Offshore Wind Industry Council

Catapult Offshore Renewable Energy

OFFSHORE WIND AND HYDROGEN

SOLVING THE INTEGRATION CHALLENGE

ACKNOWLEDGMENTS

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The Offshore Wind Industry Council is a senior Government and industry forum established in 2013 to drive the development of the UK's world-leading offshore wind sector. OWIC is responsible for overseeing implementation of the UK Offshore Wind Industrial Strategy.

ORE Catapult is a not-for-profit research organisation, established in 2013 by the UK Government as one of a network of Catapults in high growth industries. It is the UK's leading innovation centre for offshore renewable energy and helps to create UK economic benefit in the sector by helping to reduce the cost of offshore renewable energy, and support the growth of the industry.

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FOREWORD

As the Offshore Wind Champion, I am delighted to support this report which has been commissioned by OWIC as part of the Offshore Wind Sector Deal. It looks at the opportunities and challenges from integrating high levels of renewables on the electricity grid make a strong case for the synergies between offshore wind (OSW) and green hydrogen production. Offshore wind and hydrogen together form a compelling combination as part of a net zero economy for the UK, with the potential to make major contributions to jobs, economic growth and regional regeneration as well as attracting inward investment, alongside delivering the emission reductions needed to meet our commitment to Net Zero.

As demonstrated by the Future Energy Scenarios published in July 2020 and Progress Report by the CCC there will be more need for long term storage. With an increasing proportion of variable renewable power on the UK electricity system there will be more time when wind resource is available but capacity is not required on the grid. Combining zero carbon electrolytic hydrogen production – green hydrogen - with OSW provides effective use of capital assets and wind resource and a means of long term energy storage. This strengthens the business case for future renewables investment as we move beyond the current system of long term contracts for electricity supply.

The conclusions from the report on hydrogen and offshore wind, work carried out by the Offshore Renewable Energy Catapult for OWIC are as follows:

1. **Offshore wind with green hydrogen is a major UK opportunity.** The UK has outstanding OSW resource, with the potential for over 600GW in UK waters, and potentially up to 1000GW, well above the figure of 75-100GW likely to be needed for UK electricity generation by 2050. This opens up the possibility of growing the OSW industry beyond electricity requirements, with the producing green hydrogen for export if OSW costs continue to fall.

2. **The industrial base is strong.** UK has an established industry base to build on: the OSW industry itself, the oil and gas industry with BP and Shell developing Net Zero compatible strategies, and companies on the demand side such as Johnson Matthey, Wright Bus, Alexander Dennis, Baxi, and Worcester Bosch. This is further strengthened by rapidly growing UK technology-based companies which combine global reach with UK manufacture - ITM Power, Ceres Power, Intelligent Energy are all important technology players in the electrolyser and fuel cell area. Many emerging businesses such as Bramble, Arcola, H2GO, Riversimple, Microcab, FCEV, RFC Power, Ryse Hydrogen also form a key part of the UK's hydrogen ecosystem.

3. **Our universities provide the underpinning science and engineering for electrolysers, fuel cells, and hydrogen, and are home to world-leading capability in these areas.** This research will not only support cost reduction but will help to deliver the next generation of both technologies and companies as well as the scientists and engineers to work in this new industry.

4. **By 2050 green hydrogen can be cheaper than blue hydrogen.** The main elements of cost for green hydrogen from electrolysis and OSW are electricity cost, equipment costs and electrolyser efficiency. With OSW wind costs continuing to decline, electrolyser efficiency increasing and electrolyser costs falling with experience, the time is right to follow an approach akin to that which has been so successful for OSW deployment and cost reduction. With accelerated deployment, green hydrogen costs can be competitive with those from methane-based production with CCS (blue hydrogen) by the early 2030s.

5. **Action is urgent: developing green hydrogen in the next 5 years will be critical to achieving cost reduction and growing a significant manufacturing and export industry, based on UK technology.** From an emissions perspective a green hydrogen industry can be safely kick-started without waiting for operational CCS in the UK.

6. **This can create a major new manufacturing sector for the UK.** The overall demand for hydrogen by 2050 in the UK is predicted to be between 100- 300TWh, of comparable scale to the UK's electricity system today. It is estimated to be 25% of Europe's energy supply, with much more needed globally. With green hydrogen becoming as cheap as blue by the 2030s much of this could be produced by OSW and electrolysis. The combination of additional OSW deployment and electrolyser manufacture alone could generate over 120,000 new jobs, replacing those lost in conventional oil and gas and other high carbon industries.

7. **And generate significant economic impact: the OSW and hydrogen study estimates a cumulative GVA of £320bn between now and 2050.** This global market for equipment and hydrogen includes £250bn of electrolyser exports. A further potential £48bn from green hydrogen exports to Europe, would need an additional 240GW of OSW. These figures are for OSW and electrolysers only, they do not include significant other original equipment and supply chain opportunities in both the supply and demand areas. Opportunities for further inward investment to create jobs have already been demonstrated in ITM Power and Ceres Power, and Siemens interest in investing in an electrolyser giga-factory here.

8. **Production needs a market, investment needs both.** Government intervention across multiple Departments is needed to support the concurrent creation of supply and demand in this new industry. A national strategy and is needed: an integrated approach to deliver accelerated deployment, supported by appropriate regulation and policy, targeted R and D, demonstration and large scale validation of new developments, combined with continued OSW cost reduction.

This is an exciting opportunity for the UK, we must act with urgency to get this industry operational and build on the UK's strengths in this energy source that has finally come of age as we drive for Net Zero.

Many people have been involved in the work of this Sector Deal working group. I would like to thank all of them, particularly my Co-Chair Danielle Lane of Vattenfall and Jane Cooper of Orsted. The team at the Offshore Renewable Energy Catapult has produced an important report. The members of the Steering Committee, Expert Group and specialist advisory groups who have made numerous suggestions to improve the quality of the analysis and make our conclusions more robust, deserve special credit for their engagement and advice.

JULIA KING
THE BARONESS BROWN OF CAMBRIDGE DBE FRENG FRS
OFFSHORE WIND SECTOR CHAMPION
30th July 2020

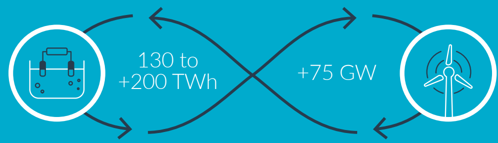
KEY FINDINGS

OSW OPPORTUNITY

There is sufficient offshore wind for UK energy needs, plus substantial energy export exports; to exploit this the UK will need to coordinate infrastructure and markets, with neighbours in Europe.

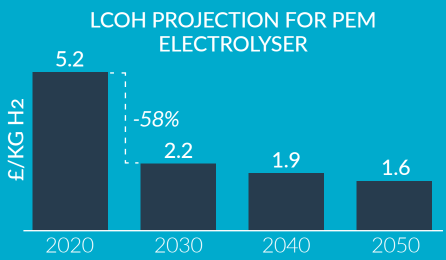
ENERGY SYSTEM

The UK energy system requires 130TWhr to over 200TWhr hydrogen in 2050, to integrate 75GW, or more of offshore wind.



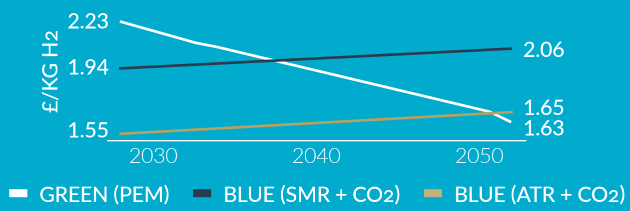
COST REDUCTION

Most of the cost reduction for green hydrogen from offshore wind occurs by 2030, by which point it can meet a significant part of energy demand.



GREEN AND BLUE HYDROGEN

Green hydrogen from offshore wind costs less than blue hydrogen by 2050*, although factors including more rapid adoption of electrolysers, swings in natural gas prices, leakage of natural gas, or cheaper blue hydrogen generation technologies, could change this picture.



**Hydrogen production from natural gas with CCS might not be a necessary part of a net-zero UK energy economy in 2050.*

Technology acceleration is an essential means of reducing electrolysis costs – the UK has strong leadership in academia and industry to build on.

There are signs in the marketplace that green hydrogen will take off faster than we assumed, cutting costs by 2030 by more than we have estimated.

Driving deployment of electrolysers is essential for reducing their cost – the UK has done this before, with offshore wind.

POTENTIAL BENEFITS

£320BN

Cumulative GVA in 2050 (electrolysers and UK OSW enabled by H2) of which £250bn is exports

120,000 JOBS

Delivering up to 120,000 new jobs, many in manufacturing, mainly outside London & SE

£48BN P.A.

Additional potential in green hydrogen exports to Europe, using up to 240GW of dedicated offshore wind

A wide range of UK companies will benefit from growth of the green hydrogen industry

NEXT STEPS

To avoid lost opportunities, our roadmap of research, projects and supporting actions to 2030 should be adopted as soon as possible.

TRACK 1 R&D programme

TRACK 2 Demonstrations at Scale

TRACK 3 Enabling Actions

EXECUTIVE SUMMARY

For the UK to achieve Net Zero emissions in 2050, we are likely to need a minimum of 75GW of offshore wind (OSW). Integrating this level of OSW into our energy system requires us to deal with the variability in its output. Recent modelling of the whole energy system, including electricity, heating and transport, indicates that hydrogen will play a major role in integrating the high levels of OSW that feature in least-cost pathways to decarbonisation. Scenarios from the Energy Systems Catapult, Imperial College London, Committee on Climate Change, and others, suggest that the requirement for hydrogen ranges from 130TWh, to over 200TWh, per annum. A green hydrogen economy using 130 TWh of hydrogen, would require the annual output of 40GW of offshore wind.

This study looks at the viability, and economic opportunities, of combining offshore wind with hydrogen, via electrolysis. We have analysed the cost of green hydrogen generated from UK OSW ('OSW-H2') out to 2050, and expect that, in 2050, OSW-H2 will cost less than hydrogen produced from natural gas, with carbon capture and storage (CCS), typically referred to as 'blue' hydrogen. However, more rapid cost reduction for blue hydrogen generation technology could help it maintain a cost advantage, whereas more rapid deployment of electrolysers, or higher carbon costs for blue hydrogen, e.g. from stricter accounting of gas leakage, could accelerate the cost advantage of green hydrogen. Volatility in natural gas prices could act to favour either green, or blue, hydrogen. The cost reduction in green hydrogen is achieved through accelerated deployment of electrolysis, coupled with targeted research and development (R&D), and demonstration projects and technology validation at large-scale. The majority of the cost reduction takes place by 2030 driven in part by the continued cost reduction of OSW itself. The period from 2020-2030 is therefore critical, for ensuring steady growth of a hydrogen economy that can integrate increasing amounts of offshore wind, on the path to 2050, and for securing the substantial economic benefit that can flow from green hydrogen.

UK academia has world-leading strengths in the research areas required to develop improved electrolyser technologies to help drive cost reduction and efficiency gains. We have set out the research priorities for a green hydrogen R&D programme, in materials, electrochemistry, and other essential disciplines. This forms a key part of our technology roadmap, of core R&D on electrolyser technology, demonstrations of new technology, and development of facilities and standards to validate the market-readiness of new hydrogen generation products.

We have set out a roadmap of actions for the UK to rapidly scale up OSW-H2 and become competitive with other fuels. Through a series of projects across industry, mobility and heating for homes and business, stable demand side applications can be developed. By targeting sectors and projects where green hydrogen will quickly become competitive, the roadmap minimises the public investment required. There is a growing amount of existing activity aimed at developing markets and technologies for hydrogen. We have summarised these and the potential pathways, and essential stakeholders, for accelerated deployment. Building on this, our roadmap points to a series of enabling actions to support the technology innovation journey, and to support development of markets, and in particular, near-term development of hydrogen hubs around large industrial clusters.

The OSW-H2 roadmap creates substantial economic benefit for the UK. By 2050 the cumulative gross value added (GVA) from supply of electrolysers and additional OSW farms, is up to £320bn, the majority from exports of electrolysers to overseas markets. This activity supports up to 120,000 additional jobs, which are expected to be based mainly in regions outside London and the South-East, in manufacturing OSW-related activity, shipping and mobility. We have identified a wide range of potential beneficiaries in UK manufacturing and engineering, giving us confidence that UK companies can secure a major share of the supply chain for electrolyser projects. In addition, we have identified a strong potential for creating a major UK energy export industry, supplying our abundant, low-cost OSW-H2 to mainland Europe, which is forecast to have a large demand for green hydrogen imports in 2050. Our OSW-H2 exports to Europe alone, could have an annual value of up to £48bn, comparable with the best years of the North Sea oil and gas industry. We have ample, and inexhaustible, OSW to meet this need, and to supply into a global market for green hydrogen. In addition, the green hydrogen consumer economy that this will create in the UK, is likely to have even greater value, in downstream hydrogen gas networks, vehicles, heating appliances, industrial applications, and power generation.

For government and industry, the journey, and the required commitments, are similar to the successful cost reduction journey for OSW, but the financial support required is on a smaller scale. Ambitious national targets for deployment are essential, to bring forth the private investments required in innovation, and early projects. Our abundance of affordable renewable resources gives the UK a competitive advantage. However other governments with smaller resources recognise the hydrogen opportunity and are already setting ambitious targets for green hydrogen. The window of opportunity is short.

By supporting the level of deployment on our roadmap, the UK can replicate the successful, rapid reduction in cost that we have seen for OSW, making OSW-H2 the lowest cost source of bulk hydrogen for the UK in 2050, and providing a secure, economically rewarding path to a zero-carbon energy sector by 2050.

1 INTRODUCTION – THE OPPORTUNITY FOR HYDROGEN WITH OFFSHORE WIND

1.1 OBJECTIVES OF THE STUDY

In its 2019 report on how the UK can achieve 'Net-Zero' carbon emissions in 2050, the Committee on Climate Change (CCC) pointed to OSW becoming potentially the largest source of zero-carbon energy, in 2050[1], with installed capacity of 75GW. The CCC report emphasised the need for measures that can integrate this level of variable-output renewable energy into the energy system.

Offshore Renewable Energy (ORE) Catapult has partnered with the Offshore Wind Industry Council (OWIC) Solving the Integration Challenge (StIC) task force on this study, to examine the potential for hydrogen to play a key role in providing the flexibility, and short and long-term energy balancing, required for integrating high percentages of OSW into the UK energy system, and the actions required to achieve this.

Our study addresses:

- The amount of hydrogen required to achieve Net-Zero in 2050.
- The costs of green hydrogen produced with OSW (OSW-H2), compared with the cost of fossil-fuel derived alternatives.
- The technology challenges for driving down OSW-H2 costs, particularly for electrolysers, and the R&D programmes and demonstration projects required to solve these challenges.
- The growth in hydrogen markets required to drive down costs.
- The promising sources of cost-reducing market growth, to 2030.
- The supply chain opportunity for the UK, including exports, in particular of electrolysers.
- The supporting policies, for research and demonstration and for market scale-up.

In a related study, Energy System Catapult (ESC) has applied its whole energy system modelling to provide insights into the potential scale of OSW, and the scale and role of H2 in system balancing.

1.2 INCREASED OFFSHORE WIND IN THE ENERGY SYSTEM

By 2050 the UK energy sector may have to be 100% decarbonised. Other sectors such as agriculture, and steel and cement manufacturing are intrinsically difficult to decarbonise. The recent trend of accelerating negative effects from climate change may continue, pulling forward zero-carbon deadlines, for the UK and her trading partners.

100% decarbonisation will require the replacement of natural gas for heating, and oil for vehicles, with zero-carbon alternatives. If there is an affordable, large-scale source of zero-carbon electricity, the majority of heating and personal transport is likely to be electrified. In this scenario, even with robust efficiency improvements, UK electricity end-use demand may double, from ~300TWh today, to 500-600TWh by 2050[2].

[1] Net Zero – The UK's contribution to stopping global warming, CCC, 2019
[2] Digest of UK Energy Statistics, Chapter 5: Electricity, National Statistics, 2019

UK OSW is a renewable energy resource that has become a cost-competitive source of energy and in the next five years it is expected to cost less than wholesale electricity (Figure 1.1)[3]. OSW farms are predicted to reach higher capacity factors, or energy yield, than today, helped by bigger turbines accessing higher wind speeds. Together with the falling cost of capital and innovation throughout the supply chain, this has allowed OSW prices to reduce faster than the industry expected[4]. The UK government and devolved administrations have been quick to recognise that OSW can make a large contribution to our zero-carbon energy needs. The UK's target for operational OSW capacity by 2030 has been raised from 30GW to 40GW.

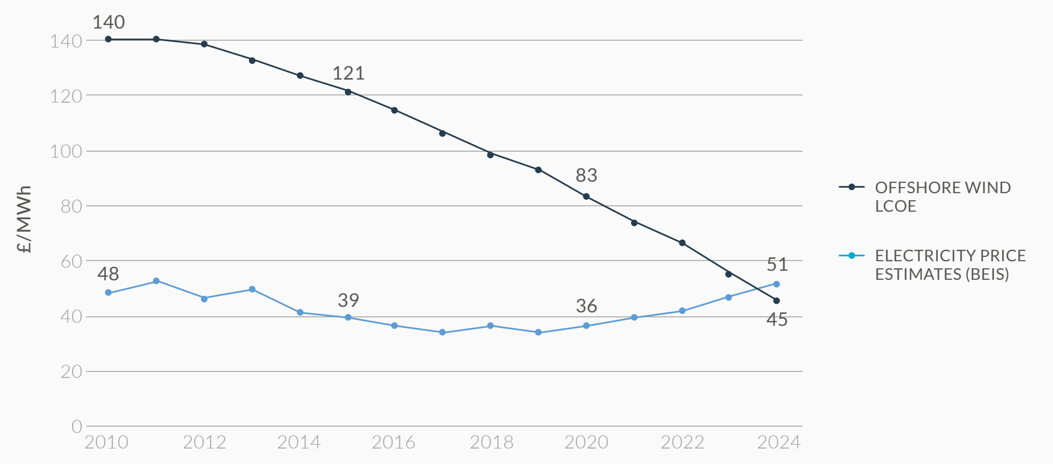


Figure 1.1 Wholesale electricity price comparison with offshore wind LCoE

As a consequence of this price reduction, multiple recent forecasts indicate growing confidence that, by 2050, high levels of deployment, representing a significant proportion of electricity needs, and even total energy needs, can be achieved. Figure 1.2 compares a range of forecasts for OSW installed capacity:

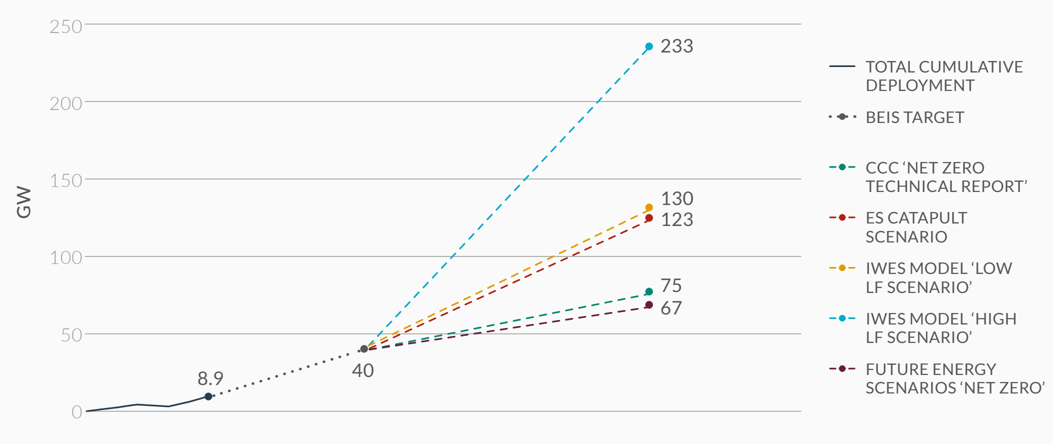


Figure 1.2 Total installed capacity of offshore wind in the UK - comparison of different scenarios

For this study, we have extended previous work on the scale of the UK OSW energy resource, to demonstrate that it is sufficiently large to be capable of supplying the total UK energy demand in 2050. The Science and Technology Facilities Council (STFC) (Cavazzi, 2016) used GIS data layers from The Crown Estate, covering non-constructible features such as shipping lanes and oil and gas (O&G)

[3] Contracts for Difference Allocation Round 3 Results, BEIS, 2019
[4] Cost Reduction Monitoring Framework, ORE Catapult, 2016

infrastructure, to identify a UK OSW potential of 675GW, at, or close to, then-current levelised cost of energy (LCOE)[5]. A more recent study of global OSW resource estimated that more than 1,000GW is available, affordably, in UK continental waters[6]. ORE Catapult has taken the original STFC energy resource analysis and updated their cost tables to produce a detailed resource map for UK waters (Figure 1.3), where the two lowest price tranches (50£/MWh; 60£/MWh) correspond approximately to the 675GW in the 2016 study[7].

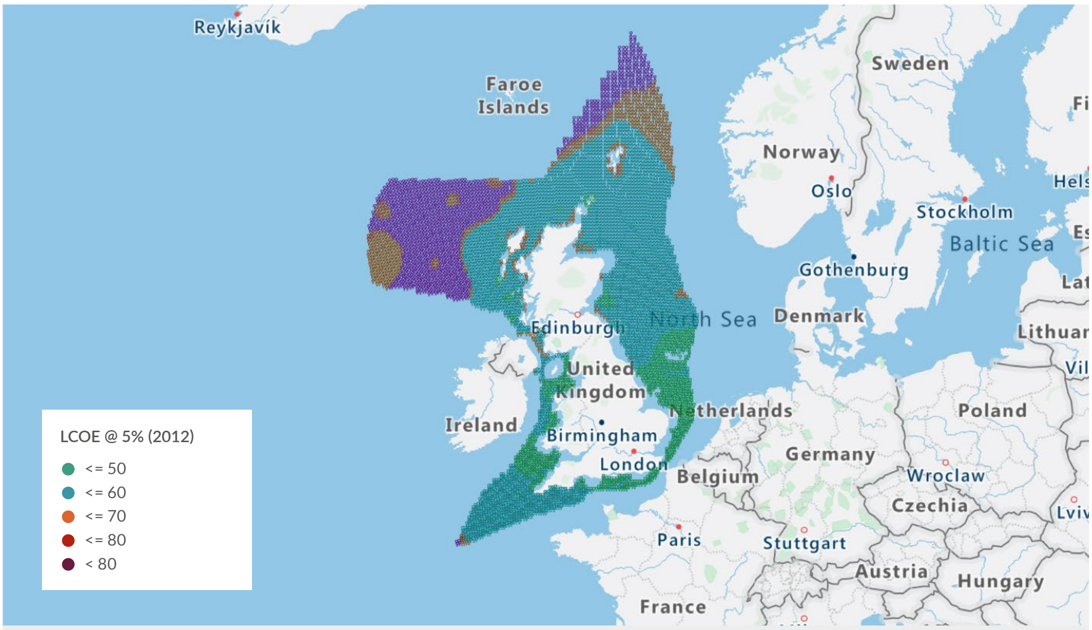


Figure 1.3 Modelled LCOE for UK waters

Results are calibrated as far as possible with the September 2019 Contracts for Difference (CfD) auction. LCOE estimates are based on physical parameters, including water depth and wind resource, on a 1km x 1km grid. For water depth >60m we assumed that floating wind has been commercialised to the point where it is competitive with bottom-fixed OSW.

OSW has the potential to supply all of the UK's final consumption of energy (ca. 1,600 TWh in 2018), and more. Since each GW of OSW provides around 5TWh of electricity per year, 675GW could produce 3,375TWhs per year. This is a natural resource large enough to support major energy exports to Europe, via electricity interconnectors and hydrogen pipelines, and globally, via hydrogen cargo vessels.

Some OSW farms already achieve capacity factors over 55% (percentage of turbine nameplate rating, delivered to the grid)[8]. It is therefore more straightforward, and cheaper, to provide the short-term and seasonal balancing required for an energy sector dominated by OSW, rather than onshore wind or solar, which have substantially lower capacity factors (typically around only 10% for solar). Exploiting consistent, high-speed wind resource in deep-water sites, both close to and further from shore (particularly Scotland and the South West), provides an additional layer of energy security and stability through exposure to different weather systems.

This combination of technology characteristics, low cost, and large and consistent wind resource over the sea, makes OSW the strongest prospect for attaining a higher percentage of renewables in the UK energy mix. But for OSW to become the backbone of the UK energy sector, the variable nature of its output must be overcome.

[5] An Offshore Wind Energy Geographic Information System (OWE-GIS) for assessment of the UK's offshore wind energy potential, S.Cavazzi, A.G. Dutton, Renewable Energy 87, 2016
[6] Global levelised cost of electricity from offshore wind, Jonathan Bosch, Iain Staffell, Adam D. Hawkes, 2019
[7] Prices are in 2012 £s and assume a 2023 commissioning date.
[8] Global levelised cost of electricity from offshore wind, Jonathan Bosch, Iain Staffell, Adam D. Hawkes, 2019

1.3 HYDROGEN FOR ESSENTIAL FLEXIBILITY AND BALANCING OF THE ENERGY SYSTEM

Hydrogen is one of the most common elements on earth, but rarely can be found in a pure form. It can be extracted from its compound (e.g. by splitting water) using any primary source of energy.

Different colours are used to distinguish between different sources of hydrogen production. “Black”, “grey” or “brown” refer to the production of hydrogen from coal, natural gas and lignite respectively. “Blue” is used for the production of hydrogen from fossil fuels with carbon emissions reduced using CCS. “Green” is a term applied to production of hydrogen from renewable electricity, using electrolysis. Electrolysis is a process where water (H_2O) is split into hydrogen (H_2) and oxygen (O_2) gas with energy input. Green hydrogen can be also produced from biomass by gasification.

Steam Methane Reforming (SMR) is most frequently reforming of natural gas. The primary ways in which natural gas, mostly methane, is converted to hydrogen involve reaction with either steam, oxygen, or both in sequence. The emissions can be captured using CCS. Reforming of natural gas with CCS is called blue hydrogen.

The essential difference between hydrogen and electricity is that hydrogen is a chemical energy carrier, composed of molecules and not only electrons. Chemical energy can be more attractive as it can be stored and transported in a stable way. Molecules can be stored for long periods, transported across the sea in ships and burned to produce high temperatures.

In recent years numerous studies have highlighted the need for hydrogen to provide flexibility and balancing of the energy system in 2050[9] [10] [11]. In the CCC’s report “Hydrogen in a low-carbon economy”[12], which examined the role of hydrogen in decarbonising the economy, even in scenarios with relatively lower uptake, hydrogen provided an essential energy balancing function.

Other forecasts of the energy system in 2050 also point to a key role for hydrogen, including recent work by ESC and the integrated whole energy system (IWES) modelling group at Imperial College London, both of whom we have collaborated with on this study. In scenarios with zero carbon allowed in the 2050 energy system, green hydrogen from OSW emerges as a major source of the overall flexibility required to balance the energy system. Electricity storage requirements, for example grid-scale batteries, are small by comparison with the energy stored in green hydrogen. Generation of power from hydrogen in turbines provides support to the electricity grid during periods when electricity generation from variable renewables is low, such as cold spells in winter with low wind.

1.4 HYDROGEN’S ROLE IN SECURING ZERO CARBON ENERGY SUPPLY

In an energy system dominated by OSW, green hydrogen will play the same essential role in ensuring security of supply for the UK’s heating, electricity and transport needs, that North Sea oil and gas, and Liquid Natural Gas imports do today. The UK has been fortunate in having this fossil fuel resource, and is arguably even more fortunate in having inexhaustible reserves of OSW that, with green hydrogen, can continue to provide us with an affordable, secure, energy supply, and an energy export industry, in a zero-carbon future.

[9] Net Zero – The UK’s contribution to stopping global warming, CCC, 2019
[10] Path to hydrogen competitiveness, A cost perspective, Hydrogen Council, 2020
[11] Research needs towards sustainable production of fuels and chemicals, Energy X 2019
[12] Hydrogen in a low-carbon economy, CCC, 2018

Mainland Europe is not as fortunate. Germany, for example, has a high dependence on natural gas imports from Russia, and is expected to have a deficit of zero-carbon energy sources in 2050. A recent study by Gasunie and Tennet forecast a need for mainland Europe to import 200TWh to 1,200TWh of hydrogen per year, for their range of scenarios for 2050. This energy could be produced by 40 to 240GW of UK OSW. At a price of £20 to £40/MWh, this would represent a UK export industry of £4bn to £48bn annually. These flows of energy from UK OSW to Europe will require substantial new infrastructure. The North Sea Wind Power Hub, a consortium of the Port of Rotterdam, Energinet, Gasunie, and Tennet, is advancing pathfinder studies aimed at proving the concept of offshore Energy Hubs. The proposed Energy Hubs are artificial islands or platforms, each of which would connect 10-15GW of OSW to centralised high-voltage transmission and hydrogen generation assets, for delivery of energy to the mainland via a mix of high voltage DC cable and hydrogen pipelines[13].

1.5 OPPORTUNITY FOR HYDROGEN IN THE OIL AND GAS TRANSITION

The potential demand for secure, green hydrogen in mainland Europe, could help to secure a future for the extensive skills and assets of the UK offshore O&G industry. There is significant potential for collaboration between the OSW and O&G industries, particularly on re-purposing of O&G assets. The O&G sector will be required to decommission around 600 installations, and associated infrastructure, such as pipelines[14]. Rather than removing this infrastructure, some of it may be suitable for re-use to directly support OSW projects, or for offshore production of hydrogen. The UK Continental Shelf infrastructure is shown in Figure 1.4.

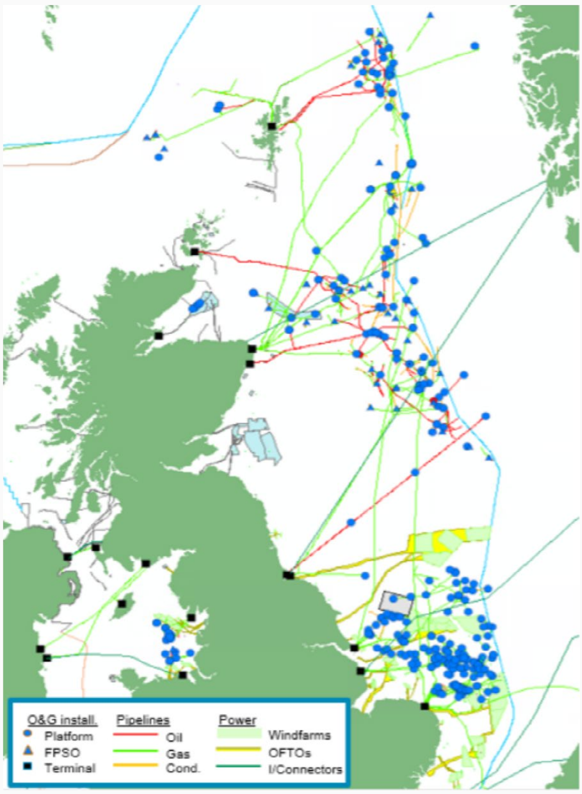


Figure 1.4 Map of UK Continental Shelf infrastructure

[13] Modular Hub-and-Spoke Solutions: Case studies have demonstrated technical feasibility, NSWPH, 2019
[14] On the economics of offshore energy conversion: Smart combinations, Catrinus J. Jepma, EDI, 2017

Repurposed O&G platforms could serve as operation and maintenance (O&M) bases for OSW farms, with offshore accommodation for technicians and charging stations for electric or hydrogen-powered Crew Transfer Vessels (CTVs). These platforms could be repurposed to host electrolysers and enable hydrogen production via water electrolysis using wind power. Hydrogen could be stored on the platform and transported to shore using existing pipelines.

This solution does not come without challenges. O&G platforms are not always electrically interconnected, can be located far from OSW farms or the infrastructure might require repurposing investment. Thus, the roll out of green hydrogen should not be designed around existing O&G infrastructure, but there are potential synergies to examine and grasp case by case. R&D programmes should identify optimal ways of achieving centralised and decentralised offshore electrolysis and hydrogen storage, with or without using existing rigs and pipes.

For this study, our estimates of the cost of producing hydrogen at wind farms assume that projects will require new pipelines to take the hydrogen to shore. We note that re-purposing O&G pipelines could significantly reduce this cost, but we did not include this option due to a lack of reliable estimates of pipeline re-purposing costs.

2 COSTS OF HYDROGEN FROM OFFSHORE WIND

2.1 OFFSHORE WIND INPUT COSTS FOR GREEN HYDROGEN PRODUCTION

The UK is a global leader in OSW with decades of experience in bottom-fixed installations. However, floating wind turbines are required to access the enormous OSW resources available in deeper waters. Although the LCOE of floating wind is currently higher than for bottom-fixed, the LCOE reduction of floating wind will be rapid, as it adopts existing wind turbine and related technology at a large scale.

We forecast that the LCOE of bottom-fixed projects will have dropped to £46/MWh (the implied LCOE, from strike prices awarded in UK auction rounds), after 16GW of capacity has been installed. However, floating wind LCOE is forecast to reach price-parity with bottom-fixed OSW, after only 8GW of floating capacity has been deployed. Globally, the LCOE of floating wind is expected to converge with bottom-fixed LCOE after reaching 16GW of installed floating wind. By this point an estimated 88GW of bottom-fixed OSW will have been deployed globally (see Appendix 1 for details of the OSW LCOE curves we used as the cost of electricity for electrolysers, in our hydrogen cost calculations). For this study, we adopted the CCC's Net-Zero forecast of 75GW OSW in 2050, to derive an annual deployment trajectory from the standard learning rate-based LCOE methodology. This incorporates the pipeline of known projects and The Crown Estate/Crown Estate Scotland leasing rounds, thereby constraining the rate of deployment of floating wind up to 2030.

Although the LCOE for floating wind for 2020 projects is more than double the LCOE of bottom-fixed wind, by the mid-2040's, both technologies will have comparable costs - in the region of £30/MWh. LCOE has reduced by 50% from 2019 to 2024 projects, following the award of £40/MWh strike prices. From 2024 to 2030 a 23% further reduction is estimated (which is less than half of the reduction in the previous five years) and a further 15% over the next 20 years to 2050. A key driver of LCOE is the average capacity factor of a windfarm (energy delivered to the national grid as a percentage of turbine nameplate generation capacity). We have assumed this to be 48% in 2020, increasing to 54% in 2023 and then kept stable through to 2050 – a conservative assumption.

2.2 HYDROGEN PRODUCTION ONSHORE AND OFFSHORE

We estimated the levelised cost of hydrogen (LCOH), by 2050, for two different types of OSW-H_2 projects: onshore ongrid – hydrogen being produced onshore by grid connected electrolysers, and offshore offgrid centralised – hydrogen being produced offshore at centralised facilities (see Figure 2.1 and Figure 2.2). We assumed an OSW farm of 1.2GW, in 60m water depth, 80km from shore, with an average annual capacity factor of 41% increased to 54% from 2025 (based on the current UK OSW project pipeline and the constant improvements in turbine technology - hub height and longer blades). Capacity factor does not stay the same throughout the year and there are periods of peak and low load so an annual average value was used.

For the onshore ongrid scenario, the OSW farm has a typical design with electricity exported to shore where an onshore electrolyser system and a hydrogen compressor are installed. To allow a like-for-like comparison of LCOH, 100% of the electricity produced by the windfarm is assumed to be used for hydrogen. In real-world projects, where detailed wind assessment has been conducted, the onshore configuration between output to hydrogen production and output to the grid will be based on the estimate of the distribution of actual electricity generation around the average and the power demand, in order to optimise the size of electrolysers and the size of grid connection. The peak electrical capacity of the electrolyser is sized to be 80% of the windfarm peak, rated capacity. This is considered as the most acceptable ratio for optimal curtailment and lowest cost of green hydrogen, according to the Energy Delta Institute (EDI)[15]. Minimal curtailment is assumed to occur, as electricity will be able to be directed to the grid or the electrolyser or an installed stand-by battery depending on signals coming from the grid (Appendix 1). The wind farm uses high voltage alternating current (HVAC) export cable so an onshore AC/DC converter has to be installed to allow electricity conversion and to feed the electrolyser with DC. The hydrogen produced is then distributed directly to end users or through high-pressure distribution gas networks.

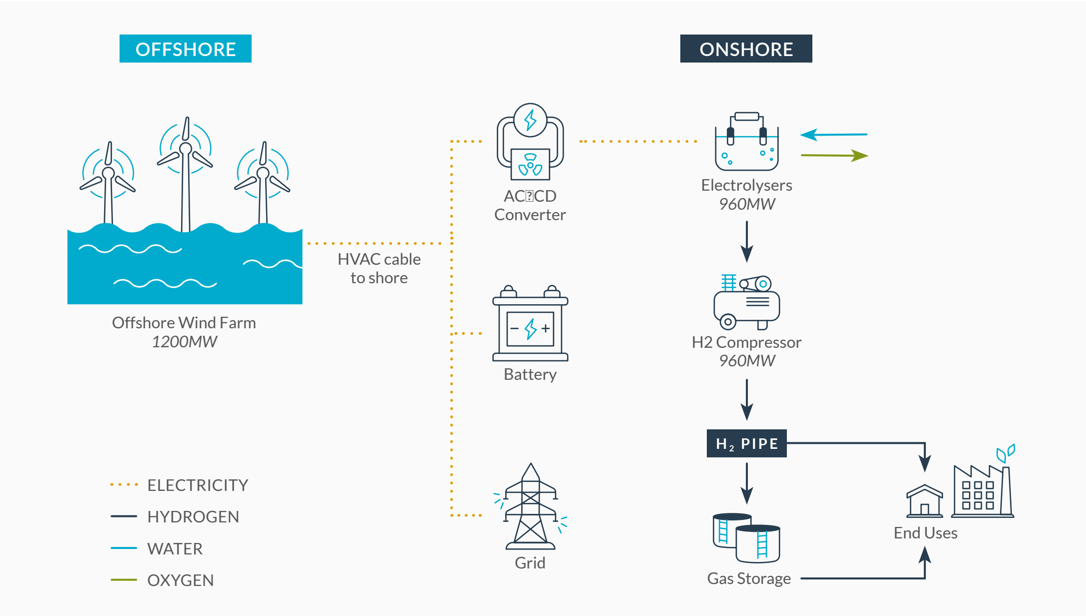


Figure 2.1 Outline of Onshore Ongrid - Offshore wind with onshore electrolysis grid connected

15 The EDI report assumes that in cases of curtailment the operator of the electrolyser will have to compensate the wind farm for all the lost revenue from curtailed wind power. In our analysis the addition of the standby battery can reduce curtailment close to zero. https://pdfs.semanticscholar.org/39e6/60db8aca8f7dbf5c10cac9f63767d5fbdddd.pdf

In the offshore offgrid electrolysis scenario the windfarm is connected with an AC cable to offshore platform(s) where an AC-DC converter, a water desalination system, an electrolyser system (again, 80% ratio of electrolyser to windfarm capacity) and a hydrogen compressor are placed. The hydrogen produced is then transferred through a large new offshore pipe to shore for distribution through a gas network or directly to end users. All the electricity production from the windfarm will be converted to hydrogen. The offshore offgrid electrolysis system eliminates the need for electrical infrastructure like offshore and onshore substation, export cables and grid connection charges, and instead bears the cost of the offshore pipe from wind farm to shore. It also includes the provision of a 120MW standby battery to provide a backup buffer in times where a surplus of electricity is produced due to excess wind.

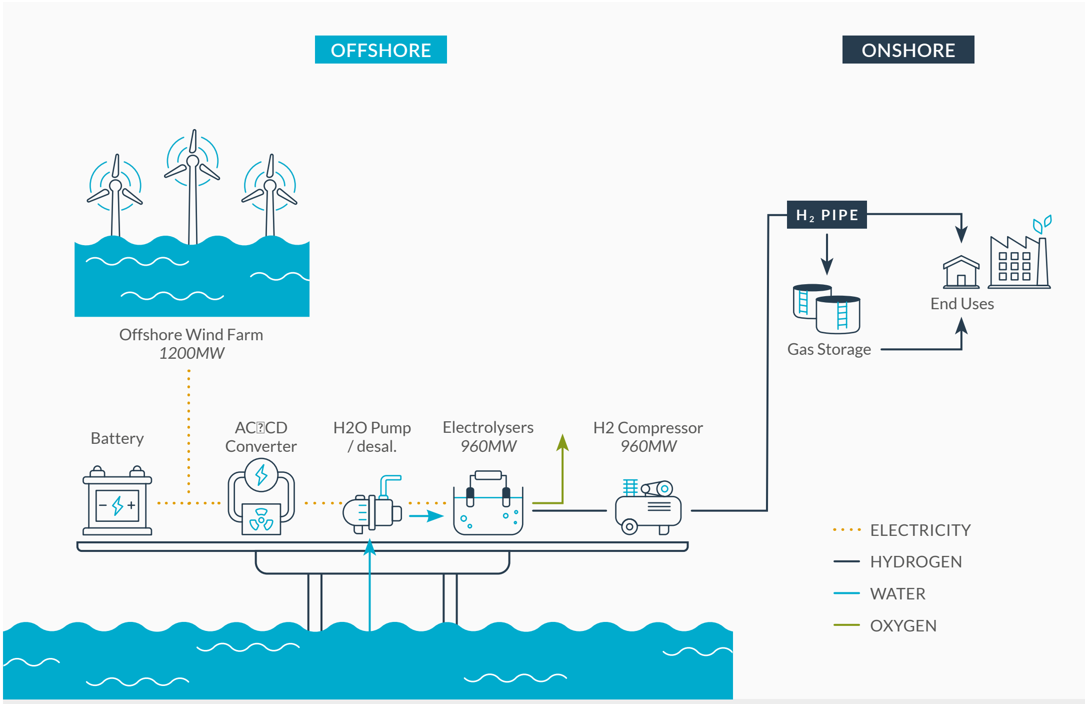


Figure 2.2 Outline of Offshore Offgrid Centralised - Offshore wind with offshore electrolysis and no grid connection

For a hypothetical bottom-fixed and floating wind farm, the summary CAPEX, OPEX and DEVEX of electricity and system cost estimations as part of the total LCOH analysis are listed in tables in the Appendix 1 for 2020, 2030 and 2050. A summarised cost breakdown of the LCOH of the electricity and hydrogen system (except the electrolyser described in the next section 2.3) for all concept scenarios is visualised in charts (Figure 2.3, Figure 2.4, Figure 2.5 and Figure 2.6).

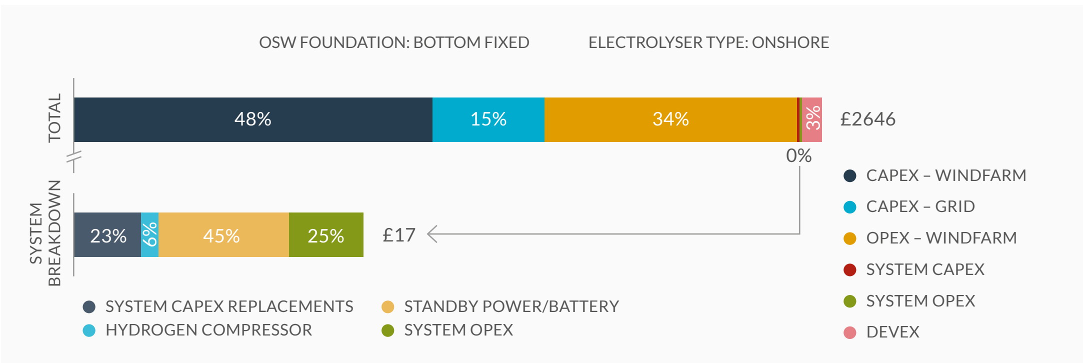


Figure 2.3 Cost breakdown of ongrid bottom- fixed offshore wind with onshore electrolysis in 2050 (%, £/kWh)

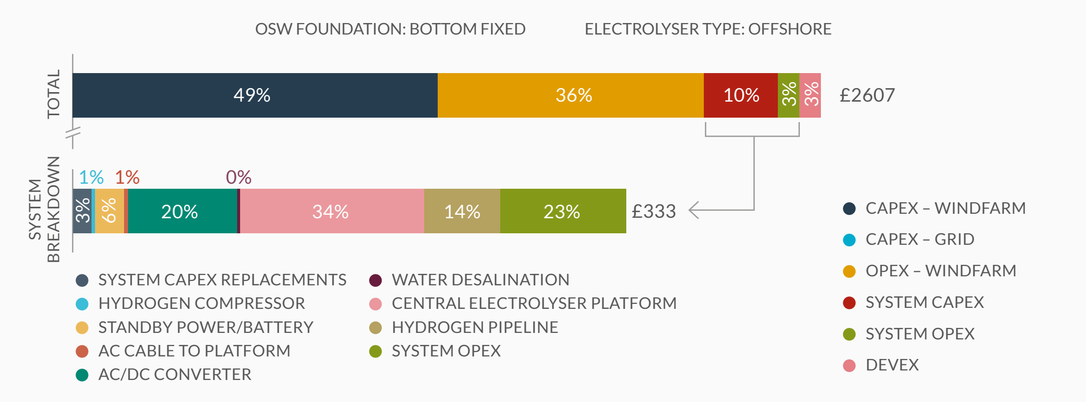


Figure 2.4 Cost breakdown of offgrid bottom- fixed offshore wind with offshore electrolysis in 2050 (%, £/kWh)

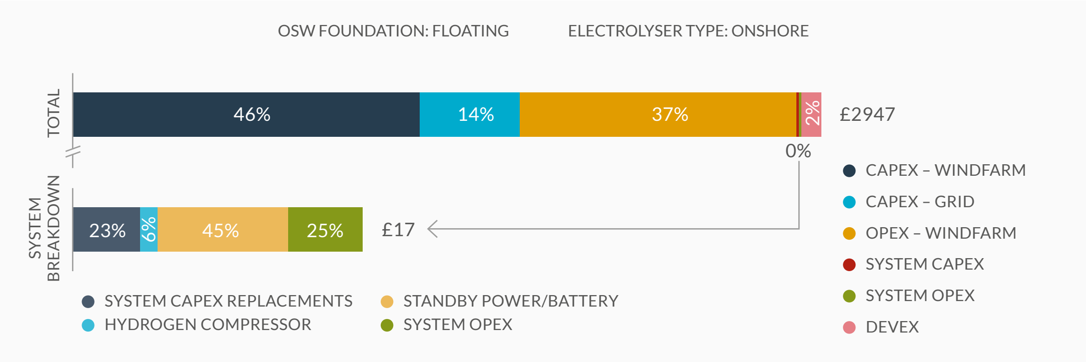


Figure 2.5 Cost breakdown of ongrid bottom- fixed offshore wind with onshore electrolysis in 2050 (%, £/kWh)

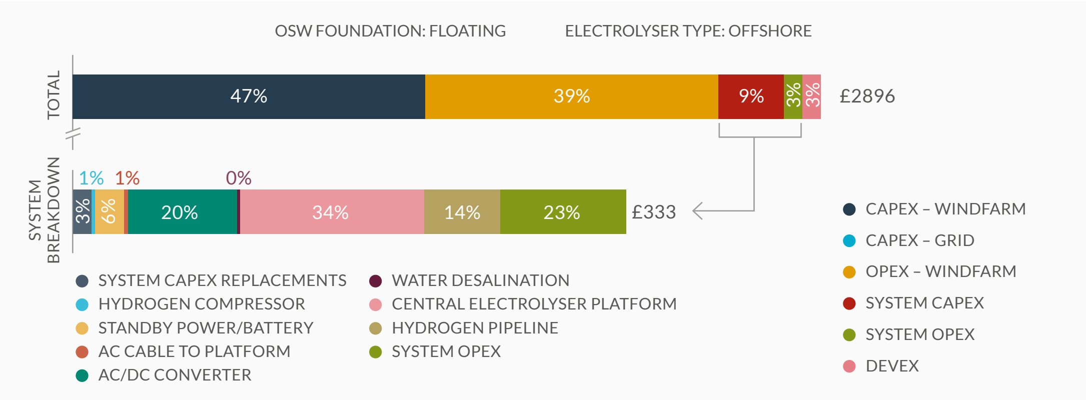


Figure 2.6 Cost breakdown of ongrid floating offshore wind with onshore electrolysis in 2050 (%, £/kWh)

2.3 ELECTROLYSER COST CURVES

2.3.1 INTRODUCTION

An overview of the hydrogen generation technologies analysed in this section is provided in Appendix 3 For the three types of electrolysers, a CAPEX analysis was conducted to estimate the cost reduction potential by 2050 examining the breakdown of system components (stack, gas conditioning, balance of plant and power electronics). The methodology included assumptions of the learning rates by component. The learning is driven by an estimate of 4,000GW of total, global electrolyser capacity in 2050 (Appendix 1)[16]. The electrolyser capacity was scaled up from 5MW to 10MW and then to 100MW for each electrolyser type based on its current level of technological and commercial maturity. In addition, gradual improvements in efficiency through the years are expected. Most electrolysers are characterised by modular stacks, especially alkaline electrolysers (AEL) however scaling factors of system components were added where applicable to reflect potential cost savings per unit of power from upscaling. The CAPEX forecast takes into account the nominal capacity of the electrolyser and is expressed in kW electrical to allow a like-for-like comparison of the cost curves. All costs are adjusted to 2012 prices.

However, electrolyser type characteristics can differ also in other aspects such as durability, efficiency, current density, degree of purity, type of electrolyte, pressure, load range and dynamics which can affect the market adaptability and the CAPEX if expressed per kW H_2 produced. Gradual improvements in efficiency through the years are expected for each type. Current density is also an important factor in comparing electrolysis methods. PEM electrolysers operate at 5-10 times the current density of AEL, which has a significant impact upon the footprint and packaging of electrolyser capacity with wind turbines or oil rigs. The efficiency of a PEM cell is dependent on the current density during operation. While a higher current density is crucial to cut down the start-up cost, a lower current density is needed to cut down the cost of operation[17].

Figure 2.7 to Figure 2.9 show the CAPEX reduction potential in kW electrical for each type of electrolyser and the cost breakdown by component. These electrolyser CAPEX projections were included in the estimations of LCOH. Annual OPEX was assumed to be 2.5% of the electrolyser CAPEX. The cost data in the graphs below shows jumps in milestone years which reflects the electrolyser unit size upscaling (e.g. from 5MW to 10MW) and the change of market shares between the three types of electrolyser. AELs are the most established technology, with the lowest cost for bulk hydrogen production, but proton exchange membrane (PEM) electrolysers are following suit: some studies forecast cost parity by 2030 due to higher compactness and suitability for stack pressurization as well as reduction in the rare earth material content in membranes[18 19 20 21]. In 2050 CAPEX could be below £210/kW electrical, based on our analysis. This is in line with the recent 2x40GW Green Hydrogen Initiative Paper which estimates a more aggressive CAPEX reduction, to below £175/kW by 2050[22]. On the other hand, our analysis showed that solid oxide electrolyser cell (SOEC) is expected to have almost three times higher CAPEX in 2050, compared to AEL and PEM (£585/kW).

The NOW study on water electrolysis in Germany, reports that industry experts expect AEL and PEM to be more expensive compared to SOEC by 2050[23]. However, SOEC has greater uncertainty associated with future development than the other two technologies, so this rapid fall in its cost is debatable. SOEC electrolysis is, therefore, an immature but promising technology, which is expected to achieve higher

16 https://webcache.googleusercontent.com/search?q=cache:M7I994cCPFsJ:https://www.bloomberg.com/news/articles/2019-08-21/cost-of-hydrogen-from-renewables-to-plummet-next-decade-bnef+&cd=12&hl=en&ct=clnk&gl=uk
17 Millet P, Grigoriev S. Water electrolysis technologies. In: Renewable Hydrogen Technologies: Production, Purification, Storage, Applications and Safety. 2013. pp. 19-41
18 Hydrogen In The Electricity Value Chain, Group Technology & Research, Position Paper, DNV GL, 2019
19 The Potential Of Power-To-Gas, Enea consulting, 2016
20 Economics of converting renewable power to hydrogen, Glenk Gunther, 2019
21 Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimization, Store and go, 2019
22 Green Hydrogen for a European Green Deal A 2x40 GW Initiative, Hydrogen Europe, 2020
23 Industrialisation of water electrolysis in Germany, NOW GmbH, 2018

efficiencies for hydrogen conversion by 2050 (up to 85%) compared to AEL and PEM. This higher efficiency offsets the higher CAPEX of SOEC, with the result that the LCOH for all types of electrolyser - AEL, PEM and SOEC – are expected to be below £2/kg H2 by 2050.

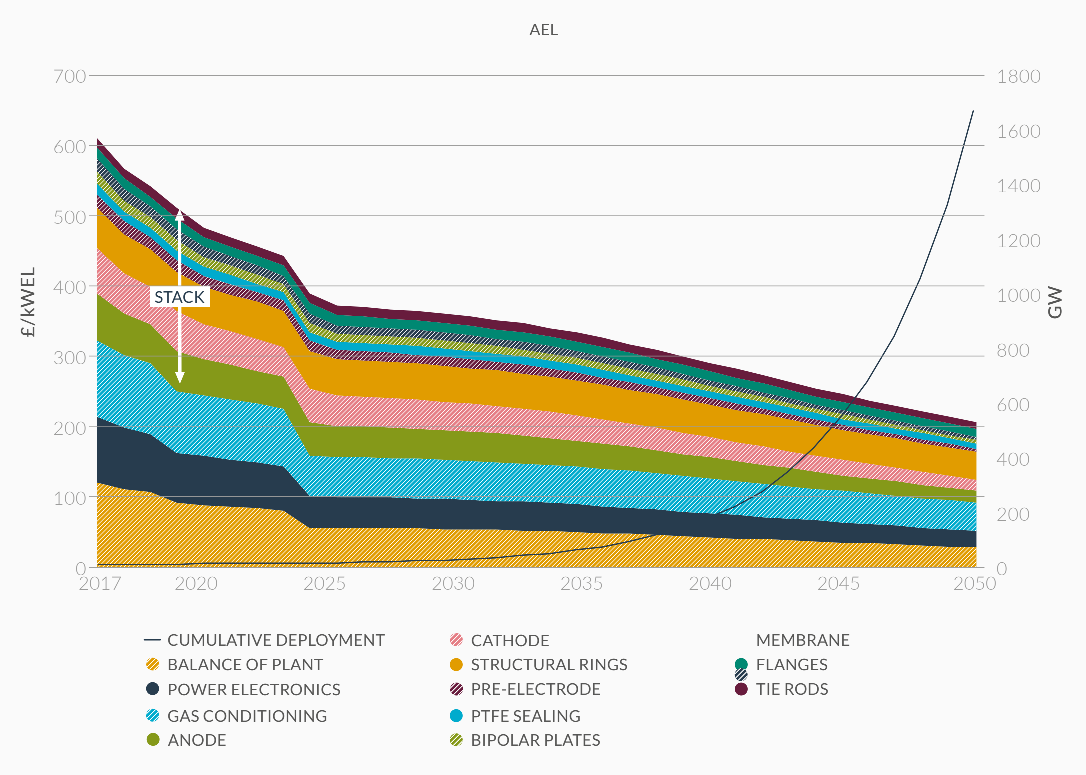


Figure 2.7 CAPEX breakdown and reduction potential for AEL electrolysers by 2050

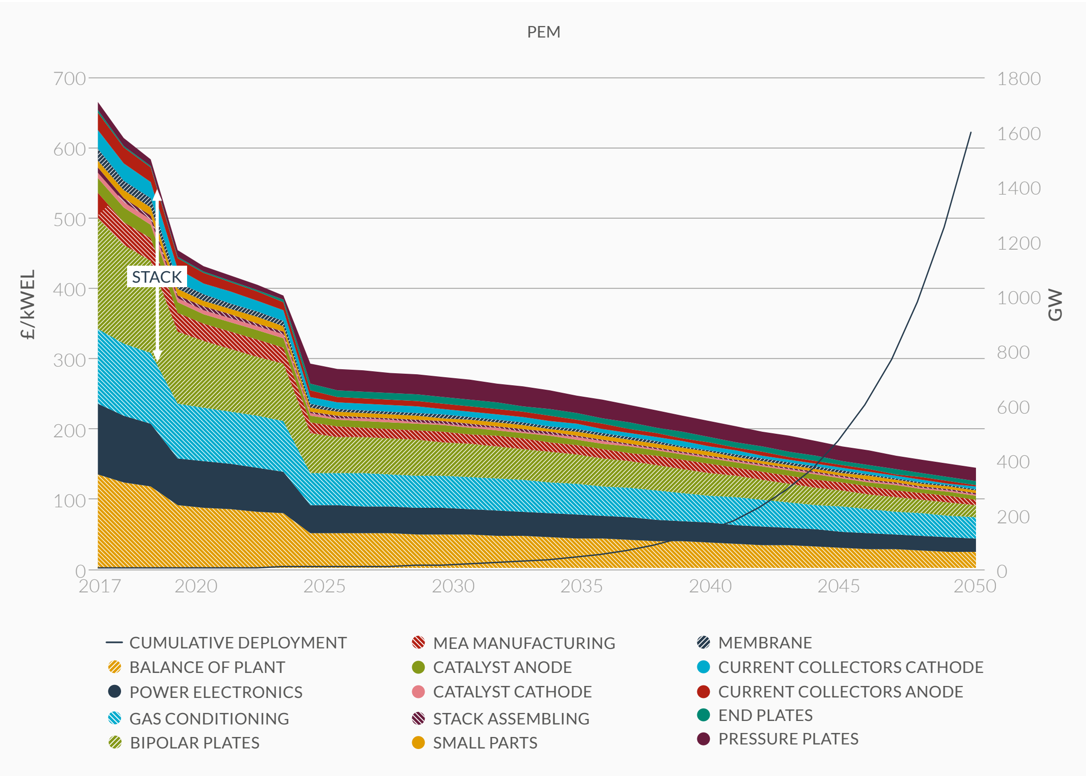


Figure 2.8 CAPEX breakdown and reduction potential for PEM electrolysers by 2050

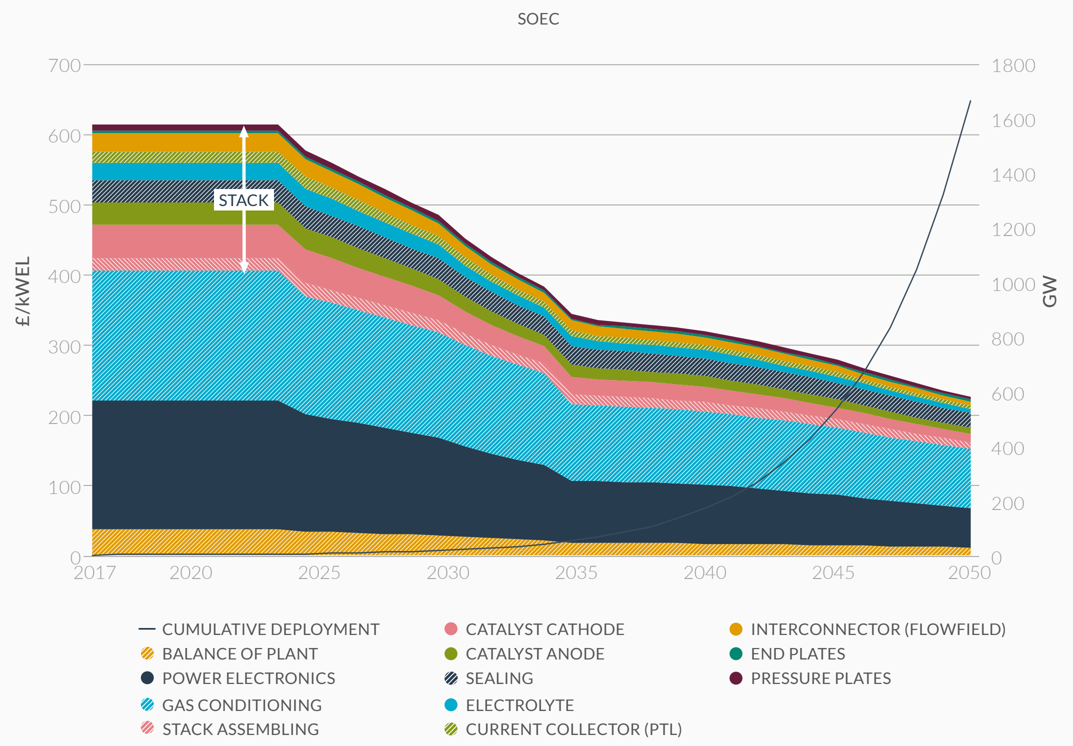


Figure 2.9 CAPEX breakdown and reduction potential for SOEC electrolysers by 2050

2.3.2 LCOH COMPARISON OF OFFSHORE AND ONSHORE ELECTROLYSIS

Figure 2.10 shows the average LCOH comparison of the two OSW-plus-electrolysis concepts (ongrid with onshore electrolysis and offgrid with offshore electrolysis) for a bottom-fixed and floating wind farm. The majority (75%) of the cost reduction is expected to be achieved by 2030, with further cost reduction continuing from 2030 to 2050. Cost reductions throughout are driven mainly by the electricity costs and by improvements in electrolyser efficiency, lifetime extension, industrialisation methods and WACC reduction. The average LCOH converges to the same value for systems with AEL and PEM technology from the mid 2030s and approaches in both concepts an average £2.20/kg H2 by 2030 and £1.70/kg H2 by 2050. The PEM technology, which is already scaling up rapidly, is expected to become cost competitive with AEL technology by the late 2030s. As SOEC technology is at a lower technology readiness level (TRL), and is yet to be commercialised, the uncertainty in the LCOH based on this technology is significantly higher. The need of SOEC for heating to reach high temperature levels will require more electricity in offshore applications, so in this case the efficiency will be reduced. However, if similar cost reduction could be achieved with SOEC (without requiring higher electricity consumption), the greater efficiency of this technology (expected to be as high as 85% by 2050) will yield lower LCOH. Electricity accounts for 70% of the LCOH in 2020 and 80% by 2050 so the rapid OSW cost reduction drives early LCOH reduction. From 2025, there is significant reduction in electrolyser cost with an increase from 10MW to 100MW size of units.

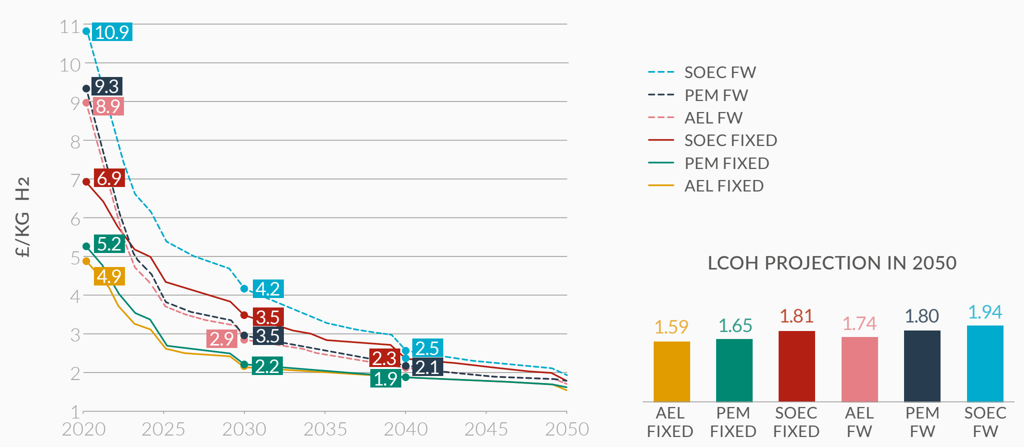


Figure 2.10 Average concept LCOH projection by electrolyser type and offshore wind substructure

Figure 2.11 shows a like-for-like comparison of LCOH onshore-ongrid electrolysis and offshore-offgrid electrolysis with PEM combined with a bottom-fixed and floating wind. The other concept combinations with AEL and SOEC show similar trajectories. Overall, the offshore system shows higher cost compared to the onshore system in 2020 but reaches comparable cost with onshore by 2050 as there is more scope for cost reduction. In both scenarios almost 85% of the cost reduction is expected to happen by 2030. In the offshore scenario all electricity produced is directed to the offshore platform where the electrolyser is installed eliminating the need for electrical infrastructure. However, the onshore scenario directs the electricity to shore using HVAC cables without the need for new offshore platform and pipeline. Therefore, LCOH for bottom fixed drops below £2/kg H2 by 2037 for onshore electrolysis and by 2038 for offshore. In floating wind, LCOH drops below £2/kg H2 by 2043 for both onshore and offshore electrolysis.

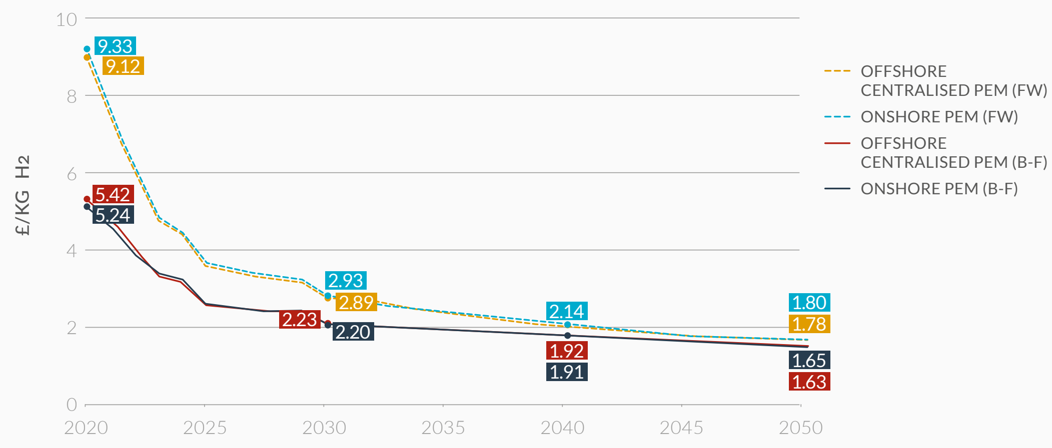


Figure 2.11 LCOH projection for onshore and offshore concepts with PEM electrolyser by offshore wind substructure

This is in line with a number of studies investigating the most cost-effective OSW systems[24 25 26 27]. In other studies, onshore systems are considered more feasible due to simplicity in operation, no need for transporting hydrogen, and lower costs of building infrastructure on land[28 29]. However, offshore systems can be a feasible alternative in the future depending on the size of system and its ability to meet hydrogen demand in regions with high installed and planned OSW capacity. Also, the cost of the pipelines to shore is found to be lower compared to electricity cables and this is closely dependent on the distance of OSW farm and platform to shore. The cost to supply and install the hydrogen pipeline is estimated at roughly £1m/ km. This compares favourably with the cost to supply and install 220kV export cable of roughly £1m/ km and a 1.2GW windfarm requiring three to four cables, giving an export cable supply cost of >£3m/km. If retrofitting of existing O&G pipelines is also considered, then the cost can drop even lower.

2.3.3 OSW-H2 COMPARISON WITH METHANE-DERIVED H2

Green hydrogen has the capability to support the integration of OSW, and variable renewable energy generally, in the energy system. Low-carbon hydrogen production from natural gas with carbon capture, based on SMR or autothermal reforming (ATR) technology, is an alternative to green hydrogen that can produce low, but not zero, carbon emissions. Figure 2.12 compares the costs of OSW plus electrolysis, with SMR and ATR including carbon capture, in 2050[30 31]. Both onshore and offshore OSW-H2 production can achieve lower costs than either SMR or ATR by 2050, especially when AEL or PEM electrolysers are utilised.

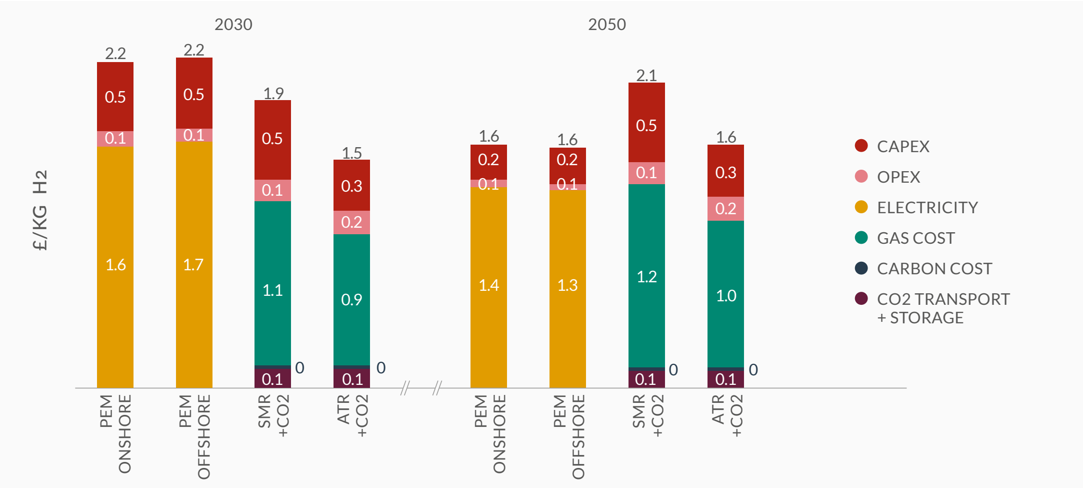


Figure 2.12 Comparison of LCOH of PEM electrolyser for onshore and offshore scenario with SMR and ATR including CO2 capture[32]

24 Offshore renewable energy resources and their potential in a green hydrogen supply chain through power-to-gas, Irfan Ahmad Gondal, 2019
25 Dolphyn Hydrogen Phase 1 - Final Report, ERM, 2019
26 Bringing North Sea Energy Ashore Efficientlyv, World Energy Council, 2019
27 Hydrogen as an energy carrier, DNV GL,
28 Hydrogen production with sea water electrolysis using Norwegian offshore wind energy potentials, Konrad Meier, 2014
29 A Norwegian case study on the production of hydrogen from wind power, C. J.Greiner, 2017
30 IEAGHG Technical Report, Techno-economic evaluation of SMR Based on Standalone (Merchant) Hydrogen Plant with CCS, 2017
31 HyNet Low Carbon Hydrogen Plant, Phase 1 Report for BEIS, Progressive Energy, 2019
32 For SMR 90% CO2 capture was assumed while for ATR 97%. The gas cost was assumed conservatively to reach £23/MWh by 2050. All costs were normalised to 2012 values.

2.3.4 PROJECT COMPONENT-LEVEL CONTRIBUTIONS TO LCOH

Figure 2.13 shows a representative example from the scenarios we examined, to illustrate how the main cost reduction parameters affect the total LCOH by 2050 (waterfall graphs for the rest of the scenarios can be found in Appendix 1). The LCOE and electrolyser CAPEX are the two main drivers of total LCOH reduction in all scenarios. The LCOH in the milestone years (2030/2040/2050) was estimated assuming a stable 63% efficiency, to observe the one-variable impact all parameters have on the final LCOH. LCOH reduces by 58% by 2030, and 69% by 2050, compared to 2020, without efficiency improvements. However, efficiency has an indirect impact in CAPEX, OPEX and LCOE and it is expected to improve in PEM electrolysers from 63% in 2020 to 70% in 2030 and 71% in 2050. Almost 85% of the efficiency improvements are expected by 2030 leading to an LCOH cost below £1.70/kg H_2 by 2050.

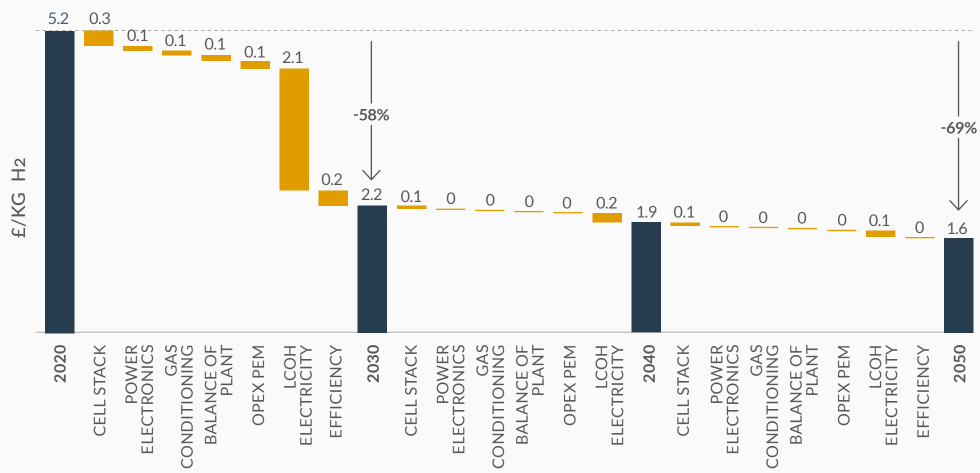


Figure 2.13 Example of the system cost breakdown on LCOH PEM with bottom-fixed offshore wind onshore electrolysis scenario including the impact of efficiency increase[33]

2.3.5 IMPACT OF RAPID COST REDUCTION ON LCOH

In the above analysis, we have made conservative assumptions, based on the best sources available. However, decision-makers have been continually blind-sided by the unexpectedly rapid fall in the costs of wind and solar energy. We tested the outer bounds of what may be possible, if rapid cost reduction continues for OSW, and is replicated for electrolysis. If OSW LCOE reaches £30/MWh in 2030 (some manufacturers are indicating that this is their expectation) and electrolyser CAPEX reaches £300/kW H_2 (there are already indications in the market that sales contracts are being struck at less than £400/kW H_2), the LCOH for OSW-H_2 would be £1.73/kg H_2 in 2030, approximately 20 years ahead of our forecast.

33 An upward trend in efficiency by 2050 was assumed for all types of electrolysers and in all basic scenario estimations (see Appendix 1).

2.3.6 HYDROGEN DISTRIBUTION COST

To allow comparison of green hydrogen with consumer costs for other fuels, we have modelled the extra cost associated with the distribution of hydrogen to end users such as, industry, buildings and refuelling stations (through pipe and trailers). Figure 2.14 presents the LCOH estimated for the offgrid scenario in 2050 plus this distribution cost for PEM electrolyser. LCOH estimates for other scenarios and other types of electrolyser are in Appendix 1.

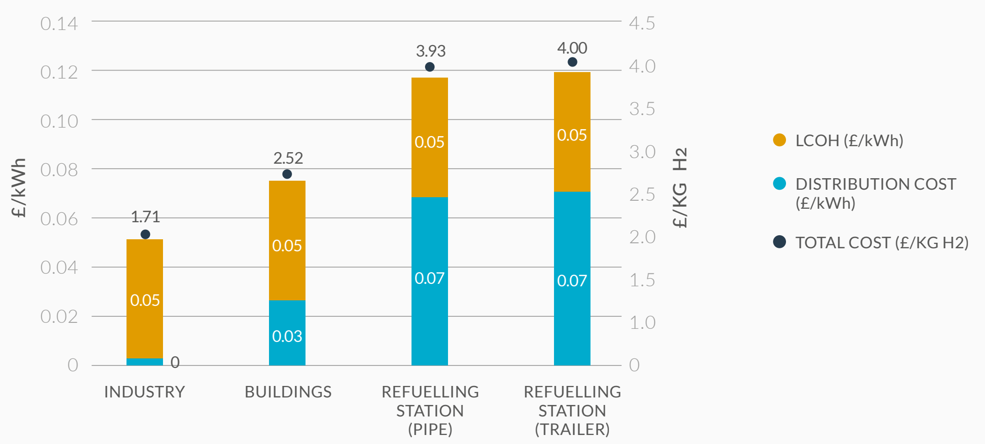


Figure 2.14 Hydrogen cost from PEM including distribution cost in 2050 [34]

34 Distribution costs were calculated based on IEA report "The Future of Hydrogen" (2019). Natural gas (NG) price for industrial use in 2019 was sourced from National Statistics (March 2020), Prices of fuels purchased by non-domestic consumers in the UK and includes the Climate Change Levy. All prices are expressed in 2012 real values.

3 PRIORITIES FOR A GREEN HYDROGEN R&D PROGRAMME

3.1 INTRODUCTION

In this Chapter we draw together the priorities for an R&D programme aimed at rapidly reducing the cost of producing green hydrogen.

The previous Chapter indicated the relative contribution to the final cost of hydrogen, of the major components of a large electrolyser facility. OPEX has also been included here, as R&D effort should also be applied to reducing OPEX. Taking PEM electrolysis as an example, the contributions to the cost reduction required to reach £1.65/kg of H_2, are shown in Table 3.1:

Electrolyser component	LCOH reduction by 2050, £/kgH_2
Cell stack	£0.39
Power electronics	£0.12
Gas conditioning	£0.12
Balance of plant	£0.16
OPEX	£0.17
Total	**£0.96**

Table 3.1 Contributions of major electrolyser components to LCOH reduction

Technology improvements in the cell stack, power electronics, gas conditioning and balance of plant will increase electrolyser efficiency, accounting for a further cost reduction of £0.21, by 2050.

Each of these components can form a research theme, within a comprehensive R&D programme aimed at accelerating cost reduction of green hydrogen. For the cell stack, there is a substantial body of R&D: electrolyser cell stack technology is closely related to fuel cell stack technology, which has been a major focus of international energy R&D programmes for many decades. There is therefore substantial prior knowledge of the research challenges that are fundamental to reduced cost, improved longevity and efficiency of electrolysers, as these tend to overlap with the challenges in fuel cell technology. However, electrolysers for large-scale production of hydrogen will present new challenges related to the technical requirements for reliable operation within the electricity grid, or offshore in proximity to windfarms.

In light of the importance of the cell stack to cost reduction, and the existence of world-leading research capabilities in the UK, we have developed the R&D roadmap for the cell stack to a greater level of detail than for the other major electrolyser components. The main innovation challenges for the cell stack, and suggested areas of focus for the other components, are set out overleaf.

3.2 ASSESSMENT OF R&D PRIORITIES FOR THE ELECTROLYSER CELL STACK

There are many different innovation challenges across the electrolyser technologies (see Appendix 3 for an overview of electrolyser technologies). These range from materials development to improve the lifetime of electrolysers, to improving quality, through to technologies that enable larger units. These innovations have varying potential to improve important enabling factors such as improved costs or lifetime of the device.

We have reviewed the main innovation challenges for electrolysers identified by the materials science community, the H2FC Supergen, and others. To accommodate the broad range of technology enablers for the cell stack, we developed a flexible technology assessment and prioritisation methodology. Each technology was scored 0-3, on seven criteria – cost reduction, durability, demand response, technical risk, market value, case for intervention, and health and safety impact. The scoring criteria were developed to align with existing technology innovation roadmaps for the OSW industry. These have been created and are maintained by ORE Catapult, for the BEIS-funded Offshore Wind Innovation Hub. Each scoring criterion was given equal weighting, to remove any biases. A full description of the scoring criteria, the R&D challenges we assessed, and their technology priority scores, are provided in Appendix 5.

All challenges with their time to market and current TRL are shown in Figure 3.1 and Figure 3.2:

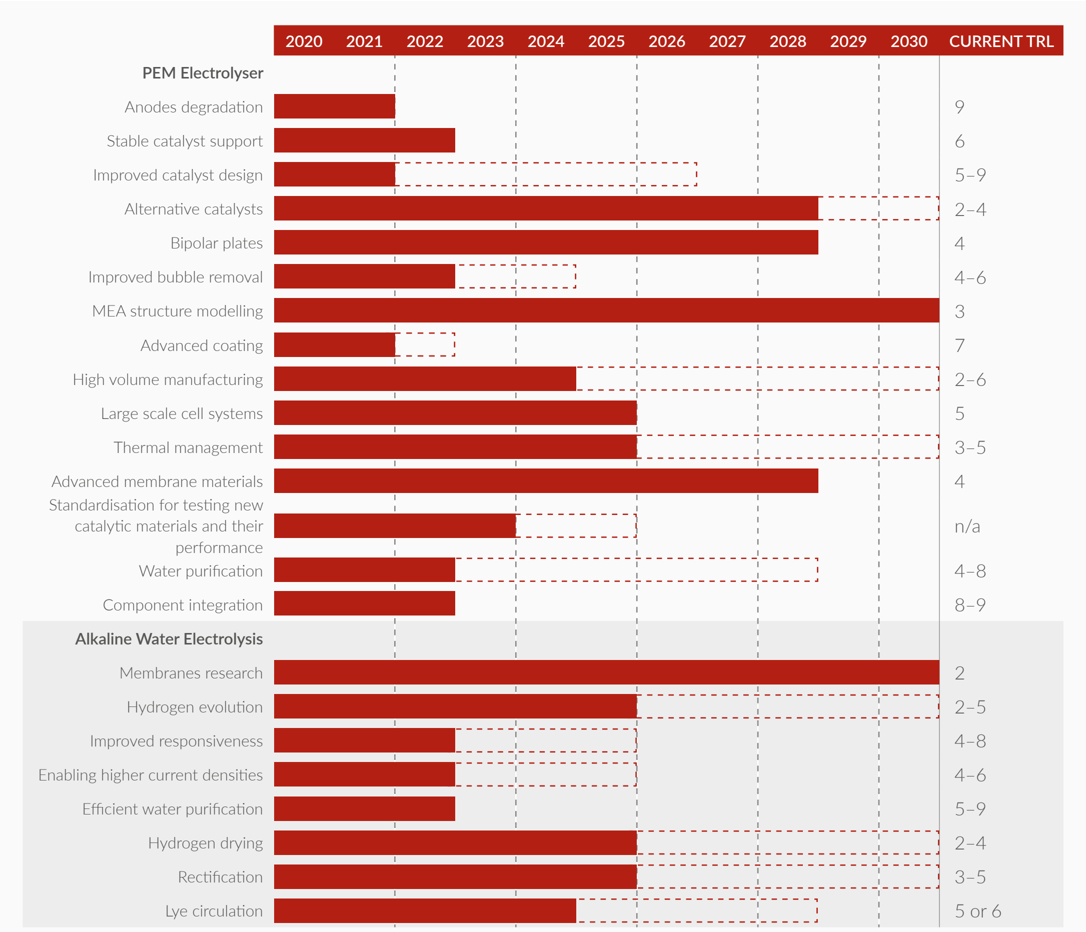


Figure 3.1 R&D challenges for PEM electrolyser and AEL

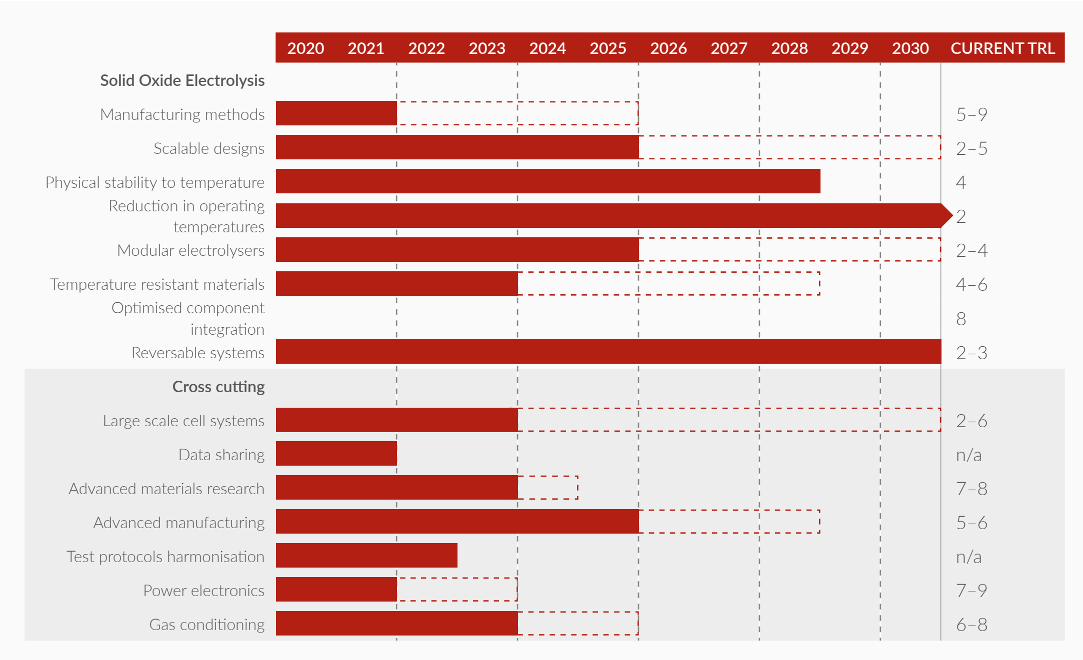


Figure 3.2 R&D challenges for SOEC and cross cutting

The number of innovations being actively pursued in PEM electrolysers, is higher than in alkaline and solid oxide electrolysers. This is due to PEM being seen as the next big innovation winner, with some of the performance advantages of PEM over AEL being seen as important in a hydrogen rich future. For this reason, more industrial research is focused on PEM technologies. By contrast, most SOEC research is being conducted in academia, and at a small scale.

3.3 TECHNOLOGY ROADMAP – ILLUSTRATIVE KEY R&D CHALLENGES

The innovation challenges that were identified as having a score of 11 or above, for PEM technologies, and 10 or above, for all other categories, provide a useful, broad overview of the types of challenges across electrolyser technologies and applications. These high-scoring challenges are described in Table 3.2:

Innovation challenge	Description	Time to market
PEM Anodes degradation	Research into developing anodes that are slow to degrade and improve efficiencies under high current densities. New technologies will also be able to withstand higher current densities and fluctuations to make response times faster for more renewable energy applications	2 years
PEM Stable Catalyst Support	Better stability in fluctuating conditions which would enable different use cases, especially renewable applications	2 years
Advances Membrane Materials (cross cutting)	Improved membrane materials can improve the purity of the output, reducing costs and improving lifetimes	8 - 10 years

Innovation challenge	Description	Time to market
Research enabling higher current densities in AEL	AEL being used under higher current densities would increase the potential use cases and applications (not only in renewable energies but industrial feedstock production)	2 - 5 years
Solid Oxide Temperature resistant materials (and physical stability to temperature)	SOEC require high temperatures (steam) processes, and this gives many material instabilities and degradation. Improved operating stability will improve the efficiencies, and improved temperature resistant materials will reduce degradation and improve lifetime costs.	8 years
Standardisation for testing (cross cutting)	Standardised tests would improve the quality and trust in the sector, enabling wider uptake of hydrogen applications	Immediate (with the right enablers)
Large Scale Systems (cross cutting)	Economies of scale would drive down costs and enable large scale applications. Larger stacks and coupled systems would also allow for optimisation of use, allowing some fuel cells to be run at optimal power while preserving the longevity of other stacks	3 - 10 years
Data Sharing (cross cutting)	Economies of scale would drive down costs and enable large scale applications. Larger stacks and coupled systems would also allow for optimisation of use, allowing some fuel cells to be run at optimal power while preserving the longevity of other stacks Fault and efficiency benchmarking would drive up improvements and enable sector wide improvements.	Immediate (with the right enablers)

Table 3.2 R&D challenges with descriptions

4 UK AND GLOBAL MARKET POTENTIAL FOR GREEN HYDROGEN

4.1 THE KEY MARKETS FOR HYDROGEN

Figure 4.1 gives an overview of possible hydrogen applications. Of these, industry feedstocks, heating, and fuels for heavy goods vehicles and for ships, are sectors that are difficult to decarbonise where hydrogen is increasingly looked to as being a major contributor to a net-zero pathway. Hydrogen, especially green hydrogen sourced from indigenous OSW, can also contribute to preserving or improving energy security of supply.

MOBILITY	HEAT AND POWER FOR BUILDINGS	HEAT AND POWER FOR INDUSTRY	INDUSTRY FEEDSTOCK
LIGHT-DUTY ROAD TRANSPORT (CARS & VANS)	BOILERS FOR HEATING	MEDIUM TEMPERATURE HEATING	OIL REFINING
HEAVY-DUTY ROAD TRANSPORT (TRUCKS & BUSES)	FUEL CELLS FOR COMBINED HEAT & POWER (FC CHP)	HIGH TEMPERATURE HEATING	AMMONIA AND METHANOL PRODUCTION
MARITIME		FLEXIBLE POWER GENERATION	IRON AND STEEL PRODUCTION
RAIL		BACKUP AND REMOTE POWER GENERATION	
AVIATION		SEASONAL AND LARGESCALE ENERGY STORAGE	

Figure 4.1 An overview of hydrogen applications

Successful development of early markets for these hydrogen applications would drive greater investor interest, boost revenues available for re-investment in innovation, improve learning-by-doing and highlight regulatory and market barriers that need to be addressed.

4.2 UK AND GLOBAL MARKET FORECASTS FOR HYDROGEN

We have considered a wide range of estimates, and forecast methods, for potential demand for hydrogen from 2020 to 2050.

Currently, about 95% of the hydrogen produced globally is derived from fossil fuel, but it can also be a means to allow renewable energy to replace fossil fuels where electrification is difficult. According to

Bloomberg New Energy Finance (BNEF), global demand for renewable hydrogen, currently up to three times more expensive than from fossil fuels, could rapidly accelerate to reach 275 million tonnes per year (equivalent to 9,150 TWh) by 2050 as costs fall, while electrolyser capacity could climb to 4,000GW[35]. This is the deployment estimate that we adopted in our cost modelling, described above. For comparison, other notable green hydrogen market estimates are summarised below.

The Hydrogen Council's "Hydrogen scaling up" report states that by 2030, 250 to 300TWh of surplus renewable electricity (wind and solar) could be stored in the form of hydrogen, rising to 500TWh by 2050[36]. Hydrogen from 'surplus' renewable electricity is expected to be cost-competitive with natural gas-based hydrogen before 2035, but this quantity will not be adequate to cover the hydrogen demand (78 EJ in 2050)[37 38].

The CCC's "Hydrogen in a low-carbon economy" report looks at different scenarios of hydrogen decarbonisation in the UK with or without repurposing gas infrastructure. In the scenario where full gas network repurposing occurs, it projected that the volumes of hydrogen produced using very low-cost electricity would be small, up to 44TWh in 2050, or around 6% of total consumption in the energy system. In a full hydrogen scenario where the primary source of hydrogen is electrolysis , the CCC estimates that approximately 380TWh of electricity generation can be converted to hydrogen by 2050, with 300TWh generated from wind, primarily OSW[39].

For 2050 the CCC states that at least 75GW of OSW will be needed to decarbonise the power sector, including bottom-fixed and floating wind. If all the electricity produced from OSW (346TWh per year) is converted to hydrogen, then green hydrogen potential is estimated at 10 million tonnes in 2050[40]. Likewise, global hydrogen production from OSW (2,900 TWh) has the theoretical potential to reach 87 million tonnes in the mid-century.

ESC's latest whole energy system modelling indicates that hydrogen production is vital for decarbonisation of sectors including industry, shipping and heavy vehicles. For a range of scenarios, over 200TWh per year of hydrogen is required, from very low, or zero GHG emission sources in 2050. In the scenarios they analysed, OSW plays a significant role, ranging from 95GW to 150GW by 2050.

In addition to these forecasts, Imperial College London provided us with the outputs of custom runs using their IWES model. IWES has a high time resolution model of Europe's electric grid infrastructure. This enables exploration of scenarios with realistic assumptions around net energy flows between the UK and European grids. ICL based their exploratory runs on the 'hybrid' gas and electricity scenario they developed to support the CCC's report on Hydrogen for a Low-Carbon Economy. For a range of IWES scenarios, OSW deployment varied from 130GW to 233GW, using the cost-supply curves for OSW developed by ORE Catapult for this study. The highest level of OSW was dependent upon unconstrained electrical interconnection to European grids. For zero-carbon scenarios, where biomass availability was assumed to be highly restricted, hydrogen supply from electrolysis was 190TWh per year. Raising the capacity factor for OSW from 53% to 60%, reduced the deployment of electrolysers from 47GW to 43GW, due to the reduction in grid balancing requirements for higher-capacity factor generating plant.

We have built on the estimates above to provide additional insights into how the level of conversion of OSW into hydrogen will affect the size of the green hydrogen market. Figure 4.2 shows the estimates of the cumulative electricity production from OSW and hydrogen systems in the UK and rest of world (RoW), for a scenario where hydrogen integration is increased in steps, from 2020, to reach 40% of OSW electricity converted to H_2, by 2050.

35 https://www.bloomberg.com/news/articles/2019-08-21/cost-of-hydrogen-from-renewables-to-plummet-next-decade-bnef
36 Hydrogen scaling up, Hydrogen Council, 2017
37 https://www.windpowermonthly.com/article/1578773/green-hydrogen-economically-viable-2035-researchers-claim
38 Hydrogen in a low-carbon economy, CCC, 2018
39 Hydrogen in a low-carbon economy, CCC, 2018
40 1kg of hydrogen contains 120-142 megajoules of energy or 33.3-39.4 kWh.

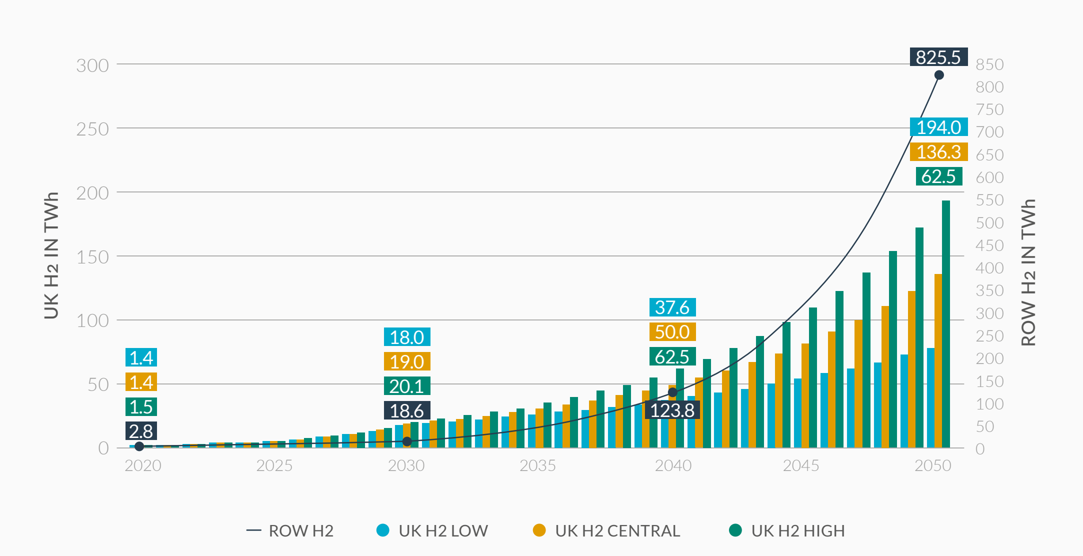


Figure 4.2 Projection of electricity produced for offshore wind and converted to green hydrogen

In 2050, the OSW capacity was assumed to be 75GW in the UK and 550GW in RoW in the low scenario. At 40% integration, approximately 110TWh of UK OSW is used to produce 78 TWh of green hydrogen in 2050. However, this falls short of the lower bound of estimates of total system demand for hydrogen, from a range of studies. Based on the IWES model central estimation of 182 GW OSW and assuming again a 40% hydrogen integration and available OSW electricity generation of 273 TWh, the supply of electricity for green hydrogen production can reach 194TWh in 2050 in the high scenario. For the above estimations, the efficiency of the electrolyser was assumed to be 63% in 2020, rising to 71% in 2050. In terms of electrolyser capacity that is supplied by OSW, this is estimated to reach 175GW by 2050 for ROW, with up to a further 58GW in the UK for the high scenario of Figure 4.3, assuming an electrolyser capacity of 80% of OSW farm capacity and 40% of OSW conversion to hydrogen.

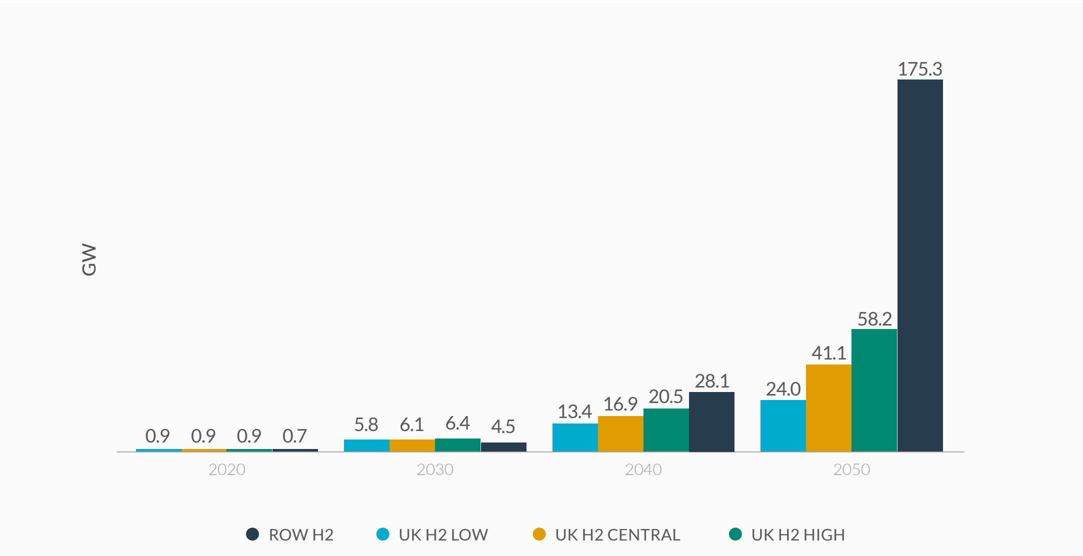


Figure 4.3 Projections of green hydrogen from offshore wind - electrolyser capacity, GW, in the UK and RoW

These estimates reflect a hybrid scenario for conversion of heating to a mix of electrification (heat pumps) and hydrogen boilers. Full hydrogen heating scenarios are likely to require levels of hydrogen generation many times greater than are considered here.

5 SUPPLY CHAINS AND ECONOMIC OPPORTUNITY

5.1 ESTIMATES OF THE NEW UK ECONOMIC OPPORTUNITY (GVA) FROM OSW-H_2

There are multiple opportunities for the UK supply chain that play to existing industry strengths. The hydrogen economy could support the automotive sector by manufacturing light duty vehicles (e.g. Riversimple) and buses (e.g. Wrightbus) as well as integrating FC into existing designs (Magtec, Vantage Power). There are significant opportunities in materials development, fuel cell components manufacturing (Johnson Matthey) and electrolyser production (ITM Power). Having a competitive advantage in developing a hydrogen economy would provide a boost to existing and new companies with capabilities in engineering, consulting and financial services.

Using the green hydrogen market projections above, we estimated economy wide Gross Value Added (GVA) benefits using the same methodology that we apply to GVA estimates of the OSW industry. We calculated the project values for the UK and RoW deployment estimates for OSW-H_2, to estimate UK GVA, and associated numbers of new jobs (FTEs). To recap, UK OSW-H_2 production capacity reaches 24GW by 2050 in low scenario, globally, it is 199GW by 2050; while in the high scenario UK OSW-H_2 production capacity reaches 58GW by 2050 and 233GW globally by 2050.

We assumed that the UK content of UK projects, i.e. the UK supply chain's share, follows the growth path that the UK OSW supply chain has followed, to reach 50% UK content. The UK content of the RoW market (i.e. exports) includes the entire electrolyser market (i.e. not restricted to OSW-H_2 and including, for example, solar-H_2), and grows steadily (from 2.5% in 2020, to 5% in 2030, then to 10% in 2050, low scenario, and from 5% in 2020, to 10% in 2030, then to 20% in 2050, high scenario). For the UK, it was assumed that green hydrogen has 'unlocked' the capacity for the energy system to absorb the OSW capacity that is coupled to electrolysis, so the GVA and jobs associated with those windfarms are included in the estimates below.

In the low scenario, from 2021-30, the average number of UK FTE jobs sustained by the UK OSW-H_2 and electrolyser export market is 5,000, growing to 62,000 for 2031 to 2050. Total cumulative UK GVA exceeds £160bn by 2050. These figures include £127bn GVA and 50,000 FTE's from exports to the RoW addressable electrolyser market, which is forecast to be more than four times the size of the UK supply chain share of the UK domestic OSW-H_2 market.

In the high scenario, from 2021-30, the UK OSW-H_2 and electrolyser export market can reach an average number of 5,800 FTE jobs, growing to 128,000 for 2031 to 2050, including 100,000 from exports of equipment and related services. By 2050 the total cumulative GVA is estimated to reach approximately £320bn including export capability of £250bn for ROW electrolysers. By 2050 the total cumulative GVA is estimated to reach approximately £320bn including export capability of £250bn for ROW electrolysers. UK GVA estimates for both scenarios are shown in Figure 5-1 and Figure 5-2:

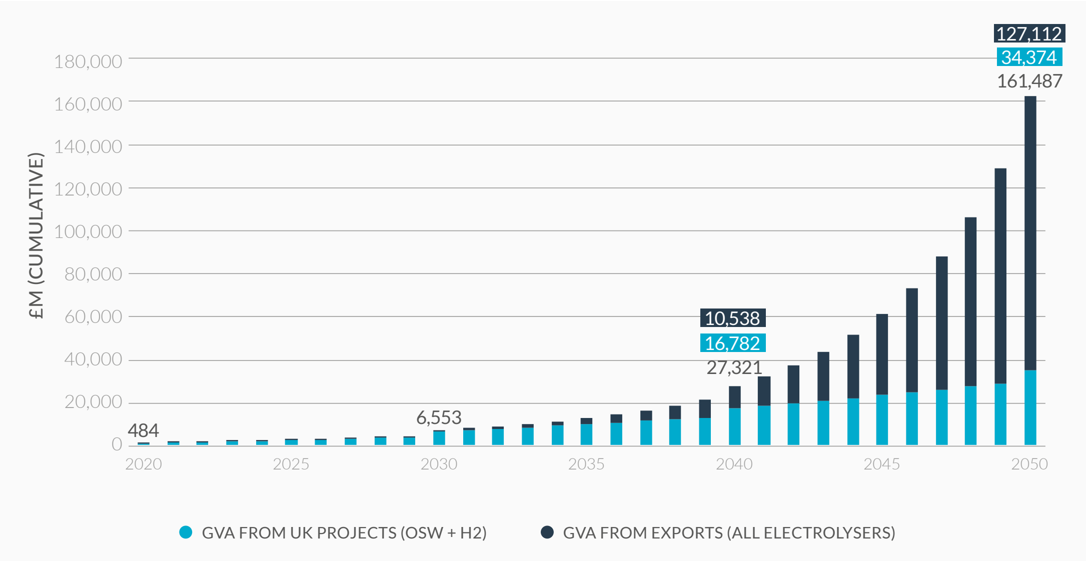


Figure 5.1 Low scenario - UK GVA from UK offshore wind hydrogen projects and electrolyser exports

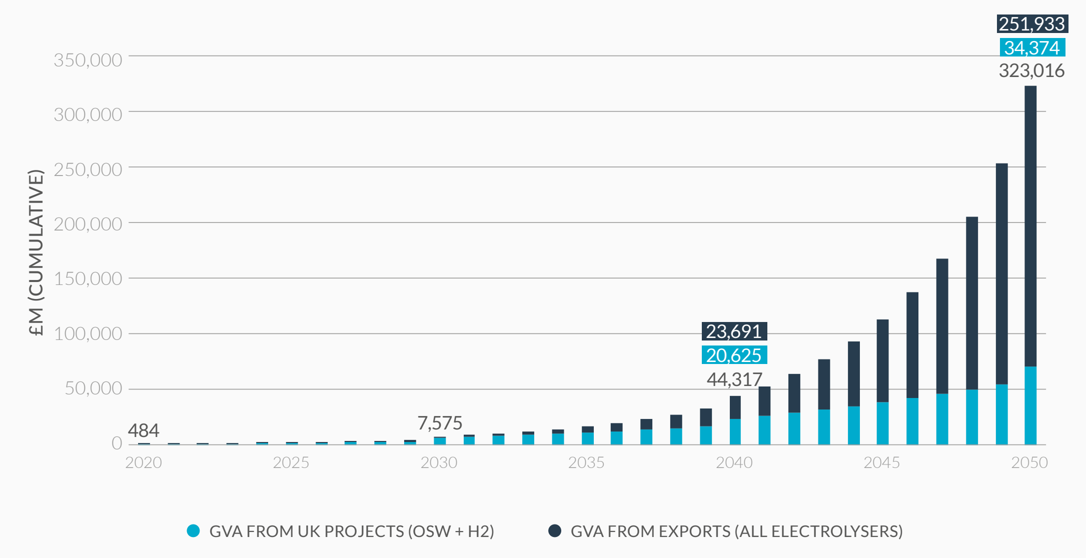


Figure 5.2 High scenario - UK GVA from UK and export projects from Hydrogen electrolyser (PEM)

5.2 MARKET OPPORTUNITIES FOR HYDROGEN

5.2.1 INTRODUCTION

The key enablers for the UK to grow its hydrogen economy are increasing potential markets and identifying UK industry strength. The UK has a strong gas supply and distribution network, supplying natural gas to 80% of UK homes and businesses for heating[41]. There are industrial gas import and storage clusters around South Wales, Aberdeen, and in the East Midlands. The UK is therefore in a strong position to see a large conversion to hydrogen in areas described overleaf.

41 DUKES, 2019

5.2.2 MOBILITY

In the transport sector hydrogen is able to complement other zero-carbon alternatives. The automotive industry is particularly important to the UK with a sector turnover of £82bn and employment of 823,000 workers as of 2018[42]. The principal goal of investing in fuel cell vehicles would be to safeguard jobs in this sector. Asian manufacturers Hyundai, Honda, and Toyota are leading the development of H2FC cars. They operate primarily in Japan, Korea, and the USA, where networks of hydrogen refuelling stations have been constructed. European and US manufacturers have tended to focus on battery electric vehicles. The UK automotive supply chain is adapting to electrification and is well placed to take a more active role on FCEV manufacturing and electric drivetrain integration.

Battery electric vehicles (BEVs) are becoming one of the fastest growing choice of small cars. However, the suitability of electric batteries to power long-haul transport is still poor. This is due to the battery weight reducing the payload, the charging times increasing delivery times, and the limited battery range for long-haul vehicles.

For segments that require long-range or heavy-duty capabilities (e.g. heavy-duty trucks, large passenger vehicles with long-ranges, and long-distance coaches), hydrogen is considered to be the most practical and cost-effective decarbonisation alternative. While the market for hydrogen powered vehicles is still small, the potential market size for HGVs could be in the order of 30,000 vehicles a year by 2030, increasing to 500,000 a year by 2050[43].

Table 5.1 gives an overview of hydrogen applications for mobility applications:

	Cost competitiveness	Opportunities for hydrogen	Challenges	Low carbon competition
Cars and vans (light-duty vehicles)	Medium-term	Short refuelling time Less weight added for stored energy Fuel cells likely to have lower material footprint than lithium batteries No operational compromise	Overcoming niche status, relative to battery vehicles, in fuel cell, storage and fuel costs (due to initial low utilisation of refuelling stations)	BEVs
Trucks and buses (heavy-duty vehicles)	Short-term		Overcoming niche status, relative to battery vehicles, in fuel cell and storage costs	BEVs
Maritime	Short-term	Few other alternatives for domestic shipping decarbonisation Many ports have poor air quality Ferries that sail near populated areas are an early potential	Storage cost higher than other fuels	Biofuel Ammonia fuel
Rail	Short-term	Higher customer comfort (smoother and quieter operations) Maintenance should be easier and cheaper Cheaper than electrifying a line	Rail is the most electrified transport mode Hydrogen and electric trains are options to replace non-electrified operations	Electric catenary
Aviation	Long-term	Fastest growing passenger transport mode Can supply on-board energy at ports and during taxiing	Large storage volume and redesign would be needed for pure hydrogen Biofuels more cost competitive at the moment	Biofuel

Table 5.1 An overview of hydrogen applications for transport

42 https://www.smmt.co.uk/industry-topics/uk-automotive/
43 Hydrogen fuel cells: A Quick Guide to UK market, technologies and infrastructure, SMMT, 2019

5.2.3 HEAT AND POWER FOR BUILDINGS

The decarbonisation of heat and power for buildings has been proven to be challenging due to few low-carbon alternatives to heating fuel and the complexity of reducing heat demand through increasing building efficiency. Recently, there has been an increase in interest in converting gas networks to hydrogen, as the plastic pipes that are now standard across the vast majority of the gas distribution system are compatible with hydrogen. This would make hydrogen among the most attractive ways to enable the sector's energy transition as it could provide a cost-effective, decarbonised fuel in a flexible way without compromising continuity of supply to customers. An additional advantage is users' preference of using gas heating to electric. The UK is among the global leaders in efforts to understand whether hydrogen can power boilers to decarbonise heating. Fuel cells are an alternative to boilers that could provide both heat and electricity generation. Mostly operating during the coldest periods, they would help to decrease peak electricity demand.

Current natural gas infrastructure could potentially have up to 20/80% mix of hydrogen with natural gas without upgrading appliances, however more than this is required to meet carbon emission reduction targets. 100% hydrogen for heating would require transport, storage and conversion upgrades across the network. According to the CCC, in a low carbon future energy scenario, the cost of upgrading to a fully hydrogen heat network by 2050 would cost less than electric-powered heating, and a hybrid or blended system was the cheapest overall[44]. In a blended system with the use of emerging technologies such as hybrid heat pumps the overall infrastructure investments required were minimal. Table 5.2 gives an overview of hydrogen applications for mobility applications:

	Cost competitiveness	Opportunities for hydrogen	Challenges	Low carbon competition
Boilers for heating	Short-term	Most cost competitive in regions with existing natural gas infrastructure Lower efficiency losses than synthetic methane Most attractive for large commercial buildings, buildings complexes	Some investment to upgrade gas network to allow >20% hydrogen blend Investment in appliances upgrade Co-ordination between gas suppliers and distributors if various networks coexist	Electric heating Heat pumps
Fuel cells for combined heat and power (FC CHP)	Medium-term	Multiple energy services (e.g. heat and electricity) Demand-side response potential	R&D required to boost efficiency of equipment Considered more expensive than hydrogen boilers[45].	Electric heating Heat pumps

Table 5.2 An overview of hydrogen applications for heat and power for buildings

5.2.4 HEAT AND POWER FOR INDUSTRY

There is an opportunity for hydrogen to provide industrial heat as well as power for grid and off-grid demand.

Industrial heat usage varies from melting to drying an array of chemical reactions. It is classified into three temperature ranges: low (< 100°C), medium (100–400°C) and high (> 400°C). Hydrogen can supply these classes of heat. Other decarbonisation pathways for the sector include electrification, biomass and CCS[46]. Table 5.3 gives an overview of hydrogen applications for heat and power for industry.

44 Analysis of alternative UK heat decarbonisation pathways , CCC, 2018
45 Hydrogen in a low-carbon economy, CCC, 2018
46 Path to hydrogen competitiveness, A cost perspective, Hydrogen Council, 2020

	Cost competitiveness	Opportunities for hydrogen	Challenges	Low carbon competition
Medium temperature heating	Medium-term	Offers high flexibility (better suited for applications with intermittent heat demand) Can become more cost competitive if CO2 prices were increased Can be a more practical decarbonisation option than CCS in some locations Most cost competitive option among other low carbon options for high temperature heating but still expensive	Fuel cost - it will correspond to ~80-90% of the total cost for providing heat via hydrogen burning by 2030 Technology – Some energy conversion devices (kilns, furnaces, boilers, reactors) would have to be adjusted to use hydrogen which would additionally increase the total cost of conversion	Direct electrification, Biomass CCS
High temperature heating	Long-term			
Flexible power generation	Medium-term	Increasing need for dispatchable, flexible power supply in the future energy system dominated by variable sources	Cost – hydrogen can be a low-carbon baseload power generation option only in areas with constrained renewables generation potential	Renewables
Backup and remote power generation	Short-term	More robust than battery storage Few zero carbon alternatives to support the grid with short-term flexibility	Cost – higher investment cost in comparison to diesel generators Access to low-cost fuel will have a critical role in enabling hydrogen power generation	Battery storage
Seasonal and large-scale energy storage	Short-term	Relatively low-cost storage option due to high energy content of Hydrogen Conversion losses minimised if Hydrogen could be used in end-use applications	High conversion losses Research needed if depleted O&G fields could be applicable	Battery storage

Table 5.3 An overview of hydrogen applications for heat and power for industry

5.2.5 INDUSTRY FEEDSTOCK

At present hydrogen is used for industrial applications such as feedstock for oil refining, ammonia, steel and methanol production[47]. The majority of it is produced from non-renewable sources - natural gas, coal and oil - and the only decarbonisation options are CCS or green hydrogen production. In the future, chemicals, iron, and steel production offer a significant potential for large-scale, low emission hydrogen demand. A single plant could provide a baseload demand for electrolyser installation and outputs which would enable a general scale-up in production for a wider hydrogen economy. Contrary to transport and residential heating, it would require smaller level system change as the number of production sites is smaller and the decision-making process is usually limited to several companies. Table 5.4 gives an overview of hydrogen applications for heat and power for industry.

47 The Future of Hydrogen, IEA, 2019

	Cost competitiveness	Opportunities for hydrogen	Challenges	Low carbon competition
Oil refining	Short-term	Can be used to purify crude oil and upgrade heavier crude Increasing regulatory pressure to remove impurities will increase future demand Could help decarbonising O&G sector CCS is not yet commercially available and also requires public sector support	Fuel cost – plays a significant part in refining profitability Regulatory support required	CCS
Ammonia and methanol production	Short-term	Some production can be decarbonised by retrofitting CCS, but it is not a universal option which creates a market for green hydrogen Biomass is considered too expensive for this application Electrolysis considered the best option for zero-emissions ammonia and methanol production if electricity prices are low	Cost – usage very much dependent on gas and electricity prices Methanol production may still require some source of carbon	CCS Biomass
Iron and steel production	Medium-term	Technical viability to blend green hydrogen into existing processes All decarbonisation options require processes changes		CCS Electrification

Table 5.4 An overview of hydrogen applications for industry feedstock

5.3 EXISTING SUPPLY CHAIN AND CAPABILITIES IN THE UK

5.3.1 INTRODUCTION

The UK has a sizeable number of large and small companies already working in the hydrogen economy, either through the manufacture of fuel cells or generation to distribution of hydrogen. Some of these companies are multinationals (e.g. large O&G firms branching out into hydrogen). However, there are many small and medium companies and innovators providing technology and consulting solutions, playing to the UK's strengths in innovation and logistics.

5.3.2 MOBILITY

A large proportion of UK companies that use hydrogen in the form of fuel cells are vehicle manufacturers and transport companies. These companies are distributed across the UK and specialise in a wide range of automotive subsectors.

Riversimple, based in Wales, and Microcab, based in Coventry, are vehicle manufacturers. Both have designed a novel and highly efficient fuel cell electric vehicle (FCEV) rather than fitting fuel cells to existing designs. Riversimple aims to launch a commercial model in 2022. They operate under 'sale of service' model, under which users do not buy vehicles but rather pay a monthly fee which covers insurance, fuel and maintenance cost. Arcola Energy and Millbrook are systems engineering companies that specialise in hydrogen and fuel cell technology integration. Few other notable businesses include Intelligent Energy (PEM fuel cell manufacturers for a range of end uses) or Raffenday EV (power electronics).

Several UK bus manufacturers and integrators are actively working on BEV and FCEV technologies. Bus services in the UK require specific vehicle types (e.g. double deckers) which are not common in other countries and less frequently offered by overseas suppliers. Over three quarters of UK demand for buses is met by domestic manufacturers, which makes this market easier to decarbonise if appropriate policy support and actions are taken. Wrightbus has already delivered hydrogen buses to London and in 2020 to Belfast through The Hydrogen for Transport Programme. Alexander Dennis, a bus manufacturer based in Guilford has recently published a vision of 10000 clean energy buses in the UK by 2025. Additionally, numerous integrators (e.g. Magtec, Vantage Power) have active hydrogen programmes.

5.3.3 OTHER END USES

Other end uses are less prevalent in the UK, but there are emerging areas of research such as combined heat and power hydrogen fuel cells for domestic use.

Hydrogen boiler manufacturers are involved in several projects aiming to decarbonise gas network and deliver zero carbon heat. Baxi Heating based in Preston has developed a protype boiler that could run on 100% hydrogen. In 2020 Worcester Bosch has also launched a first hydrogen fired boiler prototype. Clean Burner Systems is a manufacturer of gas burners and components which is involved in Hy4Heat – a feasibility study of 100% hydrogen residential gas supply.

There are also large ammonia and other industries that use hydrogen produced using fossil fuels on or near site. These industrial clusters create high potential demand for hydrogen production. The Mineral Producers Association is testing switching UK cement production to operate on low carbon fuels including hydrogen, biomass and electrification. Glass Futures is trialling the potential for the glass sector to use alternative fuels (electric, hydrogen, biofuel and hybrid-fuel melting technologies). British Lime Association is testing the use of hydrogen in high-calcium lime manufacturing, servicing markets such as steel manufacturing.

A full list of hydrogen stakeholders is listed in Appendix 4

5.3.4 HYDROGEN SUPPLY: PRODUCTION, STORAGE, DISTRIBUTION, REFUELLING

The UK has a large natural gas distribution network, that is equipped to deal with up to 20% blended hydrogen in the system. Large distribution networks based in the UK, such as Cadent or Thyson, are investigating hydrogen (though not active in the sector). Some large multinationals, such as Air Products, are developing hydrogen specific transmission pipelines.

ITM Power and Ceres Power are two UK based companies that are developing electrolysers and hydrogen production. ITM Power, especially, have large fuel stations based in London, Sheffield and the Midlands, and have won government funding to expand their operations. ITM Power also owns seven hydrogen refuelling stations in the UK. Ceres, originally a spin out from Imperial College London, produces solid oxide fuel cells for micro combined heat and power in the heat and electricity markets. Johnson Matthey is a FTSE100 technology company with a long-standing fuel cell division. It is one of the world leaders in materials development and manufacturing fuel cell components such as membrane electrode assemblies, fuel processors, and fuel cell catalysts for portable, automotive, and stationary applications. Their manufacturing facility in Swindon was the world's first dedicated production facility for membrane electrode assemblies for PEM fuel cells. They own at least 15 patents directly related to hydrogen technologies.

5.3.5 THE KNOWLEDGE BASE – SCIENTIFIC AND CONSULTING CAPABILITIES

Academia plays an important role in technology and innovation by educating students, providing skilled researchers and by conducting research that underpins technological development. There are at least 24 universities in the UK where academics are active in researching hydrogen and fuel cells topics[48]. The UK's strong science base is perceived to be a particular strength of the UK's hydrogen sector. This can be observed in increased number of published journal articles. Globally, the number of hydrogen papers have increased by an order of magnitude in the past 20 years and the UK has kept pace[49].

Additionally, the UK has excellent capabilities in engineering and consulting services, and in financing and other service industries. As such, the UK has a sizeable supply of these services with a hub of activity in London, the North West and Scotland.

48 UK H2FC Capability Document, EPSRC H2FC Hub, 2019
49 Opportunities for hydrogen and fuel cell technologies to contribute to clean growth in the UK, EPSRC H2FC Hub, 2020

6 CREATING VALUE CHAINS – PATHWAYS TO MARKET DEVELOPMENT

6.1 SIZE OF THE OPPORTUNITY

Market demand for hydrogen applications has been supported through several programmes and competitions. As technologies mature, demand increase could be triggered further through public procurement and other targeted subsidies. Light duty vehicles and boilers have lifetimes of 12-15 years. A significant zero carbon market must be established by the 2030s, to avoid higher costs from the early retirement of high-carbon technologies. In order for the UK to develop domestic capabilities and benefit from emerging global hydrogen fuel and technology markets, the government will have a critical role in supporting domestic experimentation and learning. A number of hydrogen technologies are on the edge of commercial viability and large markets could emerge over the next decade.

Figure 6.1 presents the break-even points where a specific hydrogen application becomes cost competitive in comparison to a zero-carbon alternative. The Y-axis shows hydrogen cost at which a single end-use becomes cost competitive with a zero-carbon alternative in 2030, and the X-axis shows the estimated total energy demand of that end-use. For some applications, such as industrial heating, trucks, buses, cars and vans, a range of break-even points is given, due to the difference in transmission and distribution costs for specific locations. A range is given for boilers for heating, and aviation, due to the range of possible alternative zero-carbon technologies.

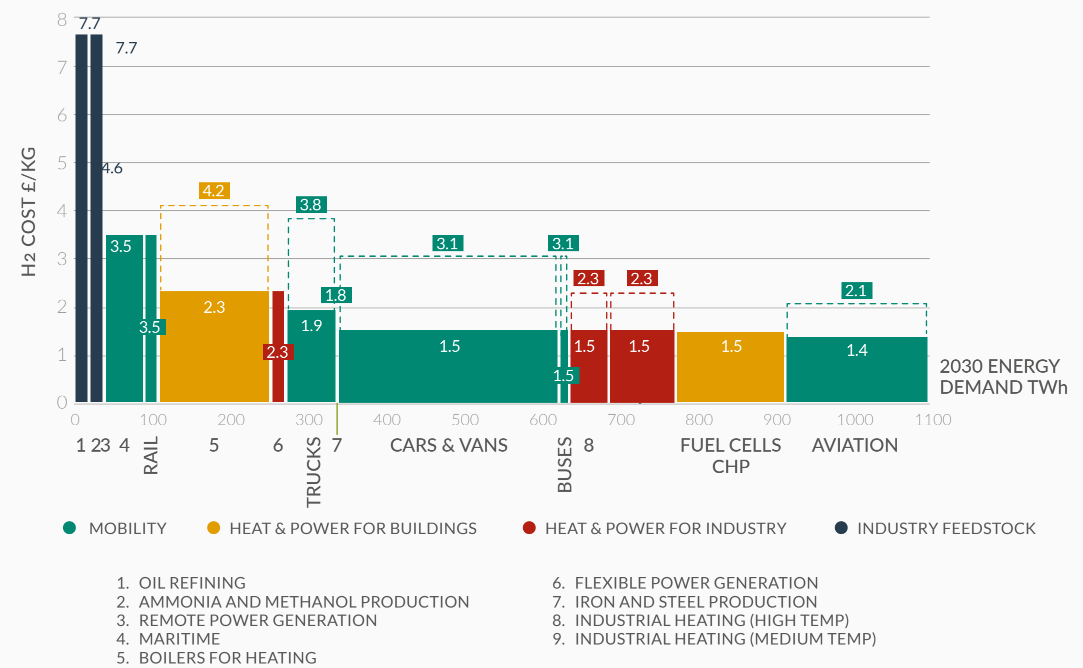


Figure 6.1 Cost curve for hydrogen production across segments

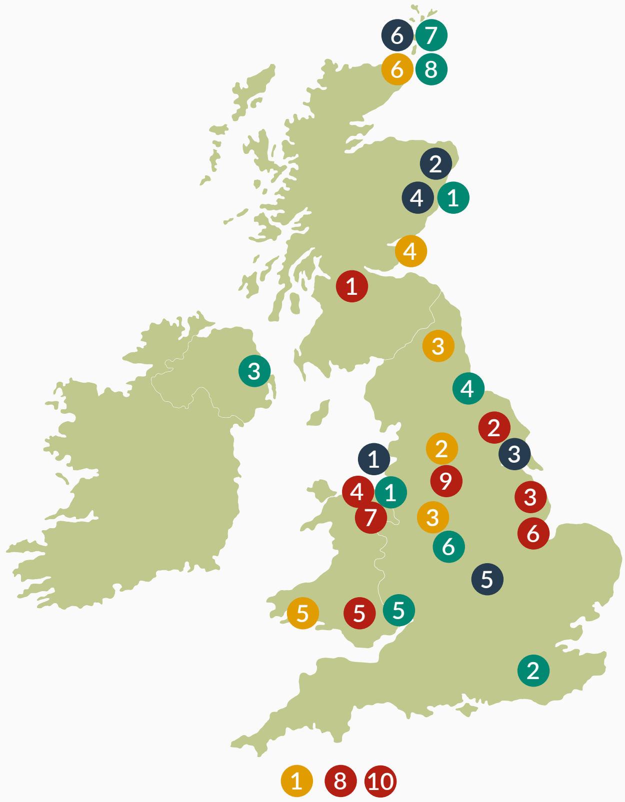
Our cost modelling forecasts that the cost of OSW-H_2 will be around £2.20/kg by 2030. At this price level, green hydrogen can meet a significant part of energy demand in sectors that otherwise would be difficult to decarbonise. Figure 6.1 does not imply that hydrogen will satisfy all of the energy demand in each sector, not least because, as the dotted lines indicate, there is a wide range of uncertainty in the cost of many of the alternative decarbonisation options. However, it illustrates the major role OSW-H_2 can play in our energy supply, even in the medium-term, to 2030.

The subsections below summarise recent publicly funded programmes to support market development for hydrogen and suggest priorities for action to develop value chains for green hydrogen.

6.2 PROGRESS SO FAR

6.2.1 INTRODUCTION

Figure 6.2 gives an overview of significant projects to develop applications of hydrogen in the UK. More detailed description of these projects can be found in Appendix 2.



	PROJECT NAME	LOCATION
	INDUSTRY	
1	Scotland's Net Zero Infrastructure	Scotland
2	Net Zero Teeside Project	Teeside
3	Humber Industrial Decarbonisation Deployment Project	Humber
4	HyNet CCUS	North West
5	South Wales Industrial Cluster	South Wales
6	Green Hydrogen for Humber	Humberside
7	HyNet North West	North West
8	State-of0the-art fuel mix for UK cement production to test the path for net zero	TBC
9	Alternative fuel switching technologies for the glass sector	Yorkshire
10	Hydrogen Alternatives to Gas for Calcium Lime Manufacturing	TBC

	PROJECT NAME	LOCATION
	MOBILITY	
1	Towards commercial deployment of FCEV buses and hydrogen refuelling	Aberdeen Liverpool
2	Hydrogen Mobility Expansion Project II	Crawley
3	Northern Ireland Hydrogen Transport	Belfast
4	Tees Valley Hydrogen Initiative	Middlesbrough & Stockton on Tees
5	Riversimple Clean Mobility Fleet	Monmouthshire
6	HydroFlex	Birmingham
7	HySeas III	Orkney
8	HyFlyer	Orkney

	PROJECT NAME	LOCATION
	GAS NETWORK	
1	Hy4HEat	TBC
2	H21	Leeds (Yorkshire)
3	HyDeploy 1 & 2	Keele & North of England
4	H100 Feed Study	Levenmouth
5	Energy Kingdom	Milford Haven
6	BIG HIT	Orkney

	PROJECT NAME	LOCATION
	PRODUCTION	
1	HyNet 1 & 2	Liverpool Bay Area
2	Dolphyn	Aberdeen
3	Gigstack	Grimsby
4	Acorn Hydrogen Project	Aberdeen
5	HyPER	Cranfield
6	Surf'N'Turf	Orkney

Figure 6.2 An overview of hydrogen projects and their locations in the UK

6.2.2 MOBILITY

Research on hydrogen use in mobility has been progressed by Department for Transport via The Hydrogen for Transport Programme (HTP)[50]. It sets out the next steps to develop the UK hydrogen vehicle market, providing up to £23m of new grant funding from 2017 to 2020 to support the growth of refuelling infrastructure alongside the deployment of new vehicles. Additionally, there are several mobility projects in Orkney islands including HySeas III that develops a vehicle and passenger ferry fuelled by green hydrogen and HyFlyer will demonstrate a medium range small passenger aircraft with electric motors, hydrogen fuel cells and gas storage.

6.2.3 DECARBONISING GAS NETWORK

The UK is among the global leaders in its efforts to understand whether hydrogen can power boilers to decarbonise heating. Research programmes funded by BEIS and Ofgem are examining the challenges, technical feasibility, safety evidence and economic viability of hydrogen use to decarbonise heat and power for buildings. For instance, the Hy4Heat programme is developing hydrogen-powered home appliances to demonstrate whether hydrogen can be used for heat in buildings or for cooking.

6.2.4 INDUSTRIAL CLUSTERS

Industry accounts for almost a quarter of all UK GHG emissions[51]. This challenge is widely recognised by BEIS and there are several programmes established or planned to tackle it.

The £170m Industrial Decarbonisation Challenge (IDC), funded by the Industrial Strategy Challenge Fund, forms part of the government's Industrial Clusters mission. It aims to accelerate the cost-effective decarbonisation of industry, by developing and deploying low-carbon technologies. The ambition is to establish at least one low-carbon industrial cluster by 2030 and a net-zero carbon industrial cluster by 2040. Through the IDC, the government is kick-starting the development of technologies like CCS and hydrogen networks in industrial clusters.

The Industrial Fuel Switching competition aims to identify and demonstrate solutions that will enable fuel switching in industry to less carbon intensive fuels. The latest phase allocated funding to demonstration projects numbered as 7 to 10 as shown in Figure 6.2.

Additionally, there are two further BEIS funds:

- Industrial Energy Transformation Fund (£315m on a UK-wide basis), which will support businesses with high energy use to improve their energy efficiency and reduce their emissions by decarbonising industrial processes.
- Clean Steel Fund (£250m), which will support the UK steel sector to transition to lower carbon iron and steel production.

50 https://ee.ricardo.com/htpgrants
51 Industrial Clusters mission, BEIS, 2019

6.2.5 HYDROGEN PRODUCTION

In 2020, five demonstration projects received funding to develop low carbon bulk hydrogen supply solutions. Successful applicants of the two-phase £33m Low Carbon Hydrogen Supply competition will demonstrate blue and green hydrogen production and others as shown in Figure 6.2.

In addition, there is an intention to establish a £100m Low Carbon Hydrogen Production Fund, to support the deployment of low carbon hydrogen production at scale by stimulating capital investment. The Government intends to engage with industry on this fund throughout 2020.

6.3 PATHWAYS – ENABLING TRANSPORT SECTOR VALUE CHAIN

Even though the deployment of BEVs is at a more mature stage, FCEVs will play a crucial role for heavy duty vehicles and long-distance travel for light duty vehicles. Additionally, there are few zero-carbon alternatives for shipping. Few commercial FCEVs manufacturers exist, therefore public intervention is necessary to enable a widespread uptake. Over the next 10 years, the production of components and vehicles needs to scale-up and more market players need to enter the sector to help to decrease the production cost. In order to ensure vehicles market uptake refuelling infrastructure has to be strategically located around hydrogen clusters and then UK wide. A national coverage of 150 refuelling station by 2025 and 1,100 stations by 2030 would enable close-to-home refuelling for whole UK.

Hydrogen light duty vehicles (LDVs), buses, trains and ships are on the path to commercialisation, but more work will be needed to enable HGVs. They require a large payload capacity and are challenging to decarbonise. Even though there are no long-haul fuel cell HGVs demonstrated there is international interest in developing them with first movers showing initial results[52]. HGVs could make a critical contribution to transport decarbonisation and in order to move to zero-emissions solutions by 2050, a roadmap for decarbonising HGVs with innovation support will be required in upcoming years[53].

LDVs for long-range journeys or high daily mileage (e.g. taxis, light commercial vehicles and buses) could be a stepping stone in helping to decrease the fuel cost, by increasing the utilisation rate of refuelling stations. If linked with industrial clusters they could create hydrogen hubs which would foster long-term transport hubs, including for shipping if located by the coast and decrease fuel transmission costs. Fuel incentives (e.g. Renewable Transport Fuel Obligation) will be necessary to initiate the uptake of these vehicles[54].

Vehicles that can access untaxed fuel, e.g. trains and boats, will require significant support to shift to hydrogen. It could either come in the form of cost incentives for hydrogen or the removal of rebates for diesel for these industries.

In order to secure a wider roll-out of vehicles, the Government should focus on ensuring a steady deployment of refuelling stations and development of vehicle technology. Acquisition and operational cost are key decision criteria for bus operators and, as many bus fleets are subsidised by local councils, it creates an environment where government support can drive early uptake. The Hydrogen for Transport Programme will deliver five new hydrogen refuelling stations, 73 FCEV light duty vehicles and 33 FCEV buses[55]. It is an important step, but additional measures will have to be taken in order to reach 1,100 stations by 2030, as recommended by UK H_2 Mobility consortium[56]. The Road to Zero strategy is supportive towards hydrogen application in transport but it is missing firm targets on deployment of

52 Nikola launched a hydrogen truck Nikola Tre with a range of 500-1000 miles and a 15-minute refuel time
53 Hydrogen in a low-carbon economy, CCC, 2018
54 Gigastack, Bulk Supply of Renewable Hydrogen, ElementEnergy, 2020
55 https://fuelcellsworks.com/news/uk-government-announces-winners-of-14-million-competition-to-fund-hydrogen-fuel-cell-vehicles-and-hydrogen-refuelling-infrastructure/
56 UK H_2Mobility (2013) Phase 1 Results

refuelling stations, FCEVs and buses. Any government funding should prioritise bids which allow a variety of vehicles to refuel. This would guarantee security for investors and enable development of an early market for hydrogen usage in the mobility sector. Refuelling stations could be co-located with industrial hubs which would help to focus an initial investment required for hydrogen supply and decrease the cost of transmission and distribution of the fuel.

6.4 PATHWAYS – DECARBONISING THE EXISTING GAS NETWORK VALUE CHAIN

Using existing gas infrastructure would decrease the need for investment in electrifying heat and would create a significant market demand for zero-carbon hydrogen supply. Even blending in 5-10% would create a significant hydrogen demand and be a steppingstone for 100% decarbonisation in the longterm. Blending hydrogen into networks at up to 20% by volume would require only minor, if any, changes to existing infrastructure and most end-user appliances. Provided that hydrogen production facilities were located near the gas transmission or distribution network, blending offers a non-invasive and fast way to transmit hydrogen supplies to end users. If outcomes of projects like HyDeploy or H21 turn out to be successful, a sizeable hydrogen demand could be created. However, at current LCOH, country-wide blending will require policy support, such as the Renewable Heat Incentive, that at the moment is used to support the injection of biomethane. This would stimulate demand from gas suppliers, encourage hydrogen appliances production and safeguard infrastructure use.

Conversion of the gas network to supply 100% hydrogen would further decrease the distribution costs of hydrogen and enable sources of pure hydrogen demand to connect to the same network, such as mobility or industrial users. Full conversion would pose a greater challenge to blending, as investment in meters, compressors and gas appliances would be necessary. The H21 project supports the conversion of the UK gas networks to carry 100% hydrogen in Leeds from the late 2020s with hydrogen supply from natural gas and CCS from a North Sea industrial cluster. Similar projects linking green hydrogen production and the decarbonised gas network are necessary.

In order to maintain the UK's global leadership position in efforts to decarbonise gas network, the government should establish network decarbonisation targets and support strategic demonstration projects. Outcomes of the projects listed in Appendix 2 will help to evaluate the health and safety of hydrogen use, create standards for the tolerance of appliances and equipment to different blending levels and establish a safety case of blending levels. Trials conducted by e.g. HyDeploy or H100 projects will validate each of the identified equipment types but in order to reach commercialisation, a number of additional demonstrations will be required. A future phase of H100 plans to demonstrate 100% supply of green hydrogen produced from the ORE Catapult Offshore Wind Demonstration Turbine to 300 homes. Additionally, a research facility for the decarbonisation of heat should be established. It could offer flexible demonstrators to develop electrification, repurposing for hydrogen and district heating.

6.5 PATHWAYS – DECARBONISING INDUSTRIAL CLUSTERS AND CREATING HYDROGEN HUBS

Industrial clusters can be a trigger in developing a hydrogen economy and building hydrogen hubs. Coastal locations that are close to OSW farms would benefit from reduced cost of developing transmission and distribution infrastructure. As shown in Figure 6.3 most industrial clusters in the UK are located close to shore and some of them in proximity with OSW farms (e.g. Humberside, Teesside).

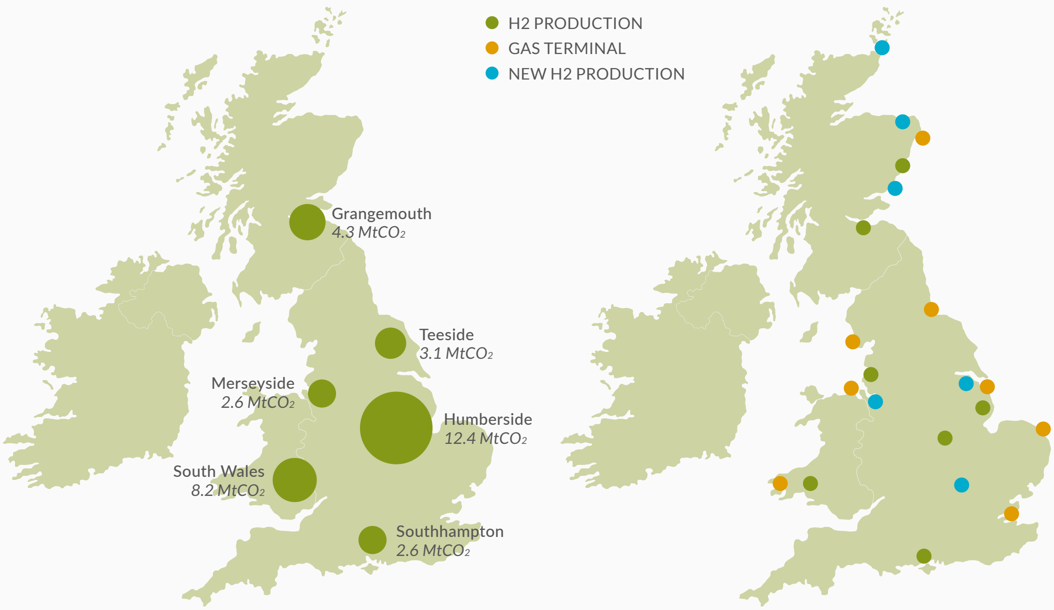


Figure 6.3 Largest industrial clusters by emissions in the UK and hydrogen production locations

Clusters offer a significant and growing demand for established users of hydrogen for refining, chemicals and steelmaking. There is a potential to create hydrogen hubs and expand the range of end-users to heat for buildings, refuelling stations and dispatchable power generation. These synergies could translate into savings on transmission infrastructure and commercialising hydrogen applications. In addition, in the long-term, nearby port facilities could be used for the international maritime trade or as a fuel for trucks, fleet vehicles and maritime fuel.

The majority of hydrogen projects shown in Figure 6.2 are located in proximity to or are in the industrial cluster, e.g. Humberside, Merseyside, South Wales but most of the time they are not interlinked (as e.g. HyNet projects). There is more industry and policy work and funding needed for revolutionary designs and demonstrations for local energy systems around industrial clusters. There are only a few projects that link green hydrogen production with an end-use application (e.g. Gigastack). Addressing the integration challenge will require projects that will have several hydrogen applications combined with zero-carbon production at scale.

Figure 6.4 shows potential clusters of hydrogen activity, especially around Aberdeen, South Wales, East Anglia and in the East Midlands. The creation of clusters is an essential first step towards development of a national hydrogen network. Gas pipelines already exist at these locations (as shown in Figure 6.4) allowing for the export and import of hydrogen. Port infrastructure especially in Aberdeen and South Wales will also allow for hydrogen to be transported by ship.

The creation of hydrogen clusters needs the cooperation of local and national government, local enterprises and larger industrial players. Government incentives to boost the hydrogen market, local government for allocating deals and infrastructure and large industry to invest in the infrastructure would allow for smaller developers to break into the market and grow.

Figure 6.4 Gas network in the UK

6.6 THE SCALE OF AMBITION FOR THE GREEN HYDROGEN ROADMAP TO 2030

The hydrogen deployment levels in the scenarios we used in Chapter two, are essential for driving cost reduction through scale-up of unit sizes and learning-by-doing. Rapid scale up also provides the industry with larger revenues to re-invest in further cost-reducing innovation.

We estimate that most of the cost reduction for PEM electrolysis will have been achieved when global deployment has increased by approximately 10GW, to around 11GW. To stay on track for cost-reduction, this should be achieved by 2030. We have chosen 25% of global PEM deployment, as a minimum target for the share of deployment that should be ensured within the UK, given our technology lead in PEM electrolysis. With this target, new UK deployments of PEM electrolysers would have to total a minimum of 2.6GW by 2030. This represents around 10% of our estimate for total, global electrolyser deployments, which is shared primarily between PEM and AEL electrolysers, with smaller deployments of SOEC.

We have used the example of an HGV refuelling centre, to illustrate how to achieve a the 2.6GW minimum deployment level for our technology acceleration ambitions. Multiples of this type of programme, or of programmes of similar scale in other sectors, would provide greater certainty of both driving costs down, and securing substantial economic benefit for the UK.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Annual global deployment, MW	182	240	307	393	503	644	942	1,205	1,542	1,974	2,525	**10,460**
Annual UK deployment (25%), MW	46	60	77	98	126	161	236	301	386	493	631	**2,615**
Annual UK investments, £m	30	37	46	57	70	67	95	121	154	195	246	**1,117**
Diesel cost per litre (inc tax), £	1.20	1.22	1.25	1.27	1.28	1.30	1.33	1.35	1.37	1.40	1.42	
LCOH from PEM, £/kg	5.24	4.76	4.03	3.52	3.33	2.70	2.60	2.56	2.52	2.49	2.20	
H2 from diesel, £/kg	3.53	3.57	3.67	3.72	3.77	3.82	3.92	3.97	4.01	4.11	4.16	
H2 produced each year, kt	3.6	8.5	15.4	24.2	35.5	50.0	71.1	98.1	132.7	177.0	233.6	**849.9**
Premium / Saving PEM vs diesel, £m	6	10	5	(5)	(16)	(56)	(93)	(138)	(198)	(288)	(458)	**(1,229)**

Table 6.1 UK PEM deployment, investment cost and payback for an HGV refuelling programme to 2030

Table 6.1 illustrates the investments required to deploy 2.6GW, using a hybrid project of an OSW farm and an HGV hydrogen refuelling hub. The project structure could be similar to combined OSW farm-onshore battery storage projects that have been completed in recent years, with the onshore electrolyser facility taking the place of the battery in those earlier projects. In the model programme above, the early electrolyser installations require incentives to bring the cost of hydrogen in line with the retail price of diesel. However, because the projects are relatively small in the early years, the public investments required are also small: 46MW, and £30m, respectively, in 2020. Other countries have announced near-term hydrogen strategies that greatly exceed these levels. These OSW-H2 transportation fuel projects quickly become cost-effective. Their net cost saving over diesel is more than £1.2bn by 2030.

The need for hydrogen storage would add to the cost of these projects, but careful choice of sites with predictable demand, for example at ports, would minimise the storage cost element.

7 ROADMAP FOR A GREEN HYDROGEN CHALLENGE PROGRAMME

7.1 INTRODUCTION

The roadmap for the UK to accelerate the transition to a green hydrogen-based heat, transportation and industrial uses, sourced from our extensive OSW resources, is set out as three essential tracks. The first is the R&D track, based on the innovation elements we identified above, for the Core R&D programme. Track 2 is a set of key demonstrations of critical technologies and integrated systems and markets, at scale. Track 3 is a set of enabling actions, to unblock and accelerate innovation, and support market growth for green hydrogen. These tracks will engage the research community, a broad range of industry actors from manufacturers to energy project developers to engineering and service companies, and other key stakeholders from government, regulatory agencies, and local communities. A list of some of the important stakeholders from these groups is included in Appendix 4.

7.2 TRACK 1 – R&D PROGRAMME

The innovation priorities for an R&D programme were set out in Chapter 3. The assessment criteria used to select R&D priorities for the cell stack, should form the basis of the objectives for the wider hydrogen R&D programme which objectives and example challenges are summarised in Table 7.1:

	R&D programme objectives	Example challenges
1	CAPEX reduction	Reducing the use of high-cost materials; simplifying design to reduce labour and increase automation.
2	Unit scale-up	Pressure management across larger stacks.
3	Improve efficiency	Improved surface reaction characteristics; improved designs and greater design integration across balance-of-plant; new power electronics solutions, including compound semiconductors.
4	Increase reliability	Materials aging challenges, especially high temperature for SOEC; hydrogen embrittlement management.
5	Flexible operation	Improved integration across components; optimised electrochemistry; materials for a wider range of operating conditions.
6	Increase manufacturability	Electrolysers are currently not manufactured in scale. Continuous serial production methodologies have to be established. Manufacturing equipment will be required that can handle even larger structures at low cost.
7	Better marine environment tolerance	Decreasing OPEX and tackling O&M challenges related to operating devices in harsh, offshore environment. Developing more resistant materials.
8	Non-electrolysis technologies (maximum 5% of funding)	Potentially to include direct cracking of methane to H_2; photo-catalytic H_2 production.

Table 7.1 R&D programme objectives with example challenges

The R&D programme, and in particular the theme relating to the cell stack component, will draw upon world-leading capabilities that already exist within UK academia, including those listed in Table 7.2:

Electrolyser component	Core disciplines	Academia - examples
Cell stack	Materials; Electrochemistry	Royce Institute; H2FC Supergen
Power electronics	Materials; Electronics	Royce Institute; Newcastle, Manchester; Cardiff, Edinburgh...
Gas conditioning	Chemical engineering	H2FC Supergen, Cambridge, Nottingham, Bradford
Balance of plant & OPEX	Systems engineering	Strathclyde, UCL, Warwick, Cranfield...

Table 7.2 Overview of core disciplines and academic expertise per electrolyser component

Royce Institute: Manchester (Hub) plus Sheffield, Leeds, Liverpool, Cambridge, Oxford and Imperial College London, as well as UKAEA and NNL

H2FC Supergen: Imperial College London, St. Andrews, Newcastle, Birmingham, Bath, Ulster, University College London - Management Board

This R&D programme could be delivered through a hub programme structure and would consolidate and build on existing research and industrial capabilities in the UK. It would include both short-term upscaling of lower risk current technology and disruptive, higher risk projects.

7.3 TRACK 2 – DEMONSTRATIONS AT SCALE

7.3.1 INTRODUCTION

Demonstrations at scale are an essential means of validating the robustness of new technologies and approaches, and encouraging the private sector to invest alongside the public sector in the innovation journey. Public support for demonstrations at the right scale, and at the right level of technology maturity frequently make the difference between success and failure, for an innovative company.

Demonstration projects will also contribute to the 2.6GW of electrolyser deployment, or multiples thereof, that we have recommended as a target for 2030. Demonstration projects should be at the right scale, to match the maturity, and the volume manufacturing plans, of electrolyser suppliers.

7.3.2 PRODUCTION

At least three demonstration projects by 2025 proving the integration of electrolysis with wind turbines and farms offshore. This should include the development, demonstration and optimisation of integrated solutions with OSW (considering decentralised, centralised, ongrid and offgrid approaches).

7.3.3 MOBILITY

At least two hydrogen transportation hub conversion projects coordinated with existing programmes to promote refuelling infrastructure and fuel cell vehicles. This requires immediate implementation. Multiple project phases can provide a smooth pathway for demonstration of scale up of PEM electrolysers. A focus on FCEV buses is necessary to promote an affordable mode of transport that is suitable for urban locations and to support the existing technological lead of several UK companies.

7.3.4 HEAT AND POWER FOR BUILDINGS

Six demonstrations of 10,000 homes using 100% green hydrogen for heat, at each of the six major Industrial Decarbonisation zones, if local demographics are suitable - by 2030.

7.3.5 HEAT AND POWER FOR INDUSTRY

Minimum of two electrolyser-based hydrogen demonstrations at >100MW H_2 production - by 2025 to create investor confidence in developing manufacturing capabilities.

Ensure UKRI funding for the roadmapping phase of the Industrial Decarbonisation clusters includes large-scale electrolysis to green hydrogen.

7.3.6 INDUSTRY FEEDSTOCKS

Ammonia and methanol production switched to green hydrogen use at selected three sites – by 2035.

7.4 TRACK 3 – ENABLING ACTIONS

7.4.1 FOR OSW-H2 TECHNOLOGY

- More flexible funding sources are essential for demonstrations due to their complexity (e.g. H100). Given the projection for OSW-H2 to be cheaper than blue hydrogen in 2050, the Low Carbon Hydrogen Production Fund should focus on zero carbon technologies.
- Creating a single or multiple site facility that would validate emerging technology and build on existing capabilities. It should include a facility to develop bulk production of low-carbon, low-cost, resilient hydrogen including piping, large-scale ORE storage demonstration facility and a 'living laboratory' for energy storage integration and local generation systems.
- A revenue support mechanism for production of green hydrogen, as fuel credits, building upon the CfD mechanism for low-carbon electricity, which has evolved to protect consumers and target innovative technologies.
- To accelerate complex demonstration projects, make regulatory sandpits easy to access and multi-agency; lessons should be learned from the integrated approach to innovation of the Oil and Gas Authority (OGA), the O&G regulator.
- Certification of hydrogen-ready boilers for residential and commercial heating as zero-carbon compliant heating technologies. Mandating all new boilers sold from 2025 are hydrogen ready.
- Establishing a cross-departmental Hydrogen Strategy within the UK Government including BEIS, Department for Transport, HM Treasury, Department for Environment, Food and Rural Affairs and Ministry for Housing, Communities and Local Government.
- Guarantee a collaboration mechanism to build on existing links between UK researchers, companies and European counterparts.

7.4.2 FOR CLUSTER DEVELOPMENT

- Creation of multi-market hydrogen hubs around industrial clusters with existing hydrogen infrastructure.
- Development of refuelling hubs around hydrogen hubs. Rollout of 150 refuelling stations by 2025 and 1,100 by 2030, to first provide coverage around, and between hubs, then to provide close-to home UK-wide coverage. Stations could be used by project participants at first and then by public.
- Support existing bus manufacturers by expanding, electrifying (BEV or FCEV) and making public transport more affordable. Allow local authorities to regulate bus services sufficiently to boost coordination, stability, of an effective network, and single ticketing. Set out a public transport strategy that will ensure all new buses are emission-free from 2025 onwards.
- Planning support and guidance for local authorities and residential and commercial developers, for new buildings around hydrogen hubs to use hydrogen for heat. To support LCOH reduction, a scheme similar to the Renewable Heat Incentive should be established.
- Mechanisms for Ofgem to approve investments by gas distribution network operators in 100% hydrogen network infrastructure around hydrogen hubs, and to recover any additional costs from the pool of total UK gas customers, to protect individual consumers and avoid disincentives for first-mover network operators.
- Critical infrastructure funding to enable the gas import ports – Milford Haven, Isle of Grain, Fraserburgh – to develop roadmaps and begin the transition to hydrogen imports, exports and storage.
- Adaptation of climate related charges in the industrial sector, to allow offsets against investment in green hydrogen production.
- Ensure that the national infrastructure commission supports the hydrogen infrastructure needs.

7.4.3 FOR MARKET DEVELOPMENT

- Develop readiness for internationally-traded bulk hydrogen at key UK ports – Milford Haven and Grimsby.
- Engage with, and shape, European initiatives to develop North Sea hydrogen infrastructure for OSW farms.
- Development of strategic heat decarbonisation policy and discussion between regulators, stakeholders and industry on financing the transition.
- Amend Gas Safety Management Regulations to support hydrogen blending into the gas grid.
- Consider mandating that new boilers sold after 2025 are hydrogen ready to guarantee a market uptake if community trials show that there are no substantial technical or economic impediments.
- Support the use of HGVs and FCEV buses around hydrogen hubs through fleet trials and encouraging coordinated procurement to achieve scale.
- Promote carbon accounting of embodied carbon, internationally. Carbon accounting from imports will support a UK unique selling proposition of secure, affordable, zero-carbon OSW-H2 for industry. This will help to tip the 'make-or-buy' decision in favour of manufacturing in the UK, helping to create new and safeguard existing capabilities and potentially reversing the offshoring of UK industry to high-emission producers.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 AVAILABILITY AND COST OF GREEN HYDROGEN FROM OFFSHORE WIND

8.1.1 CONCLUSIONS

Our re-analysis of detailed modelling of the UK OSW resource shows that at least 675GW of OSW is available in UK waters, at or close to prevailing OSW contract prices. The anticipated cost reduction of floating OSW enables access to this resource, from 2030.

Forecasts of the net-zero energy system in 2050 indicate that at least 75GW of OSW, and potentially much more, will be required, and that hydrogen demand for decarbonisation of heating, transport and industry will be at least 140TWh.

Using our OSW resource to satisfy that level of hydrogen demand, the cost of green hydrogen produced by electrolysis, either onshore or on centralised platforms offshore ('OSW-H2'), falls to £1.65/kg in 2050. This is cheaper than H2 from natural gas, with carbon capture and storage, in 2050, and equivalent to a wholesale gas cost of £42/MWh (prices in 2012£). Distributed offshore electrolysis, at wind turbines, using SOEC technology, has potential to cost even less, but this is a less mature technology path, with greater uncertainty around cost reduction.

Most of the reduction in the capital cost of AEL and SOEC occurs by 2035, when global deployment of electrolysers has reached approximately 100GW. However, based on manufacturing plans provided by industry, we forecast that the majority of capital cost reduction for PEMs will occur by 2025, driven by global deployment of less than 10GW of electrolysers. (From a similar starting point on the technology maturity journey, OSW achieved this level of cost reduction when global deployment reached 10-15GW.)

Early action by the UK to support deployment of a minimum of 2.6GW of electrolysis projects by 2030, would contribute 10% of the global deployment that will be required by 2030, in order to ensure that OSW-H2 is the lowest cost source of hydrogen by 2050. Multiples of this commitment would provide a greater ability to convert our current industrial and academic leadership into UK economic success.

The speed of cost reduction for OSW-H2 depends strongly on how quickly the global electrolyser market grows, particularly between now and 2030. More rapid deployment of electrolysers, will accelerate the reduction in the cost of OSW-H2, and green hydrogen in general.

8.1.2 RECOMMENDATIONS

The UK should seize the opportunity to repeat the success of its intervention to drive global OSW deployment and cost reduction, by playing a similar role in accelerating electrolyser deployment and innovation, including measures to expand hydrogen demand in the near term (in residential and commercial heating, transport, and industry) and essential R&D programmes.

Urgent action is essential if the UK is to secure a leading position in benefitting from the economic opportunities we have outlined. Our proposed OSW-H2 roadmap of R&D programmes, demonstration projects, and policies and regulations for market support, should be adopted by the UK Government and devolved administrations as soon as possible, to accelerate the cost reduction of OSW-H2, and to ensure that substantial benefits flow to the UK supply chain, from the emerging global market.

Our projection that hydrogen produced from natural gas with CCS will be out-competed by OSW-H2 by 2050, indicates that the blue hydrogen pathway might not be essential for achieving net-zero in the UK.

The CO2 emissions from hydrogen currently derived from natural gas and used as feedstock in industrial clusters, might be abated in the near term by developing and applying lower emission NG-H2 technology, including ATR with 100% renewables electricity supply. Further study of these transitional abatement options is warranted, to determine the role they should play in publicly funded programmes for industrial decarbonisation.

8.2 UK ECONOMIC VALUE FROM OSW-H2, AND ENERGY EXPORT POTENTIAL

8.2.1 CONCLUSIONS

The UK OSW resource is large enough to supply a majority of UK energy needs and create an energy export industry comparable to the O&G sector. Cost reduction in hydrogen electrolysis is necessary to unlock the full economic potential of OSW.

UK GVA from additional OSW enabled by hydrogen, and directly from hydrogen generation projects, can reach a cumulative GVA of up to £320bn, by 2050, including exports of electrolysers to the rest of the world with a value of £250bn. This new activity sustains up to 128,000 new jobs in the UK, including 100,000 from exports of equipment and related services.

In addition, UK OSW-H2 can supply a projected deficit in zero-carbon hydrogen in mainland Europe, in 2050, with an export value of up to £48 billion annually, provided by an additional OSW fleet of up to 240GW.

UK OSW-H2 will not only compete on price, it will ensure the UK continues to enjoy security of energy supply, and enhance security of supply for Europe by reducing dependence on Russian gas, and on future North African solar power, both of which carry political and economic risks.

The potential demand for secure, green hydrogen in mainland Europe, could help to secure a future for the extensive skills and assets of the UK offshore O&G industry with strong prospects to preserve critical skills from the O&G sector.

8.2.2 RECOMMENDATIONS

To avoid the risk that piecemeal, project-by-project, infrastructure development will limit the ability of the UK economy to benefit from the UK OSW resource, either by slowing development of the resource, or by driving the sector to a development path where the terms are set by early-movers, such as the Netherlands, Germany, Denmark and Norway, the UK Government should play a leading role in pan-European infrastructure planning, such as emerging proposals for international H2 pipelines and energy islands.

Relevant UK bodies should engage closely with regional energy pacts, including the EU's North Seas Energy Cooperation, which has the remit to facilitate cost-effective deployment of OSW and promote interconnection between the countries around the North Sea.

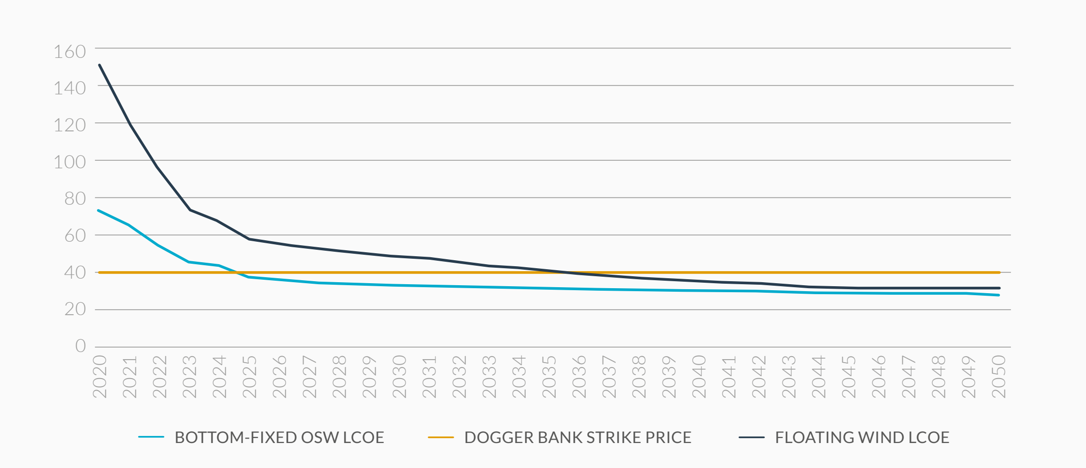
The UK government should establish programmes to promote the UK as a location for zero-carbon manufacturing, based on OSW-H2, and our traditional manufacturing capabilities in regions; in the period before OSW-H2 becomes competitive with grey H2, the government should provide incentives for inward investing manufacturers to secure OSW-H2 energy supply agreements.

Development of cross-border gas pipelines can take decades of ministerial-level engagement and constant Foreign and Commonwealth Office attention – OSW-H2 should be elevated to a commensurate status across relevant UK departments. Additionally, in relationships with countries in north-west Europe (e.g. Germany which has a green hydrogen ambition but insufficient renewable resources to meet its 2050 energy requirement), the Government should seek to exploit the long-term potential of exporting green hydrogen.

A APPENDIX 1
OSW-H2 COST ASSUMPTIONS

INPUT COST OF ELECTRICITY FROM OFFSHORE WIND

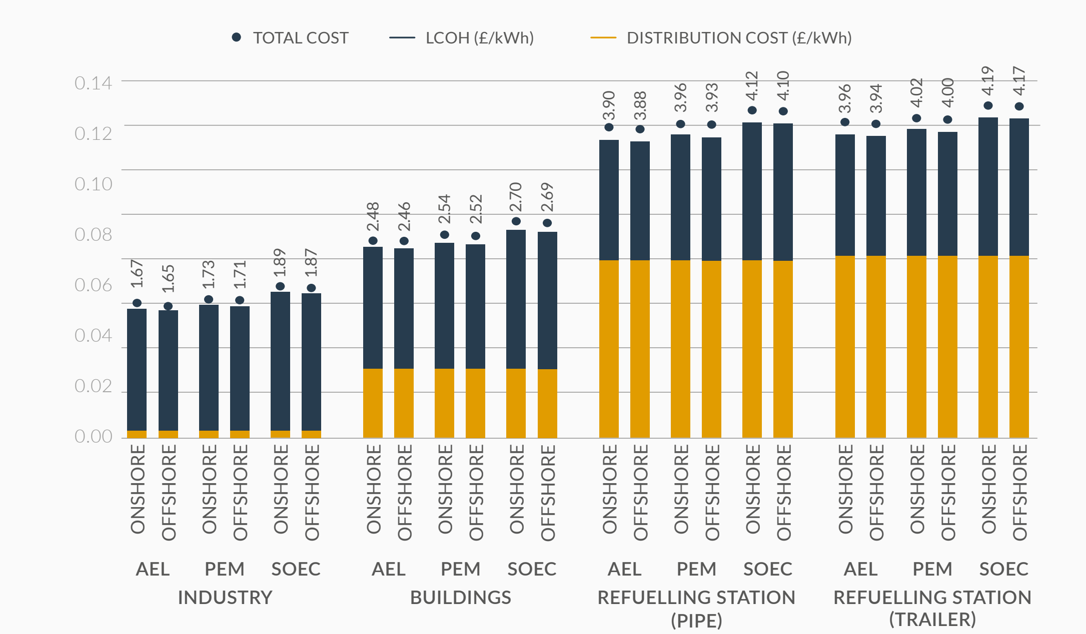
The following chart of OSW LCOE is referenced in Section 2.1:



Underlying OSW LCOE £/MWh (2012 real)

HYDROGEN COST INCLUDING DISTRIBUTION COST IN 2050

The following chart comparing hydrogen cost is referenced in Section 2.3.6:



Hydrogen cost including distribution cost in 2050

ELECTROLYSER CAPEX

Assumptions:

Alkaline Electrolyser			
Stack Component	**Learning Rate**	**Cost Fraction**	**CAPAX 2017 (£/kWel)***
Structural rings	5%	15%	67
PTFE sealing	8%	4%	18
Bipolar plates	18%	7%	31
Pre-electrode	18%	8%	35
Anode	18%	26%	115
Cathode	18%	25%	111
Membrane	18%	7%	31
Flanges	5%	4%	18
Tie rods	5%	4%	18
Cell stack total		**50%**	**444**
Power electronics	**12%**	**15%**	**133**
Gas conditioning	**7%**	**15%**	**133**
Balance of plant	**13%**	**20%**	**177**
Electrolyser system			**887**

PEM Electrolyser			
Stack Component	**Learning Rate**	**Cost Fraction**	**CAPAX 2017(£/kWel)***
Stack assembling	8%	2%	11
Small parts	5%	3%	17
MEA manufacturing	8%	10%	56
Catalyst cathode	8%	2%	11
Catalyst anode	8%	6%	34
Membranes	18%	5%	28
Current collectors cathode	18%	9%	50
Current collectors anode	18%	8%	45
Bipolar plates	18%	51%	286
End plates	8%	1%	6
Pressure plates	8%	3%	17
Cell stack total		**50%**	**560**
Power electronics	**12%**	**15%**	**168**
Gas conditioning	**7%**	**15%**	**168**
Balance of plant	**13%**	**20%**	**224**
Electrolyser system			**887**

Solid Oxide Electrolyser			
Stack Component	**Learning Rate**	**Cost Fraction**	**CAPAX 2017 (£/kWel)***
Stack assembling	8%	9%	43
Electrolyte	18%	12%	57
Catalyst anode	18%	15%	71
Catalyst cathode	18%	23%	110
Current collector (PTL)	18%	8%	38
Interconnector (Flowfield)	18%	12%	57
Sealing	5%	15%	71
End plates	8%	2%	10
Pressure plates	8%	4%	19
Cell stack total		**30%**	**476**
Power electronics		**30%**	**476**
Gas conditioning		**6%**	**95**
Balance of plant		**34%**	**540**
Electrolyser system			**1588**

**All costs are adjusted to 2012 prices*

Parts of the stack that contribute the most to the total electrolyser CAPEX have been highlighted in green.

Sources:

- Bohm et al (2019): https://doi.org/10.1016/j.ijhydene.2019.09.230,
- 2018_Store&Go_Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimization
- 2015_FCHJU Electrolysis study, Bertuccioli et al. (2014)

OFFSHORE WIND LCOE COST BREAKDOWN

Overview of CAPEX, OPEX and DEVEX of electricity and system cost estimation for bottom-fixed OSW:

	Ongrid OSW / Onshore H2			Offgrid OSW / Offshore H2		
DEVEX and CAPEX (£/kW)	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
DEVEX	105	84	71	105	84	71
CAPEX - windfarm	2,086	1,494	1,268	2,086	1,494	1,268
CAPEX - grid	564	483	394			
Subtotal	**2,755**	**2,003**	**1,700**	**2,191**	**1,578**	**1,339**
System CAPEX (see table below)	26.3	23.7	12.6	466.6	401.7	256.6
Total CAPEX	**2,781**	**2,085**	**1,746**	**2,658**	**1,980**	**1,596**

OPEX (£/kW/year)	2020	2030	2050	2020	2030	2050
O&M	45	34	29	45	34	29
Other	29	23	20	29	23	20
Subtotal	**75**	**57**	**49**	**75**	**57**	**49**
System OPEX (see table below)	1.30	0.96	0.51	7.53	6.31	3.94
Total OPEX	**76**	**57**	**49**	**82.2**	**63.4**	**52.4**

Overview of CAPEX, OPEX and DEVEX of electricity and system cost estimation for floating offshore wind:

	Ongrid OSW/Onshore H2			Offgrid OSW/Offshore H2		
DEVEX and CAPEX (£/kW)	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
DEVEX	204	106	69	204	106	69
CAPEX - windfarm	4,029	2,093	1,363	4,029	2,093	1,363
CAPEX - grid	1,164	625	403			
Subtotal	**5,397**	**2,824**	**1,835**	**4,125**	**2,177**	**1,434**
System CAPEX (see table below)	26.3	23.7	12.6	466.6	401.7	256.6
Total CAPEX	**5,423**	**2,848**	**1,848**	**4,592**	**2,579**	**1,691**

OPEX (£/kW/year)	2020	2030	2050	2020	2030	2050
O&M	128	67	43	128	67	43
Other	46	24	16	46	24	16
Subtotal	**175**	**91**	**59**	**175**	**91**	**59**
System OPEX (see table below)	1.30	0.96	0.51	7.53	6.31	3.94
Total OPEX	**175.1**	**91.1**	**59.3**	**182.0**	**97.0**	**63.0**

Overview of CAPEX, OPEX and DEVEX of electricity and system cost estimation for hydrogen system:

	Ongrid OSW/Onshore H2			Offgrid OSW/Offshore H2		
CAPEX (£/kW)	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
Hydrogen compressor	3.3	2.3	1.0	3.3	2.3	1.7
Standby Power/Battery	19.3	14.2	7.7	48.2	35.5	19.3
AC cable to platform				2.4	2.2	1.7
AC/DC converter[57]				145.8	116.0	66.9
Water desalination				1.2	0.8	0.2
Central Electrolyser Platform (offshore)				198.4	167.5	111.5
Hydrogen pipeline				57.9	59.3	45.5
Subtotal	**22.6**	**16.5**	**8.7**	**457.2**	**383.6**	**246.8**
System Replacements	3.75	7.22	3.93	9.37	18.05	9.82
Total System CAPEX	**26.3**	**23.7**	**12.6**	**466.6**	**401.7**	**256.6**

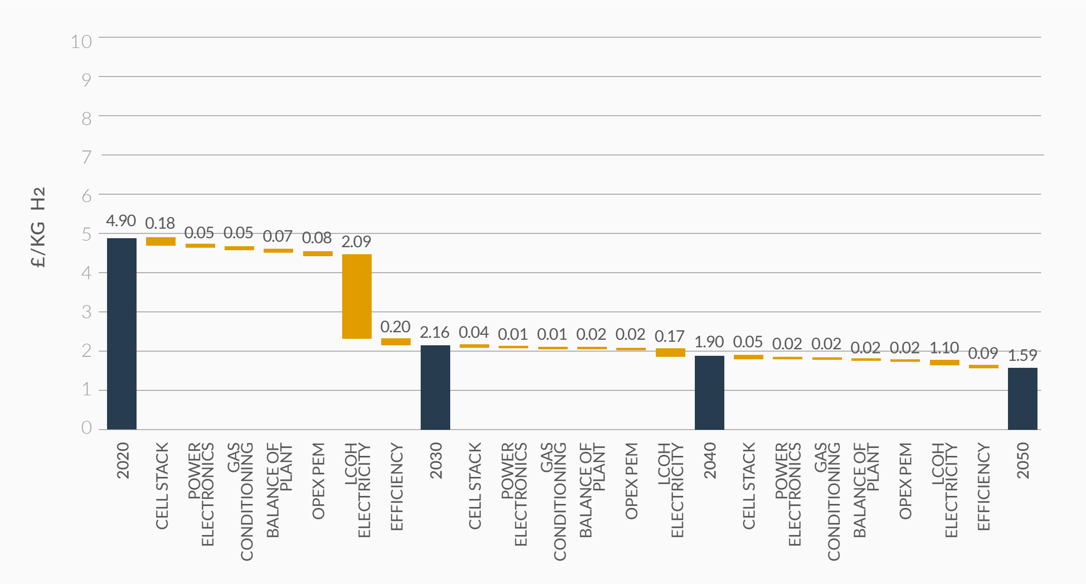
OPEX (£/kW/year)	2020	2030	2050	2020	2030	2050
Hydrogen compressor	0.10	0.07	0.03	0.10	0.07	0.03
Standby Power/Battery	1.20	0.89	0.48	1.20	0.89	0.48
AC cable to platform				0.07	0.06	0.05
AC/DC converter				4.38	3.48	2.00
Water desalination				0.04	0.02	0.01
Hydrogen pipeline				1.74	1.78	1.36
Total System OPEX	**1.30**	**0.96**	**0.51**	**7.53**	**6.31**	**3.94**

All costs are expressed in 2012 prices.

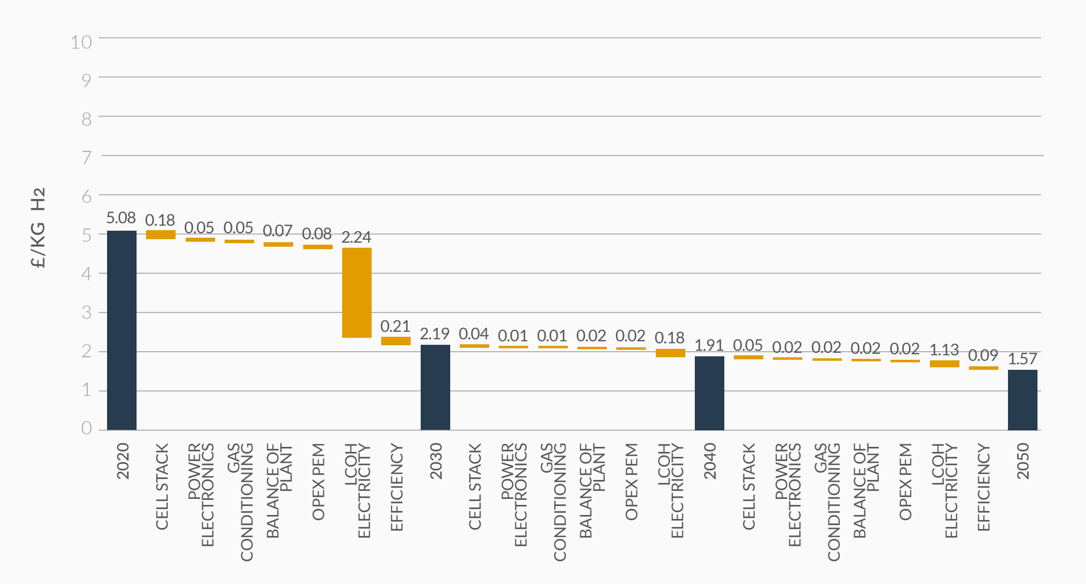
57 The cost of the converter is included in the windfarm CAPEX for grid connection in the ongrid scenario

LCOH COST BREAKDOWN (INCLUDING EFFICIENCY)

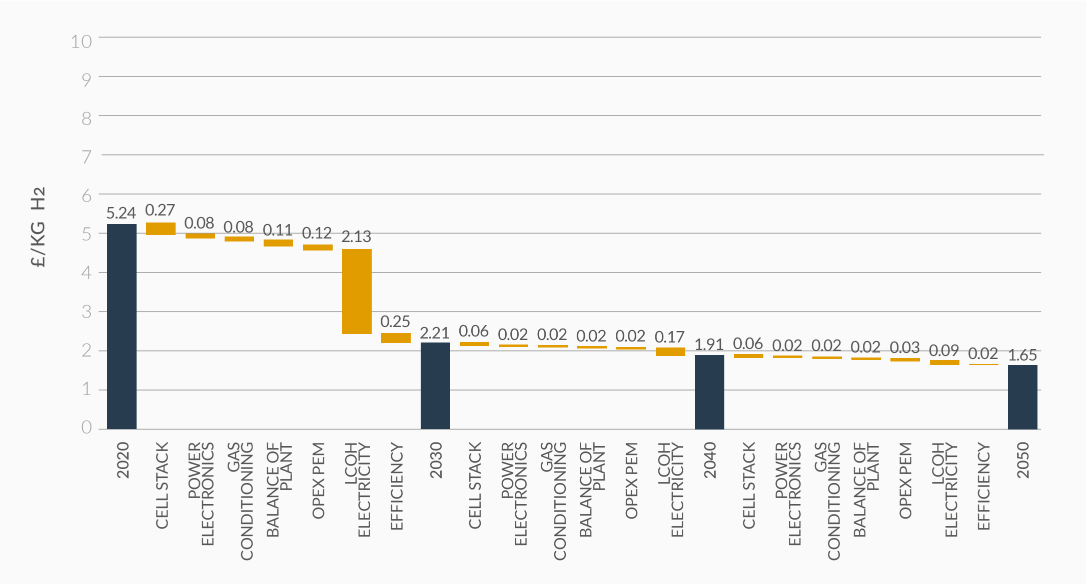
Bottom-fixed wind ongrid-onshore AEL electrolysis:



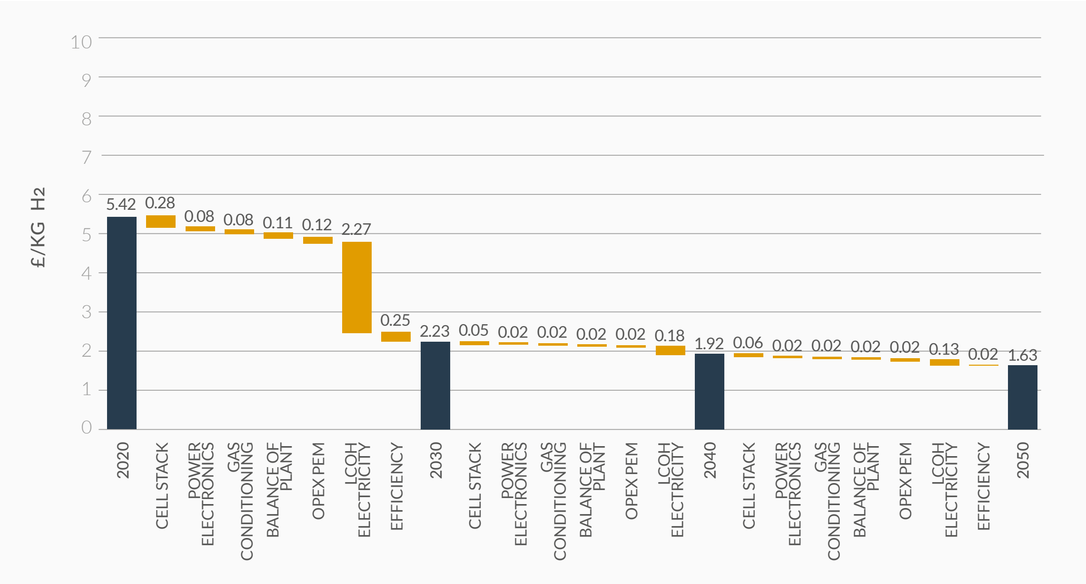
Bottom-fixed wind offgrid-offshore AEL electrolysis:



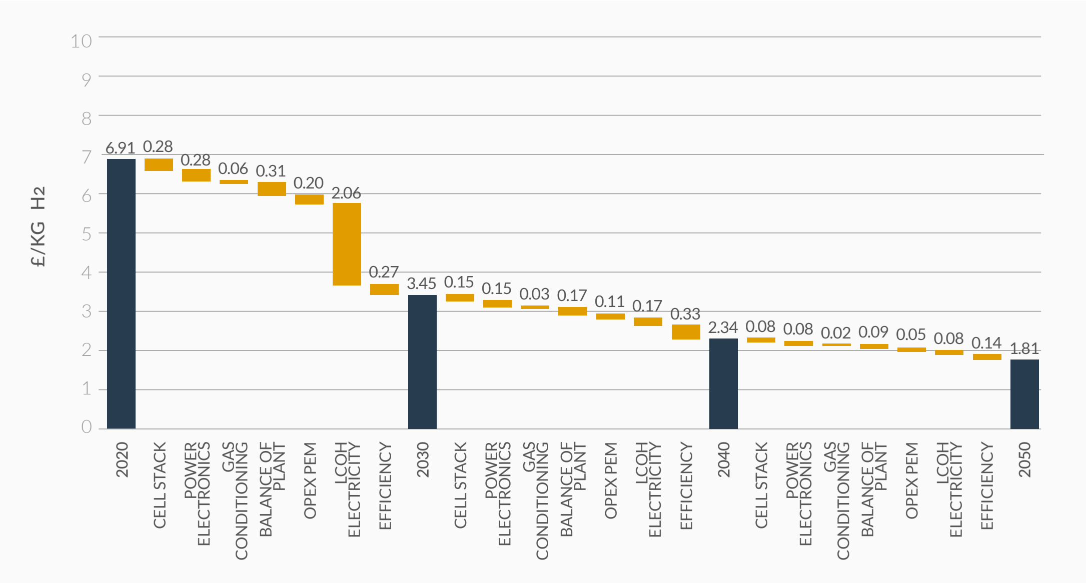
Bottom-fixed wind ongrid-onshore PEM electrolysis:



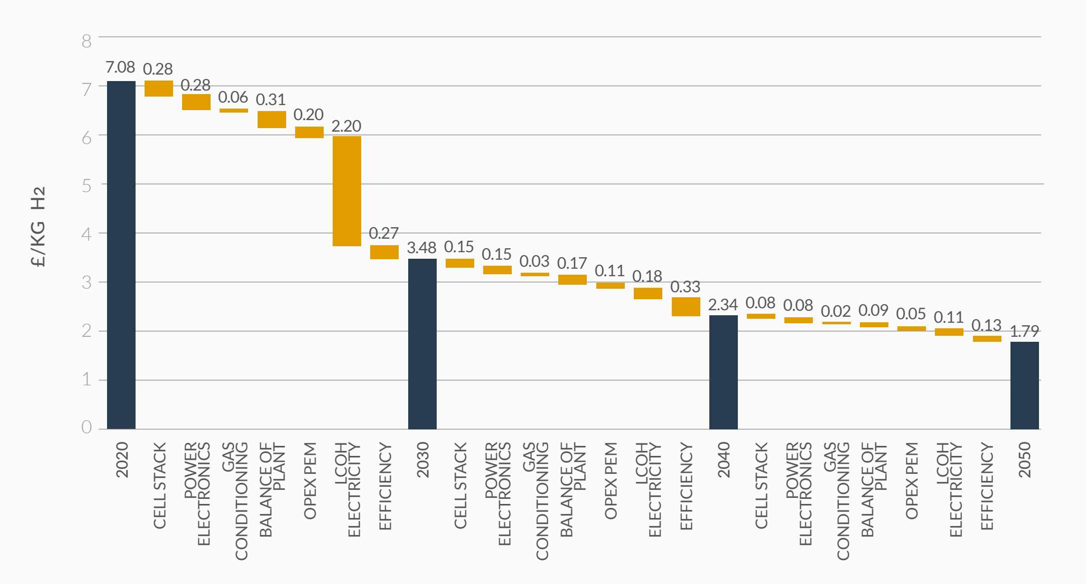
Bottom-fixed wind offgrid-offshore PEM electrolysis:



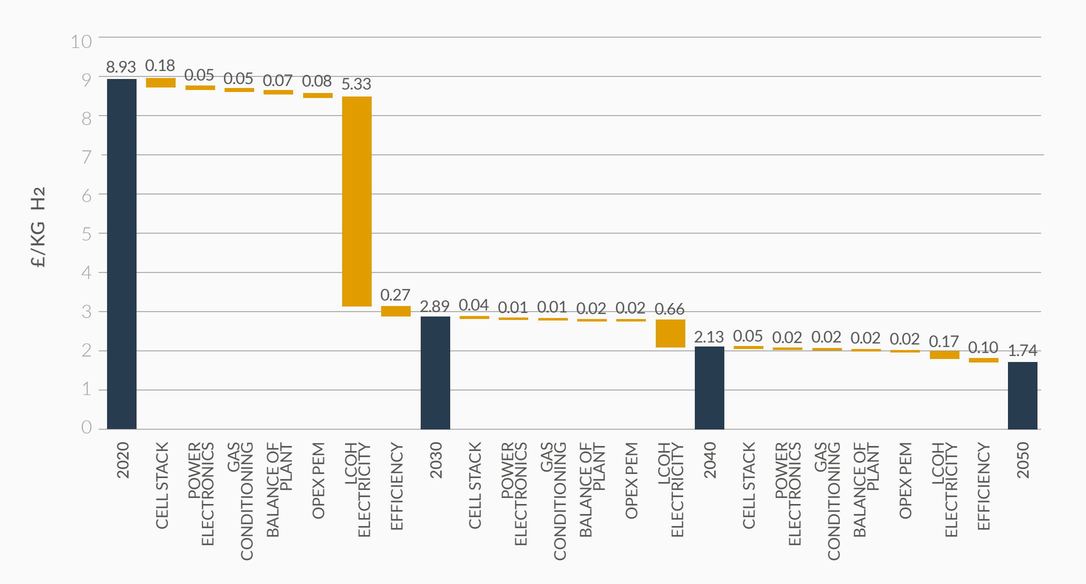
Bottom-fixed wind ongrid-onshore SOEC electrolysis:



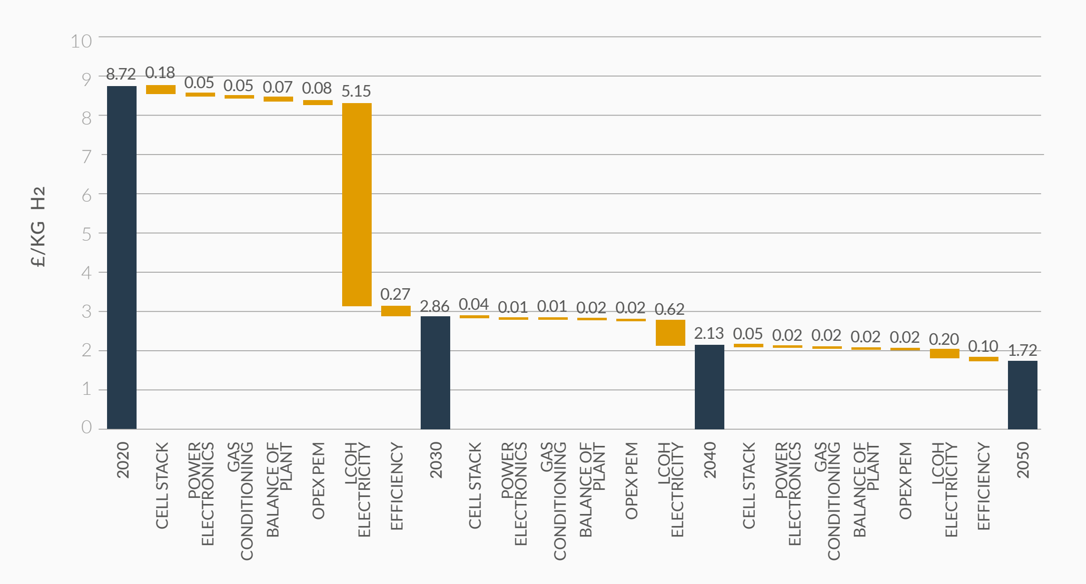
Bottom-fixed wind offgrid-offshore SOEC electrolysis:



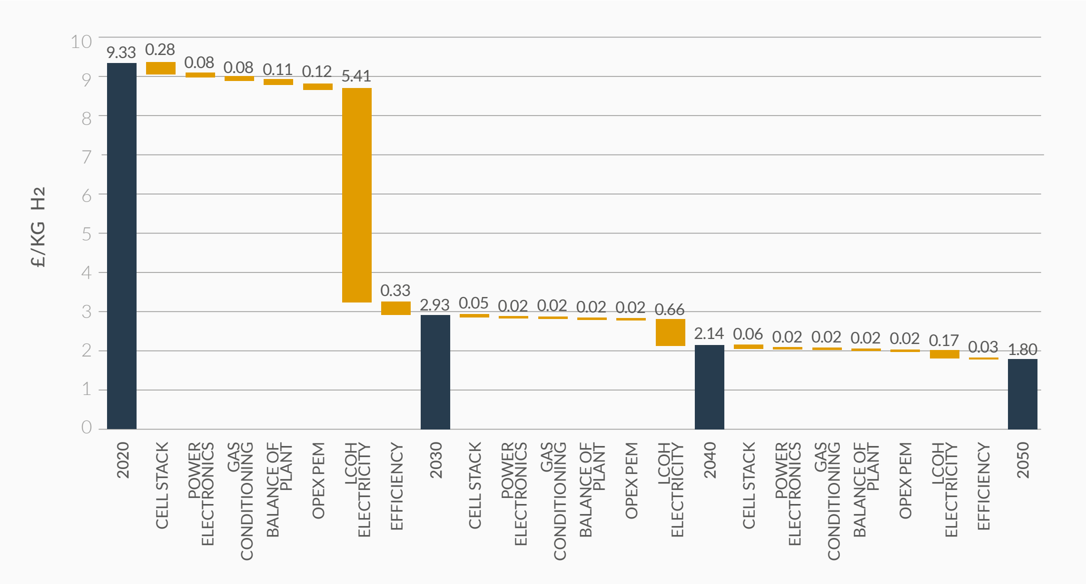
Floating wind ongrid-onshore AEL electrolysis:



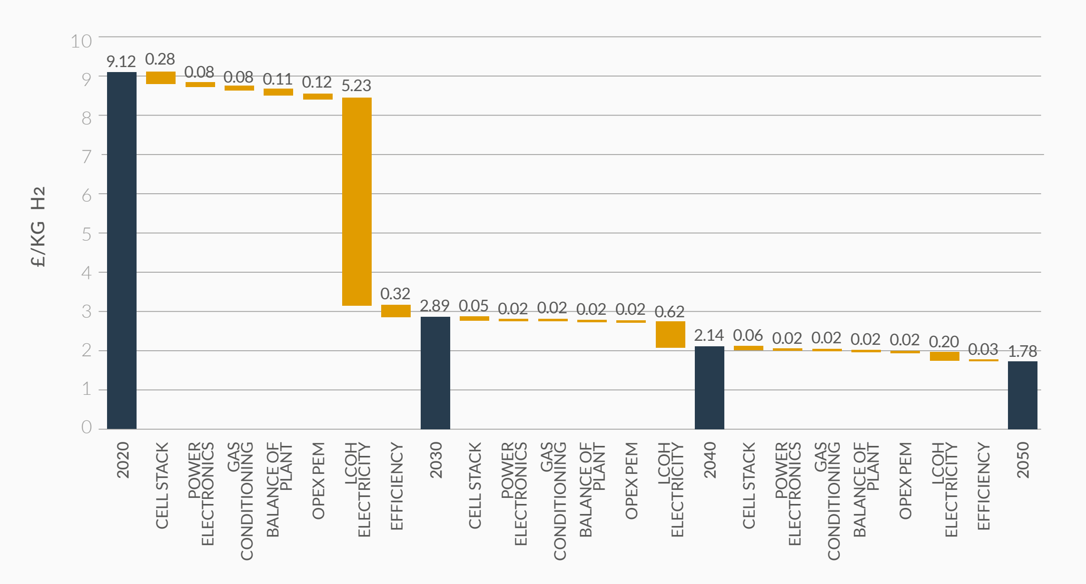
Floating wind offgrid-offshore AEL electrolysis:



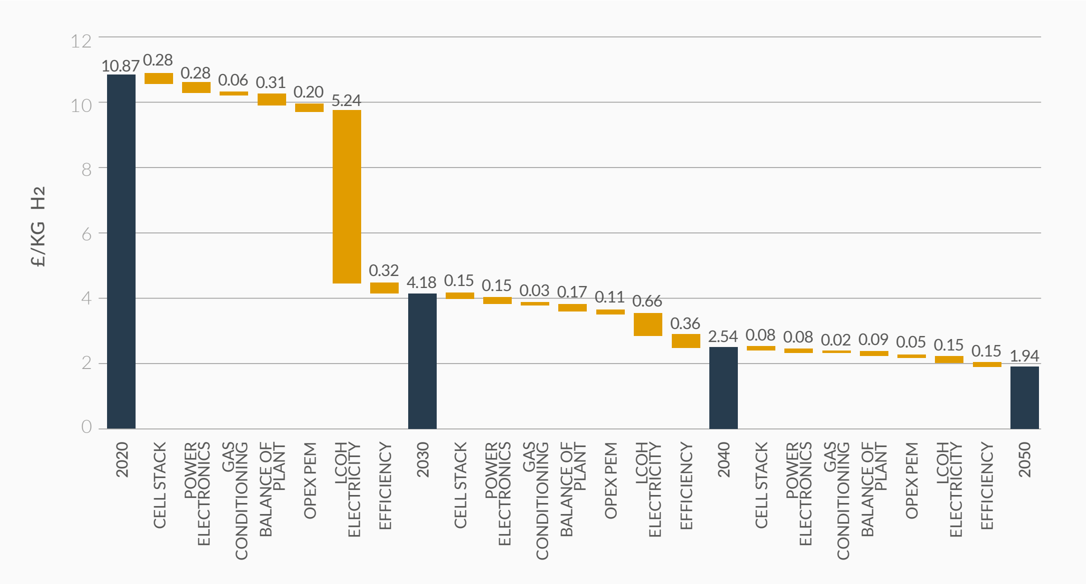
Floating wind ongrid-onshore PEM electrolysis:



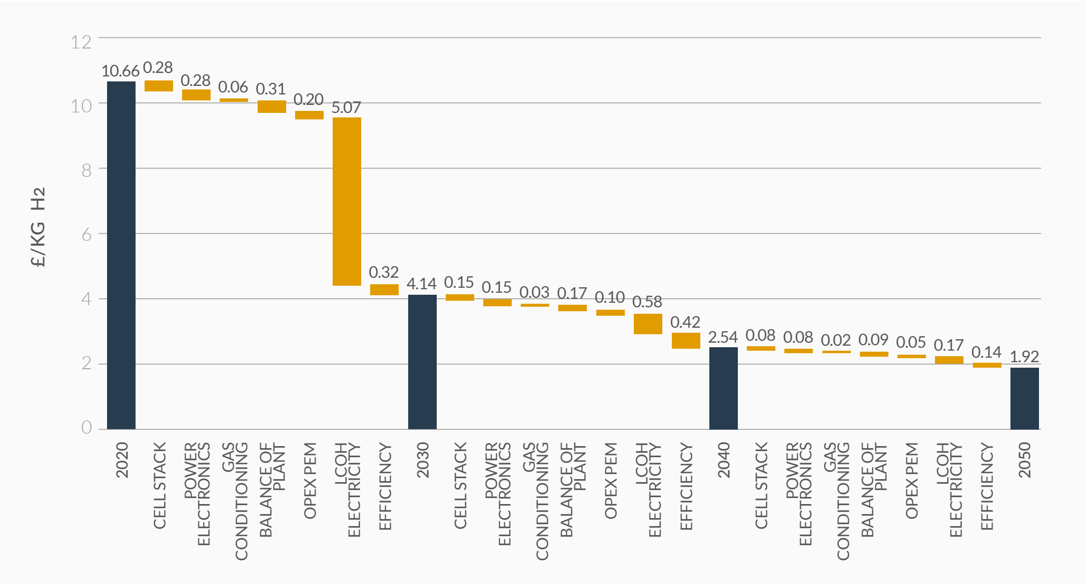
Floating wind offgrid-offshore PEM electrolysis:



Floating wind ongrid-onshore SOEC electrolysis:



Floating wind offgrid-offshore SOEC electrolysis:



NEW OFFSHORE PIPELINE AND PLATFORM COST

Cost of offshore natural gas lines was found to have reduced from more than $100,000/in.-km to around $25,000 to $40,000/in.-km. For the calculation of offshore hydrogen pipe CAPEX per km, a cost of $40,000/in.-km ($37,360/in.-km in 2012 prices) was assumed for a 22.7-inch diameter pipe and actual throughput of 121,318 tonnes H_2 per year. A slight 1% cost reduction per year was considered to include any improvements in installation practices or industrialisation methods. Most transmission gas pipelines operate at pressures of more than 60 bar, and some operate as high as 125 bar. The pressure of the offshore hydrogen pipe was assumed 80bar. Higher pressure requires larger and thicker pipes, larger compressors, and higher safety standards, all of which substantially increase the capital and operating expenses of a system. OPEX/CAPEX ratio for offshore pipeline was assumed 3%.

The capital cost of new platform(s) is based on experience from substation design and construction in OSW. The cost was assumed £220/kW (2012 values) for an HVDC self-installation system (exc. electricals assumed 38% of total cost) with a topside weight of average between 12,000 and 18,000 tonnes. In the offgrid scenario, the platform(s) is expected to accommodate the AC-DC converter, the water desalination system, the electrolysers, the hydrogen compressor and the standby battery. For the electrolysers a vertical stacking was considered (8m2/MW) as the most cost-effective approach for future application although this is still in the R&D phase. Annual OPEX of HVDC platform was assumed to £2.5/kW.

Sources:

- Natgas.info http://www.natgas.info/gas-information/what-is-natural-gas/gas-pipelines
- TCE Guide to OSW farm https://www.thecrownestate.co.uk/media/2861/guide-to-offshore-wind-farm-2019.pdf

STANDBY POWER/BATTERY

In the ongrid and offgrid scenario a standby battery was added to store any excess electricity produced from the OSW farm. The CAPEX was assumed equal to £529/kW of battery based on an onshore battery cost of £1.06m (2012 adjusted) with 2.3MWh capacity from Total. “Global assumptions” of Everoze and Crown Estate Scotland analysis on tidal power integration assume a half cost of £250k/MWh in 2017 (£233k/MWh in 2012) but this cost was considered optimistic. In addition, considering that batteries are not currently widely installed in OSW, the capacity of the Hywind “Batwind” project was used as an assumption to estimate the required battery capacity of these scenarios. Hywind has installed a 1.2MW (1.3MWh) battery corresponding to 4% of the total nominal capacity of the windfarm (30MW). This percentage was adopted for the ongrid scenario as a provision for the case when the excess electricity cannot be directed to the grid or to the electrolyser. If no battery is used in this scenario then the spillovers should be handled by other system flexibility measures such as electricity interconnectors to Europe. The required capacity was calculated to 48MW with CAPEX cost of £21/kW following a linear extrapolation. For the offgrid scenario, the remaining capacity from the 90% ratio of electrolyser to windfarm is assumed to be covered from a battery storage. This is estimated to £52.7/kW for a 120MW battery. The optimal electrolyser/wind farm capacity ratio will increase as CAPEX costs of electrolyser technology would come down and decrease if compensation costs for curtailed wind power would decline further and/or power prices would increase. The cost of batteries is high; however, this was gradually decreased by 3% annually for the analysis accounting for any effect from economies of scale. OPEX was assumed to a constant 2.5% of the CAPEX.

Sources:

- https://www.total.com/media/news/press-releases/total-build-largest-battery-based-energy-storage-project-france
- https://www.windpowermonthly.com/article/1486312/equinor-installs-batwind-battery
- https://renewablesnow.com/news/equinor-masdar-deploy-floating-wind-power-storage-system-in-scotland-617849/
- Everoze & Crown Estate Scotland 'OFFSHORE GENERATION, ENERGY STORAGE & SYSTEMS FEASIBILITY STUDY'
- https://pdfs.semanticscholar.org/39e6/60db8aca8f7dbf5c10cac9f63767d5fbdddd.pdf
- https://atb.nrel.gov/electricity/2019/index.html?t=st

SYSTEM COMPONENTS

System Component	Learning Rate
Hydrogen compressor	15%
AC cable to platform (A)	5%
Risers and gathering	14%
Central electrolyser platform (Offshore)	7.5%
Sea-water lift	10%
Water desalination	20%
Offshore AC-DC converter	10%

Sources:

- DNV GL (2018) 'Hydrogen as an energy carrier', https://www.dnvgl.com/publications/hydrogen-as-an-energy-carrier-135922
- Caldera Upeksha, Breyer Christina (2017), 'Learning Curve for Seawater Reverse Osmosis Desalination Plants: Capital Cost Trend of the Past, Present, and Future', https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2017WR021402
- ORE Catapult (2019) Feasibility Study of Large Scale Hydrogen Production from Offshore Wind in the UK
- https://www.sciencedirect.com/science/article/pii/S096014811630043X#fig3
- https://www.sciencedirect.com/science/article/pii/S0360319919320841

HYDROGEN END USES

The transmission and distribution of hydrogen to end users was calculated using the IEA hydrogen model looking at pipeline and storage cost in buildings as well as cost of refuelling stations.

TRANSMISSION

Technology	Parameter	Units	Hydrogen	LOHC	Ammonia	References
Pipelines*	Lifetime	years	40	-	40	
	Distance	km	Function of supply route			
	Design Throughput (Q)	ktH2/y	GH2: 340	800	240	
	Actual Throughput (Q)	ktH2/y	GH2: 260	620	180	
	Pressure in	bar	100	-	-	
	Internal diameter	cm	35	-	-	
	Gas velocity	m/s	15	-	-	Baufume (2013)
	Capex/km	Million USD/km	1.21	2.32	0.55	Baufume (2013)
	Utilization rate	%	75%	75%	75%	
Liquefaction	Installed capacity	ktH2/y	260	-	-	IAE (2019)
	Capacity capex	Million USD	1 400		-	
	Annual opex	% of capex	4%	-	-	
	Electricity use	kWh/kg H2	6.1	-	-	
Conversion**	Installed capacity	kt_{Tol}/y	-	4 200	-	IAE (2019)
	Plant capex	Million USD		230	-	
	Annual opex	% of capex	-	4%	-	
	Electricity use	kWh/kg H2	-	1.5	-	
	Natural Gas use	kWh/kg H2		0.2		
	Start-up toluene	kt	-	260	-	
	Toluene cost	USD/t	-	400	-	
	Toluene markup	kt/y	-	99	-	
	Start-up Tol. Cost	Million USD	-	104	-	
Export Terminal	Capacity/tank	t_{liquid}	3,190	51,750	34,100	IAE (2019)
	No of tanks		Based on days of storage needed for a given ship loading frequency			
	Capex/tank	Million USD	290	42	68	
	Annual opex	% of capex	4%	4%	4%	
	Electricity use	kWh/kg H2	0.61	0.01	0.005	
	Boil off rate	%/day	0.1%	-	-	
	Flash rate	%	0.1%			
Seaborne Transport***	Capacity/ship	$t_{liquid\ carried}$	11,000	110,000	53,000	IAE (2019), ETSAP
	Capex/ship	Million USD	412	76	85	
	Ship speed	k/h	30	30	30	
	No of ships used		Function of distance			
	Annual opex	%	4	4	4	
	Fuel use	MJ/km	0	3,300	2,500	IMO (2014)
	Boil off rate	%/day	0.2%	-	-	
	Flash rate	%	1.3%	-	-	

Technology	Parameter	Units	Hydrogen	LOHC	Ammonia	References
Import terminal	Capacity/tank	**tliquid**	5,680	61,600	56,700	IAE (2019)
	No. of tanks	**#**	Based on 20 days of storage capacity			
	Capex/tank	**Million USD**	320	35	97	
	Electricity use	**kWh/kg H_2**	0.2	0.01	0.02	
	Boil off rate	**%**	0.1	-	-	
Reconversion ****	Capacity	**kt_{Tol}/y or kt_{NH3}/y**	-	4 200	1 500	IAE (2019)
	Capacity capex	**Million USD**	-	670	460	
	Annual opex	**% of capex**	-	4%	4%	
	Heat required	**kWh/kg H_2**	-	13.6	9.7	
	Plant power	**kWh/kg H_2**	-	0.4	-	
	H_2 Purification (PSA) power	**kWh/kg H_2**	-	1.1	1.5	
	H_2 recovery rate	**%**	-	90%	99%	
	PSA H_2 recovery rate	**%**	-	98%	85%	

Notes: System life-time assumed to be 30 years, unless stated otherwise; discount rate = 8%; utilisation of production, conversion and reconversion capacity = 90%.

*Hydrogen pipeline transmit hydrogen gas, with Capex (USD/km) = 4,000,000D^2 + 598,600D + 329,000 (Baufume, 2013), where Internal Diameter D (cm) = SQRT(F/V)/p*2*100 , Volumetric Flow F (m3/s) = Q/r, V=Gas Velocity (m/s), throughput Q=mass flow rate (kg/s), gas density r (kg/m3) based on real gas law.

**Conversion: LOHC = Toluene +H_2 à MCH; for ammonia conversion (synthesis) data-set, see table on ammonia for 2030 above.

*** Ship carrying liquid hydrogen uses boil-off gas for propulsion, LOHC and ammonia ship uses heavy fuel oil.

****Reconversion: LOHC = MCH à Toluene + H_2; Ammonia = NH_3 à N_2 +H_2.

Sources:

- Baufume, S., Gruger, F., Grube, T., Krieg, D., Linssen, J., Weber, M., Hake, J-F., Stolten, D., GIS-based scenario calculations for a nationwide German hydrogen pipeline infrastructure, International journal of hydrogen energy 38 (2013) 3813-3829, http://dx.doi.org/10.1016/j.ijhydene.2012.12.147
- ETSAP (2011), LOHC Ship Cost from: Oil and Natural Gas Logistics https://iea-etsap.org/E-TechDS/PDF/P03_oilgaslogistics_PS_revised_GSOK2.pdf
- IAE (2019), Institute of Applied Energy (Japan) data based on revisions from Economical Evaluation and Characteristic Analyses for Energy Carrier Systems (FY2014-FY2015) Final Report, 2016. Also presented in: Y. Mizuno et al., Economic analysis on International Hydrogen Energy Carrier Supply Chains, Journal of Japan Society of Energy and Resources, Vol. 38, No.3. p.11.
- IMO (2014), Third IMO Greenhouse Gas Study 2014, Online PDF file

DISTRIBUTION

Technology	Parameter	Units	Hydrogen	LOHC	Ammonia	References
Pipelines *	Lifetime	years	40	40	40	
Pipelines (high pressure)	Pressure in	bar	80	-	-	
	Distance	km	End-use case dependent			
	Design Throughput (Q)	kt/y	GH_2:38	-	-	
	Actual Throughput (Q)		GH_2:36	-	-	
	Pressure in	bar	80	-	-	
	Internal Diameter	cm	13	-	-	
	Gas velocity	m/s	15			
	Capex	Million USD/km	0.5	1	0.25	Baufume, 2013
Pipelines (low pressure)**	Distance	km	3	3	3	
	Design Throughput (Q)	t/y	GH_2: 365	-	-	
	Pressure in	bar	7	-	-	
	Internal Diameter	cm	3			
	Gas velocity	m/s	15	-	-	
	Capex/km	Million USD/km	0.3			
Trucks***	Depreciation period	years	12	12	12	Reuß (2017)
	Capex	Thousand USD	185	185	185	
	Annual opex	% of capex	12	12	12	
	Speed	km/h	50	50	50	
	Driver cost	USD/h	23	23	23	
Trailers	Depreciation period	years	12	12	20	Reuß (2017)
	Capex	Thousand USD	LH_2: 1 000 GH_2: 650	170	220	
	Annual opex	% of capex	2%	2%	2%	
	Net capacity	kg H_2	LH_2: 4300 GH_2: 670	1800	2600	
	Loading/unloading time	hrs	LH_2: 3 GH_2: 1.5	1.5	1.5	
H_2 refuelling stations****	Station lifetime	yrs	10	10	10	Reuß (2019)
	Station size (Z)	kg/day	1000	1000	1000	
	Capex (for size Z)	Million USD	LH_2:2.0 GH_2: 2.2	3.5	2.2	
	Opex as % of capex	%	5%	5%	5%	
	Electricity demand	kWh/kg H_2	LH_2:0.6 GH_2: 1.6	4.4	10.8	
	Heat demand	kWh/kg H_2	0	13.6	0	
	Boil off	% of total weight	LH_2: 3% GH_2: 0.5%	0.5%	1.5%	
	Utilisation rate	%	50%	50%	50%	

Notes: LH_2 = liquid hydrogen; GH_2 = hydrogen gas.

*Hydrogen pipeline transmit hydrogen gas, with Capex (USD/km) = 3,400,000D2 + 598,600D + 329,000 (Baufume, 2013), where Internal Diameter D (m) = SQRT(F/V)/p*2, Volumetric Flow F (m3/s) = Q/r, V=Gas Velocity (m/s), throughput Q=mass flow rate (kg/s), gas density r (kg/m3) based on real gas law.

**Pipeline with lower throughput to hydrogen refuelling stations, taking partial flow from high pressure distribution pipe.

*** Journey distance doubled to account for journey time and fuel cost calculations, and loading time for LOHC should be doubled for Toluene being returned to site of origin

****H_2 Refuelling station with decentralised re-conversion technology in the case of LOHC and ammonia. Capex for large fuel cell station (size Z) scaled up from small size reference station receiving compressed hydrogen gas: Capex = X*Y*g(Z/a)b, where X=reference station cost (EUR 600,000) for reference station size (a = 210 kg/day), with Installation factor Y=1.3, scaling factor b = LH_2: 0.6, GH_2: 0.7, LOHC: 0.66, Ammonia: 0.6; Station multiplier g = LH_2: 0.9, GH_2: 0.6, LOHC: 1.4, Ammonia: 1.4.

Sources:

- Reuß, M., Grube, T., Robinius, M., Preuster, P., Wasserscheid, P. and Stolten, D., Seasonal storage and alternative 0fcarriers: A flexible hydrogen supply chain model, Applied Energy 200 (2017) 290–302, http://dx.doi.org/10.1016/j.apenergy.2017.05.050
- Reuß, M., Grube, T., Robinius, M., Stolten, D., A hydrogen supply chain with spatial resolution: Comparative analysis of infrastructure technologies in Germany, Volume 247 (2019) 438-453, https://doi.org/10.1016/j.apenergy.2019.04.064

SMR & ATR WITH CO2 CAPTURE (2050)

Parameter	Units	H2 from SMR + CO2 Capture	H2 from ATR + CO2 Capture
Design life	years	25	
Construction time	years	3	
OPEX/CAPEX	%	3.0%	5.2%
H2 output	MW H2	300	
CAPEX	£/kW H2 (2012)	1477	1009
OPEX	£/kW H2 (2012)	45	52
Availability	%	90%	95%
Synthesis yield	Assumed	100%	
Electricity output	GJelec/GJH2	0.5%	
Efficiency (LHV)	GJH2/GJgas	64%	79%
CO_2 capture rate	%	90%	97%
CO_2 Emissions	kg CO_2/kg H2	10.4	8.5

The gas cost in 2050 was assumed to £23/MWh, the CO2 emissions cost £32/t CO2 and CO2 transport and storage cost £15/t CO2 in 2012 prices.

Sources:

- IEAGHG Technical Report 2017-07 (August 2017), CCS Deployment in the Context of Regional Developments in Meeting Long-Term Climate Change Objectives https://ieaghg.org/exco_docs/2017-07.pdf
- BEIS Hydrogen Supply Programme HyNet Low Carbon Hydrogen Plant Phase 1 Report for BEIS https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866401/HS384_-_Progressive_Energy_-_HyNet_hydrogen.pdf

A

APPENDIX 2 OVERVIEW OF HYDROGEN PROJECTS IN THE UK

An overview of hydrogen projects in decarbonising mobility sector:

	Name	Location	Output	Funding value	Leader
1	Towards commercial deployment of FCEV buses and hydrogen refuelling	Aberdeen Liverpool	1 station 30 buses	£6.4m	BOC
2	Hydrogen Mobility Expansion Project II	Crawley	1 station 51 cars	£3.1m	Element Energy
3	Northern Ireland Hydrogen Transport	Belfast	3 buses	£2.0m	Viridian Energy Supply Wrightbus
4	Tees Valley Hydrogen Transport Initiative	Middlesbrough and Stockton on Tees	2 stations 5 cars	£1.3m	Tees Valley Combined Authority
5	Riversimple Clean Mobility Fleet	Monmouthshire	17 cars	£1.3m	Riversimple
6	HydroFlex – fitting a hydrogen pack to an existing Class 319 train set	Birmingham	1 train	Confidential	Porterbrook BCRRE
7	HySeas III	Orkney	1 ferry	Confidential	Ferguson Marine Engineering
8	HyFlyer	Orkney	1 medium range small passenger aircraft	£5.3m	Zeroavia EMEC
8	Alstom H2 Breeze - conversion of existing Class321 trains for the UK market. Available in 2022[58].	n/a	Series of trains	Confidential	Alstom Eversholt Rail

58 http://www.ukh2mobility.co.uk/news-media/announcement/alstom-and-eversholt-rail-unveil-a-new-hydrogen-train-design-for-the-uk/

An overview of hydrogen projects in decarbonising gas network:

	Name	Description	Location	Funding value	Partners
1	Hy4HEat	Study to establish technical and safety feasibility of 100% hydrogen residential gas supply	TBC	£25m	ARUP Kiwa
2	H21	Projects designed to support conversion of the UK gas networks to carry 100% hydrogen	Leeds (Yorkshire)	£10m	Cadent Northern Gas Networks SGN
3	HyDeploy 1 & 2	Energy trial to demonstrate the injection of (up to 20%) hydrogen into the public gas network	Keele & North of England	£22.1m	Cadent ITM Power
4	H100 feed study	Project to trial a 100% hydrogen residential gas supply	Levenmouth	£2m	SGN ORE Catapult
5	Energy Kingdom	Whole energy systems feasibility study to trade flexibility across electricity, NG and hydrogen, heat (hybrid heat pumps) and transport	Milford Haven	£2m	Pembrokeshire City Council ORE Catapult Riversimple
6	BIG HIT	Demonstrating Orkney Islands as a replicable Hydrogen Territory, using curtailed renewable energy generated locally to produce hydrogen.	Orkney	£5m	EMEC ITM Power

An overview of hydrogen projects in industrial sector:

	Name	Description	Location
1	Scotland's Net Zero Infrastructure	CCS project that will link industrial emitters around Grangemouth, with a pipeline to St Fergus.	Scotland
2	Net Zero Teesside Project	CCUS project that aims to decarbonise a cluster by 2030.	Teesside
3	Humber Industrial Decarbonisation Deployment Project	It will identify and develop potential anchor projects to maximise emission reductions and develop industrial CO2 transport and storage system.	Humber
4	HyNet CCUS	Part of HyNet projects that will provide the infrastructure to transport and store the CO2 produced as a by-product of the hydrogen production process.	North West
5	South Wales Industrial Cluster	SWIC will identify process options to reduce carbon emissions and options for CCUS.	South Wales
6	Green Hydrogen for Humber	It will lead to the production of renewable hydrogen, at the GW scale, from PEM electrolysis. This will be distributed to a mix of industrial energy users in Humberside.	Humberside

An overview of hydrogen projects in industrial sector:

	Name	Description	Sectors	Funding value	Partners
7	HyNet North West	Testing a range of hydrogen industrial use opportunities across the North West and developing a hydrogen CHP	Glass Beauty Refinery	£5.2m	Progressive Energy Pilkington Unilever
8	State-of-the-art fuel mix for UK cement production to test the path for net zero	Testing switching UK cement production to operate on low carbon fuels including hydrogen, biomass and electrification	Cement production	£3.2m	Mineral Productions Association
9	Alternative fuel switching technologies for the glass sector	Trialling the potential for the glass sector to use alternative fuels (electric, hydrogen, biofuel and hybrid-fuel melting technologies)	Glass	£7.1m	Glass Futures Ltd
10	Hydrogen Alternatives to Gas for Calcium Lime Manufacturing	Testing the use of hydrogen in the high calcium lime manufacturing, servicing markets like iron or steel manufacturing.	Iron Steel	£2.8m	British Lime Association

An overview of hydrogen projects in production sector:

	Name	Description	Location	Funding value	Partners
1	HyNet 1 & 2	Development and deployment of low carbon hydrogen plant which enables CCS	Liverpool Bay area	£7.5m	Cadent Progressive Energy
2	Dolphyn	Detailed design of a 2MW prototype system to enable the production of hydrogen at scale from offshore floating wind	Aberdeen	£3.1m	ERM
3	Gigastack	Feed study of PEM electrolyser using electricity from OSW farm to generate hydrogen for refinery	Grimsby	£7.5m	ITM Power, Orsted, Humber Refinery
4	Acorn Hydrogen Project	FEED study to develop an advanced reformation process for hydrogen production from North Sea Gas using CCS	Aberdeen	£2.7m	Production CCS
5	HyPER	Build a 1.5MW pilot scale demonstration of the sorption enhanced steam reforming process to supply hydrogen	Cranfield	£7.4m	Cranfield University GTI
6	Surf 'N' Turf	Tidal power devices and community-owned onshore wind turbine route their surplus electricity to a 500kW electrolyser.	Orkney	£1.46m	Community Energy Scotland, EMEC, ITM Power

A APPENDIX 3 OVERVIEW OF HYDROGEN GENERATION TECHNOLOGIES

I HYDROGEN PRODUCTION TODAY

Hydrogen is a key feedstock in many industries such as ammonia production and in steel working industries. Most hydrogen in the UK (96%)[59] is produced through SMRs. Most hydrogen production is therefore centralised around four main locations in the UK (Pembroke, Humber region, Cheshire and north east Scotland) and distribution in the UK is limited to fuel tankers.

Large-scale distribution of hydrogen for a low carbon economy would require the use of hydrogen within existing gas networks and in the transport sector. This requires not only a large uptick in the production of hydrogen using green methods but also the upgrade of gas and distribution networks.

The UK government is moving towards a more distributed hydrogen economy, with five new hydrogen production plants proposed equalling £28m of investment[60]. This is part of the wider BEIS industrial strategy towards a greener economy. The five projects are a mixture of green hydrogen through the electrolysis of water, or blue hydrogen through steam methane reforming with carbon capture.

Most of the hydrogen produced today is derived from methane (natural gas) in one of the UK's seven refineries. The three main methods are through steam methane (using water as the oxidant and source of hydrogen), partial oxidation (using air as the oxidant), or through autothermal reforming. The current cost of hydrogen using SMR is between £1.3 and £1.9/kg H_2. The lower range are for systems with a low gas cost and no CCS process, and the upper cost is for high gas prices and including CCS.

There are other ways to generate hydrogen without the use of a fossil fuel as a feedstock, such as gasification of biomass, or electrolysis from water and electricity. Technology costs and efficiencies vary depending on the scale and technology type, but the table below gives an outline of hydrogen production and the relative costs of each pathway. While relative costs of electrolyser technology are high today, the falling costs of electricity with the increase of renewables, along with falling costs associated with technology scale, will make hydrogen markets increasingly competitive through the next decade[61].

Fuel	Technology	Carbon Emissions	Relative Cost
Natural Gas/ Oil	SMR, ATR, Partial oxidation	High (without CCS) Low (with CCS)	Low Medium
Coal	Fuel Gasification	High	Medium
Biomass	Fuel Gasification	Medium	Medium
Electricity	Electrolysis	Medium	High
Renewable Electricity	Electrolysis	Low	Medium

59 Hydrogen production share in the UK by method 2019 (sourced on statista.com)
60 BEIS strategy 18 Feb 2020: www.gov.uk/government/news/90-million-uk-drive-to-reduce-carbon-emissions (accessed 25/02/2020)
61 The Future of Hydrogen, IEA report 2019

II ELECTROLYSER TECHNOLOGIES

Commercially available electrolyser technologies tend to come in two main types: AEL and PEM which is a new commercially available offering. Other, less commercially mature technologies such as solid oxide electrolysers have promise, but are unlikely to be commercially competitive in the next 10 years. The following table compares the two technologies, at current levels and in 2025[62].

Technology		AEL		PEM	
	unit	2017	2025	2017	2025
Efficiency	kWh electricity/ kg H_2	51	49	58	52
Efficiency (LHV)	%	65	68	57	64
Response time	H/M/L	H	M	M	H
Lifetime operation	Operating hours	80,000	90,000	40,000	50,000
CAPEX	EUR/kW	625	400	1000	585
OPEX	% of CAPEX/ year	2	2	2	2
Stack replacement cost	£/kW	285	180	350	175
Typical Output pressure	Bar	1	15	30	60
System Lifetime	Years	20		20	

III PROTON EXCHANGE MEMBRANE ELECTROLYSIS

Polymer electrolyte membrane, or PEM electrolysers, submerge a cathode and anode into an H_2O solution with a solid polymer barrier that is responsible for the conduction of protons (H+). This allows for the production of oxygen on the anode side and the production of H_2 gas on the cathode side.

A COMMERCIAL VIABILITY

PEM electrolysis at commercial scale is around five years away, with only small-scale deployment currently available. As such, the current costs and lifetime replacements associated with PEM technologies is higher than other types of electrolysis. However, the typical output hydrogen for PEM electrolysers are high density, high purity hydrogen. This is useful for long term and cheaper storage of hydrogen. In addition, PEM electrolysers operate at high current densities, and their efficiencies, especially in fluctuating conditions, can be high (over 60% in some cases).

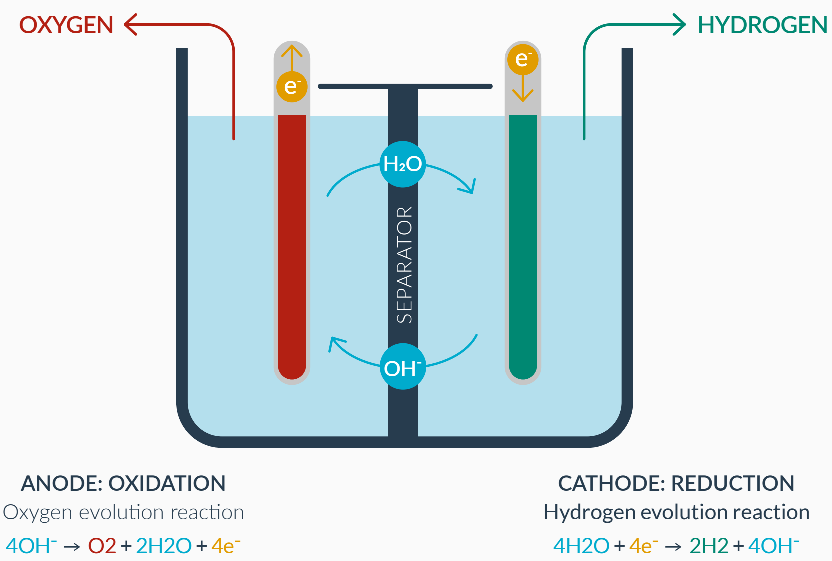
[62] Hydrogen production via electrolysis, 2017

B APPLICABILITY TO OFFSHORE WIND

The main appeal of PEM electrolysis over AEL technologies is the demand response applications of PEM technologies. Their ability to perform well not only in fluctuating conditions, but also in partial or overloaded conditions make them an attractive option when combined with renewable electricity sources.

IV ALKALINE ELECTROLYSIS

Alkaline water electrolysis produces hydrogen from having two electrodes in a liquid alkaline electrolyte solution. The electrodes are separated by a diaphragm, which transports the hydroxide (OH) from one electrode to the other (as shown below):



A COMMERCIAL VIABILITY

AEL has been the main industrial scale electrolysis for nearly a decade. For this reason, it is well understood as the most commercially advanced form of electrolysis. AEL have certain advantages over PEM technologies such as: cheaper catalysts; higher durability due to an exchangeable electrolyte; and higher gas purity due to lower gas diffusivity in alkaline electrolyte.

B APPLICABILITY TO OFFSHORE WIND

The technology works most efficiently under high, steady electricity flow. Disruptions to the flow can reduce the efficiency by over 20% while also reducing the lifetime of important components like the anodes. Most electrolysis systems have an inherent ‘inertia’ in which they take time to respond to changes in power. This is most pronounced in alkaline water technologies, which has slow starting times, and so would therefore not be wholly suitable for being used to generate hydrogen from fluctuating electricity sources like wind energy.

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APPENDIX 4
LIST OF HYDROGEN STAKEHOLDERS

Stakeholder Category	Stakeholder	Location
Hydrogen production and supply chain	Aragon Hydrogen Foundation	International
	Arcola Energy LTD	National
	AREVA H2Gen	International
	Ballard Fuel Cells	National
	Boc	National
	Bright Green Hydrogen	Fife
	Calvera	International
	Ceimig	Dundee
	Cenex	East Midlands
	Ceres power	West Sussex
	Enocell	Bo'Ness
	Fuel Cell Systems	Berkshire
	ITM Power	Sheffield
	Linnet Technology	Stirling
	Logan Energy	Edinburgh
	NanoSUN	Lancashire
	Pale Blue Dot	Aberdeenshire
	Proton Motor GmbH	International
	Proton Onsite	International
	Pure Energy Centre	Shetland
	Taylor Construction	National
	Vivarail	Humber Region
Hydrogen transmission	Air Products	Surrey
Refineries/SMRs	Fawley Exxon	Southampton
	Grangemouth Petrolneos	Central Belt
	Killingholme Phillips	Humber Region
	Lindsey Total	Humber region
	Pembroke Valero	Pembrokeshire
	Stanlow Essar	Cheshire
End User	Hydrogen Fuel Cell Association	National
Storage	Chesterfield special cylinders	Chesterfield
	EDF	National
	Equinor	National
	Scottish Power	Scotland
	SSEHL	Humber Region
	Storenergy	Cheshire
	Uniper	East Midlands

Stakeholder Category	Stakeholder	Location
Industrial Groups	Aberdeen Renewable Energy Group	Aberdeenshire
	British hydropower Association	National
	Hydrogen London	London
	HySAFE	International
	North West Hydrogen Alliance	North West
	The hydrogen Group	National
Policy and decision makers	BEIS	London
	Fife Council	Fife
	HIE	Scottish Highlands
	Orkney Islands Council	Orkney
	Scottish Enterprise	Scotland
Relevant Skills (eg O&G)	Anglo American	London
	BP	National
	British Geological Survey	National
	Caledonian Maritime Assets	Scotland
	DEME	National
	Johnson Matthey	National
	OGTC	Abderdeenshire
	Shell	National
	SPR	Glasgow
	SSE	Glasgow
Gas network	Cadent	
	Express Pipework Systems	
	Phoenix Natural Gad	NI
	Scotia Gas	
	SGN	
	Thyson	
	Wales and West Utilities	
Natural Gas production (onshore pipeline)	Bacton	North Norfolk
	Barrow	Cumbria
	Easington	East Yorkshire
	St Fergus	Aberdeenshire
	Theddlethorpe	East Lindsey
Academia	Edinburgh Napier University	Edinburgh
	ESP	Stirling
	Heriot Watt University	Edinburgh
	St Andrews University	St Andrews
	University College London	London
	University of Edinburgh	Edinburgh
	University of Strathclyde	Glasgow
Testing and R&D	AVL	Midlands (Coventry, Basildon)
	DNV GL	Aberdeenshire
	EMEC	Orkney
	ETC	East Kilbride

Stakeholder Category	Stakeholder	Location
Consultancy and Engineering	Abbott Risk Consulting	Edinburgh
	Anderson Strathern	Edinburgh
	Aquaterra	Orkney
	Arup	National
	Delta-EE	Edinburgh
	E4Tech	London
	Element Energy	London
	Ellis IP	Edinburgh
	Europeam Policy Solutions	Clackmannanshire
	Frazer-Nash Consultancy	Dorking
	Green Hydrogen consulting	Glasgow
	Hydrenor	Aberdeenshire
	ICS	East Midlands
	Kiwa Gastec	Gloucestershire
	Locogen	Edinburgh
	Risktec	National
	Systeng Consulting	Edinburgh
	TUV SUD	National
	ULEMCo	Liverpool
SMEs	Almaas Technologies	Glasgow
	iPower	Stirling
Road transport	Arcola Energy	Huyton
	Intelligent Energy	Loughborough
	Luxfer	Nottingham
	MicroCab	Coventry
	Millbrook	Bedford
	Raffenday EV	
	Riversimple	Powys
Boilers	Baxi Heating	Preston
	Worcester bosch	Worcester

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APPENDIX 5 ASSESSMENT OF R&D PRIORITIES FOR ELECTROLYSERS

SCORING CRITERIA FOR INNOVATION CHALLENGES

Criteria	Explanation	Scores
Cost reduction	How much potential the technology has to reduce the cost of hydrogen	0=None/not applicable 1=Low (<2%) 2=Medium (2-5%) 3=High (>5%)
Durability	How much potential the technology has to increase the durability and lifetime of the electrolyser	0=None/not applicable 1=Low (<2%) 2=Medium (2-5%) 3=High (>5%)
Demand Response	The potential for the technology to improve response time and power output under fluctuating electricity sources. A high score would therefore increase the markets as part of the wider energy system	0=None/ not applicable 1=Small amount of improved response time (<2% improvement) 2=Medium improvement (2-5%) 3=High improvement (>5% improvement).
Technical Risk	How much risk (and time/costs etc.) is involved with bringing the technology to full commercialisation. Early stage developments are higher risk (and lower scoring) and near to market technologies score higher	0=Not applicable 1=High risk (>10 years to full commercial development) 2=Medium risk (3-10 years to full commercial development) 3=Low Risk (<3 years to full commercial development)
Market Value	How much GVA the technology could bring to the UK market. In other words, how big a market is there in the UK for the technology	0=None/not applicable 1=Low (<5 full-time equivalent (FTE)) 2=Medium (5-100 FTE) 3=High (>100 FTE)
Case for Intervention	Whether the technology is an enabler for wider uptake or improved standards in hydrogen production. In the high case for intervention, the industry on its own may hit this roadblock and not move forward without government support either through funding or policy mechanisms	0=None/not applicable 1=Low 2=Medium 3=High
H&S impact	How much the technology might have an improved impact on health and safety, either through the manufacture, operation or removal of hydrogen technologies. Scoring is based on a contribution of this technology to a H&S risk e.g. if a technology will have a small effect on high severity risk (fatality) will be scored as Low. Most technologies that are an interim step to significantly impact HSE, relate to testing or provide an insignificant material saving are scored as n/a.	0=Negative or no impact 1=Small improvements 2= Some improvements 3=Significant improvements

The definitions of “low, medium, high” were kept broad and flexible enough to return scores that were comparable across a wide range of technologies.

INNOVATION CHALLENGE SCORES

The scores below are an average of scores from a selection of assessors, to remove biases in opinion. The broad nature of the types of technology requires comparative scoring and assessment of technology priorities in a range of areas.

Technology	Cost Reduction	Durability	Demand Response	Technical Risk	Market Value	Case for Intervention	H&S impact	Score
PEM Electrolyser								
Anodes	2	3	2	3	2	1	0	**13**
Stable Catalyst support	2	3	3	2	1	1	0	**12**
Improved Catalyst Design	2	2	2	1	2	1	0	**10**
Alternative Catalysts	2	2	2	1	2	2	0	**11**
Bipolar plates	1	1	3	1	2	3	0	**11**
Improved Bubble Removal	2	3	1	2	2	1	0	**11**
MEA Structure modelling	2	1	2	1	1	1	0	**8**
Advanced coating	1	3	1	3	2	1	0	**11**
High volume manufacturing	3	0	1	2	3	2	1	**12**
Large scale cell systems	3	1	1	2	3	3	0	**13**
Thermal management	1	3	2	2	2	2	1	**13**
Advanced membrane materials	3	3	2	1	2	3	0	**14**
Standardisation for testing new catalytic materials and their performance	2	3	3	2	2	3	2	**17**
Water purification	2	1	0	2	2	1	1	**9**
Component Integration	1	3	2	3	1	2	1	**13**
Alkaline Water Electrolysis								
Membranes Research	3	2	2	2	2	3	0	**14**
Hydrogen Evolution	2	1	1	2	1	2	0	**9**
Responsiveness	1	0	3	2	1	2	0	**9**
Enabling higher current densities	2	1	2	3	1	2	0	**11**
Efficient water purification	2	2	0	2	1	1	1	**9**
Hydrogen Drying	2	1	2	1	3	2	2	**13**
Rectification	2	1	1	2	2	1	1	**10**
Lye Circulation	2	3	1	2	1	2	1	**12**
Solid Oxide Electrolysis								
Manufacturing Methods	2	2	0	2	3	3	2	**14**
Scalable Designs	3	0	1	1	3	3	0	**11**
Physical Stability to temperature	2	3	1	2	2	2	1	**13**
Reduction in operating Temperatures	2	3	2	1	3	3	2	**16**
Modular electrolysers	3	1	2	1	3	3	0	**13**
Temperature Resistant materials	2	3	2	2	2	1	0	**12**
Optimised component integration	1	3	2	3	1	2	1	**13**
Reversable systems	1	0	3	1	3	3	1	**12**
Cross cutting								
Large scale cell systems	3	1	2	2	2	2	0	**12**
Data sharing	2	1	2	3	2	1	1	**12**
Advanced materials research	2	2	3	1	2	1	0	**11**
Advanced manufacturing	3	1	0	2	2	2	1	**11**
Test protocols harmonisation	2	1	2	2	1	2	2	**12**
Power Electronics	2	2	2	1	2	1	1	**11**
Gas Conditioning	2	1	1	2	3	3	2	**14**

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ABBREVIATIONS

AEL	Alkaline electrolyser
ATR	Autothermal reforming
B-F	Bottom fixed
BEIS	Department for Business, Energy and Industrial Strategy
BEV	Battery electric vehicle
BNEF	Bloomberg New Energy Finance
CCC	Committee on Climate Change
CCS	Carbon capture and storage
CfD	Contracts for Difference
CTV	Crew Transfer Vessel
DACCS	Direct Air Carbon Capture and Storage
EDI	Energy Delta Institute
ESC	Energy Systems Catapult
ESME	Energy System Modelling Environment
FC	Fuel cell
FC CHP	Fuel cell for combined heat and power
FCEV	Fuel cell electric vehicle
FTE	Full-time equivalent
FW	Floating wind
GHG	Greenhouse gas
GVA	Gross value added
H&S	Health & safety
H2	Hydrogen
HGV	Heavy goods vehicle
HTP	The Hydrogen for Transport Programme
IDC	Industrial decarbonisation challenge
HVAC	High voltage alternating current
IWES	Integrated whole energy system model
LCOE	Levelised cost of energy
LCOH	Levelised cost of hydrogen
LDV	Light duty vehicle
O&G	Oil and gas
O&M	Operation and maintenance
OEM	Original equipment manufacturer
OGA	Oil and Gas Authority
ORE	Offshore Renewable Energy
OSW	Offshore wind
OWIC	Offshore Wind Industry Council
PEM	Proton Exchange Membrane
PV	Photovoltaics
R&D	Research and development
RFTO	Renewable transport fuel obligation
RoW	Rest of World
SMR	Steam methane reforming
SOE	Solid oxide electrolyser
SOEC	Solid oxide electrolyser cell
STFC	Science and Technology Facilities Council
StIC	Solving the Integration Challenge
TRL	Technology readiness level
WACC	Weighted average cost of capital

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