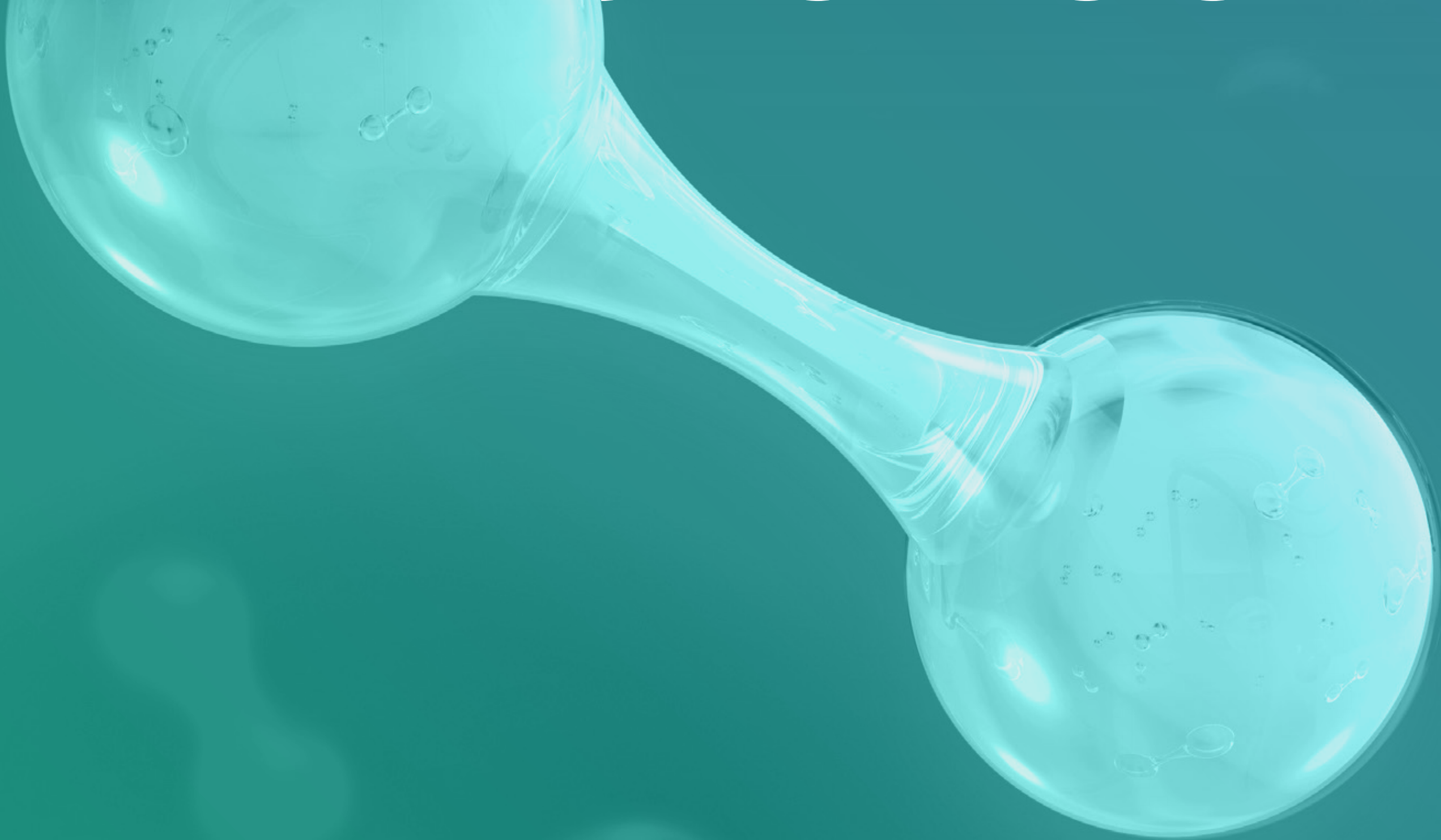
RenewableUK

Hydrogen UK

Splitting the difference



Reducing the cost of electrolytic hydrogen to accelerate deployment

January 2025

Foreword

Dan McGrail and Clare Jackson

On behalf of Hydrogen UK and RenewableUK, we are delighted to present 'Splitting the Difference — Reducing the cost of electrolytic hydrogen' which identifies the measures that must be taken by industry and Government to accelerate cost reduction during the early stages of hydrogen's journey. The coming together of our two industries has unlocked fresh insight and the result is a testament to the hard work and talent of our membership and teams as well as the power of collaboration. We would also like to thank LCP Delta for their support on the analysis.

Electrolytic hydrogen has a key role to play in delivering net zero, bolstering energy security, decarbonising energy intensive sectors and driving economic growth, and it has been fantastic to see the first projects signing contracts with the Government and getting ready to start construction over the past month.

With the introduction of the Clean Power 2030 target, increased focus has been placed on the role that electrolytic hydrogen can play in supporting the roll out of renewables, reducing curtailment and system balancing costs. If we are going to meet this ambitious target, we must urgently pick up the pace of deployment of both renewables and electrolytic hydrogen.

Hydrogen is a nascent sector and, as such, currently has high costs associated with development and delivery of projects. Rapidly driving down the cost of electrolytic hydrogen is one of the key enablers of widespread hydrogen adoption that must be unlocked if we are to deliver on our targets. There is much to be learned from the success of the offshore wind sector in scaling up deployment and driving down costs, however there are also unique characteristics to the hydrogen cost profile which require additional interventions.

We look forward to working with our respective industries and Government to implement the findings and recommendations in this report and ensuring that we deliver clean, affordable hydrogen at scale. There's no time to lose.

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Dan McGrail
CEO, RenewableUK

Clare Jackson
CEO, Hydrogen UK

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Executive summary

The UK Government has set out its ambition to decarbonise the power system in the Clean Power Action Plan 2030. This Plan starts with accelerating the roll out of new renewable power, where 95% of generation to meet demand comes from clean sources by 2030. This new energy system will bring with it new challenges, such as what to do when the wind does not blow, or when renewable generation exceeds demand.

Turning electricity into hydrogen, via the electrolysis of water, will be a central part of addressing this challenge. Hydrogen production can absorb excess power and the hydrogen can then be stored, transported and used to decarbonise other sectors, or used to produce power when the wind does not blow. Developing this hydrogen sector could create 30,000 jobs and generate £7 billion GVA by 2030.

The first Hydrogen Allocation Round (HAR1) achieved an average price of £241/MWh. But to make the hydrogen sector a reality these costs need to come down. Electricity costs account for around 70% of the cost of electrolytic hydrogen (or 'green hydrogen' when electricity comes from renewable sources) production, so addressing these costs and making electricity cheaper for hydrogen production is essential to deliver a vibrant hydrogen sector.

This report sets out 14 policy recommendations to ensure markets and hydrogen production business models are fit for the future. To date, hydrogen production business models and renewable electricity support mechanisms have been developed in isolation. We recommend that Government brings these two schemes together so hydrogen production and renewable generation can be better coordinated and co-located to reduce costs and inefficiencies, and maximise deployment.

Wind energy projects tend to be built where wind resources are most abundant, to maximise generation when the weather enables it. Hydrogen production can be more flexible, and should be encouraged to locate where it benefits the system most, and incentivise production when the system needs it. We recommend more is done to incentivise the time and location of hydrogen production with renewable energy to maximise production and minimise costs.

By its very nature, hydrogen production is an energy intensive process, but it is a process that will reduce economy-wide emissions by replacing fossil fuels in industry, heat, transport and power. However, its production is subject to the same taxes and levies as other energy industries, including carbon-intensive industries, which are designed to reduce emissions. This is counterproductive, and adds unnecessary costs to the production of green or electrolytic hydrogen. These levies need to be removed.

Making these changes will lower electricity and system costs overall and enable lower cost green hydrogen to be produced. However, the hydrogen requires transportation to get to where it is needed. It is critical that the network infrastructure to carry this hydrogen around the country is designed and delivered as a matter of urgency to drive further investment in this market.

Taken together, the recommendations in this report could **reduce the cost of electrolytic hydrogen from £241/MWh achieved in the HAR1 process to less than £100/MWh**, making it competitive with natural gas, and thus the fuel of choice for the future.

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— Explore alternative options for electrolytic hydrogen developers to index their strike price in a way that better reflects their exposure to electricity supply and prices.

2. **Making Hydrogen Production Business Model and CfD compatible**
— Government should explore options to fix power prices for electrolytic hydrogen using the Contracts for Difference (CfD) process., for example by allowing CfD contracted generators to sell some of their generation at their CfD strike price to a hydrogen producer, or allow the marginally unsuccessful CfD projects to conract directly with HAR contracts.

3. **Remove barriers to co-location**
— Introduce pre-approved design stage to the Renewable Obligation process to enable investment in retrofitting flexible assets.
— Enable hybrid sites in the CfD with clear definition of roles on the basis of perceived system benefit. This will require the introduction of a definition of hybrid BMU (HyBMU) in the Balancing and Settlement Code and requirements for performance monitoring and metering.
— Reform the Offshore Transmission Owner (OFTO) regime for an evolving offshore wind sector. It currently does not consider co-location, while there is a need to holistically resolve the issues to mitigate.

4. **Designing for success in a decarbonising energy system**
— Review the requirement for half-hourly time matching within the LCHS with the view to extending temporal correlation to monthly or annual, in line with wider industry practice and taking account of the impact of grid decarbonisation policies.

5. **Creating business models for the future**
— Work with industry to help evolve the funding landscape for renewables and electrolytic hydrogen, maximising the opportunities to co-deploy while delivering Clean Power 2030 and Net Zero at lower cost.

Incentivising flexibility and optimal location

6. **Creating markets to incentivise flexible use of electrolysers**
— Implement market arrangements that incentivise the flexible use of electrolysers, particularly for the avoidance of constraints.
— Change the Low Carbon Hydrogen Standard (LCHS) rules to allow electrolysers engaged in curtailment reduction to account for their electricity at zero carbon intensity.

7. **Reflecting regional differences in the Low Carbon Hydrogen Standard**
— Assess the impact of allowing developers to account for regional carbon intensity when purchasing power from the grid.

Cutting electricity costs

8. **Energy intensive levies**
— Review generation and demand Transmission Network Use of System (TNUoS) charging methodology and supercharger legislation to reduce the burden of electricity system costs on hydrogen production projects, particularly in areas where the system benefits to the electricity system are the greatest.

9. **Exempting low carbon electrolytic hydrogen from the Climate Change Levy**
— Clarify that all electrolytic hydrogen production facilities in receipt of a Low Carbon Hydrogen Agreement (LCHA) are exempt from paying the Climate Change Levy.

10. **Relaxing the requirement to retire Renewable Energy Guarantees of Origin (REGOs)**
— As part of a wider review of how electrolytic hydrogen compliance costs can be reduced, Government should explore whether a removal or temporary removal of the requirement to retire REGOs to comply with the LCHS would be appropriate.

Renewables, hydrogen and the need for infrastructure

11. **Develop a strategic hydrogen transmission network**
— Government should make a strategic decision on a core hydrogen network that links Scotland to England and Wales, including timelines for deployment and funding mechanisms. This will enable renewable and hydrogen developers to plan and optimise their projects based on the availability of hydrogen transport and storage infrastructure.

Introduction

The UK is set to build on its world leading position of renewables deployment, targeting as much as 50GW of offshore wind, 27GW of onshore wind and 47GW of solar by 2030 as part of the Clean Power 2030 mission[1]. As we move towards a net zero power system driven by renewables and away from unabated gas, the UK will need greater capability to manage periods of low and excess renewable generation.

Electrolytic hydrogen is a critical solution to this challenge, as the Clean Power Plan and the advice from NESO make clear. Firstly, because hydrogen can be stored for long periods of time and in large volumes, and because curtailed power can be very low cost[2]. Therefore, electrolytic hydrogen can provide cost-effective long duration energy storage[3,4], which can then be used as a low carbon alternative to natural gas for dispatchable power generation and for a wide variety of uses essential to the full decarbonisation of other sectors, including industry and heavy transport.

Secondly, electrolytic hydrogen can be produced using the renewable power in places such as Scotland that would otherwise go to waste due to the lack of network capacity or demand. Building electrolytic hydrogen production capacity in areas with high renewables and behind grid constraints has a wide range of benefits. Providing electricity demand for the increasing levels of onshore and offshore wind that is in the pipeline in Scotland is going to be critical for renewable deployment, while reducing constraint costs paid by consumers.

Thus, by providing a source of firm power and demand for excess renewable generation, electrolytic hydrogen is fundamental to ensuring security of supply in a low carbon power system.

1 DESNZ, 2024, "Clean Power 2030 Action Plan: A new era of clean electricity"
2 DESNZ, 2021, "Hydrogen Production Costs 2021"
3 ibid
4 Also see for example: The Royal Society, 2023, "Large-scale electricity storage"

'Green' or 'electrolytic' hydrogen

Hydrogen can be produced in two main ways. The most common method today is via steam methane reformation, whereby methane is 'cracked' into its components of hydrogen and carbon which is emitted as CO_2, so-called 'grey' hydrogen. When this CO_2 is captured and used or stored, it is called 'blue' hydrogen or CCUS-enabled hydrogen.

Grey Hydrogen

Natural Gas > Hydrogen
CO_2 released into atmosphere

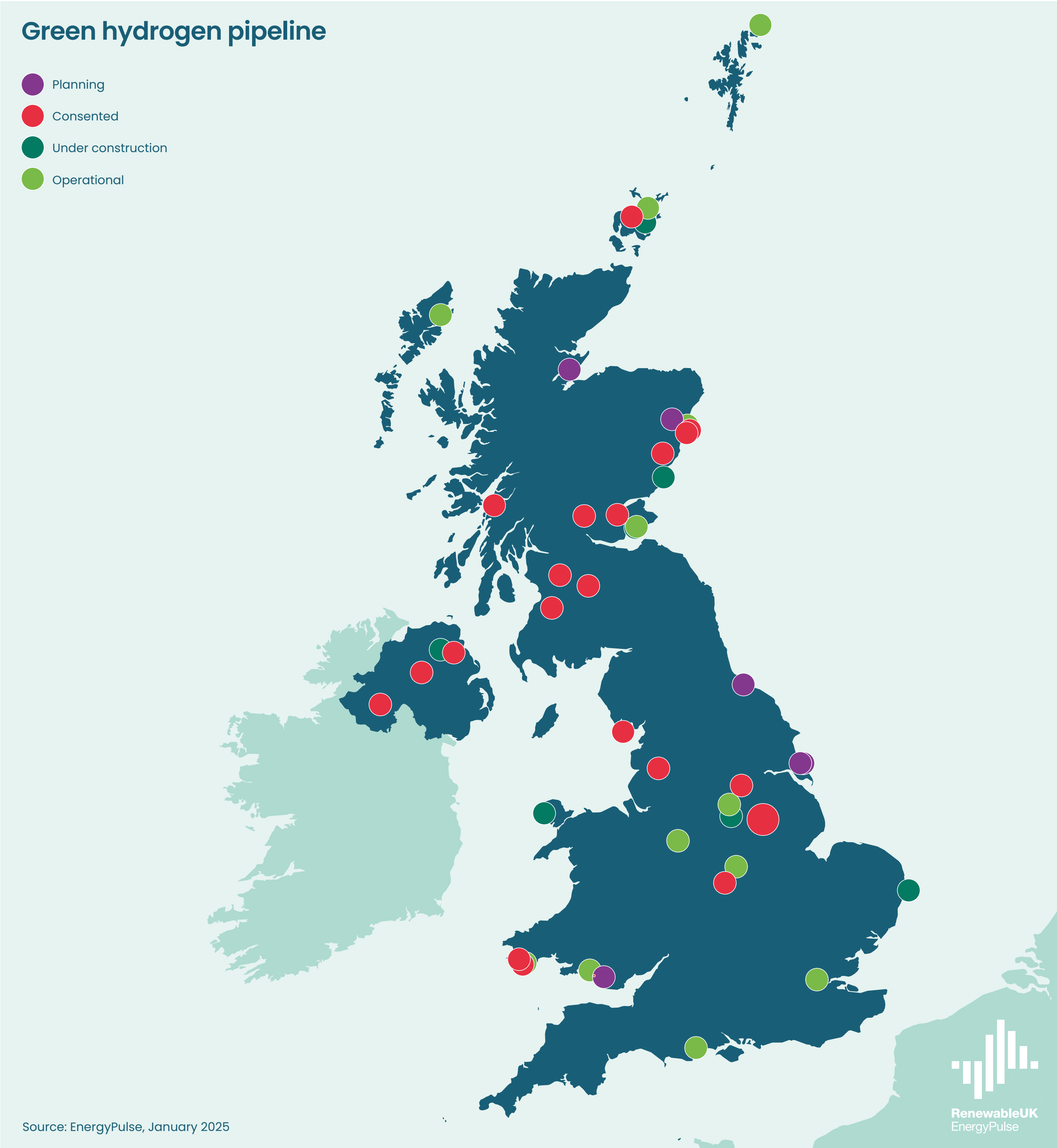
Blue Hydrogen

Natural Gas > Hydrogen
CO_2 stored underground

Alternatively, hydrogen can be produced by passing an electrical current through water to separate the hydrogen and oxygen. This is electrolytic hydrogen. When the source of electricity is from renewables it is considered 'green'. For the purposes of this paper, which focusses on electricity costs, we consider all sources of electricity.

Green Hydrogen

Green electricity and water > Hydrogen
O_2 released into atmosphere



— At the time of publication, RenewbleUK's EnergyPulse Database records 2.4GW of green hydrogen projects in the pipeline across the UK. Hydrogen UK records a further 11GW of projects planned out to 2050.

— Hydrogen UK's Economic Impact Assessment[5] estimates that hydrogen could deliver significant economic benefits, including 30,000 jobs annually and £7bn of Gross Value Added (GVA) by 2030. These figures will increase significantly out to 2050, as the UK's Hydrogen Strategy ambition for production and use grows, and underscores the transformative effect that hydrogen will have on the UK's economy and workforce.

5 Hydrogen UK, 2024, "Economic Impact Assessment for the Hydrogen Sector to 2030"

Electricity sets the floor price for electrolytic hydrogen

Projects in the first Hydrogen Allocation Round (HAR1) achieved an average of £241/MWh. To ensure deployment accelerates at a rate sufficient to meet Government targets for hydrogen production and demand, hydrogen production costs will need to come down. The measures set out in this report could help the sector reach prices below £100/MWh.

Research on behalf of Scottish Futures Trust[6] (SFT) shows that input electricity costs account for up to 70% of the levelised cost of hydrogen production, with nearly half of that being made up of electricity system costs including networks, balancing and policies.

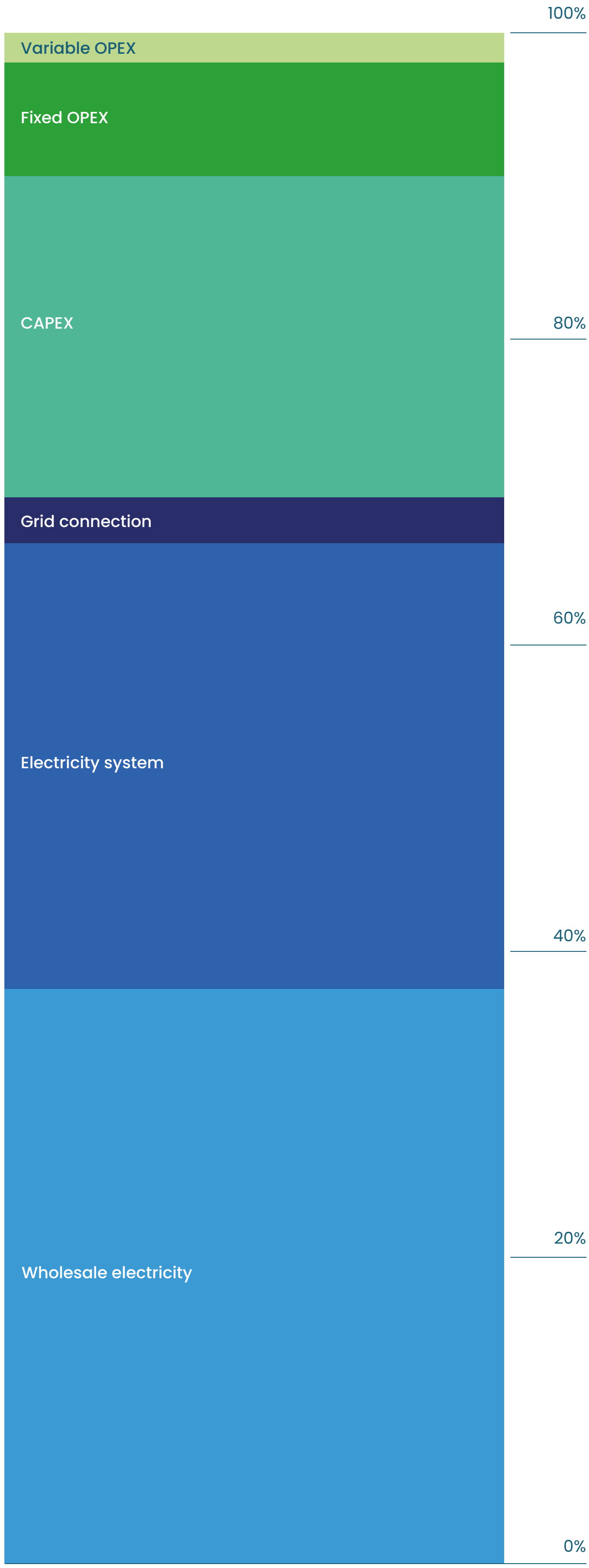
The two main models for electrolytic hydrogen production are direct wire and grid connected, with the electrolyser taking its power supply directly from a renewable electricity source or from the electricity grid, respectively. Direct wire projects avoid many of the system and network costs of the electricity grid, but this is not a practical solution for many projects. Therefore, reducing electricity costs for grid-connected projects is essential for the green hydrogen sector.

It is critical that efforts are focused on getting the cost of electricity down to complement the capital and operating cost reductions that will be achieved through learning from initial projects, economies of scale and advancements in technology and manufacturing as electrolytic hydrogen projects increase in scope. This paper sets out a series of recommendations to address this challenge.

"Reducing electricity costs for grid connected projects is essential for the green hydrogen sector."

6 TEL, 2024, "Green hydrogen in Scotland – A report for Scottish Futures Trust"

Elecrolytic hydrogen cost components



Getting costs down

Hydrogen production business model and CfDs

1. Reflecting risk in strike price indexation

In the Hydrogen Production Business Model (HPBM) the strike price is indexed to the Consumer Price Index (CPI) for electrolytic projects. This creates an uneven playing field with CCUS-enabled hydrogen, which is indexed to the gas price, protecting producers from increases in their input fuel costs.

Grid-connected electrolytic projects, on the other hand, would be exposed to any fluctuations in the electricity prices or in volumes of Low Carbon Hydrogen Standard (LCHS) compliant power if purchasing electricity in the wholesale market. This would significantly increase costs of capital, potentially preventing projects from reaching a Final Investment Decision (FID).

One way to mitigate this risk is to have a fixed-price Power Purchase Agreement (PPA). However, PPA prices will inevitably be higher than the clearing price of CfDs, given the higher risk of contracting with an electrolytic hydrogen offtaker, meaning that the PPA price will likely be far above actual outturn prices, or even current pricing forecasts. A fixed price PPA could add more than £50/MWh to the Levelised Cost of Hydrogen. Anecdotally, members have suggested that PPAs are priced at around the £80/MWh mark. This is significantly higher than expected power prices in the lowest priced 30-40% of hours in a year, particularly if a locational benefit of being in Scotland is factored in.

LCP Delta have analysed the impact that slower-than-expected decarbonisation would have on the business case for electrolytic hydrogen production. Under such a scenario, the volume of qualifying periods of low carbon power is substantially reduced in the early years of an electrolyser project's lifetime. This is a significant risk to investors in these assets which is not reflected in current indexation design and can increase LCOH substantially.

The current business model leaves producers exposed to the associated risk that the system decarbonises slower than expected, having the effect of raising strike prices for projects. LCP Delta have analysed a number of decarbonisation pathways under different scenarios to quantify these risks and designed a number of potential alternative indexation models for Government to consider, which are aimed at addressing these risks and reduce project LCOH significantly (see Figure 4 on page 23).

Recommendation: Explore alternative options for electrolytic hydrogen developers to index their strike price in a way that better reflects their exposure to electricity supply and prices.

2. Making Hydrogen Production Business Model and CfD compatible

The current design of the HPBM for electrolytic projects and the CfD for renewable projects are not compatible, creating major challenges for electrolytic projects wanting to contract with wind or solar generators that hold a CfD. As explained under the previous heading, electrolytic projects are incentivised to have longer-term fixed price PPAs to hedge the risk that the lack of HPBM indexation to electricity prices leaves them exposed to. However, CfD-backed generators are strongly incentivised by the design of the CfD scheme to sell their power in the Day Ahead markets, and thus not under any longer-term fixed price arrangement. There is therefore little financial incentive for a CfD holder to supply power and contract with an electrolytic hydrogen project. As an increasing proportion of the UK's renewable fleet will have a CfD, it will be increasingly challenging for hydrogen projects to procure power at long-term, fixed prices, despite wind curtailment being projected to increase.

Government could balance the risk it takes in both CfD and the HPBM. For example, more exposure on power prices in the HPBM would act as an inverse hedge to exposure on CfDs; if power prices go down, CfDs would require higher subsidy payments, but hydrogen projects would require lower payments, balancing the risk across portfolios.

Recommendation: Government should explore options to fix power prices for electrolytic hydrogen using the CfD process. This could potentially be done in a number of ways, for example by allowing CfD contracted generators to sell some of their generation at their CfD strike price to a hydrogen producer (with no associated requirement to achieve the market reference price for that volume of power), or, after the CfD round clears, the Government could offer to sell to the winners of the next HAR round strips of the energy they have procured at the average clearing price. Another option could involve the marginally unsuccessful CfD projects with strike prices just above the clearing price being introduced to the winners of the HAR round, allowing them to enter PPAs at the strike price the renewable generators bid into the auction, with Government providing credit support in case of default on either side.

Any future reforms will need to ensure a whole system approach is adopted, reflecting electricity market reforms proposed under the UK Government's Review of Electricity Market Arrangements (REMA) programme, which includes potential CfD reform and wider wholesale market reform.

Image courtesy of Shutterstock

3. Remove barriers to co-location

Co-location or hybridisation is the process of developing multiple generation projects or combining different technology types using the same grid connection point (e.g. renewables and green hydrogen). The drivers of co-location decisions are motivated by the benefits maximising the value from shared resources could bring — including grid connection, access and available land[7]. However, policies and regulations are hindering the growth of such projects in the UK.

Established market arrangements like the Renewable Obligation (RO) were not initially designed with co-location in mind. Retrofitting of hydrogen electrolysers to RO accredited generators is currently undertaken 'at-risk' as Ofgem does not confirm enduring accreditation until after retrofit is complete (or once the hydrogen electrolyser has been built). This provides a significant challenge to meeting FID, which is required prior to the build of the electrolyser or battery, as the RO accreditation for the whole RO-accredited site is deemed 'at risk' by the developer until Ofgem have assessed the changes to the site. We believe the solution would be for Ofgem to provide a 'minded-to' position on RO re-accreditation based on a desktop study of the amendments to a RO site at the pre-FID stage.

The Balancing Mechanism (BM) is seen as essential for unlocking and valuing flexibility. Its role can be improved by a number of different measures: allowing more participants to access the BM as well as putting in place provisions so that hybrid renewable assets can avoid the need to curtail as much as possible. Such measures should help to optimise the dispatch of renewables on a more dynamic basis, lower the overall balancing cost ultimately paid by consumers, and support the operation of a net zero grid. Allowance of hybrid sites in the CfD with clear definition of roles on the basis of perceived system benefit will require further provisions to be explored such as introducing a definition of hybrid BMU (Balancing Mechanism Unit) in the Balancing and Settlement Code and associated development of requirements for performance monitoring and metering which are currently not in place.

The Offshore Transmission Owner (OFTO) regime currently presents significant barriers to offshore wind co-located business models due to its lack of consideration for co-location. Resolving issues related to ownership boundaries, divestment process and apportioning of costs, TNUoS cost allocation and licencing is critical for offshore wind co-located developments. Reforming this regime is foundational to enabling greater offshore wind co-location with hydrogen electrolysers and electricity storage as it affects the financial viability and operational efficiency of co-located projects.

Recommendation: Introduce pre-approved design stage to the Renewable Obligation process to enable investment in retrofitting flexible assets.

Recommendation: Enable hybrid sites in the CfD with clear definition of roles on the basis of perceived system benefit. This will require the introduction of a definition of hybrid BMU (HyBMU) in the Balancing and Settlement Code and requirements for performance monitoring and metering.

Recommendation: Reform the OFTO regime for an evolving offshore wind sector. It currently does not consider co-location, while there is a need to holistically resolve the issues to mitigate some of the investment risks.

7 Outlined in more detail in RenewableUK, 2024, "Making the most of renewables: the role of onshore co-location in an integrated energy system"

4. Designing for success in a decarbonising energy system

The LCHS sets a threshold carbon intensity of 20gCO_{2e}/$MJ_{(H2, LHV)}$. Assuming a 70% efficiency for the electrolysis process, this equates to an input electricity carbon intensity of approximately 50 gCO_{2e}/$kWh_{electric}$.

The figures below show the trajectory for carbon intensity of the UK's electricity grid[8], with (top) and without (bottom) the deployment of BECCS, overlayed with the projected trajectory of electrolytic hydrogen deployment for HARs 1-7. In both cases, the national average grid carbon intensity falls below the equivalent LCHS threshold (50 gCO_2e/kWhelectric) by 2032 at the latest, inclusive of a significant deployment of networked electrolytic hydrogen production capacity.

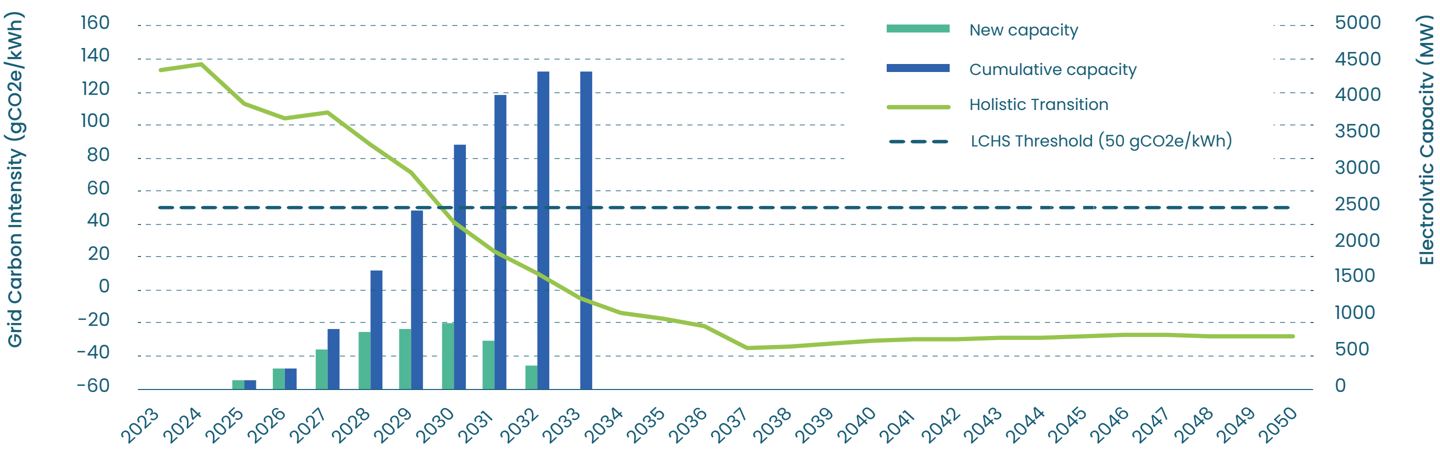
With the first round of HAR projects set to come online from 2026, and their contracts lasting 15 years, even the first mover projects will have access to low carbon grid electricity for the majority of their operating life.

Members have indicated that the 'cost of compliance' adds in the order of 10-20% to wholesale electricity costs as a result of 'shaping' an intermittent supply to become baseload, over-procuring renewables from a range of generators, the commercial risks associated with re-selling over-procured volumes back to the market, and the additional admin burden of providing the hydrogen producer with all of the necessary supporting evidence for LCHS compliance.

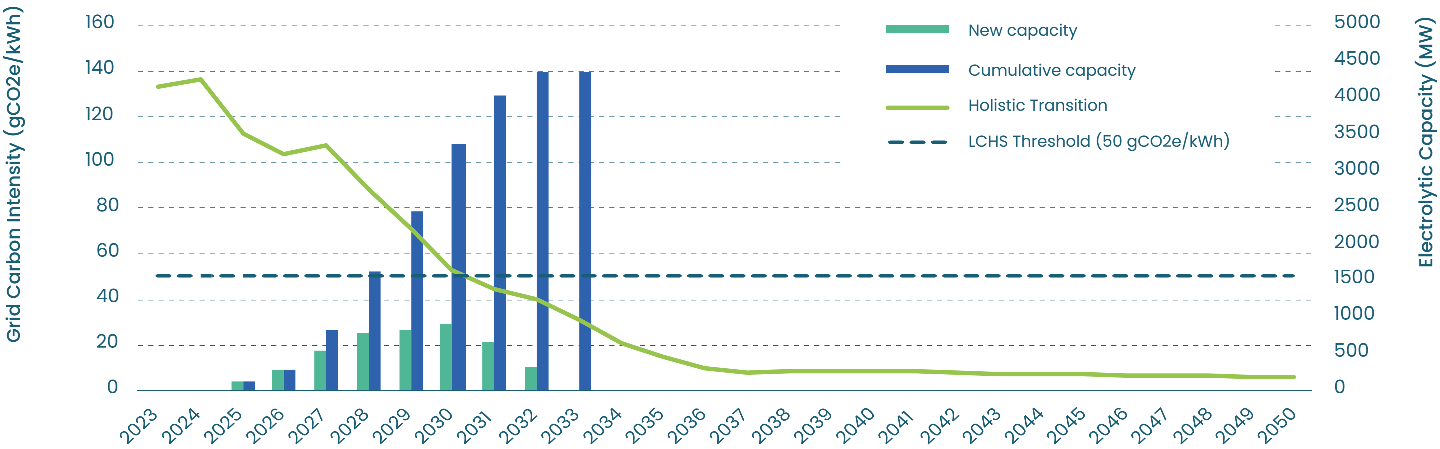
8 NESO, 2024, "Future Energy Scenarios 2024"

Recommendation: Review the requirement for half-hourly time matching within the LCHS with the view to extending temporal correlation to monthly or annual, in line with wider industry practice and taking account of the impact of grid decarbonisation policies.

Electrolytic Deployment (HAR1–7) vs Grid Carbon Intensity



Electrolytic Deployment (HAR1–7) vs Grid Carbon Intensity (excl. BECCS)

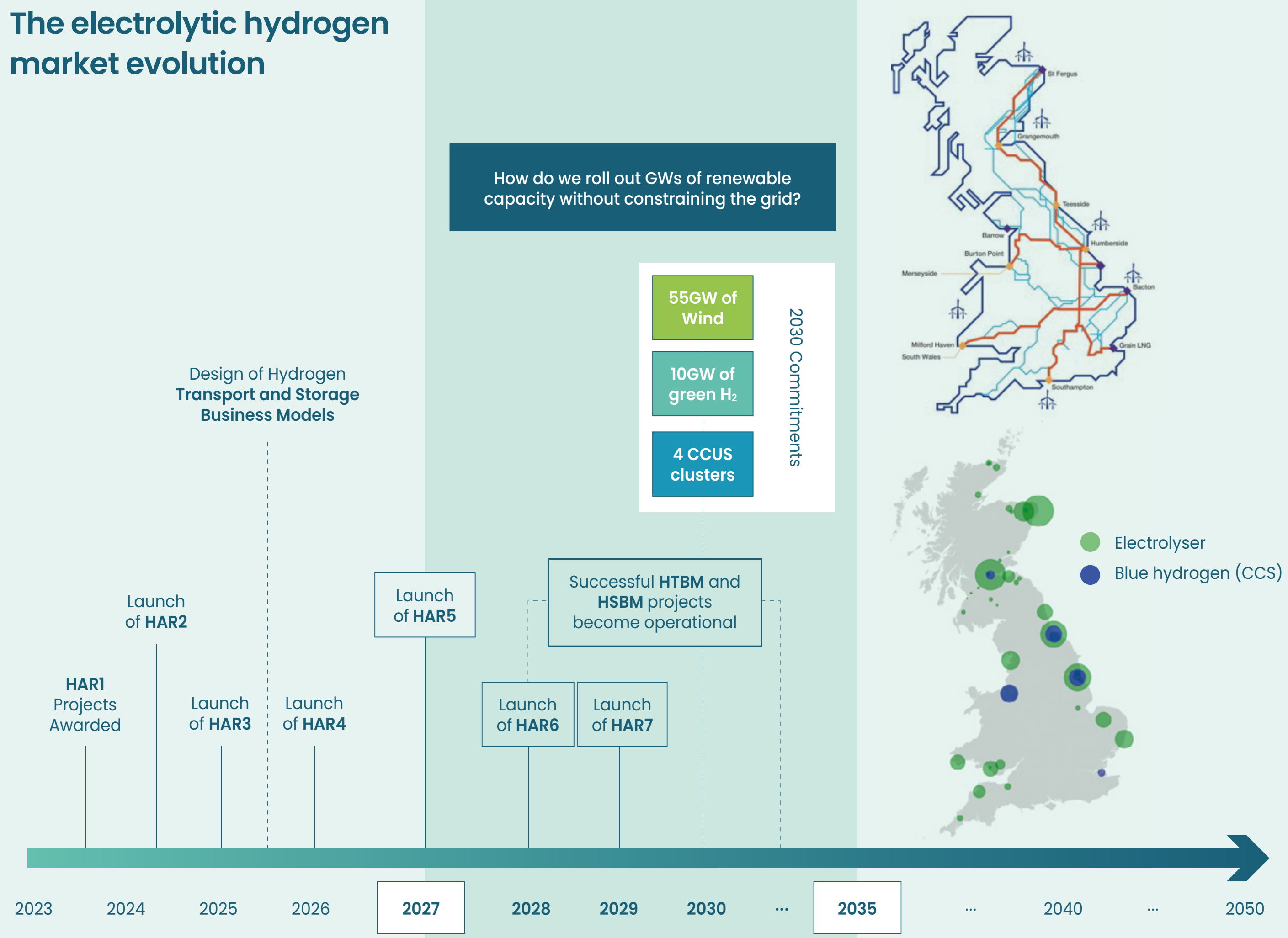


5. Creating business models for the future

The Department for Energy Security and Net Zero (DESNZ) has previously committed to a review in 2025 of the trajectory of the HAR process, in light of learnings from early projects, the evolving evidence base and strategic decisions on the use of hydrogen, taking into consideration emerging evidence on cost reductions, innovation, infrastructure requirements and demand-side developments.

Figure 1. The electrolytic hydrogen market evolution (Source: 'Developing a Whole Systems Approach to Explore Pathways to Net Zero', Centrica/FTI) Pathways to Net Zero', Centrica, FTI)

The electrolytic hydrogen market evolution



Initial HAR rounds will spur production:

- Operational subsidy support will be crucial in FOAK projects reaching FID
- Key learnings will be realised for both hydrogen developers and offtakers
- HAR1-4 should follow the current model and low-carbon hydrogen demand must be stimulated

Achieving climate goals requires planning:

- Reaching 2030 targets is important, however the longer term 2050 vision must also be considered
- Mass integration of renewable capacity must be carefully planned out, especially with an already constrained electricity network
- Need to incentivise build out of crucial T&S infrastructure

An ideally planned energy network:

- Electrolysers are located where they provide highest system benefits
- Located in areas of high offshore wind capacity, and alleviating transmissions constraints
- H2 production supported by the UK hydrogen backbone (Project Union Pipeline)

The review should consider offering alternative methods for funding electrolytic hydrogen to better reflect the wide variety of project archetypes, the interdependence with the renewable energy sector, and strategic decisions on critical hydrogen transport and storage infrastructure.

Analysis shows that there is good correlation between the carbon intensity of the grid and wholesale electricity prices, with times of high renewable output and low carbon intensity largely coinciding with lowest wholesale prices. Projections for the future show an increase in the frequency and duration of these periods of low carbon intensity (below the LCHS threshold) and low wholesale prices. This presents an opportunity to offer different funding support mechanisms beyond the current HPBM model.

Options for consideration for future funding of electrolytic hydrogen should include:

— CAPEX grants for electrolysers that will seek to operate with maximum flexibility when renewable generation is high and wholesale electricity costs are low.
— Allocations for co-deployed renewables and hydrogen, where system benefits including flexibility and reduced grid investment are addressed concurrently.
— How to maximise the benefits offered by the UK's competitive advantage for floating offshore wind deployment.

Recommendation: Work with industry to help evolve the funding landscape for renewables and electrolytic hydrogen, maximising the opportunities to co-deploy while delivering Clean Power 2030 and Net Zero at lower cost.

Wholesale electricity price duration curve (£/MWh)

Analysis shows that there is good correlation between the carbon intensity of the grid and wholesale electricity prices, with times of high renewable output and low carbon intensity largely coinciding with lowest wholesale prices."

Figure 2. Wholesale electricity prices could be lower for longer in an integrated energy system (Source: " Developing a Whole Systems Approach to Explore Pathways to Net Zero', Centrica, FTI)

Incentivising flexibility and optimal location

6. Creating markets to incentivise flexible use of electrolysers

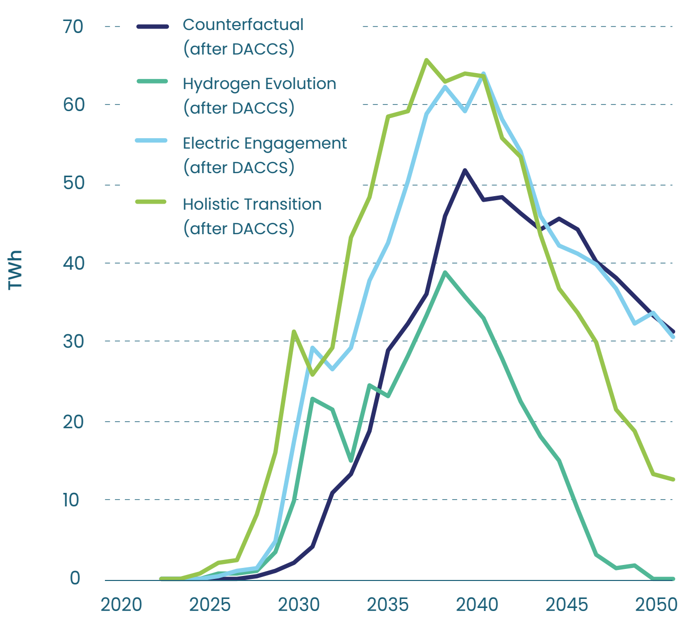
Curtailment of electricity in regions of excess supply is already a major issue, with the UK curtailing more than 4TWh of renewable generation capacity in 2023 at a cost of more than £300 million through constraint payments. The NESO Constraints Collaboration Project has identified a number of options for incentivising demand for electricity that would otherwise be constrained, including rewarding flexible use of electrolysers. Options include an ancillary service contract that offers reduced cost electricity (that would otherwise have cost NESO to curtail) in certain locations to incentivise new sources of demand, and a constraint market that allows NESO to contract for flexibility with both generators and demand in advance of real time.

Creating a product that allows electrolytic hydrogen producers to buy otherwise curtailed wind at a fixed price could reduce the need for expensive fixed-price PPAs, reducing overall power input costs and bringing strike prices down.

Recommendation: Implement market arrangements that incentivise the flexible use of electrolysers, particularly for the avoidance of constraints.

Recommendation: Change the LCHS rules to allow electrolysers engaged in curtailment reduction to account for their electricity at zero carbon intensity.

Annual curtailment after hydrogen and DACCS



7. Reflecting regional differences in the Low Carbon Hydrogen Standard

The abundance of renewable electricity on the grid already present in some regions of the UK provides an opportunity for hydrogen developers to access cheap zero carbon electricity. However, the Low Carbon Hydrogen Standard (LCHS) currently prevents this, instead requiring grid connected projects to report the UK's national average carbon intensity.

This map shows the average CO_2 intensity of electricity generation s different zones, defined by key transmission boundaries in GB. Where there are no transmission constraints, the CO_2 intensity across all zones is the same. However, when there are constraints, the average intensity can differ on each side.

This is equivalent to the current definition of average CO_2 intensity for hydrogen producers. When renewable generation is curtailed due to network constraints, the average emissions intensity in the generation constrained region can be lower than the intensity of the other side of the constraint.

The map shows that transmission constraints can lead to significant variations in the average carbon intensity of generation in different regions in GB and, by extension, the number of qualifying periods of low carbon power for hydrogen production.

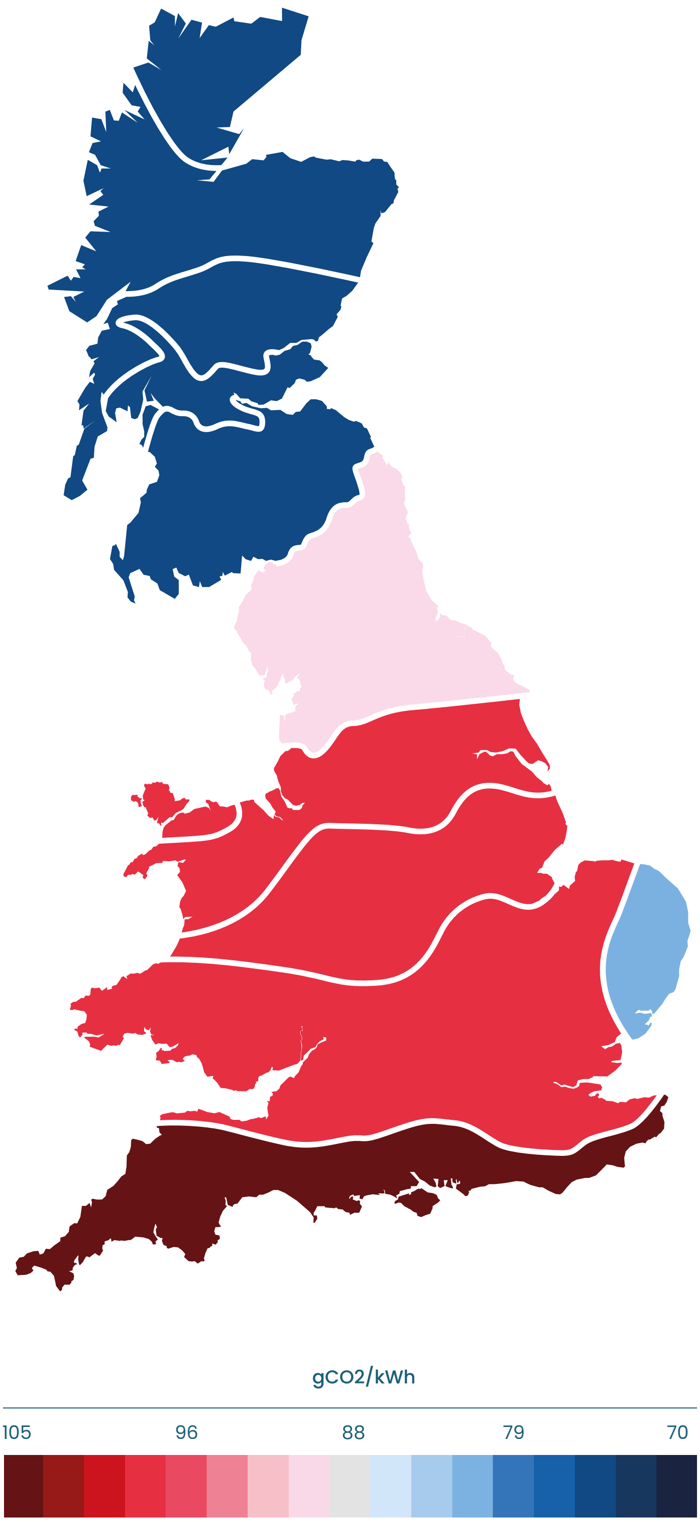
Analysis of the grid carbon intensity at a national level shows that in 2023 less than 3% of 30-minute consignments were below this threshold and therefore 'LCHS-compliant'. At a regional level, this changes dramatically, with the north of Scotland, for example, registering approximately 60% of LCHS-compliant 30-minute consignments.

Allowing developers to account for regional grid intensity would also deliver cost savings in some regions of the UK, as the requirement to source long term green PPAs is significantly reduced. Other potential benefits include providing a locational incentive for electrolytic projects to locate where there are abundant renewables, supporting renewable generation deployment by reducing curtailment, minimising price cannibalisation, and lowering the need for further investment in electricity transmission.

Recommendation: Assess the impact of allowing developers to account for regional carbon intensity when purchasing power from the grid.

Zonal maps average CO_2 intensity

Figure 3: Regional average CO_2 intensity of generation, LCP Delta 2025 forecast



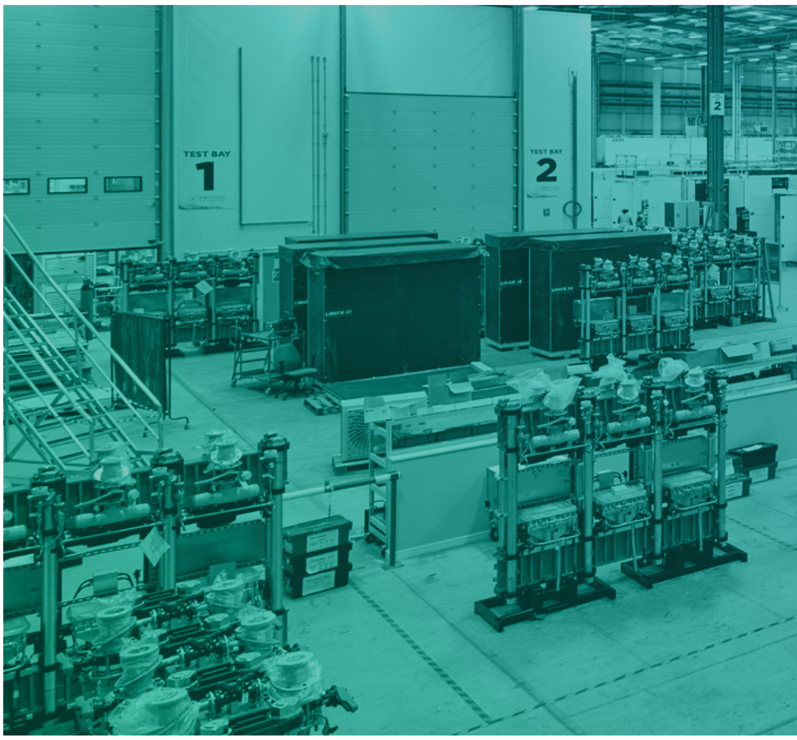
Cutting electricity costs

8. Energy intensive levies

As noted, around 70% of the cost of electrolytic hydrogen is electricity input. Therefore, the sector qualifies as an Energy Intensive Industry (EII) and falls under the eligible 'Manufacture of industrial gases' NACE code 20.11. The changes to extend the current EII exemption from 60% to 100% of the cost of some policy levies and provide a 60% refund on TNUoS and BSUoS costs are a welcome update.

However, it would be worth exploring further how network charges can better incentivise the efficient location of electrolytic hydrogen and reduce the burden on projects that are providing system benefits. Where TNUOS or other charges incentivise projects to locate to areas where there are system benefits, these signals should not be dampened by exemptions.

Recommendation: Review generation and demand Transmission Network Use of System (TNUoS) charging methodology and supercharger legislation to reduce the burden of electricity system costs on hydrogen production projects, particularly in areas where the system benefits to the electricity system are the greatest.



9. Exempting low carbon electrolytic hydrogen from the Climate Change Levy

The Climate Change Levy (CCL) was introduced in 2001 to encourage businesses to improve energy efficiency and reduce carbon emissions by imposing a tax on energy use. Power used to produce electrolytic hydrogen is currently not exempt from the CCL, and this levy is not an eligible cost in the HPBM strike price calculation. It is not clear whether electrolytic projects would be eligible for a Climate Change Agreement, which would provide a discount, as these agreements were not developed with electrolysers in mind.

Applying the CCL to electrolytic hydrogen will increase its production costs and undermine the hydrogen production business model DESNZ has developed. Producers of electrolytic hydrogen will be forced to 'absorb' the cost or try to pass it on to potential off-takers, increasing their cost to such an extent that they are far less likely to take it up. Given that the CCL is an environmental tax and the role of electrolytic hydrogen is for decarbonisation, we recommend that electrolytic hydrogen projects be exempt from the levy.

Recommendation: Clarify that all electrolytic hydrogen production facilities in receipt of a Low Carbon Hydrogen Agreement (LCHA) are exempt from paying the Climate Change Levy.

10. Relaxing the requirement to retire REGOs

Renewable Energy Guarantee of Origin (REGO) retirement is a compliance requirement under the LCHS where an electrolyser uses renewable electricity. Hydrogen producers cannot avoid or mitigate this cost as the ability of renewable generators to sell REGOs separately from the underlying power means renewable generators will always insist on securing the market value for their REGOs.

With the cost of REGOs having risen substantially in recent years, currently trading around £10/MWh[9], this is a significant extra compliance cost for electrolytic hydrogen, making it more expensive and counterproductive to wider Government objectives of facilitating hydrogen cost reduction to encourage decarbonisation and the growth of the sector.

Recommendation: As part of a wider review of how electrolytic hydrogen compliance costs can be reduced, the Government should explore whether a removal or temporary removal of the requirement to retire REGOs to comply with the LCHS would be appropriate.

9 Renewable Exchange, PPA Market Report 2023–2024

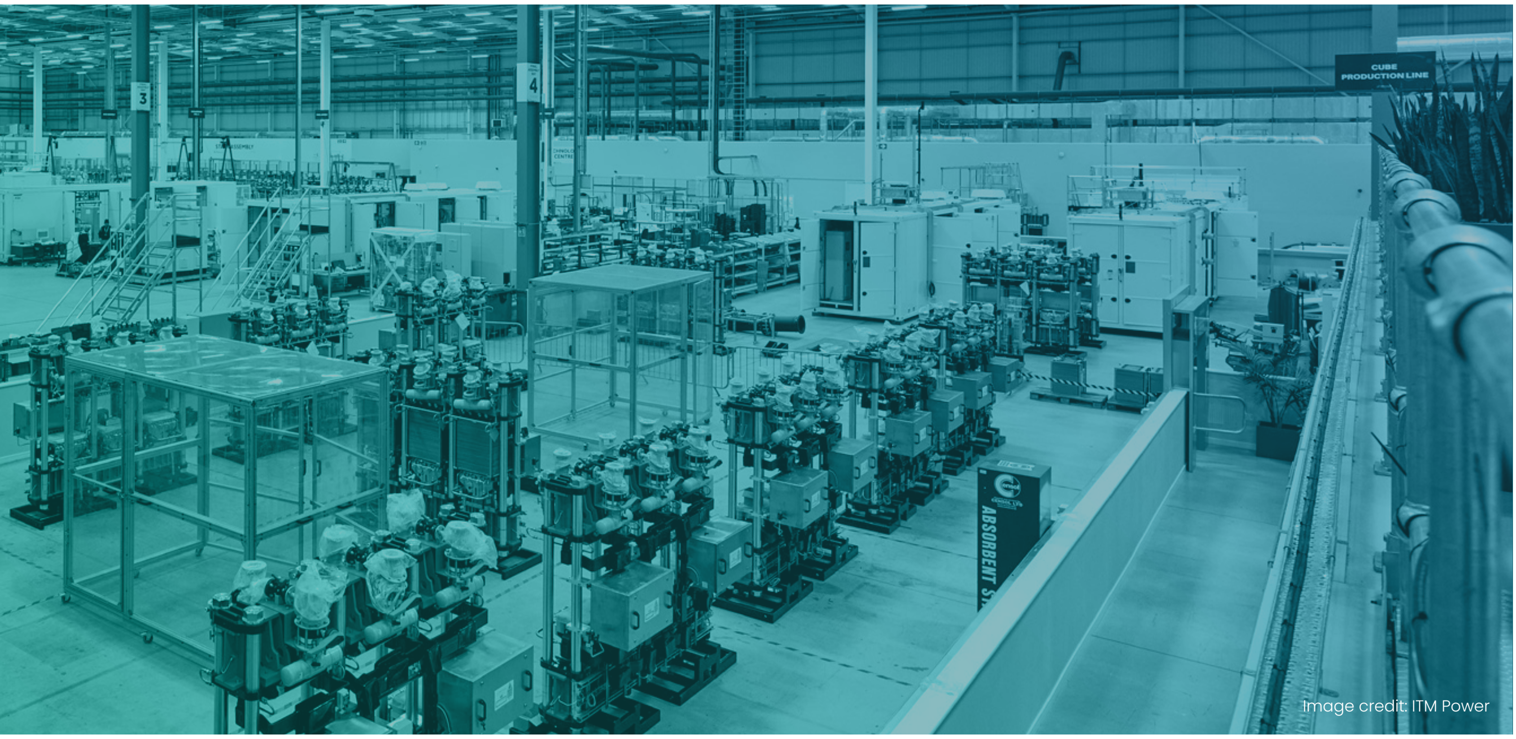


Image credit: ITM Power

Renewables, hydrogen and the need for infrastructure

11. Develop a strategic hydrogen transmission network

To maximise the hydrogen opportunity, infrastructure is required to connect hydrogen production to demand. While co-location of hydrogen production and demand will be suitable, and beneficial for some projects, especially in the early stages of the industry, in the long term hydrogen production will be distributed across the country, to complement the development of a clean electricity system.

This system will require electricity grid infrastructure to be delivered at scale and at pace, but NESO acknowledges the scale of the challenge. In its advice on Clean Power 2030, NESO forecasts £6.58-£7.79bn of constraint costs in 2030 if all 80 of the network upgrades identified in its Pathway to 2030 are implemented.

The integration of hydrogen into the energy system provides an opportunity to reduce the burden of electricity grid investment and play a vital role in balancing the system. As noted in both the Offshore Wind Champion's and Hydrogen Champion's respective reports[10, 11], integrated infrastructure planning across electricity and hydrogen transmission alone could provide energy system savings of up to £38 billion by 2050.

The National Infrastructure Commission (NIC) made a clear recommendation to develop a core network of hydrogen pipelines that links Scotland to England and Wales, including the industrial clusters. This national network would allow electrolytic hydrogen to be produced at the lowest cost i.e. close to renewable generation assets, but still be linked to 'inflexible' and/or 'immovable' demand such as heavy industry, transport and power. These sources of demand are not always located in the industrial clusters, or close to renewable generation assets, instead being located due to access to other factors beyond simply electricity supply.

A strategic plan that integrates hydrogen and electricity infrastructure will reduce overall system costs and the costs that electricity generation is required to pay, and pass on to demand, including hydrogen producers.

Recommendation: Government should make a strategic decision on a core hydrogen network that links Scotland to England and Wales, including timelines for deployment and funding mechanisms. This will enable renewable and hydrogen developers to plan and optimise their projects based on the availability of hydrogen transport and storage infrastructure.

10 DESNZ, 2023 "Independent report of the Offshore Wind Champion — Seizing our Opportunities"

11 DESNZ, 2023, "Hydrogen Champion Report"

12. Demand enablement

To improve the overall affordability of electrolytic hydrogen, attention must also be paid to 'demand enablement'. Access to hydrogen transport and storage infrastructure will greatly improve hydrogen producers' ability to sell to offtakers, increasing competition and reducing commercial risks, all of which will help to reduce total subsidy costs. Further measures to better enable demand, both short term and long term, should be explored, including those highlighted in Hydrogen UK's Manifesto[12].

12 Hydrogen UK, 2024, "Hydrogen UK Manifesto"

Image credit: ITM Power

Electrolysers, deployment and economies of scale

While the main focus of this paper is on highlighting the opportunities to improve deployment and reduce costs through addressing challenges related to electricity procurement and access to infrastructure, there are further cost reductions that will be achieved through learning from initial projects, technology development and economies of scale.

As with any nascent technology, the cost of electrolysers, and the relative contribution to LCOH, will decrease as a function of cumulative deployment. This comes about through learning, increased efficiency, mass-manufacturing and standardisation. Economies of scale, particularly for balance of plant, will also contribute to cost reduction. Analysis presented by IRENA[13] shows that increasing plant capacity from 10MW (similar to the average HAR1 project) to 100MW results in a 25% reduction in CAPEX on a per MW basis, driven largely by a 40% reduction in the cost of balance of plant also on a per MW basis.

13 IRENA, 2020, "Scaling Up Electrolysers to Meet the 1.5°C Climate Goal"

Image credit: ITM Power

Conclusion

Figure 4 shows the cumulative effect of some of the measures suggested in this paper, highlighting the potential cost reduction for future HAR allocations. The costs are based on the average of HAR1 projects which represent a range and combination of co-located (direct wire) and grid connected projects. The absolute impacts of each cost reduction measure in Figure 4 will be different for the various combinations of project archetype, where exposure to wholesale and electricity system costs vary. While not all measures may be possible for all project archetypes, it represents a fall in average LCOH from just over £9/kg to under £5/kg.

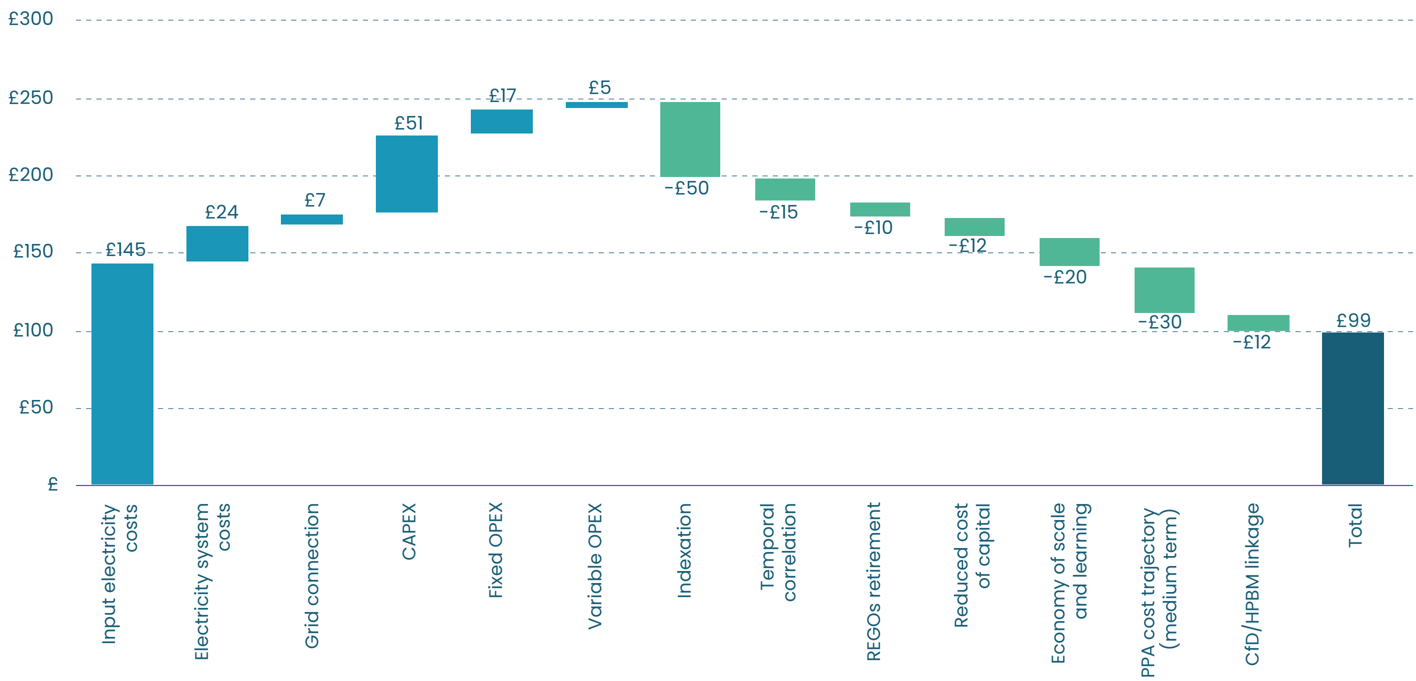
When combined with measures such as increased Price Discover Incentive, allowing RTIs and promoting demand enablement, the subsidy intensity for future electrolytic hydrogen projects can be reduced significantly from the first-of-a-kind projects, with additional learnings and economies of scale delivering further improvements.

There are significant benefits to be made from strengthening the links between renewable electricity generation and electrolytic hydrogen production, in both co-located and grid connected project archetypes. The members of RewnewableUK and Hydrogen UK stand ready to work with Government to shape the markets and business models of the future that deliver on the UK's missions for Clean Power 2030 and ambition to become a clean energy superpower, capitalising on the natural assets of the UK for deployment of renewable energy generation, the use of hydrogen to balance the energy system, and strong domestic supply chains to capture the value.

The measures identified in this paper highlight the cost reduction that could be achieved relative to HAR1, lowering the subsidy intensity of electrolytic hydrogen and strengthening the route to market for both renewables and hydrogen.

Figure 4: Regional average CO_2 intensity of generation, LCP Delta 2025 forecast

Potential options for reducing the cost of electrolytic hydrogen



Glossary

BECCS	Bioenergy with Carbon Capture and Storage
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
BSUoS	Balancing Services Use of System
CAPEX	Capital Expenditure
CCL	Climate Change Levy
CCUS	Carbon Capture, Usage and Storage
CfD	Contracts for Difference
CO_2	Carbon Dioxide
DESNZ	Department for Energy Security and Net Zero
EII	Energy Intensive Industry
FID	Final Investment Decision
GB	Great Britain
GVA	Gross Value Added
GW	Gigawatt
HAR	Hydrogen Allocation Round
HPBM	Hydrogen Production Business Model
HUK	Hydrogen UK
HyBMU	Hybrid BMU
IRENA	International Renewable Energy Agency
LCHA	Low Carbon Hydrogen Agreement
LCHS	Low Carbon Hydrogen Standard
LCOH	Levelised Cost of Hydrogen
MJ	Megajoules
MW	Megawatt
NESO	National Energy System Operator
NIC	National Infrastructure Commission
OFTO	Offshore Transmission Owner
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
REGO	Renewable Energy Guarantees of Origin
REMA	Review of Electricity Market Arrangements
RO	Renewable Obligation
RTI	Risk Taking Intermediaries
SFT	Scottish Futures Trust
TNUoS	Transmission Network Use of System
UK	United Kingdom

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Electrolyser photographs courtesy of ITM Power

With support from LCP Delta

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