Hydrogen Electrolyser Study

Reassessing Approaches to Connecting Large Electrolyser Sites: Work Package 1

National Grid Electricity Distribution

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→ The Power of Commitment

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The Power of Commitment

Executive Summary

This report is subject to, and must be read in conjunction with, the limitations set out in section 1.2 and the assumptions and qualifications contained throughout the Report.

Hydrogen is considered a key part of the challenge to meeting UK's net zero targets by 2050, with the Government targeting 10 GW of low-carbon hydrogen production by 2030. Half of this hydrogen is expected to be produced via electrolysis (HM Government, 2022), which means adding a sizeable amount of demand to electricity networks.

NGED contracted GHD to study the impact, the opportunities and the challenges of electrolyser deployment across NGED's network region, which includes the South-West, South-Wales, East Midlands, and West Midlands. This study is split into three different work packages and this report presents the findings of Work Package 1: Discovery and Criteria Development. The study will inform NGED on the issues and challenges to be addressed while creating the mechanisms that will enable value to be captured from electrolyser integration in NGED's network area in the next decade. The report is split into five main chapters, with the first chapter being an introduction to this study with an outline of how the study was conducted.

The second chapter presents a high-level summary of the National Grid ESO future energy network scenarios; looking at the impacts of an increased penetration of renewables, and the implications on NGED's network area. This section also analyses NGED's network development plans in the next decade, which will provide context for some of the opportunities and challenges that electrolytic hydrogen production may be able to address.

The third chapter looks at electrolytic hydrogen production and network implications for connecting electrolysers. This section presents the opportunities for electrolytic hydrogen production in the UK, with focus on the role electrolysers can play in enabling grid service provisions, specifically grid constraints management and long duration energy storage services, as well as the challenges electrolyser connection can present to a DNO.

The fourth chapter looks at the status of UK hydrogen projects, the requirements, and implications of the Low Carbon Hydrogen Standard (LCHS). It also provides a set of criteria that can be used for site optimisation of future electrolytic hydrogen projects. Furthermore, this chapter analyses the current and project CO_2 grid intensities, which will play a vital role in the uptake of electrolysers. In the fifth Chapter we present key Insights from project developers on grid connection of electrolysers. Finally, in the sixth chapter we present our conclusions and recommendations to NGED.

NGED's network: scenario modelling, RES connections & network plans

This study shows that NGED's network will be experiencing an increasing number of constraints in all National Grid ESO Future Energy Scenarios across its network. NGED's best view scenario shows that network constraints can increase by about 40% in the Southwest, double in East and West Midlands and more than quadruple in South Wales between 2025 and 2032 alone. NGED currently has five different ways to alleviate the projected constraint: Conventional Reinforcement; Strategic Reinforcement; Operational Mitigation; Load Management; and Flexibility Schemes. Electrolytic Hydrogen production can be part of all these schemes and could be used to lower network reinforcement costs in the last three schemes above.

Electrolytic hydrogen Production & Network Implications

Both alkaline and polymer electrolyte membrane (PEM) electrolysers can be used for providing balancing services to the grid through the Power-to-X[1] mechanism, including stability, frequency regulation, black start, short term reserve, fast reserve, upgrade deferral, energy arbitrage, capacity firming, seasonal storage, voltage support and islanding. However, batteries are predominantly used in most markets for balancing services, especially those with short activation times. Based on their fast response (seconds) and lower cost, the dominance of batteries in the Frequency Containment Reserve (FCR) markets is expected to continue, making it very challenging for electrolysers to compete with batteries in the provision of Frequency Restoration Reserve (FRR). Two areas in

[1] Here X denotes power, such that hydrogen is produced using electricity, stored and reconverted to power when needed through a fuel cell or combustion process (e.g. future combined cycle gas turbines using H2). X can also denote H2 gas stored and used in non-power applications (such as fuel for transport and gas for heat).

which electrolytic hydrogen production (Power-to-X mechanism) can potentially enable network benefits are constraints management and seasonal storage.

Electrolytic hydrogen production, using surplus renewable energy at times of low demand and high renewable energy supply, can avoid shutting off wind generation (curtailment), which cost the taxpayer £507million in 2021 (Renewables Now, 2022). There is much uncertainty in the level of electricity curtailment expected by 2050, the National Grid ESO 2022 scenarios show 45TWh in the Consumer Transformation scenario, 37TWh in Leading the Way, 21TWh in System Transformation and 4.5TWh in the Falling Short scenarios by 2030. Some estimates show that wind curtailment alone in the UK may cost the end user £1 billion per year by 2025 (Renewable Energy World, 2021).

While increasing levels of battery storage can help reduce electricity curtailment levels (arising from network constraints) and hence these costs, there is a need to better understand the economic and temporal value of electrolytic hydrogen production across different network regions. In this regard, further work is needed to understand the impact of electrolytic hydrogen production as part of NGED's upgrading strategy assessment for the next decade.

Hydrogen is considered as a competitive solution for long duration energy storage, specifically for seasonal fluctuations in energy supply and demand (for both electricity and gas networks). In the UK electrolytic hydrogen production is increasingly being considered to capture this value stream in the long run, with increasing penetration of renewables and decreasing volume of strategic gas reserves. Companies looking at producing hydrogen at large scale are starting to look at the potential for large scale geological hydrogen storage (salt caverns) in the UK, thus this consideration could have implications for where electrolysers will be placed in conjunction with renewables, unless a hydrogen gas network is built.

Hydrogen can also deliver clean firm power generation and peaking power which are valuable functions within the energy system, especially as we transition to more renewables. The use of hydrogen in gas power plants (CCGT or OCGT) is considered for peaking plants to complement the deployment of renewables. In fact, UK based companies are already making peaking plants that can be converted from using natural gas to hydrogen at a later stage. A US study looking at the cost of meeting seasonal imbalances, using least cost of energy approach (LCOE), show that the LCOE associated with meeting seasonal energy imbalances is $2,400 per megawatt hour (MWh) using a hydrogen-fired gas turbine, compared to $3,000/MWh using a lithium-ion battery system. If a gas turbine is fired with "blue" hydrogen, that is, hydrogen produced by reforming natural gas, the average LCOE decreases to $1,560/MWh (Hernandez & Gencer, 2021). Such assessments are needed for the UK, for DNOs to see the value of hydrogen storage as a method for managing seasonal imbalances.

UK Hydrogen Projects: status, LCHS, site optimisation criteria

Given that there will be an increasing number of electrolytic hydrogen projects in the UK, NGED needs to conduct further work to better understand the economic and temporal value of electrolytic hydrogen production as part of their upgrading strategy assessment to overcome network constraints in the next decade. In this regard we looked at the status of planned hydrogen production projects in the UK, based on publicly available data, and we found that the total peak production capacity for electrolytic (green) hydrogen projects is about 3.3 GW by 2030, compared to 8.4GW from CCS enabled (blue) hydrogen production projects by the same time. These projects, if they go ahead, amount to about 11.7GW of hydrogen, exceeding the UK's target of 10GW by 2030. In NGED's network area the main projects include the DelpHYnus project, in East-Midlands and is projected to produce 1.8GW of blue hydrogen. The largest potential electrolytic hydrogen project is RWE Pembroke, which aims to install 0.1GW capacity.

At this stage about 30% of the planned capacity (as publicly announced and captured in this study) is from electrolytic hydrogen, which falls short of the at least 50% targeted by the Government. This indicates that there are barriers to the growth in electrolytic hydrogen projects. While the cost of electrolytic hydrogen production today (ranging from £100-150 MWh hydrogen HHV), is higher than the cost of Carbon Capture and Storage enabled hydrogen production from natural gas (£50-60 MWh hydrogen HHV), is one of the main reasons, the added challenges of getting access to large amounts of electrical energy (whether dedicated RES or grid connection) appears to be another reason.

This Government's (BEIS's) Low Carbon Hydrogen Standard (LCHS), (20g CO_2 equivalent per MJ LHV Hydrogen or less) is another important consideration, and potentially a barrier for grid connection of electrolysers today. Those projects seeking government funding and development support need to adhere to this standard. Given most of the major projects will be seeking government support and will depend on government funding to go ahead, the CO_2 intensity of the network electricity will be an important factor for those looking at network connection. It is therefore important for NGED to provide transparency on the carbon intensity of their network over time. Today, electricity from the grid would not meet the threshold of this standard in most regions on most days in the UK. It is projected that by 2030 the CO_2 equivalent emission intensity would be around 90gCO_2e/KWh (324 gCO_2e/MJ) in the 2019 Energy and Emissions Projections (Energy and Emissions Projections).

Therefore, developers would not be able to access government funds under the Hydrogen Business Model, if they were exclusively connected to the grid, in many areas of the UK (including NGED's network region). This means many projects will need to have agreements to use low carbon energy sources (i.e. renewables or nuclear) to ensure the hydrogen produced has a CO_2 intensity below the threshold set out in this standard. In fact, any project that applies for these funds are subject to an additionality requirement, which is a criterion put in place to uphold the principles of the LCHS. This additionality criterion requires the electricity used for hydrogen production is from new low carbon electricity generation, such that low carbon electricity is not diverted from other users, avoiding negative impacts on wider decarbonation" (BEIS, 2022). Under this additionality criterion, projects are assessed against preferred sources of energy as below (BEIS, 2022): new purpose-built, curtailment of existing assets, extension of the life of existing assets and recommissioned assets. This suggests there will be an increasing number of Power Purchase Agreements between renewable energy source project owners and electrolyser project owners, and NGED will need to prepare for this.

As part of this study a set of site selection criteria was developed for NGED to use in the process of identifying the most optimal site for connecting an electrolyser to NGED's network, based on a set of conditions provided by a project developer applying for a connection. This excel based site optimisation tool is developed as part of this first work package, with some of the key with different network and non-network considerations discussed in the body of this report and listed in Appendix C. This tool, which has a scoring system, is developed with the objective of streamlining the application process of a project developer for NGED to select and advise on a set up sites based on the ranking (score) obtained from the tool.

Insights from Project Developers and Electrolyser OEMs

As part of this study, to better understand the process developers have gone through in their application to NGED for connecting electrolysers we have spoken to several project developers, in addition to conducting a survey to inform key sections of the report. We have identified some common themes in what is important for project developers as well as common challenges experienced by them. These are summarised as below:

Technical & Economic Challenges:

- Developers have reported having issues securing connections and challenges in identifying grid capacity to access.
- Many of the available load demand sites on the network are being taken by battery energy storage projects, and some cases EV charging or heat pump connections. Any synergies with electrolyser and battery co-location needs to be further investigated. Most battery storage operators prefer to have flexible contracts that do not constrain their level of operation.
- Developers foresee increasing challenge in finding capacity and connection limitations, with high cost and competition for sites.

Process Challenges (relating to new Connections):

- The timelines for both BEIS and DfT hydrogen projects to start operation (2025) do not align with the timelines for getting grid connection, which in some cases can take up to five years.
- It is a slow process to identify sites that are feasible to connect to on the network, and costs are very high. It would be good to have easier access to information on targeted for the needs of project developers on where the best electrolyser connection sites are for NGED.
- DNOs should engage with the hydrogen community and project developers at an early stage to work collaboratively in order to develop suitable solutions. To realise the benefits of electrolyser connections more open engagement is needed between DNOs and green hydrogen project developers.

- A centralised and independent body, e.g. a government formed entity or OFGEM, can create a mechanism for engagement, to ensure the role of hydrogen is realised at the system level (e.g. to help address grid constraints along with batteries) and to ensure there are no barriers in meeting the Government's electrolytic hydrogen targets due to DNO's processes and technical challenges.

Regulatory Challenges:

- If there are areas, like South Wales, where the government wants to see projects, there needs be a more comprehensive infrastructure building programme instead of piece meal solutions. Therefore, BEIS needs to be more joined up with NGED and other DNOs to ensure there are no barriers for the UK to meet its electrolytic hydrogen production target of 1GW by 2025 and 5GW by 2030. To reach this capacity or to ensure security of supply for industrial users, grid connection will be required.
- The Government's Low Carbon Hydrogen Standard of 20g CO_2e/MJ LHV creates challenges for developers as currently the GHG emissions intensity of the network is higher than this in most areas, including NGED's network areas on many days of the year.
- More clarity is needed on the CO2 intensity of the grid at more regional level (not just with 30 mins temporal resolution), as this is important for project planning and development for projects seeking government funding.

Ways to incentivise grid connection of electrolysers:

- Reducing the impact of non-energy costs and variable tariff provisions are considered important.
- Variable and interruptible tariffs would make grid connections more feasible. The DNOs advising a suitable operating regime and demand side response schemes would also help
- While electrolysers can be operated to avoid breaching a demand constraint, appropriate mechanisms (contracts) will be required to incentivise operators to produce electrolytic hydrogen in a way that benefits them and the DNO, while avoiding network constraints. Such mechanisms including Time of Use tariffs, Real-time Pricing, or payments for entering a demand-side-response or active network management schemes need to be used for hydrogen to make projects more feasible.

Next Steps

WP2 – Investigation into electrolyser network considerations

Following this work package (WP1), in WP2, we will use the key criteria tool developed with the insights from WP1 to identify optimal locations for electrolyser connection on NGED's network. This will then inform the methodology required to assess the electrical implications and impacts of electrolyser connections on NGED's network. This will involve the selection of a network area to focus on in one of NGED's licence areas. Based on the criteria determined in WP1, we will develop a GIS map showing potential sites of connection, and present the recommended site based on a real project, that can be used as a case study. A study into the electrical implications of the electrolyser demand at the selected point of connection will then be carried out.

WP3 – Hydrogen electrolyser connection considerations document

This work package will bring together the findings of WP1 & WP2 to outline the high-level considerations for assessing the impact of electrolyser connections on distribution networks and discuss the factors important for identifying optimal locations for electrolyser connections on NGED's network.

These outputs can then be used to assess the opportunity for green hydrogen in NGED's network region, with recommendations for how NGED can help meet the developers' requirements to enable greater level of electrolyser connection on NGED's network, while at the same time using electrolysers to benefit NGED's network operations and plans. A report will be drafted on the outcomes of this work package, bringing together findings of WP1 and WP2.

Contents

1. Introduction

The UK Government, in its recent Energy Security Strategy, has doubled the target for low-carbon hydrogen production to 10GW by 2030. It is anticipated that about half of the hydrogen production will be via electrolysis by 2030, which means adding a sizeable amount of demand to electricity networks (HM Government, 2022). In the UK, network innovation projects investigating hydrogen electrolyser connections have focused on hydrogen for renewable energy storage, or impacts informed exclusively by uptake of fuel cell electric vehicles (Adams, et al., 2016). With the nascent hydrogen economy growing, it is now very important for Distribution Network Operators (DNOs) to better understand how electrolytic hydrogen production systems will provide opportunities and challenges for them. This will help inform the necessary measures that could be taken to ensure electricity networks are not a barrier to increasing electrolytic (grid connected) hydrogen production and to enable the value from this sector to be captured to benefit the DNOs and the wider electricity system.

The Hydrogen Business Model, along with the Government's Net Zero Hydrogen Fund of £240m for hydrogen production projects, is likely to catalyse the growth of the sector in the near-term with many of the projects having just submitted their applications towards the fund (July 2022). A key principle of the Net Zero Hydrogen Fund is those applying for it must have off-takers for the hydrogen they produce. Understanding the rate of growth of this sector is important for decision making today for DNOs. While the target of electrolytic hydrogen production is 1GW by 2025, by which time the Hydrogen Certification Scheme is expected to be in place, the uncertainty in the type and level of support from the Government in distribution and storage infrastructure may somewhat stifle progress. The government currently plans to have the Business Models for Hydrogen Transport and Storage Infrastructure in 2025 and the Hydrogen community is pushing for this date to be moved forward.

In this study we present a picture of the publicly announced hydrogen production projects in the UK. The UK Hydrogen Strategy supports hydrogen production from both fossil fuels with Carbon Capture and Utilisation technologies (blue hydrogen) and electrolytic hydrogen production from water (green hydrogen), categorising these hydrogen production options as low carbon hydrogen. It should be noted that while the hydrogen production capacity of the publicly announced electrolytic hydrogen projects is currently around 25% of the total capacity, with the remainder being blue hydrogen, movement to grow electrolytic hydrogen capacity in the wake of the Energy Security Strategy and increasing gas prices is already visible in the UK.

While the Government's targets and these announced projects shine some light on the expected levels of deployment of electrolysers, we are currently in a period of uncertainty regarding the numbers and size of projects in the UK and hence NGED's network areas. The projects that will be awarded in the Net Zero Hydrogen Fund in the last quarter of 2022 will bring more clarity on the near-term prospects for the sector. These combined with National Grids ESO Future Energy Scenarios will help make clearer projections.

To capture the most up-to-date information and key insights from the electrolytic hydrogen production community (electrolyser OEMs, integrators and project developers) we sent out a survey to inform key questions of this study. The insights captured can also help instigate further communication between NGED and these stakeholders to inform network development plans going forward.

This study also looks at the most important criteria in identification of sites for grid connection of electrolysers, these will be discussed with actions for NGED highlighted.

1.1 Purpose of this report

The objective of this desktop study is to investigate the status and prospects of integration of electrolysers in the UK with focus on National Grid Electricity Distribution's (NGED's) network area, and to present the opportunities and challenges with regards to grid connection of electrolysers. The study will inform NGED on the actions that may be required to address the challenges while creating the mechanisms that will enable value to be captured from electrolyser integration in NGED's network area in the next decade.

1.2 Scope and limitations

This report: has been prepared by GHD for National Grid Electricity Distribution and may only be used and relied on by National Grid Electricity Distribution for the purpose agreed between GHD and National Grid Electricity Distribution as set out in section 1.1 of this report.

GHD otherwise disclaims responsibility to any person other than National Grid Electricity Distribution *arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.*

As this is a desk-based study, with a survey further informing different sections of the report, the information presented is based on the accuracy of the publicly available information and the views of the respondents to the survey.

As part of this desktop study, we have reviewed existing literature and have conducted a survey with the relevant Hydrogen Sector stakeholders. The work has been limited to a review of publicly available information and a survey sent out to electrolyser OEMs, integrators, and project developers and it is not an assessment by GHD to assess size of the electrolyser market nor a forecasting study looking at growth and impact of the sector on NGEDs network area, or any other part of the GB electricity network. It should therefore not be used as a basis to develop network plans at this early stage.

The opinions, conclusions and any recommendations in this report are based on information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

1.3 Survey on Electrolyser Connections to the Grid

As part of this study GHD developed a survey to gather information from original equipment manufacturers (OEMs), integrators, and hydrogen producers to understand the key challenges, as well as opportunities presented by electrolyser integration to the grid. The survey looked at gathering information on existing and planned electrolyser projects, an assessment of suitability of electrolysers for different grid balancing services, the selection criteria for site identification of electrolyser deployments, specific challenges experienced or forecasted in terms of network connection of electrolysers, impact of the Low Carbon Hydrogen Standard on grid connections and specifications for electrolyser connections to the grid. We have sent the survey to about 50 different stakeholders and had seven responses (this is about 15% response rate). The information gathered from this survey has been used to inform the relevant sections of this report.

The link to this survey is provided **here**, please click to access the full list of questions. The full list of questions is also provided in Appendix A.

2. NGED's network: scenario modelling, renewable energy sources, connections & network plans

This section of the report looks at some of the projections and impacts of growth of electrolytic hydrogen capacity in NGED's network area. The objective here is to see how electrolytic hydrogen is viewed within the different future energy scenarios and how the status of the hydrogen production projects, as discussed in section 4.1, align with the projections for deployed capacity of electrolysers in these scenarios.

2.1 Distribution Future Energy Scenarios

NGED has produced 4 different reports which use the DFES scenarios (National Grid ESO, 2021). Each report looks at one of NGED's license area, the Southwest, East Midlands, West Midlands, and South Wales. These scenarios provide projections for the growth of energy generation (low carbon and conventional), demand and storage technologies which are expected to connect to the distribution network. This allows the DNOs to determine the impact of different scenarios on their networks. Table 1 gives a description of the four scenarios.

Table 1 Description of different DFES scenarios

Leading the Way	The Leading the Way scenario is based on the principle that Great Britain will reach net-zero by 2040. This scenario is characterised by a high uptake of energy efficient improvements by customers, notably retrofitting homes. Hydrogen produced by electrolysis will be used in industrial processes.
Customer Transformation	In the Customer Transformation scenario GB will reach net zero by 2050. This scenario is also driven by large customer engagement, however is characterised by a large increase in electric heat pumps, a low temperature system and EVs. This will greatly increase the strain on the grid. The system will have higher peak electricity demands managed with flexible technologies including energy storage, demand-side response and smart energy management.
System transformation	In the system transformation scenario, the GB will achieve net-zero by 2050, is characterised by changes in the supply side. A typical customer will use a hydrogen boiler; however, this scenario will use blue hydrogen.
Steady progression	In the Steady progression scenario, the UK does not achieve net-zero by 2050. There is a still a reliance on gas boilers, electric vehicle uptake is slow, and heavy good vehicles still use diesel.
Note: Ofgem's announcement of their minded-to decisions related to the Network Access and Charging Significant Code Review could be beneficial for hydrogen electrolysers if it leads to reduced network connection charges. This is modelled to be a factor under Leading the Way and Consumer Transformation.	

2.1.1 Hydrogen electrolysis projections

In the technology classification, hydrogen electrolysis falls under the bracket of "future sources of disruptive electricity demand". Table 2 demonstrates the difference in installed capacity of hydrogen produced by electrolysis in the South-West license area. By 2030, leading the way will have 1120MW of hydrogen electrolysis capacity installed, whilst System Transformation leads to an installation power capacity of 116MW. This includes the split of capacity that will be connected to the distribution network or the transmission network.

Table 2 Estimated hydrogen electrolysis in the NGED's license area

Installed Power capacity (MW)							
	Baseline	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Steady progression	5	10	144	339	339	339	339
System transformation	5	43	116	334	488	753	940
Consumer transformation	5	18	141	2010	2748	5210	7304
Leading the way	5	99	1120	2384	3137	4193	5335

2.2 NGED's Network Development Plans

This section looks at plans and impacts of electrolytic hydrogen connections on NGED network area. NGED's license area includes the East Midlands, South Wales, South-West, and the West Midlands (NGED, 2021). NGED have developed four reports, each one showing where developments are expected on a 0–10-year window (2022-2032) for each different region. These reports consider future network constraints, which can be defined as the ability of a network to operate within thermal, voltage and other technical limits, excluding frequency-related limits, under both intact network and outage conditions. These reports show what the required developments are to ensure the system keeps its integrity. This is the ability of the system to operate within acceptable technical limits and maintain security under both intact network and outage conditions.

The methodology for each report uses information from the Distribution Future Energy Scenarios (DFES, see Table 1). In addition to these, NGED has developed its own DFES scenario, which includes projections for increase in power demand from the residential sector, as well as commercial and industrial sectors. This is called the NGED Best View and covers the most likely growth pathway in the next 10 years. This view was curated with input from different stakeholders, through four webinars (one for each region). The registered attendants for all four webinars were split into several stakeholder groups, including the energy industry (38%), the local governments (31%), "other" industries (10%), community energy groups (5%), academia (4%), "other" consultancies (3%), water companies (2%), national government (2%), legal (1%) and trade unions (1%).

The projected number of sites experiencing demand driven constraints and circuit outage constraints in the four NGED network regions, for the different scenarios are outlined below.

2.2.1 Network Development Report – Southwest

The Network Development Reports cover targeted areas of the extra high voltage (EHV) distribution networks where developments are expected on the 0–10 year window. The Southwest is made up of 15 different networks. Table 3 shows the total number of demand driven constraints and circuit outage constraints that could happen in the Southwest for each of the different DFES (and NGED's best view) scenarios.

Table 3 The number of sites experiencing demand driven constraints and circuit outage constraints in the various scenarios on the subnetworks in the Southwest that require improvements

Scenario	2025	2028	2032	% Increase from 2025 to 2032
Steady progression	52	67	74	42%
System transformation	56	74	84	50%
Consumer Transformation	68	124	134	97%
Leading the Way	87	141	143	64%
NGED's best view	76	103	107	41%

2.2.2 Network Development Plan South Wales

The Network Development Reports cover targeted areas of the extra high voltage (EHV) and 132 kV distribution networks where developments are expected on the 0–10-year window. The Network in South Wales is made up of 8 different subnetworks. Table 4 shows the total number of demand driven constraints and circuit outage constraints that could happen in the South Wales for each of the different DFES (and NGED's best view) scenarios.

Table 4 The number of sites experiencing demand driven constraints and circuit outage constraints in the various scenarios on the subnetworks in South Wales that require improvements

Scenario	2025	2028	2032	% Increase from 2025 to 2032

Steady progression	1	2	9	800%
System transformation	2	6	12	500%
Consumer Transformation	4	12	17	325%
Leading the Way	7	17	21	200%
NGED's best view	4	11	15	275%

2.2.3 Network Development Plan East Midlands

The East Midlands is made up of 21 networks. Table 5 shows the total number of demand driven constraints and circuit outage constraints that could happen in the East Midlands for each of the different DFES (and NGED's best view) scenarios.

Table 5 The number of sites experiencing demand driven constraints and circuit outage constraints in the various scenarios on the subnetworks in the East Midlands that require improvements

Scenario	2025	2028	2032	% Increase from 2025 to 2032
Steady progression	10	16	26	160%
System transformation	14	23	28	100%
Consumer Transformation	19	32	35	84%
Leading the Way	23	35	35	52%
NGED's best view	19	35	35	84%

2.2.4 Network Development Plan West Midlands

The West Midlands is made up of 23 networks. Table 6 shows the total number of demand driven constraints and circuit outage constraints that could happen in the West Midlands for each of the different DFES (and NGED's best view) scenarios.

Table 6 The number of sites experiencing demand driven constraints and circuit outage constraints in the various scenarios on the subnetworks in the West Midlands that require improvements

Scenario	2025	2028	2032	% Increase from 2025 to 2032
Steady progression	13	16	23	77%
System transformation	13	19	24	85%
Consumer Transformation	16	24	27	69%
Leading the Way	19	25	27	42%
NGED's best view	13	21	26	100%

These scenarios show that there will be an increasing level of constrained sites across NGED's network area over the course of the next decade. Given that there will be an increasing number of electrolytic hydrogen projects in the UK, NGED needs to conduct work to better understand the financial and temporal value of electrolytic hydrogen production as part of their upgrading strategy assessment to overcome network constraints in the next decade.

A key message from the latest the National Grid ESO's Future Energy Scenario 2022 (National Grid ESO, 2022) is that urgent power network reinforcements will be required on an unprecedented scale to avoid curtailment of renewable generation, which will occur in a large capacity in all 4 scenarios between the 2030's to 2040's. This could specifically be enabled through co-location of electrolysers with renewable energy sources, enabling greater penetration of renewables aligned with UK's decarbonisation targets.

It worth noting that NGED has developed five different solutions to alleviate the projected constraint. They are:

- Conventional reinforcement: this could be in the form of replacing overloaded assets with increased ratings
- Strategic reinforcement: where multiple constraints are identified in the same area of network, a more cost-effective solution could be to establish new substations to increase the capacity of the group
- Operational mitigation: this covers actions which can be taken to mitigate constraints without the requirement for additional network capacity. This could include proposals to change running arrangements or limit access windows where arranged outages can be taken.
- Load management schemes: This covers plant, equipment and software systems that together can manage network loading and voltages. This is achieved by either controlling demand and/or generation connected to the network, operating switchgear to change the topology of the network and/or controlling the settings of tap-change controllers, reactive compensation equipment and flexible power links. Load management schemes can be utilised to manage both demand and generation driven constraints, however this is dependent on the technical/contractual ability for customers to accept curtailment.
- Flexibility: This covers actions by network users (through contracts with the DNO) to reduce network loading for a given condition by increasing, reducing, or shifting their net import or export.

Each section of the network will require different solutions. For example, Swansea North has the potential for first circuit outage constraints and second circuit outage constraints associated with it. Therefore, the impact of the five scenarios have been quantified for both these situations. Electrolytic hydrogen production can play a role specifically in operational mitigation, load management schemes and flexibility services. Further information on the role electrolysers can play in constraints management as well as other grid balancing service provisions will be discussed in the next chapter.

2.3 Review of potential renewable energy sources under the scenarios set out above

The networks will also be impacted by other renewable energy sources. The DFES also analyses the increase in large-scale solar PV, small-scale PV, onshore wind, and offshore wind. These four different technologies were analysed under the four different scenarios. Results of these can be seen in Table 7 below. Leading the way and consumer transformation have the most increase in capacity, two scenarios which also have highest projected increase in hydrogen electrolysis. The impact of these variable load connections need to be reviewed in any assessment of electrolyser connections or optimal site identification for electrolyser connections, for which a criteria is developed in this study as outlined in sectioncriteria as discussed in section Section 4.3 4.3.

Table 7 Projection of other renewable energy sources in NGED's license area. ***Note: Offshore wind is only present in the East Midlands license area***

	Scenario	2025 (MW)	2030 (MW)
Small scale PV (>1MW)	Steady progression	1600	1769
	System transformation	1831	2723
	Consumer Transformation	2272	4148

	Leading the Way	2284	4199
Large-scale solar	Steady progression	3584	5400
	System transformation	4057	6448
	Consumer Transformation	4057	6440
	Leading the Way	5187	10769
Onshore wind	Steady progression	1392	1590
	System transformation	1395	1813
	Consumer Transformation	1703	2633
	Leading the Way	1508	2324
Offshore wind	Steady progression	194	194
	System transformation	194	194
	Consumer Transformation	194	194
	Leading the Way	194	194

3. Electrolytic Hydrogen Production & Network Implications

3.1 Why Hydrogen?

Hydrogen can be used in a variety of applications such as fuel-cell vehicles, green gas, re-electrification, and industrial uses. The hard to abate sectors (such as Steel production, aviation, shipping) are the main areas in which hydrogen is considered most important in the net-zero energy transition. The potential for using electrolytic hydrogen in multisectoral applications, also known as power-to-X (P2X), has triggered a growing interest in different electrolyser technologies, with a hydrogen market projected to significantly grow from 2025 in the UK based on current Government strategy and activities elsewhere, Europe and the rest of the world.

With increasing penetration of renewables, location of generation relative to demand is changing and can often require electricity network reinforcements. While electrolyser integration into the grid and co-location with renewables can help minimise the need for network reinforcements and result in overall lower costs, the ability to do this will depend both on the incentives created for electrolyser connections but also regional growth of electrolytic hydrogen projects.

As an energy carrier or storage medium, hydrogen’s role in the electricity sector will likely depend on the extent to which hydrogen is used in the overall economy, which will depend on future costs of hydrogen production, transportation, and storage, as well as innovation in hydrogen end-use applications. However, the cost reductions enabled by economies of scale also depend on the scale in which electrolysers are deployed on the grid, which can enable higher load factors for improved economics, while using the electrolysers for grid balancing services when needed.

Hydrogen is currently produced, transported, and sold as a feedstock for numerous industrial processes. Today, 95% of the hydrogen produced is from fossil fuels. While fossil-based hydrogen with carbon capture and utilisation (CCUS) is considered along with electrolytic hydrogen production in the UK and globally, the rising gas price is creating questions on whether electrolytic hydrogen projects would be more attractive in the long term. Bloomberg New Energy Finance (BNF) predicts electrolytic hydrogen and fossil fuel-based hydrogen with CCUS will reach cost parity by 2030 in most countries (Bloomberg, 2021). The ability to produce low-carbon hydrogen via electrolysis, a process for splitting water to hydrogen and oxygen by applying an electrical current, using low-carbon grid electricity can support decarbonization in end-use sectors such as industry and transportation, as well as in the power sector.

Hydrogen produced via electrolysis can serve as a low carbon fuel for industry as well as for electricity generation during periods when renewable energy generation is low. The use of electrolysers as a dispatchable load for the power system could also reduce the costs of power system decarbonization by increasing capacity utilisation of intermittent renewables. The National Grid in its Future Energy Scenarios, July 2021 *states that "The supply and use of hydrogen is central to all of our net zero scenarios"* (National Grid ESO, 2021).

Hydrogen storage at large scale can provide intermittent renewable sources with flexibility, allowing them to contribute a greater proportion of electrical energy and avoiding curtailment. This needs to be weighed against investment costs in backup generation, interconnection, transmission, and distribution network upgrades. Hydrogen storage at large scale can also enable sector coupling, enabling the transport, industry, power, and heat sectors to access the hydrogen, when and as needed. The power markets can also capitalise on this growth to use electrolysers simultaneously for grid balancing and hence reducing costs of upgrades. In this chapter we look at the kind of services electrolytic hydrogen production facilitates can provide to networks and provide details on how they can contribute to elevating curtailment of renewables by helping manage network constraints and hence enabling greater penetration of renewables.

3.2 Electrolysers

Electrolysers use electricity to split water into hydrogen and oxygen via an electrochemical process. The main commercially available electrolyser technologies today are alkaline electrolysers (ALK) and Polymer Electrolyte Membrane (PEM) electrolysers. These are low temperature electrolysers, operated at around 80-85 ºC (Shiva Kumar & Himabindu, 2019).The other main electrolyser technology that is less commercially mature is the solid oxide electrolyser. These are high temperature electrolysers currently operated between 600-1000 ºC (Godula-Jopek & Westenberger, 220).These have promise over the long term, in terms of cost and lifespan, but are still in R&D phase and are unlikely to be commercially competitive in the next 10 years.

PEM and ALK are differentiated by the electrolyte material as shown in Figure 1. PEM technology utilises a solid polymer electrolyte membrane and an applied current to separate hydrogen (via protons) and oxygen from water. The electrons are then transported from the anode electrode to the cathode electrode via the electrical circuit. Alkaline technologies use a liquid alkaline electrolyte solution and an applied current to separate hydrogen from water. The gas generated by the electrolysis cannot pass through the membrane to the other side in a large amount, and the generated gas and the electrolyte are discharged from the chamber together for treatment.

For grid electrolytic hydrogen production using electricity from the grid or directly from a renewable generation, ALK and PEM technologies are the main two options considered. PEM electrolysers typically have a faster ramp-up and ramp-down capability (faster speed of response), making them more suitable for balancing services and to enable flexibility (Samani, et al., 2020).The pros and cons of both types of electrolysers are discussed below.

PEM Electrolysers:

- Faster speed of response (ramp up and down rate), this matters if electricity is obtained directly from a renewable asset or if spot price of electricity is the model used, or if grid balancing services are required.
- Typically ramp up from cold start takes ~30 mins from 0-100%). In hot state (stack temperature 80-85°C) the ramp up time is less than 150 seconds from 0-100%. There are PEM electrolysers with operating range 0-120%, with the 20% above range for short duration use.
- PEM also have smaller footprint, which means more kg of hydrogen per unit area (higher hydrogen density).
- Operate with a strong differential pressure between the hydrogen side and the oxygen side of the electrolyser (30 bar output typically).
- Typically require less maintenance due to having less components, although they currently have a higher maintenance cost

- PEM technology is less mature than ALK and today it is typically more expensive (see Figure 3). While some projections show the technologies will reach cost parity by about 2030, Bloomberg Energy predicts that ALK technology will continue cost reductions with scale, suggesting the date for reaching cost parity is somewhat uncertain.
- PEM electrolysers also have synergies with PEM fuel cells, which are also being scaled up commercially, providing the opportunity to capitalise on advancements in materials and processes.

Alkaline Electrolysers:

- Alkaline electrolysers have been commercial for a long time and thus have technical maturity of equipment over PEM technology. This results in higher reliability of this technology over PEM electrolysers today.
- Long service life (80,000 hours+) and reduced material costs if refurbishment is required
- Larger footprint (up to twice the size of PEM electrolyser systems) this may become a more important consideration once costs converge
- Speed of response can be slower, but typically similar to PEM these days. Nel (a major electrolyser company) says their ALK technology can be started and brought to maximum production within less than 30 minutes (just like PEM above). With their alkaline atmospheric electrolyser, the capacity can be ranged between “15% and 100% in around 10 minutes.”

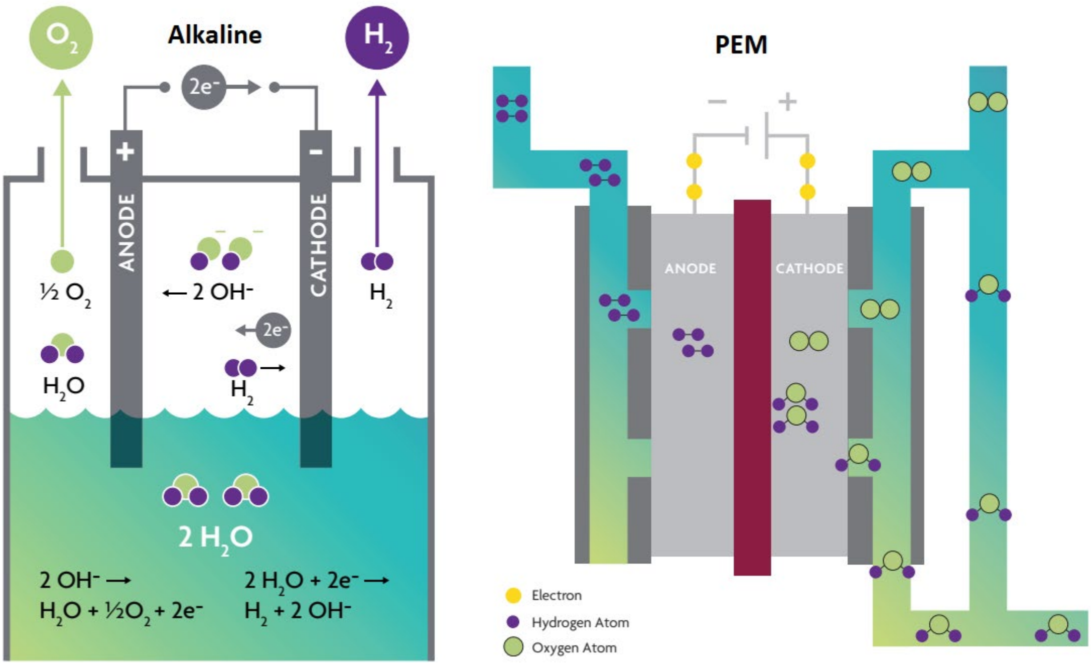


Figure 1 ***Schematic of an Alkaline and PEM electrolyser technology – taken from (Nel, 2022).***

Both PEM and ALK technologies have an efficiency range of 50-60% today, R&D work aims to improve this close to 70-75%. As discussed in reference (Siemens, 2022) it is not easy to compare the efficiencies of the two technologies as it depends on the operation conditions. PEM technology can have a relatively higher maximum efficiency (by a few % points) in fluctuating conditions.

The components of an electrolyser system are show in Figure 2

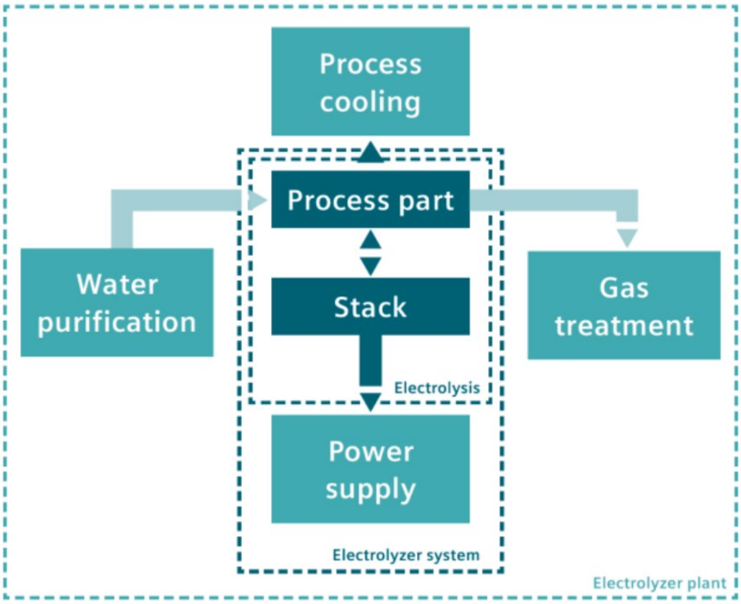


Figure 2 Different system components of a typical electrolyser system (with balance of plant components)

Electrolyser Costs and Cost Factors for Hydrogen Production

Today, the hydrogen production cost is typically broken down as: approximately 20-25% due to electrolyser CAPEX, 70-80% due to electricity cost and about 2-5% due to OPEX. While the cost of electrolysers is important when considering their operation at low-capacity factors (e.g. when operated using otherwise curtailed electricity), the main reduction in cost that is needed to have a strong business case for electrolyser operation is the cost of electricity. To minimise electricity costs over a given time, the electrolyser operation can be optimised to be on during times of low-cost electricity and off during peak periods with high electricity costs. It is expected that electrolyser operators will make use of autonomous bidding software similar to what is currently used by many utility-scale batteries around the world. The flexibility of the electrolyser is important for grid balancing services to be able to benefit from times when the electricity price is low. Co-locating electrolysers with batteries could also potential have synergies in terms of cost of hydrogen production and the provision of flexibility services, while we are not looking at economic benefits of doing this in this study, such an assessment could become important for assessing sites for connecting electrolysers in NGED's network area, especially since battery capacity of 229MVA is connected and 7.1GVA capacity connection is accepted in NGEDs network (as of 1 Sept 20222). Current and projected cost for electrolysers is shown in Figure 3.

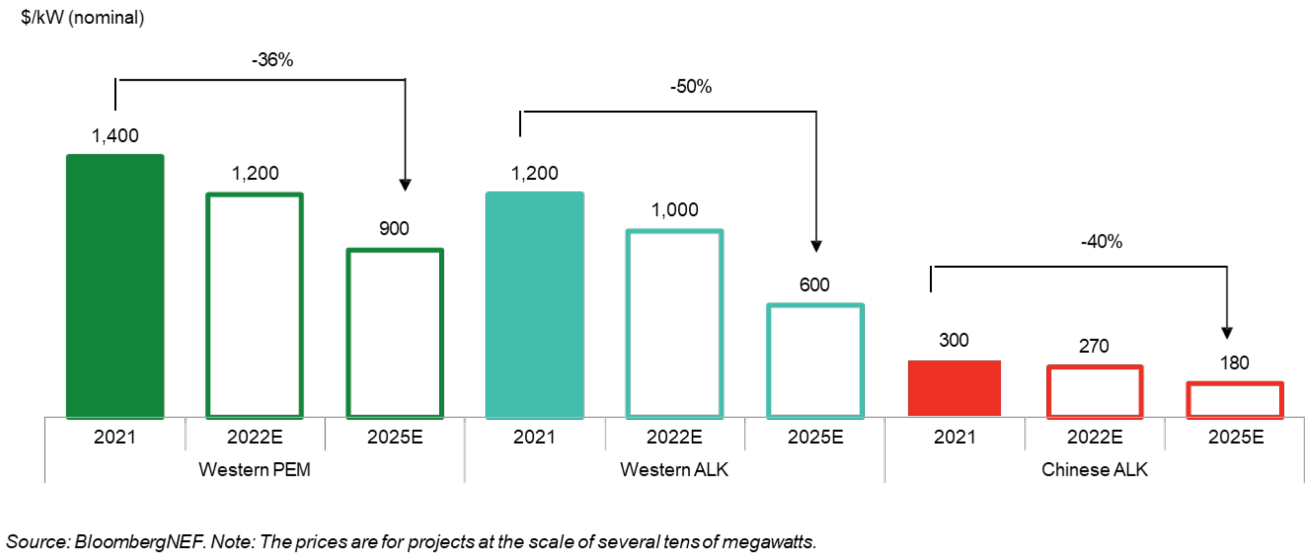


Figure 3 Current and projected cost for electrolysers (Bloomberg M. A., 2022)

3.3 The role of electrolysers in the provision of grid services

3.3.1 Flexibility services enabled by hydrogen compared to other technologies

The increased penetration of renewables into the grid will lead to increased volatility. This, in turn, will increase the value of grid balancing services. Electrolysers are considered to have a role to play in provision of grid balancing services, but the value they can provide, compared to other technologies, is still somewhat unclear. While electrolytic hydrogen production can potentially lower the cost of grid reinforcements required to manage constraints, the degree to which this can be done requires a thorough assessment of the grid constraints at the regional level and a comparison with different balancing services to assess the most optimal solutions, based on factors such as penetration of renewables, required operation profile of electrolysers, availability of storage options, etc.

Table 8 below provides a comparison of different technologies (systems) for the provision of grid services. Electrolysers, through Power-to-X (Ptx), can be used for almost all services, depending on how it is integrated, although the maturity is considered low as such applications of electrolysers are still at demonstration stage.

Flexibility will be of paramount importance to DNOs, and the relevant DSOs (Distribution System Operator). DSOs are involved in the process of maximising the efficiency of the grid and are those responsible for the distributing and managing energy from the generation sources to the final customer.

One flexibility service which hydrogen electrolysers can provide is Sustain - Peak Management. This flexibility service is delivered at times when demand for electricity is at its highest, which can lead to constraint issues on the network (e.g. overloading a transformer). The relevant DSO will pay the operator of an electrolyser to stop utilising electricity to alleviate the constraint.

Another service which hydrogen producers could partake in is Secure DSO Constraint Management. This occurs when there is an issue with an area in the network, for example a transformer undergoes a fault and therefore the other transformer is at risk of being overloaded. This would involve the hydrogen producer turning off their system to reduce strain on the network.

Hydrogen producers can also partake in the Exceeding Maximum Capacity Import flexibility service, which is a peer-to-peer service provided by some DNOs. This is when the hydrogen producer will reduce its Maximum Import Capacity, which is the maximum amount of electricity the hydrogen producer can source at any given time, based on contracts signed with the DNO. By doing this, they can sell the electricity they did not use to another generator/consumer.

Offsetting is another flexible service which hydrogen producers can partake in. Offsetting is the principle of limiting the amount of electricity that can enter that section of the network due to constraint issues. If there is a consistent local increase which consistently has to be offset at predictable times, the hydrogen producer can increase their demand to match this local increase. This will have no impact on DNOs, as the impact on the network will be instantly offset.

Table 8 Electrolyser suitability factors. PHS stands for Pumped Hydroelectric storage, CAES stands for Compressed Air Energy Storage, LAES stands for Liquid Air Energy Storage, TES stands for Thermal Energy Storage, FES stands for Flywheel Energy storage, LiB stands for Li-ion batteries, Scap stands for Supercapacitors, RFB stands for Redox Flow Batteries, RHFC stands for Reversible Hydrogen Fuel Cells.

Grid Service provision	PHS	CAES	LAES	TES	FES	LiB	Scap	RFB	PtX	RHFC
Stability	✓				✓	✓	✓	✓	✓	✓
Frequency Regulation	✓	✓	✓		✓	✓	✓	✓	✓	✓
Black start	✓	✓	✓			✓		✓	✓	✓
Short term reserve	✓	✓	✓			✓		✓	✓	✓

Fast reserve	✓	✓	✓		✓	✓		✓	✓	✓
Upgrade deferral	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Energy Arbitrage	✓	✓	✓	✓		✓		✓	✓	✓
Capacity firming	✓	✓	✓	✓	✓	✓		✓	✓	✓
Seasonal Storage				✓					✓	✓
Voltage support	✓	✓	✓		✓	✓	✓	✓	✓	✓
Islanding		✓	✓	✓		✓		✓	✓	✓
Uninterruptible power supply					✓	✓	✓	✓		✓
Other considerations										
Maturity	High	High	Med	Low	High	Med	Low	Low	Low	Low
Opportunity to reduce cost	Low	Low	Low	Med	Med	High	High	High	Med	High
Lifetime	Long	Long	Long	Long	Med	Short	Med	Med	Med	Short
Roundtrip efficiency	60-80%	30-60%	55-90%	70-80%	0.9	>95%	>95%	80-90%	35-60%	<30%

Batteries are predominantly used in most markets for balancing services, especially those with short activation times. Based on their fast response (seconds) and lower cost, the dominance of batteries in FCR (Frequency Containment Reserve) markets is expected to continue, making it very challenging for electrolysers to compete in the FRR (Frequency Restoration Reserve) and the RR (Replacement Reserve) markets.

Frequency Containment Reserve can be explained as the operating reserves necessary for containment of frequency deviations from nominal to maintain the power balance in the whole synchronously interconnected system. FRR is the active power reserve to provide static and dynamic responses for frequency regulation in normal operation and following a disturbance causing large fluctuation. Depending on the speed of delivery they are classed as a Primary or Secondary response, Primary response is delivered in 5 seconds and sustained up to 30 seconds and secondary delivered in 30 seconds and sustained for 30 minutes.

RR is the active power reserve available to restore or support the required systems for FRR. It exists to be used for additional system balances, including generation reserves. The response time of RR is set by the TSOs, the national grid requires system partaking the replacement reserve to have a minimum capacity of 1MW and a response time of less than 30 minutes.

Projects in which electrolysers are providing or planning to provide balancing services in a commercial setting are only starting to emerge. Some examples of projects in Europe are: HyBalance, H_2Future, REFHYNE, and Demo4Grid [(Slater & Joos, 2021). However, the capacity of these electrolysers are still small, for example the REFHYNE electrolyser's capacity represents less than 2% of the demand for FCR in Germany.

The electrolysers in the HyBalance (Denmark) and the H_2Future (Austria) (Eberl, 2021) projects have been qualified for all types of balancing services and are currently participating in balancing markets in their respective countries.

This includes the Demo4Grid project, which is also part of the H2020-EU project. This project, based in Austria, looked at using Alkaline Electrolyser technology (Eberl, 2021). The first project ELYGRID (finished) and the following one ELYntegration (still ongoing) have provided promising results on the development of Alkaline Electrolyser technologies to provide grid services operating under dynamic profiles. Another European project that looked at the potential use of large electrolysers (>25MW) for provision of primary reserve, frequency containment reserve, and as a grid balancing system, found that providing frequency containment reserve using large electrolysers created extra revenue. They focused on the ability of electrolysers to produce green hydrogen whilst simultaneously providing the grid support (Samani, et al., 2020)].

For network constraints management and diurnal and seasonal energy storage, electrolysers can provide value at the energy system level. This is particularly the case when hydrogen is being produced for specific end uses (i.e. with a specific value stream) during times of low-cost electricity (times of high renewables supply and low energy demand), while at the same time providing grid balancing services such as constraints management. A Hydrogen Mobility Europe study (Shane Slater, 2021) has shown that grid service provision could reduce the cost of hydrogen by up to 10%. Grid services are likely to play a transitory role in the roll out of electrolysers as markets for these services are shallow and get saturated quickly.

Our survey asked a number of questions to deduce how respondents viewed the role electrolysers in the provision of grid balancing services. Five of the respondents in the survey indicated their electrolyser application can be designed to offer flexibility services to the power system, but only four indicated that they would use their electrolysers for flexibility services. These services were listed as EFR (Enhanced Frequency Response, FCDM (Frequency Control by Demand Management), inter day and seasonal storage services by a respondent, who also added that the services that will be provided are highly dependent on the requirements of the respective DNOs, demonstrating the need for conversations between the hydrogen project developers, OEMs and the DNO's to ensure these solutions can be implemented techno-economically.

3.3.2 Constraints Management

Congestion management has become a major cost component of system operation due to renewable expansion. Local flexibility markets run by Distribution System Operators (DSOs) can contribute to cost efficient congestion management and could potentially provide attractive revenue opportunities. NGED currently operates one of the largest flexibility programmes.

Numerous studies have indicated that networks will become more constrained over the next decade due to increased demand and generation. The volatility in the flow will increase due to increased renewable energy penetration in the network and increased levels of interconnection. Therefore, NGED needs to secure more flexible resources and voltage support in order to run the system.

Traditionally, active power in GB transmission system predominantly flows from north to south. This has been mainly due to the historic geographical concentration of demand in the south and generation in the north. The integration of variable renewable energy sources (RES in the south (notably wind and solar) could change this, providing opportunities for hydrogen generation (to be used in different sectors), while also enabling electrolysers to support constraints management.

Electrolytic hydrogen production, using surplus renewable energy at times of low demand and high renewable energy supply, can avoid shutting off wind generation (curtailment), which incurs costs to end-consumers. Wind curtailment alone costing UK users £507million in 2021, and £299 million in 2020 (Renewables Now, 2022). LCP, an investment firm, predicts that wind curtailment will cost the end user £1 billion per year by 2025 (Renewable Energy World, 2021). However, given the rapid increase in gas prices the actual cost of curtailment in 2025 will be larger, unless sufficient energy storage systems (electrolysers or batteries) can offset the curtailed energy. The LCP report shows that installing 20GW of battery storage could reduce the amount of wind power curtailed by up to 50%.

Understanding the value that electrolysers add to network constraints management and for lowering hydrogen production costs depends largely on the capacity load factors (assuming zero cost of otherwise curtailed electricity) and the Capex and Opex of the electrolyser. Curtailment of renewables due to network constraints leads to extended periods of "zero marginal cost electricity", which in turn could make lower load factors attractive to electrolysers. However, as the main factors determining the cost of hydrogen production are electricity cost, load (capacity) factor, CAPEX and OPEX, even if the otherwise curtailed electricity cost is zero, the load factors are still low, and as the CAPEX of electrolysers are still high today (around $700/kWe) – curtailed electricity does not create a good business case for use of electrolysers today. In the future, renewable oversupply rather than network constraints could become dominant driver of curtailment and lead to extended periods of zero marginal cost electricity, which could make electrolytic hydrogen production economically viable with increased load factors and decreased electrolyser capex (Committee on Climate Change, 2018). The required level of penetration of renewables that create a business case for hydrogen production from otherwise curtailed electricity will need to be calculated at a regional level based on other balancing services and interconnections being used.

The National Grid ESO (2022) projects the total curtailment in the UK within their four scenarios: 45TWh in the Consumer Transformation scenario, 37TWh in Leading the Way, 21TWh in System Transformation and 4.5TWh in the Falling Short scenarios by 2030. Some estimates show that wind curtailment alone in the UK may cost the end user £1 billion per year by 2025 (Renewable Energy World, 2021).

In our survey for this study four of the seven respondents indicated they anticipate they will be deploying electrolysers for hydrogen production using curtailed energy by 2030 and two of them indicated they would not. Out of these four who indicated yes, three of them would anticipate using curtailed energy from a privately owned connection to the solar/wind farm.

3.3.3 Long Duration Energy Storage

Hydrogen is considered as a competitive solution for long duration energy storage to even out both daily and seasonal fluctuations in energy supply and demand (for both electricity and gas networks). In the UK electrolytic hydrogen production is increasingly being considered to capture this value stream in the long run, with increasing penetration of renewables and decreasing availability of strategic gas reserves.

The main value of hydrogen, when compared to other storage technologies considered for grid applications (as listed in section 3.3.1, is that it is a flexible fuel with diverse uses, capable of providing electricity, heat, and long-term energy storage for grid scale applications, industry, and transport, enabling sector coupling. When considered at the energy system level for use across sectors, hydrogen has been shown to lead to reduced costs for decarbonising the energy system (Shukle, et al., 2022). Given the low volumetric energy density of hydrogen (1/3 gasoline), for such applications large geological formations are being investigated to store hydrogen at moderate pressures. Companies looking at producing hydrogen at large scale are starting to look at the potential for large scale geological hydrogen storage (salt caverns) in the UK, thus this consideration could have implications for where electrolysers will be placed in conjunction with renewables, unless a hydrogen gas network is built. There have been previous concerns that salt caverns will leak hydrogen, however, research has indicated that salt caverns are mostly impermeable to leakage. The leakage that occurs through the well head or connections can be monitored and controlled. But if the grid electricity costs can be reduced through contract for difference (CFD) models and contracts such as Power Purchase Agreements (PPAs) then electrolysers deployed for such strategic energy storage projects can be connected to the grid or co-located with renewables, while also using grid power during times of no RES.

Hydrogen can also deliver clean firm power generation and peaking power which are valuable functions within the energy system that cannot be provided by renewables. The use of hydrogen in gas power plants (CCGT or OCGT) is considered for peaking plants to complement the deployment of renewables. Companies such as Shell are developing such plants for use within a hydrogen economy in the UK and across the world.

UK based companies are already making peaking plants that can be converted from using natural gas to hydrogen at a later stage. One example is Statera Energy, which has constructed three 50MW peaking plants; one at Creyke Beck in Yorkshire and two at Saltholme in Middlesborough and is proposing to construct a number of additional plants in 2022 and 2023 (Statera Energy). Hydrogen combustion has no carbon dioxide emissions, the product of combustion being water (vapour).

An MIT study, which compares cost of electricity production from Gas turbines, Combined Cycle Gas turbine and fuel cells. While today the cost of electricity production from CCGT is lowest, by 2050 cost of electricity production from fuel cells is expected to be similar to that from gas turbines (MIT Energy Initiative, 2022)

A similar study, which uses a least cost of energy approach (LCOE), looks at the cost of meeting seasonal imbalances and compares hydrogen-fired gas turbines (HFGT) and lithium-ion battery systems (LI). This study finds that in the US the LCOE associated with meeting seasonal energy imbalances is $2,400 per megawatt hour (MWh) using a hydrogen-fired gas turbine, compared to $3,000/MWh using a lithium-ion battery system. If a gas turbine is fired with "blue" hydrogen, that is, hydrogen produced by reforming natural gas with the associated CO2 being captured and stored, the average LCOE decreases to $1,560/MWh (Hernandez & Gencer, 2021).

Another study, which compared grid-scale energy storage of batteries against regenerative hydrogen fuel cells (both alkaline and PEM, composing of an electrolyser, a compressed hydrogen gas storage tank and a fuel cell), shows that despite the lower electrical efficiency of alkaline fuel cells (70% efficiency and a stack lifetime of 100,000 h) and PEM fuel cells (47% efficiency, with a stack lifetime efficiency of 10,000h and a round-trip efficiency of 30%), the electrical energy stored on invested ratio (ESOI) is higher in regenerative hydrogen fuel cells (Power-to-X), as the materials required to store compressed hydrogen in the adjacent hydrogen gas storage tanks have a lower energy cost than the materials needed in battery storage (Pellow, Emmot, Barnhart, & Benson, 2015). In a hybrid energy system, which the UK will have, batteries are a more efficient and cost-effective solution for short duration storage, whilst, due to having a low rate of self-discharge, hydrogen will be useful for seasonal storage (Zhang, Maleki, Rosen, & Liu, 2018) (Pellow, Emmot, Barnhart, & Benson, 2015) . Electrolysers response times are more variant (varying from 3 seconds to 30 minutes for a cold start-up, and 1-150 seconds in hot state, 80-85°C), which makes them less suitable than lithium-ion batteries (which have a response time of milliseconds) to respond to fast changes to the grid (Cárdenas, Swinfen-Styles, Rouse, & Garvey, 2021). Furthermore, it is not recommended that electrolysers are switched on and off in a stand-alone system, as the start-up time is needed to purge the nitrogen from the system (Samani, et al., 2020)

Another study shows that, when compared to compressed air, hydrogen or lithium-ion batteries would be more economical in a 100% RES grid (85% wind, 15% solar) in the UK (Cárdenas, Swinfen-Styles, Rouse, & Garvey, 2021). This study shows that for short-duration (5 minutes - 4 hours) storage, electrochemical batteries are the most efficient as they are ideal for frequent charging or discharging, given their high efficiency, fast response time and fast ramping capabilities. Long-duration storage (>200 hours) is much more economically feasible with the storage of hydrogen, ammonia, or biogas. Hydrogen has a lower cost per unit capacity at this scale and can be stored in salt caverns in the UK. For medium-duration storage (4-200 hours) compressed air is the optimal technology. This is because compressed air has a higher utilisation factor, and thus a faster discharge and charging frequency than hydrogen (Cárdenas, Swinfen-Styles, Rouse, & Garvey, 2021). A higher utilisation factor (in this study, at the optimum mix of technologies the utilisation factor is 25.2 for compressed air and 4 for hydrogen) indicates that a greater amount of energy is able to pass through storage in a given period of time, thus the compressed air systems have a faster response times than hydrogen systems and are more suited for medium-duration storage.

This gives hydrogen a distinct advantage over batteries when it comes to seasonal storage, as in times of high electricity demand (notably winter) there will be a need for energy produced by stored hydrogen to compensate against the lack of electricity production by RES sources. Having hydrogen stores co-located with electrolysers will help minimise costs. In their optimal scenario (assuming an optimum mix between hydrogen and compressed air, which is the most economically viable outcome) they believe the capacity of batteries will be 168GWh, whilst hydrogen will store 55.3TWh and compressed air will store 11.1TWh. The storage capacity of batteries is low as the stored energy will be in constant flux (both charging and discharging) to assist with small fluctuations in the frequency of the grid.

3.4 Impact of electrolysers on the grid

With growing demand and roll out of electrolysers to produce hydrogen, especially for hydrogen production and use near urban environments (e.g. electrolysers placed close to refuelling stations), electrolysers could contribute to demand constraints at peak hours of demand, if it is not controlled or managed. The level of impact of increased electrolyser connections on the grid is still unclear for the UK, as this largely depends on the operation modes used (continuous or intermittent operation) as dictated by the specific end uses, as well as the availability of distribution infrastructure and cost implications of added storage.

A simulation study looking at the effects of integration of water electrolysis facilities (for Power-to-X applications) in power grids in Germany (Bartels, Varela, Wassermann, Medjroubi, & Zondervan, 2022), shines some light on the kind of impact different capacities and operational modes of electrolysers can have on the grid. The assessment undertaken in this study includes the evaluation of impacts on the grid due to the flexible operation of electrolysers to minimize hydrogen production cost, while efficiently integrating locally generated renewable energy. In this study, a virtual cost term penalizes the use of non-renewable power. The penalty is based on the GHG emissions content in the grid (power generated from conventional sources) and Emissions Trading System (ETS) prices. The study finds that costs can be minimised by "allowing the electrolysis facility to operate with major flexibility over the year". This means that it can make use of low electricity prices and times of low non-renewable share. The study assumed that the local onshore generators which are approximately 10km from the electrolysis facility will contribute directly to the electrolysis operation. Such flexible operation of electrolysers, or scheduled hydrogen production, can be enabled in practice through a PPA and forward/future contracts for those times of the day when the price is cheaper.

The number of electrolysers is shown to be important to meet the target hydrogen production. A smaller number of electrolysers means that the facility has to operate at non optimum times in order to meet the demand, whereas a large number of electrolysers make the investment costs a major barrier to the process.

For operations with strict demand period goals the study looks at the effect of hourly (no flexibility), daily, monthly, and annual (total flexibility) demand constraints. The producer may have signed an off-taker agreement where it has to produce a set amount of hydrogen per hour, per day, per month or per year. As expected, if there is an hourly demand then the electrolyser will have to utilise electricity from the grid, which, due to the virtual penalty will lead to increased costs. Therefore, the most cost-efficient method for electrolysers is to allow them to operate with major flexibility throughout the year.

This study finds that the longer the time period, the more flexible the system is to react and run at periods of low electricity price or high renewables. The cost of the annual constrained production is also the lowest. The above constraint periods were then put into a model to map out the congestion on the power grid. It was found that although “all operation strategies resulted in an increase in congestion events”, the daily-constrained option resulted in the smallest rise in total congestion.

The study concludes that electrolysis capacities up to 300 MW (~50 kt hydrogen/a) have local impacts on the grid, while higher capacities cause supra-regional impacts. This simulation study also shows that whilst a greater degree of flexibility in the electrolyser facility reduces cost of the electricity and increases the share of renewables used, it also results in a greater demand on the power grid and increases the number of congestion events in the grid. This kind of impact needs to be investigated for NGED’s network and can be the subject of further work.

In the UK, Scottish and Southern Electric Networks have modelled the impact of hydrogen refuelling station (HRS) roll-out on their network (Adams, et al., 2016). This study uses the estimates from the H_2 Mobility initiative that predicted 1.6 million fuel cell electric vehicles (FCEV) in the UK by 2030, with 51% of the hydrogen required produced by hydrogen electrolysers. A set of 12 trials (scenarios) were modelled, that dictated the operation schedule of the electrolysers in a constrained network. These trials were conducted over an eight-month period and aimed to understand the impact on DNOs if the roll-out of this technology becomes more widespread.

Each trial had an electrolyser operation schedule, based on information and data obtained from the factors considered for the modelling, including the ‘network capacity, real-time data from a local demand, a gas injection supply point, historic wind farm and PV data’ (Adams, et al., 2016). Time of Use (ToU) pricing was used for trials with commercial considerations. While some trials sought to minimise the cost of running the electrolyser to benefit the hydrogen producer, some trials focussed on grid constraints to avoid network reinforcement costs, or to defer the network reinforcement.

The results for the trials undertaken are divided into successful and unsuccessful trials. The main conclusion from this study is that electrolysers can be operated to avoid breaching a demand constraint. However, appropriate mechanisms (contracts) will be required to incentivise operators to produce electrolytic hydrogen in a way that benefits them and the DNO, while avoiding network constraints. Such mechanisms include Time of Use tariffs, Real-time Pricing, or payments for entering a demand-side-response or active network management scheme.

One implication of these studies is that Power-to-X projects (using electrolysers) would benefit from having participation from DNOs in the design of these large-scale hydrogen projects to optimise not only hydrogen cost but also for DNS to develop the operational models that do not create further constraints on the network.

Our survey asked a number of questions to deduce how respondents viewed the role electrolysers in the provision of grid balancing services. Five of the respondents in the survey indicated their electrolyser application can be designed to offer flexibility services to the power system, but only four indicated that they would use their electrolysers for flexibility services. These services were listed as EFR (Enhanced Frequency Response, FCDM (Frequency Control by Demand Management), inter day and seasonal storage services by a respondent, who also added that the services that will be provided are highly dependent on the requirements of the respective DNOs, demonstrating the need for conversations between the hydrogen project developers, OEMs and the DNO’s to ensure these solutions can be implemented techno-economically.

4. UK hydrogen Projects: status, LCHS, site optimisation

4.1 Electrolytic hydrogen projects in the UK

This section provides an overview of the publicly announced hydrogen production projects in the UK. Figure 4 shows both green and blue hydrogen projects in the UK, based on GHD's database of UK hydrogen projects, combined with data obtained from the trade association Hydrogen UK, which captures a total of 55 publicly announced projects at different stages of development from its members and publicly available data.

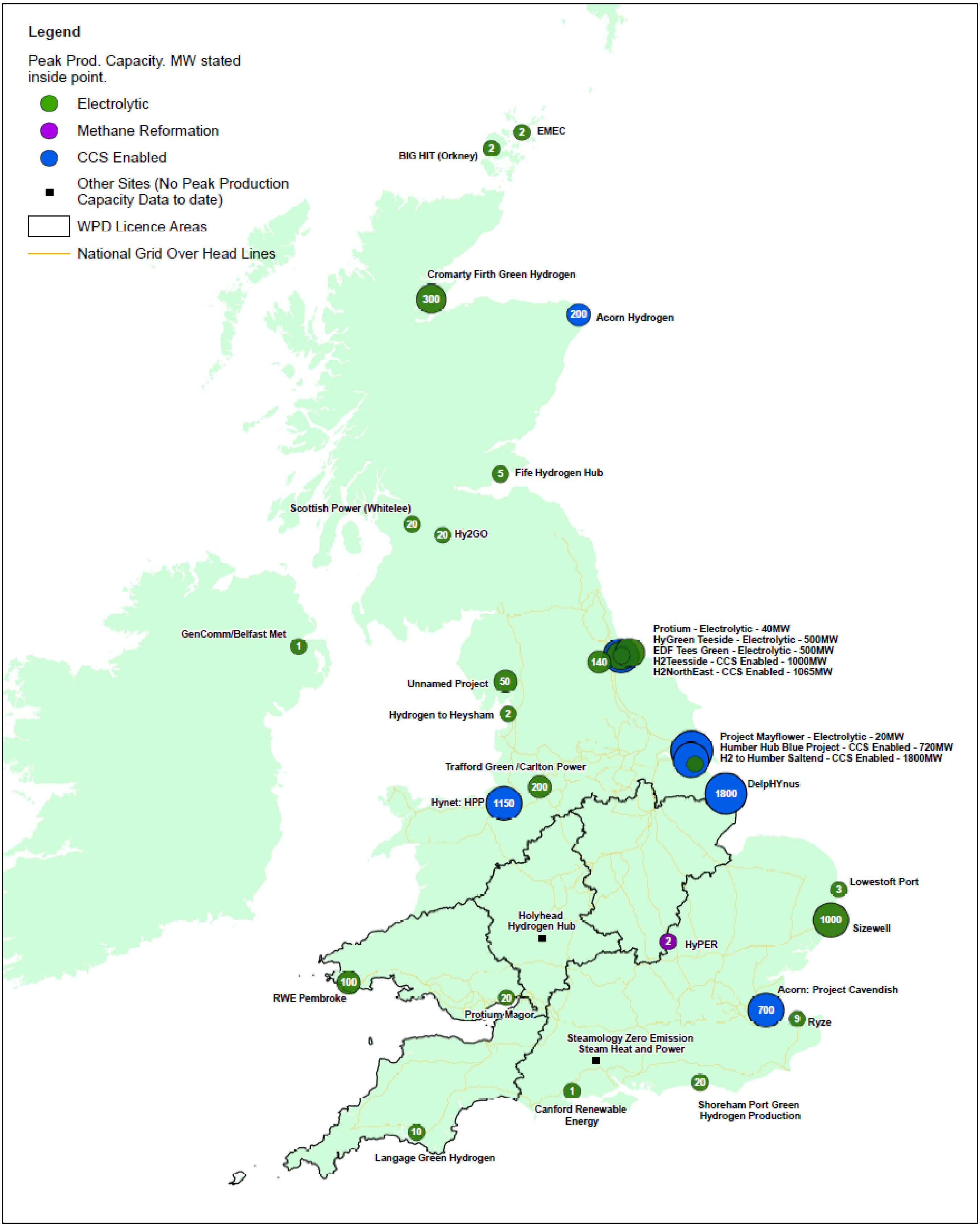
Based on this database there are plans to build 380MW of green hydrogen projects in the near terms, reaching a total peak capacity of 3,295MW by 2030 (peak production capacity of these projects), as shown by Figure 5.

Based on this database, there are plans to build 380MW of electrolytic (green) hydrogen projects in the near terms, reaching a total peak capacity of about 3.3 GW by 2030, compared to total peak production capacity of 8.4GW for CCS enabled (blue) hydrogen projects by 2030, as shown by Figure 5. These projects, if they go ahead, amount to about 11.7GW of hydrogen, exceeding the UK's target of 10GW by 2030. However, as only about 30% of the planned capacity is from electrolytic hydrogen, there appear to be to less drivers or more challenges to developing electrolytic hydrogen projects. While the cost of hydrogen production, which is higher than the cost of CCUS enabled hydrogen production from natural gas, is one of the main reasons, the lack of off-takers of hydrogen (future revenue streams) is also creating uncertainty for investors in this area. We will discuss in section the results of the survey looking at the challenges developers experience in connecting electrolysers to the grid, which also has a negative impact on the number of electrolyser connections.

The project phase of the electrolytic projects is also shown on the right-hand side of Figure 5, with only eight (20%) of electrolytic hydrogen projects currently in the FEED (Front-End Engineering Design) stage. Figure 6 shows how these projects plan to connect to a respective energy source. Of the electrolytic projects about 35% of them could potentially be requiring grid connection, although renewables will be needed to meet the Low Carbon Hydrogen Standard or the additionality requirement of a low carbon energy source (as discussed in Chapter 4)[2], whilst for CCS enabled (blue hydrogen) projects about 55% of projects could be grid connected to get power for running equipment, but this power demand will be significantly lower than that required for electrolysis.

[2] This estimate is based on the data that was obtained from Hydrogen UK – with some blank cells assumed to be grid connection as plans for connection to a RES were typically listed.

Figure 4. Green and blue hydrogen projects throughout the UK



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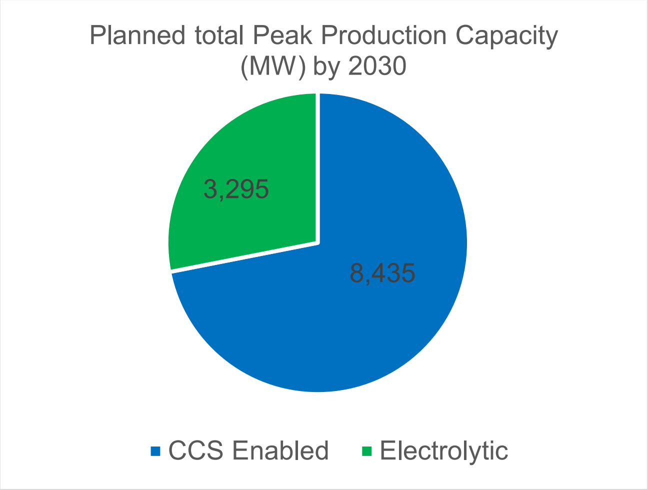

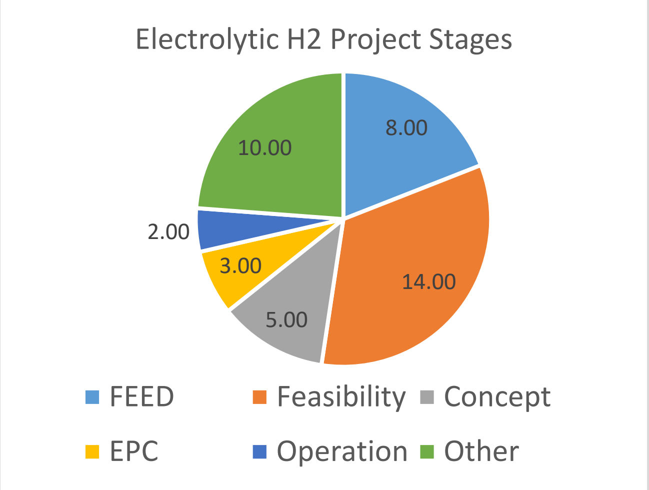

Figure 5 ***The pie chart on the left shows the total planned peak capacity (MW) by 2030 for the projects on the database we have obtained. The pie chart on the right shows the total electrolytic projects and the stage they are in***

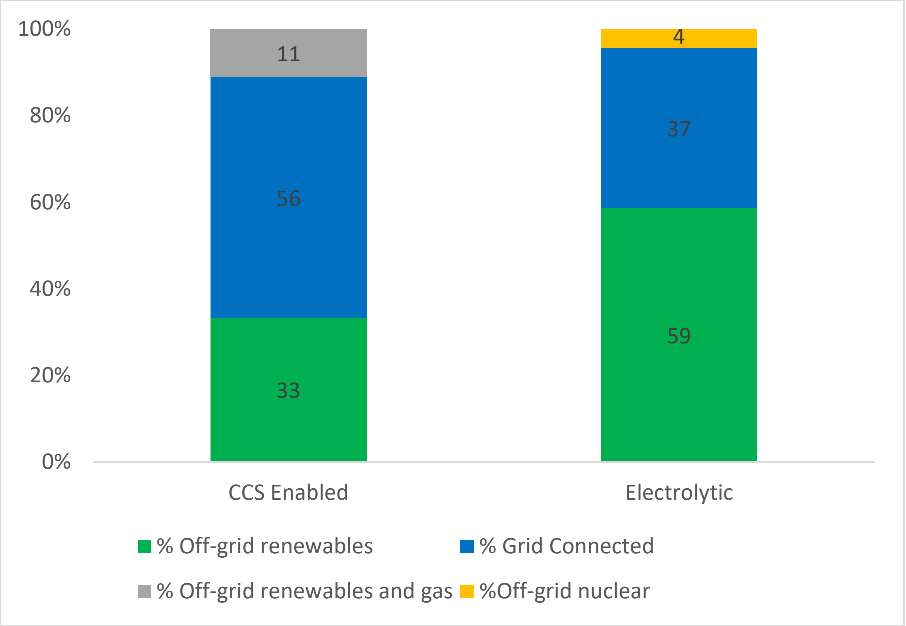

Figure 6 ***The connection method of the projects. CCUS enabled projects need an electricity source for the hydrogen production process using Steam Methane Reforming SMR) with CCUS or Autothermal Reforming (ATR) with CCUS.***

Appendix B (Table B1) shows the hydrogen projects that can potentially impact NGED's network. Projects marked as likely to proceed are those in FEED or EPC stage. Starting by 2024, the confirmed capacity is 20MW (Protium Magor). This roughly aligns with the projections for 2025 in the Consumer Transformation scenario (18MW).

The total capacity of planned projects in NGED's network area is 136MW, with RWE's Pembroke project amounting to the bulk of this capacity (with a peak of 100MW by 2030). The Langage Green Hydrogen project applied for planning permission in the second quarter of 2022.

The potential capacity in 2025, 30MW (assuming RWE Pembrooke does not reach the 100MW peak capacity until 2030), is in between the consumer transformation scenario (18MW, Table 2) and the System Transformation scenario (43MW, Table 2). In 2030, assuming the 100MW capacity has been achieved at Pembroke, the potential capacity, a total of 130MW, in 2030 is closest to Consumer Transformation (141MW, Table 2).

There are several projects in Appendix B (Table B1) which do not have an initial production capacity, or a peak production capacity associated with them, as they are still in at feasibility stage. One of these, the South Wales Industrial Cluster (SWIC), aims to produce green hydrogen at Milford Haven and at Port Talbot in Swansea. Currently the SWIC is undergoing FEED studies which will aid in future financial investments decisions. The project at Milford Haven aims to develop a roadmap to decarbonisation through the design of a hydrogen and renewables smart local energy system. (Milford Haven: Energy Kingdom, 2022) The first stage, which was delivering a FEED study was due to be completed in spring 2022. Another green hydrogen demonstration project is constructed in Port Talbot, the green hydrogen will be mixed into a furnace where it will be burnt with methane. After around 500 days, the electrolyser at Port Talbot has produced 111m^3 of hydrogen (Hydrogen at Hanson, 2022).

Both projects are initial small demonstrations. It is currently uncertain how they plan to source the energy required to transition into a green energy cluster, and the capacity they will require. Given that the SWIC is responsible for over 16million tonnes CO_2 equivalent and is the second largest industrial cluster it can be assumed that the electrolysers needed will have a large capacity, and therefore more aligned with the scenario Steady Progression or Leading the Way by 2030 (Deployment Projects, 2022). Whilst the Steady Progression scenario assumes the UK will not achieve net zero by 2050, there is still an increase of electrolysers up to 339MW by 2035, as shown by Table 2. Figure 7 and Figure 8 show how the respondents plan to connect to current projects and future projects.).

In our survey we asked for the type of connection the electrolysers had in existing and planned projects (whether 100% grid connected, co-located renewables with a PPA, or exclusively connected to a RES). Figure 9 shows how the respondents plan to connect to current projects and future projects. Based on this small set of data, there appears to be no clear trend in the type of current and planned electrolyser connections. One respondent answered more than 90% of their projects will be 100% grid connected, whilst other respondents indicated that none of their current projects are 100% grid connected. We can say many projects will be seeking a PPA and will be grid connected.

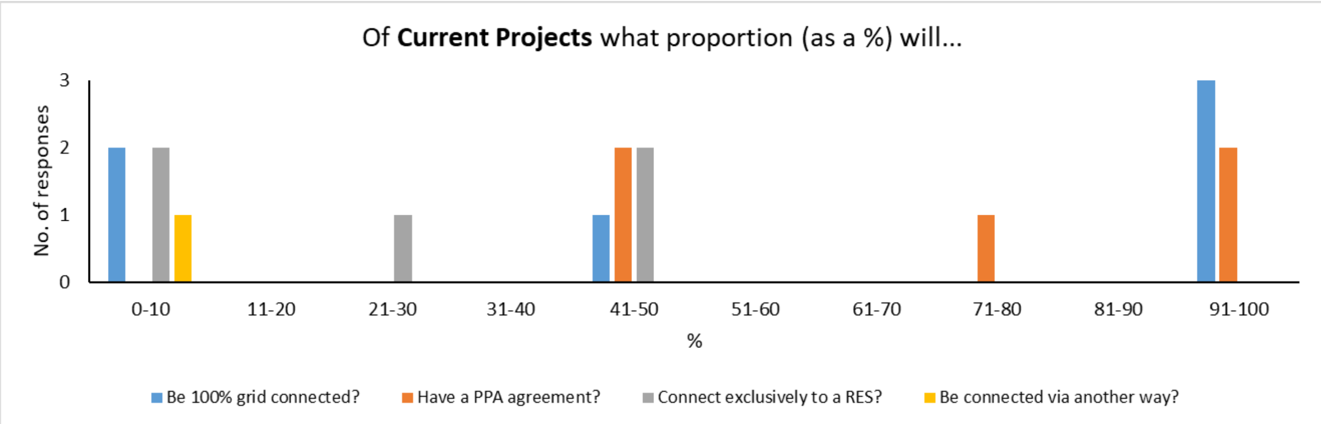

Figure 7 *Current projects and their connections*

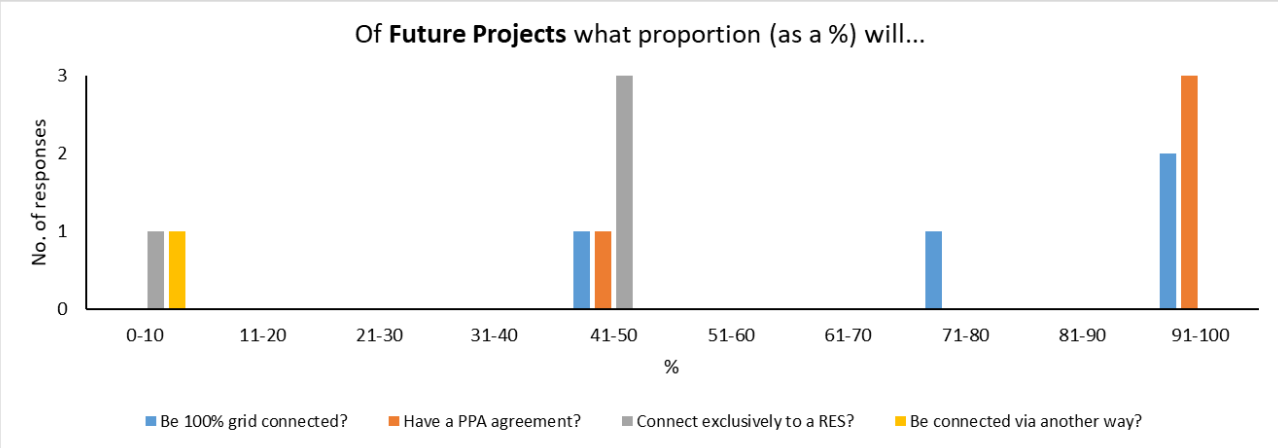

Figure 8 ***Future projects and their connections***

4.2 UK Low Carbon Hydrogen Standard

This Government's (BEIS's) Low Carbon Hydrogen Standard (LCHS) defines the threshold for 'low carbon hydrogen' at the point of production. This standard sets out to describe the methodology for calculating the emissions associated with hydrogen production and also sets out to inform producers of the steps they need to take to ensure the carbon intensity of the hydrogen they produce is lower than the target set by this standard (20g CO_2 equivalent per MJ LHV Hydrogen) (Department for Business, Energy & Industrial Strategy, 2022).

Those projects seeking government funding and support need to adhere to this standard. Given most of the major projects will be seeking government support and will depend on government funding to go ahead, the CO_2 intensity of the network electricity will be a determining factor for those looking at network connection. Hydrogen producers who receive financial support will be expected to provide ongoing compliance, with the yearly checks made on compliance.

It is therefore important for NGED to provide transparency on the carbon intensity of their network over time. Today, electricity from the grid would not meet the threshold of this standard. For this reason, while hydrogen producers are allowed to use grid connected electricity; they must use other low carbon energy sources in conjunction to ensure the hydrogen produced has a CO_2 intensity below the threshold set out in this standard. Where tracing of physical low carbon electricity generation linked to a specific low carbon source is not possible through temporal correlation, the actual average carbon intensity of the national grid at the time the electricity was consumed will be required. Therefore, if producers are near the threshold using electricity from the grid and from renewable sources in summer, then in winter they will have to increase uptake of low carbon electricity from other sources in the winter. The sources of electricity can be seen in Figure 9, which is found in the UK Low Carbon Hydrogen Standard: annexes to guidance document (Department for Business, Energy & Industrial Strategy, 2022)

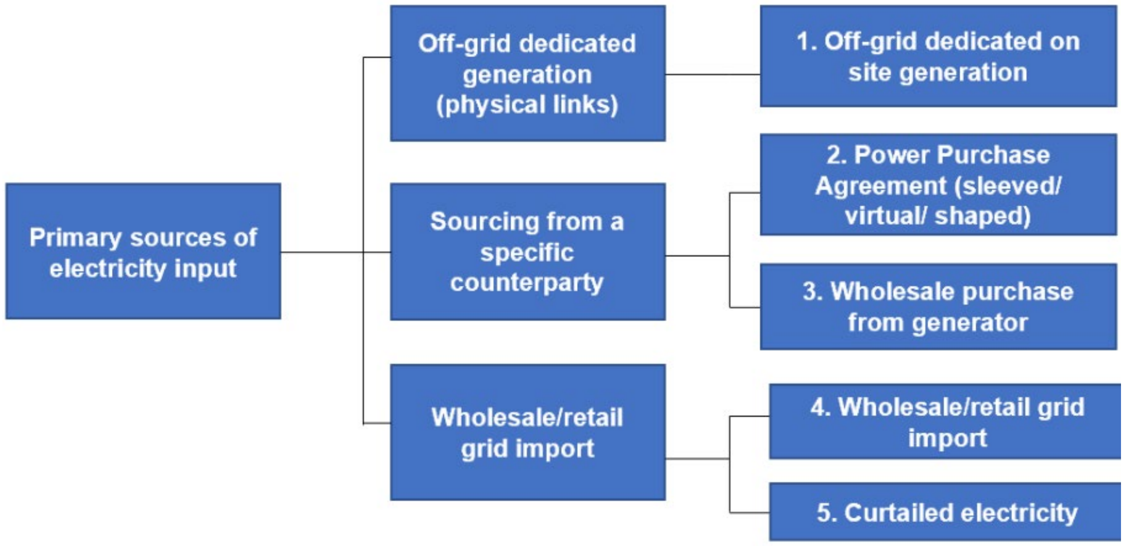

Figure 9 ***Primary sources of Low Carbon Electricity Input for Hydrogen Production (found at UK Low Carbon Hydrogen Standard: annexes to guidance) (Department for Business, Energy & Industrial Strategy, 2022)***

The survey assessed the views of the respondents on the UK's Low Carbon Hydrogen Standard and the UK's Hydrogen Business Model. Of the seven responses, four thought that the UK's low-carbon hydrogen standard would not impact on their decision for grid connected electricity. However, there were some concerns raised with one respondent saying that it would prohibit connection and another stating that it would require a PPA to make it work. Three out five of the respondents to this question believe that the UK's hydrogen business model does not sufficiently incentivise grid connection of electrolysis. Therefore, it appears there are some concerns relating to the Government's Low Carbon Hydrogen Standard (LCHS) and Hydrogen Business Model, which has an additionality criterion (as discussed 4.2.4) in relation to grid connection of electrolysers. These concerns need to be addressed with greater communication between the Department for Business, Energy & Industrial Strategy (BEIS), NGED and hydrogen producers. The survey asked questions about whether producers will use the LCHS in current and future projects.

Appendix B (Table B2) shows that of the current projects the respondents of the survey were involved in, 4 out of 7 currently planned projects will utilise grid connection with the LCHS, furthermore, there will be five future projects which will utilise the LCHS (Table B3 in Appendix B).

4.2.1 Principles of the Low Carbon Hydrogen Standard

In this standard, GHG contributions are defined in grams of carbon dioxide equivalent per megajoule of produced hydrogen at lower heating value ($gCO_2e/MJLHV$).

The standard provides a list of principles. They are as follows:

- Meet a GHG emissions intensity of 20g CO_2e/MJ LHV (72g CO_2e/kWh) of produced hydrogen or less for the hydrogen to be considered low carbon.
- Account for the emissions associated with meeting a theoretical minimum pressure level of 3MPa and a theoretical minimum purity of 99.9% by volume at the production plant gate, in the emissions calculations.
- Include emissions associated with capture, compression, transport, and storage of CO_2 in the emissions calculation: while some of the associated infrastructure may be located outside the point of production, the related emissions were generated through the hydrogen production and are considered within the scope of the standard.
- Account for the use of electricity:
    - Using actual data to demonstrate that the electrolyser is operating at the same time as the electricity input source. The data used will be in 30 minutes consignments and will be provided by the relevant parties for verification and settlement by an independent third party organisation like

in the case of electricity market settlement by Elexon for example. Further evidence on the exact methodology and metering requirements will be provided in due course.

  - Evidencing hydrogen producers have exclusive ownership of the electricity used to cover the amount of electrolytic hydrogen produced.

- Set out a risk mitigation plan for fugitive hydrogen emissions including:
  - Risk Reduction Plan: Produce a plan demonstrating how fugitive hydrogen emissions at the production plant shall be minimised.
  - Risk Plan: Provide estimates of expected rates of remaining fugitive hydrogen emissions by the plant. Noting that these are not accounted for in the GHG emissions calculation above.
  - Risk monitoring: Prepare a monitoring methodology for fugitive hydrogen

4.2.2 GHG calculation method

The GHG calculation method in the Low Carbon Hydrogen Standard (LCHA) is based on a 'point of production' system boundary. This includes scope 1, scope 2 and partial scope 3 emissions. Thus, GHG emissions emitted from the feedstock extraction, collection and transportation, and the impacts of hydrogen production processing facilities (including emissions from fuel and electricity use) are included. In this case, partial scope 3 emissions include raw material acquisition phase emissions, raw material transportation phase emissions and hydrogen generation phase emissions.

Certain scope 3 emissions have not been included to ensure this standard has the same principles with GHG reporting in other sectors. The emissions from the construction, manufacturing, and decommissioning of the capital goods (including hydrogen production plant, vehicles etc.), business travel, employee commuting, and upstream leased assets are not within scope.

Global Warming Potential (GWP) factors are included in this methodology and their impact shall be assessed over a period of 100 years.

This standard provides an equation for calculating GHG emissions associated with hydrogen production. In the future this methodology will be developed into a tool, named the 'Hydrogen emissions calculator', or HEC. The equation, whereby Et is total emissions gCO_2e, is the following:

$$E_T = E_{\text{feedstock supply}} + E_{\text{energy supply}} + E_{\text{input materials}} + E_{\text{process}} + E_{\text{fugitive non}-CO2} + E_{\text{CCS process and infrastructure}} - E_{\text{CO2 sequestration}} + E_{\text{compression and purification}}$$

Each individual emission category will have subcategories. If any CO_2 is captured and permanently stored in geological storage it is removed from total emissions.

The relevant categories for electrolysers are the following:

- Energy supply (electricity, steam, heat and fuel)
- Input materials
- Compression and purification of hydrogen
- Emission allocation for co-products

4.2.2.1 Electricity supply

Hydrogen can be produced using several different energy inputs and production pathways. Each production pathway can have a varying amount of upstream emissions associated with them. Scope 1 electricity supply can be provided with Off-grid renewable generation. Assuming sufficient evidence is provided, this will lead to total emissions of 0.

Grid imported emissions can be calculated using actual national grid average GHG intensity data per 30-minute settlement period. This figure will include the combustion emissions of generation on the UK grid, and transmission and distribution losses from generation to use. However, upstream emissions of UK generation plants are not included due to a lack of time resolved upstream emissions data.

Hydrogen producers receiving electricity from the schemes above may need to report the inputs for production pathways. These pathways may have different upstream emissions associated with them. If this is the case, there are two types of methodologies, or consignments, which can apply. These are the discrete hydrogen consignment and the average hydrogen consignment. Each month a discrete consignment, one averaged consignment or a combination of consignment types must be provided to the relevant authority to demonstrate compliance.

To be considered a discrete consignment the environmental characteristics of the input should be identical:

- Energy input
- Energy generation process
- Feedstock input
- The feedstock form i.e., solid, liquid, ga.
- Feedstock production process
- Country of origin
- Feedstock classification (e.g. biogenic waste, fossil waste, residue), where relevant
- Compliance with the additional sustainability and other criteria, for biogenic inputs
- GHG emissions intensity of the input

There are 3 different types of inputs that are relevant to electrolysers. These are:

- Wholesale grid imported electricity.
- Direct or Sleeved Power Purchase Agreement (PPA) with a renewable or low-carbon generator.
- Off-grid on-site connection to a renewable or low-carbon generator.

Electricity inputs have a set of criteria which they must adhere to. These include

- All electricity inputs shall have a discrete consignment size of 30 minutes.
- Real time tracking of generation and consumption (temporal correlation) is required across all 30-minute consignments.
- Different types of discrete consignment will need to track carbon intensities in different ways:
  - Off-grid physical links must provide generation data matched to hydrogen production consumption per 30 mins.
  - Direct or sleeved PPA must provide generation data matched to hydrogen production consumption per 30 mins (accounting for all transmission and distribution losses).
  - Wholesale grid import must provide actual carbon intensity data per 30 minutes matched to consumption for hydrogen production (accounting for all transmission and distribution losses) using data provided by NGESO.
  - Where a mix of renewable, low carbon electricity and/or grid import are used this should be separated into individual discrete consignments within the 30-minute period with the % of each input clearly matched to hydrogen output volumes (and with all transmission and distribution losses factored in).

4.2.2.2 Documentation required for compliance checks

The list below shows the data/documents that may be required as evidence or for verification is below:

- A scanned copy of the application unit’s business license.
- The hydrogen production flow chart of the application unit.
- The main equipment list for hydrogen production.
- Supply agreements for feedstock, fuel, energy and input materials.

- The life cycle of hydrogen production and associated GHG emissions to point of production.
- List of raw materials for hydrogen production and their associated GHGs emissions.
- Energy/mass flow diagram.
- Energy metering system diagram.
- If hydrogen production facilities and equipment involve multiple locations, a list of production locations, processes, and processes of each facility should be maintained.
- Production date and production capacity information.

Specific reporting requirements will be set out under guidance for government schemes applying the standard, which will be available upon launch of these schemes. The LCHA recommends that compliant hydrogen is reported on a monthly basis with annual third-party verification. This gives the DNO adequate time to transfer the relevant information over to the producer.

4.2.3 Grid carbon intensity projections and implications for electrolyser connections

The National Grid has produced the Carbon Intensity API (National Grid ESO, 2022). This tool forecasts the carbon intensity (gCO_2/kWh) and generation mix of the UK's electricity grid 96 hours in advance. It does this for all the regions of the Great Britain, which are divided according to DNO boundaries, currently it does not provide for regions within a DNO boundary at GSP or BSP levels. Those regions relevant to NGED include South Wales, West Midlands, East Midlands, and the Southwest England.

The grid CO_2 intensity data (for 24^{th} of August 2022) can be seen in Figure 10. The four regions that fall under NGED's network area appear to have some of the highest carbon intensities at different time points. In fact, all regions in Figure 10, except North East England have a CO_2 equivalent intensity greater than the threshold set by the Low Carbon Hydrogen Standard, LCHS (20g CO_2e/MJ = 72g CO_2e/kWh LHV) of hydrogen.

#	Region	Forecast Carbon Intensity (gCO_2/kWh)	Index
1	North East England	24	very low
2	South Scotland	80	low
3	North West England	102	low
4	North Scotland	161	moderate
5	East England	205	moderate
6	Yorkshire	207	moderate
7	North Wales & Merseyside	216	high
8	West Midlands	224	high
9	London	224	high
10	South England	239	high
11	South East England	243	high
12	South West England	271	high
13	East Midlands	294	high
14	South Wales	349	very high

Figure 10 ***National Grid CO_2 intensity on the 24th of August 2022***

The tool works by analysing a 30-min temporal resolution using machine learning regression models. GB is divided into regions and represented as an N-bus network connected by lines. By doing this, the tool can determine whether each region is an exporter or an importer (based on a 30-min temporal resolution). Using a power flow analysis, the carbon intensity of power flows is then calculated, which allows the carbon intensity of power consumed in each region to be calculated. This tool can be used by electrolyser projects to determine if the grid carbon intensity will meet the greenhouse gas emission threshold set out in the LCHS.

NGED have developed their own tool (NGED, 2018) which determines the carbon intensity of the different regions. Each region is then split into the several different areas, each one representing a substation that NGED operates. The tool allows the user to select a date seven days into the future, therefore allowing the user to analyse the projected carbon emissions for that seven-day period. It is important for NGED to better publicise this tool and to make it most functional for electrolytic hydrogen project developers looking to connect to NGED's network. The LCHS is one of the critical factors influencing project development decisions as producers of hydrogen looking to access UK government funding have to prove the hydrogen produced will meet the LCHS.

In 2020, BEIS updated their energy and emission projections (BEIS, 2020). Their projections, from 2022 to 2040, show that the projected total electricity demand from 2022 to 2040 for industry is projected to marginally decrease although the total electricity demand across all sectors is expected to slightly increase.

Figure 11 shows the projected emission intensity up to 2040, one using EEP (Energy and Emissions Projections) data from 2018, and the other using data from EEP in 2019. As seen, the projections between the two years vary quite a substantial amount, this is due to an increase in RES capacity installed/planned in 2018. It is projected that by 2030 the CO_2 equivalent emission intensity (gCO_2e/kWh) is $85gCO_2e/kWh$ ($306\ gCO_2e/MJ$) in EEP 2018, and around $90gCO_2e/KWh$ ($324\ gCO_2e/MJ$) in the EEP 2019. Based on these projections, in some areas of the UK (including NGED's network region), developers would not be able to access any government funds under the Hydrogen Business Model. This means grid connection would not be a viable option for hydrogen production unless renewables are co-located with hydrogen production projects to lower the CO_2 intensity of the electricity to a value below the LCHS.

Projections regarding the different regions within a DNO licence area could not be found. It is important for NGED to produce plans for connections of renewable generation on its network with the corresponding projections for greenhouse gas (CO_2 equivalent) intensity of the electricity in its network area to 2030 and ideally beyond.

This should be done in conjunction with the various industrial clusters and potential electrolyser operators in the region, to ensure the data provided is as accurate as possible thus the emission intensity is accurately projected. It is also important carbon intensity information between NGED, and the electrolyser operators is shared in a streamlined manner, thus the operators are able to determine when CO_2 intensity levels is below the threshold.

Carbon intensity estimates produced at regional levels or locally at bulk supply points (BSP) within NGED licence area could highlight the opportunities for connection of both renewables and electrolysers.

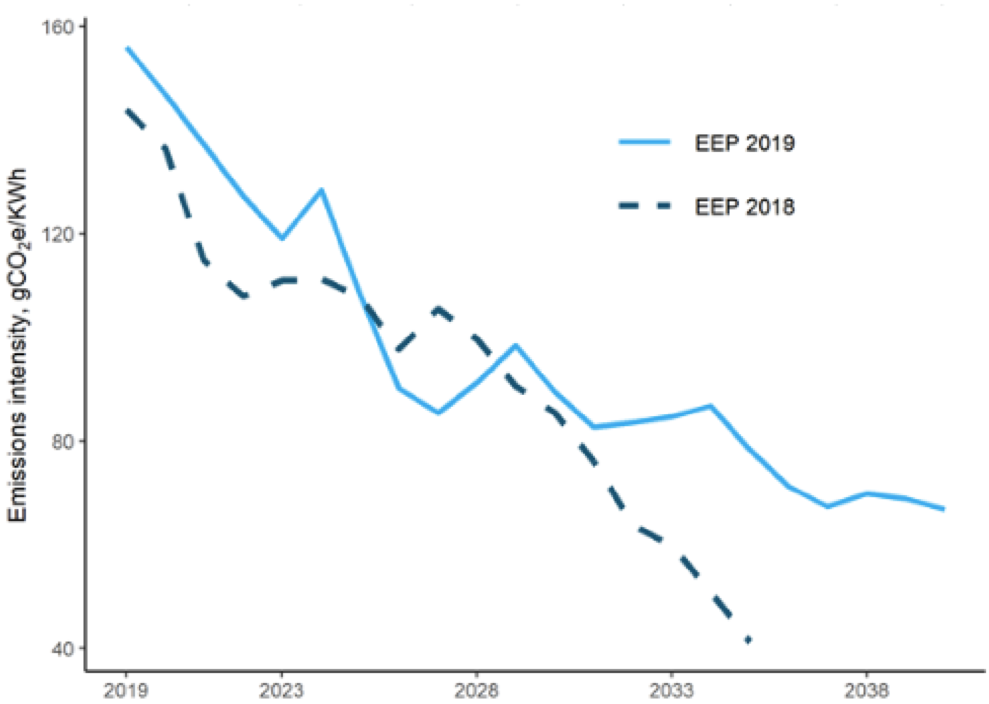

Figure 11 Emission intensity – all power producers (BEIS, 2020)

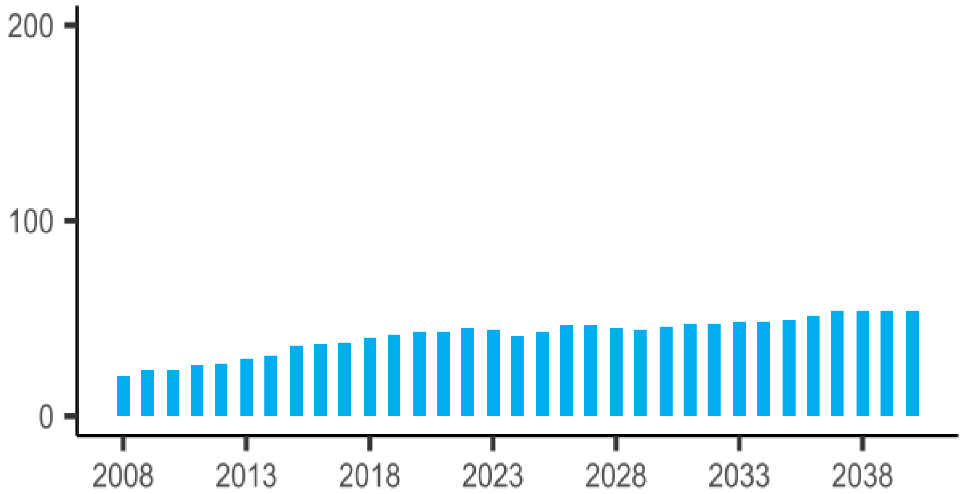

Figure 12 Primary energy demand of electricity from renewables, nuclear and other sources, in Mtoe (BEIS, 2020)

The electricity generation from renewables will increase over the course of the next two decades (2019 to 2040) and renewable energy sources are predicted to be the most prominent source of electrical energy. This increased penetration of renewables presents opportunities for the hydrogen sector, while the power sector has both opportunities and challenges to deal with. There will be an increasing number of PPA agreements between RES project owners and electrolyser project owners, and NGED will need to prepare for this. Especially since, PPAs will be required for hydrogen producers to achieve the LCHS.

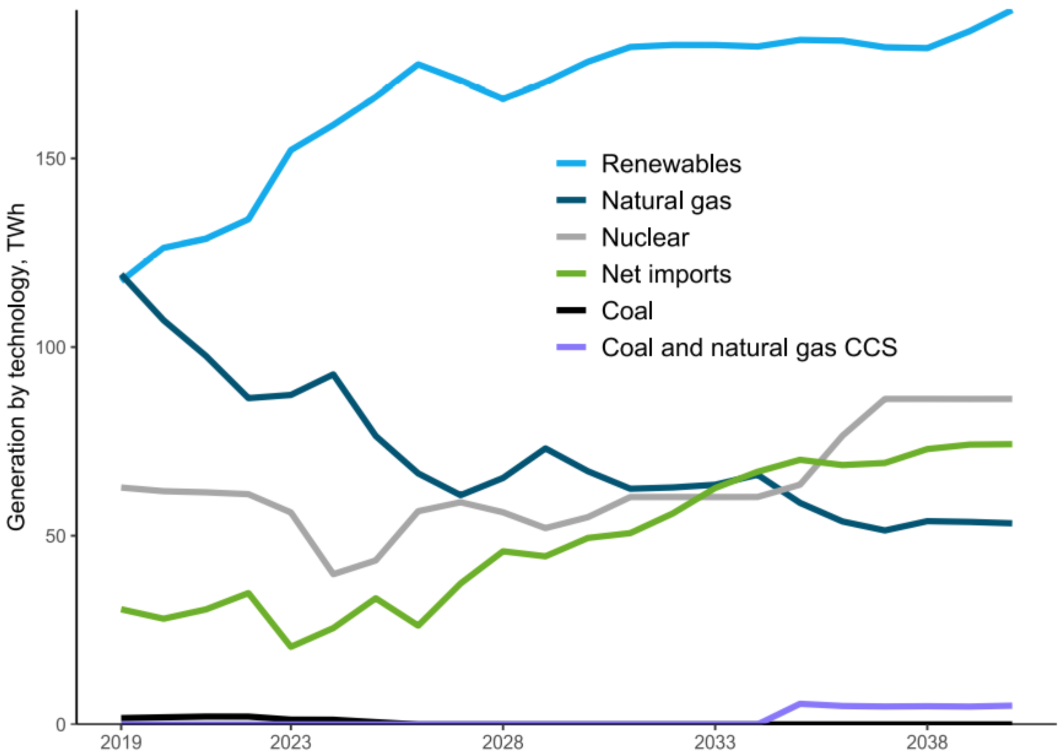

Figure 13 ***Electricity generation by fuel source, TWh (BEIS, 2020)***

4.2.4 Additionality of Electricity Source

The UK currently has two main mechanisms for funding Hydrogen Projects, the Hydrogen Business Model (HBM) and the Net Zero Hydrogen Fund (NZHF). The HBM is revenue support model that is designed to overcome the cost gap between low carbon hydrogen and cheaper counterfactual fuels while this nascent market develops. The Net Zero Hydrogen Fund (NZHF) is a £240 million fund that aims to support the commercial deployment of new low carbon hydrogen production projects during the 2020s and will be to be delivered between 2022 and 2025.

Any project that applies for these funds are subject to an additionality requirement, which is a criterion put in place to uphold the principles of the LCHS. In this context, additionality means that “hydrogen production should be met by new low carbon electricity generation and should not divert low carbon electricity from other users, avoiding negative impacts on wider decarbonation” (BEIS, 2022). The projects that apply for HBM or NZHF would be scored against an additionality criterion assigned a 5% weighting, which is in fact lower than other elements of the assessment criteria: deliverability (35%), costs (20%), economic benefits (10%), CO2 emissions (10%), and market development and learnings (10%). Under this additionality criterion, projects are assessed against preferred sources of energy as below (BEIS, 2022):

- New purpose-built
- Curtailment of existing assets
- Extension of the life of existing assets
- Recommissioned assets

Projects will be scored for providing clear and credible evidence, such as a “procurement plan to demonstrate that the intended electricity source will meet one of the four additionality principles set out above”, or “the percentage of the overall electricity supply that will be generated from additional regeneration”, etc. (BEIS, 2022). Therefore, while H2 production via otherwise curtailed energy can be done for projects seeking government funding, it is likely that many of the new hydrogen productions in the next few years will have renewable energy source agreements such as PPA’s to help meet the LCHS.

4.3 Criteria for identifying optimum electrolyser siting locations

This section will look at the factors that will be important for selecting network connection sites for connecting electrolysers to the electricity grid for green hydrogen production.

The siting of electrolysers needs to consider a range of factors to maximise value to the energy system and the hydrogen producers and users. Today, the optimal sites for locating electrolysers from the network connection perspective is still highly uncertain for electrolytic hydrogen production projects and project developers, due to a number of unknowns, including:

- The potential for hydrogen electrolysers to be co-located with existing or new distributed renewable generation
- The availability of low carbon electricity (based on demand and supply balance in the grid) and how this is likely to change in the next decade. This will quantify the ‘capacity factor’ e.g. from otherwise curtailed energy available for hydrogen production, or from co-location with renewables.
- Regions with network constraints
- Carbon intensity of the network
- Whether or not there will be construction of a national hydrogen network that would be able to transport hydrogen around the UK and thus creating flexibility on siting electrolyser deployments
- The location of large-scale storage facilities, which are currently been explored for hydrogen storage
- Availability and access to water pipes with sufficient pressure and flow, and possible desalination needs
- Access to electricity network infrastructure, including distance to infrastructure, network voltage and network capacity
- Access to gas network infrastructure (for blending into existing gas network)
- Market demand for hydrogen and proximity to the market of potential electrolyser sites (this can be based on publicly announced projects and scenario for potential growth in the next decade)
- Availability of suitable sites, including factors such as accessibility, size of electrolysers, and requirements for storage and distribution infrastructure.
- Availability of land

As discussed in Chapter 3 locating electrolysers close to renewable generators could minimise the need for electricity network reinforcement to transport this energy. On the other hand, sub-optimal siting could potentially increase network costs and constraints. Therefore, assessments are needed at the regional level to determine most suitable sites for connecting electrolysers based on a pre-determined set of criteria.

Detailed investigations of the local impact of large-scale electrolysers and their operation strategy on the power grid operation and congestion rates, analysed via active power flows on the georeferenced power lines, are required. Depending on the capacity availability and size of the electrolyser unit, the EHV network is likely to be most suitable for connection.

In the survey sent out, we asked respondents to rank from 1-3 a set of criteria for identifying optimum locations, with 1 being low importance and 3 being high importance. Figure 14 shows the outcome of this ranking from the six respondents. The two most important factors are electricity cost profile and connection costs, with one of the respondents indicating that electricity cost is 80% of the project and another stating that the DNO must play a leading role in reducing electricity costs (e.g., by reducing fees and/or levies).

Distribution (both trailer and pipeline) was, on average, less important. Given that proximity to off-taker is noted to be of high importance for these specific operators, this is consistent. Furthermore, one of the respondents indicated that they did not believe that hydrogen distribution by pipeline would be useful in the near future, given the current restrictions in hydrogen blending. This is supported by another respondent, who stated they do not believe hydrogen pipelines would exist before 2030. The same thinking was presented for underground hydrogen storage, a lack of current availability of underground storage sites made it less of a factor in the criteria for optimising deployment sites.

Two of the respondents discuss the benefits of underground storage. One of them stated how underground storage could be useful for providing energy grid balancing, and the other stated that underground storage could be of paramount importance if domestic heat provision switches to hydrogen. The complete set of responses for each factor can be seen Appendix C (Table C1).

All of the respondents indicated proximity to water was important, with one of them indicating that water for cooling could lead to CAPEX and OPEX savings too.

Using this information and information gathered from conversations with project developers we have developed an excel based site selection criteria for NGED to use when reviewing potential sites for connecting electrolysers, based on the stated needs of project developers looking to site electrolysers on a DNOs network. The set of criteria used in the assessment for site selection is shown in Appendix C (Table C2). This tool, which has a scoring system, is developed with the objective of streamlining the application process of a project developer for NGED to select and advise on a set up sites based on the ranking (score) obtained from the tool.

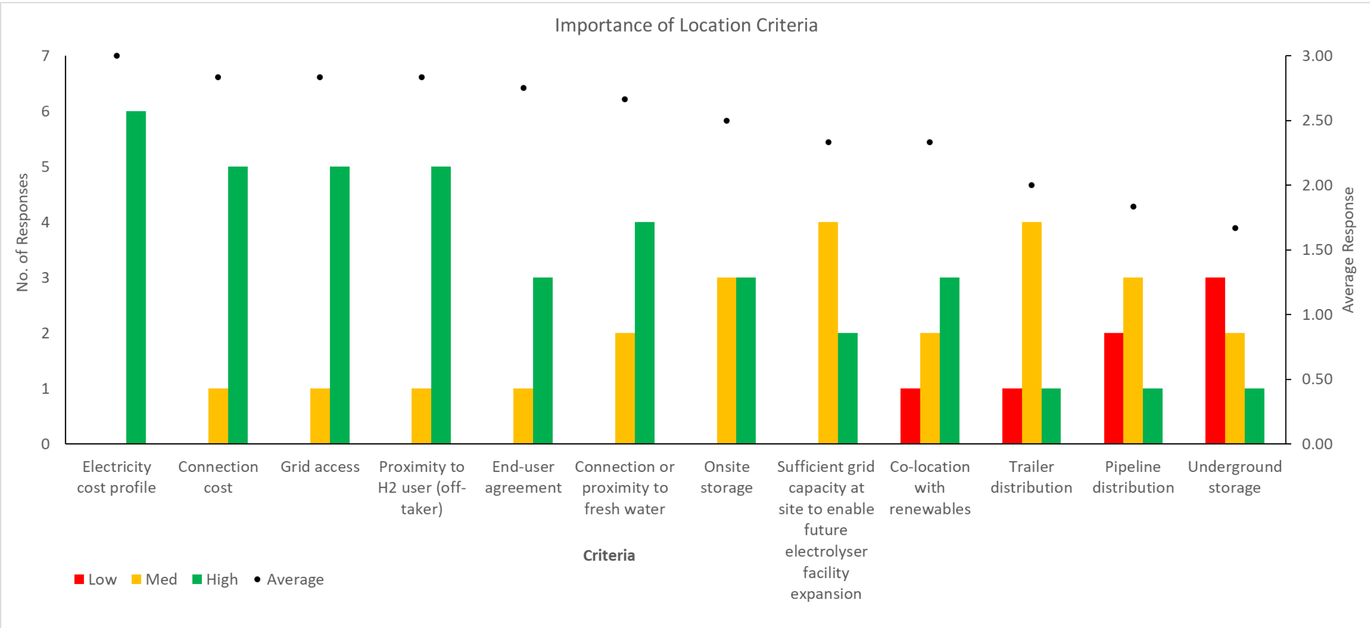

Figure 14 ***The importance of different location criteria for each of the respondents for identifying optimum locations***

5. Insights from Project Developers on Grid Connection of Electrolysers

5.1 Survey questions and responses on electrolyser connections to the grid

In addition to some of the key questions and findings from our survey, as noted in the relevant sections above, we asked a set of questions to identify any key challenges with regards to grid connection of electrolysers, and the ways it can be incentivised etc.

Several of the comments in the questionnaire indicated the need for effective communication between DNOs and electrolytic hydrogen project developers for developing solutions that incentivise grid connection of electrolysers to benefit hydrogen producers but also for grid balancing services. From a hydrogen producer's perspective, this is especially important for understanding the operational modes and optimisation of site selection. From the DNOs perspective, it will show how much of the electrolyser capacity can be used for grid balancing services.

Some of the other relevant questions and a summary of the answers are below.

Q) How can DNOs make grid connection of electrolysers more technically feasible?

The respondents said they would like the DNOs to communicate with them and discuss how they would like the electrolysers to operate to minimise problems and help find a suitable solution for all parties.

Q) How can DNOs make grid connection of electrolysers more economically feasible?

Respondents noted that variable and interruptible tariffs would make grid connections more feasible. The DNOs advising a suitable operating regime and demand side response schemes would also help. One respondent used an example from Germany where they reduced grid fees. Overall communication between DNOs and project developers would improve feasibility and allow mutually acceptable solutions for all parties.

Q) How else can DNOs incentivise grid connection of electrolysers?

Reducing the impact of non-energy costs and variable tariff provisions are considered important. One respondent mentioned that distinguishing between flexible and inflexible electrolysers would be important to enable better deals for flexible systems. Other respondents added Generator Distribution Use of System (GDUoS) charges and negative demand use of system charges.

Q) How can DNOs be involved in determination of sites for electrolyser connections – to optimize site choices (in terms of costs, and operational efficiency and speed of connection etc.)?

DNOs should engage with the hydrogen community and project developers at an early stage to work collaboratively in order to develop suitable solutions. One respondent mentioned that using government or OFGEM to facilitate the early stages of communication may help enable progress in this regard.

Q) Please indicate any other financial incentives/policies that could increase deployment of electrolysers on the grid?

CAPEX sharing and rewarding projects that offer good flexibility to DNOs were suggested by respondents. Also, early deployment of 100% hydrogen backbone includes low costs no regrets funding of early-stage development and identification of locations where electrolyser deployment would have system benefits.

Q) Do you currently experience any challenges in connecting electrolysers to the grid?

Q) Do you anticipate any challenges in connecting electrolysers to the grid in the future?

If yes to above, please describe the challenges you experience or expect to experience, especially if these are network related.

In response to questions above, regarding current and future challenges experienced by electrolyser OEMs and project developers, 2/5 respondents said that they currently experience challenges in connecting electrolysers to the grid. It was mentioned that they had issues securing dynamic connections and there were problems with insufficient grid capacity. Based on current challenges the timing of electrolyser connections may not aligning with government ambition of 1GW electrolyser capacity by 2025.

In the future all respondents expect to face challenges in connecting electrolysers to the grid. They anticipate that there will be issues around capacity and connection limitations as well as cost issues and competition for connections. Respondents also anticipate challenges around government policy on grid connected hydrogen and its 'low carbon' credentials. One respondent stated that there is "a lack of appreciation and experience of electrolyser/hydrogen projects in the electricity sector, which is a challenge to overcome." And that "more liaison and discussion between the nascent hydrogen community and long-established electricity community is required."

5.2 Discussions with Project Developers: Site selection Criteria and Challenges

As part of this study, we have spoken to several project developers to better understand the process developers have gone through in their application to NGED for connecting electrolysers. In addition to the information provided by the survey, we have identified some common themes in terms of what is important for project developers as well as common challenges experienced by these developers.

The factors that are considered as important are:

- Proximity to off-takers. Given that the current BEIS funds for hydrogen production projects require off-taker agreements, many of the projects prioritise the hydrogen production site being close to the point of use (off-taker). This is predominantly to remove the logistics and cost of hydrogen storage and distribution.
- For industrial clients, security of supply can be a high priority, requiring grid connection or large energy storage if only RES is used to power electrolysers.
- All projects in HBM are 5MW - commercial scale, which can limit the sites with available capacity, and more clarity on the available sites needed.

Challenges and Requirements:

- Many of the available load demand sites on the network are being taken by battery energy storage projects, and some cases EV charging or heat pump connections. Any synergies with electrolyser and battery co-location needs to be further investigated. Most battery storage operators prefer to have flexible contracts that do not constrain their level of operation.
- The timelines for both BEIS and DfT hydrogen projects to start operation (2025) do not align with the timelines for getting grid connection from NGED, which can be as long as five years.
- If there are areas where the government wants to see projects like South Wales, then instead of piece meal solutions there needs be a more comprehensive infrastructure building programme. Therefore, BEIS needs to be more joined up with NGED and other DNOs in order to meet UK's electrolytic Hydrogen production target of 5GW by 2030. To reach this capacity, grid connection will be required, as the RES capacity would need to be at least double this for electrolyser connections alone, which is also limited to certain parts of the UK.
- It is a slow process to identify sites that are feasible to connect to on the network, and costs are very high. It would be good to have transparency of where the best electrolyser connection sites are for NGED.
- More clarity is needed on the CO_2 intensity of the grid at more regional level (not just with 30 mins temporal resolution), as this is important for project planning and development for projects seeking government funding.

Questions to NGED:

- How electrolytic hydrogen production, as a flexible electricity demand can bring value to NGED? Especially in regions with high RES being connected to the grid.
- Would NGED allow derogation with P26, for security of supply?
- How can developers engage with NGED to discuss and address the challenges experienced?

6. Conclusions and recommendations

This desktop study has shined some light on the status of the electrolytic hydrogen production projects in the UK by looking at the current plans of the sector, some of the challenges of project developers, as well as the opportunities and challenges presented by these projects for the electricity grid.

To capture the most up-to-date information and key insights from the electrolytic hydrogen production community (electrolyser OEMs, integrators and project developers), we sent out a survey to inform key questions of this study. The insights captured can also help instigate further communication between NGED and these stakeholders to inform network development plans going forward.

The current plans for hydrogen projects are aligned with the UK’s 10GW hydrogen production target by 2030, however less than a third of these projects are planned to be electrolytic hydrogen production projects. This indicates that there are barriers to the growth of these projects. While the cost of electrolytic hydrogen production, which is higher than the cost of CCUS enabled hydrogen production from natural gas, is one of the main reasons, there our survey and conversations with developers show that they experience challenges in connecting electrolysers to the grid. These are predominantly connection process challenges, as well as cost, technical and regulatory challenges. The main challenges that have been raised are difficulty in identifying suitable connection sites with sufficient capacity, as well as high cost and competition for available sites. Another challenge is the mismatch in the project timelines dictated by BEIS’s Hydrogen Business Model and other hydrogen funds to support major electrolytic hydrogen production projects, which are required to start by 2025, and the time frames for getting site access from NGED, especially if reinforcements are needed, which can be as long as 5 years.

The newly introduced Low Carbon Hydrogen Standard also creates an additional challenge for exclusive grid connections today, as the GHG intensity of the electricity is higher than the threshold mandated by the standard (20g CO_2 equivalent per MJ LHV Hydrogen or less). One reason for this is the lack of information on the long-term forecasts for the CO_2 intensity of the grid in NGED’s network area, and the other being that grid electricity often does not meet this threshold. This aspect is quite important to enable commercial assessment of projects with higher levels of certainty and aid in investment decision making. While hydrogen can be produced in excess and stored for use later during times of low CO_2 intensity of the grid, this creates added costs, and complexities as the CO_2 intensity of the grid is likely to be reducing over time creating stranded assets.

The CO_2 intensity projections currently available covers only a short duration of the order of a few days ahead. Projections for longer periods will help in project assessments over a longer period of time and also help in planning the operations in the short term.

With the lack of adequate storage and transport infrastructure currently, the production of hydrogen needs to be closer to the off takers and therefore developers have very limited flexibility in the choice of locations for siting electrolyser plants. This prevailing network capacity shortage issues and the high costs of network reinforcements and long lead times pose significant issues for the developers.

Our survey and discussions with developers has shown that they are keen to engage with DNOs to overcome some of these challenges but to also to jointly assess how DNOs can capitalise on the opportunities presented by electrolysers.

We have discussed that electrolytic hydrogen production (or Power-to-X) via grid connection of electrolysers can help enable flexibility with increasing penetration of renewables to balance seasonal supply and demand discrepancies, through long duration energy storage, and a range of ESO and DNO managed services enabling constraints management, flexibility, Demand Side Response and specific balancing services such as Frequency Regulation, Black Start, Fast Reserve, and Sort-term Reserve.

It should be noted that while the low storage costs of hydrogen make it appealing for long term energy storage, using that hydrogen to produce power is more expensive and inefficient compared to similar power technologies today. This technology needs to be scaled up to make it more competitive. Therefore, the chances of using Power-to-X for grid services is still very much dependent on the future size of the electrolyser market. Increasing capacity and number of electrolysers can also contribute to network constraints issues. It is therefore important for the DNOs and the hydrogen stakeholders to further engage and create a system that enables the developers to streamline their efforts to identifying connection sites for electrolytic hydrogen production.

Furthermore, appropriate mechanisms (contracts) will be required to incentivise operators to produce electrolytic hydrogen in a way that benefits them and the DNO while avoiding network constraints. Mechanisms such as Time of Use tariffs, Real-time Pricing, payments for entering a demand-side-response and Active Network Management schemes should be made available for participation of electrolytic hydrogen projects.

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Appendix A Survey assessing connection of electrolysers to the grid

WPD Survey: Assessing Connection of Electrolysers to the Grid

Estimated time to complete survey : 30 mins

Introduction

The UK Government, in its recent Energy Security Strategy, has doubled the target for low-carbon hydrogen production to 10GW by 2030. It is anticipated that about half of the hydrogen produced will be via electrolysis by 2030, which means adding a sizeable amount of demand to electricity networks. Studies looking at electrolyser connections to the grid have focused on the potential of hydrogen for energy storage to balance supply and demand, for services such as constraints management or for developments informed entirely by uptake of fuel cell electric vehicles. This is distinct from the growth of the hydrogen production economy, and there is a need to ensure electricity networks will not be a barrier to increasing electrolytic hydrogen production.

In this light, Western Power Distribution (WPD), the electricity distribution network operator (DNO) for the Midlands, South Wales and the South West, has commissioned GHD to look at the prospects and challenges of connecting electrolysers to the grid to 2030. This study will inform WPD to take necessary actions to plan for and implement the changes needed to accommodate and incentivise increased level of electrolyser connections to the WPD network. This study will also have implications for other DNOs.

As part of this work, we are looking to better understand from electrolyser OEMs, integrators, as well as project developers, the key challenges, as well as opportunities presented by electrolyser integration to the grid. The findings will inform WPD on the necessary changes required in power distribution networks to help facilitate grid connection of electrolysers.

Some of these questions apply only to project developers and some to electrolyser OEMs. If a question does not apply to you, please indicate Not Applicable (N/A) in the text box. A summary of the findings from this study can be shared with those participating in the survey. Please send an email to Dr. Zeynep Kurban (zeynep.kurban@ghd.com) if you would like to have this summary, and we will let you know when the report is completed.

Disclaimer: This survey is being done anonymously, neither GHD nor others will know the identity of the respondents.

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Hydrogen Project Questions for UK deployments

Type of electrolyser connections to distribution networks and agreements

1. Please indicate which category your organisation falls under

- ◯ Electrolyser OEM
- ◯ Electrolyser OEM and Integrator
- ◯ H2 Project Developer
- ◯ All those above
- ◯ Other

2. Are you a UK registered entity?

- ◯ Yes
- ◯ No

3. Do you have any existing electrolyser projects in the UK?

- ◯ Yes
- ◯ No

4. If Yes to Question 3, please provide further project details where possible, giving the information below.
   - Project Name (optional)
   - Project Location (town/city)
   - Type of Electrolyser (PEM, Alkaline, other)
   - Size of Electrolyser
   - Source of Electricity (Grid, Wind, Solar, co-sourced e.g. via PPA)

Enter your answer

5. Do you have any panned electrolytic H2 production projects that you hope to commence by 2030 in the UK?

If your answer is No, then please review the rest of the survey for questions you can answer. OEMs please see Section 4.

◯ Yes

◯ No

6. If Yes to Question 5, please provide further project details where possible, giving the information below.
   - Project Name (optional)
   - Project Location
   - Type of Electrolyser (PEM, Alkaline, other)
   - Size of Electrolyser
   - Source of Electricity (Grid, Wind, Solar, co-sourced e.g. PPA)

Enter your answer

7. Please indicate what proportion of your projects deploying electrolysers (or planned projects deploying electrolysers in the next 2 years) are in the UK?

Enter your answer

8. Of current projects, what proportion (as a %) will be 100% grid connected?

Enter your answer

9. Of current projects, what proportion (as a %) will have a PPA agreement?

Enter your answer

10. Of current projects, what proportion (as a %) will connect exclusively to a Renewable Energy Source?

Enter your answer

11. Of current projects, what proportion (as a %) will be connected via another way (please explain)?

Enter your answer

12. Of planned projects to be built by 2030 what proportion (as a %) will be 100% grid connected?

Enter your answer

13. Of planned projects to be built by 2030 what proportion (as a %) will have a PPA agreement?

Enter your answer

14. Of planned projects to be built by 2030 what proportion (as a %) will connect exclusively to a Renewable Energy Source?

Enter your answer

15. Of planned projects to be built by 2030 what proportion (as a %) will be connected via another way (please explain)?

Enter your answer

16. Do you anticipate deploying electrolysers for H2 production using curtailed energy by 2030?

- ◯ Yes
- ◯ No
- ◯ Maybe

17. If yes to Question 16, will you use a dedicated privately owned connection to the solar/wind farm?

- ◯ Yes
- ◯ No

Grid Connection Requirements

In terms of the factors that will determine grid connection, how important are the following elements to your decision for electrolyser deployment projects? (**1=Low Importance, 2=Medium Importance, 3=High Importance**).

18. Connection cost

1 2 3

○ ○ ○

19. Please explain how **connection cost** is important or any key considerations.

Enter your answer

20. Grid access

1 2 3

○ ○ ○

21. Please explain why **grid access** is important or any key considerations.

Enter your answer

22. Sufficient grid capacity at site to enable future electrolyser facility expansion

1 2 3

○ ○ ○

23. Please explain how **sufficient grid capacity at site to enable future electrolyser facility expansion** is important or any key considerations.

Enter your answer

24. Co-location with renewables

1 2 3

○ ○ ○

25. Please explain how **co-location with renewables** is important or any key considerations.

Enter your answer

26. Electricity cost profile

1 2 3

○ ○ ○

27. Please explain how **electricity cost profile** is important or any key considerations.

Enter your answer

28. Connection or proximity to fresh water

1 2 3

○ ○ ○

29. Please explain how **connection or proximity to fresh water** is important or any key considerations.

Enter your answer

30. Proximity to H2 user (off-taker)

1 2 3

○ ○ ○

31. Please explain how **proximity to H2 user** is important or any key considerations.

Enter your answer

32. End-user agreement

1 2 3

○ ○ ○

33. Please explain how **end-user agreement** is important or any key considerations.

Enter your answer

34. Onsite storage

1 2 3

○ ○ ○

35. Please explain how **onsite storage** is important or any key considerations.

Enter your answer

36. Underground storage

1 2 3

37. Please explain how **underground storage** is important or any key considerations.

Enter your answer

38. Pipeline distribution

1 2 3

39. Please explain how **pipeline distribution** is important or any key considerations.

Enter your answer

40. Trailer distribution

1 2 3

41. Please explain how **trailer distribution** is important or any key considerations.

Enter your answer

42. Please state any other factor(s) that is an important consideration for site selection

Enter your answer

Grid Connection: Challenges, Opportunities and Incentivisation

43. Do you currently experience any challenges in connecting electrolysers to the grid?

◯ Yes

◯ No

44. If yes to Question 43, please describe the challenges you experience, especially if these are network related.

Enter your answer

45. Do you anticipate any challenges in connecting electrolysers to the grid in the future?

◯ Yes

◯ No

46. If yes to Question 45, please describe the challenges you experience, especially if these are network related.

Enter your answer

47. In your view, how can DNOs make grid connection of electrolysers more **technically** feasible

Enter your answer

48. In your view, how can DNOs make grid connection of electrolysers more **economically** feasible?

Enter your answer

49. How can DNOs incentivise grid connection of electrolysers?

Enter your answer

50. How can DNOs be involved in determination of sites for electrolyser connections – to optimize site choices (in terms of costs, and operational efficiency and speed of connection etc.)?

Enter your answer

51. Please indicate any other financial incentives/policies that could increase deployment of electrolysers on the grid? This can relate to National Grid or policy creation.

Enter your answer

52. How does the UK's low-carbon hydrogen standard (≤ $20gCO_2e/MJ_{LHV}$ of produced hydrogen) impact your decision for grid connected electricity? Note: This standard applies to projects seeking government funding.

- [ ] Prohibits connection
- [ ] Does not make a difference for non-government funded projects
- [ ] Requires a PPA (with renewables co-located) to make it work
- [ ] Do not know

53. Does the UK Hydrogen Business Model sufficiently incentivise grid connection of electrolysers?

◯ Yes

◯ No

54. Does your electrolyser application require steady H2 production throughout the day/year?

◯ Yes

◯ No

55. Can your electrolyser application be designed to offer flexibility services to the power system?

◯ Yes

◯ No

56. Are you interested in providing flexibility services to the grid operator and/or the DNO?

◯ Yes

◯ No

57. If yes to Question 56, can you explain what services you wish to provide?

Enter your answer

58. Please provide any other comments you have with regards to grid connection of electrolysers.

Enter your answer

59. In the future, renewable oversupply rather than network constraints could become dominant driver of curtailment and lead to extended periods of zero marginal cost electricity, which could make lower load factors attractive to electrolysers.

Have you looked at the conditions for when this makes the use of electrolysers viable for reducing curtailment?

- ◯ Yes
- ◯ No

60. If yes to Question 59, what cost of electrolyser and capacity factors make this viable (If known)?

Enter your answer

61. What are the range of size(s) of electrolysers that you are currently building? Please provide the following information:
    - Size Range (MW electrical)
    - Estimate Cost Range (if available)
    - Unit of Cost (£/kWe, Euro/kWe)

Enter your answer

62. What are the range of size(s) of electrolysers you expect to build by 2025 and by 2030? Please provide the following information and the target year:
    - Size Range (MW electrical)
    - Estimate Cost Range (if available)
    - Unit of Cost (£/kWe, Euro/kWe)

Enter your answer

63. What is the 0-100% response time of your electrolyser plant?

Enter your answer

64. What is the 100-0% response time of your electrolyser plant?

Enter your answer

65. What is the operating power factor of your electrolyser plant (P and Q)?

Enter your answer

66. What is the cold start duration of you electrolyser plant?

Enter your answer

67. What is the hot standby condition of your electrolyser plant?

Enter your answer

68. What is the hot start response time of your electrolyser plant?

Enter your answer

69. What are the ramp-up and ramp down rates of your electrolyser plant?

Enter your answer

70. What is the max power rating of your electrolyser plant?

Enter your answer

71. What is the minimum 'on' duration ,if any, of your electrolyser plant?

Enter your answer

72. What is the minimum notice time from the system operator required to shut down, if any?

Enter your answer

73. Do you have a back-up power facility?

- [ ] Yes, to maintain continuity of operation when there is supply interruption.
- [ ] Yes, for a short duration to facilitate supply switch-over.
- [ ] No

74. Are you able to provide operating plan for the Day Ahead, Week Ahead periods?

Enter your answer

75. Is the demand flexible for grid balancing requirements?

Enter your answer

Appendix B UK Hydrogen Projects

Table B1: The projects that will or may impact NGED network

Location	Project Name	Stage	Type of project	Peak Prod. Capacity (MW)	Electricity Source
Wales	RWE Pembroke	Feasibility	Installation hydrogen plant project	100 (Peak production by 2030)	Off-grid renewable/s and grid connected renewables
Wales	Holyhead Hydrogen Hub	Feasibility	Demonstration project	400kg/day at the Holyhead Hydrogen Hub	Grid
Wales	Protium Magor	FEED	Installation project	20 (Project starting 2024)	Off-grid renewable/s
East & West Midlands	Tyseley Energy Park	Feasibility	Hydrogen refuelling station		Off-grid renewable/s
East & West Midlands	Shropshire Council	Feasibility	Hydrogen refuelling centre		Off-grid waste
East & West Midlands	Octopus Hydrogen /MIRA Technology Park	FEED	Hydrogen refuelling centre		Off-grid renewables
South West England	Bristol Airport	Concept	Roadmap		
Wales	Energy Kingdom	Feasibility	Research		Off-grid renewable/s
East & West Midlands	HyPER	FEED	Installation hydrogen plant project	1.5	Methane reformation
Wales	Riversimple Clean Mobility Fleet	Concept	Hydrogen powered cars		
Wales	South Wales Industrial Cluster	Feasibility	Roadmap		
East & West Midlands	HyDeploy 1	Feasibility	Blending hydrogen in gas grid		
East & West Midlands	HyDeploy 2	Feasibility	Blending hydrogen in gas grid		
East & West Midlands	HydroFlex	Feasibility	Hydrogen powered train		
Wales	Green Energy Ferries	Concept	Hydrogen powered ferries		
South West England	H_2GEAR	Concept	hydrogen propulsion system for sub-regional aircraft		
East & West Midlands	HyDEX	N/A	Research		
South west england	Langage Green Hydrogen	EPC	Installation project	10MW	Off-grid renewables

Table B2 Description of current projects from respondents of the survey

	Project Name	Location	Type of Electrolyser	Size of Electrolyser	Source of Electricity
1	Steamology Zero Emission Heat and Power	Salisbury	Alkaline	8kW	
2		London and Birmingham	PEM	0.2-3MW	Renewables / PPA
2		Whitelee Windfarm	PEM	10MW	Wind
3	Pembroke Green Hydrogen	Pembroke	PEM	110MW	Grid connected with renewable / PPA
4	Langage Green Hydrogen	Plymouth	TBD	10MW	Grid via LCHS
5	Trafford Green Hydrogen	Manchester	TBD	up to 200MW	Grid via LCHS
6		South Lakes	TBD	50MW	Grid via LCHS
7		Central Scotland	TBD	50MW	Grid via LCHS

Table B2 shows the current projects as described by the respondents of the survey. Several of these projects will be grid connected using the LCHS as a funding mechanism.

Table B3 Description of future projects as per respondents of the survey

	Project Name	Location	Type of Electrolyser	Size of Electrolyser	Source of Electricity
1	Multiple industrial steam and transport projects			50-100MW	
2	Gigastack	Humber Refinery		100MW	Wind / PPA
3	Multiple Projects				
4	Langage Green Hydrogen	Plymouth	TBD	10MW	Grid via LCHS
5	Trafford Green Hydrogen	Manchester	TBD	up to 200MW	Grid via LCHS
6		South Lakes	TBD	50MW	Grid via LCHS
7		Central Scotland	TBD	50MW	Grid via LCHS
8	10 No. projects		TBD	up to 50MW each	Grid via LCHS

Table B3 shows the future electrolysers projects the respondents of the surveys will be involved in. It is worth noting these projects are subject to change. Five of these projects will be grid connected using the LCHS as a funding mechanism.

Appendix C Site Selection Criteria

Table C1 Respondent's views on each of the site selection criterion

Criteria for site selection	Average score	Responses on each criterion
Electricity cost profile	3.00	• "The cost of electricity is the key component to decide the end cost of hydrogen produced. over the lifetime of a hydrogen system the OPEX cost is much higher than CAPEX, and the vast majority of that cost (~80-90%) is electricity. Therefore, the cost of electricity and the accuracy of predicting that cost into the future play a key role in running calculations on whether a system is profitable or not." • "We offer energy storage so can take advantage of variable tariff" • "It is by far the most important factor in determining the hydrogen cost and for that reason it is essential for DNOs and hydrogen stakeholders to liaise to identify solutions for locating and operating electrolysers in ways that reduce electricity costs (including fees and levies). The various stakeholders should take a whole systems view and the DNO has a leading role to play, not least because it is facilitator of the energy input arriving at the electrolyser which then enables the XYZ hydrogen application to proceed." • "Electricity cost is ~80% of operational costs so very important to project economics."
Connection cost	2.83	• "We offer access to variable tariff by storage" • "Large impact on LCOH" • "It inflates the total project cost. The project developer needs advice from the DNO about the connection costs, consideration of preferred site locations for the electrolyser in the network and about preferred operating regimes if that can help reduce costs (eg. Interruption or turn down instruction of the electrolyser during peak demand periods)." • "Competitive subsidy process. Lower CAPEX means more competitive subsidy application therefore more likely to be acceptable to Government." • "Cost of connection critical to overall project, need for more dynamic connections for electrolysers (unlikely to be producing hydrogen at peak periods on the grid)"
Grid access	2.83	• "Of course, grid access is important if a grid connection is going to be required (either import or export). Additionally a lack of grid connection (or severely limited connection) is a driving force for developers looking at hydrogen in the first place and we see as an opportunity in many ways." • "We offer an alternative to allow peak demands" • "Most developers are looking to buy electricity from the grid, as opposed to building the electrolyser adjacent to the renewables and trucking/piping the hydrogen to the off-taker, so grid access is essential. The DNO should communicate where locally in the network it is best to connect electrolysers in terms of managing

		power flows and integrating renewables before the project developer finalises the site location (ie. proactively identify good potential locations in the region/town for electrolysers and preferred operating regimes that assist rather than exacerbate power system management, rather than just react to a project developer's request)." • "No grid = no power." • "An electrolyser reliant solely on co-located renewables will not be to produce enough hydrogen regularly to meet the demand warranty for hydrogen offtake. Only once the infrastructure exists to transport hydrogen by pipeline will grid access become less important."
Proximity to hydrogen user (off-taker)	2.83	• "At present having a relatively short distance from hydrogen production to offtake is important as the vast majority will be transferred via tube trailer/tanks - the longer the distance the greater the complexity of the model, and the costs associated with transport. Looking into the longer term, hopefully a move to hydrogen pipelines may make this a less important factor." • "In the early years, without the existence of a hydrogen pipeline infrastructure, positioning the electrolyser adjacent to the hydrogen user is the default option. It is sometimes feasible to locate the electrolyser further way because it makes economic sense with respect to the electricity network and then pipe the hydrogen to the user across a short distance; or to truck the hydrogen to HRS across a region once the hydrogen demand is big enough. However, in the early years, it is likely that electrolysers will mainly be located on site adjacent to or nearby the offtaker." • "Very important as UK does not have a hydrogen market."
End-user agreement	2.75	• "If they don't agree to buy the hydrogen, no one will implement the electrolyser!"
Connection or proximity to fresh water	2.67	• "Water is of course a key ingredient for electrolysis, and higher purity of feed water will also have an impact on the efficiency of the system (requirements for water purification will impact the electrical consumption of the system and add CAPEX/OPEX costs. In addition to the water for electrolysis an abundance of water for cooling of the system is also beneficial, potentially leading to CAPEX and OPEX savings as well." • "We return good quality water from our process" • "Water use is a minor issue and a minor cost, but clearly the site needs to have nearby access to mains tap water or river water." • "Electrolysers use water (lots of it). If no water, no project."
Onsite storage	2.50	• "on site storage is important as it has a surprisingly significant impact on CAPEX and OPEX. key considerations are around the size and pressure of storage, as well as the flexibility this storage offers - we have had success with portable storage which can be used both on site and for transportation. when designing an implementing a system sizing the storage appropriately is key in keeping costs under control while being able to deliver on offtake agreements." • "Gas fuel storage enables time shifting"

		• "In some applications it is a fundamental requirement (e.g. an HRS). In others the offtaker usually wishes to avoid installing hydrogen storage because of the cost and footprint implications. However, in all cases if there is economic advantage in terms of electricity cost, then most offtakers will consider fitting storage, a larger electrolyser and following an operating regime that keeps the hydrogen cost down. The storage sizing exercise can be driven by the desire for the electrolyser to be offline for a number of hours or days if it is financially expedient for the operator to do so (e.g. turn off for 72h in winter during high pressure weather when solar and wind generation is very low). However, there are limits in the COMAH regulations concerning how much hydrogen storage is permitted, which for large electrolysers (several tens of MW upwards) will limit the degree of flexibility offered to the network." • "Onsite storage of hydrogen or electricity may be beneficial."
Sufficient grid capacity at site to enable future electrolyser facility expansion	2.33	• "The ability to scale up a hydrogen system over time is a great asset when developing. Currently the demand for green hydrogen is relatively low, but forecast to increase over time, however it's hard to be confident of the offtake level you may achieve in 5-10 years, so having the flexibility at the outset to start small and grow with demand is very useful." • "For most HRS and large industrial processes, there is a need to plan for further expansion of electrolyser capacity 5-10 years down the line. This expansion is likely to lie in the range of 3-10 fold, depending on how the hydrogen market develops and how much pressure future governments place on decarbonising industrial clusters/hubs." • "Will be important in the long-run but not so much for early projects." • "Increasing capacity at existing sites using shared infrastructure will be more cost effective than building new dedicated sites."
Co-location with renewables	2.33	• "co-location with renewables provides a relatively straightforward model for renewables developers (a key potential client of ours), and a clear route to genuinely "green" hydrogen." • "yes we can work with hybrid supply" • "It will become an increasingly important consideration for developers of wind and solar farms, especially those that are reasonably close to population centres or industries that use hydrogen. Because the levies charged for using the grid are currently excessive, which inflates the cost of producing hydrogen, there is an incentive to co-locate with renewables where feasible but the feasibility of doing so is usually poor. The DNOs should help guide the rollout of electrolyser projects to improve the feasibility of colocation and of electrolyser location in the grid between the renewables and the hydrogen end use." • "More likely to co-locate with hydrogen demand users due to lack of a liquid hydrogen market."
Trailer distribution	2.00	• "It becomes an economic option once the hydrogen mobility demand in a region reaches a significant level (e.g. several bus and lorry depots, or say 10% of the car population. It is the only

		way of bringing green hydrogen from a remote location to a demand centre many miles away." • "Co-location with offtaker is better option but may be useful in some mobility projects."
Pipeline distribution	1.83	• "if pipeline distribution becomes more widespread then it will makes the location of hydrogen generation and offtakers less connected to each other, providing much greater flexibility. additionally, it will reduce the requirement for storage on site as the pipeline acts as a kind of storage." • "hydrogen distribution by pipeline will always help, if feasible in all respects. However, it's not a real-world option for most project developers in the near future. hydrogen grids become critical for storing renewable energy at scale once the renewables capacity is high and for distributing hydrogen once many different types of user (in various locations with various demand patterns) want to use hydrogen- something for the 2030s and beyond. Conversely if the government decides to allow and facilitate hydrogen NG blends next year then things will change considerably in the near future - a floodgate will open allowing electrolysers to inject hydrogen into the existing (large) natural gas grid at multiple locations. The latter decision could have a large impact on electricity networks." • "Potentially useful to be located near to 100% hydrogen pipelines but these do not exist yet and won't until circa 2030ish. Long-term is attractive."
Underground storage	1.67	• "if underground storage is available it can greatly improve the potential of a hydrogen site, enabling much larger and longer term storage. we see this as a key route to enabling a greater deployment of hydrogen into renewable energy grid balancing, differentiating hydrogen from batteries for long term energy storage" • "It's important for a national hydrogen grid serving many users, and to a lesser extent to a local hydrogen grid that serves several different hydrogen users, in order to supply/demand match. It's most needed if a very seasonal demand is placed upon hydrogen (e.g. domestic heat) and when a region is powered almost entirely by variable renewables. We are walking towards a substantial need for underground storage in the 2030s and beyond, but in the early years it's not critical (or achievable quickly)." • "Unlikely to be relevant in Wales as no real opportunity except Cheshire."

Table C2. Site selection criteria extracted from the excel based tool, developed as part of this work package (WP1). This tool can be used for identifying optimal locations for electrolyser connections on a DNO's network.

Site Details
Is the electrolyser siting fixed or variable
Post Code of Electrolyser site if fixed
Connection capacity needed
Connection voltage level
Name of connection site (Substation) considered in this review
Coordinates for Substation

Criteria	Unit
Network Connection Considerations	
GSP (275kV/400-132kV) or BSP (33 kV)/Primary(11kV) - connection time	months
Distance to connection point	(km)
Electricity cost	(p/kWh)
Connection cost (per 1 MVA capacity)	(£/MVA)
Connection capacity available	(% Plant rating)
Grid constraint level	CF (% of FLH)
Availability of battery storage - size specific	CF (% of FLH)
Existing renewables (for co-location)	CF (% of FLH)
Potential access to behind the meter renewables and/or curtailed energy	CF (% of FLH)
Opportunity for Flexibility Services (Sustain/Dynamic/Secure/Restore)	No. of services
CO2 intensity of the grid (CO2e/kWh) - LCHS mandates < 72 CO2e/kWh LHV (<20g CO2e/MJ LHV)	CO2e/kWh
Non-network considerations	
Proximity to fresh water	km
Size of onsite H2 storage, if needed?	Nm3
Size of onsite O2 storage, if needed?	Nm3
Required Electrolyser Proximity to H2 user (off-taker)	km
Proximity to roads (for Trailer or pipeline distribution).	km
Length of pipeline for distribution, if required?	km
Size of underground storage, if required?	MWh H2
Does the project require COMAH (is the H2 stored >2tonnes)	Yes/No

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