natural gas system. It is not clear whether the same could be said for hydrogen storage infrastructure which is expected to be a key part of future network infrastructure and play multiple important roles.

Progress to date and remaining challenges

The market barriers outlined above may deter investment in hydrogen storage infrastructure and a number of policy and commercial interventions could be required to overcome these barriers. Progress has already been made in some areas. For example, government has progressed the HBM to support low-carbon hydrogen production and has opened up deployment pathways for CCUS-enabled hydrogen (via the CCUS cluster sequencing programme) and for electrolytic hydrogen (via the joint HBM and NZHF allocation round). Furthermore, and as set out in the General Considerations chapter, there is now scope for some initial support to be provided for small scale storage infrastructure through the HBM and NZHF, adding to potential indirect support provided through the RTFO. In the power sector, hydrogen produced from electrolysis, stored and then used in the power sector (hydrogen storage operating as large-scale, long-duration electricity storage) could be considered in scope for an appropriate policy to enable investment in large-scale, long-duration electricity storage technologies committed to in the BESS.[39]

Nevertheless, it is apparent from our initial engagement with stakeholders that the scale and scope of support provided through the routes set out above is unlikely to be sufficient to bring forward the kind of larger-scale storage infrastructure that government expects will be required in the late 2020s and beyond. Many stakeholders remain of the view that there is a need for a business model which is aimed at supporting larger-scale storage infrastructure and which addresses demand uncertainty (and by implication revenue uncertainty). While this uncertainty, in combination with the others highlighted earlier, persists, prospective developers of storage facilities and their investors have indicated that they will be very unlikely to take FIDs on their storage projects.

On the remaining market barriers, our initial engagement indicates that stakeholders are less concerned about regulatory and commercial uncertainties at this point in time, and that their main focus is demand uncertainty, exacerbated by high costs. Therefore, whilst government seeks the views of stakeholders on market and regulatory matters in the Regulatory Framework chapter of this consultation (and notes that some of the more interventionist high-level business model design options that are set out below would also provide greater certainty surrounding aspects of the regulatory framework and industry commercial arrangements), we consider that the focus of a business model should be primarily to address volume risk that stems from demand uncertainty.

Question 22

In your view, have we correctly identified and characterised the key market barriers facing larger-scale hydrogen storage infrastructure, and in particular its deployment by the late 2020s? Please explain your answer and provide any relevant evidence.

[39] Facilitating the deployment of large-scale and long-duration electricity storage: call for evidence (2021): https://www.gov.uk/government/consultations/facilitating-the-deployment-of-large-scale-and-long-duration-electricity-storage-call-for-evidence

Question 23

Do you agree that volume and revenue risk stemming from demand uncertainty represents the main barrier to the deployment of storage infrastructure? Please explain your answer and provide any relevant evidence.

A business model to address volume and revenue risk

We have given consideration to how best to provide business model support to overcome the market barrier of demand uncertainty. Two main approaches have been identified:

- Provide business model support to owners, or prospective owners, of hydrogen storage facilities;
- Provide business model support to users of hydrogen storage facilities.

A storage user will be those parties who will utilise the capacity within storage facilities to store hydrogen for a period of time, providing revenue to the storage owner. They will arrange with the owner for hydrogen to be conveyed into and out of the facility as required. Subject to regulatory requirements, users could potentially be:

- The owners of storage facilities (hydrogen storage might support other business activities they are involved in); and/or
- Other market participants, for example hydrogen producers, hydrogen offtakers and hydrogen shippers/intermediaries.

It is expected that other market participants would be charged storage fees by the owners of storage facilities. The potential value of any benefits or revenues received will be relevant to the question of how much additional support a business model might need to provide.

On the question of how best to provide business model support, our initial view is that providing support to users of storage facilities would be unlikely to achieve the desired outcome since it would not fully address the volume risk which is faced by storage providers. This is because even if future users of storage were offered support to cover potential storage costs, there would be no certainty that these users would either materialise or use hydrogen storage infrastructure in sufficient quantities. Volume risk would therefore remain, and developers and their investors might not receive sufficient certainty on returns in order to make investment decisions in the nearer term. Consequently, it is our initial view that business model support should be given to owners or prospective owners of storage facilities. Nevertheless, and for balance, we provide one example of a business model that would be targeted at end users in the business model design options section of this chapter.

Whilst revenue generated by a storage provider is expected to come from storage users, it is likely that specific subsidy payments, delivered via a storage business model would be needed. These subsidies could be funded by levy funding (similar to the government's proposals for hydrogen production) and/or government funding or other possible options. We would expect the level of any subsidy provided through a business model to fall over time as the hydrogen economy grows and the revenue or benefit generated by storage users increases.

Question 24

Do you agree that government should develop a dedicated business model for hydrogen storage (subject to value for money and need) and that it should be designed to be technology-neutral? Please explain your answer and provide any relevant evidence.

Question 25

Do you agree that business model support should focus on larger-scale storage, or is there a need to provide further support for small scale storage? Please explain your answer and provide any relevant evidence.

Question 26

In your view, who are likely to be users of hydrogen storage infrastructure and which group, or groups, might be best placed to provide revenue to storage owners? Please explain your answer and provide any relevant evidence.

Question 27

Do you agree with our initial view that a storage infrastructure business model should support providers of hydrogen storage infrastructure (as opposed to users of storage infrastructure)? Please explain your answer and provide any relevant evidence.

Question 28

What are your views on possible approaches to funding a potential subsidy mechanism? Please explain your answer and provide any relevant evidence.

Business model design – stakeholder needs

A hydrogen storage infrastructure business model will need to balance the needs of storage owners and their investors, storage users and government. Government has identified the primary needs of these parties as follows.

Storage owners and their investors

- Confidence that proposed storage facilities will generate sufficient revenue that FIDs can be taken.

Storage users

- Sufficient visibility and predictability over the long-term availability and costs of hydrogen storage capacity to give confidence to participate in the hydrogen economy (e.g. activities that result in hydrogen production and consumption).

Government

- To achieve the strategic objectives set out in Hydrogen Strategy and updated ambition in BESS for up to 10GW low carbon hydrogen production capacity by 2030 (subject to affordability and value for money), as well as wider net zero targets, at lowest possible costs;
- To be comfortable that the correct projects are being supported since the business model may involve subsidies being paid to storage providers, and these subsidies will need to be funded;
- To keep any subsidy to a minimum to reduce distortions created by government intervening in the market, and for the right duration necessary to trigger investment and establish a self-sustaining market and an exit route for subsidy support;
- Where relevant, to ensure all subsidy control requirements have been met and be comfortable with any balance sheet implications and;
- To ensure security of supply is maintained at an acceptable level.

Question 29

In your view, have we correctly identified the main parties whose needs any storage business model will need to account for, and have their needs been correctly outlined? If not, what additional needs should be accounted for? Please explain your answer and provide any relevant evidence.

High Level Business Model Design Options for Hydrogen Storage

The analytical annex to this consultation sets out a design framework for the development of business models and identifies categories of business model to overcome volume and revenue risk. In the following sections we categorise, at a high level, a number of business model design options, and consider how they might support the development of hydrogen storage infrastructure.

As noted previously, storage infrastructure may be available in a diverse range of sizes and types and could play a variety of roles. Furthermore, developers and their investors are likely to have differing appetites for risk. Consequently, it is possible that one particular model may not be suited to all circumstances, and indeed, none of the models, as presented, may prove suitable. The business model designs set out below list potential options and some of the risks they address. Government is keen to hear the views of stakeholders on these options.

Most of the business models would require the involvement of additional participants in order to be implemented. For example, those that fall under the “regulated returns” category would require an economic regulator. Those that fall under the “contractual payments” category may require a counterparty to collect any relevant levies, make subsidy payments to storage providers, and to manage any compliance issues arising. Those that fall under the remaining categories would require, to a greater or lesser extent, administration activities to be undertaken, including compliance and enforcement action. Government is keen to hear the views of stakeholders on which parties are best placed to fulfil these roles.

Counterfactual

No business model (hydrogen storage operates on a merchant basis)

Under this arrangement, the storage provider would make storage capacity available to the market at risk, and FIDs would be taken on this basis. Revenues would be highly uncertain for the reasons set out earlier and this could act as a deterrent to investors. However, storage providers would also be able to take advantage of volume opportunities if demand for hydrogen storage turned out to be greater than expected, including the possibility of charging a higher price to users.

Regulated returns

Regulated Asset Base (RAB) with allowed revenue

Under this regulated arrangement, the storage provider would agree an allowed revenue (AR) with a regulator ahead of a price control period. The AR would be an amount that the provider could recover across a specified period – say a year – and would be reflective of the costs incurred by the owner in operating the storage facility and servicing its debt, as well as incorporating a reasonable level of profit. The AR would be conditional on operational performance targets being met.

The storage provider would be allowed to recover an amount up to the level of the AR, and storage users would be charged in accordance with an agreed charging methodology. However, given the likelihood of there being a relatively small user base in relation to the AR, it may be necessary for revenues to be subsidised through an external funding mechanism, especially whilst the hydrogen economy is in its infancy. This would enable storage costs to remain non-prohibitive to initial users. Commercial arrangements would likely be drawn up in a code to provide the basis for access and charging arrangements.

Under the RAB arrangement, volume risk would be wholly transferred from the storage provider to whoever is required to fund any subsidy. The rate of return on investment, provided to the storage provider through the AR, should therefore be reflective of this risk transfer.

The removal of volume risk would also remove volume opportunity, and with it any incentive for storage providers to maximise usage of the storage facility – this may not be a good outcome for whoever was required to fund any subsidy. It might therefore be necessary to incentivise volume usage through performance targets.

Revenue cap and floor

Under this regulated arrangement, the storage provider would agree a revenue cap and floor with a regulator which would apply to a specified period. During each period, the storage provider would seek to recover revenues from storage users in accordance with an agreed charging methodology, and would be incentivised to recover up to the level of the cap.

The floor would be the minimum amount of revenue that the storage provider could recover. Typically it would represent the amount needed to cover the provider's operating expenditure and the servicing of debt. If the floor was not reached, revenue would be 'topped up' to the floor level through subsidy. This arrangement would be conditional on operational performance targets being met.

The cap would be the maximum amount of revenue that a storage provider would be allowed to recover. If the cap was exceeded, excess revenue would be transferred to whoever was being expected to subsidise the floor revenue if it were not reached. In other words, it provides them with a reward in return for their exposure to under-recovery risk.

Under the cap and floor arrangement, whilst most of the volume risk would be transferred to the party underwriting the revenue floor, some would typically be retained by the storage provider. However, this residual risk would be traded-up for a band of merchant opportunity between the floor and the cap, giving storage providers an incentive to increase usage of their facilities. The cap would ensure that storage provider revenues are not excessive (given the protection they are offered by the floor) and can be set at an appropriate level.

Variations of the cap and floor arrangement are possible including, for example, the opportunity for revenues received in excess of the cap to be shared. This would incentivise storage providers to maximise asset use and might also be of benefit to whoever was required to fund any subsidy.

Contractual payments

Contracts for difference

Ordinarily, a contracts for difference (CfD) arrangement is adopted to address price risk through a variable premium which is paid to (or by) an asset owner to top-up (or reduce) regular sales receipts for a commodity. The strike price is the price that the asset owner is prepared to accept in order to operate the asset, and the premium is paid/received by a counterparty, usually via a private law contract. For example, for the government's low-carbon electricity CfD scheme, the counterparty is the Low Carbon Contracts Company (LCCC). The LCCC recovers scheme costs through a levy placed on electricity suppliers.

The CfD arrangement is primarily aimed at addressing price risk, i.e. the risk associated with the market barrier of high cost, where users are unable or unwilling (if there is a cheaper competitor) to pay the full cost of the good or service, but would utilise it if it were available at a price which they could afford, or if it were available at a competitive price.

If a CfD arrangement were to be adopted as a means of supporting hydrogen storage, it would need to be adapted to address volume risk, the key barrier we have identified. This could be achieved through the adoption of a variable strike price, as is the case for the HBM. Under this arrangement, a higher strike price would be provided for initial storage volumes, and the strike price would then tail-off for subsequent volumes. Some volume risk would still remain (for both storage provider and whoever was required to fund the scheme) so the CfD arrangement could be ‘wrapped’ in a cap and floor type mechanism to protect against this risk.

Government offtake frontstop

Under this arrangement, government would agree to reserve a certain volume of storage capacity for a certain number of years. The storage provider would prioritise the resale of this capacity, but in the event that it remained unsold, government would be the offtaker of last resort, guaranteeing payment to the storage provider for an agreed level of storage capacity being provided.

The volume of the capacity that government would be liable for would be equal to that considered necessary and proportionate to de-risk investment to the extent that FID could be taken by the developer. Since the guarantee of a set amount storage capacity by government would represent a firm revenue commitment (as opposed to just a forecast), the storage provider would be able to raise finance on more favourable terms which would lower overall project costs, potentially resulting in lower storage costs for users.

Capacity availability

Under this arrangement, payments would be made to storage providers for providing storage capacity when and where it is required. Payments could be targeted at specified volumes of capacity at specified times. They could also relate to specific types of storage, including how fast it can cycle. It is conceivable that requirements for tranches of capacity could be tendered, introducing an element of competition into proceedings. A capacity availability type arrangement would give revenue certainty to storage providers, but alone may not encourage usage unless combined with a usage top-up payment.

Obligations

Compulsory stock obligation

Under this arrangement, market participants would be obliged to hold a certain volume of hydrogen in store by means of a Compulsory Stock Obligation (CSO). A CSO could be delivered either physically (a requirement to physically hold certain volumes of hydrogen in storage) or on a paper basis (a requirement to ensure that someone else is holding volumes).

The scope of a CSO could be limited to market participants above a certain size/market share threshold to lessen the impact on smaller participants who might find the cost a barrier to entry or operation. The CSO would address volume risk by ensuring that a certain amount of storage capacity was utilised (and therefore purchased) at all times.

For oil, the International Energy Agency already mandates a CSO as a security of supply measure for its member countries. For natural gas, there is no such arrangement in GB which reflects a diversity of supply sources. Within the EU, where there is a much greater dependency on natural gas imports, eight out 18 (44%) member states who have underground storage place a storage obligation on market participants.[40]

From an implementation perspective, and in the absence of a mature pipeline system, a physical obligation may be difficult to achieve unless there are widespread and accessible storage facilities. Even a paper obligation may be challenging in a nascent economy since it would likely require a small number of participants to store significant volumes of hydrogen, and obligated parties would be exposed to both commodity and storage capacity costs. Furthermore, the scale of any CSO might need to be significant in order that storage providers receive the level of revenue they require to be commercially viable. Consequently, and in order to be viable, a CSO might need to be paired with an additional intervention whilst the market is immature, e.g. some kind of subsidy mechanism. As the hydrogen economy grows, a CSO could potentially support storage by itself.

End user subsidies

End user subsidy

Under this arrangement, market participants would be paid for storing volumes of hydrogen in excess of a minimum threshold. This could be administered as either a rebate against storage costs or something akin to an interest payment for "depositing" hydrogen. Alternatively, there could be a payment-in-kind (PIK) style arrangement where either a portion of the volumes put into storage are paid-in-kind to government in exchange for subsidy, or where contributing towards cushion gas gives the end user transferrable rights to working gas capacity. The PIK type options are fairly commonplace in the market already. For example, the US Strategic Petroleum Reserve works on the former principle, whereas the latter was used to attract cushion gas to the Bergemeer gas store in the Netherlands.

Other

Co-investment by government

Under this arrangement, government would choose to co-invest in selected hydrogen storage facilities which it considered to be of strategic importance, potentially on a low- or zero-return capital investment basis. This would represent an endorsement of such facilities, potentially leveraging additional private sector capital on the basis that government would have "picked a winner". In aggregate this would lower the amount of revenue that the facility would need to earn in order to cover its costs which may put downwards pressure on storage fees or reduce the amount of storage capacity that would need to be sold in order for the facility to break even.

[40] ACER Report on Gas Storage Regulation and Indicators (2022): https://extranet.acer.europa.eu/official_documents/acts_of_the_agency/publication/acer%20report%20on%20gas%20storage%20regulation%20and%20indicators.pdf

Long term financing arrangements for cushion gas (underground gas storage facilities only)

Underground gas storage facilities require significant volumes of “cushion gas” which act to maintain sufficiently high working pressures. Ordinarily, the cushion gas is the same gas as the working gas – for example, a hydrogen storage facility would use hydrogen cushion gas. This means a significant volume of gas is essentially “locked-up” until such time as the facility is decommissioned. Cushion gas represents a significant proportion of the capital costs of underground gas storage projects, and whilst it can eventually be recovered and sold, this may be decades later, during which time wholesale prices may have fallen significantly. This makes it an unattractive investment proposition.

A long-term financing arrangement supported by an external funding mechanism would enable storage developers to finance the purchase and/or lease of cushion gas on terms that may not be available from the market – for example, either by underwriting the price risk of the cushion gas over the expected life of the facility, or simply by providing a low cost of financing that would in turn reduce the level of cost recovery required by the storage provider from its customers.

Concluding remarks on business model design options

The options listed above are high-level examples of business models. There are additional possibilities which could be a hybrid of these examples, and there are many additional features that could be incorporated into business models. For example, policies with the aim of driving market development and use of storage infrastructure could be incorporated into the business model or delivered alongside a business model. The business model would be designed to overcome the key risks to enable investment whilst additional policies could drive efficiency and value for money by encouraging more use of the infrastructure.

Question 30

In your view, have we set out the main business model design options, or are there others design options, or variants, that should be considered? Please explain your answer and provide any relevant evidence.

Question 31

In your view, are any of the business model design options set out above more suited to supporting particular types of storage infrastructure than others? Please explain your answer and provide any relevant evidence.

Question 32

In your view, which business model design options would be most suitable to address the identified market barriers? Please explain your answer and provide any relevant evidence.

Question 33

In your view, which organisations are best placed to carry out the roles of economic regulator/counterparty/administrator that would be required to implement the business models set out above? Are there any other roles that you consider may be required? Please explain your answer and provide any relevant evidence.

Question 34

In your view, are there any early interim measures that we should be exploring to support the development of the first hydrogen storage projects, ahead of a hydrogen storage business model being available? Please explain your answer and provide any relevant evidence.

Chapter 5: Strategic Planning

Background

The UK Hydrogen Strategy envisages that hydrogen transport and hydrogen storage infrastructure will play a key part in the future of the hydrogen economy and will be central to its expansion. Connecting producers with consumers and balancing misalignment in supply and demand, we will likely need significant development and scale up of this infrastructure in order to achieve our ambition of up to 10GW of low carbon hydrogen production capacity by 2030 (subject to affordability and value for money).

Geographical location and interactions with hydrogen producers and end users will be important in determining the need and potential value of both hydrogen transport and hydrogen storage infrastructure. Increased complexity and interlinkages within the wider decarbonised energy system will also mean the development of hydrogen infrastructure cannot be considered in isolation. Strategic planning may be required to account for such locational factors, wider energy system interactions, and the need to enable an efficient transition to a deep, well-functioning hydrogen market.

As set out in the UK hydrogen strategy, we believe it will be important that initial investments and later evolution of the hydrogen network are achieved in a coordinated manner, which manages investment risks and delivers benefits to consumers while delivering government's 2030 ambition and positioning the hydrogen economy for significant expected growth beyond this.

This section considers whether a strategic planner would be beneficial to guide the roll out of hydrogen transport and storage infrastructure and seeks views on potential implementation options for this.

Hydrogen and the Whole System

The energy system needs to go through radical change over the coming years to meet the government's net zero targets by 2050. Decarbonisation will increase the level of low carbon and renewable technologies across the energy system, which will lead to greater interactions across vectors like natural gas, electricity, biofuels, carbon capture, utilisation and storage (CCUS) and hydrogen to provide system flexibility, resilience and security.

Within this context, the location and sequencing of hydrogen transport and storage infrastructure roll out will have important implications not just for the growth and development of the hydrogen economy, but also for the wider energy system.

Availability

The roll out of hydrogen transport and storage infrastructure will determine who has access to hydrogen and when. This has important implications for potential hydrogen producers and end users who have identified hydrogen as their preferred route to decarbonisation. In geographical areas where access to hydrogen is constrained by a lack of transport and storage infrastructure, these potential end users might face barriers to decarbonising. For example, alternative decarbonisation options to hydrogen could be more costly, or may not yet be commercially viable. This could reduce the potential benefit of hydrogen in helping the UK progress towards net zero, creating a potential missed opportunity.

These implications will be especially relevant for dispersed industrial sites that have identified hydrogen as their preferred route to decarbonisation. The timeframe in which hydrogen infrastructure will develop will determine whether and when these dispersed sites might be able to decarbonise using hydrogen, or whether they will be reliant on alternative decarbonisation options becoming cost effective or commercially viable.

Where the main alternative to hydrogen is electrification, this could have impacts on the power sector, with increased demand and potentially the need to reinforce parts of the electricity grid.

The issue of who will have access to hydrogen and the timelines for this will likely affect and be affected by several factors including the roll out of hydrogen for heating should this occur, the role hydrogen plays in the transport sector and in what form it is used (e.g. as ammonia in shipping), and the extent to which hydrogen is imported/exported and from which locations.

Natural gas grid implications

The development of hydrogen transport and storage infrastructure will have implications for the existing natural gas grid. As presented in the Hydrogen Transport Infrastructure chapter, repurposing gas assets for hydrogen is expected to be considerably cheaper than building new assets, meaning that the growth of the hydrogen economy will likely drive an increase in the amount of existing gas infrastructure that is repurposed.

As elements of the existing gas grid are repurposed (potentially including existing natural gas storage facilities), there will be a need to ensure that the gas system's functionality, resilience and security is maintained as long as consumers rely on it for their energy needs. This may not be problematic to begin with – as redundancy in parts of the gas system will allow the repurposing of some assets to hydrogen with minimal impact on the overall gas grid capability. However, this potential tension may become more pronounced as the hydrogen economy and its accompanying infrastructure grows, and the gas market overall reduces on the way to net zero.

Government will take strategic decisions in 2026 on the role of hydrogen in heating. These decisions will be key to determining the future trajectory of the gas network, particularly beyond industrial clusters, and to what extent elements of it might be decommissioned, repurposed for hydrogen, or indeed maintained for the future role of natural gas in a net zero system (e.g., to serve CCUS-enabled hydrogen producers, power stations, etc).

If blending hydrogen into the existing gas network is allowed, following a decision by the end of 2023, this would by definition create new interactions between the hydrogen network and natural gas, and hence influence the shape and nature of the gas system as a whole. If multiple hydrogen producers were to wish to use blending as a primary or partial route to market for their hydrogen, there would be a need to determine where, when, and how hydrogen could be injected into the system to ensure any established blending limits are not exceeded.

Power system implications

Hydrogen has the potential to play several roles in the decarbonisation of the power system, and the availability of hydrogen transport and storage infrastructure will be critical in unlocking this potential.

Government analysis shows that having hydrogen available in the power sector could achieve lower emissions at a lower cost than under corresponding scenarios without hydrogen.[41] Through hydrogen to power, hydrogen can provide low carbon flexible generation to complement intermittent renewables and replace and retrofit existing unabated gas generation to further support our power sector decarbonisation targets.

It can also provide production of hydrogen using electricity, which would otherwise be curtailed[42], through electrolysis. By reducing curtailment, it may enable us to use renewable generation more efficiently by allowing load factors to be maximised in optimal locations, which in turn might help to reduce whole system costs. This reduction could also be optimised with hydrogen electrolysers being incentivised to turn down production during periods of high electricity demand. Moreover, hydrogen produced through electrolysis could also be used as a form of long-duration electricity storage utilising larger-scale hydrogen storage and hydrogen to power technologies.

Hydrogen in the power system, therefore, has considerable potential to provide significant hydrogen demand and aid the development of the hydrogen economy, provide electricity balancing services, and increase overall power system flexibility. Hydrogen transport and storage infrastructure is key to achieving this. Storage will be needed to ensure certainty of supply for hydrogen to power generation and for hydrogen's potential role as long-duration electricity storage. Transport infrastructure will be needed to connect hydrogen production, hydrogen storage and power generators for both hydrogen to power and power to hydrogen generation. The strategic deployment of hydrogen and power infrastructure will be critical to realising the benefits of a coordinated hydrogen and power system, for both the decarbonisation of power and the growth of the hydrogen economy.

[41] Modelling 2050 – electricity system analysis (2020): https://www.gov.uk/government/publications/modelling-2050-electricity-system-analysis
[42] Curtailment is a purposeful reduction in electricity output which is a result of either oversupply, where there is not enough demand for the electricity that could be produced due to e.g., high wind speeds or transmission constraints, where there is not sufficient transmission infrastructure to transport the electricity to areas of demand. Curtailment is described more in the first section of the analytical annex.

CCUS implications

The roll out of hydrogen transport and storage infrastructure will likely have implications for CO2 transport and storage networks. The increasing development of CCUS-enabled hydrogen production will inevitably strengthen the link between CCUS and hydrogen transport and storage infrastructure. The synergy of the two sectors would therefore need to be optimised for reduced system costs.

CCUS-enabled hydrogen production will rely heavily on access to both CO2 and hydrogen transport and storage infrastructures and coordination will be required between the two systems to ensure an effective build out of transport and storage. Construction of new transport assets for the production facility should be synchronised to minimise disruption and costs and decisions for repurposing of gas transport and storage assets for either hydrogen or CO2 will need to be taken to ensure the development of an optimised system.

Transport and Storage Infrastructure Development

Assessing whole system value

The market building and wider systemic considerations described above for the development of hydrogen transport and storage infrastructure imply that the potential value of specific projects might be viewed through three distinct ‘lenses’:

- Meeting an immediate or known future need to connect one or more specific producers to one or more specific end users of hydrogen (for transport projects) and/or to balance misalignment between them (for storage projects);
- Building enabling capacity for future producers/end users to access the network, and hence grow the hydrogen economy in line with government ambitions while improving resilience, lowering risk, costs etc, especially given that the long lead times for developing larger-scale transport and storage infrastructure mean that there may be uncertainty as to the exact number and type of future users;
- Wider systemic benefits, e.g., to the power system, or to gas grid management on the path to net zero.

A ‘whole system’ approach to infrastructure development implies assessing specific projects broadly through all three lenses. While assessing the first of these would be a reasonably typical function of asset owners, a business model delivery/allocation body or regulator, assessing the other two may require reference to wider strategic priorities and plans that would go beyond assessing “narrow” project eligibility criteria or asset values.

This introduces questions as to whether a strategically planned approach is needed, where infrastructure is purposely planned and delivered against strategic objectives, to achieve the efficient roll out of hydrogen transport and storage infrastructure that maximises likely long-term benefit to the whole energy system.

Transport and storage infrastructure can develop via a market-led approach, where the capacity and location of new network connections and storage is determined by market demand (although the terms of any applicable business model may impose restrictions such as permitted uses or additionality requirements). Where the market and regulatory framework involves cost-reflective prices this can help produce efficient whole system outcomes but may be difficult to plan for longer-term infrastructure demand and wider systemic benefits in practice.

The analytical annex uses the Theory of Change framework to understand what actions are needed to overcome the barriers in hydrogen transport and storage infrastructure and deliver the wider vision for the hydrogen network and economy. It sets out that a framework for strategic planning could be needed to ensure a coordinated rollout to enable the ongoing matching of supply and demand as the hydrogen economy grows.

Approaches to strategic planning

There are a number of different ways in which to implement a strategic planning approach, such as:

- a strategically planned approach to infrastructure development where decisions are made centrally or in coordination to develop an optimised system;
- a system where strategic planning and markets both have roles to play in determining the capacity and locations of new network connections and storage, for example, a system where investment is supported by a mixture of user commitments and potentially additional support from government/bill-payers where the strategic planner decides this is appropriate;
- an approach that evolves in time, for example an initial strategically planned approach to establish first of a kind projects, which evolves into one that is more market-led as the market becomes more established.

Case studies

The energy system will go through significant change and integration as it progresses towards net zero, and as the energy system becomes more integrated there appears to be a shift towards a more coordinated and planned approach to the development of future energy systems. There is a spectrum of options for developing transport and storage infrastructure, as can be seen through a number of case studies we consider here.

Central network planning[43]

The Future System Operator (FSO)

As set out in Ofgem and BEIS' recent consultation response[44], we have committed to create an expert, impartial FSO, established as a public corporation with operational

[43] A central network planning approach is conducted by a single entity.
[44] Future System Operator: government and Ofgem's response to consultation (2021): https://www.gov.uk/government/consultations/proposals-for-a-future-system-operator-role

independence from government. Amongst its other duties and responsibilities across both the electricity and gas systems, it is intended to have a statutory duty to have regard for whole system impacts and is therefore, amongst other things, expected to consider the development of hydrogen as part of its responsibilities in system forecasting, strategic network planning and when providing advice to government or Ofgem.

Ofgem's consultation on its minded-to-decisions on the Electricity Transmission Network Planning review[45] sets out its intention to introduce a new "centralised strategic network planning" (CSNP) model and process[46], to deliver its objectives for efficient electricity transmission network planning. Ofgem intends for the CSNP model to be led by the FSO as the "central network planner". Ofgem's initial findings indicated the FSO should be taking a whole system approach when undertaking this role, which means considering the interactions across electricity, gas, and other emerging markets, both on and offshore, and between transmission and distribution systems. This was endorsed and considered a priority by respondents to Ofgem's initial findings consultation.[47] For hydrogen in particular the review also indicates hydrogen will need to be factored into the planning of the electricity transmission system if the UK requires significant amounts of electrolytic hydrogen, and therefore electricity, in the future.

A coordinated approach[48]

EU gas legislative package

The European Commission published its proposed recast legislative package on common rules for the internal markets in renewable and natural gases and in hydrogen in December 2021.[49] The proposed legislation sets out that coordinated planning and operation of the entire EU energy system, across multiple energy carriers, infrastructures, and consumption sectors is a prerequisite to achieving its 2050 climate objectives.

[45] Consultation on our minded-to-decisions on the initial findings of our electricity transmission network planning review (2022): https://www.ofgem.gov.uk/publications/consultation-our-minded-decisions-initial-findings-our-electricity-transmission-network-planning-review
[46] The CSNP would take a GB-wide holistic view to develop an optimised plan for necessary investment in the electricity transmission network to meet anticipated future needs of the changing energy system to meet net zero, including identifying and specifying the high-level design of low regret strategic investments. It will also facilitate a move to strategic energy system planning, achieved by proactively coordinating electricity transmission network planning with wider system planning.
[47] Consultation on the initial findings of our Electricity Transmission Network Planning Review (2021): https://www.ofgem.gov.uk/publications/consultation-initial-findings-our-electricity-transmission-network-planning-review
[48] A coordinated approach is where multiple entities coordinate to deliver a strategically planned approach, for example via committee or a coalition.
[49] Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast) (2021): https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2021%3A804%3AFIN and Proposal for a Directive of the European Parliament and the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) (2021): https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0803

The European Commission is looking to create better linkages between network planning schemes such as the EU-wide ten-year network development plan and national network development plans in EU member states. It is also proposing to factor in hydrogen into gas network planning and creating dedicated plans for hydrogen. The legislation also proposes to establish a European Network of Network Operators for Hydrogen (ENNOH) similar to the gas European Network of Transmission System Operators (ENTSO)[50] where hydrogen network operators can cooperate, with one of its roles to develop a non-binding EU-wide 10-year development plan for hydrogen infrastructure. National development plans will feed into the EU wide plan developed by the ENNOH and would include modelling of integrated networks, scenario development and an assessment of the resilience of the system. The plan will also build on the needs of users, integrate long term investment commitments, and identify investment gaps, needs and requirements for decommissioning and infrastructure repurposing.

While the UK is no longer a member of the EU, this is likely to impact cross-border UK-EU trade in hydrogen, renewable gases, and natural gas. Exploring a strategic planning approach to hydrogen would enable the UK to ensure that the impact of future changes to the EU's energy system are factored into the UK's future energy security and the development of UK energy markets. This is particularly relevant following the increased production ambition announced in the British Energy Security Strategy, which may open up opportunities for UK producers to export hydrogen to the international markets.

The Netherlands – Multi-Year Programme for Infrastructure, Energy and Climate

The Netherlands is taking a coordinated strategic planning approach to the development of its hydrogen infrastructure.[51] To achieve its climate targets the Netherlands is accelerating the sustainability of its energy infrastructure ensuring the infrastructure is ready in time for the growing demand for electricity, hydrogen and CCUS. They are developing their infrastructure first before production and end use demand are in place, repurposing one of their two natural gas networks. The Netherlands has six industrial clusters similar to that of the UK's industrial clusters; each cluster has a Cluster Energy Strategy which outlines the future energy supply and demand per cluster, including hydrogen, and necessity for energy infrastructure. These plans feed into the Multi-Year Programme for Infrastructure, Energy and Climate which describes the energy and raw materials infrastructure projects that the government aims to tackle in order to contribute more quickly to decarbonising industry. The programme is directed by the National Infrastructure Programme for Sustainable Industry which acts as a steering committee where all key stakeholders are represented, and which coordinates the plan of accelerating the construction of the energy infrastructure in the Netherlands.

[50] The role of the ENTSO is to facilitate and enhance cooperation between national gas transmission system operators across Europe. To ensure the development of a pan-European transmission system in line with EU energy and climate goals.

[51] Multi-year infrastructure Energy and Climate Programme – Overview 2021 (2021) https://www.rijksoverheid.nl/documenten/rapporten/2021/11/26/meerjarenprogramma-infrastructuur-energie-en-klimaat---overzicht-2021 (translated June 2022)

An approach that evolves over time

CCUS

With an approach that evolves over time, CCUS infrastructure would initially be strategically planned. As the market matures, decisions on infrastructure would be made by market mechanisms.

For the UK's developing CCUS industry, the CO2 transport and storage (T&S) infrastructure is expected to be planned and developed by the T&S companies (T&SCo) that operate the assets.[52] It is envisaged that the UK's CCUS T&S capacity will initially be developed at separate CCUS clusters, with the potential for future expansion of these assets into a UK CO2 network.

Government expects T&SCo to be responsible for developing economically efficient plans for new connections to the T&S network. However, in the early phases of market development and expansion, the government will also be involved as delivery against such plans will, in part, be dependent on decisions made by the government on the timing and award of support to the proposed T&S network users. Where there are support arrangements with T&SCo to manage financial risks, the government will need to engage on network planning decisions. Over the longer term, there is expected to be a decline in the involvement by government in network planning decisions and the association with the award of funding to proposed network users.

A similar approach may apply to the development of hydrogen networks, whereby the initial infrastructure development requires centrally planned direction but once established can rely on market led factors.

Question 35

In your view, should the build out of hydrogen **transport** infrastructure evolve through either a) a solely a market-led approach, b) a form of strategic planning, or c) neither? Please explain your answer and provide any relevant evidence.

Question 36

In your view, should the build out of hydrogen **storage** infrastructure evolve through either a) a solely a market-led approach, b) a form of strategic planning, or c) neither? Please explain your answer and provide any relevant evidence.

Question 37

[52] Transport and storage business model: January 2022 update (2022): https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models

In your view, if strategic planning was to be implemented for hydrogen **transport** infrastructure what form should it take? a) central network planner, b) coordinated approach, c) evolved approach, d) a blend of strategic planning and market-led approaches, or e) none of the above? Please explain your answer and what this approach might look like in a UK context.

Question 38

In your view, if strategic planning was to be implemented for hydrogen **storage** infrastructure, what form should it take? a) central network planner, b) coordinated approach, c) evolved approach, d) a blend of strategic planning and market-led approaches, or e) none of the above? Please explain your answer and what this approach might look like in a UK context.

Question 39

Further to your answers to questions 35 – 38 above, in your view, is it important for there to be alignment between the ways in which hydrogen transport infrastructure and hydrogen storage infrastructure are built out and, if relevant, the form of strategic planning involved? Please explain your answer and provide any relevant evidence.

Question 40

Considering onshore and offshore hydrogen transport and storage infrastructure, do they have specific characteristics, or wider interactions with other infrastructure, which may mean the different infrastructure types favour a market-led approach or a form of strategic planning? Please explain your answer and provide any relevant evidence.

Strategic Planning Implementation

Strategic planning could support hydrogen transport and storage infrastructure to develop in a way that ensures a mature hydrogen market grows efficiently while maximising wider systemic benefits, enabling the UK to meet its hydrogen ambitions and contribute to meeting CB6 and net zero targets.

If the UK were to take a strategically planned approach to developing hydrogen transport and storage infrastructure, strategic priorities for the development of this infrastructure would need to be identified, through a strategic planning process, based on whole system considerations. These strategic priorities could then potentially be used to inform decisions on which projects should receive any available support.

Factors to consider in strategic planning

When planning and constructing hydrogen transport and storage infrastructure to meet the increasing demand for hydrogen across the energy system, the strategic planning process would need to take into account a number of factors, which may include identifying and managing trade-offs between factors. Some of these factors include:

- The **location of assets** would be an important factor to consider. Balancing locational signals for assets on both the demand and production side would ensure optimum placement of assets and efficient infrastructure build out. For example, the increase in development of onshore and offshore wind farms, including an ambition of up to 50GW of offshore wind capacity by 2030[53], will mean that electricity generation is expected to move further away from demand centres. Where hydrogen is being used to capture excess electricity from wind generation, the location of electrolysers and power generation will need to be considered alongside one another in conjunction with hydrogen storage and transport infrastructure to minimise any system losses, inefficiencies, and costs (which may need to be balanced against each other).
- Understanding the **required capacity** of transport and storage infrastructure should also be considered. It will be important to understand the level of hydrogen storage required by producers and end users, whether it be small scale above-ground storage (e.g., containerised hydrogen) or underground geological storage. There will be locational constraints for any larger-scale underground hydrogen storage, as it is dependent on an area's geology, so if projects require access to large storage capacity this would need to be considered in any strategic planning process. Similarly, the ability to access suitable transport infrastructure capacity to give end users access to hydrogen as well as storage, either in the power sector or to dedicated hydrogen end user such as transport, industry, or heat (subject to future decisions), would be a factor that needs to be considered.
- The **lead times** for hydrogen transport and storage infrastructure would be important factors to consider in strategic planning in order to enable new production and/or demand to come on stream. Larger-scale assets such as salt caverns have long lead times and would need to be planned well ahead of demand. This would require coordination both within the hydrogen sector and between energy vectors, to ensure that the correct amount of capacity is available where and when it is needed, and in a cost-effective and efficient way. For example, the potential for offshore electrolytic production of hydrogen and larger-scale offshore hydrogen storage would need to be considered in marine spatial prioritisation alongside other potential uses of the marine space. Understanding the lead times of transport and storage would also provide end users clear signals for when they would likely have access to hydrogen, allowing them to proceed with investment in their decarbonisation.
- **Impacts on the gas system** would also need to be considered, especially in deciding whether to support new or repurposed transport and storage infrastructure. As the UK transitions to a decarbonised energy system and seeks to reduce reliance on natural gas for wider energy security purposes, there are questions around what role the existing natural gas infrastructure will play in the wider energy system in coming decades. Even early strategic decisions on the location, timing and type of hydrogen

[53] British Energy Security Strategy (2022): https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy#renewables

transport and storage infrastructure could have important implications for the operation and eventual transition or decommissioning of existing natural gas assets as the gas system decarbonises.

- **Coordination** among owners and operators of hydrogen infrastructure assets could be beneficial to reduce the risk of stranded assets. This could be a risk particularly in the early stages of the hydrogen economy where isolated pipelines may be built to connect single producers to single end users, only to become redundant once networked solutions become available. Reducing the risk of stranded assets through planning could support a more efficient build out of network infrastructure (including storage), thus reducing overall costs, including those to network users.

Question 41

In your view, are there any factors, other than those listed above, that should be considered if a strategic planning approach was to be adopted? Please explain your answer and provide any relevant evidence.

Institutional features

The strategic planning and coordination of hydrogen transport and storage infrastructure could take place in various guises including through industrial collaboration, central planning, effective market structuring, price signalling, trading and regulatory obligations, and the design of transport and storage business models.

The level at which this planning and/or coordination takes place would also be relevant to ensure effective build out. This could be national, regional, local, or involve a combination of these, implying a range of potential institutional options. Future policy decisions, such as on blending or hydrogen heating, might also affect the level at which coordination would be most effective.

The roles and responsibilities of different bodies and institutions would need to be established and developed. As highlighted by the case studies set out above, there are a number of different ways in which a strategic planning approach might be implemented, and within these configurations different institutions can fulfil different roles.

Using the central strategic network planner case study, the FSO’s role could be expanded to take on responsibility for central strategic planning of the hydrogen network, alongside its electricity and gas network planning responsibilities. This would allow the FSO to oversee the investment and build out of hydrogen transport and storage infrastructure, ensuring optimisation within the hydrogen economy and with other energy vectors. If it did become the strategic planner for the hydrogen network, the FSO might recommend and advise on the location of new and repurposed hydrogen assets, with separate body/bodies (for example a regulator or business model delivery body) making the actual decisions on whether and how to support specific projects.

Further consideration and engagement would be needed to determine when the FSO might be able to take on such a role for hydrogen, given this will be a newly established organisation whose initial priorities will be on electricity and natural gas. Depending on a number of factors, including timings of the current Energy Bill and discussing timelines with key parties, the FSO could be established by, or in 2024. If it were to be designated as the central strategic planner for the hydrogen network, we would expect it to take some time to build up the necessary expertise and capability without compromising its wider energy system operation activities. An alternative temporary solution for planning the initial hydrogen transport and storage infrastructure build out may therefore be needed, for example with BEIS or a coalition of organisations, taking this planning role for the earliest stages of development until the FSO is established and has capacity for this role. Furthermore, consideration would also need to be given to how the FSO, as the strategic planner, would interact with Gas Transmission Owner (GTO), due to GTO remaining separate with its own responsibilities.

Strategic planning may not require a single system architect or central network planner but instead could use a coalition of bodies to inform decisions as highlighted in the EU and Dutch approaches. A coordinated approach in the UK, for example, could involve the separate industrial clusters and other key hydrogen project developers feeding individual plans into a wider national programme which is overseen and implemented by a committee consisting of representatives from industry, government, regulators, academic experts, etc.

Further policy work will be required in order to determine the institutional features of a strategically planned approach, should this be adopted. The responsibilities for existing organisations would need to be explored alongside determining the need to establish new institutions with a role to play in the strategic planning process.

Similarly, it will be important to ensure there is alignment with the wider planning system and processes. These are discussed in further detail in the Regulatory Framework chapter of the consultation document.

Question 42

If the UK were to create a central network planner role for hydrogen, would the FSO (if it is established by the Energy Bill) be best placed to take this role on? If not or if the FSO is not established, is another organisation more suited to the role or would a new body need to be created? If yes, in your view what temporary solution could be implemented prior to the FSO taking on the role? Please explain your answer and provide any relevant evidence.

Strategic planning interactions with the provision of business model support for transport and/or storage projects

If a strategically planned approach is used to develop the UK's hydrogen transport and storage infrastructure, a strategic planner is likely to play an important role in either informing or making decisions on the provision of business model support to projects. This would ensure that the build out of transport and storage infrastructure is consistent with the strategic plan.

The way in which decisions are taken may vary on the form of strategic planning approach that is taken. However, decisions on provision of business model support would likely be influenced either by a proactive or reactive approach:

- **Proactive**: The strategic planner proactively identifies the need for hydrogen transport and/or storage infrastructure of strategic importance.
- **Reactive**: Project developers make business cases to the strategic planner to assess through the strategic planning process.

To achieve an optimised build out of transport and storage infrastructure a strategic planner would need to consider the broad lenses and specific factors described above.

Question 43

In your view, what role could the strategic planner have in the provision of business model support? How would this role change under different strategic planning approaches? Please explain your answer and provide any relevant evidence.

Early support for “low or no-regrets” and systemically important projects

From early on, it may be possible to identify “low or no-regrets” projects, and systemically important projects, which could be key enablers for the future growth of the hydrogen economy. “Low or no-regrets” projects are those which have little to no risk of becoming stranded assets and which are highly likely to provide value to the hydrogen economy in the long-term. Systemically important projects are those which are likely to provide significant capacity that allows for future growth in the hydrogen economy. For instance:

- For transport infrastructure, early projects that facilitate the build-up of capacity to connect producers to known demand points may be deemed ”low or no-regrets”. Projects that provide a long-term connection between separated production and demand centres (whether within, between or beyond industrial clusters) to build overall network resilience and connectivity may be deemed systemically important. Both could play a key enabling role in allowing future producers and end users to access regional or national-scale hydrogen markets. This might include electrolytic producers and industrial consumers, power stations or transport refuelling stations located away from industrial clusters. Furthermore, such projects might help to build systemic resilience across the areas that are connected, reducing the risk of outages, and hence lowering the overall costs of further investments to bring forward more connections. Supporting early investment in such projects might therefore have the potential to reduce the overall costs of building the hydrogen economy and the related decarbonisation benefits.
- For storage infrastructure, National Grid’s Future Energy Scenarios suggests that between 11 TWh and 56 TWh of hydrogen storage may be required in 2050 across varying net zero scenarios.[54] A project may be deemed “low or no-regrets” if demand for

[54] National Grid Future Energy Scenarios 2022 (2022): https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2022

storage is already in place, guaranteeing usage from the outset, whereas projects that can act as critical enablers for a range of future demand scenarios may be deemed systemically important. Such projects could involve, for example, developing new larger-scale storage assets or repurposing existing natural gas geological storage.

If a strategic planning approach were to be taken within the UK, the body responsible for strategic planning could develop a process of identifying and selecting specific projects of systemic importance and/or ”low or no-regrets”, with a view to potentially fast-tracking their development through early bespoke support, be that through regulatory or financial means.

While this may be part of the enduring role of an independent strategic planner, it may be necessary for BEIS to play this role for the earliest decisions, ahead of enduring institutional arrangements being finalised and operational. Further considerations will also need to be made regarding how this support is integrated in the longer-term and its interactions with any support provided through business models.

Question 44

In your view, should government seek to identify “low or no-regrets” and/or systemically important projects to prioritise their development if possible? If so, how might such projects be identified and how might the best be prioritised? Please explain your answer and provide any relevant evidence.

Chapter 6: Regulatory Framework

Market Framework

In Chapters 3 and 4 we address issues relating to hydrogen transport and storage infrastructure respectively. For each we:

- Explain why they will be key to the growth of the hydrogen economy;
- Set out how demand for infrastructure is expected to grow through the 2020s and into the 2030s;
- Identify some of the key market barriers that might deter private investment, which could delay deployment and potentially impact the growth of the hydrogen economy;
- Set out a series of high-level business model design options which could address these barriers.

We also recognise that the existing market framework and industry commercial arrangements that would apply to hydrogen (including in relation to the ownership and operation of hydrogen transport and storage infrastructure) may not be conducive to the emergence of hydrogen transport and/or storage infrastructure. For example, hydrogen is a “gas” for the purposes of the Gas Act 1986, consequently, regulatory requirements and prohibitions that apply to the transportation, shipping, supply and storage of natural gas may also apply to hydrogen.

Some of the business model design options would potentially provide greater regulatory certainty in some areas (for example with regards to revenue recovery) and would likely involve the introduction of commercial arrangements codifying access and charging arrangements. For example, for CCUS, government is developing a CCUS Network Code that establishes the strategic, commercial and regulatory frameworks, as well as the technical rules and arrangements, that underpin CCUS transport and storage assets. This is something that will likely need to be considered for hydrogen transport and storage infrastructure.

With this in mind, we are keen to hear whether stakeholders believe the existing market framework and industry commercial arrangements are optimal for supporting the deployment of hydrogen transport and storage infrastructure.

Question 45

In your view, are the existing market framework and industry commercial arrangements for hydrogen optimal for supporting the development of hydrogen transportation and/or storage infrastructure? Please note we are seeking your views on the whole existing market framework and industry commercial arrangements, including any possible gaps, and not just matters relating to the Gas Act. Please explain your answer and provide any relevant evidence.

Question 46

If you answered ‘No’ to the previous question, how do you think this should be addressed:

a) Through amendments to the existing market framework / industry commercial arrangements?

b) Through the replacement of aspects of the existing market framework / industry commercial arrangements (for example, with new arrangements that are specifically designed for hydrogen)?

c) Through a different approach?

Please explain your answer and provide any relevant evidence.

Non-Economic Regulation

BEIS has been working closely with the relevant regulators and competent authorities to start to review the current non-economic regulatory framework for hydrogen. This includes planning, health and safety, licensing, permitting, technical standards and wider environmental regulations. The combined non-economic regulatory framework will underpin the future hydrogen economy and careful consideration is therefore required regarding its current suitability.

Thus far, for non-economic regulatory work, BEIS has focused on delivering the Hydrogen Strategy commitment to establish the Hydrogen Regulators Forum. To date, the forum has focused on mapping current regulatory roles and responsibilities across the hydrogen value chain. More broadly, the forum’s remit is to consider activities required throughout the 2020s to identify, prioritise and implement any changes to the existing non-economic regulatory framework, including addressing any gaps, to support development across the hydrogen value chain. This constitutes a range of complex regulatory areas – including those centred on different production methods, transport and storage operations, and potential end users.

The current non-economic regulatory framework for hydrogen is designed to accommodate the limited use of hydrogen that exists today (predominantly within industrial settings). This may need updating in the future, for example to adequately facilitate much larger volumes of hydrogen production, consistent with our 10GW production ambition and expected demand needed to meet our future carbon budget targets, as well as a greater variety of end uses. Consideration of potential regulatory changes to enable and support the future hydrogen economy will involve working collaboratively with a number of other government departments, arms-length bodies and competent authorities. An optimal regulatory framework will also require working with the devolved administrations on any aspects of regulation that fall within devolved policy areas.

BEIS recognises that, as a department, we are not responsible for all relevant non-economic regulation. Therefore, we will not be consulting in this document on some regulatory areas that will be essential to the future hydrogen economy. For example, health and safety legislation falls outside of the remit of this consultation as the Health and Safety Executive (HSE) has responsibility for this regulatory area in Great Britain, in its role as the national regulator. This chapter does not, therefore, set out a comprehensive analysis of the existing regulatory landscape. Instead, it provides an opportunity for stakeholders to comment on the optimality of current arrangements to enable and support the development of the future hydrogen economy. This will enable BEIS to work with the relevant governmental or regulatory bodies to ensure a robust and conducive non-economic regulatory framework. BEIS further recognises that, for any such regulatory framework to be effective, it will also need to account for wider issues, such as resourcing, funding, and time constraints.

Alongside regulation related to transport and storage infrastructure, given the natural interrelations with other parts of the hydrogen economy (e.g., production), we are also seeking stakeholder views, and encourage stakeholders to submit evidence, on whether the non-economic regulatory framework is optimal across the hydrogen value chain.

Question 47

Further to the regulatory areas set out below, in your view, is the existing onshore non-economic regulatory framework optimal for supporting the development of a rapidly expanding UK hydrogen economy?

Question 48

If you answered ‘No’ to the previous question, how do you think this might be addressed (regulation/standards/guidance, etc.)? Please explain your answer and provide any relevant evidence.

Onshore Health and Safety

For the hydrogen economy to develop, existing health and safety regulations need reviewing to assess their suitability and applicability to enable the future hydrogen economy. BEIS recognises it is imperative that essential health and safety measures are in place to protect people and the environment, and we are engaging closely with HSE regarding any impacts our work may have on health and safety legislation. This engagement includes helping to build the necessary evidence base to determine whether hydrogen blending (up to 20% by volume) meets the required safety standards to be enabled into gas networks, as well as broader engagement through the Regulators Forum. HSE also aims to provide a comprehensive assessment of the safety of 100% hydrogen for heating in 2025 and options for a future health and safety regulatory framework. This will include work to review evidence on the safety of hydrogen, such as for wider scale transmission within the gas network and starting to engage key stakeholders on potential changes to HSE regulations to support industry. If necessary, HSE will consult on any potential changes to relevant regulations in due course.

In addition, a number of safety and innovation trials and demonstrations are being undertaken by gas network companies and industry consortiums, with funding granted by Ofgem. These trials are generating evidence to help understand the suitability of the existing gas networks for hydrogen transportation, and include the HyDeploy and FutureGrid blending safety (and asset performance) trials, LTS Futures and H21 projects.[55]

Transporting hydrogen through non-pipeline vehicular means (e.g., by road, rail, sea, or air) currently occurs only in low volumes in the UK. Regulations currently exist to facilitate the safe transportation of hydrogen. If non-pipeline vehicular capacities were to increase in terms of volume and pressure, existing standards may need to be reviewed. We would welcome stakeholder views on the suitability of existing regulations to enable and support the development of the future hydrogen economy.

Question 49

In your view, is the existing regulatory framework for the non-pipeline transportation of hydrogen optimal for supporting the development of a rapidly expanding UK hydrogen economy?

Question 50

If you answered ‘No’ to the previous question, how do you think this might be addressed (regulation/standards/guidance, etc.)? Please explain your answer and provide any relevant evidence.

Onshore Planning

As the low carbon hydrogen economy is in its relative infancy, there is an opportunity to understand how best government(s), regulators and local authorities can work together to ensure prospective projects are best informed on what regulatory processes they must consider and follow. This section is separate to the strategic planning of hydrogen transport and storage infrastructure, covered in Chapter 5 of the consultation document.

For projects that meet Nationally Significant Infrastructure Project (NSIP) thresholds,[56] a suite of six National Policy Statements (NPSs) set out government objectives for energy infrastructure, together with environmental (and other) principles. It is against these NPSs that

[55] https://hydeploy.co.uk/;
https://www.nationalgrid.com/gas-transmission/insight-and-innovation/transmission-innovation/futuregrid;
https://www.sgn.co.uk/about-us/future-of-gas/hydrogen/lts-futures;
https://h21.green/

[56] Full definitions are in Articles 17 (storage) and 20 (pipe-lines) of the Planning Act 2008; in summary:
Underground gas storage - Either (a) the working capacity of the facilities is expected to be at least 43 million standard cubic metres, or (b) the maximum flow rate of the facilities is expected to be at least 4.5 million standard cubic metres per day.
Pipelines - Either (a) the pipe-line must be more than 800 millimetres in diameter and more than 40 kilometres in length, or (b) the construction of the pipe-line must be likely to have a significant effect on the environment. The pipe-line must have a design operating pressure of more than 7 bar gauge. The pipe-line must convey gas for supply (directly or indirectly) to at least 50,000 customers, or potential customers, of one or more gas suppliers.

NSIP applications will be principally assessed by the appointed Examining Authority as it examines the case and draws up its recommendation report, and ultimately by the Secretary of State as the decision taker. Successful projects will be granted a Development Consent Order (DCO) – the NSIP equivalent of planning permission – which brings together the various consents required to deliver the project.

In the *Energy White Paper: Powering our Net Zero Future*, published in December 2020, the government committed to completing a review of the existing energy NPS suite to ensure it reflects current energy policy and enables a planning framework which can deliver investment in the infrastructure needed for the transition to net zero.[57] As part of this review, EN-1 (the overarching energy NPS) has been redrafted to clearly set out the urgent need for all types of low carbon hydrogen infrastructure to allow hydrogen to play its role in the transition to net zero.

A public consultation on the draft NPS was launched in September 2021, closing in November 2021, and the documents were subject to parliamentary scrutiny between 22 September and 28 February, including an inquiry by the BEIS Select Committee which published its recommendations on 25 February 2022.[58] Government will publish a response to the consultation, an updated draft NPS and a response to the BEIS Select Committee inquiry in due course.[59]

Projects that do not meet the necessary thresholds to be considered under the NSIP regime but wish to go through the DCO process can request that they are considered as nationally significant despite not meeting the threshold. This will be decided by the relevant Secretary of State. The alternative for projects below the NSIP threshold is to obtain planning permission via the relevant local planning authority using the planning regime, under the Town and Country Planning Act (TCPA) 1990. In such cases, any other related consents (such as environmental related licensing/permits, and compulsory purchases) would need to be applied for separately to the relevant authority. Local authorities are also likely to be responsible for monitoring the implementation of many of the requirements laid out in the DCO, along with taking on enforcement roles with regards to DCO provisions and requirements.

Planning processes differ across the devolved nations and are dependent on the nature of a project. Those referenced above generally apply in parts to England and Wales, subject to certain exceptions. The UK Government intends to work closely with devolved administrations to understand the best way to optimise hydrogen project development across the whole of the UK.

Securing the necessary planning consents for a major infrastructure project can be a time-consuming and complex process. Recent decisions on offshore wind plants, solar farms and nuclear power stations have involved significant amounts of public consultation, environmental

[57] Energy White Paper: Powering Our Net Zero Future (2020): https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[58] https://committees.parliament.uk/work/1602/energy-national-policy-statements/publications/
[59] Planning for New Energy Infrastructure: Review of Energy National Policy Statements (2021): https://www.gov.uk/government/consultations/planning-for-new-energy-infrastructure-review-of-energy-national-policy-statements

assessments, challenges from interested local communities, and extensions to deadlines as further relevant information is sought from developers, environmental experts and other interested parties. It is therefore important that the process of securing planning consent is factored into overall project timelines in a realistic way.

Question 51

In your view, are the current NSIP and TCPA regimes optimal for supporting the development of a rapidly expanding UK hydrogen economy?

Question 52

If you answered 'Yes' to the previous question, please explain which elements you think are conducive to the development of the hydrogen economy. If 'No', please explain how you think they might be improved (e.g., a dedicated hydrogen NPS). Please explain your answer and provide any relevant evidence.

Onshore Environment

Environmental regulations are essential to ensuring that the natural environment is protected from any adverse impacts of the hydrogen economy. Safety and environment often have large areas of commonality, and it is important therefore that any solutions are complementary rather than conflicting in nature. As hydrogen projects are being designed, environmental impacts of such projects must be considered by the appropriate environmental authority.

Given the nascent nature of low carbon hydrogen technologies, further work is required to determine the environmental impact of the future hydrogen economy – and therefore whether new, hydrogen-specific environmental regulation may be required. In April 2022, BEIS published two research papers: *Fugitive Emissions in a Future Hydrogen Economy*;[60] and *Atmospheric Implications of Increased Hydrogen Use*.[61] BEIS will continue to work closely with the relevant regulators to understand wider environmental concerns and the suitability of existing regulation to protect the environment as appropriate. This includes monitoring new research into the Global Warming Potential (GWP) of hydrogen and the resulting need to mitigate against the potential environmental risks, for example, fugitive emissions through leakage from any future hydrogen infrastructure. In addition, we have announced £3.85 million funding to explore the environmental response to hydrogen emissions, with successful projects starting from October 2022. This research programme aims to address uncertainties and gaps in knowledge regarding hydrogen's environmental behaviour. Notwithstanding the further work needed in this area, we would welcome views from stakeholders on whether the existing environmental regulatory framework is optimal for the future hydrogen economy.

[60] Fugitive Hydrogen Emissions in a Future Hydrogen Economy (2022): https://www.gov.uk/government/publications/fugitive-hydrogen-emissions-in-a-future-hydrogen-economy
[61] Atmospheric Implications of Increased Hydrogen Use (2022): https://www.gov.uk/government/publications/atmospheric-implications-of-increased-hydrogen-use

Question 53

In your view, is the existing environmental regulatory framework optimal for the future hydrogen economy?

Question 54

If you answered 'No' to the previous question, how do you think this might be addressed? Please explain your answer and provide any relevant evidence.

Offshore

As discussed in Chapter 3, we anticipate that the future hydrogen economy may include the storage of hydrogen in suitable offshore reservoirs such as salt caverns and/or depleted oil and gas fields, with pipelines connecting offshore storage facilities to an onshore hydrogen network. In addition, Government's ambition to deliver up to 50GW of offshore wind by 2030, including up to 5GW of innovative floating wind, presents new opportunities for electrolytic hydrogen projects to be co-located with new and/or existing offshore wind developments; these too would likely require pipelines connecting electrolytic production facilities with offshore storage and/or direct connections to a future onshore hydrogen network.

Regulatory responsibilities across the future offshore hydrogen economy are currently not clearly defined in some areas of the existing framework. For example, storage of hydrogen is not currently a licensable activity under Section 2 of the Energy Act 2008. Our current position is that BEIS should, for non-economic regulatory work, prioritise considering the future offshore regulatory regime for hydrogen. We welcome stakeholders' views on the value of this approach.

Question 55

Further to the regulatory assessment set out above, in your view, is the existing offshore non-economic regulatory framework optimal for supporting the development of a rapidly expanding UK hydrogen economy?

Question 56

If you answered 'No' to the previous question, how do you think this might be addressed (regulation/standards/guidance, etc.)? Please explain your answer and provide any relevant evidence.

Chapter 7: Hydrogen Blending

Background

Blending hydrogen into the existing gas network may help provide market-building benefits for the hydrogen economy, especially ahead of larger-scale hydrogen transport and storage infrastructure being available to connect producers with a wider range of end users. Hydrogen is currently limited to 0.1% by volume in the GB gas networks, as set out in the Gas Safety (Management) Regulations 1996. Government is aiming to reach a policy decision in 2023 on whether to allow blending of up to 20% hydrogen by volume into the gas distribution networks. This could generate carbon-savings of up to 6-7% on current GB grid gas consumption. We are building the necessary evidence base to determine whether blending meets the required safety standards, is feasible and represents value for money.

For blending to be enabled, it must demonstrate economic and strategic value as well as being safe. Industry is undertaking trials and demonstrations to provide safety evidence for blending to inform the safety case. The economic case will be based on technical models, considering where hydrogen should be injected into the networks, what market and trading arrangements should be in place and how billing processes might need to be amended. The economic case will also assess commercial models, including the question of whether and, if so, how blending should receive government financial support.

If the decision to proceed with blending is positive, we will then look to start the legislative and regulatory process to enable blending, as well as the process to make any physical changes to gas networks that are required. Given the timelines for this work, we do not anticipate blending at a commercial scale to commence before 2025, at the earliest.

This chapter seeks to better understand the hydrogen market-building potential of allowing hydrogen blending into the existing gas grid, and how this might affect the economic and strategic case for blending. This includes assessing the potential role of blending to act as a reserve offtaker if production capacity outstrips demand and its potential to help manage demand volatility, to help bring forward investment and support delivery of our hydrogen ambitions. Alongside efforts to understand these potential benefits of hydrogen blending, work is on-going to assess the costs and potential means to implement blending, if enabled, which is not the focus of this consultation chapter.

The Strategic Role of Blending

There may be significant value in having blending available to support development of the hydrogen economy, especially while the development of hydrogen transport and storage infrastructure is in its early phases and the number of available end users for hydrogen is more limited. By providing a route to market for hydrogen producers during the early development of the hydrogen economy, blending may help to bring forward investment and support its early growth.

However, blending can only be a transitional option. It relies on an extensive natural gas network being available to blend into, which will reduce as we progress to net zero. For this reason, it may only have a limited and temporary role in gas decarbonisation as we move away from the use of natural gas. Even in the shorter term, and as set out in the UK Hydrogen Strategy, the use of hydrogen is expected to be most valuable where there are limited alternative routes to decarbonisation, such as for industries for which direct electrification is not an option.

As such, we believe the most appropriate strategic role for blending, if enabled, is to act as a reserve offtaker, to support hydrogen economy growth, whilst managing the impact of blending on the supply of hydrogen to alternative end users who require it to decarbonise. Blending could absorb excess volumes of hydrogen for which there are no alternative routes to market. It may fulfil this role for hydrogen producers suitably located to blend and/or with any required transport infrastructure, under scenarios where a local blending limit (e.g. 20% by volume) has not already been reached. This strategic role is likely to be reflected in the design of any potential financial support made available for blended volumes.

Blending may also generate transferable insights and infrastructure for a potential future transition to 100% hydrogen and raise public awareness and/or acceptance of hydrogen for heat. However, a decision on 100% hydrogen for heat is not contingent on a decision on blending. Alongside our work on blending, the government is working with industry and regulators on a range of research, development and testing projects, including community trials, to enable strategic decisions in 2026 on the role of 100% hydrogen for heat. In light of these decisions, and as the hydrogen economy develops beyond our initial blending policy decision, we will continue to explore the strategic role of blending.

Blending to Manage Volume Risk

Ahead of a mature hydrogen market, with widespread demand and an extensive hydrogen network to connect producers to end users and/or storage facilities, there may be significant value in having blending available to offer producers a route to market. Blending could manage the risk of producers being unable to sell enough volumes of hydrogen to cover their costs (i.e. volume risk) by absorbing excess volumes of hydrogen for which there are no alternative routes to market. This may de-risk investment in additional hydrogen production capacity, helping to drive up the pace of hydrogen economy growth.

As we develop the economic case for blending, we are seeking to develop the evidence base to assess the nature and scale of this volume risk and the extent to which blending has value in mitigating this, especially relative to other potential reserve offtakers. The evidence we are gathering here is to understand the potential benefits of blending in addition to other measures to manage volume risk (e.g. sliding scale support under the Hydrogen Business Model for production)[62].

The categories of volume risk we have identified are as follows:

Early years of hydrogen economy

• **Hydrogen transport & storage infrastructure risk:** There is risk that producers will likely sell their volumes to offtakers within a localised area, with limited ability to grow new offtake markets due to an initial lack of larger-scale transport infrastructure. Prospective electrolytic hydrogen producers using renewable electricity with intermittent production profiles may also struggle to find suitable offtakers, potentially discouraging investment in the initial absence of larger-scale storage infrastructure and/or alternative reserve offtakers.

• **Delays to at scale adoption of hydrogen:** There is uncertainty around the scale and pace of hydrogen adoption across sectors. This may be affected by the need for regulatory changes, the availability of alternatives (e.g. electrification), the need for industrial changes (e.g. permanent changes in industry structure), the lack of technology readiness, concerns about security of supply for end-use sectors, and the pace and effectiveness of hydrogen research and innovation.

Ongoing

• **Demand volatility:** Natural and commercial demand cycles, or financial and technical issues can lead to offtaker outages or closures. These may be temporary, e.g. if an offtaker shuts down for maintenance, or long-term, e.g. if an offtaker goes insolvent.

In the following sections, we will review the categories of volume risk identified above and seek to further understand the value that blending, or another reserve offtaker, may have in mitigating them.

Hydrogen Transport and Storage Infrastructure Risk

The government has committed to design new business models for hydrogen transport and storage infrastructure by 2025. However, there would then be further lead times for infrastructure development. Whilst the Hydrogen Business Model for production may provide support for transport and storage infrastructure through initial contracts, blending may have value as a reserve offtaker that can 'bridge' the gap while larger-scale transport and storage infrastructure develops (which would help enable producers to grow their offtake market beyond a localised area).

On transport, whilst producers may identify suitable offtakers that are ready to switch to hydrogen, it may not be suitable to locate their production facility near these end users and/or

[62] Design of a Business Model for Low Carbon Hydrogen (2021): https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

there may be limited means of delivering hydrogen to them in the absence of larger-scale hydrogen transport infrastructure. Blending may be able to absorb those volumes of hydrogen before larger-scale transport infrastructure is available.

Blending may also have value as a reserve offtaker in the absence of larger-scale storage infrastructure. This could be beneficial for electrolytic hydrogen producers using renewable electricity, for instance. These producers have the potential to provide flexible system balancing services to the broader energy system and support the growth of renewable power generation, such as by absorbing excess renewable electricity that would otherwise have been curtailed.[63] Hydrogen produced using renewable electricity that would otherwise be curtailed is likely to be highly intermittent, creating challenges in finding suitable offtakers and a potential need for storage infrastructure. Blending into the gas grid could indirectly play a transitional role as a reserve offtaker for excess renewable electricity whilst larger-scale hydrogen storage infrastructure develops. This could be especially useful as government has doubled its ambition to up to 10GW of low carbon hydrogen production capacity by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen production.

Question 57

To what extent might lead times for hydrogen transport and storage infrastructure limit the scale of hydrogen production capacity in the early years of the hydrogen economy? If applicable, can this be quantified for your project (e.g. in terms of production volumes, load factors, etc.)?

Question 58

Do you see a potential for blending in helping to address this challenge by providing a route to market as a reserve offtaker? For how long do you expect this role for blending may be required? Please explain your answer and provide any relevant evidence.

If producers intend to blend and are not located close to the existing gas network and/or a suitable blending injection point, they may require new 100% hydrogen transport infrastructure to transport their hydrogen to a suitable injection point on the gas network to enable blending. As blending can only be time-limited, given our transition away from natural gas, there is a risk that new 100% hydrogen transport infrastructure developed for blending, especially physical pipelines as opposed to vehicular hydrogen transport, may become obsolete and the assets may become stranded. This could also occur if those producers switch from blending to alternative offtakers for which this infrastructure could not be repurposed. However, that infrastructure may be able to assist a potential future transition to 100% hydrogen for heat and/or other end users.

[63] Curtailment is a purposeful reduction in electricity output which is a result of either oversupply, where there is not enough demand for the electricity that could be produced due to e.g., high wind speeds or transmission constraints, where there is not sufficient transmission infrastructure to transport the electricity to areas of demand.

Question 59

Do you think that new transport infrastructure for 100% hydrogen may be required solely for the purposes of blending? If applicable, what scale of 100% hydrogen transport infrastructure would your project require to reach the GB gas networks (at distribution or transmission level)?

Delays to at Scale Adoption by End Users

There is a risk that offtakers may delay their adoption of hydrogen, e.g. due to concerns about security of supply, technology readiness, etc. This may cause a mismatch where the potential for hydrogen production capacity outstrips available demand. A reserve offtaker, such as blending, may help mitigate this volume risk by providing a route to market for any volumes of hydrogen without an alternative offtaker. This may incentivise additional production capacity by reducing investment risk which, in turn, could promote resilience and certainty of hydrogen supply and provide more confidence for end users to switch to hydrogen, thus also increasing demand. Any potential commercial support mechanism for blended volumes would likely be designed with consideration given to the impact on the supply of hydrogen to other end users. This could help provide confidence for end users of pure hydrogen to switch, as they could potentially displace those volumes of hydrogen being blended.

Question 60

Do you think that a reserve offtaker (e.g. blending) could help stimulate growth in hydrogen demand, by providing potential offtakers with more confidence to switch to hydrogen? If so, for how long might this be beneficial? What alternative measures could be enacted to help stimulate growth in hydrogen demand? Please explain your answer and provide any relevant evidence.

Demand Volatility

Even where producers have secured offtaker(s) of hydrogen, they may face volatile demand. Demand volatility can be driven by natural and commercial demand cycles, or financial and technical issues, which may lead to offtaker outages or closures. These risks may be temporary, e.g. if an offtaker shuts down for maintenance, or long-term, e.g. if an offtaker goes into insolvency.

Longer term, there is potential for storage and/or depth of market to help mitigate this risk, but blending could have value in helping to manage demand volatility by acting as a reserve offtaker, particularly during the early years of the hydrogen economy. In the next few paragraphs, we will review alternative means to help mitigate demand volatility and/or manage any impacts it may cause, to better understand the potential value of blending in this role. These means could be adopted by hydrogen producers or may be available through government support mechanisms, such as the Hydrogen Business Model for production.

If a producer is able to operate flexibly, they could more easily adjust production levels to respond to changes in demand. This may help mitigate any technical impacts caused by demand volatility. We have reviewed evidence on the ability for producers to operate flexibly, which indicates that electrolytic and CCUS-enabled methane reformation hydrogen production technologies are technically able to ramp up and down, though the extent of ramp down differs and operating at lower load factors may increase costs and risk equipment damage with some technologies.[64] We can also expect that advancements in technology will enable more production flexibility in the future.

There are technical and commercial risk mitigation strategies that may be available for hydrogen producers to help manage demand volatility and avoid the need to ramp up and down production. For example, a producer could design their production plant with multiple production units (sometimes called trains for CCUS-enabled projects or a number of electrolysers) to provide additional production flexibility in aggregate as well as increasing resilience of supply.

Demand volatility risk can also be mitigated through the commercial relationship between the producer and its offtakers, for example Take and Pay provisions which obligate the offtaker to both pay for a minimum volume of hydrogen and take physical delivery of it, transferring some of this risk to the offtaker. Requirements for Credit Insurance/Bank Guarantees can also mitigate the financial risk of counterparty default, providing time for a producer to find an alternative offtaker. Furthermore, as the hydrogen economy and number of available end users grows, contracting with multiple diverse offtakers with different demand profiles and contract lengths can smooth out variations in demand and reduce the impact of outages.

Government has also taken initiative to support hydrogen producers in managing volume risk. This includes the Hydrogen Business Model for production, which has been designed to help mitigate volume risk by providing a sliding scale of volume support. This manages volume risk (i.e. the risk of producers being unable to sell enough volumes of hydrogen to cover their costs) by paying a higher level of price support on low offtake volumes, with the level of price support tapering off as volumes increase. There are other features of the Hydrogen Business Model for production that could potentially manage volume risk, for example potential support towards smaller scale transport and storage costs through initial contracts to help connect producers and offtakers, and a requirement to have at least one eligible offtaker identified at the point of allocation. This business model forms part of a wider holistic approach to developing the hydrogen economy, as set out in the UK Hydrogen Strategy. We continue to build evidence and develop policy to support use of hydrogen across the economy, accelerating work to stimulate early demand in the 2020s.

The above mitigations may be sufficient to manage demand volatility risk without the need for a reserve offtaker, such as blending. However, blending may have value as an additional risk mitigation option, particularly in the early years of the hydrogen economy when there are likely to be fewer offtakers and when the geographical spread of offtakers is likely to be more

[64] Hydrogen Supply Chain Evidence Base (2018): https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base

constrained. If an offtaker became insolvent, for instance, blending may be able to absorb those volumes of hydrogen from the producer with relative flexibility. It is worth noting that it may only fulfil this role for hydrogen producers suitably located to blend and/or with any required transport infrastructure, under scenarios where a local blending limit (e.g. 20% by volume) has not already been reached.

Question 61

Do you agree with our assessment of the range of options to address demand volatility? In addition to these measures, do you think a reserve offtaker (e.g. blending) could have value in managing producer volume risk caused by volatile demand? Please explain your answer and provide any relevant evidence.

Summary and Further Considerations

As evidence for future hydrogen production and demand grows, we will assess the potential magnitude of volume risk to help determine the value that blending may have in managing this risk, and thereby help inform the economic case for blending. Any potential gap between available hydrogen production, the deployment of transport and storage infrastructure and the availability of end-users will be assessed, with consideration of whether blending could help 'bridge' this gap. The role of blending to manage volume risk will be assessed against other potential reserve offtakers.

Question 62

If you believe a reserve offtaker would be beneficial for the hydrogen economy, are there any alternative reserve offtakers that could fulfil this role instead of, or in combination with, blending? Please explain your answer and preferred reserve offtaker(s) with supporting evidence.

Question 63

In addition to those mentioned in this chapter, do you see any benefits and/or risks associated with blending? Please explain your answer and provide any relevant evidence.

Consultation questions

General Considerations

1. Do you agree with Government's analysis and vision for hydrogen network evolution through the different phases as described? Please explain your answer and provide any relevant evidence.
2. Do you agree with these key design principles for the transport and storage business models? Please explain your answer and provide any relevant evidence.

Hydrogen Transport Infrastructure

3. In your view, do you agree we have correctly identified and characterised the market barriers facing the development and operation of hydrogen pipelines and a hydrogen network? Are there any other market barriers we should be considering? Please explain your answer and provide any relevant evidence.
4. In your view, have we set out the main business model design options, or are there others that should be considered? Please explain your answer and provide any relevant evidence.
5. In your view, do you agree that uncertain demand and supply and limited user base will be the predominant barriers in a growth phase of hydrogen network development? Please explain your answer and provide any relevant evidence.
6. In your view, which business model design options do you consider may be suited to address the barriers in a growth phase? Please explain your answer and provide any relevant evidence.
7. In your view, are there any interim measures that we should be exploring to support the development of early hydrogen pipelines ahead of a hydrogen transport infrastructure business model being available? Please explain your answer and provide any relevant evidence.
8. In your view, is a RAB model, based on the natural gas RAB design, likely to be the most suitable business model during a steady state, or would another business model design be more appropriate? Please explain your answer and provide any relevant evidence.
9. In your view, is there a need for compatibility between a business model for a growth phase and a business model for a steady state, and how should this be managed? Please explain your answer and provide any relevant evidence.

10. In your view, is there a need for compatibility between a business model for hydrogen and a business model for natural gas, and how should this be managed? Please explain your answer and provide any relevant evidence.

11. In your view, are there any other considerations we should take into account? Please explain your answer and provide any relevant evidence.

12. In your view, what ownership arrangements do you think are likely to be suitable for hydrogen networks? Does this depend on the chosen business model and/or phase of network evolution? Please explain your answer and provide any relevant evidence.

13. In your view, is an external funding mechanism needed in a growth phase of network evolution? If so, at what stage of market and network evolution might it no longer be required? Please explain your answer and provide any relevant evidence.

14. In your view, if needed, what are your views on possible approaches to funding a potential external subsidy mechanism? Please explain your answer and provide any relevant evidence.

15. In your view, how may other onshore hydrogen pipelines, including pipelines transporting hydrogen through a carrier, develop in the UK? Please explain your answer and provide any relevant evidence.

16. In your view, is a business model required for the development of other onshore pipelines for hydrogen and, if so, how might a business model for onshore pipelines transporting hydrogen as a gas be adapted for this? Please explain your answer and set out the specific market barriers that a business model would be required to address as well as providing any relevant evidence.

17. In your view, how may offshore hydrogen pipelines develop in the UK? Please explain your answer and provide any relevant evidence.

18. In your view, is a business model required for the development of offshore hydrogen pipelines and, if so, how might a business model for onshore pipelines transporting hydrogen as a gas be adapted for this? Please explain your answer and set out the specific market barriers that a business model would be required to address as well as providing any relevant evidence.

19. In your view, how may vehicular transport for hydrogen develop in the UK? Please do include any other vehicular transport we may have missed. Please explain your answer and provide any relevant evidence.

20. In your view, is a business model required for vehicular transport and, if so, how might a business model for onshore pipelines transporting hydrogen as a gas be adapted for this? Please explain your answer and set out the specific market barriers that a business model would be required to address as well as providing any relevant evidence.

Hydrogen Storage Infrastructure

21. What do you consider to be the key technical barriers associated with the development of particular approaches to storing hydrogen which should be considered? Please explain your answer and provide any relevant evidence.

22. In your view, have we correctly identified and characterised the key market barriers facing larger-scale hydrogen storage infrastructure, and in particular its deployment by the late 2020s? Please explain your answer and provide any relevant evidence.

23. Do you agree that volume and revenue risk stemming from demand uncertainty represents the main barrier to the deployment of storage infrastructure? Please explain your answer and provide any relevant evidence.

24. Do you agree that Government should develop a dedicated business model for hydrogen storage (subject to value for money and need) and that it should be designed to be technology-neutral? Please explain your answer and provide any relevant evidence.

25. Do you agree that business model support should focus on larger-scale storage, or is there a need to provide further support for small scale storage? Please explain your answer and provide any relevant evidence.

26. In your view, who are likely to be users of hydrogen storage infrastructure and which group, or groups, might be best placed to provide revenue to storage owners? Please explain your answer and provide any relevant evidence.

27. Do you agree with our initial view that a storage infrastructure business model should support providers of hydrogen storage infrastructure (as opposed to users of storage infrastructure)? Please explain your answer and provide any relevant evidence.

28. What are your views on possible approaches to funding a potential subsidy mechanism? Please explain your answer and provide any relevant evidence.

29. In your view, have we correctly identified the main parties whose needs any storage business model will need to account for, and have their needs been correctly outlined? If not, what additional needs should be accounted for? Please explain your answer and provide any relevant evidence.

30. In your view, have we set out the main business model design options, or are there others design options, or variants, that should be considered? Please explain your answer and provide any relevant evidence.

31. In your view, are any of the business model design options set out above more suited to supporting particular types of storage infrastructure than others? Please explain your answer and provide any relevant evidence.

32. In your view, which business model design options would be most suitable to address the identified market barriers? Please explain your answer and provide any relevant evidence.

33. In your view, which organisations are best placed to carry out the roles of economic regulator/counterparty/administrator that would be required to implement the business models set out above? Are there any other roles that you consider may be required? Please explain your answer and provide any relevant evidence.

34. In your view, are there any early interim measures that we should be exploring to support the development of the first hydrogen storage projects, ahead of a hydrogen storage business model being available? Please explain your answer and provide any relevant evidence.

Strategic Planning

35. In your view, should the build out of hydrogen transport infrastructure evolve through either a) a solely a market-led approach, b) a form of strategic planning, or c) neither? Please explain your answer and provide any relevant evidence.

36. In your view, should the build out of hydrogen storage infrastructure evolve through either a) a solely a market-led approach, b) a form of strategic planning, or c) neither? Please explain your answer and provide any relevant evidence.

37. In your view, if strategic planning was to be implemented for hydrogen transport infrastructure what form should it take? a) central network planner, b) coordinated approach, c) evolved approach, d) a blend of strategic planning and market-led approaches, or e) none of the above? Please explain your answer and what this approach might look like in a UK context.

38. In your view, if strategic planning was to be implemented for hydrogen storage infrastructure, what form should it take? a) central network planner, b) coordinated approach, c) evolved approach, d) a blend of strategic planning and market-led approaches, or e) none of the above? Please explain your answer and what this approach might look like in a UK context.

39. Further to your answers to questions 35 – 38 above, in your view, is it important for there to be alignment between the ways in which hydrogen transport infrastructure and hydrogen storage infrastructure are built out and, if relevant, the form of strategic planning involved? Please explain your answer and provide any relevant evidence.

40. Considering onshore and offshore hydrogen transport and storage infrastructure, do they have specific characteristics, or wider interactions with other infrastructure, which may mean the different infrastructure types favour a market-led approach or a form of strategic planning? Please explain your answer and provide any relevant evidence.

41. In your view, are there any factors, other than those listed above, that should be considered if a strategic planning approach was to be adopted? Please explain your answer and provide any relevant evidence.

42. If the UK were to create a central network planner role for hydrogen, would the FSO (if it is established by the Energy Bill) be best placed to take this role on? If not or if the FSO is not established, is another organisation more suited to the role or would a new body need to be created? If yes, in your view what temporary solution could be implemented prior to the FSO taking on the role? Please explain your answer.

43. In your view, what role could the strategic planner have in the provision of business model support? How would this role change under different strategic planning approaches? Please explain your answer and provide any relevant evidence.

44. In your view, should government seek to identify "low or no-regrets" and/or systemically important projects to prioritise their development if possible? If so, how might such projects be identified and how might the best be prioritised? Please explain your answer and provide any relevant evidence.

Regulatory Framework

45. In your view, are the existing market framework and industry commercial arrangements for hydrogen optimal for supporting the development of hydrogen transportation and/or storage infrastructure? Please note we are seeking your views on the whole existing market framework and industry commercial arrangements, including any possible gaps, and not just matters relating to the Gas Act. Please explain your answer and provide any relevant evidence.

46. If you answered 'No' to the previous question, how do you think this should be addressed:

    a. Through amendments to the existing market framework / industry commercial arrangements?

    b. Through the replacement of aspects of the existing market framework / industry commercial arrangements (for example, with new arrangements that are specifically designed for hydrogen)?

    c. Through a different approach?

47. Further to the regulatory areas set out below, in your view, is the existing onshore non-economic regulatory framework optimal for supporting the development of a rapidly expanding UK hydrogen economy?

48. If you answered 'No' to the previous question, how do you think this might be addressed (regulation/standards/guidance, etc.)? Please explain your answer and provide any relevant evidence.

49. In your view, is the existing regulatory framework for the non-pipeline transportation of hydrogen optimal for supporting the development of a rapidly expanding UK hydrogen economy?

50. If you answered ‘No’ to the previous question, how do you think this might be addressed (regulation/standards/guidance, etc.)? Please explain your answer and provide any relevant evidence.

51. In your view, are the current NSIP and TCPA regimes optimal for supporting the development of a rapidly expanding UK hydrogen economy?

52. If you answered ’Yes’ to the previous question, please explain which elements you think are conducive to the development of the hydrogen economy. If ‘No’, please explain how you think they might be improved (e.g., a dedicated hydrogen NPS). Please explain your answer and provide any relevant evidence.

53. In your view, is the existing environmental regulatory framework optimal for the future hydrogen economy?

54. If you answered ‘No’ to the previous question, how do you think this might be addressed? Please explain your answer and provide any relevant evidence.

55. Further to the regulatory assessment set out above, in your view, is the existing offshore non-economic regulatory framework optimal for supporting the development of a rapidly expanding UK hydrogen economy?

56. If you answered ‘No’ to the previous question, how do you think this might be addressed (regulation/standards/guidance, etc.)? Please explain your answer and provide any relevant evidence.

Hydrogen Blending

57. To what extent might lead times for hydrogen transport and storage infrastructure limit the scale of hydrogen production capacity in the early years of the hydrogen economy? If applicable, can this be quantified for your project (e.g. in terms of production volumes, load factors, etc.)?

58. Do you see a potential for blending in helping to address this challenge by providing a route to market as a reserve offtaker? For how long do you expect this role for blending may be required? Please explain your answer and provide any relevant evidence.

59. Do you think that new transport infrastructure for 100% hydrogen may be required solely for the purposes of blending? If applicable, what scale of 100% hydrogen transport infrastructure would your project require to reach the GB gas networks (at distribution or transmission level)?

60. Do you think that a reserve offtaker (e.g. blending) could help stimulate growth in hydrogen demand, by providing potential offtakers with more confidence to switch to hydrogen? If so, for how long might this be beneficial? What alternative measures could be enacted to help stimulate growth in hydrogen demand? Please explain your answer and provide any relevant evidence.

61. Do you agree with our assessment of the range of options to address demand volatility? In addition to these measures, do you think a reserve offtaker (e.g. blending) could have value in managing producer volume risk caused by volatile demand? Please explain your answer and provide any relevant evidence.

62. If you believe a reserve offtaker would be beneficial for the hydrogen economy, are there any alternative reserve offtakers that could fulfil this role instead of, or in combination with, blending? Please explain your answer and preferred reserve offtaker(s) with supporting evidence.

63. In addition to those mentioned in this chapter, do you see any benefits and/or risks associated with blending? Please explain your answer and provide any relevant evidence.

Next steps

The purpose of this consultation is to ensure that ongoing policy development on business model designs, regulatory arrangements, strategic planning and the role of blending takes in to account all relevant considerations in meeting the policy objectives that government initially set out and summarised above and that all stakeholders have the opportunity to provide relevant feedback.

The consultation will be open for **12 weeks closing on 22 November 2022**. The department will analyse all responses to identify if we have overlooked any aspects that may inhibit the application of policy and address any relevant points made by stakeholders to ensure we can fully achieve our policy aims. We aim to publish our response to this consultation alongside a summary of the responses received in **Q2 2023**.

On-going engagement will form an important part of our work. We intend to continue to engage with stakeholders through working groups, forums and bilateral meetings.

This consultation is available from: www.gov.uk/government/consultations/proposals-for-hydrogen-transport-and-storage-business-models

If you need a version of this document in a more accessible format, please email enquiries@beis.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.