XODUS

THE UK THE GLOBAL HYDROGEN CENTRE

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INTRODUCTION

The UK is ideally placed geographically, technically, financially and politically to be a global low carbon centre, spanning both green and blue hydrogen production. We have an abundance of all the raw materials needed for low carbon hydrogen:

The UK is the windiest country in Europe and best located for green hydrogen production from offshore wind.

The UK has the political will – including the most ambitious decarbonisation targets of any major economy.

The UK has financial power which should enable good access to ever-growing green and transitional funds.

The UK possesses sophisticated and cooperative regulatory bodies with a common goal of building towards green energy.

The UK is also optimally located for blue hydrogen production, sitting on a developed and diverse gas supply chain which can take price advantages from Norway and Europe (from Russia and the Middle East) as well as import of LNG (from Qatar and Rest of World), alongside indigenous gas reserves in combination with huge potential for CO_2 and even hydrogen storage.

The UK has advantaged existing infrastructure, including an established gas grid with European interconnectors, deep water ports linked to historic industrial centres, and oil and gas assets. Significant parts of this infrastructure can be efficiently re-purposed and re-used for a low carbon world.

The UK is located close to major industrial hydrogen use centres, both within the UK and Northern Europe. Intercontinental and long-distance transportation of hydrogen is costly with few technical solutions; hence this location is financially advantageous.

The UK possesses world-class engineering and project management skills. This is evidenced by pioneering engineering projects such as the world's first hydrogen production system from tidal energy, the world's first hydrogen-powered bus fleet and a track record of scaling up emerging technologies.

The UK is thus one of a few global locations ideally suited to be a hub for hydrogen production, use and export. But how can we become a global centre of low carbon hydrogen from where we are today, with negligible production and without clear fiscal drivers to capitalise on our geography? And what lessons can we learn from other new green UK industries such as offshore wind?

BACKGROUND

The UK, through its presidency of the UN climate summit COP26 (to be held in Glasgow during 2021) is urging countries and companies to meet a global target of net zero emissions by 2050, in addition to setting 'staging post' targets for cutting emissions by 2030. Ahead of COP26, the UK Government launched the Together for Our Planet campaign calling on businesses, civil society groups, schools and the public to take action on climate change. This UK-wide initiative contributed to the milestone achievement of securing pledges from a third of the UK's largest businesses to eliminate their contributions to climate change by 2050.

When it comes to 'walking the walk' we have seen an increase in terms of commitments, pledges and policies coming from the UK Government, including the announcement in April 2021 of the world's most ambitious climate change target (expected to be set into law during June 2021) to reduce emissions in 2035 by 78% compared to 1990 levels. This follows the already ambitious climate target of reducing emissions in 2030 by at least 68% compared to 1990 levels, and aims to be net zero by 2050 through the UK's latest Nationally Determined Contributions. This is a clear statement from the UK Government to front load our emission reductions. These commitments and ambitions are rapidly being followed up with strategies and policy documents, underpinned by the work completed by the UK Government's Committee on Climate Change (CCC), an independent statutory body with responsibility for setting the Sixth Carbon Budget as required under the UK Climate Change Act.

Notably, one of the measures set out by the CCC to achieve the emissions targets is the extensive use of low-carbon hydrogen. Following the publication of the Sixth Carbon Budget, key policy documents such as the Industrial Decarbonisation Strategy have been released, highlighting the need to focus on 'low regret' deployment of key technologies such as hydrogen and CCUS. In the UK Government's ten-point plan for a green industrial revolution, it has committed to develop 5GW of low-carbon production capacity by 2030, with plans to create several renewable energy hubs based around hydrogen and CCUS.

In parallel, we have seen both the establishment of hydrogen focussed funding and public-private sector working groups. These include the Net Zero Hydrogen Fund which will provide up to £240 million to enable the development of a hydrogen economy; the Hydrogen Advisory Council (HAC) which is the primary forum for the Ministerial engagement with representatives from the hydrogen industry; and the All-Party Parliamentary Group (APPG) on Hydrogen which is the primary interface for the private sector and Parliament. Within these groups, discussions are being held as to the development of blue and green hydrogen, the basis being that blue hydrogen could become the pathway to a green hydrogen economy.

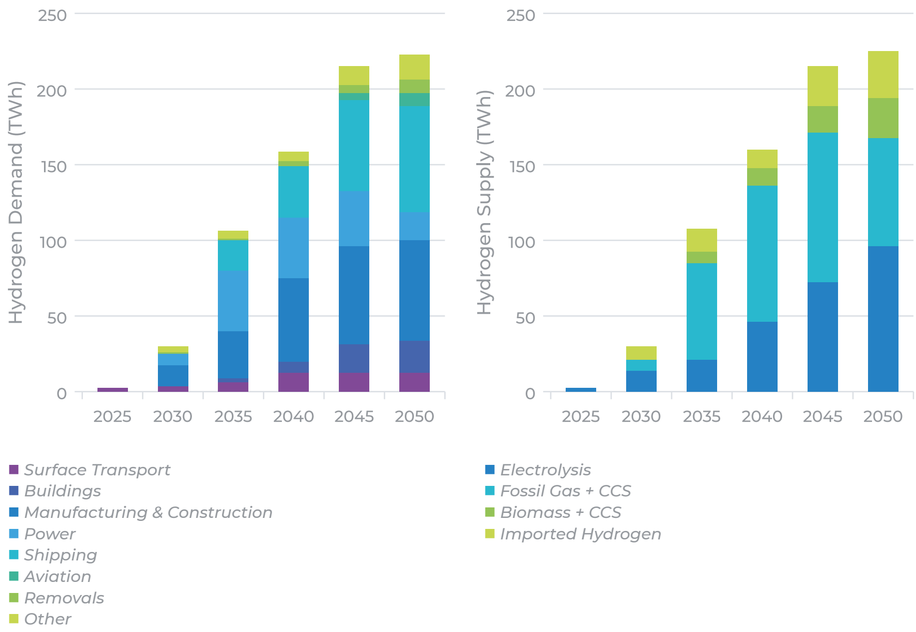
Industry and investors alike are eager to see what sort of cross-sector hydrogen deployment roadmap will be set out in the delayed, but imminent, UK Hydrogen Strategy Document (due later in 2021). Once this is published the Government will begin its consultation on hydrogen business models and revenue mechanisms in order to create an environment that is supportive for private sector investment. So now is clearly a propitious time to influence and lobby Government.

UK'S HYDROGEN AMBITION IN CONTEXT

Global low-carbon hydrogen production is predicted to be around 8 MMte/y in 2030 (IEA, 2020) dependent on which scenario one believes to be accurate. (As this is an evolving and somewhat artificial market, there is a very wide range of predictions for hydrogen demand). To put this figure in context, the current global demand for hydrogen is 70 MMte/y with only 3-5% of this being produced from electrolysis. The bulk of current production is so-called grey hydrogen produced by steam methane reforming with venting the associated CO_2 emissions to the atmosphere. Grey hydrogen is currently the cheapest method of production at $0.9 - $1.8 per kg of hydrogen (excluding any CO_2 tariffs). The UK produces approximately 1% of global hydrogen, which is mainly used in refining and chemical production and has a high associated CO_2 emission of approximately 6.3 MMTe/y. The UK's 2030 target for low carbon hydrogen is 5 GW or 1.1 MMte/y supplying 10% of the world's demand.

For 2050 the UK's hydrogen projections, as set out within the Climate Change Committee's Balanced Net Zero Pathway, is 213 TWh/yr of low carbon hydrogen, or some 5.4 MMte/y (Climate Change Committee, 2020). The manufacture of 5.4 MMte/y of blue hydrogen equates to 2,320 MMSCFD of methane. Blue hydrogen comes in at $1.50 - $2.40 per kg of hydrogen (increased as compared to grey hydrogen production due to the added CCS infrastructure) and captures 90-95% of the CO_2 emissions.

Green hydrogen uses renewable electricity to electrolyse water and create hydrogen with an oxygen by-product. Bar the CO_2 (energy) used in the manufacture, installation and maintenance, the process is CO_2 neutral but is also currently the most expensive hydrogen production methodology at $2.5 - $8 per kg of hydrogen. To make 5.4 MMte/y of green hydrogen requires approximately 33 GW of dedicated electricity supply, equating to 61 GW of installed wind turbines (UK offshore wind capacity factor).



Source: *CCC Analysis* ***Notes:*** *Demand in shipping is likely to be as ammonia rather than compressed hydrogen. Demand given is for H2 produced in the UK or for imports of H2. Imports of ammonia (used in shipping) and imports of synfuels (used in aviation) are not included, but on a H2 feedstock basis would equate to another 23 and 5 TWh respectively by 2050 (i.e. 18 TWh of ammonia and 2.6 TWh of synfuels).*

Source: *CCC Analysis* ***Notes:*** *This only includes H2 produced in the UK or imports of H2. Imports of ammonia and synfuels are not plotted, but on a H2 feedstock basis would equate to another 23 and 5 TWh respectively by 2050 (i.e. 18 TWh of ammonia and 2.6 TWh of synfuels).*

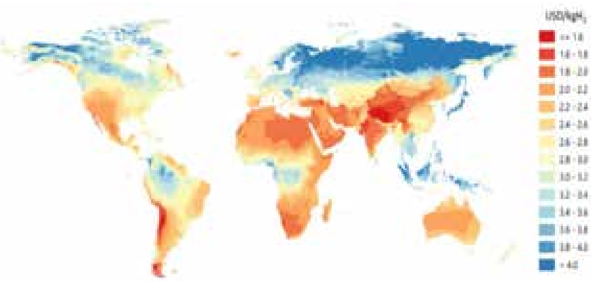
Figure 1 – Hydrogen demand / supply in balanced net zero pathway (Climate Change Committee, 2020)

Analysis performed by Xodus indicates that the UK has developable wind resources of over 150 GW. The most recent UK Climate Change Committee forecast (Climate Change Committee, 2020) foresees total UK wind production in 2050 to be just 95 GW. The UK's wind resources are also far away from UK energy demand centres, which are predominantly in the South and Midlands. The onshore grid is already highly constrained and is not designed for the north-south transmission of tens of GW of power. Historically power stations have been located close to demand centres, with fuel sources brought to the power stations. Offshore wind changes that, by delivering power at the periphery of the UK. Hence without an alternative route to market such as that offered by hydrogen, much of this zero-carbon energy source risks being stranded.

A key opportunity for green hydrogen in the UK is thus to further unlock our substantial offshore wind resources that might otherwise be stranded by grid constraints. Current UK decarbonisation plans to 2050 envisage only around 30 GW of Scottish wind being developed to electricity, in large part due to grid constraints and distance to the major demand centres in southern England. Scotland's own demand for electricity is already substantially met by wind. Even connecting the initial 10 GW of offshore development planned in the current ScotWind round poses significant grid connection challenges, especially from more northerly development areas. Xodus' recent report to Scottish Enterprise (Scottish Government, 2020) identified a credible opportunity to develop up to 60 GW of Scottish offshore wind feeding dedicated green hydrogen production by 2045, generating 200 TWh/year and sufficient to replace roughly half Europe's current industrial consumption of grey hydrogen.

Figure 2 – Scotland's hydrogen surplus potential (Scottish Government, 2020)

Pricing is clearly key if UK low-carbon hydrogen is to compete, especially with potentially cheaper green hydrogen produced from solar energy in southern Europe, North Africa, the Middle East or even further afield. Xodus predicts that the levelised cost of hydrogen (LCOH) produced by UK offshore wind at the point of production will be around $2.6/kg by the early 2030s and for blue hydrogen $1.0/kg (depending on the gas price). By contrast, solar-derived green hydrogen in southern Europe, North Africa, Middle East or other global green energy centres (such as Chile) may become as low as $1.3/kg or even lower in the same time period.



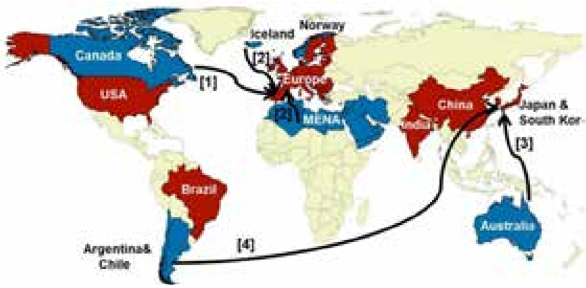


Figure 3 – Hydrogen costs from hybrid solar PV and onshore wind systems (IEA, 2019)

However, to the cost at point of production must be added the costs of transportation, in order to derive a comparative cost at point of use. Previous analysis has suggested that pipeline transportation to Europe may be as low as £0.5/kg, whereas longer distance transportation by ship could be in the range £2 - £5/kg, making UK low-carbon hydrogen very competitive at the point of use.

Currently hydrogen is not cost-competitive to displace existing energy sources. Projected low carbon hydrogen production say at £2/kg is equivalent to £50.80/MWh, higher than the £16.40/MWh natural gas commodity price equivalent (excluding any future carbon tax).

An Xodus study for the Scottish Government (Scottish Government, 2020) examined the cost-competitiveness of green hydrogen across various sectors and considered what equivalent carbon tax is needed to bridge the commercial gap. For the chemical feedstock market, a carbon tax of around £100/te of CO_2 is required. Heating and non-duty-paying transportation fuels require closer to £200/te of CO_2. (Ironically, hydrogen already competes favourably with petrol, due to existing fuel duty and VAT which is effectively a carbon tax of over £300/te).

In summary, from both a resource and advantageous world relative pricing viewpoint, we could set higher UK hydrogen production targets.

WHAT CAN WE LEARN FROM OFFSHORE WIND?

The UK has always had ambitious targets and strong policies in the renewable energy space, but it has not always taken the time to join these up strategically to maximise the benefit for UK Plc. There are lessons to be learned from offshore wind, some good and some not so good.

On the plus side, the Renewables Obligation Certificate (ROC) established the UK as a global wind energy leader by obliging electricity suppliers to buy a specific proportion of their energy from renewable sources, enabling the mass deployment of offshore wind. The move to the Contract for Difference (CFD) led to unprecedented cost reductions making offshore wind the most cost-efficient new-build electricity generation technology now available. However, despite an oft-stated desire to reindustrialise the UK, little has resulted in terms of long-term industrial economic benefits from the vast CAPEX investments in these projects (ca £2 billion for a 1 GW nameplate project).

There are several issues which led to this. Initially, the strong potential project pipeline visibility did encourage foreign Original Equipment Manufacturers (OEMs) to make plans to invest in manufacturing in UK, but the investment uncertainty that came from the policy change between ROC and CFD led to investment opportunities being lost. Governmental confusion over the primary drivers for wind placed technology development and manufacturing investment below achieving the lowest possible cost of electricity, therefore making it impossible to encourage developers to invest in supply chain capabilities. There were no KPIs for local content, just low pricing.

These are key learnings that we should bring to hydrogen, specifically: consistent fiscal intentions reward for investing early akin to the ROCs for gas suppliers, alongside a progressive Contract for Difference approach and, most importantly, both linked to a national content KPI that makes a material difference to award of funding (ROC, CFD, consents, licenses, seed funding, etc). These manufacturing and technology KPIs need to show a real plan to create local value, focusing on high-end production facilities.

[1] Ryberg, D., et al. Evaluating Land Eligibility Constraints of Renewable Energy Sources in Europe. Energies. 11 (2018) 1246.

[2] Reuß, M., et al. Seasonal Storage and Alternative Carriers: A Flexible Hydrogen Supply Chain Model. Applied Energy. 200 (2017) 290-302.

In addition, development of green hydrogen at scale would provide a clear line-of-sight for the largest global portfolio of offshore wind capacity available. It is already likely that the UK will develop offshore wind at scale, but current line-of-sight is lacking a 'hydrogen plus' scenario. Without one we will see only low levels of investment trickle into the UK to meet political pressure, but with negligible economic impact.

A key barrier for green hydrogen is the current long timeline to offshore wind development, particularly the long and complicated consenting processes. Current applications for ScotWind projects are unlikely to come onstream before 2030. Whilst environmental factors and stakeholder concerns are important, these need to be better-balanced against the imperative of the climate emergency and the need to rapidly accelerate decarbonisation.

The irony of environmental regulatory delays for projects that actually save the environment needs to be better voiced. We can learn from offshore wind that a visible project pipeline, a consistent policy with local content, fiscal environment and fast-tracking of environmentally positive projects are all required.

WHAT IS STOPPING US FROM BECOMING A WORLD LEADER IN HYDROGEN PRODUCTION?

In this section we attempt to debunk the perceived risks associated with blue and green hydrogen production.

Blue Hydrogen – Production

The UK has been producing hydrogen for over 150 years (note that town gas plants produced a gas that was 50-60% hydrogen). Currently large-scale hydrogen production is via established technologies, notably steam methane reforming (grey hydrogen).

This hydrogen, mainly used in refining and chemicals production, is made normally onsite or reasonably adjacent to the end consumer with limited pipeline length. Competition has optimised the process. Grey hydrogen production is an established technology with well-understood operations, storage and distribution.

Most technology used in blue hydrogen production comprises small evolutions of existing processes, with the exceptions being:

- The optimum combination of technologies is still to be identified, particularly in terms of how to obtain higher CO_2 capture efficiencies. With the UK's pilot plants, we have an opportunity to prove up these technology combinations in the real world. Achieving high capture rates will be essential if blue hydrogen is to be accepted as a true 'low carbon' technology and to address perceptions of greenwashing.
- The co-production of green and blue hydrogen (teal) has many technical and commercial advantages. On the technical side, using the 'waste' pure oxygen from green hydrogen production to make the process smaller needs to be explored. Commercially, hydrogen storage and export facilities can be shared, enabling currently cheaper blue hydrogen to establish these facilities, reducing the future cost of green hydrogen as well as providing longevity.

Technically it is possible to reach world-scale blue and green hydrogen production within a short timeframe, and if one could ignore planning and permitting, such plants could be delivered in a 4-year horizon. There are several UK companies who have EPC experience in large scale reformer-based plant (e.g. ammonia, urea, methanol), so delivery of these types of plant is within the capability of the UK contracting industry.

Blue Hydrogen – Carbon Capture, Usage and Storage (CCUS)

The UK enjoys a huge amount of potential CO_2 storage; the BGS estimates about 70 Gigatons (CO_2 Stored, 2021). This equates to 190 years of UK CO_2 emissions (based on 2019 figures) – more than we will ever need. The vast majority of the potential storage is estimated to be in non-chalk saline aquifers.

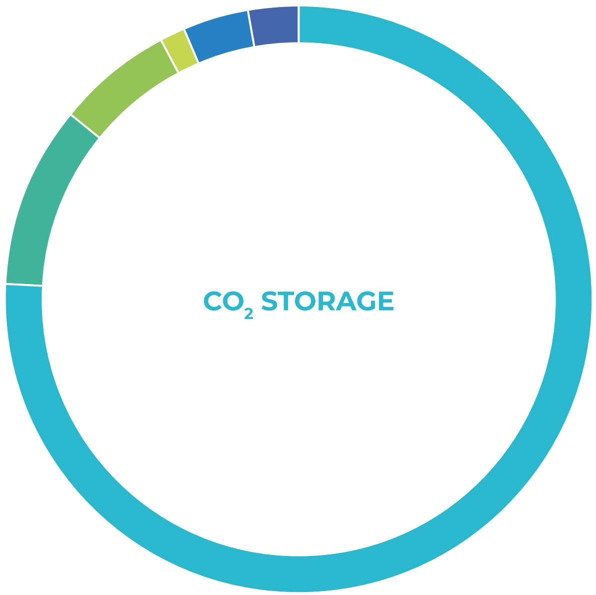


Figure 4 – Potential for CO_2 storage in the UK (CO_2 stored, 2021)

So why aren't we making more use of CCUS in the UK? There are three main factors: perceived risks, technical challenges and economic issues.

Perceived Risks

As with blue hydrogen, CCUS has some public perception issues:

- Being a 'dirty cousin' to renewable energy in the drive to net zero.
- A fear that the CO_2 sequestered will leak or rupture back into the atmosphere rending the CCUS endeavour to be a waste of time or even hazardous.
- That CCUS is seen as just an accounting trick to cover the growing gap between predictions of ongoing CO_2 production and the remaining carbon budget.
- That public funding of CCUS will put money back in the pockets of the polluters (oil and gas companies) who allegedly 'caused' the problem in the first place.

Technical Risks – Subsurface

Saline aquifers

Saline aquifers have some uncertainty over their actual storage potential, and there is no operational history for these reservoirs, so saline aquifer CCS options come with a subsurface risk, i.e. uncertainty over how the reservoir will respond. On the positive side the reservoirs tend to be very large structures with good storage characteristics. Whilst there are trapping mechanisms such as CO_2 dissolving in the saline water, most of the storage potential comes either from displacement or having an overall pressure rise within the aquifer. UKCS saline aquifers have few existing wells, meaning that leakage risk from an incorrectly abandoned well is very low. The main subsurface risk comes from overestimating the aquifer size and the pressure response is outside the expected range.

European offshore CO_2 injection projects to date (Sleipner and Snøhvit) have been into saline aquifers, as have a lot of pure CCS schemes (e.g. Gorgon and In Amenas). The reasons for this are the size of storage and the elimination of issues arising from having wide-ranging injection pressures as experienced in depleted oil and gas reservoirs.

Depleted oil/gas reservoirs

In contrast, depleted oil and gas reservoirs are well-understood due to their production histories, resulting in less subsurface risk. Depleted oil and gas reservoirs typically have a smaller storage potential 'per store' than saline aquifers. Most of the storage potential comes from compressing the gas already in the reservoir by adding CO_2, leading to pressure rising over time.

The rise in pressure over time is an issue as at the start of rejection field life, since a large Joule-Thomson effect is seen at the injection well when using dense phase CO_2. Fortunately, as most of the UK's potential depleted gas reservoir storage (about 80% of the overall volume) is in the Southern North Sea and fairly close to land, there is the potential to use highly-insulated pipe (with heat tracing) to keep the CO_2 warm. This means that the arrival temperature in the reservoir is much warmer, resolving the issues with low injection temperatures. This is the approach taken by the Porthos/Athos Project in Holland.

A further issue for depleted oil and gas reservoirs surrounds wells that have been previously drilled and then plugged and abandoned. It is likely that these wells were abandoned without making 'rock to rock' contact in the well bore and that the cement used was not resistant to CO_2. This does present a possible small leakage risk over time, but this risk should not rule out such reservoirs for CCUS as solutions do exist should the risks ever materialise.

The liabilities along with the long-term storage risks are already somewhat solved underwritten by the UK Government. Currently, there is a nominal 20-year transfer point following cessation of CO_2 injection where the liability for any leaks from a store would pass from the transportation and storage operator to the Government. This date could move depending on what the monitoring, measurement and verification (MMV) activities post-injection show in terms of progression of the CO_2 within the reservoir.

CCUS Plus Enhanced Oil Recovery

The question is often asked – why do we not make more use of CO_2 for Enhanced Oil Recovery (EOR) in the UKCS, as CO_2-EOR is a common oil field practice? EOR upside is generally good thing, giving depleted oil fields an extended lease of life.

Firstly, there is a significant difference between North Sea CO_2-EOR and what has been done in other locations, primarily onshore. Ideally, a reservoir can be tested for EOR without large scale investment to confirm the EOR upside before widening to a whole field. This is much easier to do onshore with shallow and low-cost wells. In the North Sea wells are very expensive as reservoirs tend to be deep. Even to test a well a lot of infrastructure is needed to get the CO_2 to the injection site. Also, the topsides processing systems (up to the gas dehydration step) will likely need replaced with systems that are CO_2 corrosion resistant, as most North Sea hydrocarbon production is sweet.

Due to the amount of infrastructure required, North Sea EOR needs to be done at scale right from the start, attaching a higher degree of risk than traditional CO_2-EOR. CO_2-EOR in the North Sea may make economic sense only for certain fields where a CCS play is occurring nearby and there is also a possibility of life extension with an increased recovery factor.

CCUS and Blue Hydrogen

CCUS is needed to facilitate blue hydrogen production. The CCUS technology and infrastructure required is established, has understood risks and is currently non-economic without governmental support. Improved economics occur when done at scale and by co-locating blue hydrogen production within industrial clusters so that other carbon emitters can use these assets.

A low carbon energy hub approach would allow the UK to continue with and/or develop new high energy industries. Blue hydrogen provides a revenue route for CCUS and should be seen as an enabler of other CCUS projects. This approach needs multiple entity coordination and would require over-sizing of common infrastructure to allow others to use it. But how can this be achieved without resulting in potential delays and complex commercial models?

Green Hydrogen – Technology

Production

The most common electrolyser used to make hydrogen is the alkaline electrolyser. These have been used for decades within the chemical industry. However, they have a large footprint and do not perform well with fluctuating power supplies. This poses a particular challenge for renewable power sources, which are often intermittent.

The green hydrogen industry is now leaning towards Proton Exchange Membrane (PEM) electrolysers, which perform better under variable power supply, require a lower spatial footprint and can rapidly ramp up and down hydrogen production. These two technologies make up the majority of operating and planned projects within the green hydrogen space.

There are other emerging electrolyser technologies. New Solid Oxide Electrolysers (SOEs) have superior performance but need low-grade waste heat alongside constant electrical supply and are therefore best paired with nuclear power or blue hydrogen energy hubs. Other new electrolysers use seawater for direct electrolysis so would be idea for offshore production but produce chlorine with hydrogen as a by-product.

Although alkaline electrolysers are still undergoing minor improvements, they are a mature technology that have been deployed on multi-MW scale (TRL 9). PEM electrolysers are now also being deployed on a multi-MW scale (TRL 8-9). SOEs and other emerging electrolyser technologies are at significantly lower TRLs (<6), which makes them unsuitable for wider roll-out by 2030. Alkaline and particularly PEM electrolysers are likely to dominate the market in the next 5-10 years.

The costs of renewable electricity and electrolyser technologies have been falling rapidly in the past years and this the trend is expected to continue. The Hydrogen Council expects green hydrogen production costs to reduce by 62% by 2030, which would make it competitive with blue hydrogen by 2028 and grey hydrogen by 2030 in certain regions. A significant carbon price could bring the cost parity dates even closer. Although electrolyser costs are the dominant part of the green hydrogen production equipment, they are significantly less important when it comes to the levelised cost of hydrogen (LCoH) production. For large scale projects, the energy feedstock (renewable electricity) makes up between two thirds and three quarters of the final cost of hydrogen produced. Therefore, pairing electrolysis with low-cost renewable electricity resources is by far the most important aspect of a cost-effective green hydrogen production. This is the reason why countries with abundant solar energy resource (such Chile, Australia or countries in the Middle East) have the potential to produce the cheapest green hydrogen in the world.

Transportation

Even though electricity cost is the most important factor of LCoH when it comes to production, the location of the end-user is equally important as up to 25% of the energy can be lost in transportation. There are several emerging technologies for the bulk transportation of hydrogen. These include high pressure compressed hydrogen at ambient temperature, liquefied hydrogen at ambient pressure, compressed and liquefied hydrogen, Liquid Organic Hydrogen Carriers (LOHCs), Metal Organic Frameworks (MOFs), ammonia, methanol etc. This paper does not explore these options, but it is sufficient to note that all are costly and likely to remain so in the future, and mainly not proven at scale. Despite hydrogen's inefficiencies in compression, in a European context pipelines are likely to remain the most efficient method of transportation in the near to mid-term.

On the other hand, green hydrogen produced in the UK from offshore wind will be more expensive at the point of production (due to higher electricity cost from UK offshore wind compared to Middle East solar). However, this hydrogen could be delivered to Northern Europe via a subsea pipeline, which is likely to be significantly cheaper and more efficient compared to hydrogen shipping. This is the reason why the location of the end-user is critical to the overall hydrogen cost, arguably more important than the cost of hydrogen production itself.

Another important aspect of hydrogen production cost is the availability of the renewable energy source. This is where hydrogen produced from offshore wind electricity significantly outperforms solar energy.

For example, offshore wind farms in Scotland have the potential to yield more than 60% capacity factor when considering floating wind sites further offshore. If these wind farms are directly paired with green hydrogen production, the utilisation factor of the electrolysis system is equal to the capacity factor (60%). On the other hand, solar farms in the sunniest regions in the world can yield a capacity factor of approximately 30%. This means that the electrolyser will only be utilised 30% of the time based on the nameplate capacity of the system. Lower capacity factor of the hydrogen system can also mean higher storage requirements to deliver constant and reliable energy source (hydrogen) to the end user.

Therefore, when assessing overall green hydrogen project feasibility, the most important factor is not only the cost of production and the type of renewable source (and its associated sparing capacity) but the location of the end user. Hydrogen is not as easy to transport compared with oil or gas; proximity to point of use is likely to remain a key factor in the economics.

PIPELINES

The UK enjoys an extensive infrastructure of natural gas pipelines that could potentially be repurposed to transport hydrogen; however, repurposing pipelines faces a number of challenges, including:

- The continued use of pipelines for natural gas. Hydrogen could be blended with natural gas, but this then limits hydrogen use to heating only, rather than to higher-value application in transportation. Hydrogen deblending at destination could also be considered to overcome this but adds further cost and complication.
- Pipeline metallurgy, age and integrity. Only certain pipeline grades are likely to be candidates for pure hydrogen due to risk of hydrogen embrittlement.
- In the UKCS there is much offshore pipeline infrastructure that could be re-purposed for CO_2 transport. The downside is that the most appropriate pipelines are the dry gas trunklines to shore, which we will continue to need in order to feed the blue hydrogen revolution.

Xodus believes that there is scope to rationalise these gas trunklines in order to provide an offshore CO_2 backbone alongside developing plans to enable hydrogen to be introduced into the UK network (Xodus, 2019). To date 23 European gas infrastructure companies are aligned with the European Hydrogen Backbone project to repurpose existing natural gas pipelines, and to build new pipelines across the continent to transport hydrogen. The UK has yet to set out its hydrogen backbone plans, but we strongly recommend that all investments in gas pipeline infrastructure today should be made with a low-carbon (hydrogen) future in mind.

On the plus side, up to 80% of the UK gas distribution network is now plastic, which is suitable for 100% hydrogen. If we had enough hydrogen available, UK natural gas emissions in the near term could be reduced by up to 20% via displacing natural gas with hydrogen, without causing significant disruption / investment to the end users (both domestic and industrial). The existing infrastructure of pipelines and production units is already designed for the safe production and storage of hydrocarbons, and while testing and retrofitting would not be at zero cost, it should be at a lower cost than building entirely new transportation, storage and export assets.

RISKS & OPPORTUNITIES

Hydrogen has its detractors, who rightly point out the inefficiencies in its production and transportation as compared to more direct use of renewable energy sources (with up to 60-75% loss of energy at the point of use). However, hydrogen should be seen as one of many tools needed to achieve the net zero target and is an appropriate way to decarbonise the hard-to-reach areas of industry and transportation. Hydrogen also enables energy to be stored much better than as electrons.

The main risks for low carbon hydrogen project developers are policy and demand uncertainties. Many governments have now enshrined hydrogen to be a key part of their net-zero pathway. Some countries (such as Japan, Australia, Germany and France) have also published dedicated hydrogen strategies. The UK has only identified hydrogen to be an important energy vector in order to decarbonise hard-to-abate industries, but a clear route to market with dedicated revenue support mechanisms (though being worked on) is still not evident. All UK low-carbon hydrogen projects developed to date were funded on a case-by-case basis rather than through market-based mechanisms to support a wider deployment of the technology beyond the pilot project phase.

An equally important risk is the demand side uncertainty. This is a chicken and egg situation and is deemed more difficult to tackle. For example, in Scotland renewable electricity was able to replace fossil fuel powered plants relatively swiftly (from 24% in 2010 to 97% in 2020). (Scottish Renewables, 2021). This was achieved not only due to Government intervention but also due to existing electrical demand linked to an existing distribution system (albeit requiring some modification).

For new low-carbon hydrogen, no route to the end user exists (unless it is produced near to chemical and refinery users). Hydrogen cannot easily replace other fossil fuels without significant pre-investment in new engines, new boilers, new burners, new compressor stations, new hydrogen outlets, alongside some gas network upgrades.

Although risks associated with low carbon hydrogen development are clear, there are significant opportunities on the horizon. The recently formed Aquaventus venture is planning to develop 10 GW of offshore wind from Dogger Bank directly to green hydrogen then exported to Germany through the new Aquaductus hydrogen pipeline. It would be logical to extend the Aquaductus pipeline north to Orkney and Shetland, where hydrogen can be generated more cheaply on natural island hubs than on offshore platforms, thereby enabling development of the stranded wind resources around both islands. Such a hydrogen pipeline backbone would also enable tie-ins from other hydrogen production centres, potentially creating new uses for existing infrastructure. Requiring such schemes to help potential rivals for the greater UK good will need Government intervention.

THE WAY FORWARD

Over the next decade we are likely to see a rapid increase in trials and low-scale use of hydrogen. These will be the kind of applications that don't rely on widely distributed networks, such as the double decker bus initiative in Aberdeen, alongside targeting industrial heat and energy, shipping and heavy transport. However, in order to get pure hydrogen as a fuel into our homes (and if hydrogen was to be used as a substitute for petrol), we would need significant market intervention from Government. Given the diversity of potential customers of hydrogen from residential to industry, a holistic approach will be needed.

To enable the rapid development of a hydrogen economy the UK Government will need to not only incentivise investment into hydrogen production but also create demand that transfers the risk away from investors. Other barriers to be overcome include the lack of a conveniently available hydrogen supply and limited and or costly (particularly in the case of vehicles) consumer choices at this emergent stage of market adoption.

Substantive carbon taxation is required to power the energy transition in the UK, and we should not delay this any longer. Carbon taxation should be used to facilitate both the supply and demand side of the industry. Within industry, incentives both positive (subsidies) and negative (taxation) are needed to support the conversion from fossil fuel to low-carbon hydrogen. Targeted subsidies for both production and demand, (particularly for new use technologies and new manufacturing, are needed now). Carbon taxation needs to be considered carefully to ensure that UK industry does not become less competitive than its international peers, or materially increase costs to consumers on UK produced products. Alongside any producer carbon taxation, a consumer point of sale carbon tax should be included, so that the consumer understands the carbon footprint of the product and service they are buying. A universal point of sale carbon tax would:

- Be able to be applied unilaterally within the UK without prejudicing UK manufacturing; if we become a true global centre of low-cost low carbon energy, it would actually act as a stimulant to the UK economy.
- Be an engine of change in the economy, enabling and empowering consumer choice.
- Stop the offshoring of emissions and manufacturing. The world of tomorrow will be dictated by locations with lower-cost energy and not by the cost of labour. Modern manufacturing facilities are capital intensive and energy intensive, with cost of labour being relatively insignificant.

Alongside carbon taxation, subsidy models such as CfD, Regulated Returns (Regulated Asset Base model), hydrogen obligations (ROC equivalents) and end user subsidies are all being considered by the UK Government.

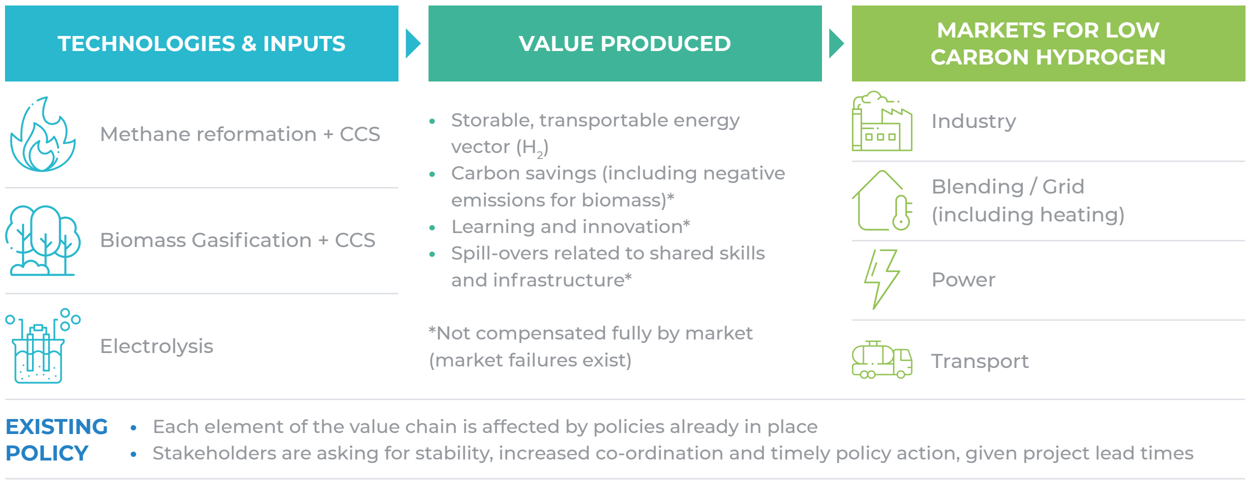
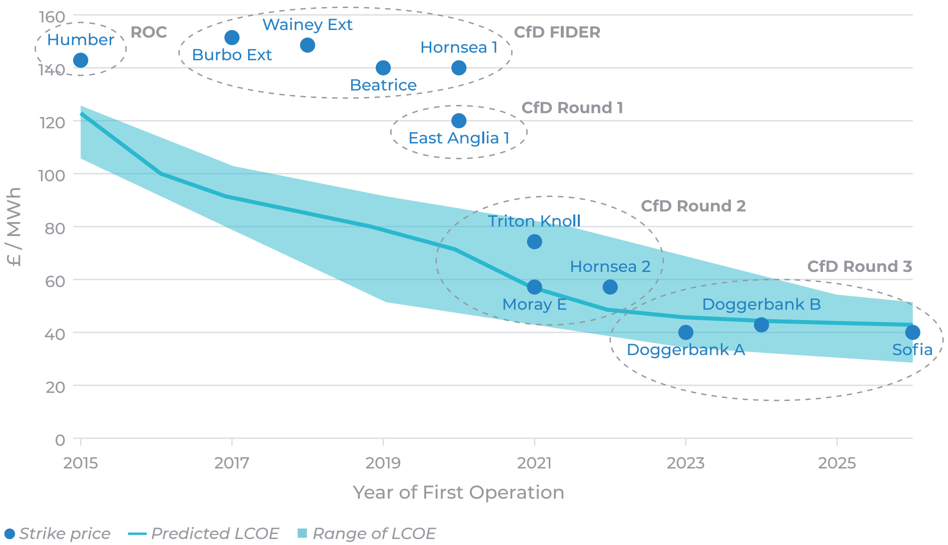


Figure 5 – Framework for considering hydrogen risks (Frontier Economics, 2020)

In the short-term, low carbon hydrogen production will come from steam methane reforming with carbon capture, as demonstrated by industrial cluster projects such as Hynet, Teesside, Zero Carbon Humber and the Acorn project. The success of these projects will heavily impact the expansion of UK low carbon hydrogen production capacity. CCUS business models within the UK are still in development with a combination of CfD and RAB models preferred, dependent on the type of CCUS assets i.e. pure Capture or Transportation & Storage. The UK Government has effectively split the value chain between emitters and transport and storage companies according to how they are proposing to fund CCS.

Low-carbon hydrogen production within the UK should come from both gas with carbon capture, and offshore wind. Any business model that is selected for hydrogen will need to consider the revenue mechanisms associated with both low carbon resources. As shown earlier, the UK has well established subsidy models that can support an emerging sector, as demonstrated by the success of ROC and CfD auctions for offshore wind in developing the market and then reducing costs (the strike price) from £140/MWh in 2015 to £44/MWh in 2025.



Strike price and estimated LCOE of operational wind farms and predicted average LCOE for round 3 offshore zones. Note: 2012 prices for comparability with the early contracts.

Figure 6 – Levelised costs of electricity for UK wind farms (Carbon Trust, 2021)

Learning from offshore wind, the approach to hydrogen subsidies should be based on these successful models but include legislated local content requirements, in particular for new UK-based manufacturing and technology development.

Setting clear intent and a matching policy framework to be a global (or at least the European) centre for low carbon hydrogen production would have the added effects of:

- Re-establishing the economic opportunity in offshore wind.
- Building up of UK low carbon hydrogen and CCUS infrastructure to be the dominant European player.
- The opportunity to develop new industry and technology by having an abundance of hydrogen produced at lower cost.
- Enable increased opportunity for the production of lower carbon components and steel within the UK. Which in turn would provide an immediate opportunity in the first wave of clean hydrogen projects, to both decarbonise the related supply chains as well as offsetting the shipping of multiple large components to further reduce supply chain related emissions.
- Repurposing existing oil and gas infrastructure.

Co-locating blue and green (so-called teal) hydrogen production has many synergies. Technical advantages include using the oxygen by product of green production to improve the efficiency of blue hydrogen production. Commercial synergies include being able to obtain pricing differential advantages between green electricity and gas, better supply and demand curve management, reducing storage and buffering requirements. It is predicted that green hydrogen may be cheaper than blue hydrogen by 2030 or sooner, by co-locating production future proofs related hydrogen infrastructure as green hydrogen is the same as blue hydrogen regarding storage, transportation & export.

Going further, co-production based in existing industrial centres, i.e. the 'low carbon energy hub' approach, allows the UK to develop high energy industries. Additional Government support for such schemes could include tax-free investment zones alongside incentives for reuse of brownfield sites for development in historic, but now decaying, industrial centres. By adopting a bolder approach to Hydrogen, the UK could be at the forefront of hydrogen technology – not so much in hydrogen production technology, as that has already crystallised and somewhat passed us by, but rather in hydrogen use technology such as hydrogen gas turbines, fired heaters and hydrogen car engines; domestic appliances such as ovens and home boilers will also need to be redesigned and manufactured.

Unfortunately, other countries are ahead of the game in hydrogen use processes, notably Germany, and foreign manufacturing companies such as Mitsubishi Power and GE already have contracts to supply hydrogen compressors. However, the UK with an abundant and lower-priced indigenous hydrogen resource could promote a 'home use market' and be a new technology test bed. An example of this is the German HYRAZE League, a hydrogen-powered racing series with a projected launch in 2023. Surely the UK with its motor racing pedigree could leapfrog this technology and produce a world-beating Formula H.

The UK gas companies need to be included in this national hydrogen planning. The concern is that gas companies sell a story of that their existing gas infrastructure is relevant to a net-zero world but have not made meaningful investments or demonstrated their capability to deliver it, resulting in delay and doubt.

Finally, we need to accelerate to capitalise on our unique position in regard to low carbon hydrogen production and to gain first-mover market advantages. To do this we should place all significant hydrogen and green energy projects under a critical national infrastructure planning process, accepting that local concerns need, in these instances, to be overridden for the national and global good. It is absurd that UK environmental regulations cause delay to environmentally beneficial projects; the climate does not have time for that.

CONCLUSIONS

Low carbon hydrogen has many advantages for the UK. Our abundant wind energy, extensive oil and gas infrastructure and proximity to major industrial centres mean that we should make the best use of this opportunity before it passes us by.

The technology in both green and blue hydrogen is sufficiently developed to enable world-scale projects to be planned, but is also immature enough to enable UK engineering and technology firms to optimise and refine the processes. When doing so, we should consider how we can hold on to this IP rather than giving it away as we have done in the past. In addition, new hydrogen use technology could be incubated in a UK globally lowest priced hydrogen centre.

Even given the scepticism surrounding hydrogen, we are in a place where to not lead in hydrogen would be a wasted opportunity. The UK should adopt a bolder vision for hydrogen, to become a global hydrogen player and the leader in Europe, gaining associated first-mover advantages on the back of an ambitious hydrogen development programme. Hydrogen infrastructure is classified as a low-regret investment; therefore, perhaps we should not be building on the back of other countries' potential demand requirements but rather adopting a 'build it and they will come' approach. The UK should become the first country to blend significant amounts of hydrogen into a national gas network. We should also be the first country to pipe hydrogen into Northern Europe.

A brand of 'UK low carbon hydrogen' should be championed, a mix of both green and blue. The UK government should resist the temptation to deliver only green hydrogen to the continent as this is not in the UK's interest. As an industry and a nation, we need to push back against just green hydrogen and actively campaign for blue or teal UK low carbon hydrogen. Blue hydrogen is a low carbon and commercially accessible technology, and we should not pander to the 'green only' ideal; we need realism not idealism to solve the energy transition conundrum. To that point, schemes that consider making hydrogen in the UK and selling direct to Europe should not be as encouraged as schemes that provide hydrogen to the UK and then the continent.

Requirements for local content are vital if we are not to repeat the missed opportunity of offshore wind, alongside creating apprenticeship opportunities to ensure that the UK's domestic workforce will be ready when required later this decade. By taking a long-term joined up approach to the market, the UK can make positive decisions on which elements and aspects of the supply chain are most beneficial to attract (e.g. high-value complex manufacturing), rather than accepting piecemeal investments to be hastily agreed prior to equivalent hydrogen CfD contracts being approved.

To miss this once-in-a-generation opportunity to position the UK as a leader in hydrogen would be irresponsible for all of us.

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