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REA response to BEIS hydrogen transport and storage infrastructure consultation

The Association for Renewable Energy & Clean Technologies (REA) is pleased to submit this response to the above call for evidence. The REA represents industry stakeholders from across the whole renewables sector and includes dedicated member forums focused on hydrogen, green gas, biomass heat, biomass power, renewable transport fuels, thermal storage and energy from waste (including advanced conversion technologies). Our members include generators, project developers, heat suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 500 corporate members of the REA, making it the largest renewable energy trade association in the UK.

The REA has a working group dedicated to hydrogen that sits under the umbrella of the long-established Green Gas and Hydrogen Forum. This represents several companies involved in this fast-moving area, including ITM Power, AMP Clean Energy, Supercritical Solution, Centrica, Vitol Services, Octopus Energy, Airliquide, AFRY Management Consulting, EY, Progressive Energy, HiiROC, Clarke Energy, Cadent Gas, Northern Gas Network, Peel NRE, Advanced Biofuels Solutions, Bioenergy Infrastructure Group, BayoTech, Drax, EQTech, Enfinium, Omni Conversion Technologies, Future Earth Energy, Kew Technology, Foresight Group, Suez Recycling & Recovery UK, CNG Services, GHD, Pegoraro Gas Technologies, JCB, BOC, Reynolds logistics, Thyson Technology, National Grid ESO, Gravitricity, Storelectric Ltd, Ricardo Energy & Environment, Fitchner Consulting Engineers, CMS Cameron McKenna, BDB Pitmans, Clarion Solicitors, Savills, Eversheds, Burges Salmon, Shakespeare Martineu, Osborne Clarke, Thames Water, Severn Trent Green Power, Anglian Water Services, Almax Partners, Siemens Financial Services, Eco Sustainable Solutions, Safe SpA and others.

Key messages

- We welcome the work undertaken by BEIS to inform and shape the consultation and their extensive engagement with industry during the consultation period.
- The roll out of critical hydrogen transport and storage infrastructure is urgently required to support the development of the hydrogen economy, help the UK meet their 10 GW hydrogen production target by 2030, as well as provide benefits to the whole energy system, energy security and a greater degree of system resilience. Hydrogen transport and storage infrastructure are key enablers of the hydrogen economy.

The enduring regime for transportation and storage

Timeframe

- The Government 2025 timeframe for the business models is far too long and may undermine the ability of the sector to scale up capacity during this decade. Given the long lead times of large-scale transportation and storage projects, we are concerned that this timeframe may result in key infrastructure not being delivered and available to support hydrogen production before the end of 2030 at the earliest. In addition, this timeframe is not aligned with

Government timescales for delivering Track 1 clusters[1] and meeting the 2 GW target of low carbon hydrogen production in construction and operation by 2025. Business models to support this infrastructure development therefore need to be designed and introduced as soon as practically possible.

Transportation

- For transportation, we consider that a Regulated Asset Base (RAB) model (e.g. a 'Hydrogen RAB') would be the best enduring option and should be designed with flexibility in mind to enable it to be adapted as the hydrogen economy evolves. This should be designed and rolled out as soon as practically possible.

Storage

- The introduction of a business model for storage owners is also critical and required immediately to enable investment in storage infrastructure. Our members' view is that business model support to owners, or prospective owners of storage facilities (as opposed to users) would be more effective to address the identified market barriers. Regulated returns (RAB or Income Cap and Floor) and/or contractual arrangements (e.g. a contract for difference or a contractual mechanism under the RAB model) could all work to support storage infrastructure development as long as they alleviate the key identified market barriers and facilitate appropriate and efficient allocation of risks between parties. We have made recommendations on how different models could work in the relevant consultation responses.

Interim measures

- We urge Government to provide interim, bespoke measures to support both, transportation and storage projects, that are strategically important to support the scale up of the hydrogen sector in the UK and can get the hydrogen economy going now. Some of these projects are already underway: these include pipelines and storage projects in the Northwest Cluster (e.g. the INOVYN Hydrogen Storage and 100% pipelines being developed in the Hynet Cluster) and in the East Coast cluster (e.g. the Aldborough Hydrogen Storage facility). These projects will need to take FID way before 2025 (e.g. in 2023).
- Interim measures for transportation and storage should be grandfathered and/or compatible with the enduring regimes.
- These measures may need to be different for transportation and storage. For storage these could take the form of contractual mechanisms underpinned by a private law contract where the Government agrees to pay for capacity made available. For transportation, the current gas RAB could be adopted, or direct Government support could be provided to deliver transportation infrastructure before a 'Hydrogen' RAB is rolled out.

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[1] Government has committed to deploy CCUS in a minimum of 2 industrial clusters by the mid-2020s. HyNet and East Coast Clusters were confirmed as Track-1 clusters to be delivered by 2025.

Hydrogen blending

- Government should take a positive decision as soon as possible and no later than 2023 on the important, strategic role of hydrogen blending into both, the gas transmission and distribution networks, to support the scale up of the hydrogen sector at the early stages of the hydrogen economy.
- Supply investment decisions needed to achieve 10 GW by 2030 will need to take place before the establishment of an expansive hydrogen network. Hydrogen blending can therefore play a crucial role in enabling early hydrogen production before the creation of extensive hydrogen networks.
- Hydrogen blending should be supported financially. Failing to provide adequate financial support for hydrogen blending will result in no blending taking place, which could hamper the development and scale up of the hydrogen sector in the UK. The Hydrogen Business Model would be the obvious mechanism to use for this in the short term. In the longer-term other mechanisms such as the successor scheme of the Green Gas Support Scheme could also be considered.
- A decision by Government on hydrogen blending should not restrict where blending can take place. Blending into the gas transmission as well as the local transmission networks would maximise the hydrogen production capacity that can be built as those networks are well geographically distributed across the UK.

Strategic planning

- In our view, strategic planning will be essential for both critical transportation and storage infrastructure to be rolled out at the right pace, in the right place and at the right scale to maximise the benefits to the whole energy system and reduce inefficiencies.
- A strategic approach would, however, need to be implemented at a sustained pace given the speed required to deliver strategic infrastructure. Coordinated decisions should be made as soon as possible to facilitate the required investments to meet the desired objectives.
- It is crucial to understand how a strategic approach is adopted ie what is the exact mechanism underpinning a strategic approach. This should be set out in detail and there needs to be a clear and detailed roadmap for how the Future System Operator (FSO) will deliver on a whole system approach which gives equal weighting within the organisation between gas and electricity.
- While we wait for the FSO to be established BEIS or another relevant organisation could act as an intermediary central planner before the FSO comes into force, to allow rapid progress to be achieved.

Regulatory framework

- Government should review existing regulatory frameworks to facilitate the supply and use of hydrogen as current regulations don’t make provisions for the use of hydrogen in gas networks and new codes must be developed to enable this. While certain aspects of the gas codes and regulations could be extended to hydrogen to promote faster deployment, it would be beneficial for the industry to have clear and concise hydrogen-specific regulation.

We are happy to further engage with BEIS on this matter following the consultation.

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.**

We broadly agree with the hydrogen network evolution described by BEIS in the consultation and we also agree that the need for a large, integrated and resilient hydrogen network is not contingent on decisions around the use of hydrogen in heating homes.

However, we emphasise that delivering this infrastructure at pace is fundamental if we are to meet the Government's hydrogen production targets (10 GW by 2030). Business models to support this infrastructure development will therefore need to be designed and introduced as soon as practically possible.

Within the Energy Security Strategy Government has committed to design by 2025 new business models for hydrogen transport and storage. Given the long lead times of large-scale infrastructure projects (which could take up to 4.5 years in some cases), the Government timeframe may result in key infrastructure not being delivered and available to support hydrogen production before the end of 2030 at the earliest.

In addition, this timeframe is not aligned with Government timescales for delivering Track 1 clusters[2] and meeting the 2 GW target of low carbon hydrogen production in construction and operation by 2025.

Our members' feedback is that the Government timeframe is far too long and may undermine the ability of the sector to scale up capacity during this decade.

If Government cannot deliver business models well before 2025, then we urge them to provide interim measures to support both transportation and storage projects that are strategically important to support the scale up of the hydrogen sector in the UK and can get the hydrogen economy going now. Some of these projects are already underway: these include pipelines and storage projects in the Northwest Cluster (e.g. the INOVYN Hydrogen Storage and 100% pipelines being developed in the Hynet Cluster) and in the East Coast cluster (e.g. the Aldborough Hydrogen Storage facility). These projects will need to take FID way before 2025 (e.g. in 2023).

<u>Alternative production pathways</u>

We would also urge government to factor into its analysis the potential for alternative production pathways, such as thermal plasma electrolysis and pathways other than water-electrolytic and CCUS-enabled, to deliver centralised or local production of hydrogen at pressure – saving transport, storage, and compression costs.

Government should be alert to the possibility that by supporting modes of production that are modular, scalable and capable of being sited at or near to the point of use, the overall

[2] Government has committed to deploy CCUS in a minimum of 2 industrial clusters by the mid-2020s. HyNet and East Coast Clusters were confirmed as Track-1 clusters to be delivered by 2025.

requirements for both transportation and storage might be reduced with attendant cost savings. These pathways should therefore be considered and supported.

Storage technologies

We would like to flag that table 1 on page 15 of the consultation is not comprehensive. There are innovative scalable approaches to hydrogen storage being developed by some of our members. For example, lined rock shaft hydrogen storage systems are a new storage technology that has been omitted from the list of potential storage solutions. A member has highlighted that lined rock shafts store a medium to large amount of hydrogen (100 to 120 tonnes) at pressures of 200bar. Shafts can be sunk in varied geologies and the system is therefore not limited to certain geologies. The ability to provide a mid-scale solution is vital. It is a segment which is poorly served by existing solutions, between the salt caverns (very large) and metal vessels (limited capacity). As such, it is well suited to the requirements of the industrial hydrogen hubs around which most of our hydrogen economy will be based. Lined rock shafts are particularly relevant in areas of the UK (which is to say, the large majority of the UK, including all of Scotland where many of the hydrogen hubs will be based) where there are no or limited salt deposits and there are few geological structures suitable for current hydrogen storage technologies.

Further information on transportation and storage technologies can be read in this blog written by another member of the REA.

A member said that the question of the right storage solution is closely connected to the question of how hydrogen will be utilised at scale as we transition to net zero. Only when there is a clear understanding of the likely producers and consumers of hydrogen, will we be able to identify the storage solutions likely to best serve their requirements.

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.**

Yes, we broadly agree with the principles set out by BEIS for the business models. However, as highlighted elsewhere in this response, rapid action is required to promote investment and business models must be designed and rolled out at pace.

In line with our members' feedback, we would also suggest further specification of the meaning of several of the core principles:

- The principle of promoting market development should be interpreted through a wider lens. While business models are required to provide the external support necessary to kick-start the hydrogen economy, they should be developed with the specific aim of building a market that is not reliant on external support in the long-term. Early decisions must pre-empt the evolution of the system, whilst incorporating flexibility to enable the transition to a market-led approach in the future as the economy matures.
- Our members also suggest that timeliness of business models should be adopted as an additional critical principle that cuts across and complements several others: compatibility with other policies; avoiding unnecessary complexity; and reducing support over time. Storage and transport will play a key role in unlocking synergies across the whole hydrogen value chain and decisions must be made as soon as possible to avoid delays and duplication of costs elsewhere.

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.**

Yes, we consider that BEIS has adequately identified the key barriers. Demand and supply uncertainty is the primary market barrier for transportation, due to high levels of uncertainty regarding prices and volumes.

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.**

Yes, we consider that the main business model options have been identified in the consultation.

Our view is that a regulatory asset base (RAB) mechanism (e.g. a 'Hydrogen RAB') would be most suited to support onshore hydrogen pipelines development and should be rolled out as soon as possible. We have set out the reasons for this below.

Firstly, by providing fully regulated returns this mechanism provides revenue certainty to investors and helps mitigate the uncertainty of supply and demand. The RAB funding model is structured to incentivise private investment in projects with significant upfront capital expenditure, a long construction period and a long asset life, by providing a secure return on investment for developers and other investors.

Secondly, it also provides the opportunity for a strong regulatory oversight, which is needed to ensure the networks are run effectively, efficiently and are independently audited and assessed. RAB can be designed to include efficiency and performance incentives for the networks, which would normally be motivated under a competitive market.

In addition, the RAB model is already widely adopted in the UK for monopoly infrastructure assets such as water, gas and electricity networks and works well. So, it is an established model and a known mechanism that deals well with market barriers associated with natural monopolies, as rightly highlighted by BEIS in the consultation.

Finally, RAB ensures fair and reasonable costs are recovered from consumers, and the regulator is there to ensure no excessive costs are placed on consumers.

We don't see an issue in rolling out a RAB during the growth phase. The model would set out the methodology to calculate how much revenues the networks would need and are allowed to recover to cover their costs and a fair level of return. We don't see any reason for delaying the development of the methodology during a growth phase. Our recommendation is that this model should be rolled out as soon as practically possible.

The model will also need to be designed to be flexible/adaptable over time.

The way such revenues are recovered, however, could be changed over time as the hydrogen economy evolves, for example from the growth to the steady phase. In other words, what could be changed according to the growth and the steady phase is the funding mechanism that sets out how these costs are recovered (i.e. who pays for them during the growth phase and the steady phase). As rightly set out by BEIS, initially the pool of network users will be small and therefore costs very high unless there is an external funding mechanism to supplement these costs, or costs are spread across a wider network of consumers.

Member feedback is that initially any cost shortfalls could be spread across both, electricity and gas consumers. This would make sense economically as the costs would be spread across a larger group and would therefore be lower. It also makes sense from a system perspective as hydrogen infrastructure would benefit electricity users, as well as gas users by benefitting the whole energy system, providing flexibility and resilience. Gas users would ultimately benefit directly from the transition of natural gas supplies to hydrogen supplies whilst electricity users would indirectly benefit from hydrogen storage and power generation from hydrogen power stations which would provide system flexibility.

Planning and clear visibility of future infrastructure requirements will also be required to avoid projects/infrastructure being oversized, which may in turn result in higher costs and lower value for money. Regulatory authorities should be able to anticipate how much infrastructure will be needed in the future to avoid overbuilding and overinvestment resulting in excessive costs for consumers.

A regulatory model will have to set out clearly what is the required level of unbundling of the monopolistic network companies from other companies performing competitive activities (e.g. production and supply of energy). Unbundling would ensure a company performing a market-based or competitive activity is constrained and eventually prevented from also performing a monopolistic activity and vice versa. A recent report published by ACER/CEER highlights that unbundling of activities shall be the main principle of the future regulatory model for mature hydrogen systems (in line with proposals under the Hydrogen and Decarbonised Gas Markets Package), though during the early phase of development flexibility would need to be provided and potentially some temporary or conditioned examples.

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.**

Yes, we agree that these would be the key barriers investors and developers would face to develop such infrastructure and reach FID.

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.**

Our view is that we shouldn't delay the adoption and implementation of a RAB model to support development of key transportation infrastructure. There can be effective ways within a RAB model to deal with the challenge caused by a small group of network users initially. For example, an external funding mechanism could initially be provided to ensure infrastructure users are not charged excessively or costs could be initially spread across a wider range of users (e.g. electricity and gas). This would make sense economically as the costs would be spread across a larger group and would therefore be lower. It also makes sense from a system perspective as hydrogen infrastructure would benefit electricity users, as well as gas users by benefitting the whole energy system, providing flexibility and resilience.

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.**

As highlighted before, the Government timeframe (introduction of the business models by 2025) will result in key infrastructure not being delivered and available to support hydrogen production before the end of 2030 at the earliest. Our members' feedback is that this is far too late and may undermine the ability of the sector to scale up capacity during this decade.

Therefore, we urge them to provide interim measures to support both transportation and storage projects that are strategically important to support the scale up of the hydrogen sector in the UK and can get the hydrogen economy going now. Some of these projects are already underway: these include pipelines and storage projects in the Northwest Cluster (e.g. the INOVYN Hydrogen Storage and 100% pipelines being developed in the Hynet Cluster) and in the East Coast cluster (e.g. the Aldborough Hydrogen Storage facility). These projects will need to take FID way before 2025 (e.g. in 2023). We also understand that an agreement on a business model for repurposing Rough to hydrogen

In the interim the current gas RAB could be adopted to cover or direct Government support that could be provided to deliver transportation infrastructure before an 'Hydrogen' RAB is rolled out.

Other interim measures could include:

- Greater government and industry coordination across projects and energy sub-sectors to realise efficiencies and synergies. For example, where low regrets hydrogen pipeline infrastructure could be delivered alongside CCUS pipeline infrastructure (e.g. National Grid Ventures' Humber Low Carbon Pipelines project), early, pre-emptive investment could avoid duplication of cost and effort; and
- focus on a specific regional cluster (e.g. the East Coast Cluster) to allow for faster planning and development of investments.

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.**

A regulatory based approach based on the current gas RAB is most suitable to this type of infrastructure as it deals best with the market barriers associated with a natural monopoly and is a model that is very well established and works well for the gas, electricity and water networks.

The model provides a high level of confidence to investors, delivers value for money and could be adapted to ensure efficient system operation.

However, it is likely that a subsidy or funding mechanism will be needed in the growth phase to ensure consumers are not made to pay an excessive cost.

A RAB would also provide the opportunity for a strong regulatory oversight which is needed to ensure there is a neutral / independent assessment of the need for the infrastructure to be built or repurposed, or even decommissioned). Properly regulated oversight of the network development would minimise the risk of overinvestment.

Some members have said other business models could be considered for the steady state, depending on how the hydrogen market evolves. A member highlighted that in the event a national market for hydrogen does not emerge, this could naturally result in a more locational market design (e.g. zonal virtual hub or point-to-point system) resulting in different locations along the network having a different price of being utilised. This would lead to price differentials which would convey the value of the transfer capability between the relevant locations. In such a situation, a more market-based model such as a Cap and Floor or even a full merchant model could be considered, but it is too early at this stage to know what alternative market design would be most appropriate. It may therefore be advisable to keep all options open at this stage.

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.**

Yes.

As highlighted above, we don't think there needs to be a different model adopted between the growth phase and the steady phase, but rather a different cost recovery mechanism. In the event there is a different business model in the steady phase, this should definitely be compatible. Within any transition from a regime to the next one it is vital that the grandfathering principle applies (such that any rights offered under the previous regime to assets cannot be withdrawn by subsequent regulatory changes / change to the regime.

There will also need to be compatibility between any measures adopted in the interim to support projects before a RAB is rolled out and the enduring RAB. The interim support needs to be consistent with the enduring regime; this can be delivered by grandfathering projects supported by interim measures.

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.**

Yes.

We consider that a degree of compatibility is required, particularly where there is an overlap with the use of existing infrastructure. Utilising the same network and similar market arrangements for hydrogen and gas would provide a greater degree of confidence and simplicity for market participants. However, this would largely depend on the technical feasibility of 'switching' from methane gas to hydrogen gas in the networks.

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

We don't have any other considerations.

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.**

We consider private ownership as most suitable for hydrogen networks. Under the appropriate regulatory/business model option, this arrangement is likely to deliver greatest levels of efficiency in the best interest of consumers.

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.**

Yes, as previously highlighted, an external funding mechanism would initially be needed to ensure consumers are not charged excessively.

Initially the pool of network users will be small and therefore costs very high unless there is an external funding mechanism to supplement these costs, or costs are spread across a wider network of consumers.

Member feedback is that initially any cost shortfalls could be spread across both, electricity and gas consumers. This would make sense economically as the costs would be spread across a larger group and would therefore be lower. It also makes sense from a system perspective as hydrogen infrastructure would benefit electricity users, as well as gas users by benefitting the whole energy system, providing flexibility and resilience. Gas users would ultimately benefit directly from the transition of natural gas supplies to hydrogen supplies whilst electricity users would indirectly benefit from hydrogen storage and power generation from hydrogen power stations which would provide system flexibility.

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.**

The cost recovery mechanism for the RAB could be adapted over time. Costs could be initially spread across a wider range of users (e.g. gas only or electricity and gas). This would make sense economically as the costs would be spread across a larger group and would therefore be lower. It also makes sense from a system perspective as hydrogen infrastructure would benefit electricity users, as well as gas users by benefitting the whole energy system, providing flexibility and resilience.

Some members have said the external mechanism should be funded through general taxation, rather than consumers' bills, to ensure this is done in a progressive manner rather than regressive. They also stressed that whatever is the mechanism, it should not place an undue burden on natural gas and/or electricity consumers, nor penalise initial hydrogen uptake.

For information, the ACER/CER report emphasises that the recast Decarbonised Gases and Hydrogen Package Regulation proposes, under Article 4, a mechanism for users of natural gas networks to partly subsidise the costs of hydrogen networks. This mechanism is based on financial transfers to be recovered from domestic points of natural gas networks. These transfers should not be larger than the allowed revenue of hydrogen operators and should be approved for a limited period in time that can never be longer than one third of the depreciation period of the hydrogen infrastructure concerned. Other relevant publications recently published by ACER can be read here and here.

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.**

Our members' view is that transport of hydrogen is likely to be predominantly in the form of gas through onshore pipelines, but hydrogen carriers, such as ammonia, could also play a potentially important role in import/export as well as certain end-uses, notably in the maritime and aviation sectors. Consequently, smaller scale networks and point-to-point pipelines suitable for these carriers may develop around port and airport infrastructure.

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.

Yes.

A business model would be appropriate and required for other onshore pipelines.

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

Some offshore pipelines will be critical assets in the development of the hydrogen sector.

A member has highlighted that in the early phase, offshore pipelines may be those used to connect offshore storage assets to onshore production and consumption. They said that any investment associated with such offshore pipelines should be considered as part of the storage asset itself and consequently covered by the storage business model.

This member has also stressed that in the long term, the UK should aim to be a net exporter of hydrogen. If this were to materialise, we expect more significant offshore pipelines (e.g. interconnectors) are likely to develop, facilitating international trade of hydrogen as part of a well-developed hydrogen economy which extends to Europe and beyond. Smaller offshore pipelines could then link offshore storage assets with these interconnectors resulting in multi-purpose assets.

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.**

See answer above.

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.**

Vehicular transport for hydrogen will be an early feature of the UK hydrogen economy, playing an important role prior to the development of extensive hydrogen pipelines. To help facilitate the early deployment of hydrogen uses and linking supply and demand, vehicular transport storage will be essential. We encourage BEIS to work with HSE and other regulatory bodies to allow vehicular transport of hydrogen at 700 bar pressure, in order to make this transport function more efficient.

In the short term, vehicular transport will enable the decarbonisation of a greater range of potential hydrogen users, particularly those who, by definition, require access to hydrogen in a range of locations.

A member stated that in cases where battery electrification is not cost effective or feasible, the switch to hydrogen for companies with large vehicle fleets operating on diesel should be relatively easy. However, it is currently inhibited by the absence of a sufficient number hydrogen refuelling stations and their limited geographic spread. Vehicular transport of hydrogen provides a clear means of overcoming this.

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.**

Yes.

A business model would be appropriate and required for vehicular transport, which has strong complementarity with large-scale storage given their distinct purposes.

An external support could facilitate the development of the vehicular transport, by encouraging investments in the appropriate technology, incentivising uptake of the technology and accelerating further use cases. Over time, this may drive the cost of vehicular transport down through innovation and economies of scale.

The most appropriate form of business model for vehicular transport would need to be explored further. In addition to business model support, there should be coordination by BEIS to overcome the existing regulatory barriers to vehicular hydrogen transport, such as ensuring the HSE and other relevant regulatory bodies have sufficient resources to facilitate the changes required. There should also be coordination and joined up thinking between BEIS and DfT.

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.**

There are further technical challenges that need to be understood for underground storage, both for repurposing existing assets to hydrogen or creating new sites. Some of our members who operate large scale storage assets in the UK will provide significant detailed feedback to BEIS in their consultation responses.

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.**

Yes. In our view BEIS have correctly identified the key barriers to develop storage infrastructure. The greatest risk for these assets is utilisation in the early phases.

Under any scenario consistent with the UK decarbonisation targets there is likely to be a significant requirement for hydrogen storage for flexibility and resilience. Storage will help manage the increased shares of variable renewable sources in the power system grid and also the high seasonality of energy demand. However, the revenues that such facilities would produce are highly uncertain given the significant uncertainties associated with hydrogen supply and demand at this stage of the hydrogen economy.

Although the hydrogen economy is developing rapidly, it is still challenging to establish precisely at what point hydrogen storage facilities will be used at sufficient scale to provide reliable revenue streams.

While existing depleted oil and gas fields such as Rough could be used to store blended hydrogen and methane in the transition to a 100% hydrogen, the high volatility of wholesale gas prices and the significant uncertainty of their trajectory over time makes it challenging to invest into this kind of projects. Due to this, investment in large-scale hydrogen storage will only be possible if underpinned by a business model that provides significant certainty and confidence to investors.

BEIS mentions in the consultation that the cost of developing larger-scale storage infrastructure is likely to be in the order of hundreds of millions of pounds, but note that some of these projects e.g. repurposing of depleted gas and oil fields could be more in the region of billions of pounds. We agree that such high capital costs, combined with long lead times and revenue uncertainty make these investments especially risky. There is a need for rapid action to promote investment, as hydrogen will be a vital component required for the UK to achieve its net zero ambitions.

A member highlighted that the uncertainty – affecting both storage capacity requirements and storage prices – relates not just to the volume's aggregate supply and demand, but also the nature of both supply and demand. For example, the storage needs patterns of electrolytic hydrogen producers (seeking to balance peaks and troughs in electricity prices) will differ significantly from those of CCUS-enabled hydrogen producers (seeking to keep production assets operating as close to stable as possible for increased efficiency). The storage needs patterns of industrial users, for example, will also differ significantly from those of domestic customers/their suppliers if hydrogen for home heating were to develop.

Prices in the storage market will also depend on the wider evolution of hydrogen prices. The evolution of hydrogen price discovery is highly uncertain, as recognised by BEIS in the decision on business models for low carbon hydrogen production. Such evolution will depend and rely on policy decisions related to the design of the Government's low carbon hydrogen production business model.

In addition to explicit revenue risk from uncertain volume and price, a member of the REA has identified that hydrogen storage faces additional barriers from:

- The limited expected user base for hydrogen in the early years of any transition, which directly limits any revenue-raising potential and makes financing significant upfront fixed costs challenging;
- Network externalities, which make the viability of critical storage infrastructure dependent on developments elsewhere in the hydrogen economy - not least volumes of supply, demand and the ability to transport, all of which are at least in part dependent on the development of adequate storage;
- Risks to the financial stability and economic success of potential counterparties/users of storage given the nascency of the hydrogen economy, which creates barriers to establishing a bankable proposition on the basis of long-term contracts or similar relationships with prospective users.
- Policy and regulatory risk: development of the hydrogen economy relies on a range of policy and regulatory interventions, and an ongoing and lasting commitment of government and regulators to supportive policies. Given uncertainty with regard to the direction of the hydrogen economy, risks (real or perceived) that government policy may change in future, as well as the overarching need for joined-up, urgent decision making on key tenets of hydrogen policy, there are significant barriers to the development of large-scale storage in this space.

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.**

Yes. See our response to question 22.

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.**

Yes.

The introduction of a business model for storage owners is critical and required immediately to enable investment in storage infrastructure.

Our members' view is that business model support to owners, or prospective owners of storage facilities (as opposed to users) would be more effective to address the identified market barriers. Regulated returns (RAB or Income Cap and Floor) and/or contractual arrangements (e.g. a contract for difference or a contractual mechanism under the RAB model) could all work to support storage infrastructure development as long as they alleviate the key identified market barriers and facilitate appropriate reallocation of risks between parties.

Regardless of the business models adopted, we believe these should be technology neutral. We have made some recommendations on the business models in our response to question 30.

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.**

Yes, we agree with this but re-iterate that the current Hydrogen Business Model is not sufficient to support the development of an integrated nationwide network of storage and transport.

A member pointed out that it is vital for there to be a clear vision of exactly where hydrogen will be produced and consumed, and by whom. Support should be then directed towards the storage approaches which will be best placed to deliver what the overall economy will require.

This member stressed that the producers and consumers of our future hydrogen economy are likely to require larger scale solutions, but the key consideration here is how 'large' and 'not large' are defined. This member's view is that industrial hydrogen hubs are likely to become the main producers and consumers of hydrogen and salt cavern storage is unlikely to be the right solution for these hubs. In most cases they will be too far away, have too long lead times and be unable to store hydrogen without contaminating it, leading to further cost. Support should be given to the solutions most likely to be appropriate for the needs of the industrial hubs, which are likely to include the need for 'mid' scale solutions.

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.**

Storage will have a key role in the system and therefore have a wide range of potential users. Producers of low carbon hydrogen production will be the likely entry users. As for exit users, these will include hydrogen or gas power generators used to manage power balancing as well as industrial users. Potentially gas shippers, suppliers, brokers or other intermediaries could also be users if a liquid and competitive market for hydrogen develops.

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.**

Yes, this seems the most straightforward solution as they would be the ones exposed to the volume risk that the business model can help mitigate.

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

This will ultimately be a decision for Government to take. However, please see our reply to question 14.

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.**

Yes, we believe the Government has correctly identified the relevant parties.

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.**

Firstly, as previously highlighted, the introduction of a business model for storage owners is critical and required immediately to enable investment in storage infrastructure if we are not to miss the Government 10 GW hydrogen capacity target by 2030.

Our members' view is that business model support to owners, or prospective owners of storage facilities (as opposed to users) would be more effective to address the identified market barriers and mitigate the identified risks. Regulated returns (RAB or Income Cap and Floor) and/or contractual arrangements (e.g. a contract for difference or a contractual mechanism under the RAB model) could all work to support storage infrastructure development as long as they alleviate the key identified market barriers and facilitate appropriate and efficient allocation of risks between parties.

We consider that <u>three main options</u> could work effectively to support the development of hydrogen storage infrastructure by providing a subsidy to the provider of a storage facility. These are well known mechanisms, which have been used to deliver other policies successfully, and can provide investors with the certainty required.

As for a merchant model, this could eventually develop in the long term but does not provide sufficient investor certainty in the short term.

<u>Option 1 - Combination of contracted storage under RAB and merchant model</u>

a. Contracted storage for network balancing

Some members suggested that the enduring support mechanism for storage could be a contracted service from a third party to the network provider(s) which provides network balancing, given that this service is an essential element of a functioning transport network.

They suggested that the contracted payment would be sufficient to establish key storage infrastructure for system balancing and could comprise an annual payment for capacity that covers risk adjusted capex return over [25] years and operational costs.

The storage services would still be an integral part of the Hydrogen RAB funding regime and be an allowable cost, but would be purchased under a long-term contract (i.e. the assets themselves would not need to sit within RAB).

b. Merchant storage for instantaneous hydrogen supplies

The regime should also allow a second type of storage services – those requiring instantaneous supply - to be provided on a more merchant basis (with no external support or funding needed), for example from storage providers to private users (e.g. dispatchable power generators) who may require high volumes or flow rates at a very short notice.

These members have stressed that a solution should allow both parts of the market to develop – development of core storage infrastructure for network balancing followed by a merchant market. This will be limited initially, but it will then grow over time, whilst there will always be a need for the network to have access to a level of storage to provide the resilience that users require.

<u>Option 2 - Regulated returns</u>

For geological storage in particular, our members have previously strongly supported the introduction of either a Regulatory Asset Base (RAB) model or an Income Cap and Floor mechanism. This is because these mechanisms are not dependent on the market for hydrogen and provide certainty to investors which could potentially lead to lower financing rates. Given the extremely uncertain revenues of hydrogen storage and current lack of a commodity market for hydrogen, regulated returns would probably be appropriate for hydrogen storage.

<u>Income Cap and Floor</u>

Compared to a RAB model, a revenue cap and floor (C&F) mechanism would have the advantage of incentivising storage owners to increase/optimise the utilisation of storage facilities and would provide merchant opportunities between the floor and the cap. The use of a regulatory backstop would make these projects bankable as it reduced the uncertainty associated with the market revenues these facilities could earn. In return, these facilities would provide benefits to consumers through lower price and security of supply.

This is broadly in line with the recommendations we gave in our Longer Duration Energy Storage Report, and REA's response to BEIS Call for evidence on large-scale and long-duration electricity storage (2021), where we favour an income floor price for a technology neutral large-scale and long-duration electricity storage (LLES technologies) support mechanism. We said that this helps de-risk investments while incentivising efficient dispatch through price signals, and also incentivising operators to react to market signals according to the operational characteristics of their project. The report does also acknowledge the strength of a RAB model, if it is government's intention to create a bespoke funding model around hydrogen, recognising that '*the traditional*

RAB approach regulates returns fully, de-risking the investment more than the other mechanisms. Investors benefit from high levels of protection from risks, including during the construction phase. From an investor perspective, this is favourable when considering investment in technologies that are relatively new to the energy market. However, this means customers may face risks from cost overruns (depending on the detailed methodology set by the regulator).'

However, a member said that the cap and floor regime would need to be adapted to ensure bankability of investment in hydrogen storage. They highlighted that typically C&F is suitable for infrastructure investments where there is a reasonable ability to forecast future revenues, which is challenging for hydrogen storage, where price and volume are both highly uncertain. The member stressed that storage demand uncertainty makes forecasting revenues outcomes within the merchant band (between the floor and the cap) challenging. A floor at the cost of debt will not remunerate equity investment. For these reasons, traditional C&F regimes will not attract equity financing for hydrogen storage. The member suggested these issues could be addressed by employing a higher floor to ensure investment financeability and implementing a form of revenue sharing above the cap to partially replicate outcomes from a merchant model.

<u>RAB</u>

As said above, a traditional RAB model may not incentivise the operator to maximise storage volumes, but a member suggested it could be adapted by overlaying an incentive scheme such as allowing revenue to increase above the requirement, with some sort of sharing determined ex-ante by regulation. The RAB framework could also incorporate third party access to storage capacity, such as via auctions. However, RAB may be resource intensive and challenging to apply to all storage sites.

<u>Option 3 - Contract for difference</u>

A contract for difference (CfD) similar to the Hydrogen Business Model could also work as long as it addressed the barrier associated with volume risk in addition to price risk. That would require an adapted design to ensure bankability and facilitate a transition to a future merchant model.

A member commented that under a traditional CfD fixed costs cannot be recovered in the case of low demand/storage volumes, as revenue is gained according to volume stored. A sliding scale CfD with a floor, similar to that built in the Hydrogen Business Model, could allow adequate revenue to be recovered. A floor would allow fixed costs to be recovered when hydrogen is traded, giving investors certainty in the case of low demand. Revenue could then be determined by a combination of volume and regulated strike price with a sliding scale.

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.**

See our answer to question 30.

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.**

Please see our response to question 30.

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.**

For regulated returns Ofgem would probably be best placed to carry this role as they are already regulating the networks under a similar model.

For contractual mechanisms it would be either BEIS or a counterparty such as the LCCC. However, we emphasise the need for both organisations to be alive to the differences and particular features of the hydrogen landscape which distinguish it from the other areas in which these organisations are more familiar. Replicating approaches which have been used elsewhere is unlikely to be successful.

To expand this point, Ofgem are familiar with regulating businesses that use commoditised technology, but hydrogen production and storage is at a much earlier stage and yet to come down its cost curve. These different circumstances require an entirely different approach to what Ofgem understands and are familiar with.

The North Sea Transition Authority is also already the regulator of the offshore gas storage market, so has experience in the gas sector which could be beneficial. They are also well integrated in the move to Net Zero and would have good access to BEIS as the market develops.

Overall, the pace of action is crucial and so this is a key factor in deciding who is to take on the role of the regulator/counterparty. It is likely that the best choice will be that which is able to kick-start the hydrogen economy the fastest.

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.**

Yes. As highlighted before, If Government cannot deliver business models before 2025, then we urge them to provide interim measures to support both transportation and storage projects that are strategically important to support the scale up of the hydrogen sector in the UK and can get the hydrogen economy going now. Some of these projects are already underway: these include pipelines and storage projects in the Northwest Cluster (e.g. the INOVYN Hydrogen Storage and 100% pipelines being developed in the Hynet Cluster) and in the East Coast cluster (e.g. the Aldborough Hydrogen Storage facility). These projects will need to take FID way before 2025 (e.g. in 2023).

These could take the form of a contractual mechanism underpinned by a private law contract where the Government agrees to pay for capacity made available for transportation and storage.

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.**

In our view some form of strategic planning (b) will be essential for both critical transportation and storage infrastructure to be rolled out at the right pace, in the right place and at the right scale to maximise the benefits to the whole energy system and reduce inefficiencies. A strategic planning approach would also enable a transition to a market-led approach to happen more smoothly as the network develops.

A strategic approach would, however, need to be implemented at a sustained pace given the speed required to deliver strategic infrastructure. Coordinated decisions should be made as soon as possible to facilitate the required investments to meet the desired objectives.

National Grid's Future Energy Scenarios (2022) includes a strong recommendation that 'Strategic coordination and whole system thinking, especially across the electricity and hydrogen sectors, is required to achieve decarbonisation targets and avoid unmanageable network constraints and potential curtailment' and we strongly agree with this recommendation.

Whole system planning and careful consideration of the interaction between gas and electricity grid is vital to ensure existing infrastructure is used in an optimised way and new, targeted and more costly infrastructure is built only when essential. Energy system savings will be delivered through integrated and coordinated infrastructure planning and we are aware of analysis currently being undertaken by a consultancy firm to estimate such savings.

It will be crucial to understand how a strategic approach is adopted ie what is the exact mechanism underpinning a strategic approach. This should be set out in detail, though members have highlighted that we also need to ensure progress is not sacrificed for perfection, and reiterated that it is important to get started and deliver at speed.

Finally, it is also critical that the body in charge of strategic planning is independent and that the process is carried out in a way to avoid potential bias and inefficiencies. The planner's tasks should therefore be separated from infrastructure asset ownership.

A market- led approach on its own, on the other hand, could lead to slower infrastructure development, weaker coverage and less consideration and may lead to more inefficiencies, less optimisation and lower benefits for the whole energy system.

This report from The Oxford Institute for Energy Studies set out in detail the advantages and disadvantages of different approaches (e.g. market driven, vs centrally coordinated, vs regulated).

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.**

For storage, again, we see that a form of strategic planning is required initially to ensure storage infrastructure is rolled out at the right pace, in the right place and at the right scale to maximise the benefits to the whole energy system and reduce inefficiencies.

However, as highlighted above, a more market-led approach could also be allowed for certain types of storage services (e.g. those requiring instantaneous supply).

Any solution should allow both parts of the market to develop – development of core storage infrastructure for network balancing, strategically planned, followed by a merchant market. The latter will be limited initially, but it will then grow over time.

Some members have highlighted that over time the build out of storage investment could become more market-led, subject to a mature liquid market emerging for the commodity.

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.**

Central planning would provide consistency and continuity, though this will need to be supported by considerations/assessments made at a more regional or local level.

Given that BEIS have committed to create a Future System Operator (FSO) independent from Government which will have a whole system mandate, the FSO would seem the best place for this central point of coordination. So, we would support a central planning approach led by the FSO for critical infrastructure which could be then followed by a market-led approach, with decisions driven by market-based mechanisms, once the market is more mature (like in the case of CCUS infrastructure).

It is, however, important that there is a detailed and clear roadmap to set out how the FSO will deliver on a whole system approach. There will need to be equal weighting within the organisation between gas and electricity (unlike the current system operator) if this is going to be a whole system organisation.

The FSO will need to consider the interactions between the transmission and distribution grids as well the interaction of the power grids with the gas grid, a future hydrogen grid and the required large scale energy storage infrastructure. There needs to be clear and transparent processes of how all “grids” will operate and incentivise all participants to deliver value-driven, reliable Net Zero services and energy security.

Whole system planning will be vital to ensure existing infrastructure is used in an optimised way and new, targeted and more costly infrastructure is built only when essential. In certain cases, for example, it may be more cost-effective to avoid power grid reinforcements and use hydrogen molecules to move energy across the country and connect supply with demand. Analysis recently carried out by Afry (2022) concludes that location of electrolysers should also be considered as locating electrolysis in zones of constrained power transmission is considered a key solution for reducing the costs of constraints and new network reinforcement.

Hydrogen blending into the gas grid initially, and repurposing of the existing gas grid to 100% hydrogen where needed, will be required to enable energy to be carried across the country, from centres of supply to centres of demand, where this cannot be delivered via electrons.

Finally, while we wait for the FSO to be established and given the urgency required to deliver infrastructure of critical importance, we consider that BEIS or another entity may be required to act as an intermediary central planner before the FSO comes into force, to allow rapid progress to be achieved.

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.**

Please see our answer to the question above which is applicable to both, transportation and storage.

As highlighted above, over time, we expect hydrogen storage to be deployed through more market-led approaches. Our vision is that by 2050 there will be a mature hydrogen market consisting of many hydrogen producers, users, shippers and storage operators, which is primarily market-led.

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.**

Yes, the need for critical transportation and storage infrastructure needs to be looked at jointly and in a fully integrated way to maximise the benefits to the whole energy system and associated savings.

A member noted that alignment is required, in particular, to ensure coordinated investment timings and to minimise the risk of asset stranding. For example, as hydrogen storage is able to serve the East Coast Cluster, a fully developed hydrogen transport system may not be required.

The same member also noted that there is a risk of over-alignment where a hard approach to planning leads to delays in investments. To minimise this risk, strategic planning could initially be focussed on each regional demand centre so that the required investment to deliver hydrogen to that demand centre can be prioritised.

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.**

N/A

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.**

No, the list highlighted by BEIS is exhaustive.

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.**

Yes, as highlighted above, the FSO would be best placed to take on this role.

However, given the scale and timings of investments required to meet the 2030 objectives, another entity might be required to undertake the planner role initially. We are open to who undertakes the role, as long as policy decisions enabling investments are not delayed.

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.

The FSO doesn't need to be the organisation that provides the business model, but business models need to be initially provided on the basis of strategic decisions made by the FSO (or prior to the FOS being in force, another appropriate entity).

The FSO should also take the role of developing a plan for the transition to a more market-led approach as the hydrogen market matures.

A member also suggested that there should be scope for users or third-parties to offer specific business cases. Once the need has been established, options can be identified before selecting a solution. The process of identifying options and selecting a solution would involve the consideration of the appropriate business model support to deliver the relevant need.

A member highlighted that a proactive role of a strategic planner is preferred as the planner should have a whole systems view, with greater knowledge of the existing and future network. However, the planning process should incorporate stakeholder views and be open for alternative and additional business cases. This would be particularly useful for participants that are exposed to market signals (e.g. storage operators).

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.**

Yes, Government should certainly identify low-regret or no regret infrastructure that is critical and should be fast-tracked by awarding business models earlier than 2025.

Regulatory frameworks

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.**

No.

Government should review existing regulatory frameworks to facilitate the supply and use of hydrogen as current regulations don't make provisions for the use of hydrogen in gas networks and new codes must be developed to enable this. There is currently no comprehensive or consistent market framework or industry commercial arrangements for hydrogen. While certain aspects of the gas codes and regulations could be extended to hydrogen to promote faster deployment, it would be beneficial for the industry to have clear and concise hydrogen-specific regulation.

In addition, the existing market framework does not envisage the provision of business model support to hydrogen transport or storage, and we anticipate that primary legislation may be required to enable them. Given the importance of developing the hydrogen economy as soon as practicable as well as constraints on parliamentary time, BEIS should urgently consider the legislation required to underpin the business models consulted on and bring forward plans to make the necessary changes.

We would also mention the need for design and performance standards which will need to be developed and updated to reflect the storage of hydrogen underground and at scale.

Two examples:

- Certain hydrogen storage technologies can add impurities to the hydrogen which will need to be removed. Users will need to be sure of the purity of their hydrogen.
- Safety is a paramount concern and here too detailed standards will need to be in place.

These two examples are highlighted because of the particular potential for unregulated activity to lead to outcomes which could cause serious reputational damage to the hydrogen economy. It is not an exhaustive list and it is likely there will be many other areas which will need to be properly addressed.

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?**

We would support c.

We understand from our members that industry would welcome the development of a Hydrogen Uniform Network Code that establishes the strategic, commercial and regulatory frameworks that specifically apply to hydrogen, as well as technical rules and arrangements that underpins hydrogen transport and storage access.

Legislation will need to be laid that sets out for a licensing regime that will prohibit the carrying out of the activities of hydrogen transportation and storage unless authorised by a licence (or exempt in limited circumstances).

In a similar way to how the CCUS Network Code is being set out, the Hydrogen Network Code should set out the commercial and technical rules and arrangements between hydrogen storage and transport providers and users, and in relation to:

- the connection by users to a transport and storage network ("T&S Network"), or part of
- a T&S Network;
- the delivery of hydrogen by users into the T&S Network at a delivery point;
- the transportation and storage of hydrogen delivered by Users at delivery points;
- the operation and maintenance of each T&S Network; and
- the interface between T&SCos in relation to different T&S Networks or parts of a T&S Network.

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

N/A

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.**

N/A

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?**

N/A

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.**

N/A

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

N/A

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.**

N/A

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

A member who operates large scale storage facilities has said that current regulation and licensing would not allow for CO_2 to be used as cushion gas. 'The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010' do not allow production of CO_2 which restricts the use of CO_2 as a cushion gas for hydrogen storage in underground porous media. Additionally, no equivalent regulations exist for the storage of hydrogen. The same member pointed out that further clarity is required for offshore projects involving hydrogen on the need to obtain 'vent consent', a requirement under the Energy Act 1976 (amended 2016) for inert gases and hydrocarbon gases which may be discharged to an atmospheric vent. The characteristics of hydrogen as a gas with global warming potential should be clarified to ensure that the requirements for either 'Vent consent' or 'Flare consent', a requirement under the Petroleum Act 1999 are understood for offshore hydrogen related projects.

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.**

The above member said legislation would need to be enacted to allow consent for a hydrogen storage license to be applied for and granted. The new legislation could be drafted using the basis set out in 'The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010' but would need to allow extraction of stored hydrogen from the storage site. It should be noted that the existing CO_2 storage regulations do not currently allow export of stored CO_2, as the intent of the legislation was for long term storage of CO_2 to align with the objectives of CCUS projects.

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?**

No. The above member highlighted that currently there is no non-economic regulator with responsibility for the hydrogen economy for offshore hydrogen storage in underground porous media.

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.**

The North Sea Transition Authority ("NSTA") should be appointed as the non-economic regulator for offshore hydrogen storage projects. The NSTA should then engage industry to lead the development of regulations for hydrogen storage in underground porous media.

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.)?**

The REA believes that blending hydrogen into the gas grid is essential to support the scale up of hydrogen production in the UK, especially at the early stages of the hydrogen economy. By providing a reliable source of demand for hydrogen, blending can help mitigate volume risks for hydrogen producers and de-risk investments.

We are unable to quantify how much lead times for building critical transportation and storage infrastructure will limit the scale of hydrogen production capacity, but we believe the impact of a negative or late decision from Government on supporting blending could be significant. All the benefits that can be delivered by hydrogen blending will be missed.

The current BEIS timeline for the hydrogen transport and storage business model is to be finalised in 2025, which would likely lead to final investment decisions (FIDs) on hydrogen networks in 2026/2027 and operation 2030 at the earliest. **Therefore, the supply investment decisions needed to achieve 10 GW by 2030 will need to take place before the establishment of an expansive hydrogen network. Hydrogen blending can therefore play a**

crucial role in enabling early hydrogen production before the creation of extensive hydrogen networks, which will be required to connect production to disperse industrial and power sites.

We therefore urge BEIS to commit to supporting hydrogen blending as soon as possible and no later than 2023. Failing to do so, combined with the current lack of transportation and storage infrastructure, could hamper the development and scale up of the hydrogen sector in the UK. This is particularly true for sectors such as decentralised electrolytic hydrogen production, which face significant volatility in the hydrogen supplies, due to the variability of renewable electricity generation.

The UK Hydrogen Blending Task Force (including REA and HUK) is in the process of finalising and submitting to BEIS a study[3] providing evidence to support the value for money (VfM) case that Government are undertaking in advance of their decision on the strategic role of blending due in 2023. The study identifies the benefits of supporting hydrogen blending and impact on the development of the hydrogen economy if blending was not to be supported by Government.

In summary, the study concluded that hydrogen blending offers a multitude of benefits to the UK hydrogen economy. Provisional results from the study show that blending provides the ability to create around 60 TWh pa national market for low carbon hydrogen, in a non-disruptive manner to existing users. This material market will stimulate hydrogen supply across the country, as well as providing the lowest cost means to manage demand risk during the early years of the hydrogen ecosystem. Alongside these market-making benefits, hydrogen blending also achieves significant carbon savings, with the potential to generate around £2.7 billion pa of social value in reduced emissions and make a material contribution to achieving the UK's carbon budgets. Blending electrolytic hydrogen into the grid would also save in excess of £20 billion by 2036 from avoided curtailed electricity.

In addition, a wide range of unique strategic benefits result from hydrogen blending, such as increasing societal awareness and acceptance of hydrogen in the home, as well as providing a critically flexible use-case for hydrogen to manage any conversion process to 100% hydrogen.

We have included provisional results from the study below, but please note the study is yet to be finalised. All detailed assumptions as well as the final validated results will be submitted to BEIS in due course.

Supply side benefits

Provisional figures from the study[3] show that blending of hydrogen can play a crucial role in enabling supply investment over the 2020's. Hydrogen blending represents a material use case of hydrogen, creating a significant market for early development of hydrogen supply. Hydrogen blending within the network could support nearly all the 2030 10GW target.

The blending of hydrogen within natural gas supplies will also lower the carbon intensity of the gas supplied to consumers, and therefore create an abatement value at the point of use. Provisional results from the study highlight that blending would deliver approximately 10.7 million tonnes of carbon savings per annum and could yield nearly £2.7 billion pa in social abatement value for the UK economy, so the social value of hydrogen blending represents a significant opportunity.

[3] Hydrogen UK, The Association for Renewable Energy and Clean Technology; "The Value of Blending in the Nascent UK Hydrogen Economy", November 2022

The carbon abatement benefits of hydrogen blending manifest themselves not only in economic value, but also in enabling the UK to meet its carbon budgets.

As the UK transitions from the 4th to 5th carbon budget and from the 5th to 6th carbon budget, a total of 225 $MtCO_2e$ and 760 $MtCO_2e$ emissions will need to be abated, respectively. In our study we provisionally estimated that the abatement potential of hydrogen blending over these periods could represent 10% and 6% of the necessary savings, respectively. Therefore, hydrogen blending represents a noticeable opportunity to assist in the carbon reduction targets the UK has legally committed to achieving.

Further detail on this analysis will be included in the final study which will be submitted to BEIS shortly.

Demand risk management

Blending provides a physical solution that enables hydrogen production levels to be maintained whilst managing this demand-risk. Using a physical solution as a mitigation strategy to demand risk is preferable as it does not lead to an increase in financial support intensity required under the Hydrogen Business Model and would enable the economic benefits of the marginal hydrogen consumption to be secured. Storage also provides a physical solution but, as previously noted, the current storage development timeline resulting from the hydrogen transport and storage business model will mean FID on the 10 GW of production needed by 2030 will likely need to be taken in-lieu of storage being available. Therefore, in the interim period, blending provides the only physical means to mitigate the demand-risk within hydrogen microgrids. This provides a strong justification for the sanctioning of hydrogen blending, including unlocking the current embargo within the HBM, to avoid the need for the HBM to absorb the demand-risk via increased support intensity.

The Hydrogen Blending Taskforce is undertaking an assessment of the marginal costs of storage and blending to understand the comparative costs of managing the demand risk. Provisional results from the study highlight that blending is an extremely cost-effective form of demand risk management, compared to a counterfactual of marginal storage. For example, the comparative cost of blending was found to be two orders of magnitude below that of storage in salt caverns. The study includes a detailed explanation of all the assumptions made to draw this analysis and the reasoning for the identified cost disparity.

Given the orders of magnitude difference in calculated levelised costs of demand risk management, it can be reasonably concluded that blending offers a more cost effective means by which to manage demand risk.

Curtailment alleviation

The UK Government is committed to decarbonising electricity by 2035. This will require significantly more renewable electricity generation to be installed in the UK.

Curtailment happens when renewable electricity generators such as wind and solar are asked to switch off by the Electricity System Operator (ESO) as a result of constraints in the transmission system and a lack of long-duration storage capacity. Curtailed electricity is likely to increase as the proportion of renewables in the generation mix increases.

Given that generators are typically paid to turn down as they need to recover their lost support payments, curtailment results in a net cost to the ESO and ultimately to the consumer. This independent report published by LCP in 2022, found that in 2020 - 2021 curtailing wind power added £806m to energy bills in Britain.

The above report also highlights that the majority of turn up actions made to replace the curtailed wind are currently provided by CCGTs (i.e. gas generation), which represent the dominant source of flexible generation in the current system. This means that in addition to the consumer costs, zero-carbon wind generation is being replaced with unabated fossil fuel generation, increasing CO_2 emissions (2% of total power sector CO_2 emissions are due to this curtailment).

A paper released by Edinburgh University estimates that wind production alone could result in 7.72TWh of curtailed generation by 2030.

Blending electrolytic hydrogen into the grid will be a strong facilitator to reduce curtailment as the gas network can absorb variable production rates of hydrogen from electricity. It could potentially drive amongst the lowest forms of levelised cost of hydrogen, as it enables electrolysers to access the cheapest electricity and could avoid the need for storage at the hydrogen production site. This is key to support decentralised net zero hydrogen production, 50 MW in size which may not be otherwise viable.

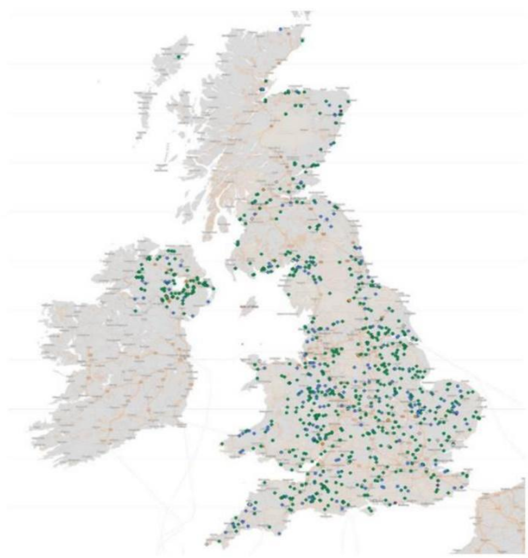
In their Sixth Carbon Budget Report (2020), the Climate Change Committee has included projections of curtailed electricity used for hydrogen production up to 2035 under all their different scenarios. The latest National Grid's Future Energy Scenarios also sees a significant role of production of hydrogen via electrolysis to help integrate renewable electricity generation and reduce curtailment.

We have roughly estimated that in excess of £20 billion could be saved on curtailed electricity by 2036 if the Government was to provide financial support for hydrogen blending into the gas grid from 2023. An analysis of the Carbon Cost Effectiveness (CCE) of blending hydrogen from curtailed electricity concludes that delivering policies to support electrolytic hydrogen blending to reduce curtailment can deliver significant value for money.

Dispersed production

Given the national coverage of the existing natural gas network, it provides a means to connect demand with dispersed production. This enabling function of the natural gas network is demonstrated within the biomethane market. The figure below provides a map (NNFCC, April 2022) of all operational biomethane plants, which shows the extensive coverage that has been achieved across the UK.

Figure 12. Map of all AD projects in the UK



By providing a means of national distribution, hydrogen blending will promote investment in hydrogen production outside of the industrialised regions, where large industrial sites are rare. This is particularly pertinent given the policy aim of delivering over 50% of the 2030 production target via electrolytic production, which therefore requires pairing at least 5 GW of electrolytic production with renewable electricity generation assets. The UK has made substantial progress in developing domestic renewable capacity, much of which lies outside of the industrialised regions of the UK.

The development of large new renewable generation assets, such as offshore windfarms, ranges between 6 - 11 years[4]; therefore developing at least 5 GW of electrolytic hydrogen production by 2030 will require leveraging the existing renewable asset base. Given that much of this capacity is located outside of the industrialised regions of the UK, hydrogen blending will be a critical enabler to connect supply with demand and support the investment cases for developing electrolytic production at existing renewable generation locations.

Strategic benefits

A wide range of unique strategic benefits result from hydrogen blending, such as increasing societal awareness and acceptance of hydrogen in the home, as well as providing a critically flexible use-case for hydrogen to manage any conversion process to 100% hydrogen.

Enduring benefits

Although we agree with BEIS that hydrogen blending is 'transitional' (as we will eventually have to move away from fossil gas supplies), much of the investment and scale of hydrogen production that blending supports will deliver enduring benefits to the hydrogen production supply chain. Once resilient hydrogen production has been built through hydrogen blending, this production can be redirected to 100% hydrogen hard to abate sectors or a 100% hydrogen network. It is therefore important that BEIS' Value for Money assessment of hydrogen blending considers this when calculating the true value of blending.

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[4] https://windenergyireland.com/images/files/iwea-onshore-wind-farm-report.pdf

Blending into the transmission system

The case for blending in the transmission network should be assessed and run concurrently with the distribution network. Using the best available information for costs, with uncertainty ranges as appropriate, will allow a value case to be ready in step with the overall program without becoming the bottleneck. Furthermore, increased visibility of the decision timelines for both transmission and distribution is essential to enable efficient planning across the value chain. Injecting hydrogen into the transmission network will increase the number of injection points that can be used across the country to inject hydrogen and support the development of the decentralised electrolytic hydrogen sector. In addition, allowing injection into the National Transmission System even at small proportion (2 – 5% v/v) would support significant volumes of hydrogen production whilst minimising any impact on the network's Flow Weighted Average Calorific Value (FWACV). Site specific exemptions could be issued by the HSE to ensure there is no impact on consumers (e.g. gas-fired stations).

Financial support

Hydrogen blending should be supported financially. Failing to provide adequate financial support for hydrogen blending will result in no blending taking place. The Hydrogen Business Model would be the obvious mechanism to use for this in the short term. In the longer-term other mechanisms such as the successor scheme of the Green Gas Support Scheme could also be considered. Our paper on financial support required for hydrogen blending can be read **HERE.**

Further supportive documents / evidence

- REA's position paper on hydrogen blending can be read **HERE.**
- The HUK/REA joint position on blending can be read **HERE.**
- You can also read **HERE** HUK/REA joint letter to BEIS following a meeting in September 2022

We also wish to flag two recent publications issued by the ENA on blending:

- ENA's report Enabling Hydrogen Blending from Industrial Clusters, showing that hydrogen blending can be facilitated by the gas networks today, with limited need for change to existing gas commercial and regulatory frameworks.
- ENA's report Britain's Hydrogen Blending Opportunity, where the network companies have mapped out where this blending capacity can be delivered. This shows that, Including the National Transmission System, there is a total of around 60 TWh per year of blending capacity equal to heating around 5 million homes with hydrogen, which could save around 10 million tonnes CO_2.

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.**

Government has committed to design by 2025 new business models for hydrogen transport and storage. However, given the long lead times of large-scale infrastructure projects (which can take up to 4.5 years in some cases, according to members' feedback), the Government timeframe may result in key infrastructure not being available before the end of 2030 at the earliest. **This**

means that blending will play a crucial role to bridge the gap at least until this infrastructure becomes available.

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)?**

Our understanding is that 100% pipelines may be required to be built to deliver hydrogen to the blending facility, however this would be most likely to be private pipes which would be included in the hydrogen production business model.

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.**

Yes, as highlighted in our various position statements, our membership considers that blending has a crucial role to play to stimulate growth in hydrogen production, particularly in the early years of the hydrogen economy. The ability to inject directly into the existing gas grid allows a materially lower risk option for hydrogen production developers to be able to develop projects, fund and build them. Blending materially de-risks the project and, crucially, allows for a much larger uptake of hydrogen production. However, the full benefits of this de-risking will only be unlocked if hydrogen output that ends up being blended is sufficiently remunerated. The way in which Government is currently looking to create a low-carbon hydrogen production market is to rely solely on the end-user demand rather than the ability to inject hydrogen into the grid. We believe, however, that Government should support hydrogen use by distinct end users where feasible, but on the other hand take advantage of the gas grid to access multiple users and to back up priority users' demand.

Even a relatively small blending acceptance will generate a significant demand for hydrogen on the network.

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.**

Yes, we agree with the options set out by Government but also believe blending has a strategic role to support the hydrogen economy that is not fully recognised by the Government as yet.

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.**

In terms of physical offtakers that can mitigate / manage volume risk we believe that blending is the only option. However, there are contractual mechanisms that could play a role in mitigating these risks, such as the sliding scale approach under the business model or 'Take and pay' contracts with intermediaries. All of these contractual mechanisms will mean that a premium will need to be paid by the party who takes that risk. This cost will ultimately have to be paid for by someone. Blending is the most cost-effective way to mitigate that risk.

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.**

Yes, in addition to those benefits highlighted in our response to the above questions, blending effectively creates a national market for hydrogen because it substantially lowers the cost of transport and storage. Without it, we may end up with different regional markets for hydrogen each with different prices for hydrogen, driven in large part by transport costs. This is an inefficient outcome and can be manipulated by first comers who establish a monopoly position in a regional market. Instead, we need to create one large liquid market for hydrogen to enable a market price to establish itself which in turn will enable buyers and sellers to trade and manage risk in much the same way as they do in other established markets. Key to this however is blending which enables multiple buyers and sellers to transact via the gas network.

A key risk associated with hydrogen blending is likely to be the sensitivity of some infrastructure to gas quality variation, particularly if adopted at the transmission level. However, the number of assets connected at a transmission level is low, numbering around 40, and there are ways to manage and mitigate the risk to end-users through GSMR site specific exemptions issued by the HSE.