

# WASTE-TO-HYDROGEN: CHALLENGES AND OPPORTUNITIES IN THE UK SCENARIO

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**ABSTRACT:** Hydrogen is widely recognised to have a key role to decarbonise various industries, as well as transportation, heating and power sectors, for it does not generate greenhouse gas emissions at the point of use. Understanding the technologies that can generate low carbon hydrogen is essential in planning the development of future gas networks and more sustainable manufacturing processes. One promising approach is hydrogen production by gasification of waste, referred to as biohydrogen. This paper summarises work undertaken to design a commercial Waste-to-Hydrogen (WtH2) plant, which includes an assessment of current development stage of technologies, the identification of an appropriate scale for the plants, and development of specifications for process design and output streams. The overall production levels of biohydrogen is observed to be limited by the availability of sustainable feedstocks; however, the results of negative CO<sub>2</sub> emissions achieved via biohydrogen production shows that its overall potential to reduce GHG emissions is significantly better, as compared to other form or low carbon hydrogen. In particular, biohydrogen application is capable of generating negative emissions that are required to offset GHGs from other sectors in the future. In combination, low carbon hydrogen production can make a very important contribution to achieving net zero commitment in UK.

*Keywords:* Low carbon hydrogen, waste gasification, BECCS, LCA

## 1. INTRODUCTION

In recent years hydrogen has received increasing attention as a potential fuel that could be produced from non-fossil fossil sources, both because it can be generated with low greenhouse-gas (GHG) emissions, and because it generates no emissions at the point of use. As such, hydrogen is believed to play a key role in achieving Net Zero ambitions, across Europe, and UK in particular.

The UK has set a target to reach Net Zero GHG emissions by 2050. This requires the current 522 Mt CO<sub>2</sub>-eq emissions per year to reduce to zero over the next three decades. Carbon emission reductions can partly be achieved through increased renewable electricity generation and electrification; however, the adoption of low or zero carbon fuels, such as hydrogen, are expected to play a significant role. Hydrogen is currently used as an industrial feedstock, mainly for ammonia production and in oil refineries. It is mostly produced from fossil fuels reformation, namely steam methane reformation (SMR) and autothermal reforming (ATR) of natural gas, also known as ‘grey hydrogen’. There are three main technologies that can produce hydrogen with low carbon impact:

- Electrolysis using renewable electricity to produce ‘green hydrogen’
- ATR and SMR with carbon capture and storage (CCS) to produce ‘blue hydrogen’
- Reformation of biogas or gasification of biomass with CCS to produce ‘biohydrogen’.

Green hydrogen offers a small-scale solution that can be cost effective for some applications such as filling stations for hydrogen vehicles. However, currently the cost of hydrogen produced by electrolysis is far more expensive than SMR grey hydrogen (£6.20/kg versus £1.90/kg for transport-grade) and it does not offer significant greenhouse gas (GHG) benefits unless renewable electricity is used (Al-Qahtani et al., 2021). Power-to-gas (PtG) technologies rely on this principle. This development is particularly attractive due to the availability of renewable power generation in excess of immediate electricity demand and an expectation that this availability will increase with the share of intermittent renewable power generation (Götz et al., 2016).

Steam and autothermal methane reforming involves reacting natural gas with steam or limited amount of oxygen, at high temperatures over a catalyst to produce syngas (a mixture of H<sub>2</sub> and CO). This is then further processed to maximise H<sub>2</sub> generation (via water gas shift reaction, WGS) and separate H<sub>2</sub> product from a CO<sub>2</sub>-rich stream. Production capacities of hydrogen from a typical steam methane reforming plant range between 150 and 440 MW with an energy efficiency of typically 70% (Al-Qahtani et al., 2021). If SMR is to become a major low-carbon source of hydrogen, carbon capture and storage is essential. It is estimated that between 71% and 92% of the CO<sub>2</sub> in steam methane reforming can be captured; however higher capture rates will be needed if the process is to be used in the long term (Materazzi et al., 2019). Furthermore, CCS barriers are not exclusively technical, with CCS cost being the most significant hurdle in the short to medium term. Auto-thermal reformation (ATR) is a similar process to steam methane reformation (SMR), which is a proven technology used to produce the majority of 'grey' hydrogen in the world today. Rather than combusting natural gas to raise steam, and produce carbon dioxide, as with the SMR process, the ATR process utilises natural gas within the reactors, with carbon dioxide produced from the feedstock at high pressures and relatively high purity. This provides a single stream for carbon dioxide separation and removal rather than multiple carbon dioxide streams at variable pressures and purities from the SMR process, allowing for a higher carbon dioxide capture rate (>95%) than SMR. As well as providing a low-cost way to capture carbon dioxide, ATR also shares the same benefits of SMR, namely that the technology is based on well-proven chemical engineering technology, which can be easily scaled-up and produces hydrogen at a relatively low cost (dependent on the natural gas price). The carbon dioxide stream captured from the ATR plant can be injected into offshore carbon storage facilities, as is being planned around several industrial clusters in the UK, including the HyNet cluster in the North West of England and the Acorn project in North East of Scotland (Edwards et al., 2021).

Biohydrogen is the newest addition to the low-carbon hydrogen choices. Several techniques have been proposed by many researchers for the thermal conversion of solid organic materials to biohydrogen, via gasification or pyrolysis (Barisano et al., 2017). Biohydrogen offers the prospect of low carbon hydrogen production from low-grade – in large fraction renewable – fuels, at parity with the cost of natural gas, and with the potential of negative carbon emissions if the separated CO<sub>2</sub> is sequestered. A number of studies have been reported in the literature for biohydrogen production from first-generation biomasses, especially from starchy and sugar-rich biomasses due to easy fermentability attribute of these feedstocks by anaerobic organisms which increases H<sub>2</sub> yield compared to other organic substrates (Chong et al., 2009). Waste and second-generation biomass materials, although readily available and abundant, have limited uses in terms of chemical feedstocks, due to the need for pre-treatment and presence of many contaminants which add complexity and costs. Thermochemical treatment of waste for hydrogen or chemical production, therefore, presents a number of unique issues demanding specific design choices and technical solutions. Generally speaking, the conversion schemes use heat and various combinations of steam, oxygen and CO<sub>2</sub>, to convert the feedstock to various amounts of char, hydrocarbon gases, hydrogen, and carbon oxides, with ash being a by-product of most waste feedstocks. Ash residues are usually classified as a hazardous waste on account of their high alkalinity and other pollutant species (e.g. heavy metals and soluble chloride and sulphate salts); as such, they require specific treatment

before disposal. Therefore, before bioH<sub>2</sub> from waste can be deployed commercially several barriers must be overcome. Firstly, the technical feasibility of hydrogen production from waste derived feedstock must be demonstrated to show that the concept is credible. Secondly, the process must be optimised for commercial deployment, with designs produced, environmental impact understood and costs modelled. Finally, the chosen designs must be deployed at larger scale, with hydrogen supplied to end users. Extensive work is needed to push forward commercial deployment of hydrogen production from waste by systematically working to address each barrier. This work aims at addressing at least some of these. First, main technical challenges and latest developments of biohydrogen plants are appraised. Different low carbon hydrogen production routes are then compared from a Life Cycle assessment (LCA) perspective, to understand deployment and integration opportunities in UK over the next 30 years.

The hydrogen production methods selected were electrolysis (on-site, large scale off-site and off-shore), methane reformation (ATR and SMR) with carbon capture and storage (CCS) and waste gasification with CCS. Fossil fuel, renewable feedstocks and energy sources, were flexed in the analysis, an example being replacing waste with pure biomass or plastics for the biohydrogen with CCS pathway. Upstream GHG emissions associated with electricity, natural gas and biomass production, plus transportation were also included in the study to give the most complete picture.

## 2. TECHNOLOGICAL ASPECTS

### 2.1 Feedstock quality

Thermochemical treatment of biomass feedstock, and gasification in particular, are gaining strong traction in Europe giving the numerous opportunities associated to product flexibility and low environmental impact. Recent studies have proven that Bio-H<sub>2</sub> offers the largest potential in terms of GHG removal (Rosa et al 2022; Valente et al., 2019), thanks to the biogenic origin of the carbon in the feedstock. However, Bio-H<sub>2</sub> production should ideally rely on the use of second or third generation biomass as primary feedstock to avoid land use competition with food crops and intensification of deforestation, habitat loss and loss of soil fertility. Municipal Solid Waste (MSW) and waste in general, represent an ideal source because of their large availability and low cost. From a climate change perspective, the use of waste as feedstock not only ensures large and economical availability for consistent hydrogen supply, but also avoids use of current disposal technologies, which are known to contribute enormously to GHG emissions and water and land pollution.

Bio-H<sub>2</sub> plant performances and environmental attributes are obviously strictly dependent on feedstock composition. Generally, the design point for the waste composition for a thermochemical facility is derived from several datasets for representative residual municipal, commercial and trade waste collected nationally as well as locally. This typically shows a substantial quantity of organic (biomass) content in the waste material, which is typically between 40% and 60% in weight (see Table 1).

Waste cannot be thermochemically treated in its original form when collected. The untreated municipal or commercial waste is first mechanically processed in a material recycling facility (MRF). This is done to homogenise the material and remove part of the moisture, recyclables (e.g., metals and dense plastics) and reject materials (e.g. oversize and inert). The material is then shredded using tearing motion to achieve a rough shred of waste residues, with a homogenous, predetermined particle size between 1 and 50 mm, depending on the gasification reactor requirements. The final feedstock is in the form of floc of refuse derived fuel (RDF), which is then further dried on-site using waste heat from the process. Typically, a 100,000 tonnes MSW feed produces an output of ca. 60,000 to 80,000 tonnes of RDF with a moisture content of 10–17%, 10–20% ash content and 15–25 MJ/kg calorific value (CV).

**Table 1.** Waste feedstock composition analysis

<b>Waste fractions [wt% as received]</b>	<b>MSW</b>	<b>Waste wood</b>
Paper and cardboard	22.7	0.8
Wood	3.7	93.4
Metals	4.3	1.7
Glass	6.6	-
Textile	2.8	-
WEEE	2.2	-
Plastics	10	0.5
Inert/aggregates/solid	5.3	2.5
Organic fines	35.5	1.1
Miscellaneous	7.1	-
<b>Proximate analysis [wt%, as received]</b>	RDF	
Fixed Carbon	8.90	10.75
Volatile matter	64.70	64.24
Ash	11.80	0.41
Moisture	14.60	24.6
<b>Ultimate analysis [wt%, dry ash free (DAF)]</b>	RDF	
Fossil Carbon	20.51	0.80
Biogenic Carbon	36.23	50.13
Hydrogen	6.86	5.76
Oxygen	31.78	43.01
Nitrogen	4.1	0.28
Sulphur	0.18	0.01
Chlorine	0.34	0.01
<b>Energy content [MJ/kg DAF]</b>	RDF	
Gross calorific value (HHV)	28.99	24.08
Net calorific value (LHV)	27.02	22.73

A good potential reference WtH2 plant size could treat around 100,000 tonnes per annum of RDF, this being supplied from a reasonably sized town, accounting for residual domestic, commercial and industrial waste arisings. This is also similar in scale to small conventional energy from waste facilities. Bus fleets have been identified as the earliest likely adopters of hydrogen for transport. A typical bus will consume around 5 tonnes per annum of hydrogen. A large depot will operate around 100 buses, i.e. 500 tonnes per annum or 20 GWh. This equates to around 5% of the WtH2 plant scale identified. This suggests that transport applications in the medium term are likely to be serviced by slip streams from larger plants designed to service grid or industrial customer applications.

## 2.2 Waste gasification development stage

Compared to pure biomass, RDF introduces a greater concentration and diversity of contaminants, due to the high number and variability of sourcing points. This presents a major challenge, compounded by the fact that more sophisticated applications (including catalytic processes for Bio-H<sub>2</sub> production and fuel cells for transportations) have very low tolerances.

The state of technology development for biomass or waste gasification is generally seen to be in the

TRL (Technology Readiness Level) range 7 to 8, however, it is not a clear-cut issue. This has recently reviewed by the Department for Business, Energy & Industrial Strategy (BEIS) in UK (BEIS, 2021). Firstly, most biomass and waste-fuelled gasifiers are fundamentally unsuited to the production of syngas as an intermediate to hydrogen or gas fuel production, principally because they are air-aspirated rather than oxygen blown. Air-aspirated gasifiers entrain large volumes of nitrogen in the syngas – the removal of nitrogen from the product (hydrogen, biomethane etc.) being expensive and difficult to accomplish. It is important to note that much of industrial fatigue with biomass or waste gasification has been with gasifiers of this type. Gasifiers suited to the production of bio-hydrogen will not be air blown – they must be indirectly heated or oxygen/steam blown, and ideally they would operate significantly above ambient pressure. At least one gasification technology, the HT Winkler, having been deployed successfully in East Germany before unification, would appear to be at or near a TRL of 9. The HT Winkler is in a class of its own in this respect, but the owners of the technology, Gidara Energy, do not offer their technology for third party developers; it is reserved for their own projects. Thus there is no extant and diversified technology base at TRL 9 that could support the immediate and widespread implementation of thermochemical biohydrogen facilities at this time. At the current time investors in bio-hydrogen projects are faced therefore with procurement of gasification technologies that are at around TRL 7 or 8 for bio-syngas production; from which bio-hydrogen would be manufactured (Hofbauer & Materazzi, 2019). Technologies for production of hydrogen from syngas are well proven and at TRL 9, so the primary technological risk rests with the gasification technology.

Another class of suitable technologies is that of multi-stage conversion processes, which combine bulk gasification in conventional fluidized bed reactors with high temperature reforming steps to deal with tars. This has also the advantages that ashes, naturally abundant in waste feedstock, are collected in a vitrified form, which is classified as inert material. Some of these technologies have been tested and demonstrated at pilot scale, but major challenges arise during scale-up (Materazzi & Taylor, 2019). To address this problem, the UK company ABSL embarked some years ago on a programme of developments at Swindon, beginning with a pilot-scale gasifier and 50kWth BioSNG demonstration project. The pilot plant experience has enabled ABSL to continue development of the RDF to BioSNG concept with a semi-commercial (1/10th scale) demonstration plant currently under commissioning in Swindon. Up-scaling to a full commercial capacity (by a factor of 10) would be a reasonable stretch in capacity, subject to learning-by-doing and satisfactory performance with the semi-commercial demonstrator. However, such a plant would be a first-of-a-kind facility and as such be seen by potential investors as presenting an enhanced technology risk, in comparison with technologies that had already accrued an operational track record and a TRL of 9. Hence, one key step in addressing technology risk – already taken by ABSL - is the demonstration of a semi-commercial facility that can be scaled-up by a reasonable scaling factor (e.g. a multiple of <10x), coupled with demonstration of satisfactory operation. Nevertheless the technology risk is enhanced compared to a “proven” technology, and pump-priming measures in the sector need to be such that investors see the enhanced risk as being acceptable; otherwise, it is likely that investment in the sector will not be forthcoming.

### 2.3 Pre-combustion CO<sub>2</sub> capture

Whilst post combustion capture from the flue gas of a biomass power station is not yet a common practice, the technologies used for both power generation and for post combustion capture are mature and each at a state of development where they could be classed as commercially proven. Hence, the technology risks associated with applying BECCS to biomass power generation are low.

Pre-combustion capture refers to removing CO<sub>2</sub> from syngas, typically post water gas shift stage. Compared to post-combustion technology, which removes dilute CO<sub>2</sub> (~5-15% CO<sub>2</sub> concentration) from flue gas streams and is at low pressure, the shifted synthesis gas stream is rich in CO<sub>2</sub> and at ideally

higher pressure, which allows for easier removal. Due to the more concentrated CO<sub>2</sub>, pre-combustion capture typically is more efficient but the capital costs of the base waste gasification process and gas cleaning sections are often more expensive than traditional fossil-based power plants. Today's commercially available pre-combustion carbon capture technologies generally use physical or chemical adsorption processes, and will cost around \$60/tonne to capture CO<sub>2</sub> generated by an integrated gasification combined cycle (IGCC) power plant (Balcombe et al., 2018). The goal of biohydrogen's research efforts is to reduce this cost to \$30/tonne of CO<sub>2</sub>. The commercial technologies for pre-combustion CO<sub>2</sub> capture available today share a similar process layout consisting of two successive phases of absorption and desorption of CO<sub>2</sub>. The absorption phase uses a solvent to remove CO<sub>2</sub> from the shifted syngas, producing a H<sub>2</sub>-rich stream. The following phase desorbs CO<sub>2</sub> regenerating the solvent that is recirculated to the absorption phase. These technologies differentiate according to the solvent used and the specific operating conditions that it requires. They are characterised as physical (e.g. Selexol, Rectisol, etc.) or chemical (e.g. amine, Benfield, etc.) depending on whether the CO<sub>2</sub> is simply physically dissolved or is chemically bound to the solvent. A key difference is that chemical absorption requires increasing temperature for desorbing CO<sub>2</sub>, whilst in physical absorption this can be achieved by solely reducing the pressure (L'Orange Seigo et al., 2014).

The H<sub>2</sub>-rich stream is purified via a methanation reactor first, and pressure-swing adsorption (PSA) to obtain a H<sub>2</sub> stream suitable for gas grid injection (>98% v/v), which is then compressed to 46 bar for storage. The tail gas from the PSA contains primarily CO<sub>2</sub> and H<sub>2</sub>, as well as traces of other combustible (e.g. CH<sub>4</sub>) and non-combustible (e.g. N<sub>2</sub>) substances from syngas and of the solvent. The gas is burnt in a gas engine for generation of electricity and thermal energy. The former can be sold to the electric grid operator, whilst the latter is recovered in the WGS phase. On the other hand, the CO<sub>2</sub>-rich stream from the desorption phase is compressed to 60 bar and transported via lorry, sea tankers and finally through pipelines prior to being injected in saline aquifer at 120 bar.

### 3. METHODOLOGY

With the application of LCA according to ISO standards, a comparison of different low-carbon hydrogen production routes was undertaken. For the construction of this LCA model, primary inventory data for a 50 MW Bio-H<sub>2</sub> plant have been collected from the UK waste gasification company, ABSL. The production of Bio-H<sub>2</sub> from waste is considered a multifunctional process, defined as an activity that fulfils more than one function; in this case, the thermochemical process dealing with waste and energy generation. Following the relevant ISO standards, the environmental benefits from recovered resources should be accounted for by expanding the system boundaries to include the avoided burdens of conventional production (Clift et al., 2000). The environmental burdens of Bio-H<sub>2</sub> production include: the direct burdens allocated to all the operational units and elementary flows considered in the system boundaries; the indirect burdens allocated to the external supply of material and energy processes; and the avoided burdens allocated to the recovery of materials from waste during the RDF preparation stage (e.g. ferrous metals and non-ferrous metals), as well as the production of electricity and hydrogen. A conservative uncertainty analysis on the impact of Bio-H<sub>2</sub> has been carried out to account for application of different technologies and corresponding energy requirements, as well as the variation due to the waste composition that results to be the main contributor to the overall uncertainty. Table 2 reports the key inventory data of the three hydrogen production technologies, summarising the total input and output flows per functional unit (1 MWHHV of transport-grade H<sub>2</sub>). Further description of the inventory for each process are presented in (Amaya-Santos et al., 2021).

Table 2. Key inventory data of the three hydrogen production processes. Flow quantity is referred to functional unit (1 MWHHV transport-grade H<sub>2</sub>) and 1h as unit of time.

Key flows	Biohydrogen (MSW)	Biohydrogen (Waste wood)	Blue Hydrogen		Green Hydrogen
			SMR	ATR	
<b>Input</b>					
Feedstock type	MSW/RDF	Waste wood	Natural gas		Water
Feedstock [kg MSW/RDF]	393.9/247.4	338.04	80.56	79.65	226.8
Oxygen [kg]	113.4	113.6	-	77.4	n.a.
Electricity [MJ]	700	640	217.13	296.91	4974
Thermal energy [MJ]	256	255	-	-	n.a.
<b>Output</b>					
Hydrogen [MJ]	3600	3600	3600		3600
Materials recovered [kg]	18.8	-	-	-	-
CO <sub>2</sub> released [kg]	32.5	41.1	21.6	13.96	0
Sequestered CO <sub>2</sub> [kg]	292.5	370.1	194.4	265.5	n.a.

## 4. RESULTS AND DISCUSSION

### 4.1. Climate Change Impact

Different scenarios of the Bio-H<sub>2</sub> production process are presented with regards to climate change impact (CCI). These scenarios showcase the consequences of capturing point carbon emissions via carbon capture and storage (CCS) and of considering (thereby crediting) the biogenic carbon fraction of feedstock. A carbon capture rate of 90% is employed in all cases with CCS. The baseline biogenic fraction of RDF used is ~60% as per Table 1. When accounting for the difference between biogenic and fossil carbon, biogenic carbon emissions to air is considered carbon neutral. Thus, in the scenario where CO<sub>2</sub> is not stored, only the impact from fossil source carbon emissions is considered. Corresponding scenarios produce a carbon negative impact when CCS is applied to the system, as carbon is effectively being removed from natural carbon cycle. This translates to the total climate change impact of the Bio-H<sub>2</sub> of -217 CO<sub>2</sub> eq. for scenario using RDF as a feedstock, and -304 kg CO<sub>2</sub> eq. for scenario using waste wood.

In Fig. 1, an additional analysis is presented, in which the avoided emissions associated to the MSW counterfactual are included. If not treated in advanced thermochemical facilities, current waste management practises call for disposal either through incineration or landfill. Incineration with energy recovery (WtE) represents the most common practice around the world and thus is considered as a realistic counterfactual. Similarly, to previous cases, only emissions associated to the fossil carbon fraction of feedstock have been accounted for. Although electricity and materials are recovered from the process, and thus credited on the final GHG output, the incineration option still shows a substantial climate change contribution of 202 kg CO<sub>2</sub> eq. per MWHHV H<sub>2</sub>. Therefore, by diverting waste from being incinerated, the benefit of Bio-H<sub>2</sub> on climate change can be further pronounced, with a negative contribution to climate change of -419 kg CO<sub>2</sub> eq. per MWHHV of H<sub>2</sub> produced. Even higher benefits could be observed if considering as counterfactual other waste management practises, such as landfill or incineration with no energy recovery.

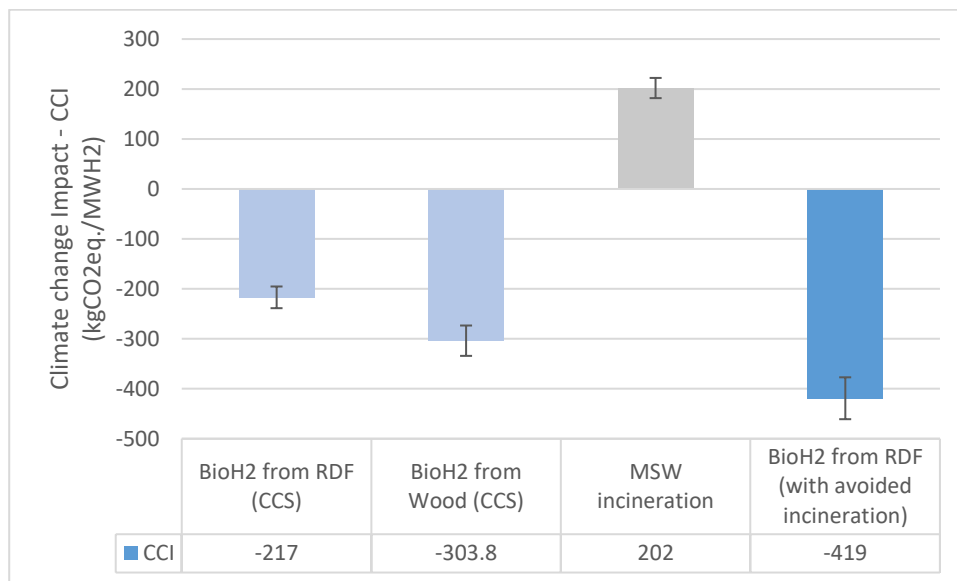


Figure 1: Climate change impact (CO<sub>2</sub> eq. per FU) regarding carbon capture and storage and considering the biogenic fraction of the CO<sub>2</sub> stream. Uncertainties calculated based on technical variations in energy usage.

#### 4.2. Comparative analysis between Bio-H<sub>2</sub>, Blue-H<sub>2</sub> and Green-H<sub>2</sub>

In the present analysis, the environmental performance of the Bio-H<sub>2</sub> technology is compared to other two competitive low-carbon technologies, Blue- and Green-H<sub>2</sub>, considering the Climate Change (kg CO<sub>2</sub> eq.) impact only. The results are expressed per functional unit, 1 MWHHV of transport grade hydrogen produced from all examined processes. The comparison of the environmental performance of the three routes has been performed taking into account the environmental burdens allocated solely to the production of hydrogen i.e. excluding system expansion methodology. To accurately compare Bio-H<sub>2</sub> with other technologies, credits associated to material recovery and the counterfactual effect of MSW incineration are not considered for analysis to ensure consistency in system boundaries between technologies. The contributions to climate change of the technologies are depicted in Figure 2. Bio-H<sub>2</sub> production shows the lowest contribution to climate change, equating to -183 kg CO<sub>2</sub> eq. These results show that the production of hydrogen from MSW together with the sequestration of carbon, is not only an effective solution to waste disposal, but it is also appropriate to achieve the objectives proposed by the Net Zero 2050; its implementation involves the removal of nearly a quarter ton of CO<sub>2</sub> per MWHHV of H<sub>2</sub> produced every hour.

Blue-H<sub>2</sub> produced via steam methane reforming process (SMR) with CCS process (carbon capture rate of 90%) produces 63.2 kg CO<sub>2</sub> eq. per MWHHV transport grade H<sub>2</sub>. Approximately 40% of the impact derives from the embodied carbon of natural gas feedstock, rendering the process sensitive to changes in natural gas source. The upstream emissions are associated to its processing and, for imported NG, to its liquefaction and shipping. An additional ~40% arises from the steam methane reforming process including 10% of the CO<sub>2</sub> process stream emitted to air. The remaining climate change impact is ascribed to the electricity required for CO<sub>2</sub> liquefaction and H<sub>2</sub> compression. The difference between SMR and ATR in favour of ATR is related to the higher CO<sub>2</sub> fraction in the syngas generated by the latter, and therefore, more efficient carbon capture.

A competitive Green-H<sub>2</sub> route of production is limited by the high electricity demand of the electrolyser. This is evident when operating an electrolyser using the current UK electricity grid mix leading to a marked environmental underperformance, with a climate change impact of 374 kg of CO<sub>2</sub> eq. per MWHHV H<sub>2</sub>. This limitation can obviously be overcome by using exclusively renewable sources. As shown in Fig. 2, the electricity demand of the electrolyser and H<sub>2</sub> compression unit met by electricity produced 100% from



solar and 100% from offshore wind contribute 99 kg CO<sub>2</sub> eq. per MWHHV H<sub>2</sub>, and 22.5 kg CO<sub>2</sub> eq. per MWHHV H<sub>2</sub>, respectively. The greater impact from solar compared to offshore wind is primarily from the energy intensive manufacture of silicon solar cells.

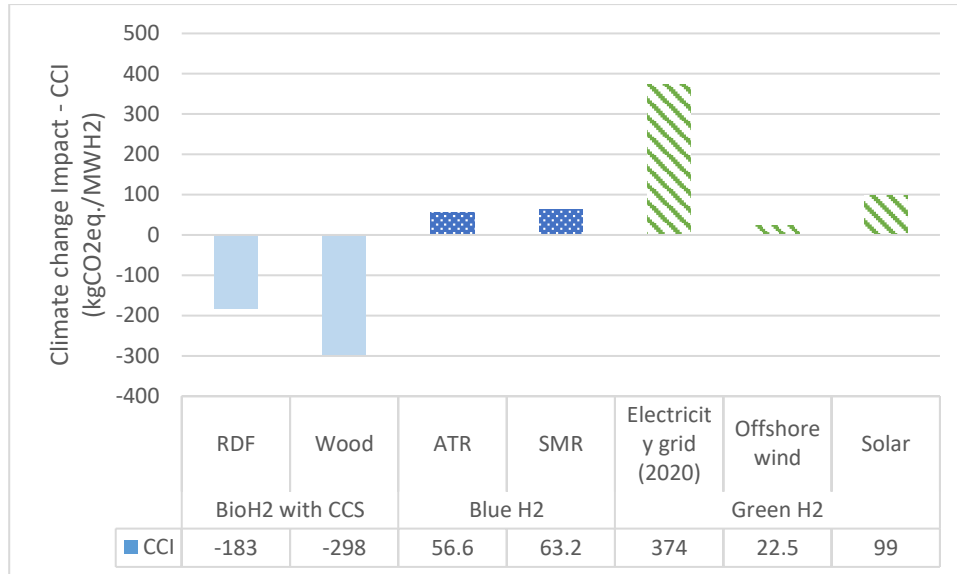


Figure 2: Climate Change contribution comparison of Bio-H<sub>2</sub>, Blue-H<sub>2</sub> and Green-H<sub>2</sub> production technologies.

The evolving pertinence of these technologies within the energy transition landscape is an important consideration as LCA results have been reported to be strongly affected by the energy supply, particularly electricity. Thus, any processes with a high electricity input will benefit from decarbonisation of the grid.

### 4.3. Interaction between low carbon hydrogen production pathways

It will be extremely challenging for any one of the low carbon hydrogen technologies to meet alone the expected level of hydrogen demand set out by Net Zero ambition. It seems likely that all options will play a role in the transition to hydrogen. Green hydrogen has the potential to be produced sustainably in large volumes. However, it will take time for low carbon electricity generation to grow to the scale that meets current electricity demand, plus the additional demand required to decarbonise heat and transport with hydrogen. In addition, electrolyser technology requires several years to develop to the point that it can produce hydrogen at costs that compete with blue hydrogen. Blue hydrogen can be produced at large scale in a few years' time at relatively low cost. However, it is a less sustainable solution in the long term and cannot match the carbon savings achieved by green hydrogen and biohydrogen. Biohydrogen has the potential to generate negative carbon emissions if combined with carbon capture and storage. However, overall production of biohydrogen is limited by the availability of sustainable feedstock. It cannot be produced in sufficient volumes to meet the overall expected demand.

There are important synergies between different low carbon hydrogen production pathways. For example, blue hydrogen might establish the hydrogen market that green hydrogen will meet in future or build the carbon sequestration network required for biohydrogen to deliver negative emissions. These negative emissions can offset the residual emissions from blue and green hydrogen production. Green hydrogen might supply hydrogen to consumers that are remote from the blue hydrogen production centres. The different hydrogen production options all have different infrastructure requirements, with blue and bio hydrogen reliant on CCS infrastructure. The large-scale ATR plants required for blue hydrogen production also suits the large industrial clusters, where infrastructure, such as a supply of natural gas

and potentially by-product oxygen are available. The industrial clusters across the UK would therefore suit blue hydrogen production, with the locations along the East coast and North West England developing plans for carbon dioxide pipelines for offshore carbon dioxide storage (see Figure 9). The industrial clusters in South Wales and Southampton would require shipping carbon dioxide to offshore storage sites. Green hydrogen production can be developed at smaller scale than blue hydrogen and although green hydrogen does not require CCS infrastructure, there are benefits to installing electrolyzers alongside renewables or close to hydrogen demands / hydrogen infrastructure. The map of industrial clusters in Figure 3 also highlights regions where there are large energy demands from industrial processes, which could become early adopters of hydrogen. At a smaller scale, where hydrogen can be transported via road tankers to serve transport demands, green hydrogen production plants could be located where renewables are best-sited (to access lowest cost power). In the medium term, larger green hydrogen production plants will be developed either in locations close to very large renewable assets (e.g. in coastal locations where offshore wind farm electricity is landed) or in locations closer to large-scale users, such as industrial clusters, to avoid long range hydrogen transport before wider conversion of the gas network becomes available to transport 100% hydrogen. A 100% hydrogen gas network would open up more options for green hydrogen production sites, including the production of hydrogen offshore, connected to offshore wind farms. At a certain scale, the cost of transporting energy in a gaseous form (as hydrogen) can be lower than the costs of transporting energy via electricity. There would be further cost benefits for hydrogen transport if oil and gas pipelines could be repurposed for hydrogen transport. Biohydrogen would require CCS infrastructure to deliver very high GHG savings and therefore is suited to the industrial clusters shown in Figure 3. The use of biohydrogen without CCS can still provide GHG emission savings relative to incumbent fuels and converts waste streams into a valuable product, with hydrogen a higher value output than electricity from energy from waste plants. There could therefore be a degree of flexibility with regard to siting some of the plants at locations without CCS infrastructure across the UK, although the full benefits of the technology would require siting around the industrial clusters, or locations with carbon dioxide demand. Biohydrogen technology can also be deployed at far smaller scales than blue hydrogen, allowing it to offer a more distributed approach to hydrogen production.

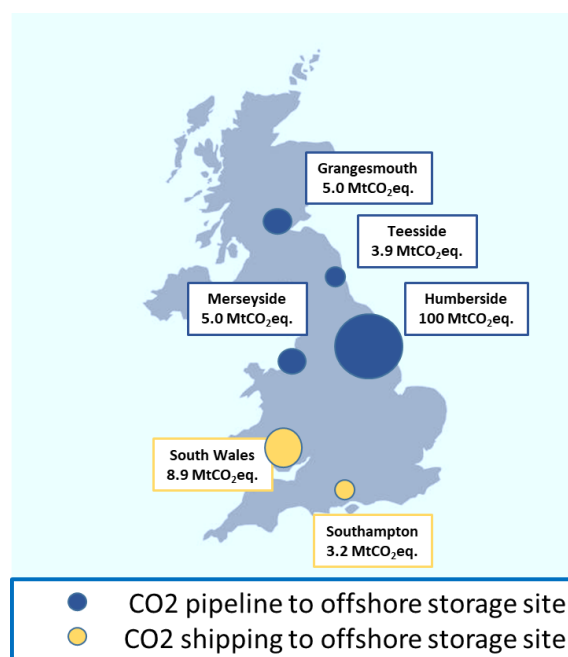


Figure 3: Location of industrial clusters in the UK and annual GHG emissions from each (Adapted from BEIS, 2021)

## 5. CONCLUSIONS

There is a significant scale-up challenge for low-carbon hydrogen production if the UK is to meet its Net Zero target by 2050. Given the significant demands for low carbon hydrogen it is clear that all of the three low-carbon production routes are needed and that these need to be developed at pace. The build out rates for all the options presented above will be challenging to meet, and support to develop low carbon hydrogen markets will be needed to encourage investment in delivering the scale-up of the hydrogen production capacity. This work showed that Bio-H<sub>2</sub> can be a competitive technology to aid the near- and medium-term transition to hydrogen economy, as well as a long-term complement to other low carbon hydrogen alternatives. Not only it is an effective solution to waste disposal, but it is also appropriate to achieve the objectives proposed by the Net-Zero 2050 for it being a viable carbon-negative technology.

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