Hydrogen as an Electricity System Asset

Project Summary Report

National Grid ESO
[Draft version]

This is the final deliverable of 5-month project by Delta-EE for National Grid considering the impacts of Hydrogen on the Electricity System

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1. The Emerging Hydrogen Market and its future role in the electricity system

Hydrogen has a long history in industry, but traditional production is reliant on Natural Gas. Interest in different Hydrogen production methods have soared in recent years, as producing hydrogen without fossil fuels could lead to the decarbonisation of numerous sectors of the economy. In this project, we investigated the potential contribution hydrogen could make to the Electricity system, both at the point of generation (electrolysers) and as fuel source for power generation.

1.1. Introduction

The hydrogen market is rapidly developing, partially driven by the interest in hydrogen as a fuel with multiple applications. There has been extensive analysis of the generation of hydrogen – blue, green, pink, etc – and the different costs and infrastructure requirements for each colour. Analysis of the end uses of hydrogen are well understood covering many sectors such as industry, transport and heat.

Hydrogen has the potential to provide cross vector energy system benefits, by bridging the gap between gas and the electricity system. This is less well researched and the focus of this project is understanding the role of hydrogen as an electricity system asset

1.2. Hydrogen as an Electricity System Asset

The ability to generate hydrogen from electricity, and generate electricity from hydrogen provides a range of possibilities for hydrogen to support the electricity system:

- **Reduced curtailment of renewables** – by using surplus renewables to power electrolysers to produce hydrogen. This will maximise the use of renewable power and reducing curtailment payments, alongside CO_2 reduction.
- **Flexibility services from electrolysis** – as more green hydrogen production comes online in the form of electrolysers, demand for electricity will increase but so too will flexibility potential. Electrolysers powered by the electricity network may be willing to 'turn down' for short periods of high demand, for the right price.
- **Power generation** – CCGTs/OCGTs (and potentially engines/fuel cells) running on hydrogen. This could replace natural gas for peaking and mid merit power generation at times of high electricity demand.
- **Inter-seasonal storage** – long-term hydrogen storage capabilities will facilitate inter-seasonal storage of electricity (using both electrolysis and power generation) to

bridge the seasonal mismatch in supply and demand.

1.3. Key Questions

This project aims to answer a range of key questions posed by National Grid:

- Timings – which hydrogen production technologies will develop first and how will this affect overall market development?
- Will there be a hydrogen gas network, what will its role be and how will this impact on the electricity system?
- What scale will hydrogen operate at and will this be significant in terms of electricity system operations?
- Is hydrogen likely to be blended or pure?
- What storage options are available and where will they be located? For example, salt caverns.
- Co-location – how will different aspects of the hydrogen value chain affect siting of infrastructure? This is particularly relevant if a gas network is not present or if this is minimal in scale. For example, a coastal location for electrolysers would support the generation of hydrogen from offshore wind, whereas the North of England would be favoured for industrial end users.

The answers to these questions will help inform analysis into National Grid's 2022 Future Energy Scenarios.

1.4. Project Scope

This project included:

- A research phase including in depth literature review, interviews with a range of industry experts, and an expert workshop to test project findings in later stages.
- The use of Delta-EE's in-house hydrogen knowledge and expertise from the Global Hydrogen Intelligence Service (GHIS) which collates information on hydrogen projects from across the world.
- Analysis of future hydrogen markets and market sizing built around the development of comprehensive Value Chains which included the whole hydrogen market, and comprise:
  - Production
  - Distribution
  - Storage
  - End Use
- Economic modelling of the Value Chains to determine a range of costs for hydrogen, and to assess the sensitivity of operation to a range of externalities.
- Collaborative work with National Grid to develop inputs for their internal bespoke model for FES and the Balancing Mechanism, to determine potential future Bids and Offers from the hydrogen sector.

2. Value Chains and Market Sizing

Ten Value Chains have been used to characterise the future hydrogen market, informed by the literature review and stakeholder engagement process. Market sizing for the Value Chains created High and Low scenarios to demonstrate the potential impact on the UK.

Table 1: Short List of Value Chains

VC	Value Chain	Description
1	Centralised blue hydrogen production for industry and early hydrogen network injection.	To account for initial blue hydrogen wave into industry. Likely to start as isolated blue plants for specific users, but as more users, plants and clusters come online network injection into a hydrogen network develops.
2	Peaking electricity generation using hydrogen for peaking power (high MWs).	Turbine, FC or engine to help mitigate national network issues, ancillary services and balancing mechanism.
3	Mid-merit electricity generation using hydrogen.	Longer term electricity generation using hydrogen CCGTs to fill the gap between base load (renewables) and peaking plants (OCGTS, engines etc).
4	Centralised nuclear hydrogen for injection into hydrogen networks (smaller scale).	Covers the installation of electrolysers at existing or new nuclear built in the 2020s - i.e. large scale nuclear in isolated locations. Helps provide nuclear base loading and provides hydrogen.
5	Electrolysis for curtailment mitigation.	Covers use case of electrolysis for avoiding curtailment of renewable assets (networked and non-networked); curtailment may occur due to electricity supply/demand imbalances and network constraints.
6	Centralised green hydrogen at onshoring point for transport near industrial clusters or ports.	Covers HGV, trains and distribution centres (forklifts) that tend to be near industry clusters or ports that need high purity hydrogen and therefore can't easily use blue hydrogen.
7	Decentralised green hydrogen production for use in heavy road and rail transport.	Distributed electrolysers that will be co-located with hydrogen refuelling stations (HRS) / transport hubs.
9	Hydrogen production from bioenergy with carbon capture and storage (BECCS).	For use in industrial applications. Expensive production method but may be required to offset emissions from Blue production.
10	Centralised green hydrogen production for use in an industrial cluster.	Hydrogen storage will be a key aspect for this value chain to decouple potentially intermittent hydrogen production from industrial output.
11	Centralised marine electrolysis.	Piped back from offshore wind (floating or fixed).

2.1. Market Sizing

Market sizing was used to determine the scale of impacts to the electricity system from hydrogen. Many value chains present several orders of magnitude difference in capacities and demand.

The Value Chains (VCs) are discrete hydrogen development pathways, that will each follow a specific business case. Due to the level of complexity and uncertainty regarding the future hydrogen market, each VC is treated as though it operates in isolation. In reality, interdependencies need to be accounted for, but the method used provides a clear assessment of the potential scale of impact from each VC. Timings were also considered across the VCs, with some being likely to develop sooner than others:

- **Present - 2035**: VC1, 4, 6 and 7
- **2035 - 2050**: VC2, 3, 5, 9, 10 and 11

See table above for detail

2.2. Contextualising hydrogen demand and impact on the electricity system

Our analysis shows that impacts to the electricity system will be substantial. Hydrogen production required for each value chain typically represents a significant increase to the level of hydrogen demand in the UK today. Where this production is provided by electrolysis, the expected capacities (10s GWs) are substantial compared to current and future demand and will have wide ranging impacts on the electricity system.

2.2.1. Example hydrogen demand from HGVs and trains (VC6) to show scale of impacts

VC 6 alone could require 20-80 TWh of hydrogen by 2035, this is a 100-400% increase in demand compared to UK hydrogen demand in 2020.

This demand would require 6-24 GW of electrolysis capacity by 2035– roughly equivalent to the capacity of the UK coal generation fleet in 2020 (5 GW) at the low end and close the UK gas generation fleet (35 GW) at the high end.

2.3. Major themes from market sizing

Across all value chains involving green H2, there will be an important dynamic between electrolyser capacity (sizing), utilisation (load factor) and storage capacity, which will vary significantly based on market and price drivers, and infrastructure development (e.g. extent of the hydrogen network). There is currently considerable uncertainty on how electrolysis will be designed in concert with storage. This applies to most, if not all, of the VCs.

Many of the VCs, and especially those that are centralised, will likely require geological scale storage (i.e. over 2 GWh per year) to achieve an appreciable market scale.

Decentralised value chain: Hydrogen production co-located with 1 single end-user. Projects often small-scale.

Centralised value chain: Hydrogen production for multiple end users, sometimes not located with end use (grid injected). Projects often large-scale.

A national or at least regional hydrogen gas network will support the viability of numerous value chains, especially the smaller scale and decentralised ones. A network makes these VCs much more viable, and significantly reducing any geographical restriction, by reducing the need for expensive small-scale storage. Additionally, a regional or national hydrogen gas network simplifies distribution and potential export.

Most hydrogen demand will emerge post 2035. Roughly one third of the value chains examined will emerge before 2035 and will consume between 35 – 145 TWh of hydrogen. The remaining value chains will appear post 2035 and will consume between 52 – 190 TWh of hydrogen.

Hydrogen fuelled power generation could be present in similar capacities to natural gas power generation today – but will have far lower utilisation due to the high cost of hydrogen. This will mean that electricity prices will need to be far higher to incentivise dispatchable power.

2.4. Workshop Findings: Hydrogen Gas Network and Storage

Echoing the findings in the interviews, the debate is more on the scale of the hydrogen pipeline network rather than whether or not it will exist.

- If the electricity generated from hydrogen is necessary to meet power demand, it will warrant the development of a large-scale pipeline network for hydrogen.

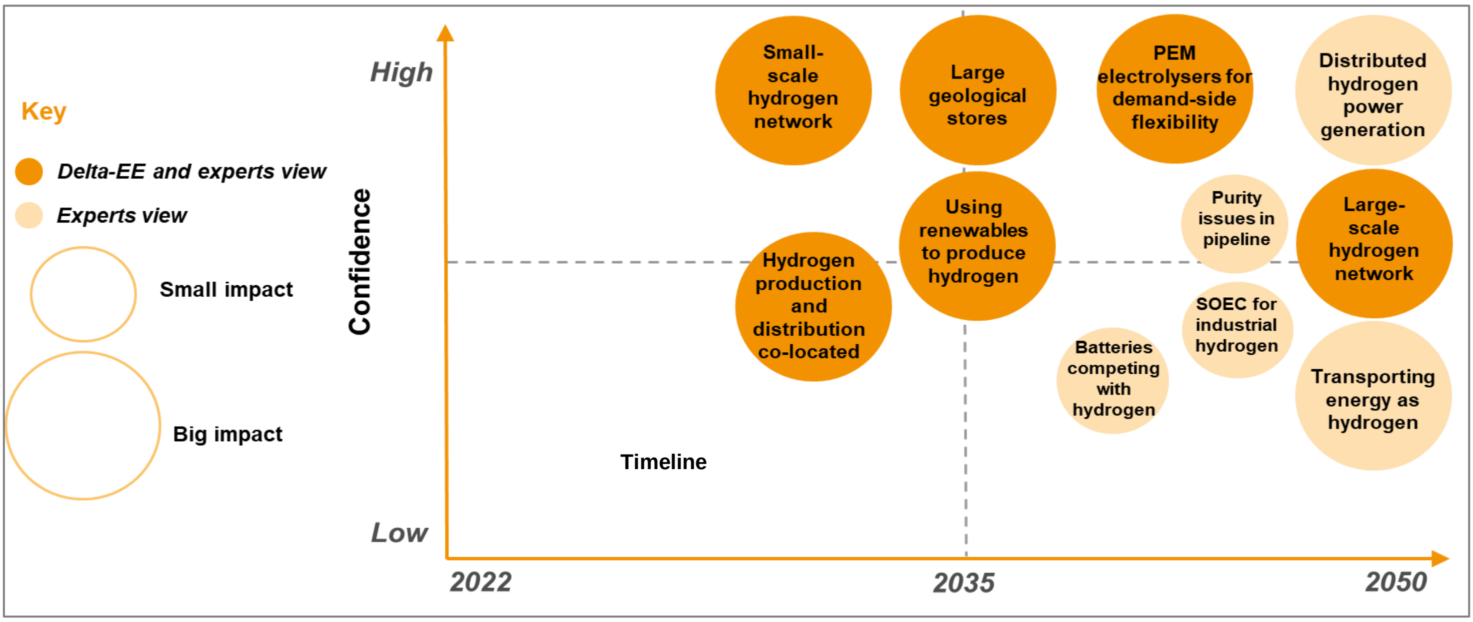
It is economically viable to transport hydrogen in tube trailers for distances under 50 miles. For longer distances, a hydrogen pipeline is more suitable.

In scenarios where a nationwide hydrogen network is not required, a smaller scale regional or local (possibly privately owned) pipeline may emerge as an alternative.

- To use hydrogen for curtailment mitigation (VC5), a small-scale hydrogen network would be required to connect electrolysers.
- To use hydrogen in small-scale peaking plants, a more localised hydrogen network would be required to distribute hydrogen to each peaking plant (VC2+3).
- Transporting hydrogen to a local hydrogen refuelling station (HRS) (VC7) would require a localised hydrogen network.
- As the electricity grid decarbonises, nuclear power will face more competition from renewables (VC4). To avoid expensive nuclear curtailment, nuclear plants can continue to provide baseload power and use surplus power to produce hydrogen.
- Storage solutions are key to limiting the intermittency of renewables and maintain steady supply despite low volumes of wind or sun.
- When hydrogen is meeting a large, steady demand such as an industrial cluster, large-scale storage is not always necessary, as production can be matched to demand. Any potential surplus can be sent onto the hydrogen pipeline network (assuming this is available).

Whilst the workshop and engagement more broadly brought out some common themes, it is important to note that the nascent nature of the sector means there is considerable uncertainty and a broad scenarios-based approach is important for any analysis. All participants in the research recognised this uncertainty when making their contributions.

Figure 1: Summary of workshop findings



2.5. Workshop Findings: Asset location and co-location

The location of assets has a direct impact on the system efficiency and responsiveness. Electrolysers need to be located strategically to ensure system frequency is maintained at 50Hz.

- In a scenario with no national hydrogen network, a regional/local or private hydrogen network would still be required to store hydrogen produced by intermittent renewables. This could then be used for electricity generation when needed: power-to-gas-to-power.
- Unabated fossil power generation will no longer be an option in 2050. Hydrogen power generation will focus on plugging the gaps that nuclear and renewables can't meet: peaking and mid-merit.
- Echoing our interview findings, where hydrogen is produced for transport applications; production and distribution should be co-located (VC7). Even with co-location allowing for production and end-use to be in close proximity, a hydrogen pipeline at some scale was still considered to be necessary by the experts.

Half the attendees agreed that using a hydrogen pipeline to transport energy long distances, for example from remote coastal areas of Scotland, is likely to be more efficient and cost effective than electricity transmission. Even when considering the losses associated with power-to-gas-to-power. Hydrogen gas transmission would also reduce electricity grid constraints, such as between North and South. Other experts did not express any opposition.

With green electricity costs reducing by 2050, half the experts thought there would be more value in using renewable electricity to produce hydrogen than exporting all electricity generated to the grid. None of the other experts expressed any opposition to this statement. This is due to the market for hydrogen expanding more than the market for green electricity, as hydrogen can be used for power generation as well as other end uses.

2.6. Flexibility and Ancillary Services offered by Electrolysers

The five VCs that have the potential to provide flexibility to the grid all generate hydrogen using electrolysers and all include the possibility of an electricity grid connection. Some VCs will make less use of the network connection, as their core model is direct consumption of renewable power.

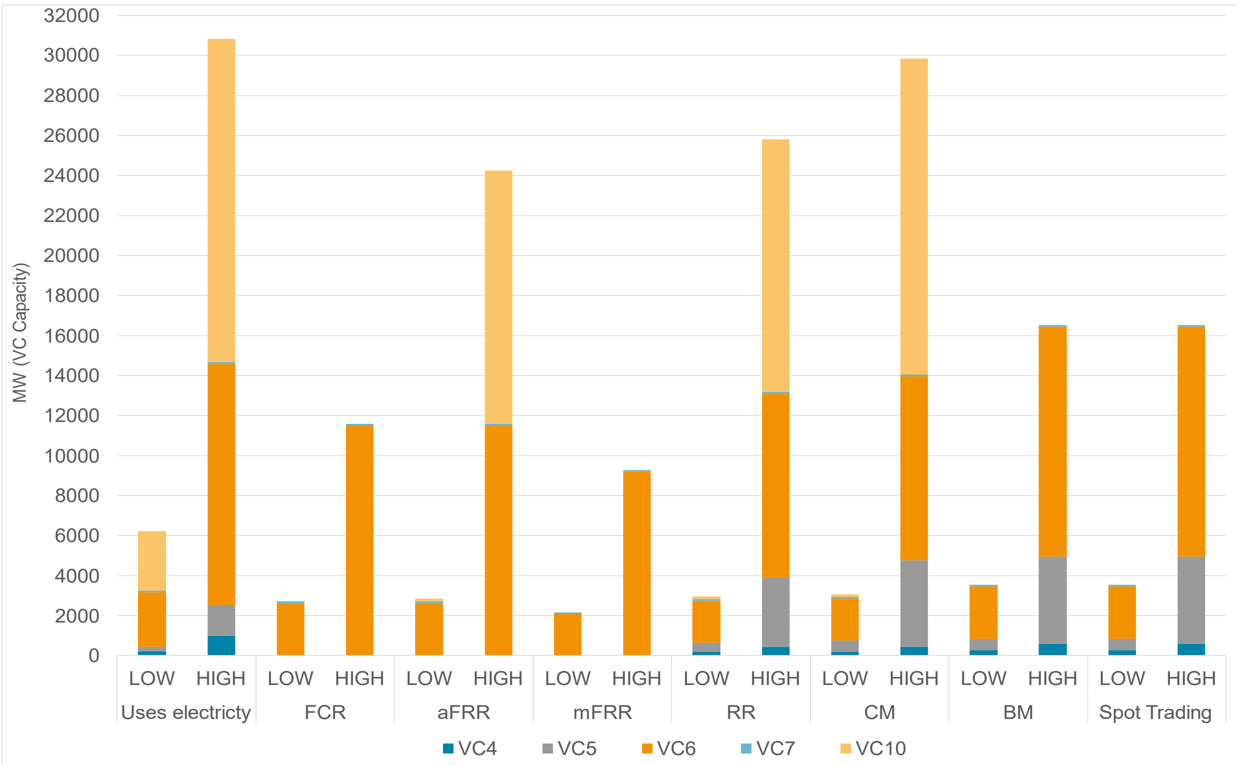
Figure 2 shows a possible Low and High scenario based on the market sizing for how much flex could be provided by the five VCs.

Ancillary services given here represent speed/duration of response required by electrolysers, with the anticipation that exact requirements will change in the future.

In both the low and high analyses both VC6 and VC5 have the potential to significantly impact the flex market.

In the high analysis, VC10 changes from having a very low level of interaction to the highest of all the VCs. This demonstrates the difference over-sizing the electrolyser makes to potential flex provision.

Figure 2: High and Low scenarios for flexibility capacity for each Value Chain.



2.7. Hydrogen Gas Network

Some VCs are more impacted by the presence/absence of a H2 network more than others:

- VCs that are strongly impacted by the presence of a hydrogen gas network:

VCs 2, 3, 5, 7

The decentralised nature of these VCs implies that H2 networks will influence the need for storage and H2 supply. A gas network makes these VCs much more viable, and much less geographically restricted, as daily small-scale storage can be avoided.

- VCs with less sensitivity to the presence of a hydrogen gas network:

VCs 1, 4, 6, 9, 10, 11

The centralised nature and scale of these VCs implies that H2 supply and storage are project requirements, irrespective of H2 network.

Table 2 provides a summary of the analysis.

Table 2: Hydrogen Gas Network Options

Name	Definition	Implications for Hydrogen Storage
Nationwide network	A national distribution and transmission network carrying pure hydrogen for residential, commercial and industrial users. Relates to FES: ST, SP (blended)	Hydrogen production and end use are largely disconnected. Inter/intraday storage requirements are minimal, as hydrogen demand and supply swings are balanced by the network. Seasonal and strategic storage will still be required to support the network during peak demands.
Regional networks	Local transmission and distribution networks carrying pure hydrogen for residential, commercial and industrial users, usually within geographical areas around industrial clusters. Some regional networks could be linked up via transmission pipelines. Relates to FES: LW	In a scenario with regional networks, storage requirements will develop according to geographical zone.
Private local networks/ pipelines	Private networks carrying pure hydrogen, primarily to industrial off-takers within a cluster. The pipelines link up hydrogen supply and storage resources with multiple off-takers (likely a short distance). Relates to FES: CT	Hydrogen will only be produced, stored and distributed at scale where it's needed (primarily within industrial clusters). Wherever possible, demand centres will utilise large-scale geological assets for storage to buffer hydrogen supply swings.

2.8. Locational Considerations

The project explored high level locational impacts on future hydrogen markets.

Scottish region

- VCs 5+11 are advantageous to this region, due to the large wind resources. However, limited geological storage resources imply that distribution networks and purpose-built storage will be important.
- Without a hydrogen network, co-location of H2 production and end use will be preferred, but the limited storage potential may limit the adoption of VCs requiring larger storage volumes (e.g. VCs 3, 6, 10).

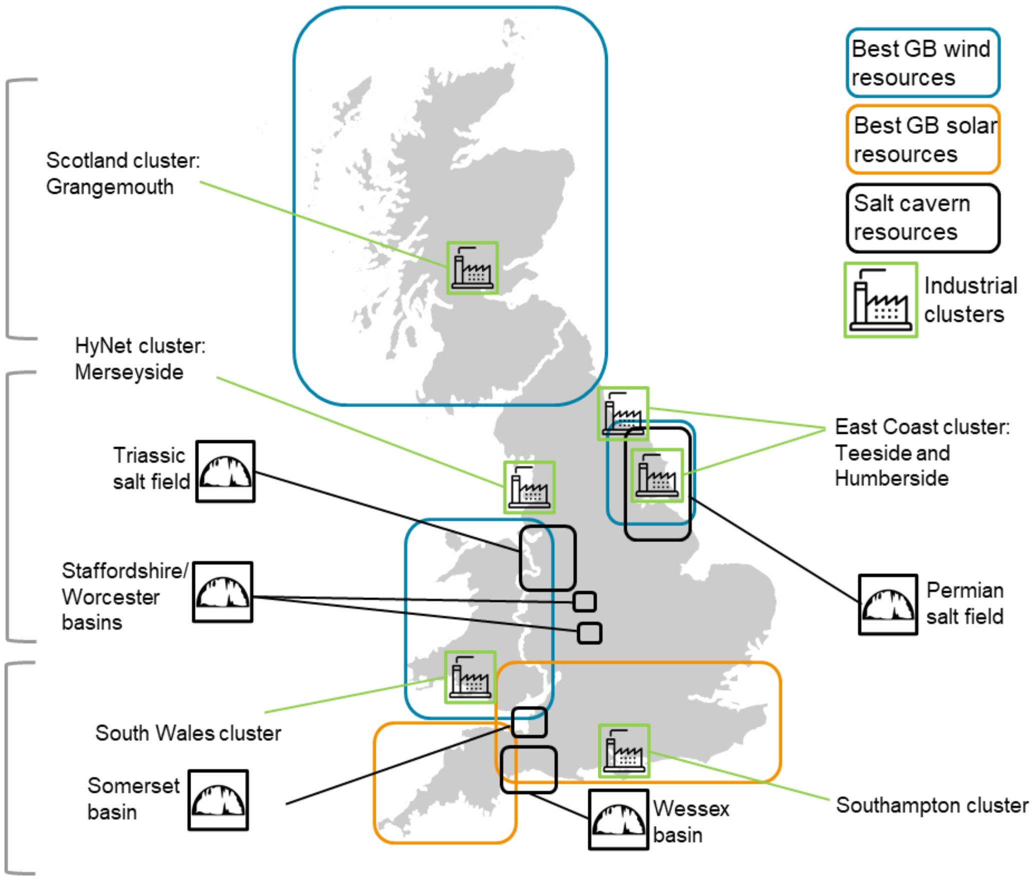
Northern England and Wales region

- This region has the best geological storage resources, alongside major hydrogen demand centres in industrial clusters. Therefore VCs 1, 6, 9, 10 are very suitable for this area. H2 production, storage and end use can be co-located for large demand.
- Without a network, VCs 2, 3, 5 will likely feature more commonly in and around the major demand and storage centres because the absence of a network makes H2 supply and storage much more challenging.

Southern England region

- This region has good solar resources for H2 production and some geological storage assets. However, the larger storage assets are not located near the industrial clusters, suggesting that (in the absence of a network) larger users will need to invest in purpose-built storage or a pipeline linking to the storage site.

Figure 3: Geographic characteristics will impact on the hydrogen market development



3. Value chain business case modelling

The extent to which the Value Chains integrate into the electricity system depends on a range of internal drivers, performance characteristics and external market forces. Modelling each VC allows the price points to be identified under a range of scenarios.

3.1. Aims of Modelling

Techno-economic modelling of each VC provides evidence to inform the FES scenario development for 2022. The analysis informs the assumptions and datasets used within the BID3 modelling to further develop the Hydrogen modelling capability. The modelling includes:

- Quantitative analysis of each VC based on market sizing analysis and market overview.
- Levelised cost calculation for each value chain to benchmark the relative cost of hydrogen for each value chain element and overall.
- Cost sensitivity analyses, to identify and quantify the primary cost drivers and greatest uncertainties in cost predictions for each value chain.
- Sensitivity assessment of impact of hydrogen storage and impact on resulting cost of electricity when used in power generation.

3.2. Modelling Results

The hydrogen economy and electricity market are fundamentally linked through electrolysers, which rely on large volumes of electricity. As the number of networked electrolysers increases over time, the impact of hydrogen generation on the electricity system will also increase.

3.2.1. Hydrogen Production

The cost of hydrogen production is dominated by fuel costs, whether via SMR or electrolysis.

- A reliable forecast of fuel costs through project life, is critical to understanding the potential costs of hydrogen production. For electrolysers, this directly links hydrogen markets and electricity markets.
- Electrolyser oversizing does have the potential to reduce average hydrogen price. However, this relies heavily on the ability to access relatively low electricity prices at volume and to efficiently utilise hydrogen storage.

3.2.2. Hydrogen Storage

The impact of hydrogen storage on the cost of delivered hydrogen is highly variable.

- Analysis of the levelised cost of storage varied from a ~20% increase in hydrogen costs for a heavily utilised storage facility, to over a 300% increase in the cost of hydrogen when used for seasonal storage.
- Uncertainties remain on further possible storage constraints, such as location and discharge rates, which could further increase costs and reduce capability.

3.3. Power Generation

Power generation costs for using hydrogen in CCGT or OCGT's for peaking and mid merit generation is estimated to be relatively high.

- This is primarily due to the very low load factors estimated for the baseline. Prices drop significantly, as load factors increase.
- Cost of electricity from OCGT was less sensitive to hydrogen price or cost of hydrogen storage, than for CCGT. At the low load factors described, the initial capital investment costs have a significant impact on the levelised cost of electricity (LCOE). Therefore, retrofitting of old plants that currently burn natural gas is likely to be preferred to significantly reduce costs.

Table 3: Baseline Modelling Cost Results

V C	Value Chain Description	Production LCOH	Storage LCOH	LCOH delivered storage component	Distribution LCOH	LCOH Delivered	LCOE
1	Blue Hydrogen	49	35	6	9	**63**	
2	Peaking Electricity						**3220**
3	Mid-merit electricity generation using hydrogen.						**558**
4	Centralised Nuclear	130	0	0	4	**134**	
5	Electrolysis for curtailment mitigation	45	35	8	7	**59**	
6	Centralised green hydrogen at onshoring point	117	35	8	5	**130**	
7	Decentralised green hydrogen production	117	31	31	0	**148**	
10	Centralised green hydrogen production for industrial use	126	35	24	6	**156**	

3.4. Levelised cost of storage (LCOS)

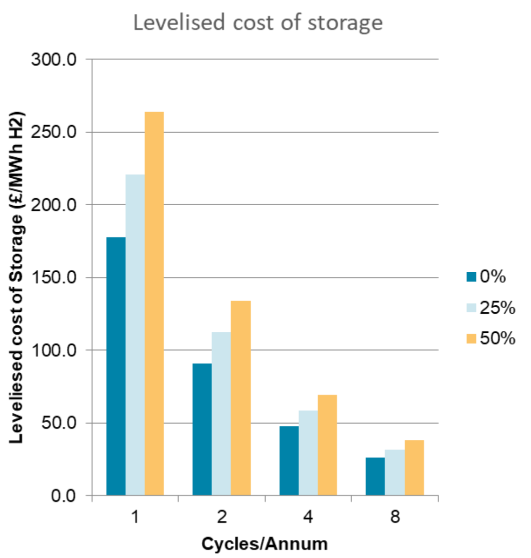
Hydrogen storage costs can vary substantially depending in the specific value chain and it is critical that storage is used efficiently. It is likely that some storage oversizing will be necessary to provide system contingency, but the precise amount required is uncertain and highly case dependent. In all scenarios a proportion of hydrogen is required for proper operational functioning (cushion gas), which is not available for cycling.

The graph below shows the greatest impact on the LCOS is the number of cycles per annum.

- Seasonal storage, e.g. production in summer and usage in winter is equivalent to 1-2 cycles per annum.
- Daily/weekly cycling is broadly equivalent 4-8 cycles/annum. Note this requires complete discharge and recharge of the store every 2-3 months.

When used seasonally, the cost of storage is greatly increased and has potentially significant consequences on certain end use cases. Oversizing has an almost proportionate impact on LCOS, 25% oversizing resulting in ~20-25% additional cost.

Figure 4 Levelised cost of storage



In the best-case scenarios, optimization of storage may enable electrolysers to access lower energy costs and reduce the average cost of hydrogen.

Further analysis can combine more detailed hydrogen production modelling with locational and performance constraints for storage facilities.

3.5. Hydrogen Production

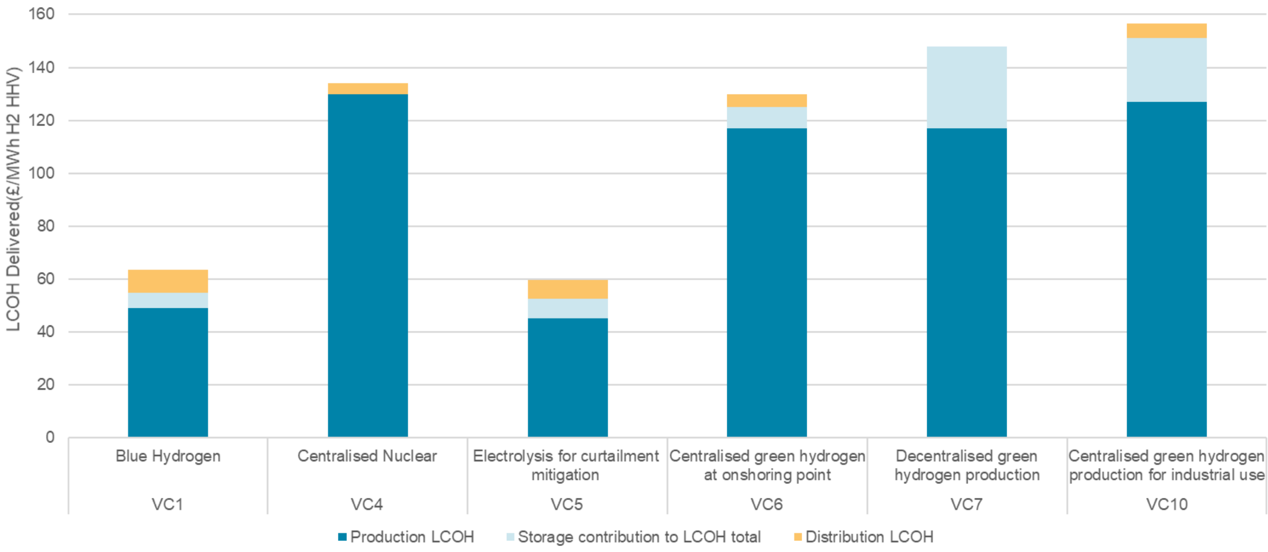
The fundamental uncertainty regarding the cost of hydrogen production is the cost of electricity the electrolysers can consistently access. At current industrial forecast rates, electricity costs account for >75% of the cost of hydrogen produced. Priority for electrolyser operators will be needed to secure predictable, lower cost electricity to ensure competitive hydrogen production.

Detailed analysis of the hydrogen market without consideration of the electricity market reduces the overall usefulness of the results. Due to the scope of this project, high-level data regarding the electricity market was used. A more explicit analysis determining how future green hydrogen production would interact with the electricity system, including half hourly pricing, would be useful.

There is potential for electrolyser oversizing when paired with appropriate storage. However, this may be niche and requires predictable electricity pricing and demand with efficiently utilised storage.

Further analysis on opportunities for electrolysers to capture electricity at volume, at lower than wholesale market price is critical to identifying real average hydrogen prices.

Figure 5: LCOH by Value Chain



3.6. Limitations

The complexity of interactions between the hydrogen market and electricity market means that a number of assumptions have been made which limit the analysis.

- The study relies on symmetric low/high pricing, high prices are likely significantly further from the average than low prices, but relative volume at different price ranges are also critical.
- Storage and discharge rates limit the potential benefits of storage, by increasing capital costs or constraining usage, which has not been assessed.
- Timing of compression and access to electricity could impact effectiveness of frequent storage.
- Demand side flexibility requirements could considerably change the profile of storage requirements depending on the end use.

3.7. Additional Support to National Grid

Using proxy information regarding how generators currently Bid/Offer within the BM, the team provided an overview of how hydrogen electrolysers could operate. The project team, in collaboration with National Grid's Economics Team, proposed possible ranges for Bid/Offer prices, in addition to a calculation approach to support the finalisation of inputs to National Grid's internal model. This included data associated with the balancing mechanism actions taken by hydrogen related technology including bid and offer spreads, as well as flexible demand.

4. Implications for FES

The project was an iterative process that included continual reference back to the 4 FES scenarios. Using learnings from the project, Delta-EE provided high-level feedback to National Grid regarding the current assumptions for hydrogen production and end-use within FES 2021. These are outlined below.

FES may be underestimating the amount of power generation that could come from hydrogen by 2050. This is particularly noticeable in the Consumer Transformation and System Transformation scenarios. Hydrogen has many applications and there are strong arguments for why industry, heat and transport may out-compete power generation most of the time. However, with the end of unabated natural gas anticipated in 2035, this fuel source will no longer be an option in 2050. As electricity use increases the likelihood for more peaking power is increased where hydrogen can be used.

The **Consumer Transformation**, as the scenario most focused on a shift to electrification, includes limited options for hydrogen:

- The scenario relies on producing significant amounts of hydrogen solely or primarily from curtailed renewables. This may not be feasible in practice and electrolysers may make use of the electricity system for back-up.
- Only networked electrolysis is currently included. As the scenario with the greatest capacity of renewables, non-networked has significant potential for electrolysers, which would prioritise renewable sites with the most consistent power supply e.g., offshore wind.
- BECCs is not currently included, despite this scenario including 12GW of electricity generation from this source. As the electrolyser market expands there is potential for a portion of this market share to be used to generate green hydrogen.

The **Leading the Way** scenario could be expanded to include more options. This would ensure the hydrogen market develops at the required pace:

- We recommend including blue hydrogen, at least initially in this scenario. This could be phased out over time but will support the development of the hydrogen market in the 2020s.
- We recommend including nuclear to produce hydrogen in this scenario. As discussed in our analysis, electrolysers have the potential to support nuclear sites with power off-taking, thereby reducing the need for downtime and ensuring baseload power is maintained.

Flexibility assumptions are too simplistic. FES currently assumes that every GW of installed electrolyser capacity would be available for system flexibility. This is highly unlikely in practice. As our analysis has shown, there is a broad variety of electrolyser Value Chains. which will operate in different ways. Therefore, the potential for electrolysers to engage with ancillary services will be highly varied depending on their specific use case.

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