EQUANS
EMPOWERING TRANSITIONS

Net Zero North West: **Electrolytic Hydrogen Recommendations Report**

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Contents

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1. Executive summary

Anchored by the proposed HyNet project, the North West of England and North East Wales is at the forefront of global hydrogen innovation. Recently announced as a Track 1 cluster, HyNet has the potential to decarbonise swathes of industry across the region by providing networked access to low carbon (CCUS enabled) hydrogen, delivering substantial carbon savings in the 2020s and beyond. However, with the region's ambition to be home to the world's first net zero industrial cluster by 2040, HyNet alone will not be the complete solution. Under current proposals, a significant number of consumers will not have access to network connected hydrogen and will need to embrace alternative decarbonisation options. There are also socio-political concerns about CCUS enabled hydrogen, and to many it is regarded as a transition fuel with its core purpose being to stimulate the development of a future electrolytic hydrogen economy. However, although the HyNet proposals are well developed and documented, there is a gap in the literature around what a future electrolytic hydrogen economy for the region would entail.

This report aims to inform the Net Zero North West Cluster Plan project by addressing that knowledge gap and designing a least cost electrolytic hydrogen production system for the region in 2030 and 2040. To achieve this, a comprehensive technoeconomic modelling exercise was completed, optimising the design of a regional electrolytic hydrogen production system for eight alternative future energy scenarios. This allowed the variables that affected the levelised cost of hydrogen (LCOH) production to be analysed and the key parameters that constitute good system design to be identified. To this end, the report aims to highlight how electrolytic hydrogen can augment the region's flagship infrastructure projects and support the zero carbon transition of North West England and North East Wales.

Sections 1.1 and 1.2 below summarise the methodology and key findings of the report and the detailed analysis can be found from page 13 onwards.

1.1 Methodology

The technoeconomic modelling in this report centres around our proprietary modelling software; PROSUMER. PROSUMER is a multi-nodal, multi-vector optimisation tool, meaning it can design an integrated energy system, accounting for geographic considerations. For this project, these geographic considerations included the availability of renewables to power electrolysers, the hydrogen distribution and storage infrastructure in the region and the location and quantum of hydrogen demand. As this modelling was conducted on a regional scale for a nascent technology, the following methodology was developed specifically for this project and is expected to be replicable and valuable to future work.

This methodology is explained in detail in Sections 3 and 4 and is summarised below.

1.1.1 Hydrogen Demand

As previously mentioned, the location and quantum of hydrogen demand was a primary input to the modelling. However, there is significant uncertainty surrounding the amount of hydrogen that will be required in North West England and North East Wales in 2030 and 2040, with the quantity dependent on national policy and key decisions which are expected in the mid-late 2020s. For this reason, this analysis was designed to address this uncertainty by modelling two future hydrogen demand scenarios:

- **Bull scenario** - Higher hydrogen scenario
- **Bear scenario** - Lower hydrogen scenario

For each of these scenarios, assumptions were made for the annual consumption of hydrogen across the residential & commercial, industrial, transport and power sectors, as summarised in Table 1 overleaf. Furthermore, given hydrogen's dependency on intermittent renewables with intraday variations in electricity output, it was important to disaggregate these annual consumptions into their hourly demands. This was achieved by analysing gas demand data from anonymised consumers, for the sectors and sub-sectors under consideration. An example of this is shown in Figure 1 overleaf which illustrates the gas demand profile for a typical food & drink customer in the region. The methodology outlining the derivation of these consumptions and demands can be found in Section 4.1.

[1]Carbon Capture Usage and Storage (CCUS) enabled hydrogen is produced when a hydrocarbon is reformed into hydrogen and carbon. The carbon is then captured and used or stored.
[2]Electrolytic hydrogen is produced through electrolysis of water, splitting it into hydrogen and oxygen.

Annual hydrogen consumption (TWh/a)	Bull		Bear	
	2030	2040	2030	2040
Residential	0.46	5.96	0.18	-
Commercial	0.71	8.97	0.27	-
Industrial	22.68	29.55	12.37	18.49
Transport	0.61	1.43	0.24	0.61
Power	0.83	3.35	0.99	4.10
Total	**25.29**	**49.26**	**14.05**	**23.2**

Table 1 The annual requirement for hydrogen for the bull and bear demand scenarios

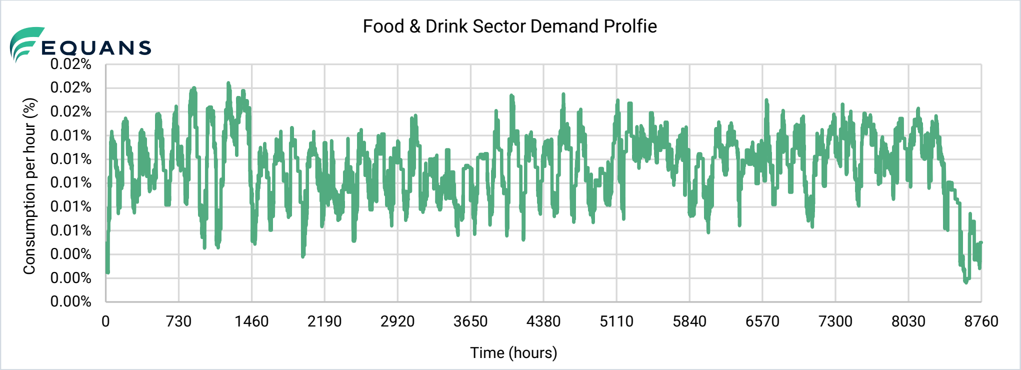


Figure 1 Hourly demand profile for hydrogen for an industrial customer in the food & drink sector

Furthermore, it was important to understand exactly where this demand was located within the region as this would allow clusters of consumers to be identified. The location of this hydrogen demand was geospatially analysed and the region was split into 13 analytical nodes to group clusters of consumers, in a process defined as regional zoning.

1.1.2 Regional Zoning

The process of regional zoning involved dissecting the region into 13 nodes, where consistent modelling constraints could be applied to each node. This meant that although each node represented a finite geographic area, it could be modelled as a singularity.

This approach allowed geographic constraints to be configured into the modelling. For example, if a node was part of the HyNet proposals then it was assumed to have access to network connected hydrogen. Otherwise, it would require an embedded (on site) solution. Similar nodal constraints were applied to reflect the availability of renewables at each location and the hydrogen demand profiles were summated for each node.

This is illustrated in Figure 2 which depicts a heat map showing the location and quantum of hydrogen consumption for the bull 2040 scenario.

A final consideration was then given to where electrolyser developments would be permitted and how hydrogen could be transported by road. These constraints were defined to assess the impact of localisation versus centralisation and two different modelling configurations were constrained as follows:

- **Decentralised configuration** - Electrolysers could be installed at any of the nodes where there was land available to do so, but no hydrogen transportation by road was allowed
- **Centralised configuration** - Hydrogen production was constrained to be centralised at up-to three nodes but could be transported elsewhere in the region by road

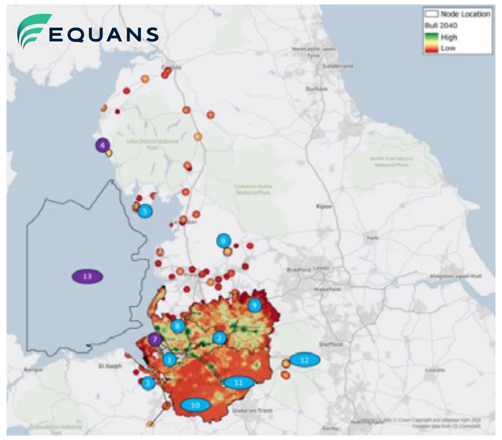


Figure 2 – A heat map showing the hydrogen requirement in the region in the bull 2040 scenario. The numbers represent clusters of consumers (aka. analytical nodes) and were used to configure the modelling

1.1.3 Hydrogen Production

In order to satisfy the aforementioned hydrogen demand, the model was given the option to use CCUS enabled hydrogen from HyNet or develop greenfield electrolytic hydrogen projects. These electrolytic hydrogen projects could be powered by dedicated new zero carbon electricity sources (e.g. renewables or small modular reactors) or supplied by electricity via the grid. The availability of these new zero carbon electricity sources was dependent on the opportunity to develop new assets in the region and was calculated for each of the technologies under consideration (onshore wind, offshore wind, solar PV, tidal & nuclear). This maximum capacity was calculated for each node by assessing the available land as well as the region's project pipeline. To illustrate this approach, Figure 3 shows the solar development potential in the region and the offshore wind pipeline.

A summary of the maximum capacities for new zero carbon electricity sources is shown in Table 2 below and more detail on this methodology can be found in Section 4.2.

1.1.4 Modelling Approach

Given these hydrogen demand, hydrogen production and centralised/decentralised configuration constraints, the technoeconomic modelling consisted of a Total Cost of Ownership (TCO) optimisation simulation for the region. This resulted in the design of a system that was capable of matching supply and demand within the specified constraints at the lowest overall cost. To capture the influence that policy could have on specifying the UK's mix of CCUS enabled and electrolytic hydrogen, this modelling was performed for two different cases:

- **No Target Mix** - A pure cost optimisation simulation, with no specified mix between CCUS enabled and electrolytic hydrogen. The results for this case are presented in Section 5.1.
- **Target Mix** - A simulation that sought to examine how and where projects may emerge in a scenario where electrolytic hydrogen was incentivised to deliver a penetration of 25%. These results are discussed in Section 5.2.

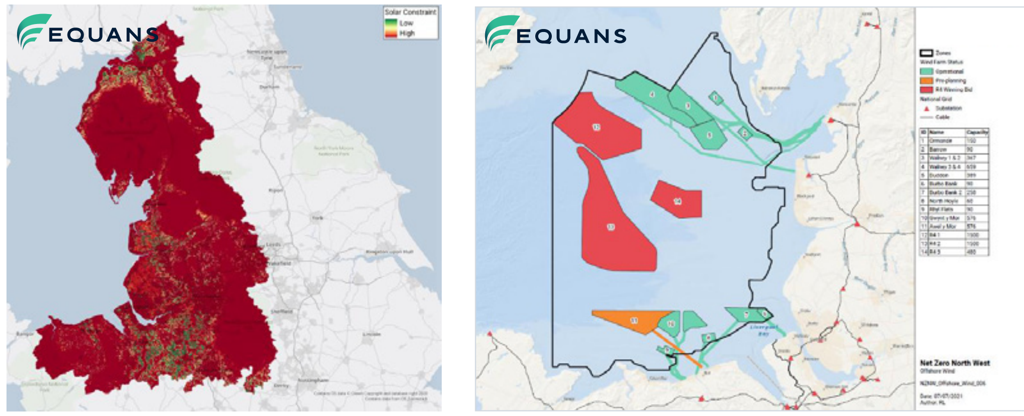


Figure 3 The solar development potential in the region and the offshore wind pipeline

Zero carbon electricity source maximum capacity (MW)	2030	2040
Onshore wind	93	93
Offshore wind	3,480	3,480
Solar PV	18,245	18,245
Tidal	1,000	4,000
Small modular reactors	470	2,350

Table 2 The maximum capacity for each electricity source in 2030 and 2040

Systemic Constraints	State #1	State #2
Hydrogen Consumption	Bull	Bear
Modelling Configuration	Centralised	Decentralised
Policy Influence	Target Mix	No Target Mix

1. *No Target Mix | Centralised | Bear*
2. *No Target Mix | Decentralised | Bear*
3. *No Target Mix | Centralised | Bull*
4. *No Target Mix | Decentralised | Bull*
5. *Target Mix | Centralised | Bear*
6. *Target Mix | Decentralised | Bear*
7. *Target Mix | Centralised | Bull*
8. *Target Mix | Decentralised | Bull*

The combination of the hydrogen consumption scenarios (bull/bear), the modelling configurations (decentralised/centralised) and the policy influence (No Target Mix/Target Mix) resulted in eight unique scenarios, as summarised above.

Each of these scenarios was modelled independently and eight unique electrolytic hydrogen production systems for the region were designed. These results were then analysed to understand the high level metrics, such as the electrolyser and renewable capacities at each node, as well as more intricate information, such as the operational profile for each of the electrolysers in question. The analysis of these intricacies enabled the characteristics of success to be identified and some development opportunities for the region to be highlighted. These key findings are summarised below and form the bulk of the report in Sections 5 & 6.

1.2 Key Findings

For each of the modelled scenarios, the outputs were a function of the constraints. As the constraints varied greatly across the different scenarios, this resulted in highly variable results. This is highlighted in Figure 4 which shows the installed electrolyser capacity in the region for each of the scenarios.

Additional high level metrics such as the installed renewables capacity, the levelised cost of hydrogen and the amount of CO_2e abatement for each of these modelled scenarios can be found in Section 5 of the report. Although these holistic results were interesting, there was significant uncertainty associated with predicting a futuristic energy scenario and it is highly improbable that any of the above scenarios will exactly reflect the region in 2030 and 2040. It was therefore more valuable to understand how each of the key variables effected the overall system design and performance as these findings could be used to inform stakeholders when developing future electrolytic hydrogen projects in the region.

1.2.1 Characteristics of Success

The analysis of the key modelling variables forms the basis of Sections 5.1 and 5.2 which focusses on identifying the main factors that could result in an LCOH reduction for electrolytic hydrogen production. This analysis was conducted both at an inter-scenario and intra-scenario level to isolate particular variables and examine whether these observations were impacted by nodal constraints, systemic constraints, or a combination of the two. This resulted in three main characteristics of success to be identified, as summarised below.

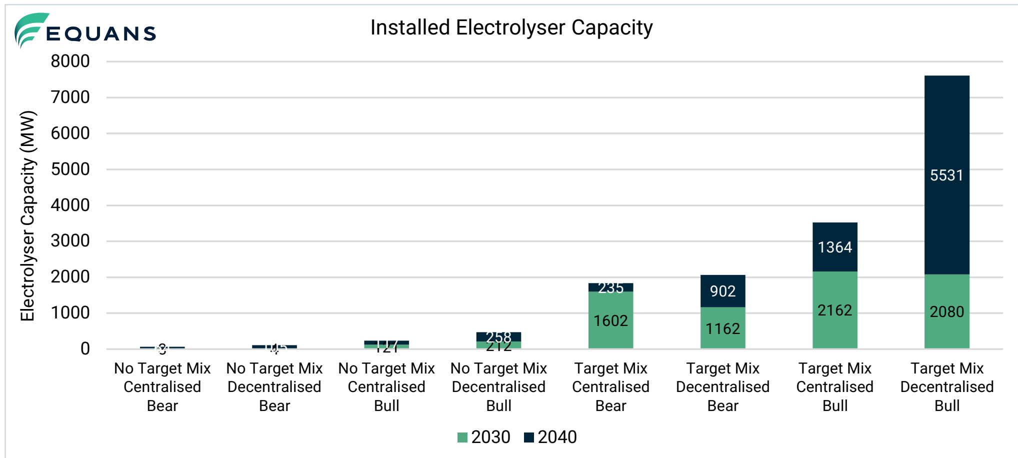


Figure 4 Installed electrolyser capacity in 2030 and 2040 for each of the modelled scenarios

1. The Electricity Source

Unsurprisingly, it was consistently observed that there was a correlation between the electricity source powering the electrolyser and its LCOH. Fundamentally, as the percentage of electricity supplied by directly connected renewables increased, the LCOH decreased, due to the avoidance of network costs. This is well illustrated in Figure 5 below which provides a breakdown of the LCOH for each node in the No Target Mix (NTM) decentralised bull 2040 scenario. It can be seen that the electrolysers at Nodes 8, 9 & 10 are powered purely by directly connected onshore wind, and the electricity proportion of the LCOH is £1.34/kg. This can be compared to the £9.42/kg at Node 6 which is powered purely by network connected electricity (grid electricity & PPAs).

Alongside the correlation between network cost avoidance and LCOH reduction, there was also a consistent correlation between the electricity source and the LCOH, with the LCOH being a function of the levelised cost of electricity (LCOE) and the load factor.

Theoretically, onshore wind was seen to be the best individual technology, given its low LCOE and relatively high load factor. However, it was severely limited in its ability to produce significant volumes of hydrogen due to the onshore wind development constraints in the region, with only 96MW of opportunity across the modelled nodes. This was not an issue for solar PV, where over 18GW of development was deemed possible. However, the LCOE/load profile combination made it a less attractive option for developments, as the solar PV was unable to provide sufficient power at the necessary times which resulted in the electrolysers remaining reliant on network connected electricity.

There was shown to be a benefit in stacking these electricity sources but, given the limited scalability of onshore wind, this option only had a moderate impact.

Offshore wind had a slightly higher LCOE than its onshore counterpart, however this was countered by a higher load factor and a greater available capacity. For this reason, offshore wind was the most selected technology in the modelling, with over 1.6GW of capacity installed in the high demand scenarios. When very high volumes of hydrogen were required in the Target Mix bull scenarios, tidal power was the only technology with sufficient capacity to match the demand. For this reason, and when compounded by competition from other electricity consumers, Mersey Tidal is expected to be a critical component of the region's energy security. That said, with its higher LCOE, it was the most expensive way to produce hydrogen from the technologies considered.

Finally, with its potential for a low LCOE and its very high load factor, small modular reactors were observed to offer a very compelling option for electrolytic hydrogen production in the region. That said, in the time periods modelled, it was limited by its development locations which were assumed to be limited to Sellafield and away from the HyNet network. If consumer confidence in this technology grows and it can be installed in locations where it can directly supply network or industrial demand, then it is a highly promising technology for electrolytic hydrogen production in the region. These pros and cons are summarised in Table 3.

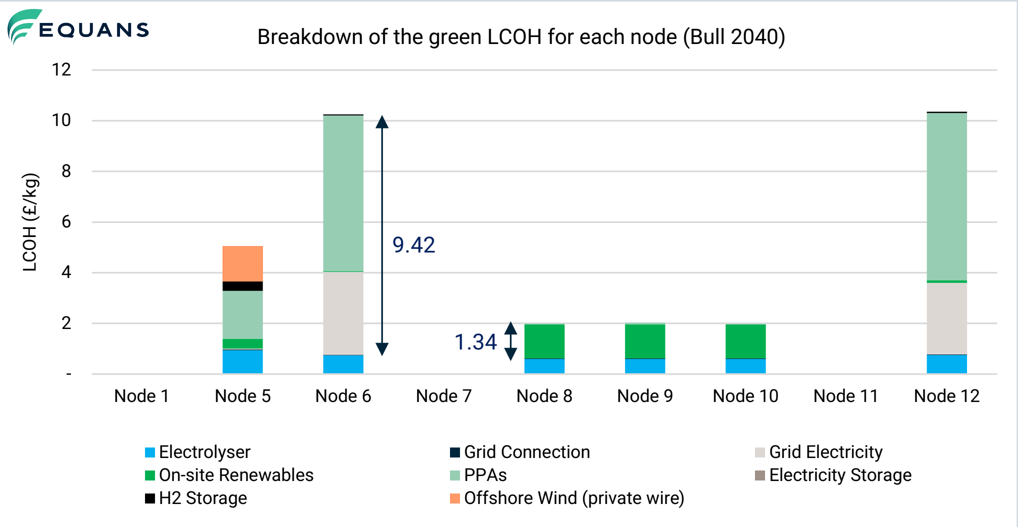


Figure 5 A graph showing the breakdown of the LCOH for each node in the NTM decentralised bull 2040 scenario

Electricity Source	Positives	Negatives
Onshore wind	+ LCOE + Load factor & profile	− Capacity
Solar PV	+ LCOE + Capacity	− Load factor & profile
Offshore wind	+ LCOE + Load factor & profile	− Location
Tidal power	+ Capacity + Load factor & profile	− LCOE
Small modular reactor	+ Load factor & profile + LCOE	− Location (short/medium term)

Table 3 The positives and negatives for different electricity sources for electrolytic hydrogen production

2. The Decoupling of Demand

The second characteristic of success was defined as the decoupling of the hydrogen demand and hydrogen production profiles. In all of the modelled scenarios, there was a clear difference in cost between the nodes that could blend into the HyNet network, and the embedded nodes where the electrolyser was fulfilling a local demand. When the electrolyser could blend into the network, there was a decoupling of the hydrogen demand from its production profile as the demand peaks could be met by the electrolytic and CCUS enabled hydrogen stored within the network. This meant that the electrolysers in these nodes could run solely at their most cost-effective times. This was not the case in the embedded nodes, where on-site storage or supplementary grid electricity was required to meet the peaks. As this grid electricity was often required in periods of low renewable generation, and high electricity cost, the impact of this was compounded.

In the case of avoiding grid electricity usage, it could be argued that the decoupling of hydrogen production and demand was an enabler of the first characteristic, rather than directly delivering the benefit. However, there are also other benefits to decoupling that warrant discussion, leading to the recognition of this characteristic as an individual category. In a scenario where there was no on-site storage, the hydrogen production profile was required to exactly match the demand profile, resulting in the oversizing of the production equipment and an additional CAPEX burden. This was somewhat reduced by incorporating on-site storage, with far less cost reduction potential than networked flexibility could provide. Furthermore, the inability to decouple production with demand led to the requirement for more complicated projects. This is highlighted by Figure 6 below which shows the breakdown of the electricity used by the Node 5 electrolyser in June 2040. Even when 41MW of H_2 storage was installed (alongside an 80MW electrolyser), a variety of different electricity sources was needed to match the demand profile. This is vastly different to the Node 10 electrolyser which simply followed the profile of the onshore wind.

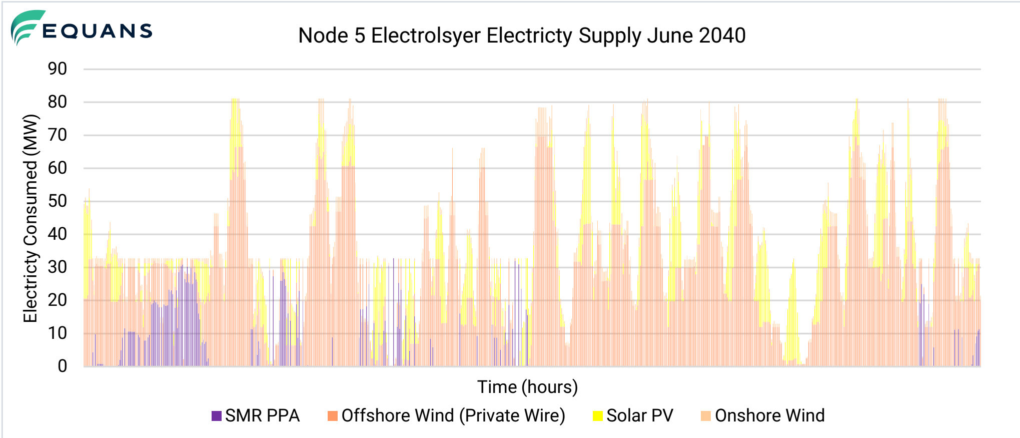


Figure 6 Breakdown of the electricity used by the Node 5 electrolyser in June 2040

The difficulty in decoupling hydrogen production with demand was the primary reason for the higher LCOH in the embedded nodes compared to the network blending nodes. This highlights the importance for different levels of government support for these decentralised embedded projects as they will be crucial in supporting the decarbonisation of UK industry outside of carbon capture clusters. Furthermore, if these decentralised projects are allowed to blend excess hydrogen into the grid, and are eligible for revenue support for this production, this could further decrease the overall cost of production.

3. Coordination is Crucial

The final characteristic of success recognised the importance of coordination and wider systems thinking. At a regional level, the modelling highlighted the importance of shared hydrogen infrastructure in the region's zero carbon transition. CCUS enabled hydrogen and HyNet's distribution and storage infrastructure were shown to be crucial in enabling network connected electrolytic projects to emerge. Furthermore, given the volumes of hydrogen forecast for this modelling, electrolytic projects alone would be unable to fulfil the demand. In the four Target Mix scenarios where electrolytic hydrogen was constrained to supply 25% of the consumption, the installed electrolyser capacity ranged from approximately 2GW to 7GW in 2040. This is already a highly ambitious electrolyser capacity and it is unlikely that the region would have sufficient zero carbon electricity in this period to increase this figure much further whilst decarbonising other sectors. In this sense, it is important that electrolyser developers coordinate with HyNet, renewable developers, regulated utilities and the other electricity consumers to ensure the optimisation of the region's energy system.

Alongside coordinating with HyNet, the centralised scenarios highlighted the importance of coordinating multiple consumers. The aggregation of demand provided many benefits which resulted in an overall reduction in system cost. Firstly, the aggregation of consumers enabled the flattening of the overall demand profile, as individual systems were no longer sized to meet each individual peak. It also allowed larger projects to develop, and crucially it enabled projects to be developed in more attractive locations (i.e. where there was a greater onshore wind development potential). In the longer term, the centralisation of production around small modular reactors appears to have strong potential. Finally, this coordination could allow for commercial optimisation from producers, selling into multiple markets (e.g. mobility and industry) to create more cost effective structures.

Finally, there was shown to be benefits when coordinating electrolytic developments alongside other on-site decarbonisation initiatives. If hydrogen is the only demand vector, then it is a challenging exercise to optimise the size of each of the components. For example, if the power source is too small the electrolyser is underutilised, but if it is too big there would be unnecessary curtailment. Both of these scenarios result in oversized CAPEX, with negative consequences for the LCOH. In the case of Node 5 in the NTM decentralised bull 2040 scenario there were over 1500 hours in the year where some of the on-site electricity production was curtailed. Had this curtailed electricity been used to displace other electricity requirements on site, the nodal LCOH would have reduced from £5.05/kg to £3.89/kg, a 25% reduction. This highlighted the importance of considering electrolytic hydrogen solutions alongside other decarbonisation initiatives, rather than considering hydrogen in isolation.

1.2.2 Development Considerations

The overall objective of the Net Zero North West Cluster Plan project is to establish a coherent vision for industrial decarbonisation in North West England and North East Wales. For this reason it was important that the aforementioned characteristics of success are considered alongside the practicalities of implementation. This meant highlighting the key considerations that developers should be aware of, as well outlining how governmental support could be used to commercialise the projects. This analysis forms the basis of Section 6 where these themes are explored for electrolytic grid injection projects and embedded hydrogen solutions for industry. The key points for each are summarised below.

1. Electrolytic Hydrogen Grid Injection

In the various modelling scenarios, an array of different electrolytic hydrogen production configurations were selected to inject hydrogen into the HyNet network. Although it was not the cheapest configuration, directly connected offshore wind was observed to be the most scalable option. In practical terms, this would involve connecting an electrolyser directly to an offshore wind turbine via a private network at the onshoring location. The electrolyser would then produce green hydrogen which would be injected into the HyNet network and sleeved to local consumers. Given the nascent nature of this solution, from a technical and commercial perspective, there is currently no precedent for the above and therefore it carries intrinsic risk. Furthermore, given the holistic nature of this modelling exercise, there are a number of practicalities that were excluded from the analysis, that could affect the viability of this solution. These would need to be explored in greater detail during future work and some of the main points are listed below:

- The competition from other electricity consumers
- The technical and economic implications of connecting at the onshoring location
- The distance between the onshoring location and suitable injection points

There were also some opportunities to increase the offshore wind capacity that was excluded from the analysis. The modelling only assumed that developments in Pre-Planning or that had been awarded as part of the Contracts for Difference Allocation Round 4 (CfD R4) auctions were in scope. In reality, there may be some alternative ways to source offshore wind power in the region, such as:

- The use of curtailed electricity at low or zero cost
- The use of legacy wind turbines following the end of their CfD or Renewables Obligation (RO) contracts
- Future offshore wind developments in the region

These considerations are explored in more detail in Section 6.1.

2. Embedded Green Hydrogen for Industry

Although embedded solutions were seen to be more expensive than their network connected counterparts, they were observed to be a crucial part of the region's zero carbon transition. Although consumers around the Ellesmere Port area could have access to network connected low carbon hydrogen by 2025 other consumers in the North West will need to wait significantly longer before they are connected to a hydrogen network, and those in Lancashire and Cumbia are unlikely to receive a connection based on current proposal. This means that to become a low carbon cluster by 2030 and a zero carbon cluster by 2040, the region will need to pioneer these zero carbon solutions. However, the actual scalability of this solution is driven by the number of sites where these solutions can be viably installed. From a cost perspective, this viability is driven by the ability to access low cost electricity sources at the site, but there are also a number of other constraints that will need to be considered during feasibility studies and engineering design, such as:

- Site specific safety considerations
- Plant and process changes required for fuel switching
- The availability of land and ability to access input resources
- The local electricity network constraints and gas grid blending options
- The consumer's hydrogen demand profile and security of supply concerns

These considerations are explored in more detail in Section 6.2.

Finally, irrespective of whether the initiative is an electrolytic grid injection project or and embedded hydrogen solution for industry, it is vital that a sustainable commercial model can be developed. There is a significant cost difference between hydrogen and the counterfactual fossil fuels it would look to displace, meaning an unsubsidised economic case is challenging. Early projects are therefore likely to require government support during their development and long term operations. The Government has recognised this requirement and, alongside the Low Carbon Hydrogen Supply Competition Phase 2 which announced its winners in February 2022, there are several forthcoming support mechanisms that could be used to deliver these projects. The most significant measures are deemed to be the following:

- **The Net Zero Hydrogen Fund** – 240m of co-capital support providing DEVEX and CAPEX to support to help projects reach investment decision. The consultation closed in October 2021 and the scheme is expected to be live from Spring 2022.
- **Industrial Decarbonisation and Hydrogen Revenue Support**– Long term revenue support scheme for hydrogen producers that is expected to bridge the gap between the cost of hydrogen and a counterfactual fossil fuel (likely natural gas). The consultation closed in October 2021 and the scheme is expected to be live from Q1 2023.
- **Proposed Industrial Hydrogen Accelerator** – A competition to support projects generating evidence on end-to-end industrial fuel switching to hydrogen. It would cover the full technology chain, from hydrogen generation and delivery infrastructure through to industrial end-use, including the integration of the components in a single project. It is proposed that the competition will launch in April 2022.

- **Industrial Energy Transformation Fund** – 315m of co-capital support to support demand side decarbonisation measures, including hydrogen fuel switching. Phase 2 Spring 2022 is open until 29 April 2022 and has 60m of grant funding available.
- **Road Transport Fuel Obligations** - Fuel suppliers that supply at least 450,000 litres of transport fuel in the UK are obliged to show that a percentage of the fuel they supply comes from renewable and sustainable sources. This creates an additional revenue stream for industrial projects that include a mobility demand.

Developers should be cognisant of how these mechanisms can be used in harmony to develop and deploy hydrogen projects. Furthermore, as the modelling demonstrated, there are intrinsic differences between different project types, with specific project factors considerably impacting the levelised cost of hydrogen. It is therefore important that there is suitable flexibility in these measures to ensure it is accessible to all industrial consumers who are looking to decarbonise. This will be important to ensure the longevity of these industries, supporting these local jobs and communities, and delivering on the Government's levelling up agenda.

To accelerate electrolytic hydrogen development activity in the region, developers must act as market makers, coordinating demand with production whilst establishing the necessary commercial and regulatory environment.

These activities can be broadly grouped into the following categories:

- **Identify suitable demand aligned with the aforementioned characteristics of success**
- **Collaborate with local stakeholders such as HyNet, renewable developers and regulated utilities**
- **Engage with Government about the design and iteration of regulation and support mechanisms**

These commercial considerations, alongside the technical observations highlighted in this report, provide an evidence base to support the development of electrolytic hydrogen projects in the region. Although it is not without its challenges, it is clear that the region is well positioned to lead the UK's industrial zero-carbon transition and become the world's first net zero industrial cluster.

2. Introduction

In the early 1700s, one could have been forgiven for thinking that North West England and North East Wales was a disparate collection of market towns, as was the norm elsewhere in the country. But with its symbiotic manufacturing processes, it was actually the world's first industrial region, acting as the blueprint for the UK's industrial revolution of the late 18th century. [1] Fast forward 300 years later and North West England and North East Wales remains an industrial stronghold, with the region delivering   185 billion Gross Value Add (GVA) and boasting the largest concentration of advanced manufacturing and chemical production facilities in the UK.

However, these complex industrial processes come at a cost to the environment and the region currently produces approximately 38.5 mega tonnes of carbon dioxide equivalent (38.5MtCO2e) per year; the same as the Republic of Ireland, [2] including nearly 17 MtCO2e of industrial Scope 1 and 2 emissions. Just as North West England and North East Wales was at the forefront of the industrial revolution, it now has the opportunity to lead the green revolution and has ambitions to be the world's first net zero industrial cluster by 2040.

To achieve these ambitions a suite of decarbonisation initiatives will need to be deployed across the region, engaging consumers from all sectors. Industrial energy efficiency is a fundamental part of this solution and as is explored in detail as part of our Industrial Consumers Report for the North West. Furthermore, just like the intertwined manufacturing processes of old, a coordinated approach to decarbonisation could yield significant benefits for consumers in the North West, with costs shared rather than duplicated.

In North West England and North East Wales, the benefits of coordination are epitomised by the HyNet project; a flagship hydrogen project seeking to reduce CO2 emissions by 10Mt/a by 2030. Drawing upon this infrastructure, and as the focus of this report, we have assessed the opportunity for electrolytic hydrogen in North West England and North East Wales and the role it could play alongside and integrated with, other high profile infrastructure projects in the regions' transition to net zero.

2.1 What is electrolytic hydrogen?

Although hydrogen is the most abundant element in the universe, pure hydrogen (H2) is not easily found on earth and must be separated from other compounds where it is a constituent part, such as hydrocarbons or water. The vast majority of hydrogen currently produced in the UK is carbon intensive **grey hydrogen** produced through the reformation of methane. If carbon capture is added to this process, then the hydrogen is considered low carbon and is called **blue hydrogen** (CCUS enabled hydrogen).

The term electrolytic hydrogen can be used to describe hydrogen that is produced through electrolysis, the splitting of water in hydrogen and oxygen. For this report, we have considered the following types of electrolytic hydrogen as part of our analysis:

- **Green hydrogen:** Electrolysers powered by renewable electricity3
- **Purple hydrogen:** Electrolysers powered by nuclear electricity

Electrolytic hydrogen is a currently a nascent solution, with only 80MW of capacity installed in Europe and approximately 370MW worldwide. [3] That said, with falling technology costs and expected growth in demand, nearly 59GW of projects have been announced by developers worldwide to come online by 2030. [3] In the UK, the early electrolytic projects that have been awarded funding through the Hydrogen Supply Competition Phase 2 are 'Dolphyn' (led by Environmental Resources Management) and 'Gigastack' (led by ITM). Both of these projects will aim to demonstrate that electrolytic hydrogen has the potential to provide a practical and scalable solution.

[3]In some of the modelling scenarios examined in this report, it is economically optimal to supplement intermittent renewables with grid electricity. Unless the carbon intensity of the grid is zero, this hydrogen is not technically 'green' and this will be highlighted alongside the results.

Despite the infancy of the market today, low carbon hydrogen is central to the decarbonisation plans of the North West Industrial Cluster and industrial decarbonisation more broadly. The recently published UK Hydrogen Strategy recognised that hydrogen is a critical component of net zero, stating that 'low carbon hydrogen will be essential for achieving net zero' and 'is suited to use in a number of sectors where electrification is not feasible or is too costly, and other decarbonisation options are limited'. [3]

Whilst some industrial processes can be electrified cost effectively, much of industry falls into the hard-to-abate definition and the UK Hydrogen Strategy suggests that the national industrial consumption for hydrogen could reach 105TWh/a by 2050. [3] There could also be significant hydrogen consumption in the transport, power, residential and commercial sectors, and due to the aforementioned benefits of coordination, we will also consider hydrogen consumption from these sectors in our report.

That said, the role hydrogen should play in the decarbonisation of heat, and the extent to which gas networks will be repurposed for hydrogen, is a subject of significant debate and a policy decision is not expected on this topic until 2026. In absence of this wider political clarity, early hydrogen clusters are likely to develop in areas with anchor industrial consumption, such as the North West Industrial Cluster, particularly around HyNet.

2.2 The Regional Context

Although the focus of this report is on electrolytic hydrogen, it is important to recognise that HyNet is front and centre in the North West's industrial decarbonisation plans. This project, led by Progressive Energy, Cadent and Essar, is seeking to accelerate the decarbonisation of major industrial users in North West England and North East Wales by supplying them with low carbon hydrogen.

Under the current proposals, the low carbon CCUS enabled hydrogen will be produced at Essar's Stanlow refinery via autothermal reforming (ATR) with carbon capture and storage (CCS). Hydrogen will then be transported to major industrial users via a dedicated local hydrogen transmission system (LTS). The LTS will also support demands from other sectors (e.g. power, transport) and will have the ability to supply the adjacent gas distribution networks (GDNs), initially blending low carbon hydrogen with methane, enabling hydrogen to support the decarbonisation of residential and commercial heat. A schematic of the proposed project is shown above in Figure 7.

That said, although HyNet is a substantial project, as per the current proposals, it does not cover the entirety of the region which stretches up into Lancashire in Cumbria. This means that there are areas in North West England and North East Wales that will not have access to hydrogen from the HyNet pipelines.

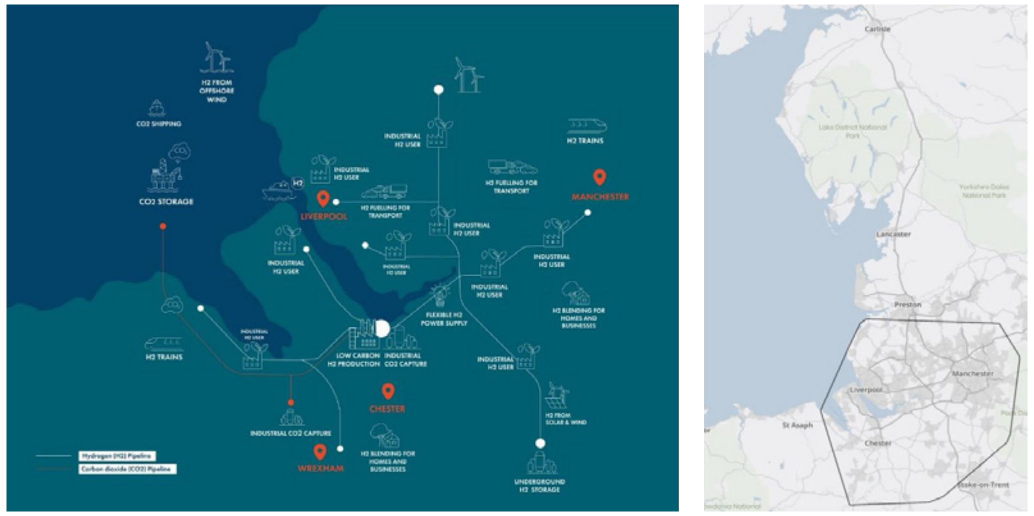


Figure 7 A schematic of the proposed HyNet project [4] (left) and the location of HyNet in relation to the wider North West England and North East Wales region

Our modelling in this report is centred around the assumption that HyNet goes ahead as planned and that no additional hydrogen pipelines are developed outside of this area. Although it is plausible that a hydrogen network could be developed to connect consumers in the wider region to HyNet, this decision is less predicated on the existing HyNet proposals and more so on national policy and wider systems thinking, as this would be speculative, and following discussions with Cadent, the only hydrogen pipelines included in our analysis were those within the HyNet area.

North West England and North East Wales also has abundant natural resources and therefore the potential to generate substantially more renewable electricity than is the case today. Much of this increased capacity will come from new offshore wind farms, a number of which are at various stages of planning, licensing and consenting today, supported by large scale solar projects and tidal energy, such as the proposed project in the Mersey. The extent to which this locally generated renewable electricity can underpin the production of green hydrogen and support the decarbonisation of industry in the region, alongside HyNet, is a central theme of this report.

3. Zoning summary

As alluded to in Section 2.2, from a hydrogen transportation perspective, the region can be split into two zones: the area within the HyNet project and the area outside of this proposal.

However, there are many more regional considerations that influence the design of a hydrogen system in North West England and North East Wales, such as the location of power producers or potential clusters of hydrogen consumers.

For this reason, to improve the accuracy and granularity of our modelling, we divided the region into 13 zones, otherwise known as nodes. The area encompassed by each of these 13 nodes was derived through geospatial analysis, which is explained in Section 4, but for ease of understanding they are introduced below in Figure 8.

As can be seen in Figure 8, each of these nodes represents a finite area, however for the purpose of our modelling, they are treated as a singularity.

This means an assumption applied to each node must be valid across its entirety. For example, Node 9 represents Greater Manchester and the hydrogen consumption at this node is the summation of all relevant consumers within this area. As we are assuming that, by 2040, the GDN within the HyNet area is hydrogen ready, then we can model the hydrogen consumption of Greater Manchester as a singularity. However, looking outside of the core HyNet area, we can see multiple isolated industrial sites, spread across the region. If we were to aggregate more than one of these consumers together then we would need to assume that they were connected by a hydrogen network, contradicting our earlier assumption about the availability of pipelines outside of HyNet.

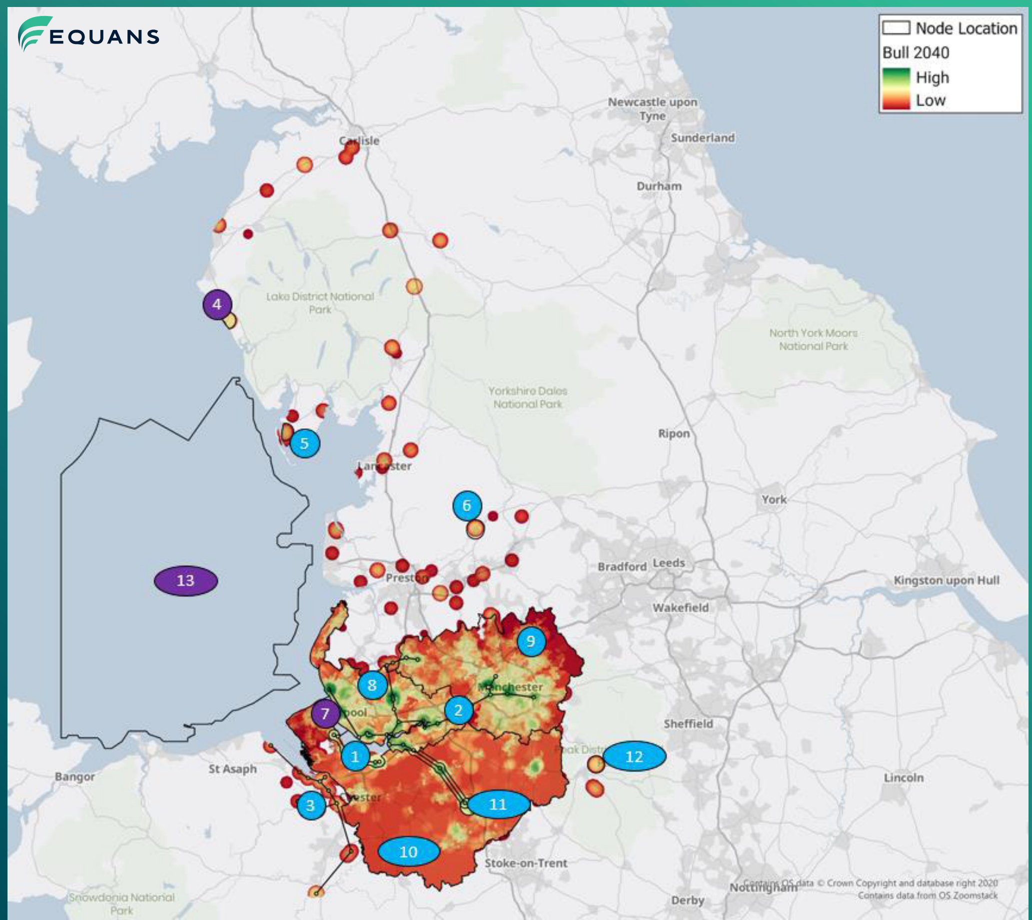


Figure 8 A map showing the location of 13 nodes used to define the region for our modelling. The heat map shows the modelled consumption of hydrogen in our bull 2040 scenario. Blue nodes indicate those with hydrogen production and consumption potential, purple nodes are those without hydrogen consumption. The area encompassed by each node (the consumers clustered at each node) is presented in Table 4.

For this reason, we needed to select indvidual sites, or business parks, outside of the HyNet area to act as archetypes for industrial consumers not connected to the HyNet network. These archetypical industrial consumers are represented by Nodes 5, 6 & 12, and the process behind their selection is explained in more detail in Section 4.1.2.

Furthermore, for each of the nodes we also need to define their hydrogen production capability and whether they can supply into a hydrogen network (network connected) or if they can only supply on-site requirements (embedded). A breakdown of the hydrogen production and consumption constraints for each node is summarised in Table 5 below.

Node	Hydrogen Production	Hydrogen Consumption
1	CCUS enabled H2 & network connected green H2 (Offshore wind)	11 industrial consumers connected to the HyNet LTS closest to Stanlow
2	-	36 industrial consumers connected to the HyNet LTS within Liverpool and Manchester
3	-	11 industrial consumers connected by the HyNet LTS within Cheshire and North East Wales
4	Purple H2	-
5	Embedded green H2 (Onshore wind, solar PV)	1 industrial consumer (Paper & pulp sector)
6	Embedded green H2 (Offshore wind, onshore wind, solar PV)	3 industrial consumers (Business Park)
7	Network connected green H2 (Tidal power)	-
8	Network connected green H2 (Onshore wind, solar PV)	Industrial, residential, commercial & transport consumers connected to the Liverpool City Region GDN
9	Network connected green H2 (Onshore wind, solar PV)	Industrial, residential, commercial & transport consumers connected to the Greater Manchester GDN
10	Network connected green H2 (Onshore wind, solar PV)	Industrial, residential, commercial & transport consumers connected to the Cheshire GDN
11	-	Hydrogen gas turbine (power sector consumer) connected to the HyNet LTS
12	Embedded green H2 (Onshore wind, solar PV)	1 industrial consumer (Cement sector)
13	Node 13 represented the offshore wind development pipeline in North West England and North East Wales. It did not have hydrogen production or consumption constraints but was used to program the capacity of Offshore Wind that could be used elsewhere in the region. This is explained in more detail in Section 4.2.2.1.2	

Table 5 The hydrogen production and consumption constraints for each of the analytical nodes

Alongside these nodal production and consumption constraints, we also needed to specify where electrolysers could be installed and how hydrogen could flow between each of these nodes. To do this we decided to model two configurations: decentralised and centralised production, and explore the impact on overall system cost of each strategy.

3.1 Decentralised Configuration

In the decentralised configuration we gave the model the freedom to install electrolysers at any of the nodes where there was land available to do so to examine the opportunity for localised production. This meant that the model could install electrolysers at every node except Node 13, which was at sea, or Nodes 2, 3 and 11 which were purely consumption nodes connected to the HyNet LTS. A proportion of the offshore wind electricity could be used on a private network at Nodes 1 and 5, illustrated by the red arrows below, or via a Power Purchase Agreement (PPA) in the other nodes.

Furthermore, in this model, we did not allow the transportation of hydrogen by road. This meant that any hydrogen requirements within the embedded nodes (Nodes 5, 6 and 12) would need to be produced on-site. The decentralised configuration is shown below in Figure 9, showing how hydrogen can flow between the nodes.

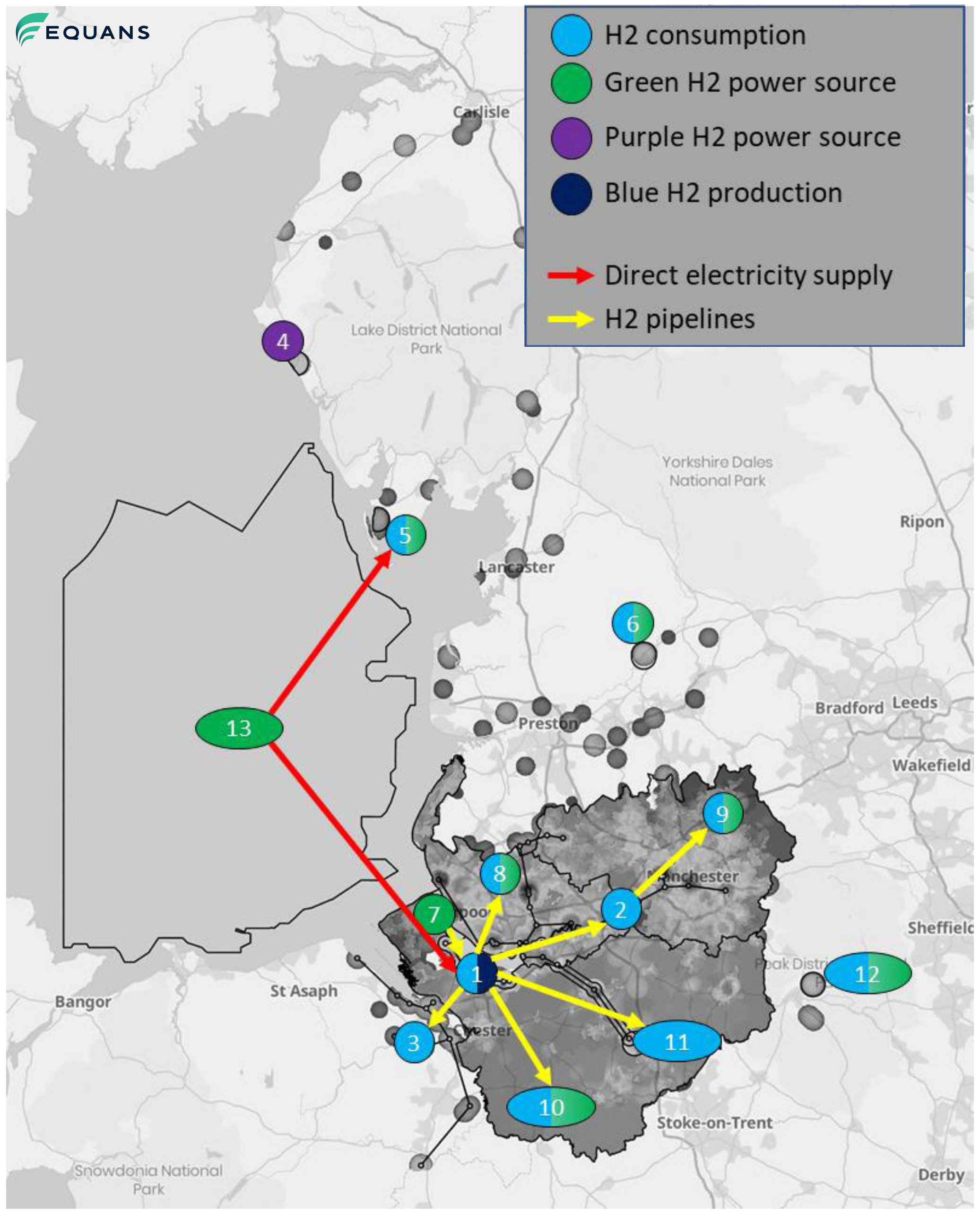


Figure 9 The decentralised modelling configuration showing nodes with hydrogen production, hydrogen consumption and outlining how hydrogen can flow between nodes

3.2 Centralised Configuration

In the centralised configuration we sought to understand if any economies of scale could be achieved by centralising hydrogen production in a smaller number of locations rather than allowing electrolysers to be installed across the region. To do this, we grouped the nodes into north and south regions, as shown by the yellow bubbles in Figure 10. The model was able to install up-to one electrolyser in the north regions and up-to two electrolysers in the south region. In this configuration, hydrogen could also be transported by road within each of the regions, as illustrated by the dotted lines.

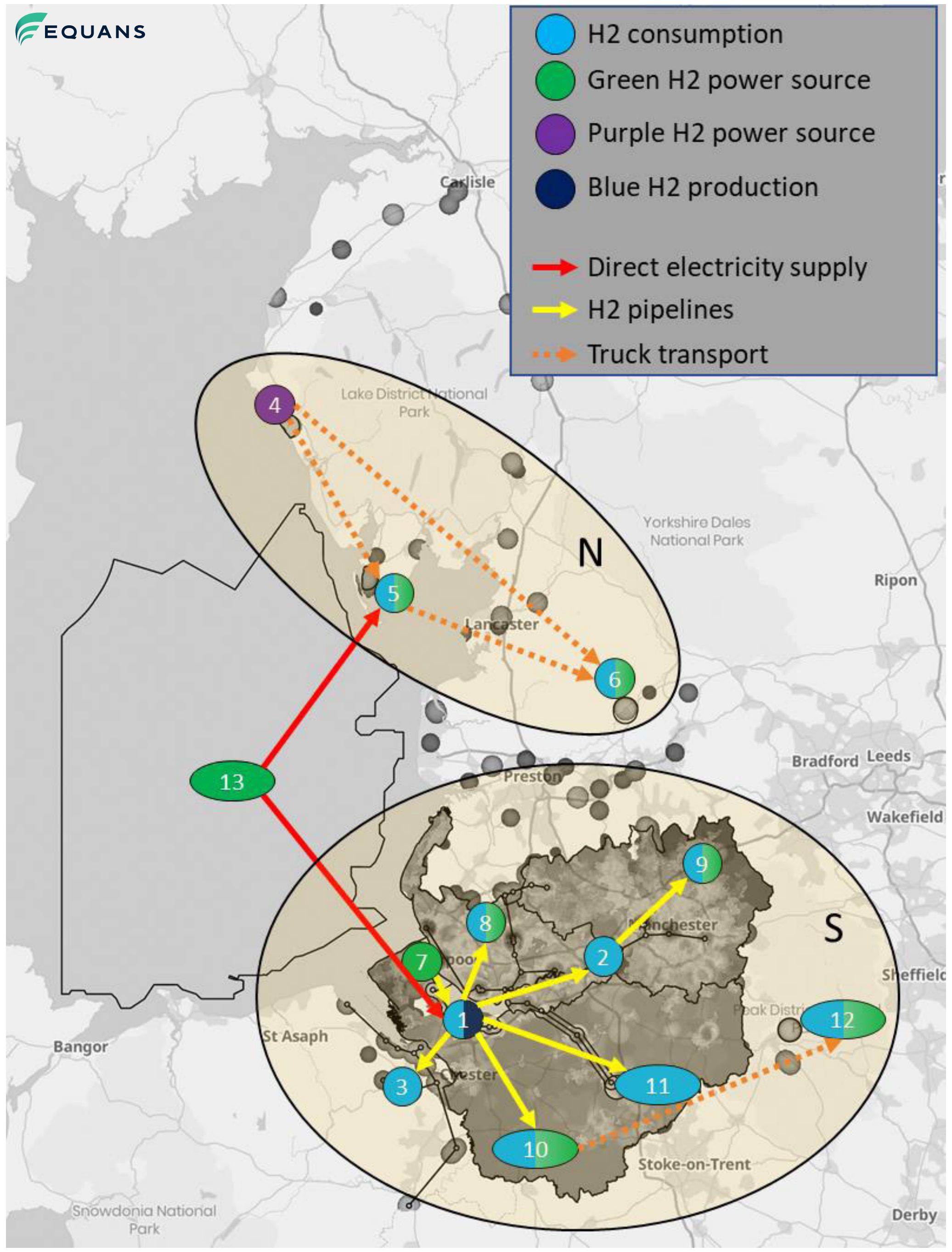


Figure 10 The centralised modelling configuration showing nodes with hydrogen production, hydrogen consumption and outlining how hydrogen can flow between nodes

4. Modelling overview

In order to develop a cost-optimised hydrogen production system for North West England and North East Wales we used our propriety simulation tool, PROSUMER. PROSUMER is a multi-nodal, multi-vector optimisation tool, meaning it can design an integrated energy system, accounting for geographic considerations.

These geographic considerations are the nodal constraints that were introduced in Section 3. The rationale for these constraints is explained further in this section. However, firstly it is important to understand how PROSUMER works.

PROSUMER works by designing a system with the lowest Total Cost of Ownership (TCO) capable of operating within the boundaries of the production, consumption, and configuration constraints. This means that PROSUMER designs the lowest cost system capable of balancing production with consumption and adhering to the constraints applied. Furthermore, this simulation occurs on an hourly basis, meaning the overall system must ensure conservation of energy and remain in equilibrium for each hourly increment. This hourly modelling capability is particularly important when considering the production profiles of renewable energy sources and the gas demand profiles of consumers which will be explained in Sections 4.1 and 4.2 below.

The cost optimisation is then driven by the technical and economic assumptions, such as the CAPEX, OPEX, cost of carbon and performance data of the different technology options. This TCO optimisation is done at the whole system level, rather than the nodal level, meaning each nodal system is designed to reduce the overall TCO.

We then performed the modelling for two different cases, to capture the influence that policy could have. Firstly, to assess the least cost option with no regulatory or fiscal levers, a scenario was modelled without specifying a target mix of hydrogen production technologies. This meant that we did not model the impact that public support mechanisms could have on commercialising different production technologies. The **No Target Mix** results are presented in Section 5.1. However, alongside the UK Hydrogen Strategy, the Government announced a consultation into business models for low carbon hydrogen. Section 6 of this consultation recognises that different technologies will require different levels of support. Although no target production mix was presented as part of the strategy, it is likely that future support mechanisms will be designed with a figure in mind. For this reason, we also ran a **Target Mix** scenario to examine how and where projects may emerge in a scenario where electrolytic hydrogen was supported to deliver a minimum penetration of 25% of total production. The figure of 25% was selected based on the BEIS Impact Assessment into the sixth carbon budget, which recommended a scenario that included a green hydrogen penetration of 5% - 40% in 2035. These results are presented in Section 5.2.

4.1 Hydrogen Consumption Considerations

The first step in defining the regional hydrogen consumption was to understand how and where hydrogen may be used in 2030 and 2040. This was a challenging task as although the UK's 2050 Net Zero commitment necessitates the use of hydrogen, there is still uncertainty over the size of the market that will develop. This was highlighted in the UK Hydrogen Strategy, with BEIS estimating that national consumption could fall anywhere between 260 and 460TWh/a by 2050.

This is because there are multiple decarbonisation pathways that different consumers can take. We have analysed the effect of this in more detail as part of our Industrial Consumers Report where we have developed decarbonation roadmaps for different sectors. However, for this report we have focussed on the hydrogen consumption and, to capture the effect of different future energy scenarios, we decided to model **bull** and **bear** scenarios, with higher and lower hydrogen consumptions respectively. In these scenarios, we considered the requirement for hydrogen across the industrial, residential & commercial, transport and power sectors. The methodology used to define the bull and bear consumptions for these sectors is explained in Sections 4.1.2 to 4.1.4.

The following sections explain how these consumptions were defined at the regional level. However as noted in earlier, we then needed to define the consumption across the 13 nodes.

We predominately took a bottom-up approach to estimating hydrogen consumption, so the process of defining the nodes represented the clustering of multiple consumers rather than the disaggregation of the overall regional consumption. This clustering process is explained in the following sections and resulted in defining the nodes that were introduced in Section 3. Finally, the sectoral consumptions were calculated on a yearly basis, but PROSUMER simulates on an hourly basis. This meant that we had to convert the annual consumptions into their hourly demands; this process is explained in Section 4.1.5.

4.1.1 Residential & Commercial

Different decarbonisation options are available in the residential and commercial sector and the extent to which hydrogen is used for heating in these sectors is a key reason for the large variance in BEIS' hydrogen consumption projections. Although the focus of the Net Zero North West Cluster Plan is industrial decarbonisation, it is impossible to isolate the effect that hydrogen's role in the wider decarbonisation of heat will have on the overall system design. For this reason, we deemed it import to model residential and commercial consumption as part of our analysis.

In order to calculate the 2030 and 2040 hydrogen requirements in the residential and commercial sectors we took a two-step approach, benchmarking the current gas consumption before exploring different decarbonisation pathways.

To benchmark the current gas consumption we used the UK local authority and regional carbon dioxide emissions national statistics from 2018. [5] Although this dataset breaks down local authority emissions by sector, there was some overlap with emissions that can be attributed to industry. These are emissions produced by smaller industrial consumers, who are not required to report under the Emissions Trading Scheme (ETS) but are captured in local authority statistics. After removing these industrial emissions from the commercial sector, we were left with a regional natural gas consumption in the commercial sector of 16.8TWh/a. We followed the same process for the residential sector, arriving at a natural gas consumption benchmark of 39.9TWh/a. Finally, we assigned these regional consumptions to Lower Super Outputs Areas (LSOAs), based on population density data.

The second step was to explore different future energy scenarios and to decide the extent to which these residential and commercial gas requirements could be replaced by hydrogen in 2030 and 2040. After discussion with our NZNW consortium partners, we decided to use National Grid's Future Energy Scenarios (FES) 2020 [6] with the bull scenario following the System Transformation pathway and the bear scenario following the Consumer Transformation pathway. As can be seen below in Figure 11, this largely equates to the electrification of heat in the bear scenario versus hydrogen for heat in the bull scenario.

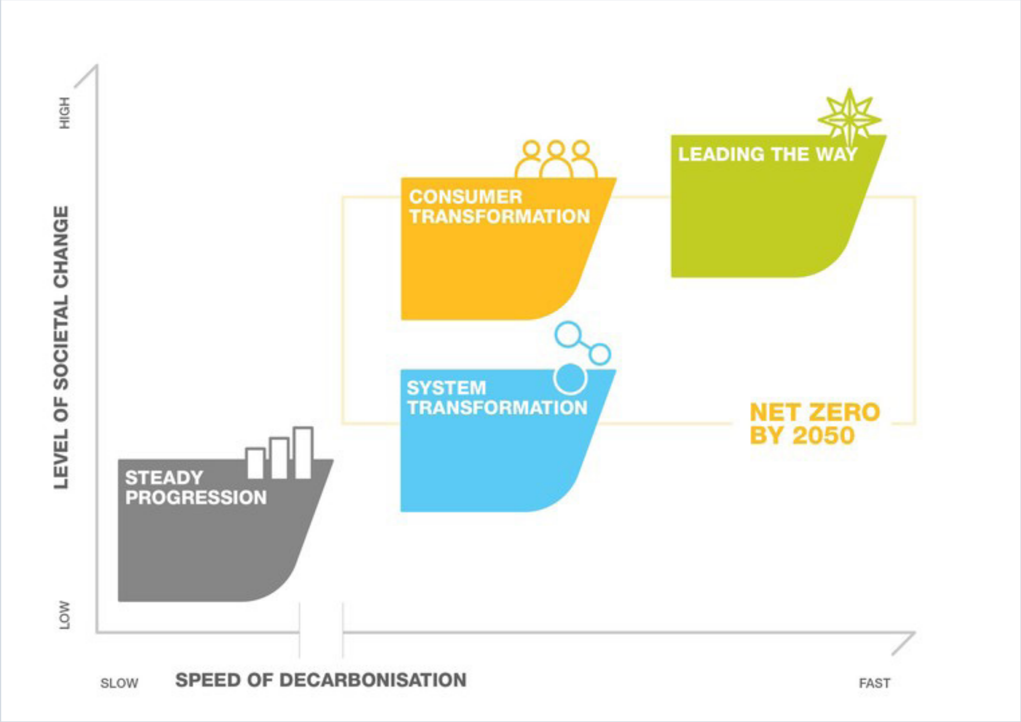


Figure 11 National Grid: Future Energy Scenarios 2020 [6]

Furthermore, even in a widespread hydrogen scenario, it would be unrealistic to expect future hydrogen consumption to equal today's gas consumption as there would still be extensive electrification and improved energy efficiency, reducing the overall gaseous energy requirements. These projected consumption reductions are provided as part of the FES 2020 data book and summarised in the table below for the bull and bear scenarios in 2030 and 2040.

Furthermore, as explained in Section 2.2, for this modelling we assumed that hydrogen pipelines would only be available within the proposed HyNet area ("LTS Area"). As the only practicable way to supply residential and commercial premises with hydrogen is via pipelines, this meant that we needed to make different assumptions around the decarbonisation pathways for the LTS Area and the non-LTS Area.

For the LTS Area of Nodes 8, 9 & 10 (i.e. Greater Manchester, City of Liverpool and Cheshire), our bull and bear scenarios were derived from the FES 2020 System Transformation and Consumer Transformation pathways respectively, albeit with a slightly accelerated timeline to account for the regional context. For the non-LTS Area, we did not model any residential or commercial hydrogen requirements as part of our analysis.

Our assumptions are summarised in Table 6 below, and the corresponding hydrogen requirements for the residential and commercial sectors are presented in Table 7 and Table 8 respectively.

Finally, we are able to visualise the location of the hydrogen requirement using Geographic Information System (GIS) modelling. This is illustrated in Figure 12 which shows the residential hydrogen consumption by LSOA in the bull 2040 scenario.

Residential & commercial assumptions	**Bull**		**Bear**	
	2030	**2040**	**2030**	**2040**
LTS area (Nodes 8, 9, 10)	20% blend & 8% reduced gaseous consumption by energy	95% H_2 & 18% reduced gaseous consumption by energy	10% blend & 27% reduced gaseous consumption by energy	0% H_2 (Electrification)
Non-LTS area	0%H_2	0%H_2	0%H_2	0%H_2

Table 6 The assumptions used to derive the H2 consumption in the residential and commercial sectors

Residential consumption (TWh/a)	**Bull**		**Bear**	
	2030	**2040**	**2030**	**2040**
Node 8	0.46	5.96	0.18	-
Node 9	0.89	11.61	0.35	-
Node 10	0.25	3.36	0.10	-
Total	**1.60**	**20.83**	**0.64**	**-**

Table 7 The nodal and total consumption requirements for hydrogen in the residential sector for each scenario

Commercial consumption (TWh/a)	**Bull**		**Bear**	
	2030	**2040**	**2030**	**2040**
Node 8	0.25	3.23	0.10	-
Node 9	0.34	4.06	0.12	-
Node 10	0.13	1.68	0.05	-
Total	**0.71**	**8.97**	**0.27**	**-**

Table 8 The nodal and total consumption requirements for hydrogen in the commercial sector for each scenario

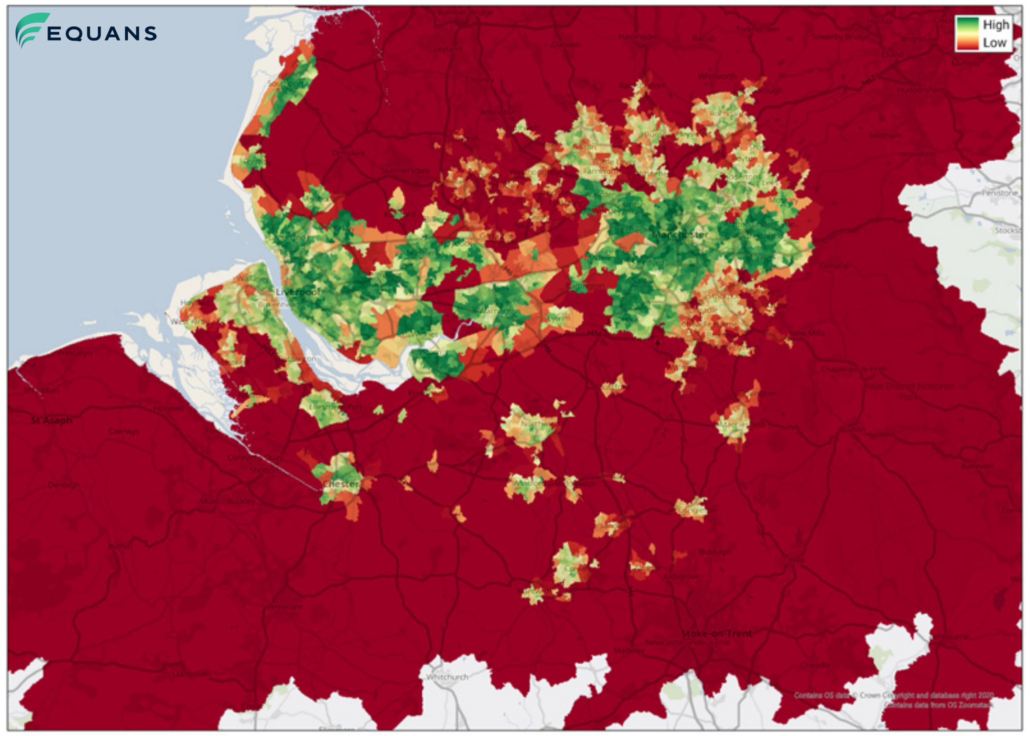


Figure 12 Residential hydrogen consumption by LSOA in the LTS area in the bull 2040 scenario

We produced these maps for each individual sector and scenario, before combining the layers and conducting suitability modelling, to develop the overall render that was presented in Section 3. The methodology for the industrial, transport and power sectors is explained in detail below.

4.1.2 Industry

To estimate the industrial hydrogen requirements, the first step was to identify the key industrial consumers in the region. To do this, we drew upon two publicly available datasets:

1. EU Emissions Trading Scheme (ETS) database (2019) [7]

Industrial consumers of a certain size and in certain sectors, are required to report their Scope 1 emissions through the EU ETS. The scheme involves over 11,000 consumers across Europe, including 95 sites in North West England and North East Wales.

2. UK National Atmospheric Emissions Inventory (NAEI) database (2017) [8]

Smaller industrial consumers are not required to report through the ETS and therefore the ETS dataset alone underestimates the emissions from industrial consumers in North West England and North East Wales. Emissions from these non-ETS industrial consumers are captured within local authority and regional carbon dioxide emissions national statistics and as point sources within the NAEI dataset. Using this NAEI dataset we identified an additional 82 industrial consumers in the region.

A map showing the locations of these 157 sites can be seen below in Figure 13 overleaf alongside Table 9 which gives a breakdown of the number of sites per sector and the Scope 1 emissions that they represent.

Sector	Number of Sites	Scope 1 Emissions (Mt CO2e/a)
Cement	6	2.734
Oil Refinery	4	2.202
Chemicals	35	1.024
Ammonia	2	0.71
Food & Drink	25	0.585
Waste	6	0.571
Paper & Pulp	20	0.541
Glass	8	0.473
Gas Terminal	2	0.306
Lime	1	0.184
Other Industry	7	0.145
Pharmaceuticals	7	0.139
Panelboard	1	0.137
Automotive	6	0.102
Ceramics	9	0.092
Non Ferrous Metal	2	0.059
Iron & Steel	1	0.055
Aerospace	4	0.054
Gypsum & Plasterboard	1	0.038
Asphalt	8	0.028
Airport	1	0.007
Gas Compressor	2	0.006
Water	2	0.002
Gas Exploration	1	0.001
Grand Total	**161**	**10.195**

Table 9 The number of sites per sector in the North West and their corresponding Scope 1 emissions

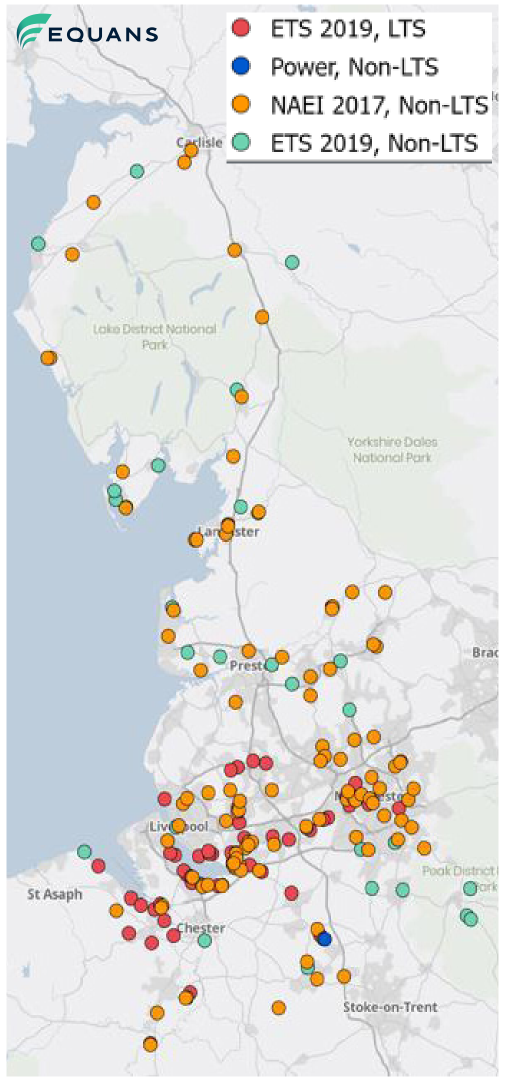


Figure 13 A breakdown of industrial sites in the North West Industrial Cluster

Scope 1 emissions are defined as the direct greenhouse emissions that occur from sources that are controlled or owned by an organisation. The percentage of a site's Scope 1 emissions that can be abated using hydrogen is dependent on the equipment and processes in place, with some sectors (e.g. glass or cement) having inherent process emissions that hydrogen may struggle to address. Therefore, to calculate the potential hydrogen consumption in the North West, we examined the extent to which these emissions could be abated using hydrogen. The percentage the of Scope 1 emissions that could be decarbonised using hydrogen was coined the maximum H_2 switching potential. These maximum H_2 switching potential percentages were sector and site specific and determined by Progressive Energy to calculate the HyNet consumption estimates.

For our modelling, we largely held these assumptions, following discussion with our NZNW consortium partners.

For this report, we converted the maximum H_2 switching potential for each site into a hydrogen consumption for each, by considering geographic and systemic factors, as explained below.

1. Geographic Considerations – LTS Area vs. non-LTS Area

As can be seen in Figure 13, there are many sites that fall within the HyNet LTS area, but there are also sites that are geographically removed from this project. Based on the previously stated assumption about the HyNet LTS and adjacent GDNs being the only H_2 pipelines in the region, it therefore follows that not all consumers in the region would have access to network connected hydrogen. To capture the influence that this could have on the hydrogen consumption at these sites, we separated the industrial consumers into **LTS** sites (Nodes 1, 2, 3, 8, 9, 10) and **non-LTS** sites.

The LTS sites would have lower barriers to entry when switching to hydrogen and thus a higher likelihood of abating a greater proportion of their emissions using the fuel. Furthermore, as part of the HyNet project, Progressive Energy has been in dialogue with a number of the sites around their fuel switching plans so we have held HyNet's hydrogen consumption assumptions for these sites.

2. Systemic Considerations - Bull and Bear Scenarios

However, just because a site could decarbonise a percentage of its Scope 1 emissions using hydrogen, does not mean that it necessarily will. If electrification is practicable, hydrogen will have to demonstrate it is the most economically viable option and there are numerous factors that will affect this economic comparison. As part of our Industrial Consumers Report for this project we have explored alternative decarbonisation options in more detail. We have amalgamated these unknowns into our systemic considerations and these are the drivers behind our bull and bear scenarios. Table 10 below summarises these assumptions.

Using these geographic and systemic considerations we then calculated the hydrogen consumption for each site, giving an overall industrial consumption in the region for each of the bull and bear scenarios. Furthermore, for the non-LTS sites, we took an archetypical approach to the modelling, as it would be unrealistic to model disconnected consumers as a singularity. This archetypical approach involved allocating 3 nodes for individual consumers, or groups of consumers, that could be reflective of other consumers in the region. We allocated these three nodes as follows:

- A single industrial consumer in the paper & pulp sector (Node 5)
- Three industrial consumers located on the same business park (Node 6)
- A single industrial consumer in the cement sector (Node 12)

This meant that the consumption requirements of 58 potential industrial consumers were not programmed into our model. Rather, using the archetypal approach outlined above, we considered the additional hydrogen consumption they could bring as part of our post-processing analysis. This is explored further in Section 5.1.

The overall nodal hydrogen requirements are summarised overleaf in Table 11 alongside Figure 14 which shows the industrial consumption heat map for the bull 2040 scenario.

Industrial assumptions	Bull		Bear	
	2030	**2040**	**2030**	**2040**
LTS Sites	Max. H2 potential for selected[4] sites	Max. H2 potential for all sites	A proportion of max. H2 potential for select sites	Max. H2 potential for selected sites
Non-LTS Sites	A proportion of max. H2 potential for all sites	Max. H2 potential for all sites	Gas grid blend (20% by volume) for all sites	A proportion of max. H2 potential for all sites

Table 10 The geographic and systemic considerations were used to derive a site-by-site hydrogen consumption for industrial consumers in the region

[4] Selected sites are those of a reasonable size and reasonable proximity to Stanlow refinery as defined by Progressive Energy

Industrial Consumption (TWh/a)	Bull		Bear	
	2030	2040	2030	2040
Node 1	9.84	9.87	7.10	9.28
Node 2	7.60	7.84	4.53	6.40
Node 3	1.16	2.30	0.25	0.46
Node 8	0.76	1.03	0.21	0.33
Node 9	0.38	1.09	0.04	0.34
Node 10	0.34	0.85	0.03	0.30
Node 5*	0.20	0.28	0.01	-
Node 6*	0.37	0.59	0.01	0.12
Node 12*	0.41	0.68	-	-
(No node)	1.69	5.02	0.20	1.25
Total (exc. no node)	**21.05**	**25.53**	**12.17**	**17.24**
Total (exc. no node)	**22.68**	**29.55**	**12.37**	**18.49**

Table 11 The nodal and total consumption requirements for hydrogen in the industrial sector for each scenario
** Denotes an archetypal node*

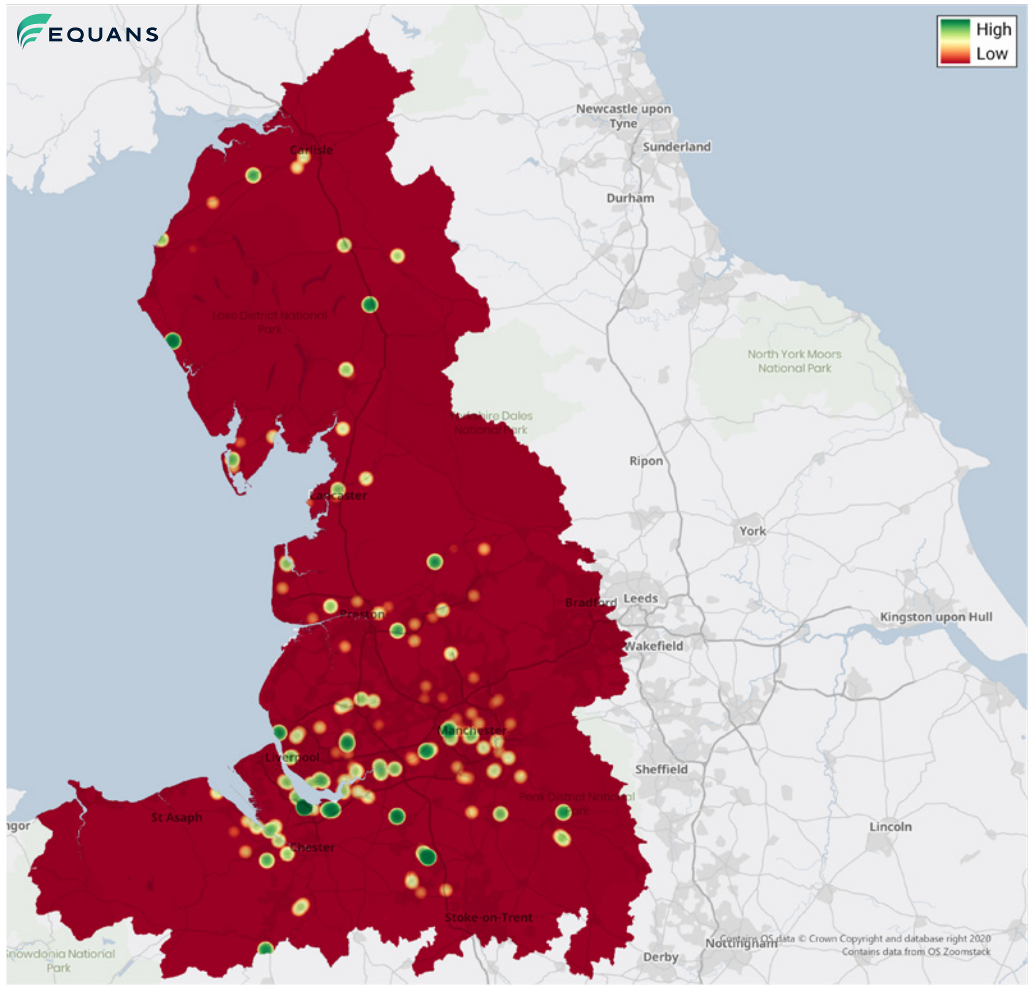


Figure 14 Industrial hydrogen consumption in our bull 2040 scenario and the relative location of HyNet

4.1.3 Transport

Alongside industry, the UK Hydrogen Strategy recognises the potential of hydrogen to decarbonise heavy transport and rail, with analysis from BEIS suggesting hydrogen consumption in transport could be 20-45TWh/a by 2035 and 140TWh/a by 2050. [9] Furthermore, as industrial consumers look to decarbonise their logistics activities, the decarbonisation of transport will become an increasingly important consideration for the North West Industrial Cluster.

To define the overall regional transport consumption, we drew upon work undertaken by Progressive Energy and Cadent for the HyMotion report, which proposed three scenarios for transport hydrogen consumption in 2030. [10] As heavy goods vehicles (HGVs) and rail are the two forms of distribution most relevant to industrial consumers, we included these modes of transport in our consumption analysis.

Based on our internal view on how the sector may develop, we then selected the following HyMotion scenarios for our bull and bear scenarios in Table 12.

However, the HyMotion hydrogen requirements were plotted at a regional level and for our modelling we needed to attribute them to specific nodes by mapping them against other relevant datasets.

To attribute the HGV consumption to specific locations in the region, we used the raw traffic count data provided by the Department for Transport (DfT) [11]. We then allocated the rigid and articulated HGV consumption proportionally to sites within the region based on traffic counts.

For rail, we used the UK local authority and regional carbon dioxide emissions national statistics from 2018 [5] which allocates the current rail emissions to the different local authorities within the region. This allowed the hydrogen consumption for trains to be attributed to the different local authorities across North West England and North East Wales.

Furthermore, like industry, these consumptions could only be aggregated if there was pipeline infrastructure in place. For this reason we solely modelled the transport consumption within the LTS Area, illustrated by Figure 16 below which shows the consumption from HGVs in the bull 2040 scenario. The nodal consumption of hydrogen for all of the scenarios is tabulated in Table 13 overleaf.

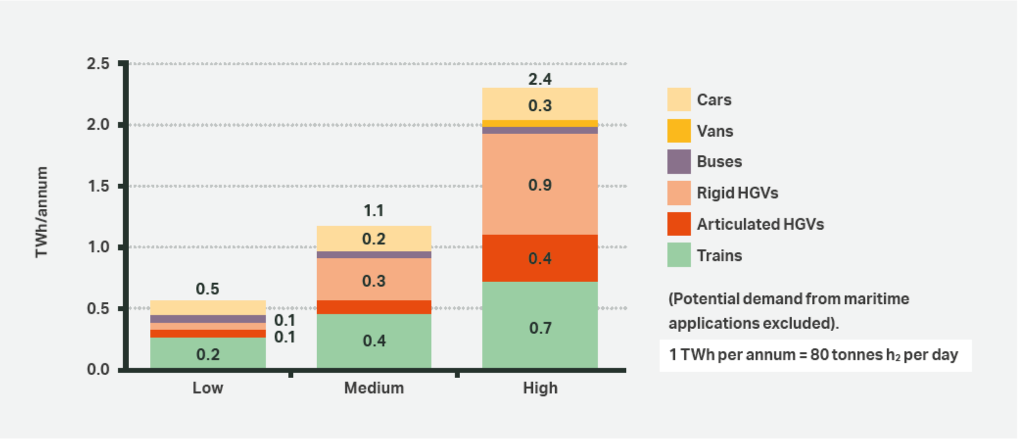


Figure 15 A summary of the transport hydrogen consumption scenarios for North West England and North East Wales, developed for the HyMotion report [10]

Transport assumptions	Bull		Bear	
	2030	2040	2030	2040
HyMotion scenario	Medium	High	Low	Medium

Table 12 The HyMotion scenario selected to calculate our transport consumption requirements

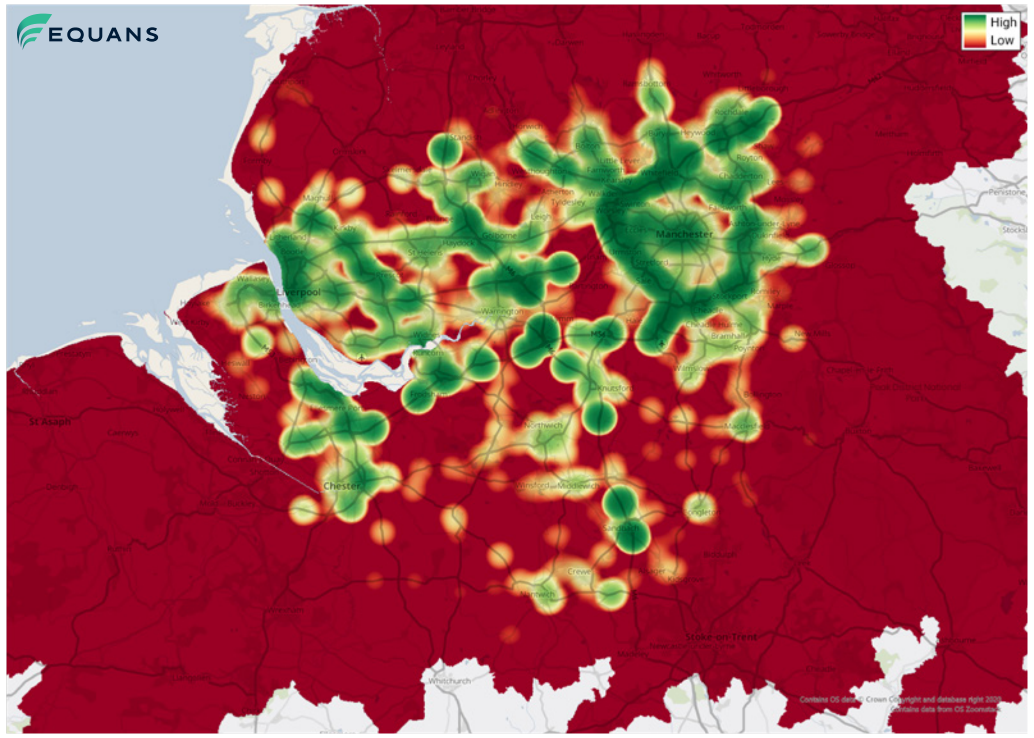


Figure 16 Hydrogen consumption from HGVs based on traffic flow counts

Transport Consumption (TWh/a)	Bull		Bear	
	2030	2040	2030	2040
Node 8	0.23	0.50	0.10	0.23
Node 9	0.27	0.66	0.09	0.27
Node 10	0.11	0.27	0.04	0.11
Total	**0.61**	**1.43**	**0.24**	**0.61**

Table 13 The nodal and total consumption requirements for hydrogen in the transport sector for each scenario

4.1.4 Power

Uniper are a consortium partner on the Net Zero North West Cluster Plan project and have performed some valuable research into the opportunities for hydrogen in the power sector. As part of their analysis, they analysed different future energy scenarios, to identify any trends that could be used to estimate future consumption in this sector. This is presented in detail within their Large Scale Power Generation report.

However, as highlighted in their report, there is little consistency between different energy system models regarding the role for hydrogen in this sector, with different models showing large variation in hydrogen requirements. For this reason, we agreed with Uniper to use the National Grid Future Energy Scenarios 2020 (FES 2020) data and follow the precedent set for the residential and commercial assumptions.

That said, FES 2020 provides a national view of hydrogen consumption used in the power generation sector and a regional view was required for our modelling. To understand the extent to which hydrogen gas turbines (H_2GTs) could be located in the region versus other areas of the country, we worked with Uniper to divide the national consumption into regional consumption using two methodologies:

1. 1/6th Scenario

This scenario assumed that the H_2GTs would be equally split across the six industrial clusters in the UK and therefore 1/6th of the national hydrogen consumption (for power generation) would be located in North West England and North East Wales. The bull scenario is therefore 1/6th of the National Grid System Transformation consumption and the bear scenario represents 1/6th of the National Grid Consumer Transformation consumption.

2. %H_2 Scenario

This scenario took a more aggressive approach to quantifying the power sectors' hydrogen consumption in North West England and North East Wales, recognising that that the location of H_2GTs is likely to be influenced by the availability of hydrogen. Rather than defining the consumption based on the national capacity, we looked at the percentage of hydrogen used in the power sector compared to the other sectors in FES 2020.

In 2040 these were 6.82% in System Transformation (bull) and 25.45% in Consumer Transformation (bear). These percentages were then used to calculate a regional hydrogen consumption from power based on the industrial, residential & commercial, and transport consumptions. As FES 2020 did not suggest any H_2 for power in 2030, it was assumed that a single unit would be installed in %H_2 scenario.

The regional hydrogen consumption for the power sector for the 1/6th scenario and the %H_2 scenario are summarised in Table 14 below. We then used the average of these two scenarios to define the power consumption in our modelling, with all the power consumption represented by Node 11. Interestingly, power was the only sector where hydrogen consumption was higher in the bear scenario, due to widespread electrification.

4.1.5 Nodal Consumption Summary

The methodology described in Sections 4.1.2 to 4.1.4 gave us the hydrogen consumption for each sector in 2030 and 2040, for the bull and bear scenarios.

We then overlayed these sectoral consumptions using the suitability modelling capability within our GIS to plot the overall hydrogen consumption in the region, resulting in the heat map that was presented earlier in Figure 13. A smaller version of this heat map can be seen again in Figure 17 for reference.

Finally, the nodal hydrogen consumptions, per sector, for the bull and bear scenarios, are summarised in Figure 18 to Figure 21 overleaf.

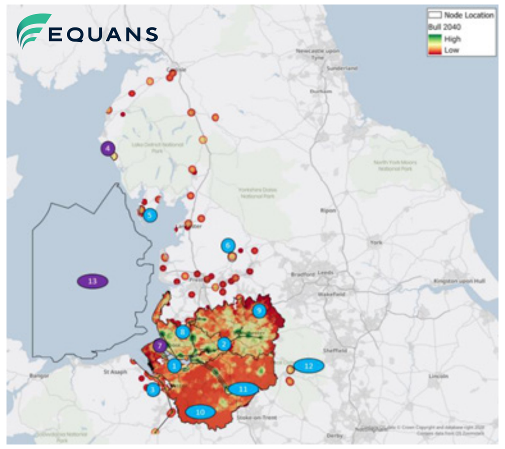
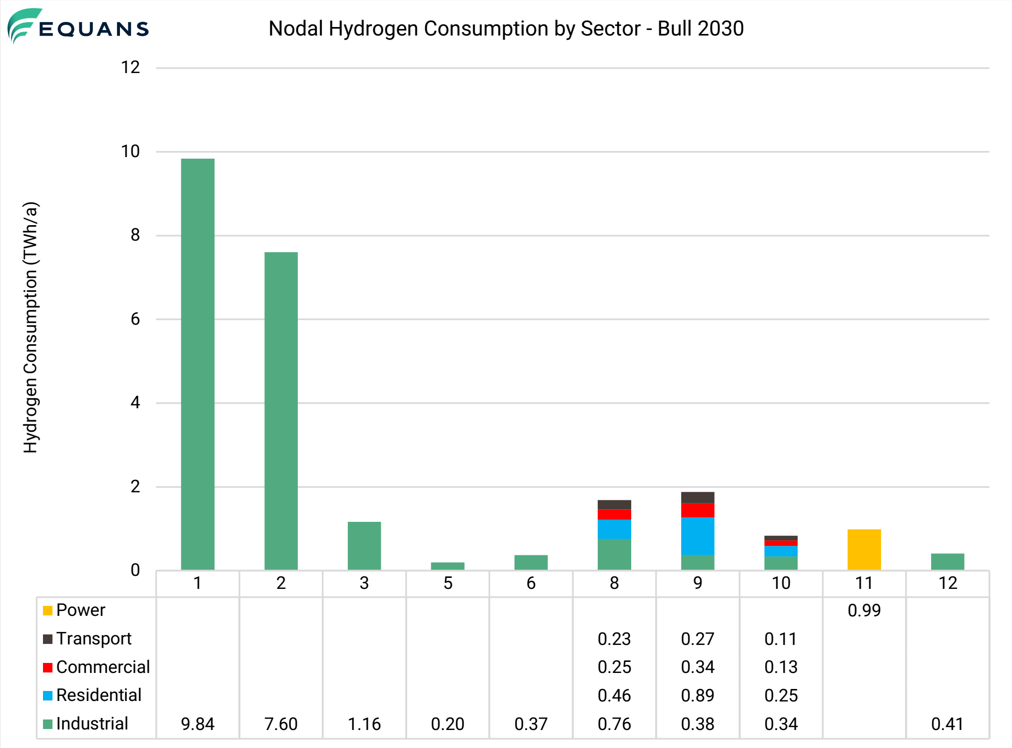


Figure 17 The location of nodes selected for the PROSUMER analysis against the bull 2040 hydrogen consumption

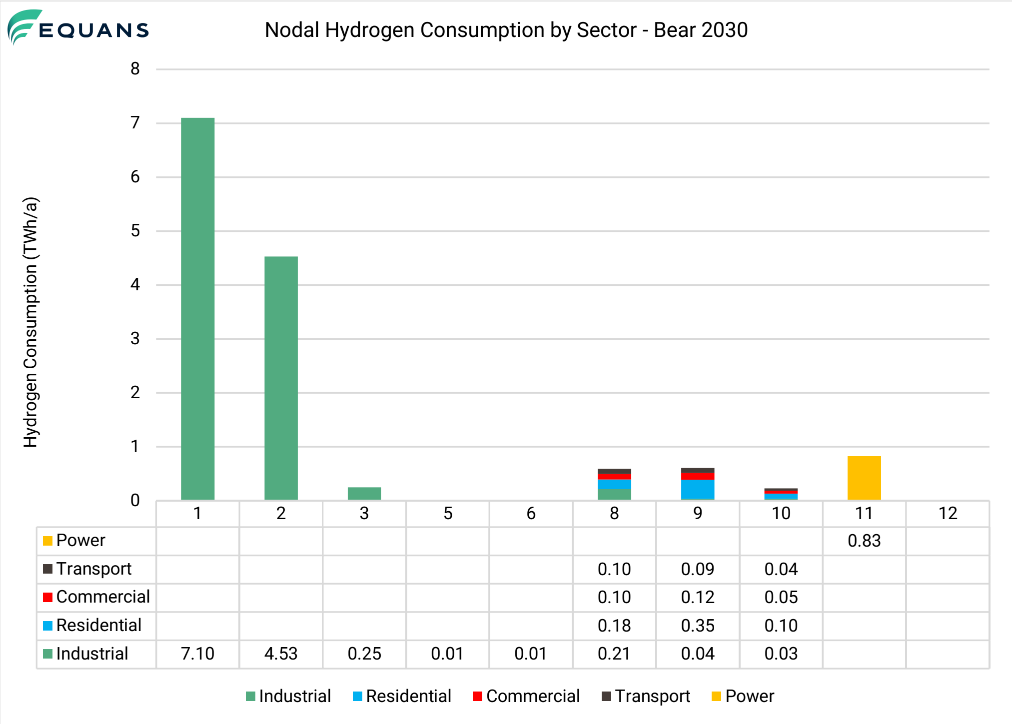
Power Consumption (TWh/a)	Bull		Bear	
	2030	2040	2030	2040
1/6th Scenario	0	2.47	0	2.18
%H_2 Scenario	1.65	4.24	1.98	6.01
Node 11 (Total) (average)	**0.83**	**3.35**	**0.99**	**4.10**

Table 14 The nodal consumption requirements for hydrogen in the power sector for each scenario



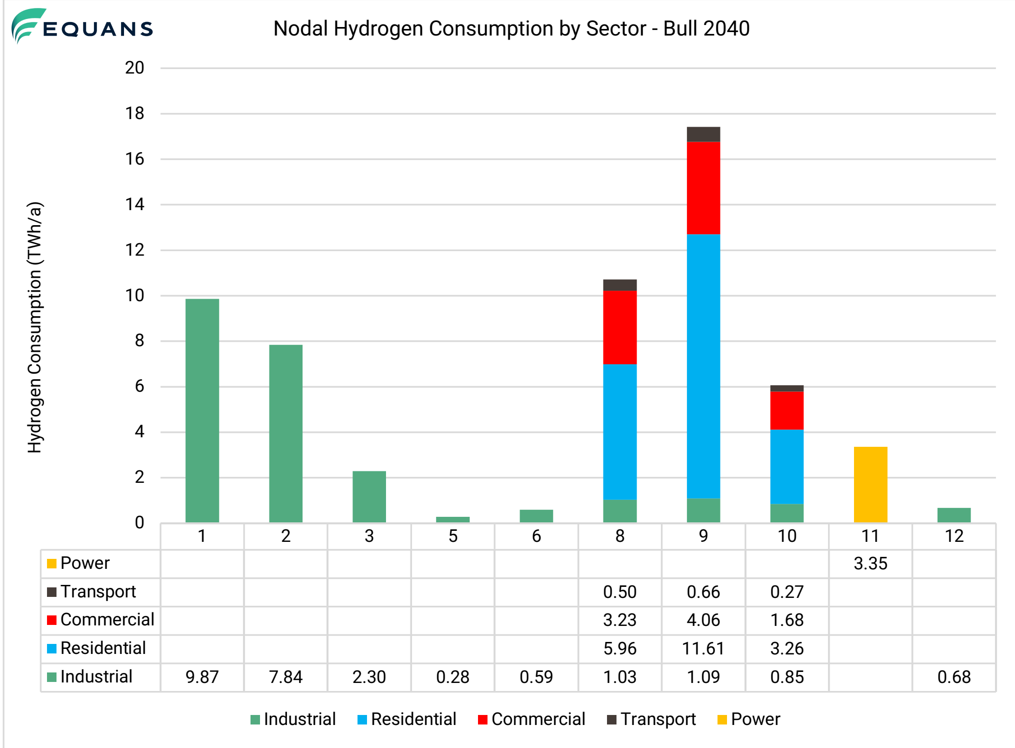
	1	2	3	5	6	8	9	10	11	12
Power									0.99	
Transport						0.23	0.27	0.11		
Commercial						0.25	0.34	0.13		
Residential						0.46	0.89	0.25		
Industrial	9.84	7.60	1.16	0.20	0.37	0.76	0.38	0.34		0.41

Figure 18 Nodal hydrogen consumption by sector for the bull 2030 scenario



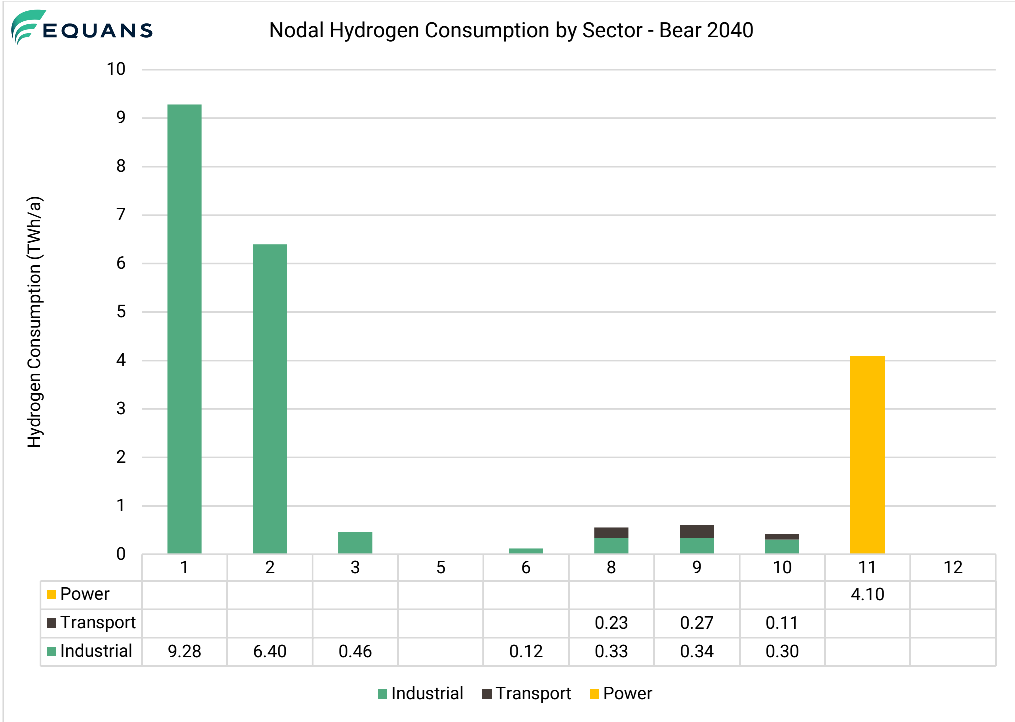
	1	2	3	5	6	8	9	10	11	12
Power									0.83	
Transport						0.10	0.09	0.04		
Commercial						0.10	0.12	0.05		
Residential						0.18	0.35	0.10		
Industrial	7.10	4.53	0.25	0.01	0.01	0.21	0.04	0.03		

Figure 19 Nodal hydrogen consumption by sector for the bear 2030 scenario



	1	2	3	5	6	8	9	10	11	12
Power									3.35	
Transport						0.50	0.66	0.27		
Commercial						3.23	4.06	1.68		
Residential						5.96	11.61	3.26		
Industrial	9.87	7.84	2.30	0.28	0.59	1.03	1.09	0.85		0.68

Figure 20 Nodal hydrogen consumption by sector for the bull 2040 scenario



	1	2	3	5	6	8	9	10	11	12
Power									4.10	
Transport						0.23	0.27	0.11		
Industrial	9.28	6.40	0.46		0.12	0.33	0.34	0.30		

Figure 21 Nodal hydrogen consumption by sector for the bear 2040 scenario

4.1.6 Defining the Hydrogen Demand

However, just understanding the annual consumption for each sector in each node is not sufficient for the purposes of system modelling. As mentioned earlier, PROSUMER works by balancing supply and demand in hourly increments, which meant that we needed to convert these annual consumption figures into their hourly demands. To achieve this, we developed demand profiles for each sector under consideration.

Wherever possible we generated these profiles using relevant anonymised and aggregated data held within our energy analytics platform. Where there was insufficient data available to maintain customer anonymity, we derived the profiles from other relevant industries. Examples of the demand profiles for food and drink, chemical and residential sectors can be seen below in Figure 22 to Figure 24.

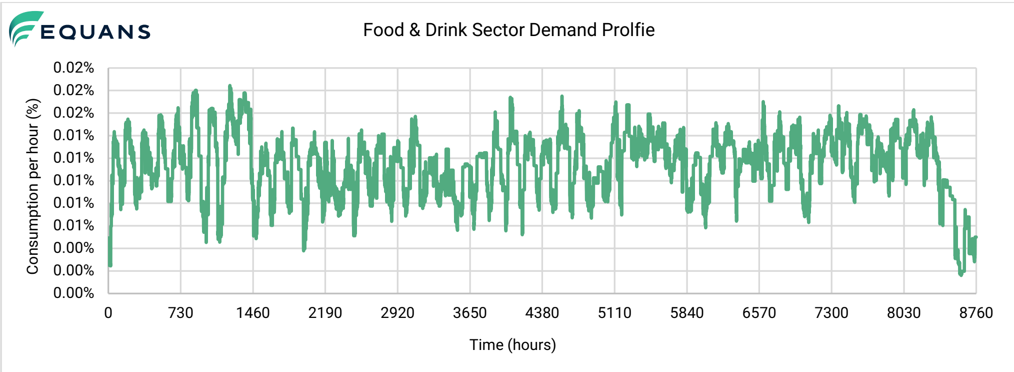


Figure 22 Hourly demand profile for hydrogen for an industrial customer in the food & drink sector

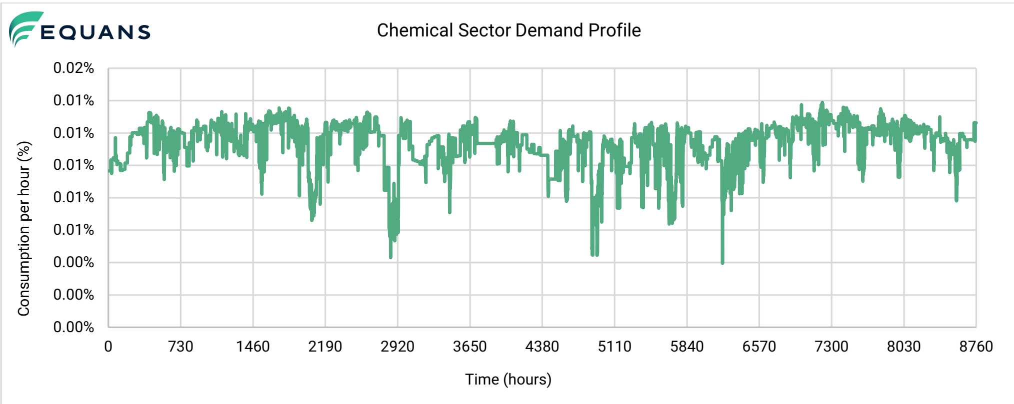


Figure 23 Hourly demand for hydrogen for an industrial customer in the chemical sector

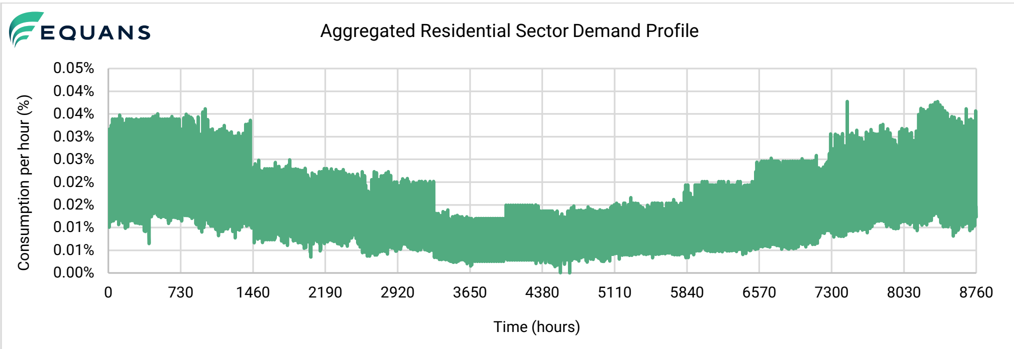


Figure 24 Hourly demand for hydrogen for an aggregation of residential consumers

To define the demand profile for the power sector, Uniper used their dispatch model to forecast when dispatchable power was most likely to be needed, during periods of high demand and low renewable generation. These renewable generation profiles were taken from the PROSUMER model to ensure consistency. The resulting demand/dispatch profile for power can be seen below in Figure 25.

As is evident in Figure 22 to Figure 25, there is significant variation in the demand profiles of the different sectors. These profiles were then multiplied by the hydrogen demand for each sector in each node to give the hourly hydrogen demand per node. Some examples of the resulting nodal hydrogen demand profiles are shown below in Figure 26 to Figure 28.

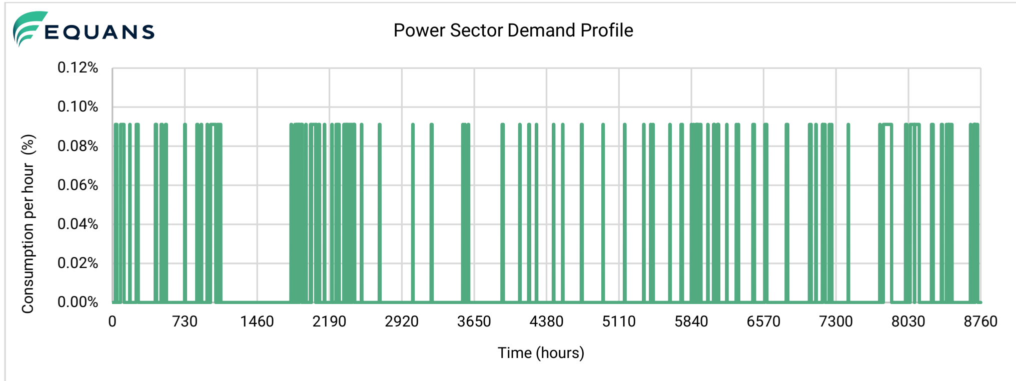


Figure 25 The hourly demand/dispatch profile for power in bull 2040

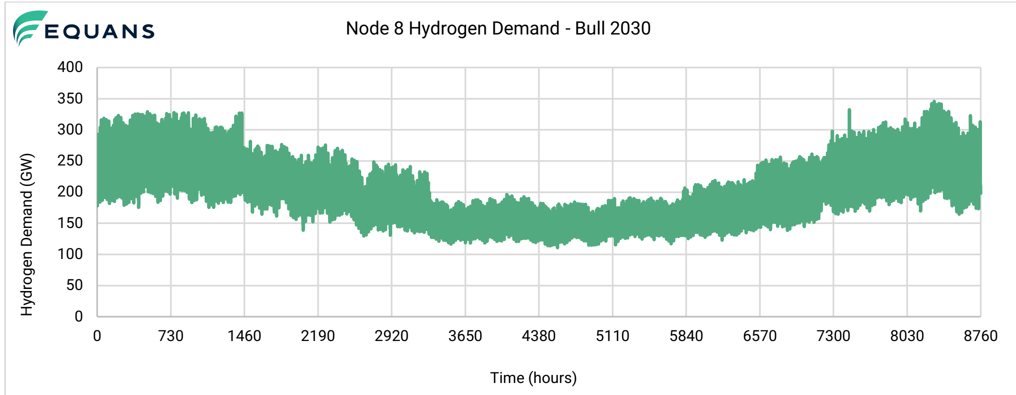


Figure 26 The hourly hydrogen demand for Node 8 in the bull 2030 scenario

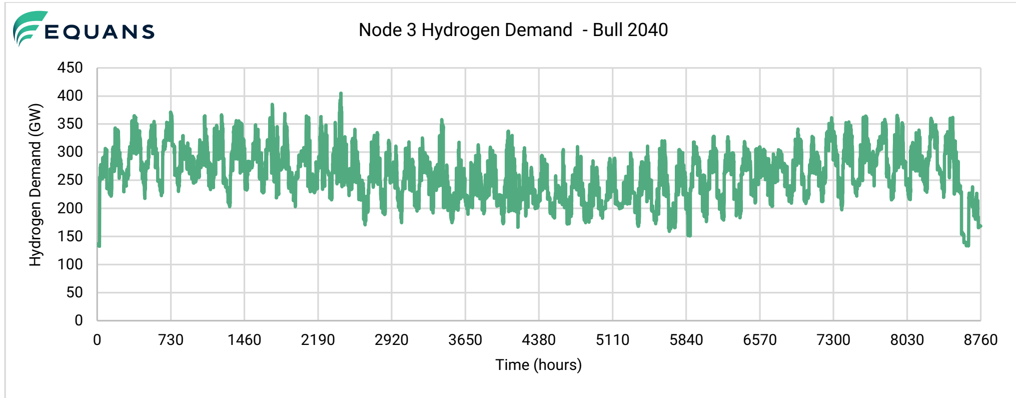


Figure 27 The hourly hydrogen demand for Node 3 in the bull 2040 scenario

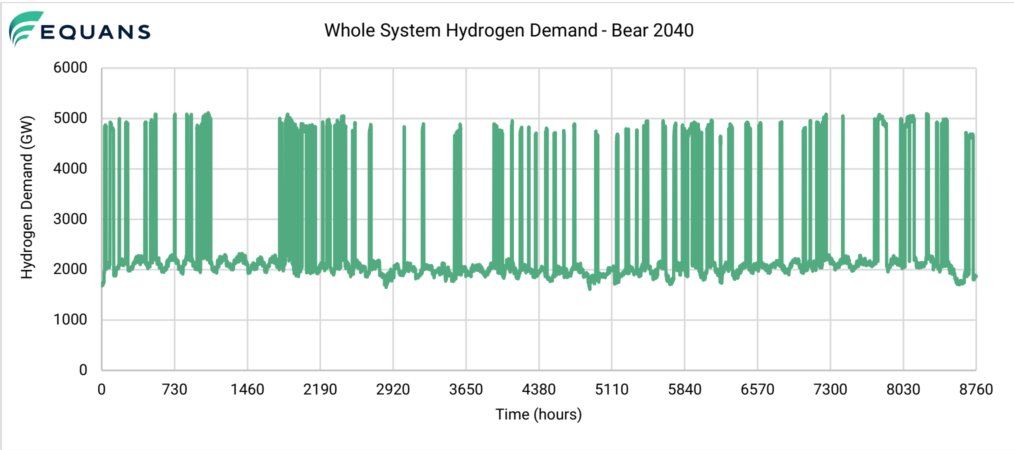


Figure 28 Hourly demand for hydrogen across all nodes in the bear 2040 scenario

As can be seen from the graphs above, the shape of the nodal hydrogen demand is highly dependent on the consumers within each node and the hydrogen production and storage configuration would need to be designed in a way to meet this demand. This is particularly significant in the nodes that are separated from the hydrogen network (5, 6 & 12) as they would not be able to make use of the linepack and dedicated gas storage available on the network, which is explained in more detail in Section 4.2.3.

Furthermore, the hourly hydrogen demand graph in Figure 28 allows for an interesting observation. As explained in Section 4.1.1, the bear 2040 scenario relates to the electrification of heat in residential and commercial premises. In this high electrification scenario, the overall hydrogen requirement is lower, however the hydrogen requirement in the power sector is greater, due to the additional electricity demand on the grid. Furthermore, the high instantaneous peak demands are caused by the dispatchable power being deployed to support the peak demand of electrified heating and domestic hot water. This has a very significant effect on the hydrogen demand profile in the region and, as a body of future work, could be explored in more detail to understand any system challenges this may bring.

The graphs shown in Figure 26 and Figure 27 are just two examples of the demand profiles which were developed from the work presented in this section. Overall, forty unique demand profiles were developed to account for the 10 demand nodes and the bull and bear scenarios, and these were use as the demand input to our modelling. However, demand was just one of the constraints, as we also needed to define the hydrogen production options for the region.

4.2 Hydrogen Production Considerations

As mentioned in Section 2.1, we have considered green, purple, and blue (CCUS enabled) hydrogen in this report. None of these hydrogen colours are infinite and all of them have a maximum resource availability. For electrolytic hydrogen, we constrained the model based on the maximum availability of the power sources. For renewables, or nuclear, this was a function of two main metrics:

- The maximum installed capacity - primarily due to the maximum land available for development
- The hourly load factor - the percentage at which the installed capacity can operate for each hour in the year

In general, we took a bottom-up approach to define these maximum resource availabilities, and the methodology is described in the following sections.

4.2.1 CCUS Enabled Hydrogen

Referring to the HyNet project introduced in Section 2.2, the proposal is that CCUS enabled hydrogen in the North West will be produced at the Stanlow refinery through a process known as autothermal reforming. These ATR plants produce hydrogen from natural gas, capturing 95 – 97% of the emissions. The CO_2 will then be piped to, and stored in, the Liverpool Bay gas fields which are nearing depletion. These

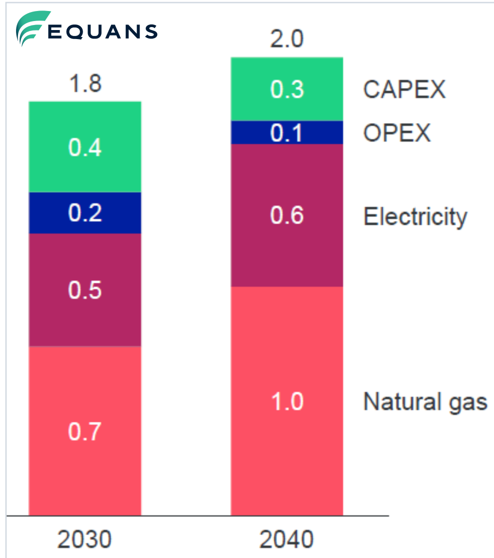
ATR plants are planning to follow a modular phased build out process with an aim of having 30TWh/a5 online by 2030 and 75TWh/a available by 2040.

For our modelling, the resource availability of CCUS enabled hydrogen will be constrained by the build out rates noted above. Furthermore, the CCUS enabled H_2 produced at the Stanlow refinery (Node 1) was only available in the nodes that are connected to the LTS (1, 2, 3 & 11) or the adjacent GDNs (8, 9 & 10) and that small scale decentralised production was not possible.

As PROSUMER is a cost optimisation model, the forecast levelised cost of hydrogen (LCOH) from the HyNet scheme, was also a key input, as PROSUMER optimises the configuration of production technologies to produce the required hydrogen at lowest overall cost. Based on discussions with Progressive Energy, as well as internal research and modelling of energy prices, the LCOH for CCUS enabled hydrogen was defined to be £1.8/kg (£59.9/MWh) in 2030 and £2.0/kg (£66.6/MWh) in 2040. The breakdown of these costs, along with the assumptions driving them, are summarised in Figure 29 below.

It is worth noting that this modelling was completed in Q2 2021. Since that time gas prices have increased to unprecedented levels. The effect of this will be discussed in Section 5.1.

Finally, although CCUS enabled hydrogen is considered low carbon, it is not zero carbon, and as such there are $0.02tCO_2/tH_2$ emissions associated with its production. For the North West Industrial Cluster to reach net zero these emissions would need to be offset. Otherwise, zero carbon hydrogen can be produced using electrolysers that are powered by zero carbon electricity.



Technical Assumptions[6]		
CAPEX (£m)	254	
OPEX (£k/a)	13,194	
Capacity (kNm3/h)	100	
Plant utilization (%)	95	
Yearly production (t/a)	74,798	
Electrical demand (MWe/kNm3/h)	0.2	
Natural gas demand (MWth LHV/kNm3/h)	3.8	
Commodity Prices[7]	**2030**	**2040**
Cost of natural gas (£/MWh th)	17	23.2
Cost of electricity (£/MWh e)	190	239

Figure 29 A breakdown of the LCOH for CCUS enabled hydrogen including the technical assumptions

4.2.2 Electrolytic Hydrogen

Electrolytic hydrogen is produced when electricity is used to split water into its constituent parts, hydrogen and oxygen. The core technology is the electrolyser and the two main categories are Polymer Electrolyte Membrane (PEM) electrolysers, which are compact and responsive, and alkaline electrolysers, which are generally cheaper.8 Electrolysers typically range in size from 0.02m2/kW - 0.11m2/kW for a PEM electrolyser to 0.2m2/kW for an alkaline electrolyser [12]. Given the regional nature of this analysis, these space constraints were not considered in the modelling, however the implications of the electrolyser size, particularly in the embedded nodes, will be discussed in Section 6. Rather, the core input to the modelling was the opportunity to produce green or purple hydrogen in the region and the methodology for deriving these constraints is outlined below.

[5] Actual output is 33TWh/a but 3TWh/a will be consumed as a parasitic load
[6] Source: HyNet Phase 1 report [10]
[7] Source: EQUANS Internal projections
[8] The assumptions around electrolyser CAPEX and OPEX for this modelling can be found the Appendix.

4.2.2.1 Green Hydrogen

Unlike CCUS enabled hydrogen where the maximum capacity was constrained by the proposed build out rate of HyNet, the availability of green hydrogen was driven by the availability of green power. For this report we have considered solar PV, onshore wind, offshore wind and tidal as the renewable energy sources (RES) available in the North West Industrial Cluster. The electrolysers can either connect directly to these RES[9] or contract this locally generated power through the grid using a PPA. In both of these cases, the utilisation factor of the electrolyser is proportional to the load factor of the RES powering it. For this reason, we recognise that some electrolyser operators may look to increase the utilisation factor by procuring grid electricity, produced anywhere in the UK, and this optionality is also available in our model. The following sections explain how we derived the maximum green hydrogen potential for the region from each of these renewable energy sources.

4.2.2.1.1 Solar PV and Onshore Wind

To assess the availability of solar PV and onshore wind we used GIS modelling, which allowed us to estimate the land suitable for renewable development in North West England and North East Wales. Our GIS model considers over 30 factors that affect RES development and produces a heat map showing the potential for developing solar PV and onshore wind. The heat map for solar is shown below in Figure 30. These heat maps were then converted into maximum renewable capacities (MW) for each node in the region.

For the embedded nodes (5, 6 & 12) the maximum renewable capacities were those that could be practically installed behind the meter (i.e. connected to an on-site electrolyser via a private wire), and these capacities were calculated using a desktop assessment on a site by site basis. An overview of the maximum onshore wind and solar PV capacities available in each node is summarised in Table 15.

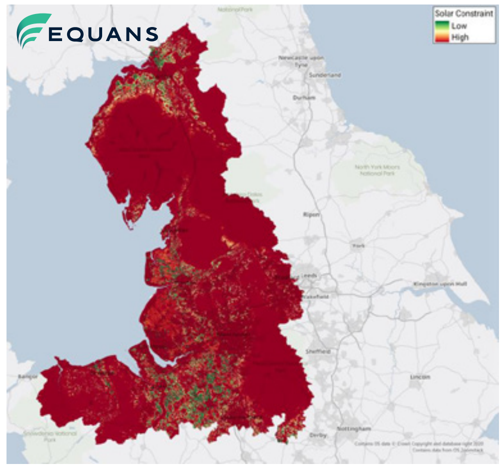


Figure 30 Constraints to solar development in the region

Maximum Capacity (MW)	Wind	Solar PV
Node 5	10	50
Node 6	-	10
Node 8	7	2,374
Node 9	26	2,328
Node 10	50	13,663
Node 11	-	50

Table 13 The nodal and total consumption requirements for hydrogen in the transport sector for each scenario

[9] We are not accounting for the cost of a private wire between the RES and electrolyser as we are assuming that they are installed at the same location. This is consistent with the approach outlined in the BEIS document 'Hydrogen Production Costs 2021' [19]

As can be seen from this analysis, the land available for onshore wind development is very limited in the areas under consideration, primarily due to areas of outstanding natural beauty and urban development.

The second important consideration was the hourly load factors for solar PV and onshore wind. Within PROSUMER we have the functionality to define different load profiles for each of the nodes under consideration. However, as we are modelling the whole region, there will still be significant variation on the load factors within the nodes, which can be greatly affected by local characteristics. For this reason, we decided that different nodal load factors would give a false impression of accuracy and opted to use one load factor reflective of the region as a whole.

The annual load factors for solar PV and onshore wind are 11% and 37% respectively and the hourly load profiles are shown below in Figure 31 and Figure 32.

These hourly load factors were then multiplied by the maximum capacities to define the maximum hourly generation from solar PV and onshore wind in North West England and North East Wales. The technoeconomic assumptions for solar PV and onshore wind can be found in the Appendix.

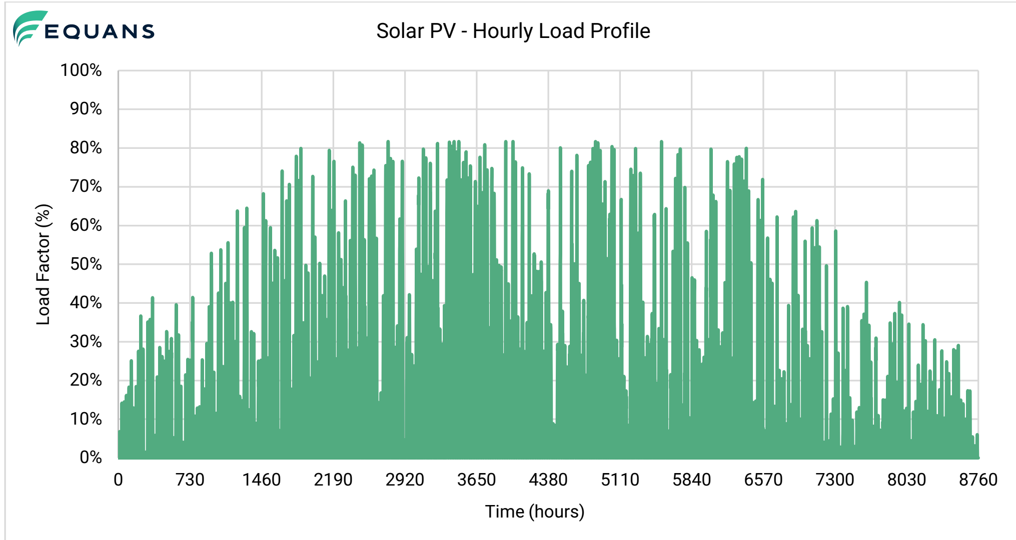


Figure 31 A graph showing the load factor for solar PV for each hour in the year

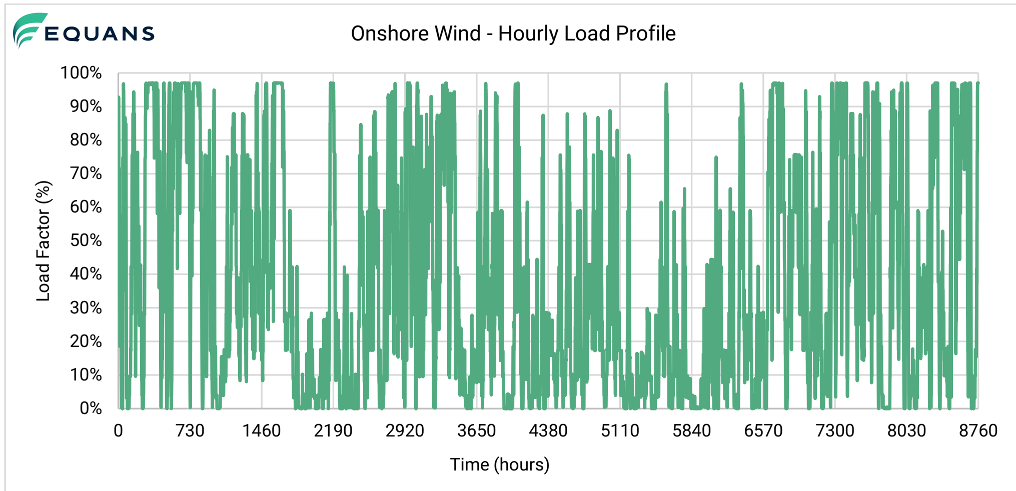


Figure 32 A graph showing the load factor for onshore wind for each hour in the year

4.2.2.1.2 Offshore Wind

The North West has a long history in offshore wind, with Liverpool Bay showcasing the world's largest wind turbines when Burbo Bank and Burbo Bank Extension came online. The area now has approximately 2.7GW of offshore wind with a further 4GW either in pre-planning or awarded as part of the Contracts for Difference Allocation Round 4 (CfD R4) auctions. The locations of these proposed and existing wind farms are shown in Figure 33.

For our modelling, we assumed that this undeveloped pipeline could be available for hydrogen production, both via private wire (if the electrolyser was located at the onshoring location), or via a PPA. Furthermore, as the winning bids for the CfD R4 auctions highlighted innovations to significantly reduce the development time, it was assumed that all of this pipeline would be developed and come online by 2030. Referring to Figure 8, we can see that offshore wind was assigned to Node 13 in our model.

Given the difficulty of developing elsewhere in the area, substantiated by previous failed developments, we assumed that no additional capacity would be available other than that depicted above. Regarding the onshoring locations, we assumed that 1,655MW would come onshore around Node 5 and that 1,650GW would come onshore around Node 1. At these locations, the electrolysers could use this quantity of offshore wind electricity via a private wire. Any remaining capacity not used with a private wire could then be used anywhere in the region via a PPA. It is worth noting that this would be an alternative route to market for these assets and the commercial challenges associated with competing with the CfD mechanism are discussed in Section 6.1.

As with solar PV and onshore wind, the offshore wind had an average annual load factor of 45% and the hourly load profile can be seen in Figure 34. The LCOE for offshore wind, including cabling and grid connection costs, was assumed to be 41/MWh. [13]

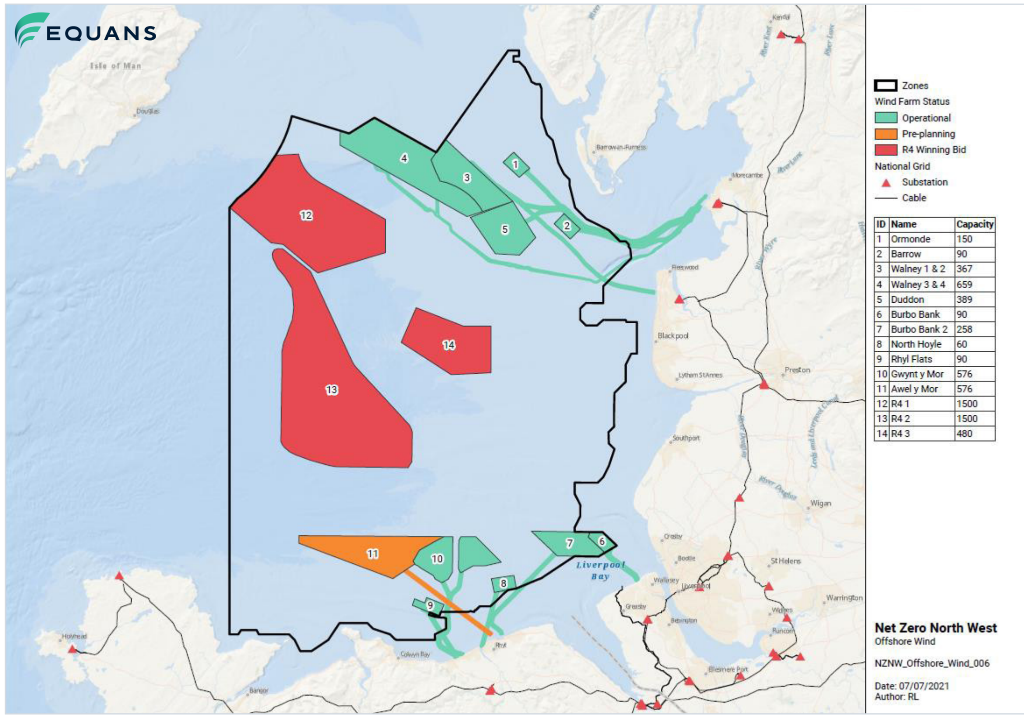


Figure 33 Proposed and existing wind farms in North West England and North East Wales

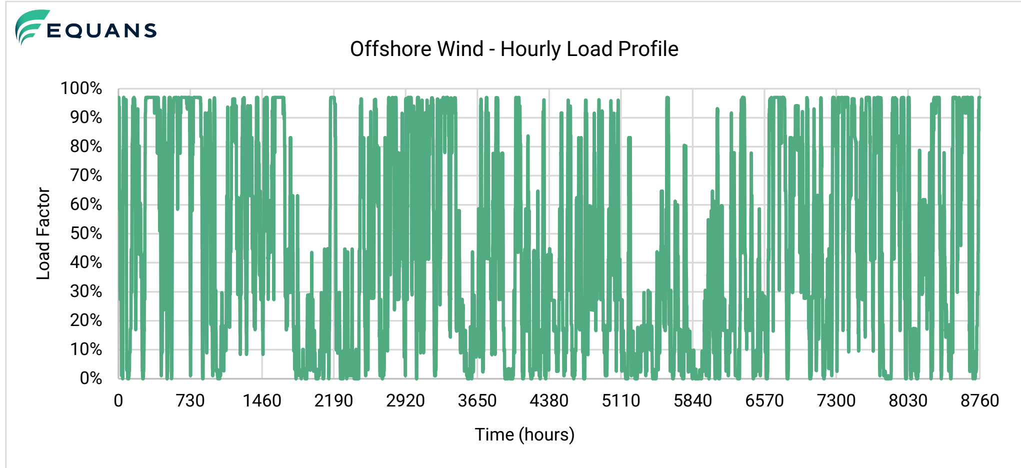


Figure 34 A graph showing the load factor for offshore wind for each hour in the year

4.2.2.1.3 Tidal

The Mersey Tidal Power project is seeking to harness the tidal energy in Liverpool Bay. The project aims to generate enough power to support 1 million homes, [14] however this energy source also has the potential to produce green hydrogen. In defining our assumptions, we are grateful for the support from Martin Land and the wider team at Mersey Tidal who have provided us with the necessary data for our modelling.

In keeping with the Mersey Tidal proposal, we have assumed that there will be 1GW of capacity by 2030 and 4GW of capacity by 2040, with a LCOE of £80/MWh.10 The annual load factor is 28.4% and the load profile follows the lunar cycle, with one full cycle shown below in Figure 35. Any production from Conway Tidal was also assumed to be captured by these assumptions.

Referring to Figure 35, it can be seen that the Mersey Tidal Power project (Node 7) is close to the HyNet LTS (Node 1). For this reason, we assumed that electrolysers using power from Tidal Energy would be able to access this energy source by private wire and inject the hydrogen into the HyNet LTS. As with other energy sources, the model also had the option to use this electricity via a PPA anywhere in the region.

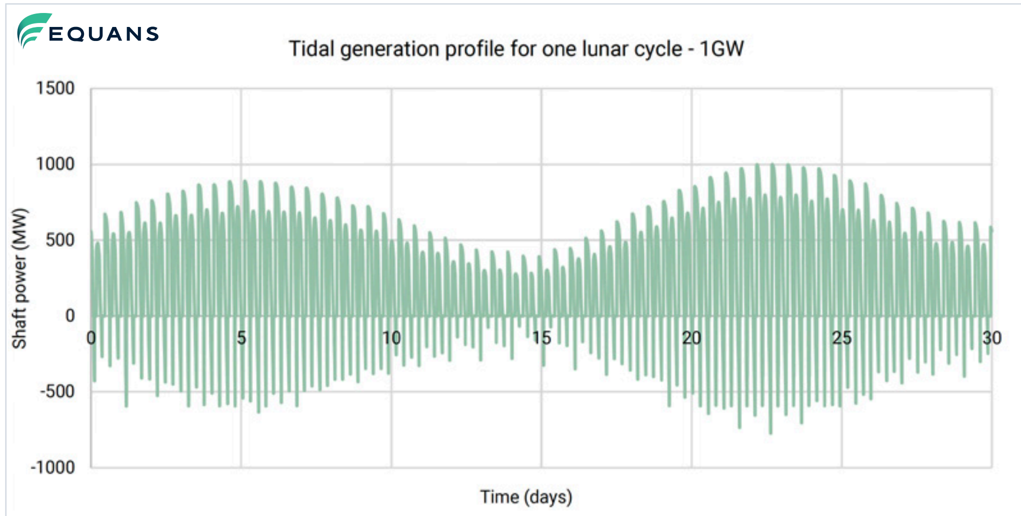


Figure 35 Tidal generation profile for one lunar cycle for 1GW (2030)

[10] The project is still at concept stage so maximum capacities and LCOE figures are subject to change

4.2.2.1.4 Network Costs & Grid Electricity

Unlike Tidal Power, not all the electrolysers can be in locations with sufficient capacities of collocated renewable power and, as such, may need to access a proportion of their electricity via the transmission and distribution networks. In these cases the cost of electricity will also include the additional fixed charges, variable charges and policy costs associated with these networks. Due to upcoming regulatory changes, predicting these costs in 2030 and 2040 is particularly challenging, however for the purposes of this analysis we have included the following components as additional costs for network supplied electricity:

- Balancing System (BS)
- Capacity Market (CM)
- Transmission Use of System (TUoS)
- Distribution Use of System (DUoS)
- Feed in Tariff (FiT)
- Contract for Difference (CfD)
- Renewables Obligation (RO)

These additional costs have been forecast on an hourly basis for 2030 and 2040 in the SP Energy Networks' region, based on internal modelling. The yearly averages for these additional network costs are summarised in Table 16 below. It was also recognised that these costs vary significantly across each half-hourly settlement period. This is illustrated in Figure 36, where each hour represents the average of the two half hourly settlement periods.

4.2.2.2 Purple Hydrogen

Due to the timescales considered in this report and the location of existing and planned nuclear assets in the region, we have also examined the opportunity to produce hydrogen using electricity generated in dedicated small modular reactors (SMRs). This zero-carbon electrolytic hydrogen, produced using nuclear power, has been defined as purple hydrogen.

	2030	2040
Additional Network Costs (£/MWh)	130	179

Table 16 Additional network costs incurred consumers in 2030 and 2040

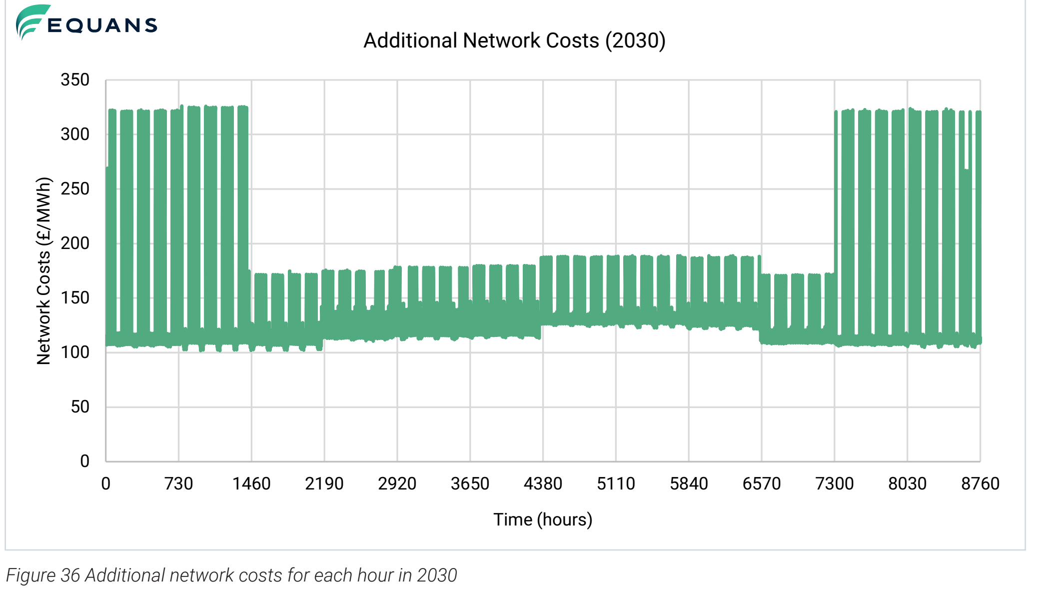


Figure 36 Additional network costs for each hour in 2030

	2030	2040
SMR LCOE (£/MWh)	60	40

Following dialogue with Rolls Royce, who are leading the SMR project in Cumbria, we have assumed that one SMR plant (470MW) could be operational in North West England and North East Wales by 2030 and five plants (2,350MW) by 2040. The load factor was assumed to be 92.5%, accounting for the fact the SMRs need to be refuelled every 18 months. The LCOE assumptions, based on Rolls Royce's publicly stated ambitions, are tabulated above:

Given the fact that Sellafield is earmarked as an early site for an SMR plant, for the modelling it was assumed that all of the installed SMR capacity would be in Cumbria. As with the green hydrogen, the electrolysers could either be directly connected to the SMR in Cumbria (with onward hydrogen distribution by road), or the electricity could be procured via a PPA anywhere in the North West (incurring the additional network costs), with electrolysers located closer to the areas of demand.

4.2.3 Storage, Water & Carbon Pricing

In our modelling, the availability of different hydrogen storage options depended on the node. In the network connected nodes, hydrogen could be stored within the network (linepack) or in dedicated salt caverns, as per the HyNet proposals. In the embedded nodes, this centralised storage was not available and therefore the only available hydrogen storage option was pressurised tasks. Given hydrogen's low volumetric energy density, storing a fixed amount of energy in the form of H_2 takes up 3-4 times more space than storing it in the form of natural gas. [15] Although we did not apply a spatial constraint to the modelling, the availability of space for onsite storage is a key consideration and is discussed in Section 6. Alongside H_2 storage, batteries were available as a means to store electrical energy and their relevant technoeconomic assumptions can be found in the Appendix.

Water is also a key part of the electrolytic hydrogen process and the volume of water that an electrolyser needs is dependent on its purity. For demineralised water, 10.5L/kgH₂ is needed. This rises to 20L/kgH₂ for tap water and even higher for brine or grey water feedstock. [12] For the purpose of our modelling, the cost of water was included in the OPEX assumptions for the electrolyser, which is tabulated in the Appendix.

Finally, to explore how the residual emissions associated with CCUS enabled hydrogen could affect its cost competitiveness, a carbon price of £93/tCO_2e was assumed in 2030, rising to £172/tCO_2e in 2040. These figures were based on BNEF projections to 2030 and internal modelling out to 2040.

4.3 Modelling Methodology Summary

The combination of the hydrogen consumption assumptions of Section 4.1 and the hydrogen production assumptions of Section 4.2 form the basis on which our model was configured. These assumptions, combined with the constraints introduced in Section 3, defined the boundaries within which our model would operate, to optimise a design for the least cost hydrogen production system for North West England and North East Wales.

As stated earlier, we have assumed that CCUS enabled hydrogen is only available within the boundaries of the LTS and adjacent GDNs. We have also not modelled the costs of this transmission/distribution and hydrogen storage infrastructure as, although the funding structures are yet to be finalised, they are expected to be borne by all UK consumers. Elsewhere in the region, any requirements for hydrogen must be met via on-site (embedded) electrolytic hydrogen projects or transported to the sites via road in the centralised scenario. The assumptions relating to these costs can be found in the Appendix.

The following graphs summarise the aforementioned assumptions and the results for the No Target Mix (NTM) case and the Target Mix (TM) case (25% electrolytic H_2) can be found in Sections 5 and 5.2 respectively.

Annual hydrogen consumption (TWh/a)	Bull		Bear	
	2030	2040	2030	2040
Residential	0 .46	5.96	0.18	-
Commercial	0.71	8.97	0.27	-
Industrial	22.68	29.55	12.37	18.49
Transport	0.61	1.43	0.24	0.61
Power	0.83	3.35	0.99	4.10
Total	**25.29**	**49.26**	**14.05**	**23.2**

Table 17 The annual requirement for hydrogen for the bull and bear demand scenarios

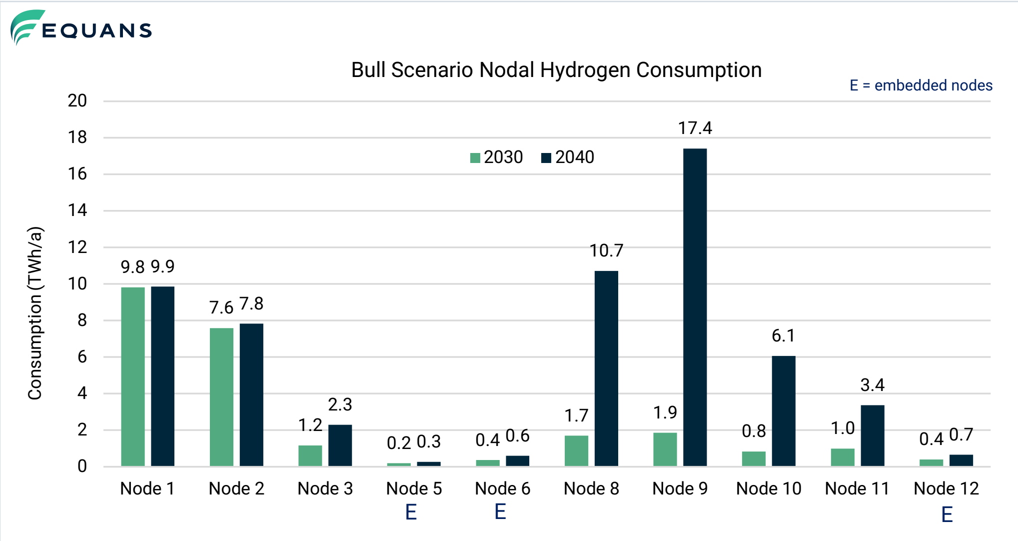


Figure 37 A graph showing the total hydrogen consumption assumptions for each node in the bull scenario

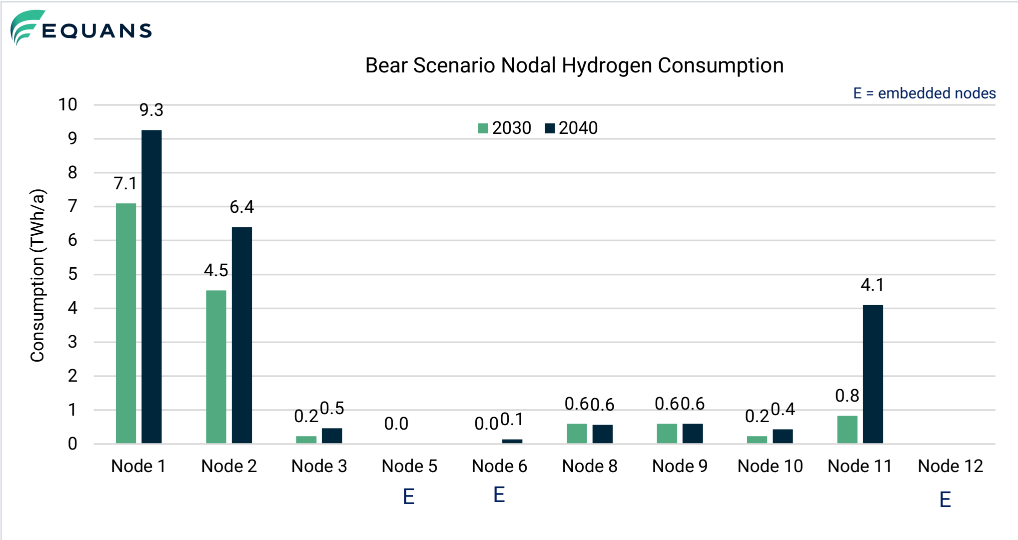


Figure 38 A graph showing the total hydrogen consumption assumptions for each node in the bear scenario

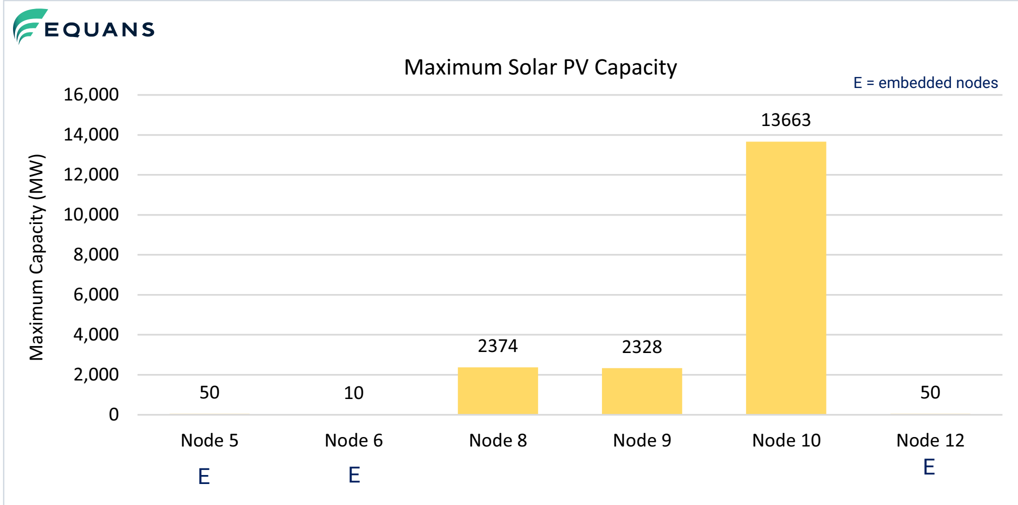


Figure 39 A graph showing the maximum solar PV capacity assumption for each node

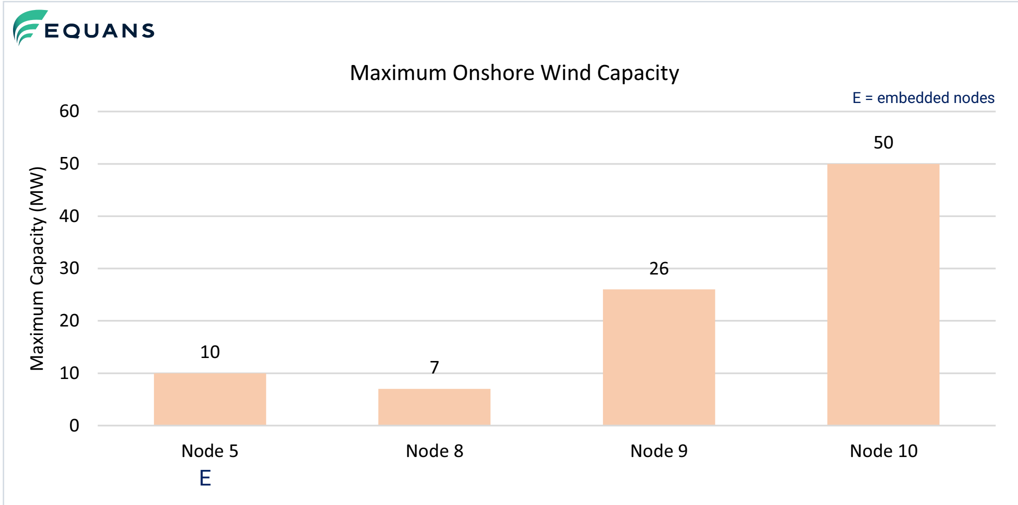


Figure 40 A graph showing the maximum onshore wind capacity assumption for each node

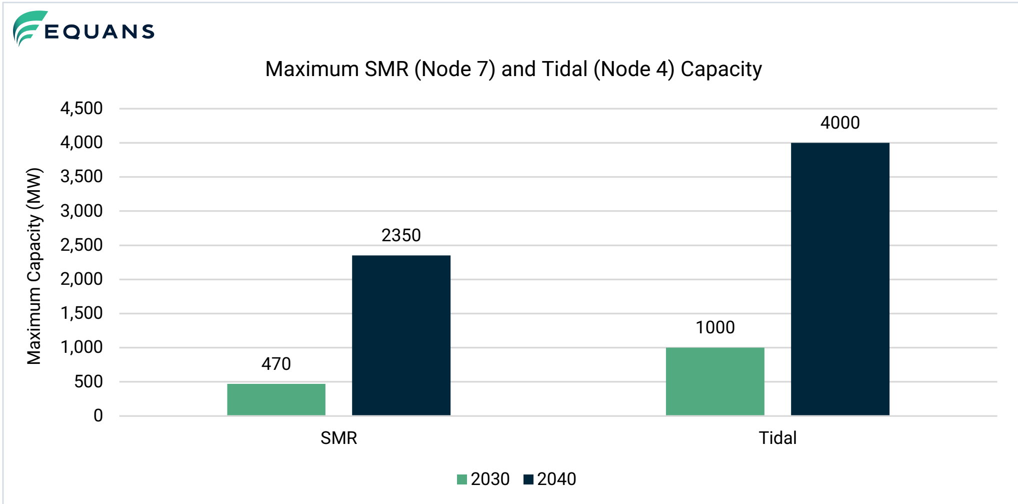


Figure 41 A graph showing the maximum SMR and tidal capacity assumptions for 2030 and 2040

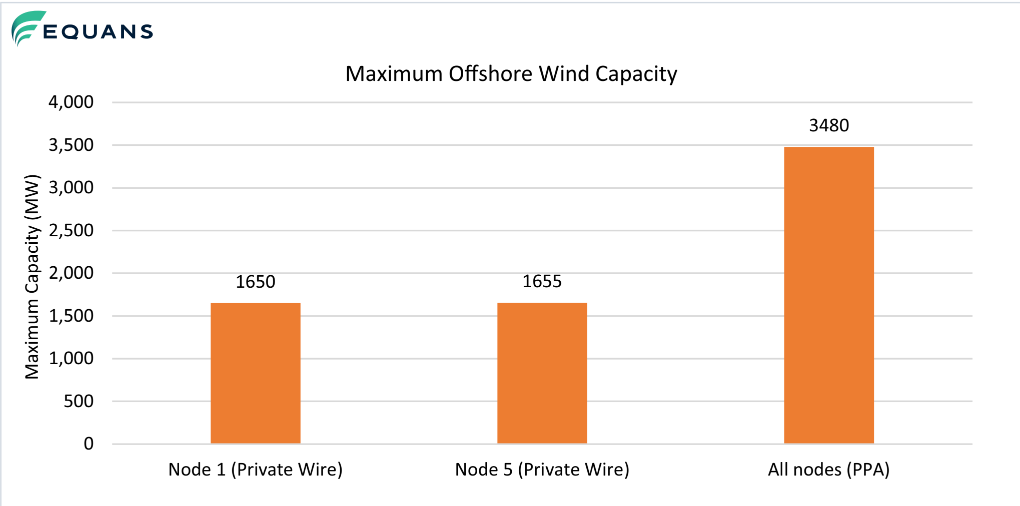


Figure 42 A graph showing the maximum offshore wind available at Nodes 5 & 6 via a private wire or in all nodes via a PPA

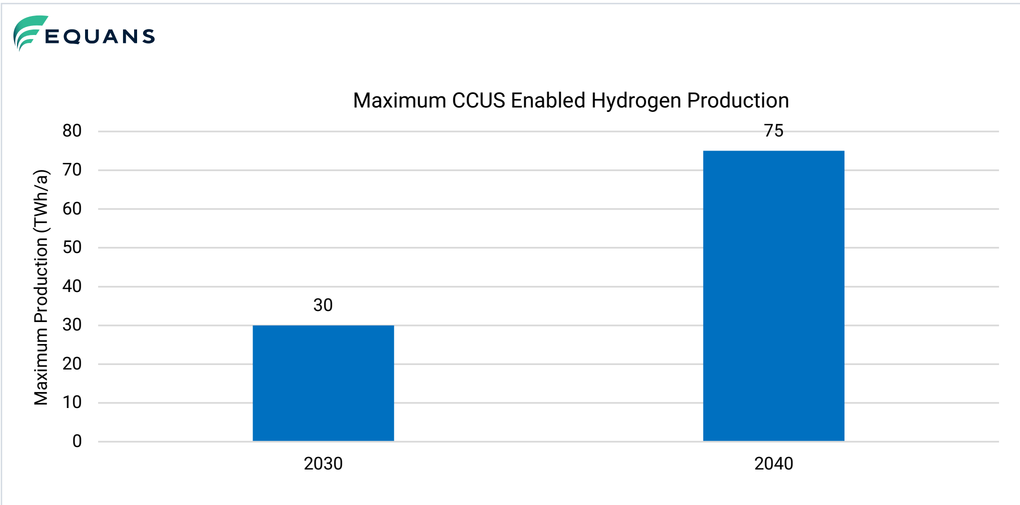


Figure 43 A graph showing the maximum CCUS enabled hydrogen production at Node 1

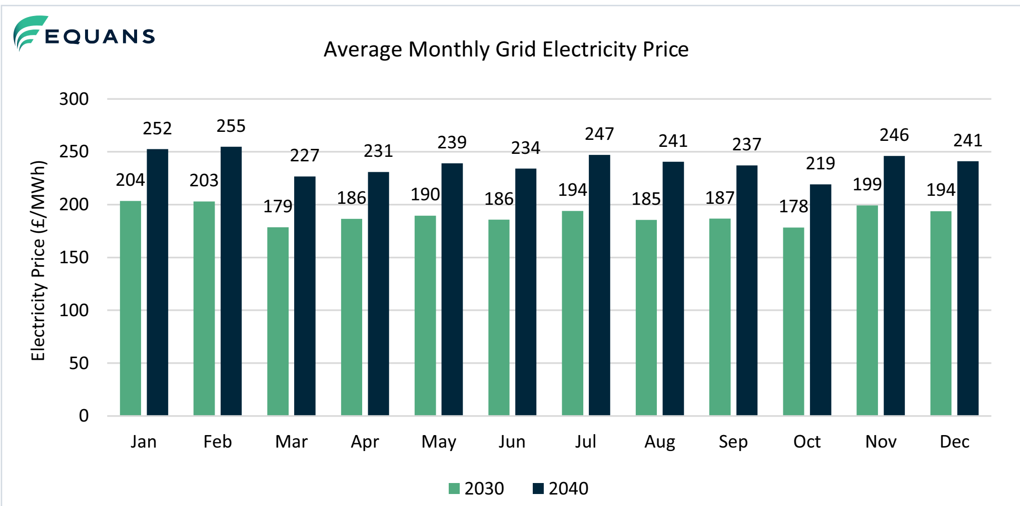


Figure 44 A graph showing the average monthly grid electricity prices in 2030 and 2040. Derived Q1 2021.

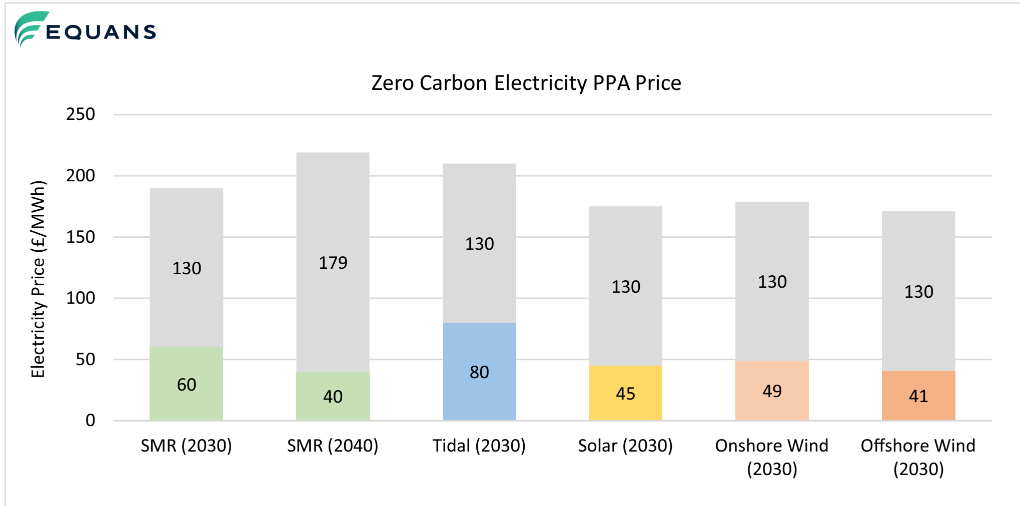


Figure 45 A graph showing the zero carbon electricity PPA price. Coloured bars indicate LCOE and grey bars indicate network costs

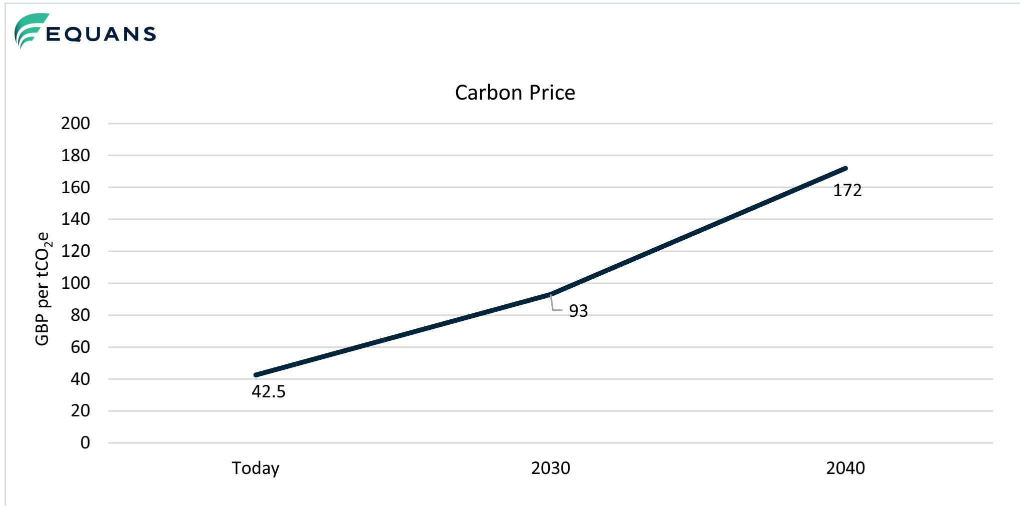


Figure 46 A graph showing the carbon price in 2030 and 2040

5. Modelling results

As with any technoeconomic modelling exercise, the results are a function of numerous assumptions that have been used to constrain the model. Some of these (e.g. commodity and technology prices, load profiles and renewables capacities) were inputs and were consistent across the different modelled scenarios. Others (e.g. the quantum of hydrogen consumption, the centralised/decentralised configurations, and the influence of policy) varied across different simulations and were defined to demonstrate how wider systemic constraints could influence the zero carbon transition in the region. For each of these systemic constraints, we defined two states, as summarised in Table 18 below.

Systemic Constraints	State #1	State #2
Hydrogen Consumption	Bull	Bear
Modelling Configuration	Centralised	Decentralised
Policy Influence	Target Mix	No Target Mix

Table 18 The systemic considerations and states used to define the boundaries of the modelling

This meant that we modelled (x^y) scenarios, where *x* is the number of states and *y* is the number of systemic considerations, resulting in us modelling 8 (2^3) different scenarios. In reality, each of these considerations could be represented by an infinite number of states, given their spectral nature and due to the subset assumptions that they were derived from.

This means that the aforementioned modelling should be used to articulate the potential boundaries within which an optimised hydrogen production system for the region could operate. As we move closer to the first target date of 2030, the uncertainty in these considerations will decrease and the states will converge. It would therefore be a useful exercise to repeat this analysis on an annual basis, updating the constraints to ensure that they are aligned with current thinking.

However, despite this uncertainty, the modelling has enabled us to observe how the different constraints impact the system design. This Section takes more holistic view of North West England and North East Wales, presenting some system wide observations in respect to the eight different scenarios:

1. No Target Mix | Centralised | Bear
2. No Target Mix | Decentralised | Bear
3. No Target Mix | Centralised | Bull
4. No Target Mix | Decentralised | Bull
5. Target Mix | Centralised | Bear
6. Target Mix | Decentralised | Bear
7. Target Mix | Centralised | Bull
8. Target Mix | Decentralised | Bull

Figure 47 and Figure 48 show the electrolyser and renewables capacities installed for each of the scenarios. Unsurprisingly there is a positive correlation between the quantity of electrolytic hydrogen that is required (Target Mix and bull) and the installed capacities.

From these graphs we can be observe that the bear to bull and the No Target Mix to Target Mix modifications are responsible for most of the capacity increase. This is not surprising as a higher consumption equals higher production which necessitates increased production capacity.

However, there is also a step change between the Target Mix | Centralised | Bull and the Target Mix | Decentralised | Bull scenario with an additional 4.2GW of electrolyser and 6GW of renewables installed in the decentralised scenario, as highlighted by Box 1 in the graphs overleaf.

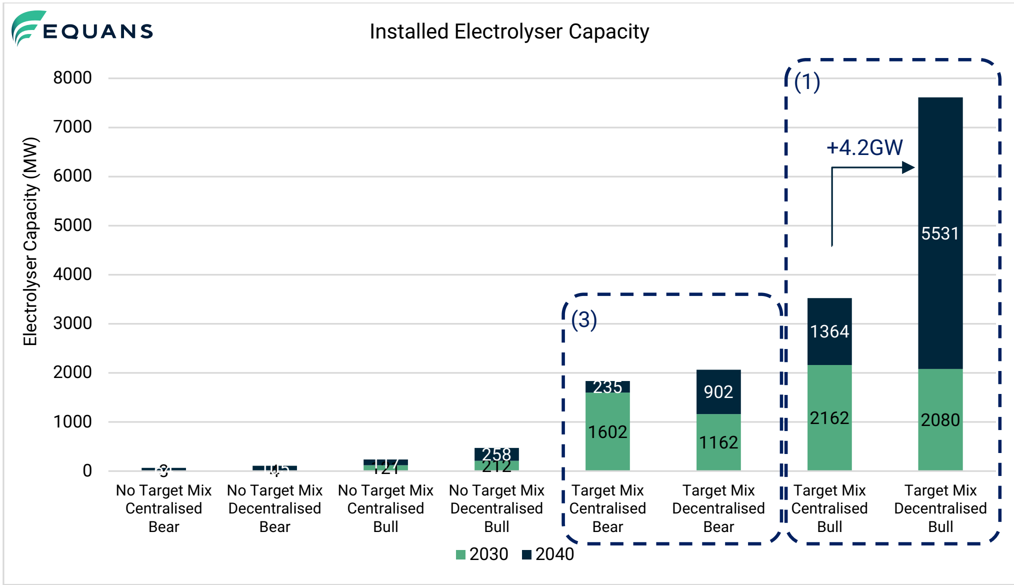


Figure 47 Installed electrolyser capacity in 2030 and 2040 for each of the modelled scenarios

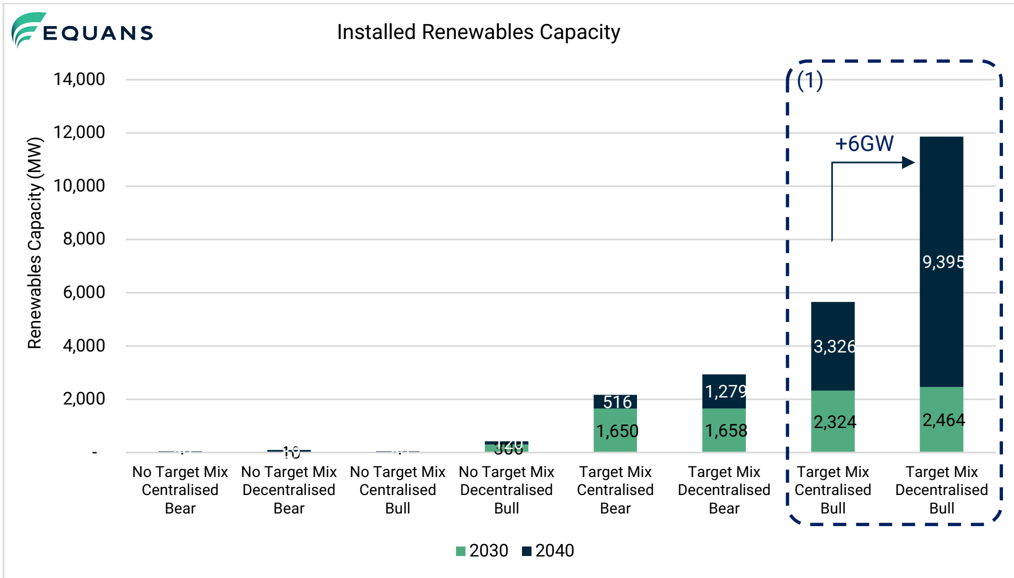


Figure 48 Installed renewables capacity in 2030 and 2040 for each of the modelled scenarios

Referring to Box 1 in Figure 49 below, we can see that these additional capacities are not being utilised for additional production, with both of these scenarios producing nearly 15TWh/a of electrolytic hydrogen by 2040. This is because in both of these scenarios, the model was constrained to deliver 25% electrolytic hydrogen (Target Mix) of the same consumption (Bull scenario). As electrolytic hydrogen was more expensive than the CCUS enabled alternative, the TCO optimisation exercise resulted in the selection of the minimum electrolytic hydrogen production volumes capable of satisfying this constraint.

The reason for the additional investment in capacity can be understood when we look at Box 1 in Figure 50 and the average electrolytic LCOH across the region. In 2040, we can see that the LCOH in the Target Mix | Decentralised | Bull scenario is £0.5/kg lower than in the Target Mix | Centralised | Bull scenario (£4.60/kg versus £5.10/kg). It therefore follows that the additional investment in capacity has resulted in a lower overall system cost. This decision was driven by the constraints on the model mandated in the centralised configuration.

Referring back to the definition of this configuration in Section 3.2, PROSUMER was only able to install an electrolyser in one location in the southern nodes and the only node with enough renewable production capacity was Node 7 (tidal power). In the decentralised scenario, the electrolysers were dispersed over Nodes 7, 9 & 10 and were primarily powered by solar PV, which had significantly lower LCOE than Tidal. This meant that despite the fact that the capacity factor was much lower for solar it was still more cost effective to build many decentralised oversized electrolysers (high CAPEX) with lower OPEX, than fewer large assets (lower CAPEX) with high OPEX. The impact of this constraint was only evident in the high electrolytic hydrogen requirements of the Target Mix | Bull scenarios, hence why it was only observed in this case.

However, the trend between decentralisation and reduced LCOH is only evident in the highest consumptions scenarios (i.e. Target Mix 2040). The benefits of a centralised approach are more apparent in the lower (bear and NTM) consumptions scenarios, such as Box 2 above. As stated in Section 5, the vast majority of the hydrogen consumption in the No Target Mix Scenarios is concentrated at the embedded nodes, due to the difference in LCOH between HyNet and the electrolytic solutions. As 2/3 of these nodes have limited renewables availability they are reliant on grid connected electricity to produce hydrogen on site. This exposure to the network costs leads to a high nodal LCOH, and a higher regional electrolytic LCOH due to the percentage of regional production at these nodes. On contrary, in the centralised scenario, the hydrogen can be produced at a small modular reactor, bringing significant cost benefits, particularly in 2040. That said, this observation should not discourage the development of decentralised hydrogen projects. Rather, it should ensure that developers are aware of the large number of factors that are required to optimise LCOH. This will be explored in more detail in Sections 5.1, 5.2 & 6.

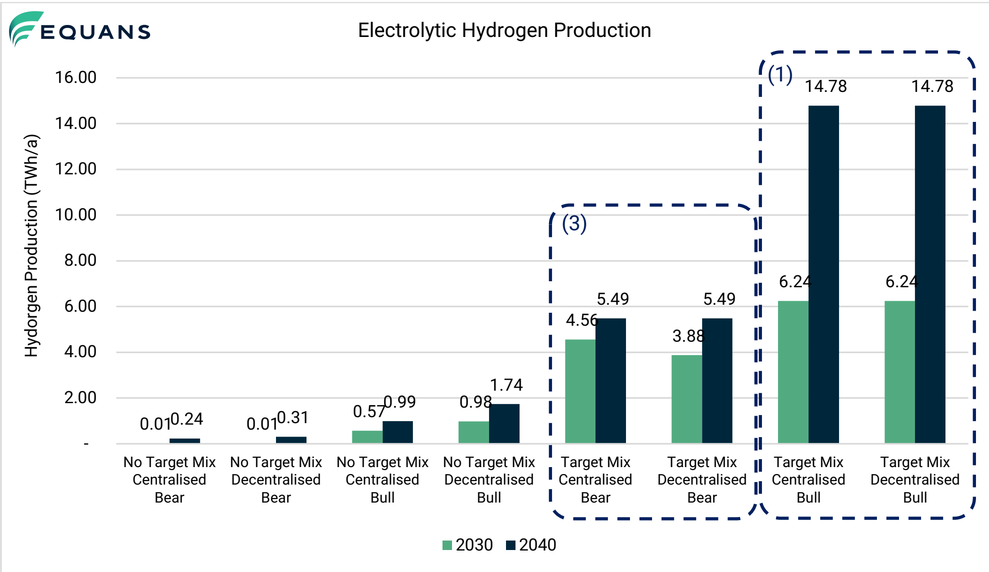


Figure 49 Electrolytic hydrogen production in 2030 and 2040 for each of the modelled scenarios

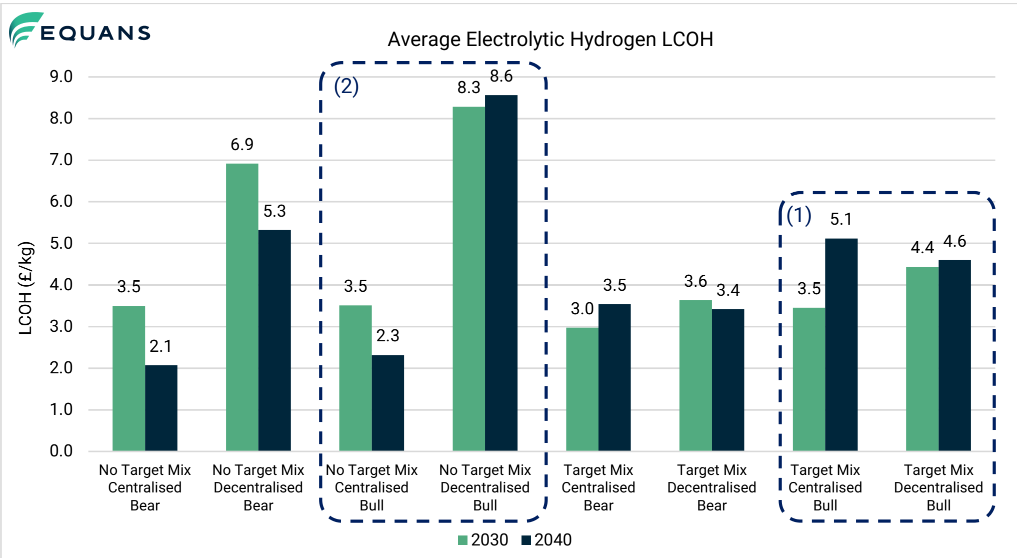


Figure 50 Average electrolytic hydrogen LCOH in 2030 and 2040 for each of the modelled scenarios

We can see one final interesting observation when looking at Box 3 in Figure 49 above. Despite the production being the same in 2040 in the Target Mix | Centralised | Bear and the Target Mix | Decentralised | Bear scenarios, the former has an additional 0.68TWh/a of hydrogen production in 2030. Unlike the decentralised configuration where electrolytic hydrogen equates to the minimum 25% of overall production, in the centralised scenario the electrolytic hydrogen is providing 32% of the overall hydrogen requirement. With reference to Box 3 in Figure 47 we can see that an additional 440MW of electrolyser capacity is installed in 2030 in the centralised configuration compared to the decentralised configuration. This was due to the increased flexibility enabled by allowing the model to transport the electrolytic hydrogen by road. In the centralised scenario it made economic sense to invest earlier in additional capacity in Node 1 to allow this to help serve the consumption of Node 12.

The opportunity for hydrogen comes from its ability to reduce the carbon intensity of processes that are currently reliant on fossil fuels. Based on the quantum of electrolytic hydrogen consumed, and an assumption that the vast majority of this is displacing natural gas, we can examine the amount of emissions abated by electrolytic hydrogen across the aforementioned scenarios. This is shown below in Figure 51.

We can see from Figure 51 that the quantum of emissions abated using electrolytic hydrogen is proportional to the amount electrolytic hydrogen consumed. The greatest emission reduction occurs in the Target Mix | Bull scenarios where 1.1Mt CO_2e/a and 2.7Mt CO_2e/a are abated in 2030 and 2040 respectively. This corresponds to a reduction of up to 8% of the region's overall emissions by 2040.

Furthermore, referring back to the modelling approach introduced in Section 4.1.2, it was explained that the embedded nodes were modelled on an archetypical basis, where three sites were selected to represent all of the non-network connected industrial consumers in the region. The emissions abated from converting these sites to hydrogen are therefore not included in the figures above. Rather, if we also assumed that the other industrial sites were decarbonised using electrolytic hydrogen, this would result in an additional 0.3Mt CO_2e/a being abated in 2030 and 0.9Mt CO_2e/a being abated in 2040. The analysis in EQUANS' Industrial Consumers report concluded that 8.4 CO_2e/a of industrial emissions could

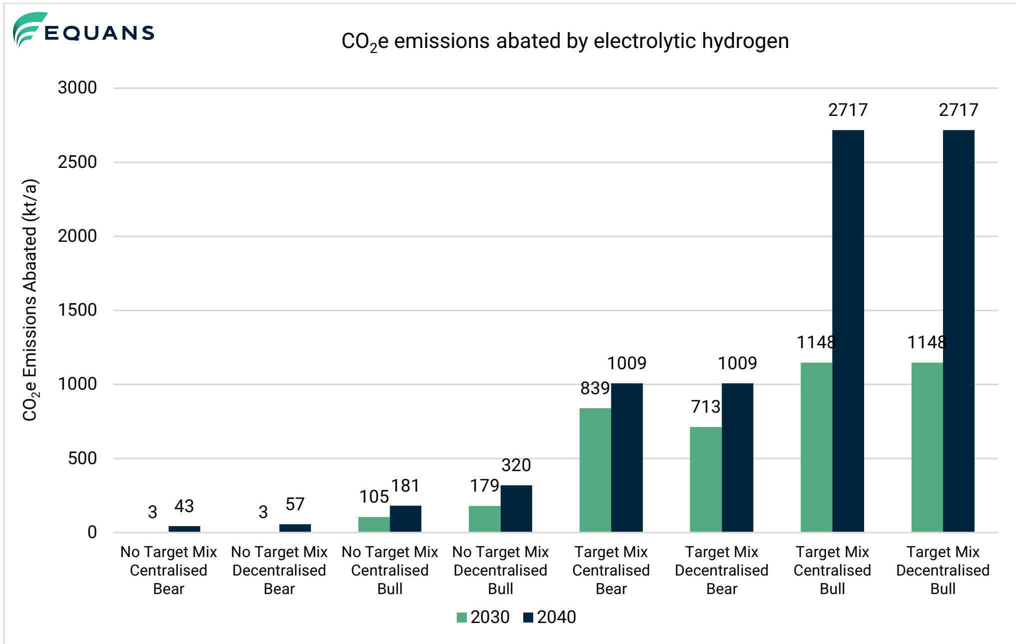


Figure 51 Emissions abated by electrolytic hydrogen in 2030 and 2040 for each of the modelled scenarios

remain in the region after energy efficiency and electrification projects have been deployed. These decentralised electrolytic projects could therefore help address over 10% of the regions' hard to abate industrial emissions, clearly demonstrating the opportunity for electrolytic hydrogen to decarbonise industry in the region.

However, the development of electrolytic projects requires careful consideration, to ensure the designs are optimised to account for the many interconnected variables. Sections 5.1 and 5.2 take a closer look at different scenarios, allowing us to analyse how specific assumptions affected the system design and to identify some key characteristics of success. Section 6 will then build upon these observations and outline some development opportunities, highlighting how these key considerations must be considered alongside the practicalities of system design.

5.1 No Target Mix (NTM)

As stated in Section 4, the first simulation that we performed was a TCO optimisation for the region with no target mix between CCUS enabled and electrolytic hydrogen. As the CCUS enabled hydrogen production capacity proposal associated with HyNet was designed to be sufficient to match the consumption within the network connected region, this meant that electrolytic hydrogen would only be selected if the LCOH was cheaper than for CCUS enabled. Based on the assumptions introduced in Section 4.2.1, this meant that the LCOH for electrolytic H_2 would need to be cheaper than £1.8/kg H_2 in 2030 and £2.0/kg in 2040.

5.1.1 NTM Decentralised Configuration

As we can see in Figure 52 and Figure 53 below, in the NTM decentralised bull and bear scenarios, there was limited development of electrolysers in the network connected nodes, with no capacity installed in 2030 and only 75MW installed in 2040 across Nodes 8, 9 & 10. This was because the production configuration in Nodes 8, 9 & 10 (directly connected onshore wind) in 2040 was the only way that electrolytic hydrogen could be produced in a more cost effective manner than CCUS enabled, given the above assumptions.

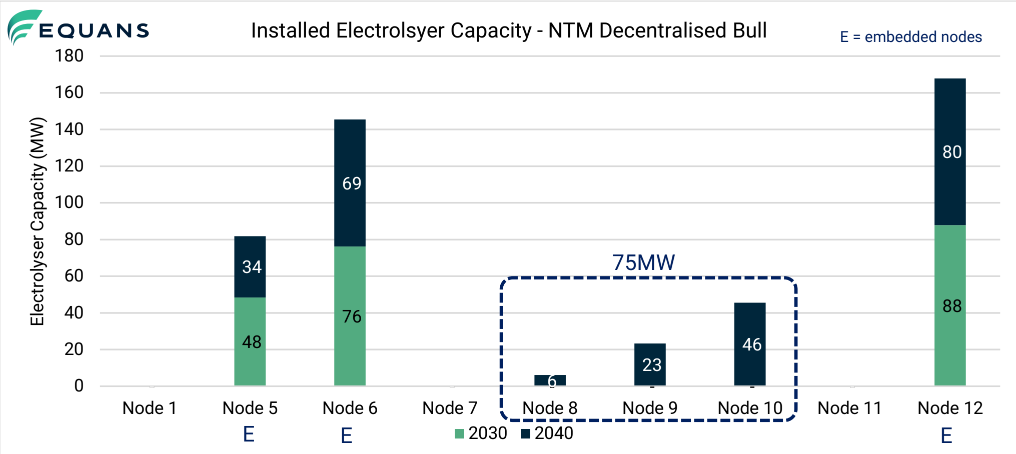


Figure 52 A graph showing the nodal electrolyser capacity in the NTM decentralised bull scenario

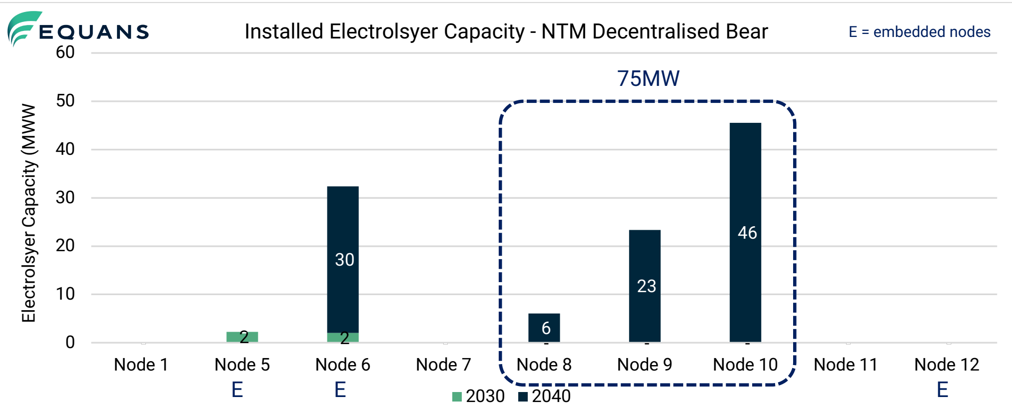


Figure 53 A graph showing the nodal electrolyser capacity in the NTM decentralised bear scenario

In the embedded nodes, which did not have access to this CCUS enabled H_2, the model was required to invest in electrolyser capacity as this was the only way to meet the demand. Therefore, the difference in electrolyser capacity is purely driven by the differing hydrogen demands assumed in the bull and bear scenarios. This is particularly evident for Node 12, a cement works, where it was assumed that the site would decarbonise using on-site carbon capture in the bear scenario, and that no hydrogen would be required. For this reason, the bull scenario will be used for the following observations and analysis.

Referring back to the embedded nodes in the bull scenario, 212MW of electrolysers were installed in 2030 and a further 183MW of electrolysers in 2040. However, it should be remembered that these embedded nodes were modelled on an archetypical basis, selecting three sites that were representative of the non-network connected consumers. Scaling these electrolysers for the remaining industrial sites in the region implies that under the bull scenario approximately 385MW of additional electrolysers would be needed in 2030 and 1,184MW in 2040, whilst in the bear scenario approximately 48MW of additional electrolysers would be needed in 2030 with a further 296MW in 2040. This highlights the opportunity for electrolytic hydrogen for consumers who do not have piped access to CCUS enabled hydrogen. However, as can be seen in Figure 54 below, the cost of green H_2 in these embedded nodes is significantly higher than the CCUS enabled H_2 price, ranging from £5.05/kg in Node 5 to £10.36/kg in Node 12, in 2040. This means that the LCOH differential between CCUS enabled H_2 and Embedded green H2 ranges from £3.05/kg to £8.36/kg in 2040.

However, there has been some turbulence in the gas market recently with UK wholesale prices reaching 215p/therm (£73/MWh) for October 2021. This was significantly higher than the forecasts we used to configure the model earlier in the year (£17/MWh in 2030 and £23.2/MWh in 2040), demonstrating the difficulty of predicting prices 20 years into the future. If were to use the October 2021 gas price of £73/MWh to calculate the cost of CCUS enabled H_2, this would give a LCOH for CCUS enabled H_2 of £4.10/kg. This is more than double the LCOH at Nodes 8, 9 & 10 and close the LCOH at Node 5. Furthermore, if the CCUS enabled H_2 price had been higher in our model, there would have been significantly more electrolytic H_2 produced in the network connected nodes. This suggests that, alongside the additional carbon savings, a potential benefit of electrolytic hydrogen is its ability to hedge against gas price volatility.

Despite the uncertainty in the underlying gas commodity price, which affects the underlying cost of CCUS enabled H2, all of the nodes are subject to these same conditions, and therefore this uncertainty can be discounted when analysing the green H2 results relative to each other, across the nodes. This is useful as it allows some conclusions to be drawn about the key drivers behind the cost difference between green H2 produced in different locations.

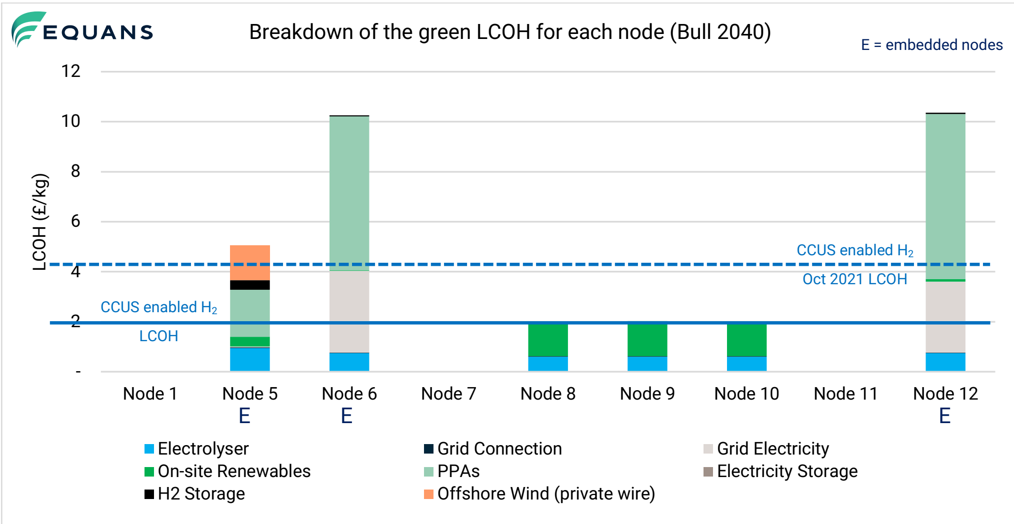


Figure 54 A graph showing the breakdown of the LCOH for each node in the NTM decentralised bull 2040 scenario

The main reason for the difference in LCOH between Node 5 and Nodes 6 and 12 can be understood when comparing the breakdown of electricity used by the electrolysers in each of these nodes, shown below in Figure 55. Due to Node 5's location, it was able to access 67% of its electricity via a private wire from the Offshore Wind. This can be compared to Nodes 6 & 12 which were limited in their on-site renewables availability and were required to access almost all of their electricity via PPAs, or the grid, to meet their demand requirements. As this network supplied electricity was subject to the additional network charges, this led to a higher LCOH. This trend is also evident in Nodes 8, 9 & 10, which have the greatest percentage of behind the meter electricity and, consequently, the lowest LCOH.

This observation is further validated when looking at Figure 56 below which shows the RES capacity installed in each of the nodes across the whole time horizon. As can be seen in the embedded nodes, the model opted to install as much on-site renewables as were allowed, and the higher the percentage of electricity sourced on-site, the lower the LCOH. This suggests that industrial sites with sufficient space for on-site renewables could achieve lower LCOH's than those without, an important observation when identifying suitable consumers for embedded hydrogen solutions.

But the ability to access electricity via a private wire is not the only metric that was considered as part of the cost optimisation exercise. The decision to invest in renewables is also a function of the load profile that the renewable energy can provide and the demand shape that it is looking to fulfil. Looking at the network connected nodes (8, 9 & 10), the maximum onshore wind capacity was installed but no solar PV was installed, of which there was multiple gigawatts of potential availability. This is because adding solar PV to these electrolysers, with its lower capacity factor and thus larger CAPEX, would have given an incremental LCOH higher than the counterfactual CCUS enabled option.

When analysing the offshore wind capacity installed in Node 13 we can see that 73MW was connected to Node 5 by private wire and 135MW that was used to fulfil the demand in the other embedded nodes via a PPA. When we consider the fact that over 1GW of additional electrolyser demand could be required by the additional non-modelled industrial loads, there appears to be a strong opportunity to commercialise offshore wind developments using locally sourced PPAs for hydrogen, subject to the appropriate subsidies being in place.

Alongside the 135MW of offshore wind PPAs shown in Figure 56, PROSUMER has opted to make use of PPA or grid electricity in all of the embedded nodes in 2040. This is primarily driven by the constraints on on-site renewables, but also to ensure the demand can be met without excessive investment in hydrogen storage. For example, Node 5 has access to 1,655GW of offshore wind capacity via private wire, should it wish to use it. It could therefore solely rely on offshore wind as the electricity source and rely on on-site electrical or hydrogen storage to manage the intermittency of generation. However, with reference to Figure 55, we can see that 14% of the electricity requirement in 2040 is supplied by a PPA from the SMR plant. With its ability to provide electricity baseload, the SMR plant can supplement the renewables to reduce the overall LCOH. This can be seen in Figure 57 which shows the breakdown of the electricity sources used to power the electrolyser in Node 5 in January 2040. As can be seen, the majority of the demand is met by the offshore wind and electricity is only needed via the SMR PPA for 17 hours out of the 730 hours in January. Clearly, the use of SMR is a function of the RES load profiles and hydrogen demand and different months have a different reliance on network connected electricity. This can be seen when comparing the January 2040 graph to the June 2040 graph (Figure 58) where the SMR PPA is used in 139 hours. It is also worth noting that, in reality, it may be commercially challenging to secure a PPA to manage intermittency as the SMR would need a more reliable commitment to the offtake.

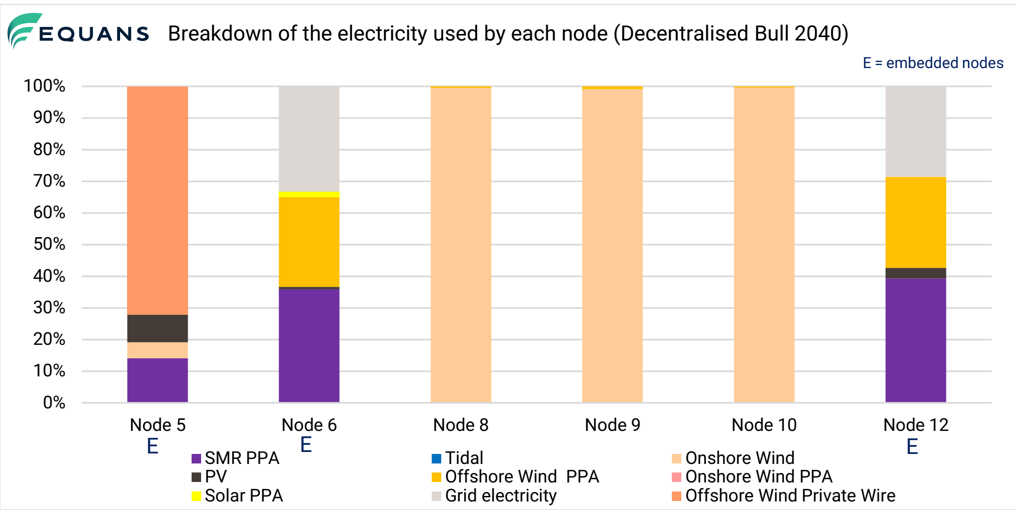


Figure 55 A graph showing the breakdown of electricity by each node in the NTM decentralised bull 2040 scenario

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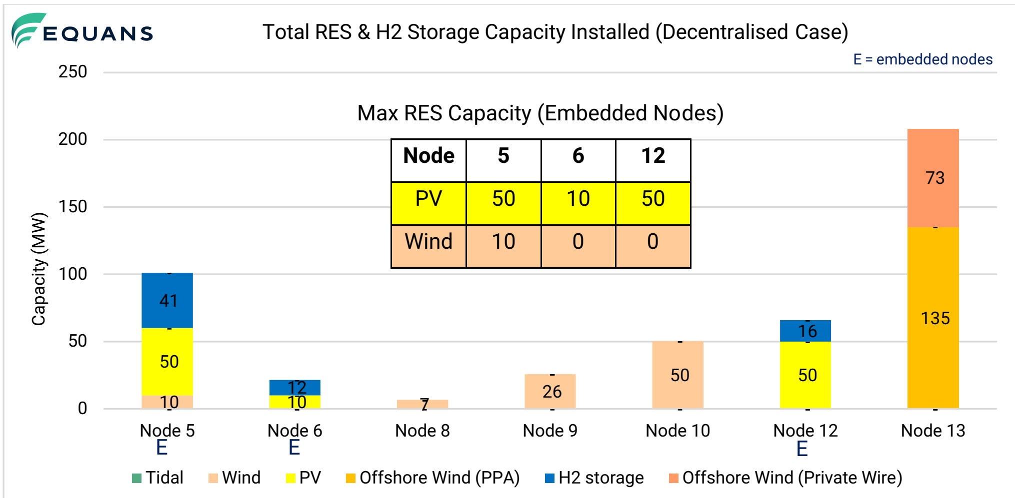

Figure 56 A graph showing the renewable energy capacity installed by PROSUMER in the NTM decentralised bull scenario

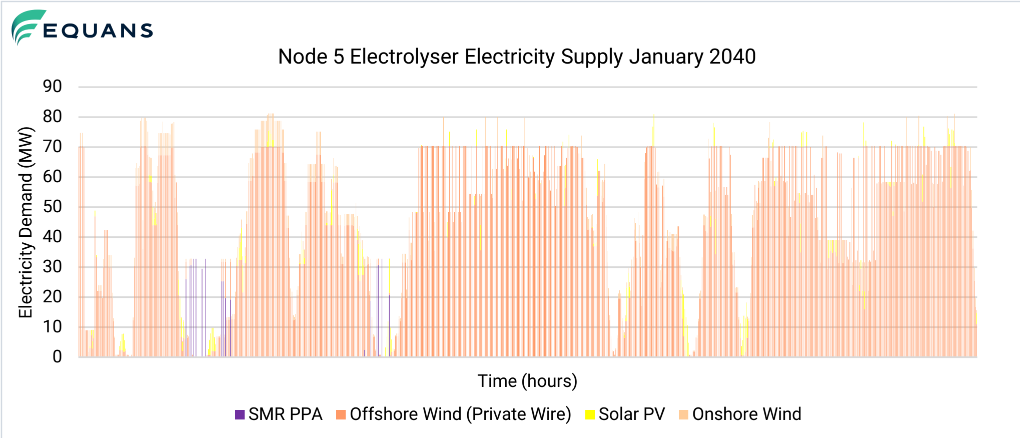

Figure 57 A breakdown of the electricity used by the Node 5 electrolyser in January 2040

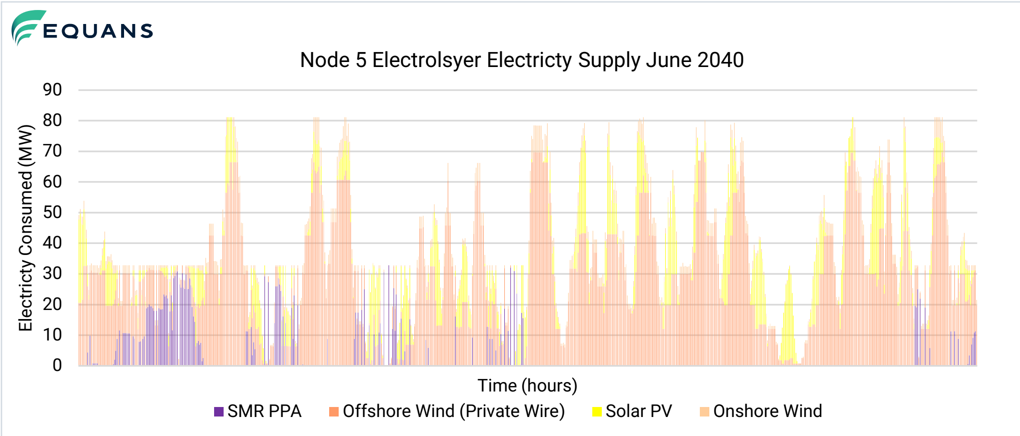

Figure 58 Breakdown of the electricity used by the Node 5 electrolyser in June 2040

However, despite the flexibility enabled by the network connected electricity supply, the hydrogen storage still has a significant role to play in matching production with consumption. With reference to Figure 59 below, we can see that the 40MW H_2 storage capacity at Node 5 is continually cycling between a state of charging and discharging to maintain equilibrium between the hydrogen produced and the hydrogen consumed. Another option being considered by BEIS is to allow producers to inject excess green H_2 in the gas grid, subject to the safety case being proven. This could provide an additional route to market for these embedded producers and help manage supply/demand, potentially improving the LCOH.

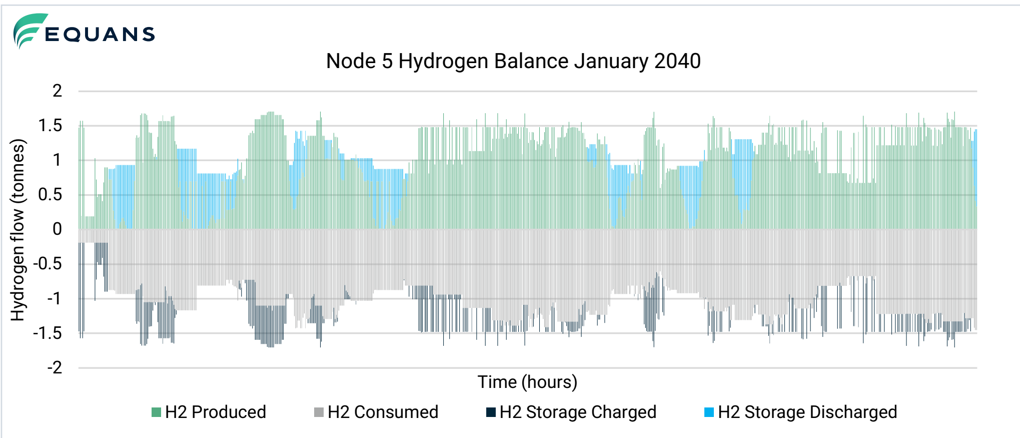

Figure 59 A graph showing the hydrogen balance at Node 5 in the NTM decentralised bull scenario in June 2040

Node 5 in 2040 has just been used here as an illustration but it is clear that these embedded systems are complex to design when the LCOH is looking to be minimised, with multiple variables to be considered. Furthermore, in our modelling we were able to assume perfect foresight in terms of renewable load factors and the hydrogen demand profiles for each year that was considered. In reality, there is uncertainty in both of these factors, adding further complexity when designing a system in the real world. This means that additional security of supply considerations would need to be designed into the system (e.g. additional storage, back up grid connections or flexible load management) to account for unforeseen periods of low renewable generation or unexpected ramp up in demand.

That said, there are also opportunities for the LCOH to be reduced in a well-integrated system. Again, referring to Node 5 in 2040 there are over 1500 hours in the year where some of the on-site electricity production is curtailed, meaning too much electricity is produced to supply the electrolyser. The £5.05/kg cost is based on the conservative assumption that this curtailed electricity is not monetised. However, it is highly plausible that the site would have an electricity demand, which could be met with this o-site generation. If we were able to use 100% of this electricity on-site, displacing grid electricity, the LCOH could be reduced by £1.16/kg. This would result in a LCOH of £3.89/kg for the electrolytic hydrogen at Node 5, cheaper than the cost of CCUS enabled H2 in the high gas price scenario presented earlier in this section.

That said, there is still a long way to go to get the green H_2 LCOH of £1.96/kg that was achieved in Node 10 in 2040, but there are some fundamental reasons as to why this is the case. Unlike Node 5, Node 10 is connected to the hydrogen network. This means that the hydrogen demand can be met by CCUS enabled hydrogen or electrolytic hydrogen injected elsewhere. As the electrolyser at Node 10 is only being used to meet a small proportion of the overall consumption (2% in 2040) the electrolyser operating requirements have been decoupled from the hydrogen demand requirements. This means that the electrolyser is free to operate in the most cost-effective manner. In the case of Nodes 8, 9 & 10, this means that the electrolyser is solely using directly connected onshore wind. This is evident in Figure 60, where we can clearly see that the electrolyser production profile is in sync with the electricity generated by the onshore wind.

This clearly highlights the inherent difference between grid blending and embedded solutions, supporting the case for different subsidy levels for different hydrogen offtake arrangements. Furthermore, this observation should not be interpreted as an affirmation for solely network connected hydrogen. As stated in Section 2.2, the network costs were excluded from the modelling, due to their likely funding structure. When considering the overall cost to the UK, we need to account for the cost of building and operating these networks. This is likely to make fiscal sense in areas of dense demand, such as around HyNet, but less so for the more isolated regional consumer (i.e. the embedded nodes in this model). Additional support will be required to ensure that green H_2 projects can be developed for industrial customers outside of the industrial clusters at an equivalent cost to those connected to H_2 networks.

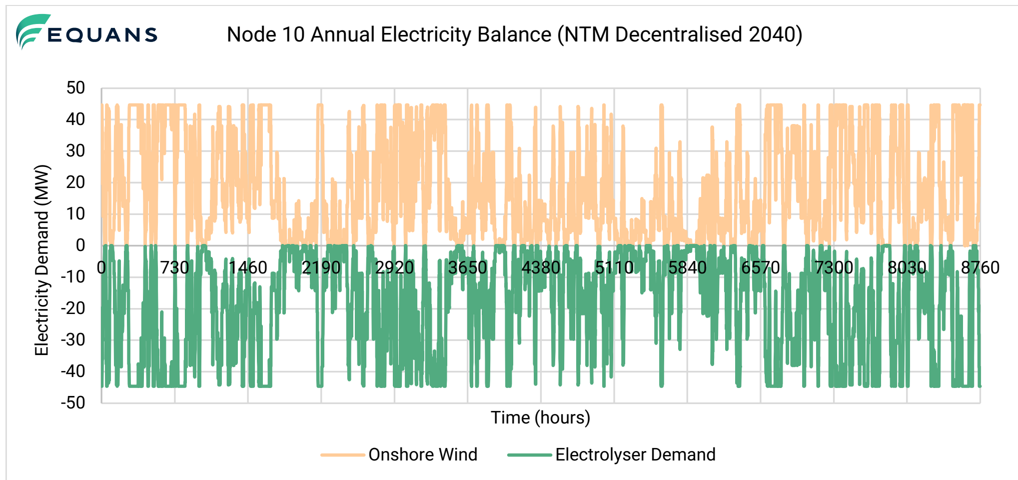

Figure 60 A graph showing the electricity balance at Node 10 in the NTM decentralised bull scenario in 2040

5.1.2 NTM Centralised Configuration

As mentioned in the Introduction, North West England and North East Wales's industrial heritage was built off a shared vision and synergistic processes. In our centralised configuration, we sought to understand whether the LCOH of electrolytic hydrogen could be reduced by centralising production at fewer locations in the region and either injecting into HyNet or transporting the hydrogen between nodes via road.

Referring to the schematic of the region in Figure 10, in the centralised configuration we constrained the model by allowing it to invest in electrolysers in one node in the north and up-to two nodes in the south. As can be seen in Figure 61 below, the model opted to invest in Node 4 in the north and Node 10 in the south.

The choice of 45MW of electrolyser in Node 10 should not be surprising given the results in the decentralised configuration. As was explained earlier, this electrolyser was sized based on the maximum capacity of onshore wind available in that node and solely follows the operating pattern of this wind. For this reason, the LCOH of green H_2 produced in this node was the same as in the centralised scenario.

However, it can also be observed, that to serve the consumers in Nodes 5 & 6, PROSUMER has opted to install nearly 200MW of electrolyser (121MW in 2030 and 73MW in 2040) at Node 4. The electrolytic hydrogen produced at this node is 100% purple, produced by an electrolyser directly connected to the SMR plant. This gives a LCOH at Node 4 of £3.51/kg in 2030 and £2.44/kg in 2040.

That said, unlike in the decentralised scenario, the hydrogen produced at Node 4 also has additional transportation costs associated with its transportation to Nodes 5 and 6, where it was consumed. This is also true at Node 12 and the breakdown of delivered costs for hydrogen (including transportation) at the embedded nodes is shown below in Table 19.

The hydrogen costs can be compared to the decentralised costs when viewing Figure 62 below. The biggest difference is observed at Node 12, with centralised hydrogen price only a quarter of its decentralised counterpart in 2040. However, referring back to Figure 10, we can see that in the centralised scenario, Node 12 can access the network connected hydrogen, albeit with some short road transportation. This means that in the decentralised scenario, the hydrogen used in Node 12 is electrolytic, but in the centralised

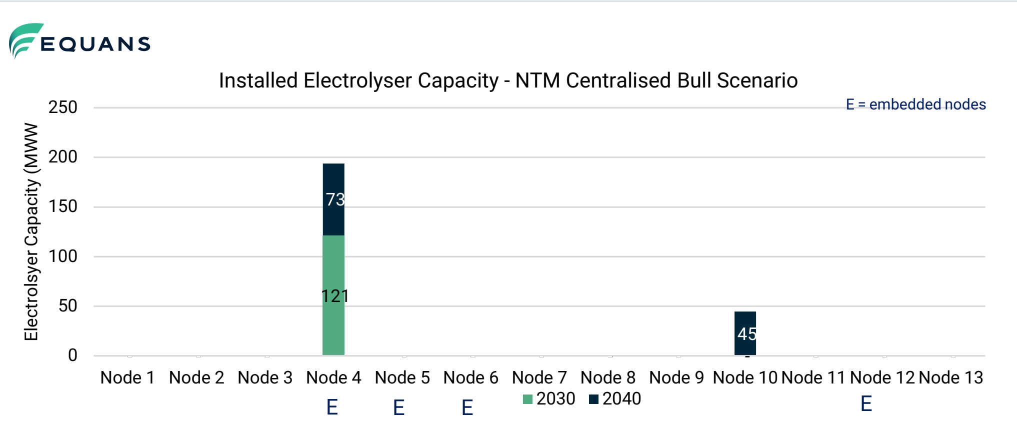

Figure 61 Nodal electrolyser capacity in the NTM centralised Bull case

Cost Breakdown (£/kg)	Node 5		Node 6		Node 12	
	2030	2040	2030	2040	2030	2040
Electrolyser	0.62	0.54	0.62	0.54	-	-
SMR	2.88	1.90	2.88	1.90	-	-
CCUS enabled H_2	-	-	-	-	1.85	1.99
Road Transport	0.57	0.53	0.74	0.70	0.55	0.53
Total	**4.08**	**2.98**	**4.25**	**3.15**	**2.40**	**2.52**

Table 19 A LCOH breakdown for road supplied hydrogen in the NTM centralised scenario

scenario it is the same blend as within the LTS (i.e. 99.8% CCUS enabled). This is the reason why the LCOH in Node 12 increases between 2030 and 2040, driven by the increasing gas prices. This can be compared to the falling LCOH at Nodes 5 & 6, caused by falling electrolyser costs and a lower LCOE from the small modular reactor.

The only difference in cost between the hydrogen in Node 5 and Node 6 is the road transport cost, driven by the fact that hydrogen needs to travel 65 miles further to Node 6 than Node 5. However even with these slightly higher transportation costs, the opportunity for cost reduction in Node 6 is significantly higher than in Node 5 due to the higher LCOH in the decentralised case. It therefore follows that there will be some industrial consumers who benefit from centralisation more than others.

The biggest beneficiaries are those with limited space for behind-the-meter renewables. As an area of further work, it would therefore be a useful exercise to undertake a site-by-site assessment for industrial consumers in the region to understand their on-site renewables constraints, as this would allow for the opportunity benefit of centralisation to be quantified. It is also worth noting that a centralised hydrogen production solution, on a customer site, would necessitate complex commercial arrangements and understanding the commercial risks associated with this would also be useful body of further work.

Referring back to the modelling results in the NTM centralised bull scenario, the LCOH at the point of production is shown below in Figure 63. This graph compares the electrolytic hydrogen produced in the centralised scenario with the LCOH for CCUS enabled H_2 that was programmed into our model. Furthermore, as discussed in Section 5.1.1, as the CCUS enabled H_2 cost is highly sensitive to the cost of natural gas, the LCOH based on October 2021 prices has also been plotted below. As we can see in Figure 63 with the increased gas prices, the electrolytic production becomes cheaper than the CCUS enabled H_2. This suggests that there could be a significant role for purple H_2, both feeding into networks and servicing industrial consumers, as it is less constrained by the maximum capacities applicable to onshore wind.

Another interesting difference can be observed when analysing the investment in hydrogen storage in the embedded northern nodes, as shown in Figure 64. As can be seen, the model was required to invest in 53MW of storage in the decentralised scenario compared to just 14MW in the centralised scenario, nearly a fourfold difference.

The primary reason for this disparity is caused by the difference in the electricity sources used to power the electrolysers in each of these scenarios. In the decentralised scenario, the electrolyser at Node 5 is primarily powered by intermittent wind, alongside on-site storage to balance supply with demand. This can be compared to the centralised scenario where the electrolyser supplying Nodes 5 & 6 is powered by the SMR with a consistent load factor. This means that very little storage is needed at Node 4 as intermittency is no longer an issue. The small level of storage installed at Nodes 5 & 6 in the centralised scenario is necessary to facilitate the delivery of hydrogen by road.[11] This observation is important as it highlights the land-use benefits that can also be achieved through centralisation.

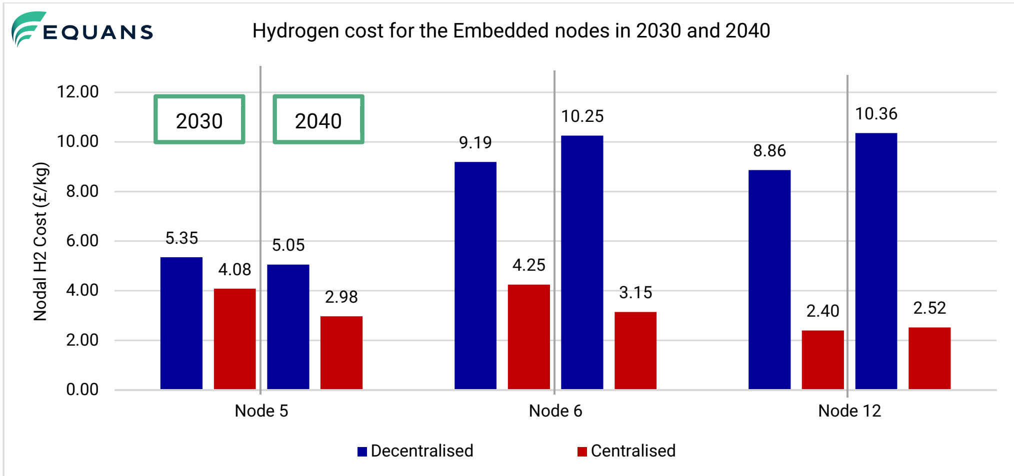

Figure 62 The cost of hydrogen in the embedded nodes in 2030 and 2040 in the decentralised and centralised scenarios

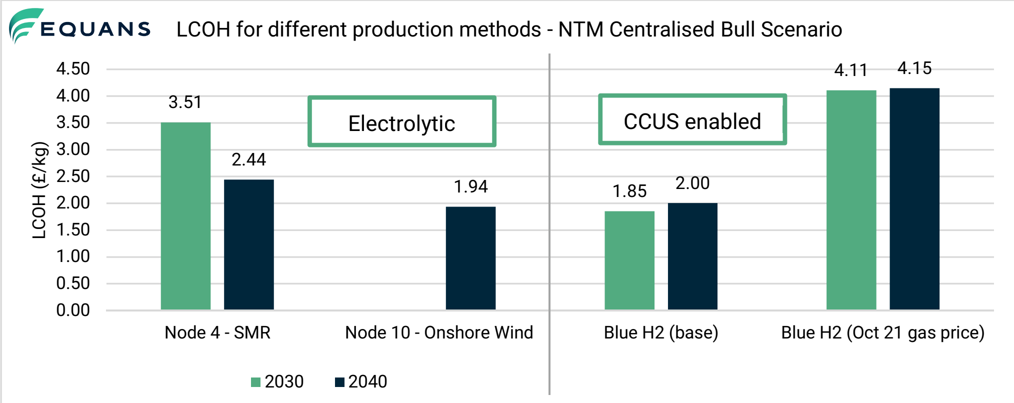

Figure 63 A comparison of the electrolytic H2 LCOH to the CCUS enabled H2 LCOH in the NTM centralised scenario

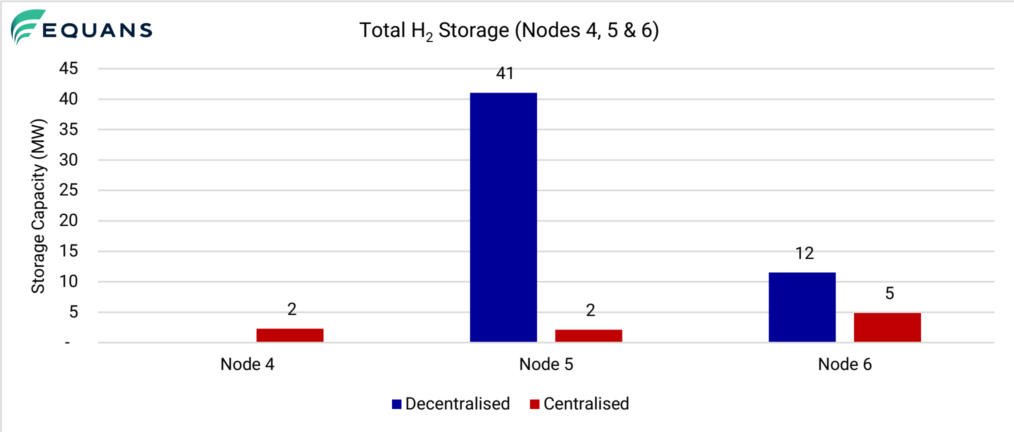

Figure 64 A graph showing the H2 Storage capacity at nodes 4, 5 & 6 in the NTM decentralised and centralised scenarios

Finally, it is worth noting that the most cost-competitive solution is likely to be a hybrid approach. As evidenced by the low LCOH achieved by Nodes 8, 9 & 10 in the decentralised case, green hydrogen can be cost competitive with CCUS enabled hydrogen when the demand requirements and production profiles are decoupled.

In a hybrid scenario, a site could size an electrolyser to run solely from the on-site renewables, fulfilling a proportion of the demand, but ensuring security of supply through a H2 supply contract. This should not be surprising, given the parallels to the electricity sector where progressive organisations are decarbonising a proportion of their demand using on-site renewables but retaining their supply contracts for periods of intermittency.

5.2 Target MIX (TM)

Although the results in Section 5.1 are interesting, the ongoing consultation into hydrogen business models recognises the need for different levels of support for different production technologies. This means that we could expect to see a policy environment that enables the deployment of a wider mix of production technologies, with different fundamental economics. Although the UK Hydrogen Strategy did not give a target production mix, the BEIS Impact Assessment into the sixth carbon budget recommended a scenario that included a green hydrogen penetration of 5% - 40% in 2035.

To assess the effect that this could have on the hydrogen production system design, we also modelled a scenario where electrolytic hydrogen was required to meet at least 25% of the overall consumption in 2030 and 2040 and these results are presented overleaf.

[11] It should be noted that given the regional nature of this modelling we did not programme any security of supply constraints on these nodes. If we were designing a system for a specific site, we would incorporate this to guarantee H2 supply to the customer.

5.2.1 TM Decentralised Configuration

In the aforementioned NTM bull scenario, electrolytic hydrogen provided 4% of the overall consumption in 2030 and 3% of the consumption in 2040. It is therefore unsurprising that when we constrained the model so that at least 25% of the total consumption had to be met via electrolysis, a far greater capacity of electrolysers was needed. The installed electrolyser capacities in the bull and bear scenarios are shown below in Figure 65 and Figure 66.

Comparing these to the NTM graphs is Figure 52 and Figure 53, we can see that the electrolyser capacities in the embedded nodes have not changed. This is not surprising as these embedded nodes did not have access to the CCUS enabled H2 in either scenario. However, the big difference comes when we compare the deployment of network connected electrolysers (i.e. those at Nodes 1, 7, 8, 9 &10), where there is a large difference in both the bull and bear scenarios. In the bear scenario, this difference is most notable at Node 1, with an additional 1,600MW of electrolysers installed versus the NTM case. This Node 1 increase was also evident in the bull case; however, it was compounded with large installations at the other network connected nodes. The difference in the total installed electrolyser capacity between the TM and the NTM case for the decentralised configuration is summarised in Table 20.

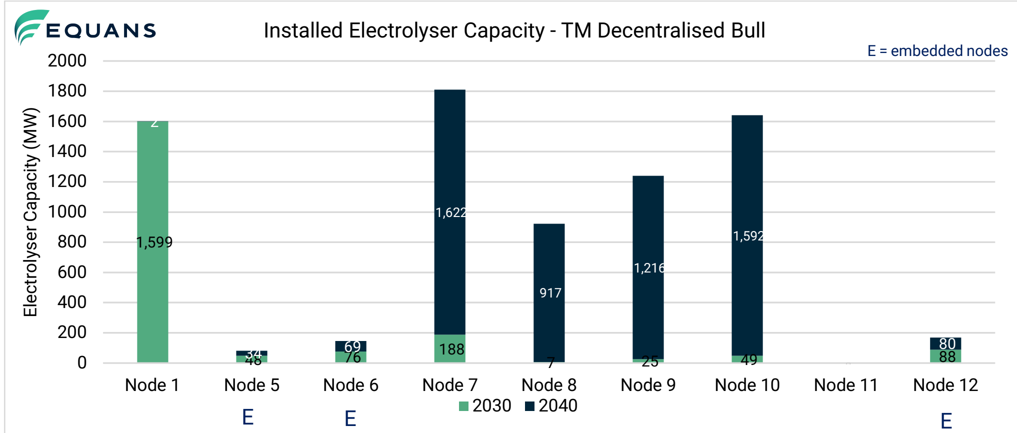

Figure 65 Nodal electrolyser capacity in the decentralised bull case in the TM scenario

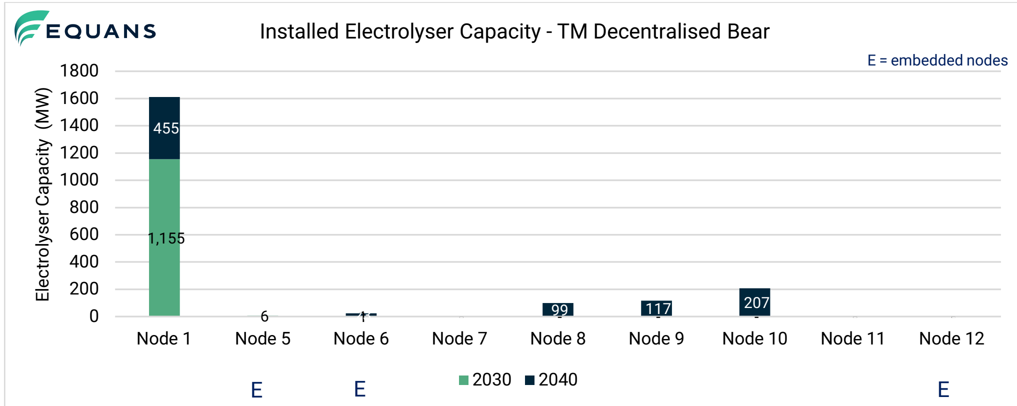

Figure 66 Nodal electrolyser capacity in the decentralised bear case in the TM scenario

ELY capacity (MW)	NTM Bull	TM Bull	NTM Bear	TM Bear
2030	-	1,868	-	1,155
2040	75	5,348	75	879
Total	**75**	**7,216**	**75**	**2,034**

Table 20 The difference between the total installed electrolyser capacity in the TM and the NTM centralised scenarios

Referring to Table 20, we can see that by 2030 there is significant divergence between the TM and the NTM scenarios, with an additional 1.9GW (bull) and 1.2GW (bear) of electrolyser capacity installed across the network connected nodes. By 2040 the additional electrolysers are producing 13TWh/a of electrolytic hydrogen production in the bull case and 5.2TWh/a in the bear case, offsetting CCUS enabled H_2 production and meeting the minimum 25% green H_2 system requirement.

To understand the most cost optimal way to replace this large volume of CCUS enabled H_2, we need to look at how and where this additional electrolytic hydrogen was produced. A graph showing the amount of electrolytic hydrogen produced at the network connected nodes in the bull case, alongside their nodal LCOH, in shown below in Figure 67.

Firstly, we can see that for Nodes 8, 9 & 10, the LCOH increases between 2030 and 2040, which is perhaps surprising given the forecast falling technology costs in this horizon.

However this can be explained when we look at the breakdown of the sources of electricity consumed by the electrolysers in 2030 and 2040, shown below in Figure 68 and Figure 69. The relationship between electrolyser capacity, utilisation factor and LCOH is also shown in Table 21 below.

Firstly, we can see that a lower nodal LCOH did not directly equate to higher hydrogen production. This may seem counterintuitive given the TCO optimisation exercise performed by our model, so to understand why this is the case, we need to examine each node individually.

In Nodes 8, 9 & 10 we can see a clear shift from majority onshore wind to majority solar PV between 2030 and 2040. This is driven by the greater hydrogen consumption requirements in 2040 and therefore a greater capacity of electrolysers was required. In 2030, the installed electrolyser capacity is essentially equal to the maximum onshore wind capacity at these nodes (7MW, 26MW & 50MW).

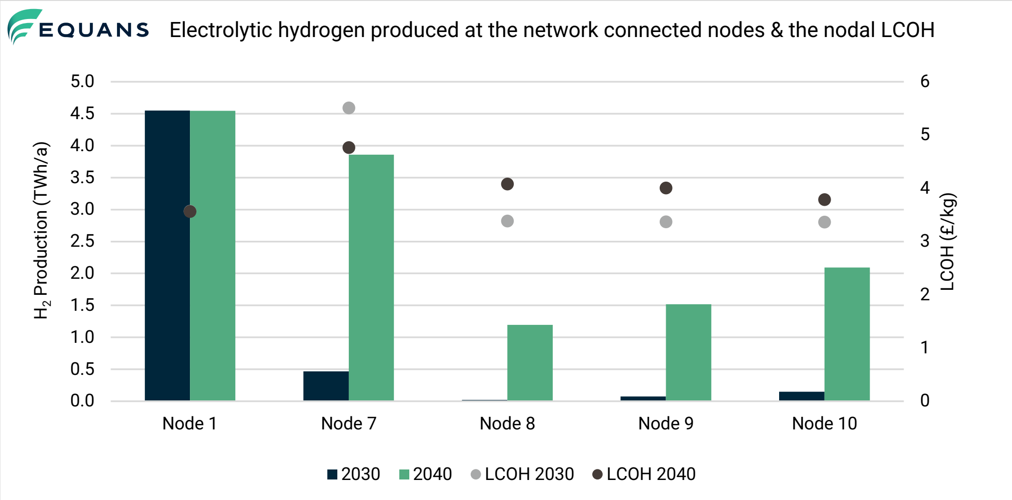

Figure 67 Electrolytic hydrogen produced at the network connected nodes in the TM decentralised bull case

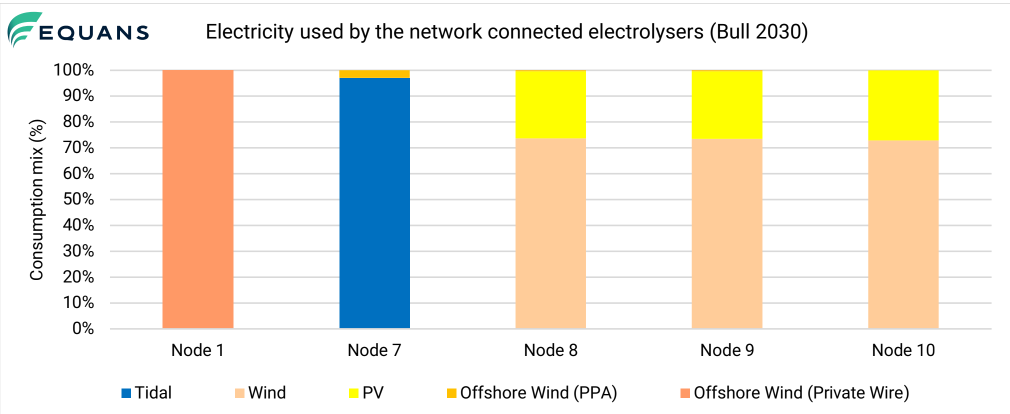

Figure 68 A graph showing the electricity used by the electrolysers in the network connected nodes in the TM decentralised bull 2030 case

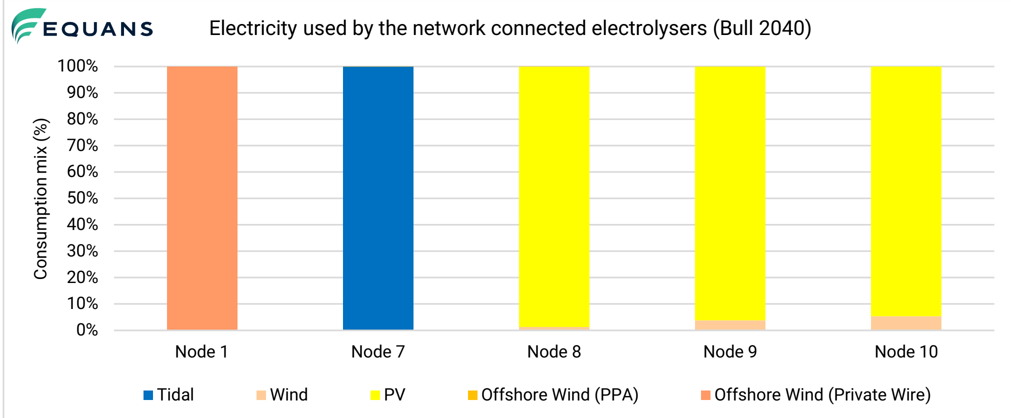

Figure 69 A graph showing the electricity used by the electrolysers in the network connected nodes in the TM decentralised bull 2040 case

Node & Year	1		7		8		9		10	
	2030	2040	2030	2040	2030	2040	2030	2040	2030	2040
Electrolyser Capacity (MW)	1,598	1,600	187	1,809	7	923	25	1,240	49	1,641
Electrolyser Utilisation Factor (%)	47	47	41	34	50	21	50	20	50	21
LCOH (£/kg)	3.57	3.57	5.51	4.76	3.39	4.08	3.37	4.01	3.37	3.79

Table 21 A table showing the electrolyser capacity, utilisation factor and LCOH in the TM decentralised bull case

This onshore wind is then supplemented with a smaller amount of solar PV, allowing the electrolysers to achieve a high utilisation factor (50%) and the lowest LCOH in 2030. However, by 2040, there is a far greater consumption requirement for hydrogen and investment in additional electrolyser and solar PV capacity is needed. Although a large capacity of solar PV is needed to fulfil the demand in 2040 (Node 8: 2.0GW, Node 9: 2.3GW, Node 10: 3.2GW), these figures are not the assumed maximum capacities and the availability of RES is not the primary driver behind the installed electrolyser size. Rather, referring back to the schematic in Figure 9, we can see that Nodes 8, 9 and 10 represent the most downstream parts of the hydrogen network. Hydrogen is able to flow from the LTS nodes (1, 2, 3 & 7) to these nodes but it cannot flow in the other direction. This means that the electrolysers in Nodes 8, 9 and 10 can only serve their local consumers and have been sized accordingly.

In Node 7 the opposite is seen, with the LCOH falling between 2030 and 2040. This can be explained by examining the electricity sources in Figure 68 and Figure 69, where we see a shift away from offshore wind PPA to purely tidal power private wire. The utilisation factor of this electrolyser in 2040 (34%) is slightly higher than tidal power (28%) due to an investment in a small amount of battery storage. Although Node 7 has the highest LCOH of the network connected nodes, it plays a vital role in the system. As explained in the previous paragraphs, the other nodes are constrained by their maximum renewables capacity or their geographic constraint on supplying the wider network. Node 7 does not have these constraints, with a large capacity of tidal power available (4GW in 2040) and an assumed ability to inject into the LTS. Node 7 therefore provides an important function of ensuring that 25% of the overall consumption can be met with electrolytic H2. The electrolyser is sized to meet this consumption, and if tidal power were not available, it would need to be sourced via the grid with significantly higher costs. For this reason, by 2040, Node 7 is supplying 26% of the electrolytic hydrogen and 6.5% of the total hydrogen in the model.

Finally, in Node 1 we see little difference between 2030 and 2040, with the electrolyser operating in harmony with the offshore wind production. By 2040, Node 1 has the lowest LCOH and also produces the largest amount of hydrogen (4.55TWh/a). The reason that it does not produce more than 4.55TWh/a is due to the maximum offshore wind capacity constraints (1,650MW) introduced in Section

4.2.2.1.2. Furthermore, as there is no capacity for other RES at this location any additional production would need to be powered via network connected electricity which is an expensive option.

As a general observation, we can see that the mix of electricity sources at each node is not as complicated as we saw in the embedded nodes. This is because CCUS enabled hydrogen can be used to help meet the demand peaks and the electrolysers can be sized and powered in the most economically advantageous fashion, whilst adhering to the aforementioned constraints.

This can be substantiated by comparing the aforementioned bull case production to that of the bear case, shown overleaf in Figure 70.

Firstly, we can see that there is no longer any production at Node 7, which is not surprising considering it was the most expensive electrolytic option. We can also observe large reductions in Nodes 8, 9 & 10, with Node 1 now providing 100% of the electrolytic H2 in 2030 and 84% of the electrolytic H2 in 2040. As per the bull scenario, the electrolyser at Node 1 was sized to use the maximum available capacity of the offshore wind private wire. However, in 2040, Node 1 does not produce enough hydrogen to satisfy the minimum 25% electrolytic hydrogen requirement and therefore an additional 0.8TWh/a of electrolytic hydrogen was produced at Nodes 8, 9 and 10. Following the same observations as in the bull case, the split of hydrogen production between these nodes is correlated with the availability of onshore wind.

5.2.2 TM Centralised Configuration

Our final simulation examined what a lowest cost hydrogen production system may look like in the TM centralised scenario. As with the decentralised configuration, the addition of the 25% electrolytic constraint did not make any difference to the northern nodes as these were already supplied by electrolytic hydrogen.

In the southern nodes, the model had the option to install electrolysers at up to 2 nodes to meet the demand. Referring back to the NTM case, PROSUMER elected to install 45MW electrolysis at Node 10 in 2040 as this was the only time and location where electrolytic hydrogen could be produced with a lower LCOH than CCUS enabled H_2. However, this was not the case for the TM centralised scenario and the installed capacity of electrolysers is shown overleaf in Figure 71. The LCOH for each of these nodes is also summarised below in Table 22.

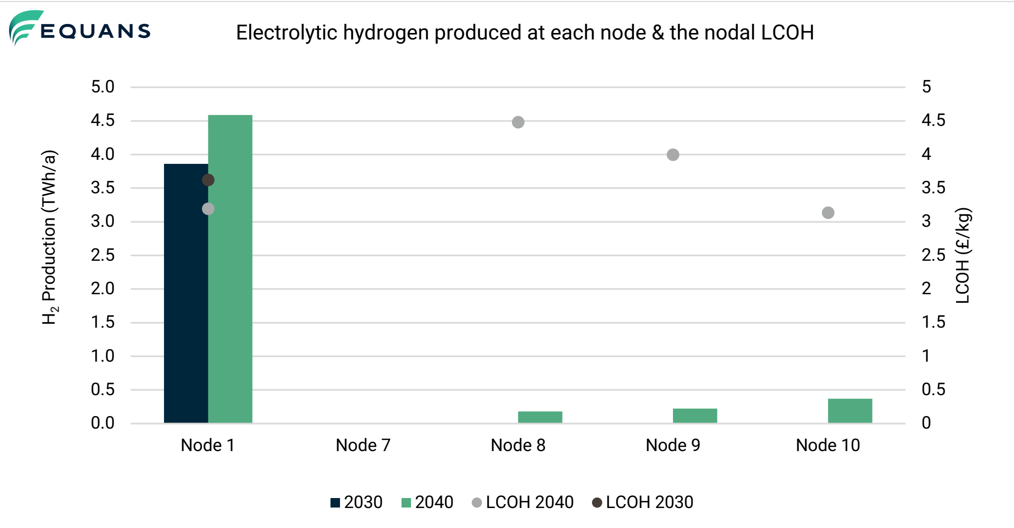

Figure 70 Electrolytic hydrogen produced at the network connected nodes in the TM decentralised bear case

Node & Year	1		7		10	
	2030	2040	2030	2040	2030	2040
Bull LCOH (£/kg)	3.0	4.5	5.4	5.8	-	-
Bear LCOH (£/kg)	3.0	3.6	-	-	-	3.3

Table 22 The LCOH for each of the nodes in the TM centralised configuration

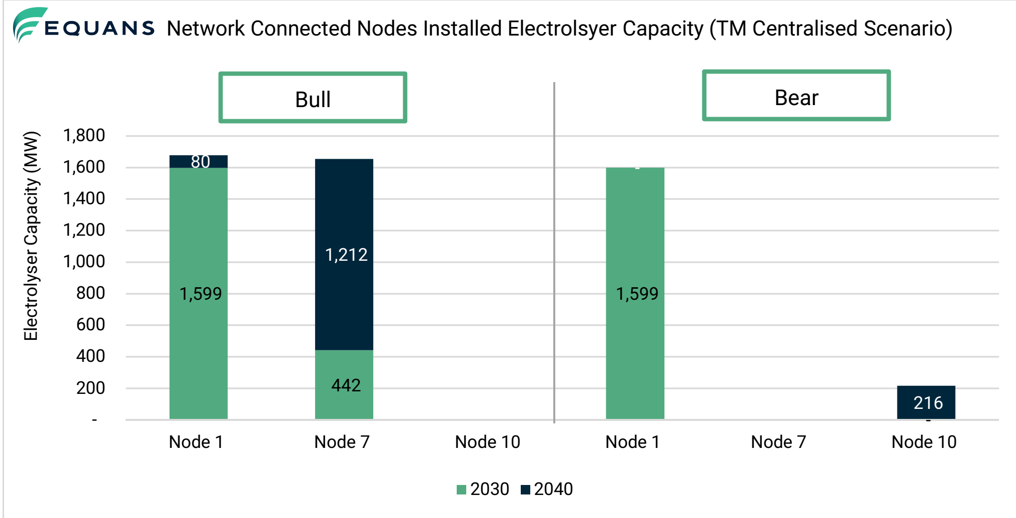

Figure 71 A graph showing the electrolyser capacity for the network connected nodes in the TM centralised scenario

Firstly, there is a clear difference between the two nodes that PROSUMER has selected in the bull and bear scenarios, opting for Nodes 1 & 7 and Nodes 1 & 10 respectively. This is driven by the significantly different electrolytic hydrogen requirements between these scenarios when a minimum of 25% electrolytic hydrogen was required.

In the bear case, we can see strong similarities with the decentralised configuration, with the majority of hydrogen being produced at Node 1. This is then supplemented by another 216MW electrolyser at Node 10. Interestingly, this meant that by 2040 1,845MW of network connected electrolysers were installed in the centralised configuration compared to 2,034MW in the decentralised case. As the hydrogen consumption requirements were the same, it therefore follows that combined utilisation factor must have been higher. The reason for this higher utilisation factor is apparent from Figure 72, where we can see that, in 2040, Node 1 uses some grid electricity to power the electrolyser in periods of low offshore wind generation. This increased from 0% grid to 9% grid between 2030 and 2040 and is the main reason for the increase in LCOH over that period.

In the TM centralised bull scenario there was also an increase in LCOH between 2030 and 2040, at Node 1 and Node 7, driven by the use of grid electricity at these nodes. At Node 1 in 2040, 22% of the total electricity was supplied from the grid and this is the reason that the LCOH is higher in the bull scenario than the bear scenario. At Node 7, 14% of the electricity requirements were met by the grid, increasing the LCOH from £5.4/kg to £5.8/kg. A graph showing the nodal electricity consumption for the TM centralised bull scenario is shown below in Figure 73.

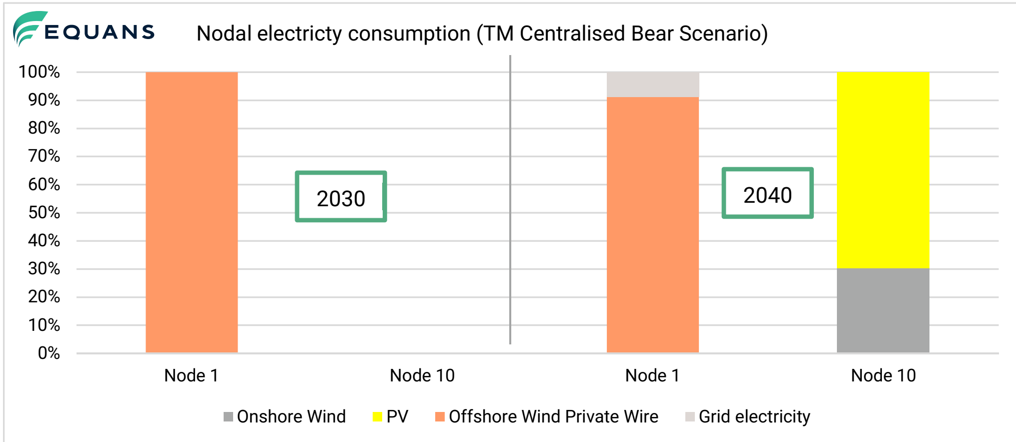

Figure 72 A graph showing the electricity consumed by each network connected node in the TM centralised bear scenario

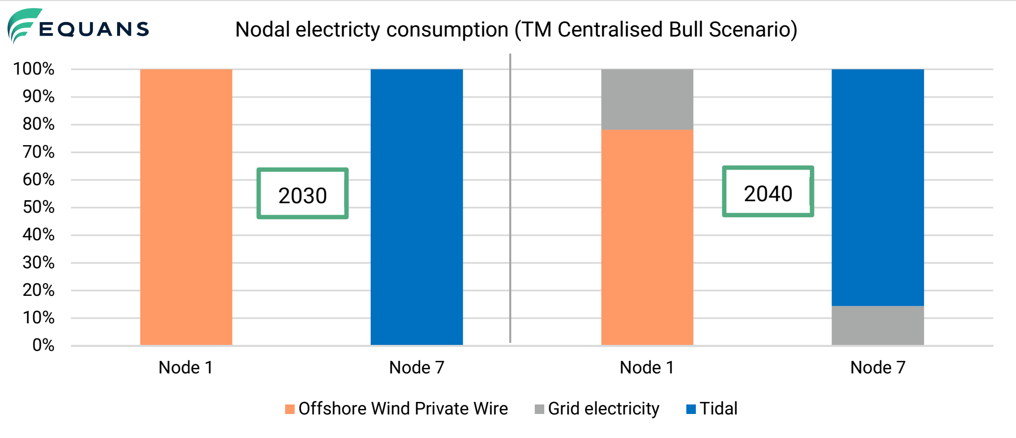

Figure 73 A graph showing the electricity consumed by each network connected node in the TM centralised bull scenario

But the addition of grid electricity is not the only interesting occurrence at Node 1 in the TM centralised bull scenario. Referring back to Figure 71, an additional 80MW of electrolyser capacity is installed in 2040 taking the total electrolyser capacity to 1,679MW. This is the first time that the electrolyser capacity at Node 1 has exceeded the maximum capacity of offshore wind private wire. In the previous simulations, there was no need to invest in extra electrolyser capacity as, with all of the electricity coming from offshore wind, the maximum demand for electricity at the electrolyser was 1,600MW. However, with the addition of the grid electricity, which was necessary to meet the 25% requirement, it became more cost effective to invest in additional capacity. This therefore allowed the electrolyser to benefit from cheaper periods of grid electricity to produce the additional hydrogen, rather than being constrained by the maximum capacity of the electrolyser. This can be seen in Figure 74 below which shows a breakdown of the Node 1 LCOH in 2040 for the TM centralised and decentralised scenarios.

As stated above, we can clearly see the influence that the grid electricity has on the LCOH, with it being the sole driver behind the higher LCOH in the centralised case. However, we can also see that the additional grid electricity enables the electrolyser to run with 10% higher utilisation factor, leading to a reduction in the electrolyser CAPEX. It therefore follows that if the electrolyser can be powered by cheaper electricity source with a consistently high load factor then this will have a positive effect on the LCOH. This is exactly what was observed at Node 4 in 2040, with the SMR plant able to produce hydrogen at a LCOH of £2.44/kg. In our simulations, the opportunity for hydrogen from SMR was fairly limited, given its location in Sellafield and therefore its inability to inject into the LTS. That said, if there was an opportunity to produce purple hydrogen within reasonable proximity of the HyNet network, then this could represent a cost-effective solution to increasing the electrolytic hydrogen percentage within the network.

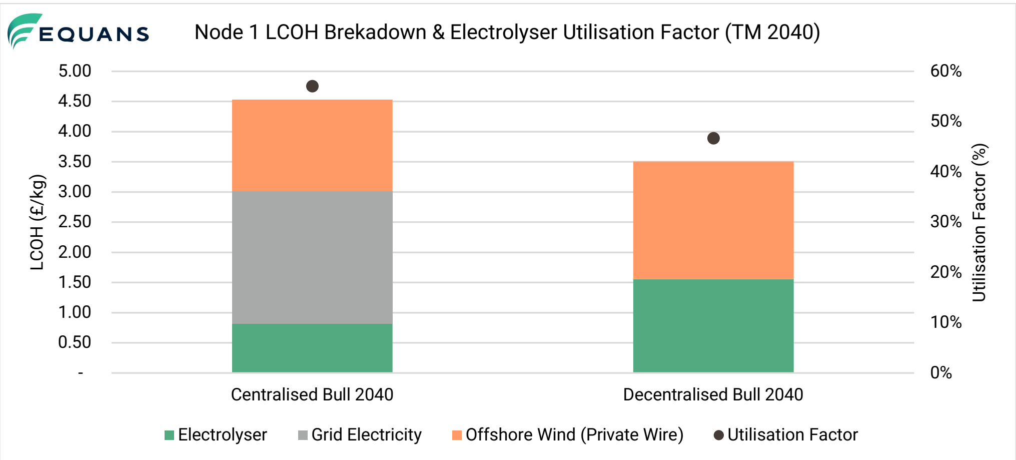

Figure 74 A graph showing the LCOH components and the electrolyser utilisation factors for Node 1 in the TM centralised and decentralised scenarios in 2040

5.3 Characteristics of Success

It was evident in Sections 5.1 and 5.2 that a large number of variables have an impact on the levelised cost of hydrogen production. Although many of these were shown to be intrinsically linked, we can also see three key themes emerging that constitute characteristics that have the greatest impact on the economic viability of electrolytic H2 production. Each of the aforementioned observations can largely be attributed to one of these themes.

In our simulations we could consistently see that the LCOH was correlated to the electricity source powering the electrolyser. For example, when the electrolyser was powered by a greater percentage of directly connected renewables the LCOH was lower and when onshore wind was dominant technology the LCOH was most attractive. This leads to the first characteristic of success to be identified; the importance of low cost electricity.

1. The Electricity Source

It is not unsurprising that the lower the LCOE, the lower the LCOH, given that electricity was shown to be primary driver of the hydrogen cost. However, we could also see that there was no single technology that could deliver the required level of electrolytic hydrogen and each technology had its drawbacks.

Onshore wind had the lowest LCOH but was limited by capacity issues. Solar PV had an abundance of available capacity, but its load factor and profile meant that it could not produce low cost hydrogen at the times it was needed. Offshore wind was scalable and relatively cheap, but its location meant that it was constrained to the areas where it could provide a behind the meter solution. Tidal power was expensive relative to other sources, but its large capacity and attractive load profile meant it was vital in the high consumption scenarios. Finally, as we moved towards 2040 and looked towards centralised solutions, we could see a strong opportunity for nuclear, with small modular reactors offering high load profiles and a competitive LCOE. These positives and negatives are summarised in Table 23 below.

Furthermore, due to the difference in availability of each of these electricity sources across the region, it is hard to draw an overall conclusion for the region. Rather, a combination of the technologies will be needed and each solution will be dependent on the local constraints. Developers will need to be cognisant of this, ensuring they have the flexibility to adapt to these factors, and this will be explored in more detail in Section 6.

Another local factor that was shown to be highly significant was the extent to which an electrolytic project was solely responsible for fulfilling the local hydrogen demand. The embedded solutions that could not benefit from network enabled flexibility had a consistently higher LCOH and therefore the second characteristic of success can be defined as the decoupling of the hydrogen demand and hydrogen production profiles.

2. The Decoupling of Demand

In Sections 5.1 and 5.2 we consistently observed the benefits of decoupling the hydrogen production with demand. Firstly, without a strict demand profile to adhere to, the electrolyser could operate in the most cost-effective way. This was most evident in Nodes 8, 9 & 10 in the NTM scenarios where the electrolyser utilisation profile was able to follow the load profile of onshore wind. This was significantly different to Node 5 which needed offshore wind, onshore wind, solar PV, SMR PPA and on-site storage to fulfil the local demand. We could therefore see that an inability to decouple production with demand led to more complex system design and operation as well as an overall LCOH increase.

Electricity Source	Positives	Negatives
Onshore Wind	+ LCOE + Load factor & profile	– Capacity
Solar PV	+ LCOE + Capacity	– Load factor & profile
Offshore Wind	+ LCOE + Load factor & profile	– Location
Tidal Power	+ Capacity + Load factor & profile	– LCOE
Small Modular Reactor	+ Load factor & profile + LCOE	– Location (short/medium term)

Table 23 The positives and negatives for different electricity sources for electrolytic hydrogen production

That said, a tiny proportion of the UK's industrial consumers will have access to network connected hydrogen and embedded solutions will be crucial for those customers wishing to decarbonise using hydrogen. It is therefore important that appropriate government support is given to these consumers to enable these sites to decarbonise, ensure their long-term competitivity and protecting local jobs. For this reason, an inability to decouple production with demand should not be seen as a predication of failure. Rather, developers will need to embrace more advanced solutions to mitigate the impact of the coupling. This could involve additional on-site storage, blending into the national gas grid or aggregating multiple consumers at one location to dampen the peaks and troughs of demand.

These mitigating factors demonstrate the requirement to maintain a holistic view of the region and to engage with multiple stakeholders. This leads on to the third characteristic of success; the importance of coordination in the development of electrolytic hydrogen projects.

3. Coordination is Crucial

Our approach to modelling allowed us to take a holistic view of the region and highlighted the interdependence of the region's infrastructure, as the proposed HyNet hydrogen network was able to connect disparate consumers within the North West Industrial Cluster. This dedicated hydrogen network creates flexibility within the region, allowing comparatively low-cost green and CCUS enabled hydrogen to be transported to consumers. Due to the LCOH benefits of injecting into this network, it is important that developers continue to coordinate with HyNet to ensure the regional system delivers the greatest benefit to consumers. Furthermore, given the significant electrolytic capacity in the Target Mix scenarios, coordination will be needed between the electricity transmission/ distribution network operators to ensure capacity is deployed in a way that minimises network upgrade costs.

This large capacity also necessitates the requirement to coordinate developments with other electricity consumers to minimise the risk to the region's energy security.

Alongside coordinating with these wider energy system stakeholders, the importance of coordinating hydrogen developments alongside other on-site decarbonisation initiatives was evident. In Node 5, when curtailed electricity could be used to meet other local electricity demand, the LCOH was seen to reduce by over 25%, highlighting the importance of taking a multi-vector approach to decarbonisation. Furthermore, in the centralised scenarios we could see the benefits associated with coordinating multiple consumers. The aggregation of demand was shown to reduce the LCOH, even when moderate road transportation costs were required. This was caused by the dampening of the demand peaks, reducing the system CAPEX, as well as enabling the development of electrolysers in more attractive locations, such as alongside dedicated small modular reactors.

However, despite these benefits, there will be technical and commercial challenges associated with delivering on these characteristics of success. Developers must be able to balance these success characteristics alongside their real world implications. These considerations are discussed in Section 6 in the context of electrolytic grid injection projects and embedded hydrogen solutions for industry.

6. Development considerations

Section 5 has articulated the scalability for electrolytic hydrogen in the North West of England and North East Wales and demonstrated the opportunity to optimise system design to minimise LCOH in the region. However, alongside the obvious opportunities, it is also clear that there is inherent complexity associated with developing these projects.

There is currently no tangible market for low carbon hydrogen and little precedent for using it as an industrial fuel. EQUANS' Industrial Consumers Report explores the most relevant R&D projects associated with the latter and how these are relevant for the region, however the conclusions remain that early hydrogen project developers will also be market makers. This is inherently different to previous decarbonisation initiatives, such as embedded renewables, where there was already an established market for electricity. Developers, therefore, need to work closely with off-takers, supply chains and other stakeholders to minimise project delivery risk and ensure that industrial consumers have the necessary confidence in the sector, to make investments and long term decisions to convert some or all of their operations to low carbon hydrogen. Furthermore, given the current cost of producing hydrogen compared to fossil fuels, developers will also need to be aware of how different public support mechanisms can be used to commercialise these projects and bring societal benefits. This section will examine these considerations for an electrolytic hydrogen grid injection project within the HyNet area and an embedded green hydrogen project for industry.

6.1 Electrolytic Hydrogen Grid Injection

HyNet was announced as a Track 1 project in the Cluster Sequencing Process in October 2021: a strong show of support for networked hydrogen in the region. This announcement was a huge boost to the industrial consumers seeking to decarbonise through this initiative; consumers around the Ellesmere Port area could have access to this network connected low carbon hydrogen as early as 2025. This project has the potential to abate millions of tonnes of CO_2 in the North West and underpin widespread decarbonisation in the region.

That said, CCUS enabled hydrogen is not universally supported as a long term industrial decarbonisation solution, primarily due to the fact it is derived from fossil fuels and the uncertainty around some aspects of large scale CCUS. Emissions still remain from the extraction and transportation of methane and 3-5% of the emissions are not captured during the reformation process. These residual emissions, as well the continued use of fossil fuels, means that large scale CCUS enabled hydrogen deployment is somewhat controversial. However, there are also its proponents who argue that CCUS enabled hydrogen is a valuable transition fuel and the only way to produce significant volumes of low carbon hydrogen in the short term; underpinning the development of hydrogen networks and kickstarting the hydrogen economy.

However, these concerns should not be overlooked and there are socio-political benefits to encouraging the injection of electrolytic hydrogen into network and as we saw in Sections 5 and 5.2, in some circumstances, there can also be economic advantages. This was observed in Nodes 8, 9 & 10 where electrolytic hydrogen offered a more cost-effective solution than CCUS enabled hydrogen in the NTM scenario. This section will summarise the key considerations associated with electrolytic blending projects in the region based on the outputs of our technoeconomic modelling.

In our modelling, the lowest LCOH was achieved when an electrolyser was directly connected to onshore wind and able to blend into the HyNet network. At less than £2/kg, this green hydrogen was highly competitive and selected in all of our modelled scenarios. However, only 75MW of electrolyser capacity was installed that was capable of producing hydrogen at that price, due to limited opportunities to develop onshore wind near the network. This suggests that this configuration is unlikely to be a scalable option to materially increase the percentage of electrolytic hydrogen within HyNet. However, it is worth noting that our maximum onshore wind constraint may be conservative given the requirement for an electricity grid connection was factored into its derivation. If the wind farms could connect directly to an electrolyser, without a grid connection, this could potentially open up previously dismissed areas for development. Developers looking to optimise LCOH for green hydrogen in the region could therefore conduct deeper analysis on onshore wind potential within close proximity to HyNet.

Another option for producing green hydrogen, presented earlier in this report, would be to connect the electrolysers to offshore wind turbines at the onshoring location and behind the meter, as was modelled in Node 1. In the TM scenarios this was the most cost-effective way to produce large volumes of electrolytic hydrogen and around 1.6GW of electrolyser capacity was installed with this configuration in these scenarios. Although this green hydrogen was more expensive than the CCUS enabled hydrogen in the base case, this was driven by the low gas prices at the time of modelling. Increases in the wholesale gas price could significantly shift the dynamic, as was observed when we compared the LCOH of offshore wind hydrogen (£3.57/kg) to CCUS enabled hydrogen using the October 2021 natural gas price (£4.10/kg). In this case, a saving of £0.53/kg was observed for the green hydrogen versus the CCUS enabled hydrogen. Electrolytic hydrogen also has the potential to provide longer term price certainty and act as a hedge against wholesale gas prices.

However, in our modelling, we did not assume competition from other electricity consumers for the greenfield offshore wind capacity and there may be challenges for electrolytic hydrogen developers in securing the necessary capacity. The typical, proven route to market for new offshore wind farms is via a Contract for Difference (CfD), with long term price certainty guaranteed. Renewable developers would be looking for a similar level of offtake and price certainty to be convinced to opt out of the CfD and to contract with an electrolyser developer instead. The Industrial Decarbonisation and Hydrogen Revenue Support Scheme (IDHRS) is expected to provide long term revenue certainty for hydrogen producers, similar to that of the power CfD and offshore wind power producers could therefore potentially secure long-term contracts, by proxy, through this mechanism. This may also allow reduced network connection costs, creating additional economic value for these offshore wind developments.

Furthermore, in our modelling, we focussed our analysis on greenfield renewables capacity and did not allow hydrogen to be produced from existing assets. In reality, there is currently approximately 2.7GW of existing offshore wind capacity in North West England and North East Wales. These legacy projects are currently supported by CfDs or the Renewables Obligation, however some of these contracts are set to end in the mid-late 2020s. Following the end of these contracts, and assuming the turbines are in good working order, these legacy turbines could potentially be used to power the electrolysers, potentially offering a competitive LCOE. At the time of writing, it is uncertain as to whether this arrangement would be supported through the IDHRS or whether additional capacity will be a requirement to secure this mechanism.

Finally, the use of curtailed offshore wind in North West England and North East Wales may present a development opportunity. In 2020, approximately, 3.6TWh of offshore wind was curtailed in the UK, primarily due to network constraints. [16] If electrolysers were connected to the assets behind the meter, then this could help reducing this curtailment. That said, these electrolysers would not be economically viable if they are solely reliant on curtailed electricity and a dedicated power source would also need to be considered. Developers should look at how other renewable energy sources, such as solar PV or a tidal private wire, could be connected to the electrolyser at the onshoring location. It is also worth noting that electrolysers will need to compete with electrical storage to be selected as the preferred solution for reducing curtailment.

Our modelling was completed on the 2030 to 2040 timeframe, however some of the aforementioned development opportunities could be deployed in the short term and commence operations in parallel with HyNet. A longer term opportunity was seen with respect to purple hydrogen, produced via electrolysers connected to small modular reactors. These SMR's have a high load factor, which is ideal for electrolytic hydrogen production. In our modelling, we limited the location of the SMR to the existing Sellafield site, meaning that injection into HyNet was not possible. However, if the technology is successfully deployed, it is possible that more locations will become available and that co-location with electrolysis and grid injection may be possible, unlocking a significant opportunity for large volumes of electrolytic hydrogen.

6.2 Embedded Green Hydrogen for Industry

If we were to simply compare the LCOH for a typical embedded project to a typical grid blending project, the obvious conclusion would be that embedded projects have a higher LCOH, with the blending projects significantly cheaper in all of the scenarios presented in Sections 5 and 5.2. This is because grid blending projects allow the dissociation of production with demand, enabling electrolysers to run in the most cost-effective manner. Also, as they are not constrained by customer location they can be situated in locations with an abundance of local renewable energy sources. However, grid blending projects do have a fundamental locational restraint as they are wholly dependent on the availability of a hydrogen network. This is a major challenge as, for the majority of industrial sites in North West England and North East Wales, or the UK in general, this is not a reality in the short or medium term.

The challenges regarding availability of networked hydrogen in the short/medium term are personified in the region. Although consumers around the Ellesmere Port area could have access to network connected low carbon hydrogen by 2025, other consumers in North West England and North East Wales will need to wait significantly longer before they are connected to a hydrogen network. Additionally, those in Lancashire and Cumbia are unlikely to receive a connection based on current proposals. In order to support these local jobs and communities, and to deliver on the Government's levelling up agenda, it is vital that industrial consumers in these areas are given the opportunity to remain competitive, with deliverable decarbonisation options.

For progressive industrial consumers in non-network connected areas, with a short or medium term Net Zero commitment, an embedded hydrogen project could offer a viable decarbonisation solution. As highlighted by the Node 5 modelling, an embedded hydrogen project can become cost competitive under the right conditions. This section will highlight some of the key considerations that must considered when developing an embedded hydrogen project.

The first consideration in any embedded hydrogen project should be the availability of land for the electrolyser and system components, either on the industrial site or in close proximity to the consumer. This is important as electrolysers are not insignificant in size, with the UK Government's Hydrogen Supply Chain evidence base (2018) suggesting that footprints range from 0.11m2/kW for a PEM electrolyser to 0.2m2/kW for an alkaline electrolyser. [12] For a 5MW project, this would equate to an area of 550 – 1,000m2. That said, ITM Powers' HGas3SP electrolyser has a rated power of 2.35MW and comes in 1x 20ft & 1x 40ft ISO containers, giving a footprint of 0.02 m2/kW. This demonstrates how quickly this sector is innovating and that this space constraint may be less of an issue in the future. Alongside this, it is also important to ensure that the electrolyser is close to the consumer as this will reduce the infrastructure costs associated with piping the hydrogen from the point of production to the point of consumption.

Secondly, the availability of resources at the location are another critical consideration, with resources defined as the input requirements to an electrolyser (i.e. water and electricity). Ensuring that the site has suitable access to a viable water source is therefore a vital part in any feasibility study. It also requires whole systems thinking and engagement with the regulated water businesses in the region. The other critical resource is electricity and, as we saw in Sections 5 and 5.2, there is a strong correlation between the percentage of the electricity sourced from on-site production and the LCOH. An ideal site would therefore have strong renewable electricity production potential, in particular from onshore or offshore wind. Although it is advantageous to source the majority of electricity in this way, and avoid network costs, there are likely to be periods when grid connected electricity is required. For this reason, the ideal site would therefore also have sufficient spare network capacity. The potential impact on the distribution network is being analysed by SPEN as part of this consortium research project.

The availability of land, and the network capacity, are both linked to the wider security of supply considerations. When converting a proportion of their operations to run on hydrogen, industrial consumers are likely to require contractual assurances to ensure that hydrogen is available when it is needed. This means that developers must ensure the system is designed to meet the relevant security of supply constraints. Although our electrolysers were given an availability factor, this was not modelled as extended periods of unavailability and therefore the electrolyser production and hydrogen storage capability were sized to meet the demand profile in the most cost-effective manner. In reality, the system needs to be designed to account for unforeseen circumstances, such as extended periods of low wind or a ramp of industrial activity, to ensure security of supply. Once projects are live, this risk would be managed commercially, but it is an important consideration during the design phase to develop consumer confidence. If available, a suitable electricity connection could help minimise this risk, otherwise additional on-site storage (either electrical or hydrogen) may need to be factored into the design, depending on the contractual position between developer and off-taker.

Another important metric to consider when assessing security of supply and overall system design is the load shifting capability of the consumer.

Electrical load shifting is not a new concept and is widely used to avoid peak electricity charges, however gaseous load shifting is a far more nascent concept. As developers look to develop hydrogen solutions, they should work closely with their industrial partners to understand if it is feasible to factor this flexibility into the design as part of a least cost solution.

Developers should also take a whole systems approach to designing the hydrogen production system to minimise the LCOH. As we saw in Section 5.1.1 there are significant financial benefits that can realised if curtailed electricity is able to be used on site. It is therefore important that the hydrogen developer has a wider understanding of the other energy demands on site. This allows the hydrogen production system to be part of a wider multi-vector decarbonisation solution, ensuring each kWh produced on-site is fully utilised. The opportunity of this should not be overlooked, highlighted by the fact that using curtailed electricity was observed to save 23% on the LCOH for the analysis for Node 5 in Section 5.1.1. Alternately, if the electrolyser producer can blend into the gas grid at the production site, this could reduce curtailment and improve the economic viability of the project.

Furthermore, as we saw in in Sections 5.1.2 and 5.2.2, cost reductions can be realised when multiple consumers are served from the same production facility. This centralisation allows for a slight decoupling of production with demand, adding more flexibility in the operating regime demanded of the electrolyser. Although it brings additional commercial complexity, it will be worthwhile exploring other local markets for hydrogen, across all markets, when developing hydrogen projects.

Serving additional consumers is just one a suite of measures that can be used to reduce the total cost of ownership of a hydrogen production system and commercial optimisation will need to be at the forefront of a developer's strategy if seeking support under a competitive incentive mechanism, such as the IDRHS.

Alongside the IDHRS, developers should be aware of the other public support mechanisms that can help de-risk the projects. At the time of writing, the two most relevant initiatives are expected to be the Industrial Hydrogen Accelerator (IAH), the Net Zero Hydrogen Fund (NZHF) and the Industrial Energy Transformation Fund (IETF). The first two are expected to provide CAPEX support to reduce development risk; the IETF can help consumers with fuel switching initiatives. Just like the aforementioned design considerations, it is important that developers are aware of these schemes and are experienced in supporting their customers in applying to these programmes, to ensure consumers are able to decarbonise at least cost.

With all of these measures considered, it is expected that an embedded hydrogen project offers a credible decarbonisation option for industrial consumers in the North West, particularly those without networked access to hydrogen in the short term.

7. Final conclusions

The UK Hydrogen Strategy states that 'low carbon hydrogen will be essential for achieving net zero' and this is substantiated by the Net Zero North West Cluster Plan project. With the largest concentration of advanced manufacturing and chemical production facilities in the UK, low carbon hydrogen has been assessed as fundamental in the region's zero carbon transition. Historically, CCUS enabled hydrogen has dominated the discourse in the region due to the substantial carbon savings that HyNet could deliver. However, this report has highlighted the opportunity for electrolytic hydrogen, both integrated with the HyNet network and distributed on industrial sites, demonstrating that it has the potential to abate up to 2.7Mt CO_2e/a by 2040.

Electrolytic projects were categorised into two solution types: Electrolytic Hydrogen Grid Injection and Embedded Green Hydrogen for Industry with both of these presenting different decarbonisation opportunities. The grid blending projects were the most cost effective solutions and, in some circumstances, achieved cost parity with CCUS enabled hydrogen. Their centralised nature created scalability, allowing significant volumes of zero carbon hydrogen to be injected into the HyNet network. This reduced the overall carbon factor associated with grid hydrogen and the requirement for negative emission technology to offset the residual CCUS enabled hydrogen emissions. The embedded green hydrogen solutions were naturally decentralised and were accessible to individual industrial consumers across the region. By providing a credible decarbonisation solution for those not connected to HyNet, such solutions could be a valuable asset in ensuring the long term stability of industry in the region.

However, the work also highlighted the complexity associated with optimising hydrogen projects and how local factors can greatly influence the LCOH. Coordinating developments, incorporating flexibility and maximising directly connected renewables were identified as three Characteristics of Success for electrolytic projects, encompassing the numerous intricacies that predicate good design. The success of a hydrogen project is a function of these and other local factors, which should be considered early in a project's life to ensure the most attractive projects are prioritised for development and the region follows a cost effective transition path.

It is evident that government intervention will be necessary to support the development of the commercial models that would underpin any electrolytic projects in the region. Support is expected through the Net Zero Hydrogen Fund and Industrial Decarbonisation and Hydrogen Revenue Support Scheme however, at the time of writing, the specifics of these funds are not known. This report has highlighted the requirement for flexibility in these measures to ensure they are accessible and appropriate for all industrial consumers who are seeking to decarbonise. If the appropriate business models emerge and developers embrace coordinated, whole system design, this report has demonstrated that electrolytic hydrogen has a clear role to play in enabling the North West of England and North East Wales to become the world's first zero carbon industrial cluster.

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8. Nomenclature

ATR – Autothermal Reforming

BS – Balancing System

CCUS – Carbon Capture Usage and Storage

CfD – Contract for Difference

CM – Capacity Market

DfT – Department for Transport

DUoS – Distribution Use of System

ETS – Emissions Trading Scheme

FES – Future Energy Scenarios

FiT – Feed in Tariff

GDN – Gas Distribution Networks

H2GTs – Hydrogen Gas Turbines

IETF – Industrial Energy Transformation Fund

IDHRS - Industrial Decarbonisation and Hydrogen Revenue Support

IHA – Industrial Hydrogen Accelerator

LCOE – Levelised Cost of Electricity

LCOH – Levelised Cost of Hydrogen

LSOA – Lower Super Outputs Areas

LTS – Local Hydrogen Transmission System

NTM – No Target Mix

NZHF – Net Zero Hydrogen Fund

NZNW – Net Zero North West

PPA – Power Purchase Agreement

RES – Renewable Energy Sources

RO – Renewables Obligation

SMR – Small Modular Reactor

TCO – Total Cost of Ownership

TM – Target Mix

TUoS – Transmission Use of System

9. Table of figures

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11. Appendix

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Technology	Parameter	Unit	2030	2040	Source/comment
Alkaline electrolyser	CAPEX	GBP/kW	245.5	127.2	IEA – The future of hydrogen, includes equipment costs and balance of plant
	OPEX	GBP/kW/y	3.7	1.9	IEA – The future of hydrogen
	Total CAPEX	GBP/kW	712.7	356.4	Internal intelligence – includes equipment cost, BOP, contingencies, owners costs, OSBL, others
	Grid connection costs	GBP/kW	47		Internal intelligence – Based on average costs of grid connection of projects in the UK
	Stack replacement costs	% CAPEX	20		Internal intelligence
	Consumption	kWh/kg H2	48	47	IEA – The future of hydrogen
	Stack lifetime	Years	10		Internal intelligence
	Electrolyser lifetime	Years	20		IEA – The future of hydrogen
Solar PV on-site	CAPEX	GBP/kWp	467.5	346.8	GOV.UK official statistics
	Fixed OPEX	GBP/kWp/y	9.9	9.9	Lazard (2020)
	Yearly degradation	%/year	0.5	0.5	NREL
	Lifetime	Years	30	30	Lazard (2020)
Wind on-site	CAPEX	GBP/kWp	626.6	509.1	GOV.UK official statistics
	Fixed OPEX	GBP/(kWp/year)	28.8	28.8	Lazard (2020)
	Lifetime	Years	20		Lazard (2020)
Battery storage	CAPEX	GBP/kW	129.9	110.4	PWC
	CAPEX	GBP/kWh	155.8	129.5	PWC
	Fixed OPEX	GBP/(kWh/year)	3.0	2.5	BNEF
	Lifetime	Years	10.0		Internal intelligence
H2 tank storage	CAPEX	GBP/kg H2 stored	438		USDOE
	Total CAPEX	GBP/kg H2 stored	876		Internal intelligence – includes equipment cost, total installed cost (materials, works, engineering, others)
	Pressure	bar	250		USDOE
H2 cavern storage	Maximum capacity	t H2 working gas	1,300.0		Based on cavern in Cheshire – Hysecure project

Figure 75 Technology assumptions

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Origin node	Destination node	Distance (km)	N° Trucks (350 bar, 784 kg) Bull 2030	Bull 2040	Bear 2030	Bear 2040	Cost trucking – GBP/kg H2 (350 bar) Bull 2030	Bull 2040	Bear 2030	Bear 2040
Node 4	Node 5	55	7	10	1	-	0.54	0.52	1.21	-
Node 4	Node 6	160	21	33	1	7	0.70	0.69	1.72	0.69
Node 5	Node 6	115	17	27	1	6	0.64	0.61	1.68	0.61
Node 10	Node 11	15	24	81	20	99	0.47	0.46	0.47	0.46
Node 10	Node 12	60	14	23	-	-	0.55	0.53	-	-

- The costs of truck transport have been calculated using the H2 transport model of Engie Impact Chile
- The number of trucks represents the trucks that need to be in continuous operations and they can be in any 5 states: loading H2, moving from production to demand site, unloading, moving from demand to production site, or unavailable.
- The trucking costs include the following assumptions:
  - Truck and local storage CAPEX and OPEX: confidential, based on market quotations
  - Availability: 20 h/day, 7 days per week, 365 days/ week
  - Truck efficiency: 3.69 km/L of diesel
  - Truck lifetime: 5 years
  - Trailer/tank lifetime: 20 years
  - Cost of diesel: 1.9 GBP/L
  - Driver wages: 20 GBP/driver/h

Figure 76 Trucking costs for the centralised configuration

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