UK Government

Energy Innovation Research Office (EIRO): An Updated Assessment of Hydrogen BECCS technologies

Final Report

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Authors

Will Bowling - *Systems Engineer (Hydrogen Production)*

Katie Chong - *Senior Systems Engineer (Bioenergy)*

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Any enquiries regarding this publication should be sent to us at:
EnergyResearch@energysecurity.gov.uk

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Executive summary

Recognising their importance in achieving net zero, the UK Government is committed to developing and deploying greenhouse gas removals (GGRs) at scale. Greenhouse gas removals (GGRs) are methods that remove greenhouse gases from the environment. There are two main categories of GGR, nature-based, such as afforestation, and engineered, such as Direct Air Carbon Capture and Storage (DACCS).

Hydrogen production from biomass with carbon capture and storage (H2BECCS) could play a key role in achieving the UK's greenhouse gas removals (GGRs) and low-carbon hydrogen ambitions. This study, commissioned by DESNZ, was conducted in two phases:

- Phase 1: Updated assessment of H2BECCS technologies and their potential deployment in the UK.
- Phase 2: Modelling study evaluating role of H2BECCS in achieving Net Zero emissions by 2050.

<u>Phase 1</u>

Phase 1 of this study focused on updating the technical and cost assumptions for H2BECCS technologies to support future modelling activities, addressing previous uncertainties caused by low Technology Readiness Levels (TRLs), data restrictions, and a scarcity of commercial demonstration projects [1], [2]. Recent advances, notably through the Hydrogen BECCS Innovation Programme and ongoing research and development have significantly increased the evidence base, enabling the refinement of assumptions using more rigorous and up-to-date data.

A detailed assessment of current literature and consultation with industry experts resulted in an updated evaluation of H2BECCS technologies.

Literature review

This process identified key technology advancements, deployment challenges, and gaps in current assumptions, ensuring that future modelling efforts appropriately reflect the most recent developments in H2BECCS feasibility, commercial readiness, and scalability. Five H2BECCS technology options were assessed, each at different stages of technological maturity and deployment readiness:

- Biomass Gasification with CCS was identified as the most commercially advanced, with existing global deployment (excluding CCS). This thermal process produces syngas from biomass and is expected to dominate H2BECCS capacity deployment by 2050.
- Biomass pyrolysis with CCS is a lower-TRL hydrogen production pathway with promising carbon reduction potential but is currently limited to laboratory-scale development. Challenges remain in scaling the process and managing coproducts.

- Anaerobic digestion (AD) with steam methane reforming (SMR) and CCS leverages well-established technologies, making it a viable route for large-scale deployment. However, commercialisation challenges persist due to its distributed production model.
- Dark fermentation builds on AD processes, enhancing hydrogen and biomethane yields, but remains at a pilot stage, with significant technical uncertainties.
- Wastewater ammonia conversion is a low-TRL innovation that integrates ammonia cracking and SMR, offering potential benefits for wastewater treatment facilities, but scalability is limited to locations with adequate infrastructure.

Workshops

Workshops 1 and 2 brought together stakeholders from industry, academia, and government to test and refine assumptions developed during the initial landscape review. Workshop 1 focused on critically assessing assumptions, identifying data gaps, and gathering expert input on technology readiness levels and commercialisation timelines. Key challenges highlighted by stakeholders included the need for large-scale deployment to meet hydrogen demands, high CAPEX and energy use, feedstock supply issues, and uncertainty around hydrogen offtake markets. Workshop 2 aimed to validate the updated techno-economic assumptions used to inform the modelling phase and explore policy options to address the barriers identified. Stakeholders reaffirmed that commercial barriers dominate, with availability of hydrogen offtakers, feedstock competition, and investment risks ranked as top challenges.

The technology with the highest level of confidence was found to be biomass gasification with CCS as commercial operations (excluding CCS) are already established. This technology option provides reliable performance and cost data, reinforcing its projected dominance in future H2BECCS deployment.

For the other four technologies (pyrolysis, anaerobic digestion with SMR, dark fermentation, and wastewater ammonia conversion), uncertainty remains higher due to:

- Limited commercial-scale deployment
- Reliance on lab-scale data or single-plant outputs
- Challenges in scaling and process optimisation

Despite these uncertainties, baseline values were captured from literature and assigned for all technologies to support future work. The report also provides process flow diagrams and key technical insights, offering clarity on the operational feasibility and deployment potential of each technology. Table 1 provides a summary of the key technical parameters that were identified in the literature review and stakeholder workshops.

Table 1 - Summary table of the key parameters of the five H2BECCS technologies. Emissions intensity is full lifecycle, taking into account the negative emissions from the biomass feedstock along with the process carbon capture. Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, and CO2 compression, transport and storage costs are not included. These are the costs for the first year available. Further explanation of costs can be found in Appendix 5.

H2BECCS Technology	TRL	First Year Available	Emissions Intensity[1] kg CO_{2eq}/kg H_2	LCOH[2] £2023/kg	Confidence Level
Biomass Gasification with CCS	7 - 8	2030	-22	**3.7**	**High**
Anaerobic Digestion with Steam Methane Reforming and CCS	5 - 7	2030	-11.6 - -8.6	**4.7 – 5.9**	**Medium**
Wastewater ammonia conversion	2 - 3	2035	-3.5 - -6.4	**2.9 – 5.3**	**Low**
Biomass Pyrolysis with CCS	3 - 4	2040	-13.8 - -3.8	**4.1 – 5.5**	**Low**
Dark Fermentation	5 - 8	2030	-1.6 – - 1.0	**2.0 - 3.2**	**Medium**

Phase 2

Phase 2 of the H2BECCS project focused on evaluating the potential for H2BECCS deployment in the UK across various policy, market and feedstock availability (domestic and international) scenarios. The key activities in Phase 2 included assessing the Maximum Technological Deployment Potential (MTP) using updated engineering constraints and insights from existing biomass power plant deployments in the UK, applying realistic build rates and alignment with industry expectations as set out during the Phase 1 stakeholder workshops. Technology assumptions were revised to reflect the latest advancements captured in Phase 1, including biomass-to-hydrogen conversion efficiency, plant availability factor, and capital and operational costs. Whole energy systems modelling was used to understand how H2BECCS might integrate within the broader UK energy landscape. This approach captures the complex interdependencies between energy supply, demand,

[1] Emissions intensity is full lifecycle, taking into account the negative emissions from the biomass feedstock along with the process carbon capture.
[2] Levelised cost of hydrogen (LCOH) was calculated using multiple results from literature, this can lead to challenges around differing assumptions and system boundaries, as a result these values are indicative and should be used with this in consideration. The costs are for the first year available and are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included. Costs have been adjusted to 2023£.

infrastructure, and policy, enabling assessment of H2BECCS in the context of decarbonisation pathways and competing technologies. This modelling was conducted using the Catapult's Energy Systems Modelling Environment (ESME) to evaluate four distinct scenarios:

- **Policy-Led** reflects a strategy driven by strong government intervention and support.
- **Industrial Cluster Propagation** represents a geographically focused approach, with hydrogen deployment concentrated around key industrial clusters.
- **Hydrogen Optimism** envisions accelerated innovation, achieving commercial viability five years earlier than anticipated.
- **Hydrogen Pessimism** reflects a future where hydrogen innovation stalls, delaying commercial viability by five years beyond current expectations.

A sensitivity analysis was also conducted to assess the impact of variations in biomass feedstock availability, carbon capture rates, and costs on H2BECCS deployment pathways. Feedstock availability and consumption was varied using three global biomass import scenarios from the UK Biomass Strategy (2023) —**Restricted** (<100 TWh), **Moderate** (~150TWh), and **Ambitious** (>200 TWh)—while UK domestic biomass production was constant across all scenarios.

The key findings from the Phase 2 study included several important insights. Compared to previous analyses, the updated technology parameters led to a slower initial deployment due to higher capital costs and tighter build rate constraints. After 2045, deployment accelerated, driven by increasing hydrogen demand and tightening CO_2 targets, ultimately reaching approximately 6 GW by 2050. The modelling result illustrates that even if a technology is expensive in the short term, and the potential to scale-up and build in the short term is slow, it can still scale up significantly in the long term as long as there are strong enough policy pressures and market demand to push growth forward. Beyond the study, this shows that early adoption should not deter policymakers and investors. Instead, they should focus on enabling the right conditions that support long-term deployment potential, such as supportive policies, funding mechanisms and market structures, to help trigger accelerated progress over time.

The availability of biomass feedstock is a critical factor in scaling H2BECCS, with the technology remaining the dominant consumer of biomass by 2050, despite variations in supply. Scenarios highlight the importance of sufficient sustainable feedstock supply to both scale up H2BECCS capacity and achieve the negative emissions necessary to meet Net Zero. The amount of biomass directly impacts CO_2 capture and negative emissions, with large supplies of sustainable biomass and CCS technologies being essential for achieving Net Zero through negative emissions technologies like BECCS and DACCS. This modelling suggests that at least 200TWh of biomass is required to reach Net Zero, although previous analyses have shown as little as 130TWh of biomass is required when combined with high penetration of DACCS (~50MtCO2 capacity).

Scenario analysis shows that H2BECCS is deployed up to the maximum technological deployment potential in 2035 across all scenarios. MTP is defined as the upper limit on how quickly and extensively H2BECCS plants can be built, based on engineering constraints and realistic build rates, rather than resource availability or market demand. MTP is therefore a constraint imposed on the model's choices. After reaching this limit in 2035, no additional capacity is added in the 2040s, except in the Policy-Led scenario, resulting in a plateau in deployment. Power-BECCS refers to electricity generation using sustainable biomass feedstocks combined with carbon capture and storage (CCS) technology. There is a key interplay between power BECCS and H2BECCS which results in most scenarios not deploying additional capacity in 2040. The model prioritises build out of Power BECCS in the mid-late 2030s due to being comparably cheaper than H2BECCS. The time and scale at which this deployment occurs is based on the cost of H2BECCS in comparison with power BECCS, relative to the negative emissions and power sector benefits each of the technologies offer respectively.

Before 2050, most scenarios show a mix of biomass use, with power BECCS playing a key role in the energy system. H2BECCS deployment is driven by hydrogen business models and carbon reduction ambitions. H2BECCS is crucial as a negative emission hydrogen vector if demand for hydrogen, particularly from transport and industry, evolves towards meeting Net Zero by 2050.

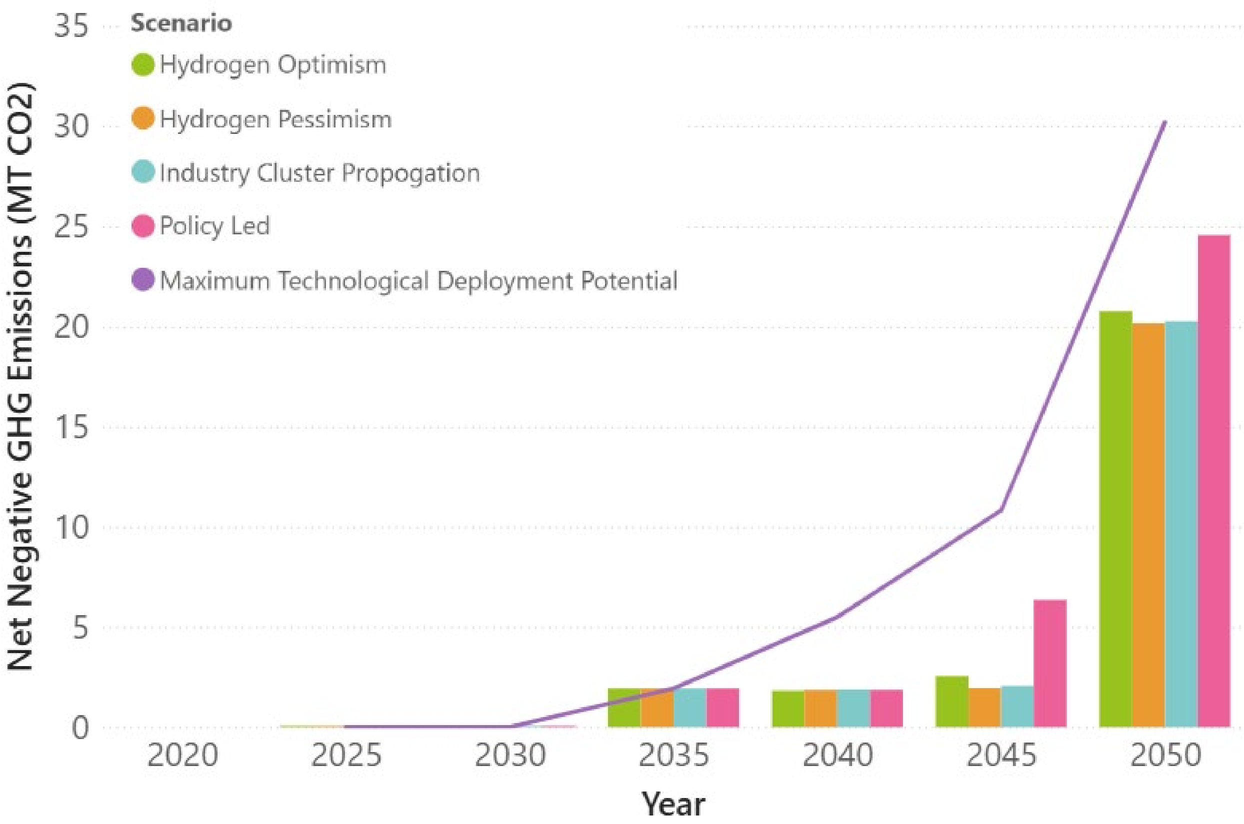


Figure 1 - H2BECCS Net Negative GHG Emissions across varying deployment scenarios compared with the negative emissions potential from the Maximum Technological Deployment Limit from 2020 to 2050. See text below for model behaviour description.

In the Policy-led scenario, as shown in Figure 1, H2BECCS captures the most CO_2 out of all the scenarios, with a projected net negative greenhouse gas emissions of 1.9 $MtCO_2$/year by 2035, rising to 6.4 $MtCO_2$/year by 2040 and 24.6 $MtCO_2$/year by 2050. In the Hydrogen Pessimism and Industrial Cluster Propagation scenarios, fossil-based hydrogen production with CCS meets most of the hydrogen demand into the 2040s, reducing H2BECCS deployment. The Hydrogen Optimism and Policy-led scenarios produce more hydrogen from electrolysers, increasing electricity consumption. To meet the increased electricity demand, additional power BECCS is deployed in these instances.

In 2050, all scenarios build as much H2BECCS capacity as possible and are once again limited by build constraints imposed on the model. This underlines the essential role of H2BECCS in meeting rising hydrogen demand and achieving Net Zero through negative emissions based on the constraints imposed. These findings highlight the need for cost reduction, favourable policy support, and coordinated whole systems planning to accelerate H2BECCS deployment as early as possible to unlock its full potential in supporting both hydrogen availability and the UK's Net Zero commitments.

Research questions

RQ1: How do the cost ranges of different Hydrogen BECCS technologies, such as biomass gasification and steam biomethane with CCS, scale over time up to 2050?

This report refines the cost assumptions for biomass gasification with CCS, improving confidence in projections for UK energy system modelling. These values have been developed using peer-reviewed literature, industry data, and stakeholder workshops, improving confidence in these projections. CAPEX and OPEX values have been scaled and validated using available data from literature. For the other technologies, constraints with data availability and TRLs have resulted in limited confidence. Further demonstration projects are needed to enhance cost confidence for lower TRL technologies.

Table 1 presents the levelised cost of hydrogen for the different H2BECCS technologies as derived from the literature review. It is important to note that due to the lower TRL of some technologies, these costs have lower confidence levels. Further analysis was completed for the highest TRL technology, biomass gasification with CCS to understand the CAPEX and OPEX values of two plant scales, 200 MW and 500 MW. Table 2 shows the plant costs as they change from 2015 to 2050[3].

[3] The values are components of a calculation of LCOH taken from various papers including the Hydrogen Europe report [65]. This is further outlined in Appendix 5.

Table 2: Cost projections for biomass gasification plant with CCS[4]. *Median value from references.

	Units	2015	2020	2025	2030	2035	2040	2045	2050
500 MW Indicative Plant Capacity									
CAPEX	£2010/kW	1206	1161	1116*	1072	1027	982	938	893
Fixed OPEX	£2010/kW/yr	60	58	56	54	51	49	47	45
200 MW Indicative Plant Capacity									
CAPEX	£2010/kW	1740	1675	1611	1546	1482	1417	1353	1289
Fixed OPEX	£2010/kW/yr	87	84	81	77	74	71	68	64

RQ2: What are the maximum technological deployment potential (MTP) and build rate limits for scaled removals (in 5-year increments) for the different Hydrogen BECCS technologies?

During Workshop 2, stakeholders provided deployment estimates for various H2BECCS technologies, considering plant size (50 MW) and the timeline for scaling from single plants (1s) to tens (10s) and then hundreds (100s).

- Biomass gasification with CCS was identified as the most mature technology, with deployment expected by 2030, reaching tens of plants by 2035.
- Anaerobic digestion (AD) with CCS was also seen as a viable route, though slightly lagging gasification.
- Pyrolysis and wastewater ammonia conversion had significantly slower predicted rollouts due to technological immaturity and integration challenges.
- Stakeholders expressed high uncertainty around the deployment potential of less mature H2BECCS technologies, as reflected in the wide ranges of estimates shown in Figure 2.

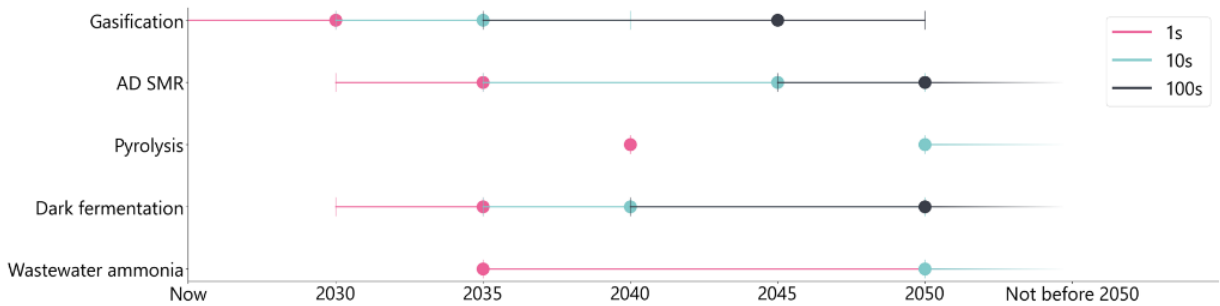


Figure 2 – Box and whisker plots of the deployment potential of various 50 MW H2BECCS plants.

[4] Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included.

RQ3: What are the key barriers to achieving the maximum technical potential?

Achieving the maximum technical potential for H2BECCS technologies involves addressing a wide range of technical, economic, regulatory, and societal barriers. Key insights from the stakeholder workshops include high capital costs, volatility in hydrogen demand and offtake certainty, and competition for biomass. To address these barriers, stakeholders emphasised the need to reduce investor uncertainty through targeted government support, such as long-term policy alignment and robust financial incentives.

RQ 4: What is the maximum technological deployment potential (MTP) and build rate limit for scaled removals (in 5-year increments from 2030-2050) for biomass gasification H2BECCS plants?

The Maximum Technological Deployment Potential (MTP) and build rate limits for scaled removals of H2BECCS technologies were estimated based on engineering constraints, stakeholder insights, and deployment trends from comparable biomass-based technologies. Initial deployment is projected from 2035, reflecting the five-year time steps used in UK TIMES and ESME models. In line with stakeholder workshop findings, hydrogen production capacity is expected to reach 6.9 GW by 2050.

Table 3 - H2BECCS Maximum Technological Deployment Potential – GW Hydrogen production capacity.

Deployment Year		2025	2030	2035	2040	2045	2050
Historical biomass powerplant deployment curve offset to 2035 (GW)		0.00	0.00	0.09	0.17	0.29	2.70
Stakeholder Workshop Outputs (GW)		0.00	0.05	0.50	1.50	3.00	6.50
Technological deployment potential (GW)	Upper Range (+50%)	0.00	0.00	0.44	1.25	2.47	6.90
	Median	0.00	0.00	0.29	0.84	1.65	4.60
	Lower Range (-50%)	0.00	0.00	0.15	0.42	0.82	2.30

RQ 5: Applying the MTP, what is the "realistic" scaling potential for H2BECCS, factoring in constraints on biomass availability, CCUS storage availability, demand from hydrogen offtakers, and delays to rollout?

While the Maximum Technological Potential (MTP) enables 7 GW of deployment by 2050, system limitations mean full-scale deployment is unlikely before 2045. The most optimistic scenarios, shown in Figure 1, see H2BECCS reaching around 6 GW hydrogen production capacity and 24.6 $MtCO_2$ net negative emissions, by 2050, but this is contingent on overcoming several bottlenecks as identified in Phase 1.

CCUS readiness will be crucial in determining whether H2BECCS can scale towards its full potential, and competition with other biomass-consuming technologies will further challenge deployment. H2BECCS competes with Power BECCS for limited biomass resources, impacting its scaling potential. Both technologies play a critical role in delivering negative emissions, but the allocation of biomass between them depends on factors such as energy system priorities and hydrogen demand growth.

Overall, while H2BECCS has significant potential, real-world constraints on biomass supply, CCUS rollout, and hydrogen demand suggest a realistic scaling potential of 4–6 GW by 2050 (24 – 30 $MtCO_2$/year Captured), with significant deployment only materialising in the later years. Stronger policy incentives and accelerated infrastructure development will be needed to unlock its full contribution to Net Zero.

About Energy Systems Catapult

Energy Systems Catapult is an independent research and technology organisation. The Catapult's mission is to accelerate Net Zero energy innovation.

Launched in 2015 by Innovate UK, the Catapult has built a team of more than 300 people, with a range of technical, engineering, consumer, commercial, incubation, digital, and policy expertise. The Catapult draws on sector-leading test facilities, modelling tools, and data collected from its back catalogue of more than 500 research projects.

The Catapult uses that 'whole energy' system capability to support innovative companies - small and large – to test, trial and scale new products and services. Impact comes when those innovators attract new customers, new investment, and new grants so they can thrive in the future energy system.

Based in Birmingham, Energy Systems Catapult is part of a network of nine world-leading technology and innovation centres, established by Innovate UK. The Catapult Network fosters collaboration between industry, government, research organisations, academia, and many others to transform great ideas into valuable products and services.

We have five strategic ambitions:

- UK companies supported by Energy Systems Catapult are global leaders in energy innovation.
- That it becomes easy and desirable for people to decarbonise their homes.
- That businesses and the public sector have the tools to quickly and easily decarbonise the energy used in their buildings and sites.
- Every local area in the UK is investing in new, Net Zero energy infrastructure, based on robust whole system plans.
- A new flexible, digitalised Net Zero energy system is being rapidly rolled out, which is more resilient and better for all consumers.

Project Introduction

This project spanned six months with two phases. The first involved updating H2BECCS technology assumptions. The second phase was to utilise the updated assumptions to provide modelling insights to DESNZ around the future deployment of the technology. The project was structured into five work packages:

Table 4 - Work package summary

Work Package Summary
Phase 1: Updated assessment of hydrogen BECCS technologies and their potential deployment in the UK
WP1: Assessment of previous work/landscape review Assess existing evidence on Hydrogen BECCS technologies, focusing on key research questions and current DESNZ assumptions. Identify gaps in current assumptions and determine areas needing further work.
WP2: Data collection & stakeholder engagement Establish a monthly government steering group to guide the project. Identify and engage stakeholders from academia, industry and government to understand latest developments and gather techno-economic data.
WP3: H2BECCS technology assessment Gather detailed data on technology performance, environmental impacts, resource usage, and economic indicators tracked from 2028 to 2050. Blank data inputs compatible with UK TIMES provided by DESNZ.
Phase 2: Modelling study of the role of H2BECCS in achieving Net Zero emissions by 2050
WP4: Methodology development and modelling baseline assumptions Utilise the learning from Phase 1 as well as the outputs from the stakeholder engagement exercise to update the baseline assumptions for the ESME modelling. This includes a definition of the Maximum Technological Deployment potential.
WP5: Analysis and reporting Investigate the impact of the updated H2BECCS technology assumptions within the context of the Hydrogen Innovation Initiative scenarios. This provides insights into the realistic scaling potential for H2BECCS, factoring biomass availability and other key metrics.

Phase 1: Updated assessment of hydrogen BECCS technologies and their potential deployment in the UK

Introduction

Bioenergy with carbon capture and storage (BECCS) is a critical technology for achieving Net Zero carbon goals. It involves using biogenic feedstocks (e.g. perennial energy crops, short-rotation coppicing, wood, waste wood, agricultural residues, and other biogenic waste) to produce energy while capturing and permanently storing the carbon dioxide (CO_2) emissions generated during the process. Since plants absorb CO_2 during growth, BECCS can result in a net removal of CO_2 from the atmosphere, contributing to net negative carbon emissions.

Hydrogen BECCS (H2BECCS) extends the concept by producing hydrogen from biogenic sources while capturing and storing the carbon emissions. Hydrogen is generated through methods such as biomass gasification or steam reforming of biomethane, with CO_2 captured during the conversion process. H2BECCS offers dual benefits: producing a clean energy carrier (hydrogen) while enabling greenhouse gas removals (GGR), addressing both decarbonisation and energy transition needs.

The urgency of climate change requires the widespread use of negative emissions technology to supplement emissions reductions and offset the harder-to-decarbonise sectors or residual emissions in other sectors. BECCS, including H2BECCS, is necessary for the following reasons:

Net Zero goal: To meet the UK's legally binding Net Zero aim by 2050, significant CO_2 removals must be combined with emission reductions. BECCS technologies can generate power, heat, and various fuels including hydrogen (H2BECCS). Hydrogen can then be supplied to difficult-to-decarbonise sectors such as heavy industries and transportation.

Policy alignment: The UK Government is committed to developing and deploying GGRs at scale, which could require large-scale BECCS deployments in addition to other GGR options.

Economic potential: Developing H2BECCS technology makes the UK a leader in clean energy innovation, promoting economic growth and employment creation.

Research questions

This project aims to assess the technological status, costs, and development potential of H2BECCS to inform the 7th Carbon Budget (CB7) and support policy development by addressing evidence gaps. To this end, the phase 1 project aims to answer the research questions below:

- **RQ1:** How do the cost ranges of different Hydrogen BECCS technologies, such as biomass gasification and steam biomethane reforming with CCS, scale over time up to 2050?
- **RQ2:** What are the maximum technological deployment potential (MTP) and build rate limit for scaled removals (in 5-year increments) for the different Hydrogen BECCS technologies?
- **RQ3:** What are the key barriers to achieving the maximum technical potential?

This report draws on a combination of desk-based research and stakeholder engagement to provide updated technical, economic, and deployment insights into five key H2BECCS technologies. Through this approach, the project aims to provide a comprehensive analysis of H2BECCS technologies, supporting future development and informing policy decisions that can help the UK achieve its Net Zero and hydrogen goals.

Landscape Review

The following section details the outputs from WP1: Assessment of previous work/landscape review. The intention of this work was firstly to assess the existing evidence on H2BECCS technologies, focusing on the key research questions and current DESNZ assumptions, and secondly to identify gaps in current assumptions and determine areas needing further work.

Current evidence base

Greenhouse gas removal methods and their potential UK deployment – Element Energy 2021 [1]

The intention of this report was to provide a comprehensive and up-to-date assessment of the potential of greenhouse gas removal methods in the UK. A literature review was completed alongside a call for evidence and stakeholder consultation. The report only covers the application of CCS (carbon capture and storage) to plants that provide biomass gasification to syngas with subsequent conversion or upgrading to products like hydrogen. The Technology Readiness Level (TRL) is assessed at TRL 5, indicating that while the reforming and conversion processes are well-established, the integration with CCS is less mature.

The report estimates the maximum technical potential for biomass gasification at 80 $MtCO_2$/yr by 2050, with deployment scenarios providing a range of 0-2 $MtCO_2$/yr in 2030 to 11 – 35 $MtCO_2$/yr in 2050. The maximum technical potential is limited by the demand and availability of bioenergy feedstocks; it is highlighted that there will be a trade-off with other biomass technologies due to the limited supply, which will result in high competition. It was emphasised that further work was needed to update and refine the evidence base of GGRs, with significant uncertainties observed in costs related to applying CCS to gasification plants, resource needs, and potential timelines for initial deployment specifically relating to H2BECCS technologies.

Hydrogen production costs report 2021 – *BEIS 2021*[3]

This report only considers CCUS-enabled biomass gasification as the H2BECCS technology route. The analysis performed uses biomass wood pellets as the process feedstock. The report relies on data from Element Energy's 2018 evidence base, within which the costs for biomass gasification originate from the 2018 Ecofys Bio Energy Pathways project [4], [5]. The cost data does not distinguish between Nth-of-a-Kind (NOAK) vs first-of-a-kind (FOAK) projects, leading to higher uncertainty in the cost data. The technical lifetime of the technology is assumed to be 30 years, with online time covered between 2030 and 2050.

This report formed the basis for the cost assumptions used in the UK Biomass Strategy (2023) modelling [6]. These assumptions were reported to be significantly cheaper than the cost used for the Net Zero Strategy (2021) modelling [7].

Following conversations from DESNZ, alongside the current evidence presented, it was concluded that there were high levels of uncertainty in the assumptions made for H2BECCS technologies. This uncertainty stems from the limited evidence base of low-TRL technologies and limited demonstrators to provide accurate data to back up assumptions. Across both reports, the H2BECCS technology was limited to biomass gasification coupled with CCS due to data availability limitations. There was a high sensitivity to the cost data due to competition with other biomass technologies, such as power generation from biomass with CCS and sustainable aviation fuels (SAFs) derived from biomass with CCS. These technologies have a more comprehensive literature base, which has resulted in further uncertainty in modelling the uptake and deployment of H2BECCS within the wider energy system.

DESNZ also provided the Catapult with several additional data sources comprising technical reports, policy and strategy documents, and assumptions workbooks. These documents were useful in providing baseline information; however, due to limitations in the output scope, they were only used to check values.

Updated evidence base

The intention of Work Package 1 was to develop an understanding of the current literature and data available from trusted sources that have been updated since the first review of assumptions. These were identified in the desk-based research and conversation with DESNZ. A key factor for ensuring high confidence in the values provided was the source of the data being validated with demonstration and commercial plants where possible. The outputs of the Hydrogen BECCS Innovation Programme projects were a valuable source of data [8]. This programme is a UK government initiative to advance technologies that produce hydrogen from biogenic feedstocks while demonstrating compatibility with carbon capture technologies. The programme is part of the wider Net Zero Innovation Portfolio, which sought to accelerate the commercialisation of clean energy technologies through the 2020s and 2030s [9]. Phase 1 of the programme focused on scoping and developing feasible prototype demonstration projects, whereas phase 2 aimed at taking projects from innovation design to demonstrators. To ensure that learning was captured from these projects, members of each project team were invited to the stakeholder workshops.

Further reports were highlighted as providing key insights and literature around greenhouse gas removals (GGR) and hydrogen production technologies, including:

- Ricardo 2023: Negative Emissions Technologies [10]
- AECOM 2021: Advanced Gasification Technologies - Review and Benchmarking [2]
- BEIS 2021: Hydrogen production costs [3]

For the technology assessment phase of the project, these studies offered helpful background information and baseline data. However, due to the age of the data and some of the assumptions made, additional sources from reputable peer-reviewed academic journals were used. To ensure accuracy and reliability, sources were cross-referenced with multiple independent academic research publications; furthermore, findings from the stakeholder engagement activities provided additional validation.

Identification of H2BECCS technologies

Utilising the outputs from Work Package 1 and recognising the impact of uncertainty in certain processes, the routes to hydrogen from biomass were mapped, as shown in Figure 3, and the literature reviewed to identify pathways to proceed with. The decision to continue with certain technologies was based on:

- Technology readiness – See Appendix 3 - Defining Technology Readiness Levels (TRL).
- Perceived availability of data
- H2BECCS Innovation Programme involvement

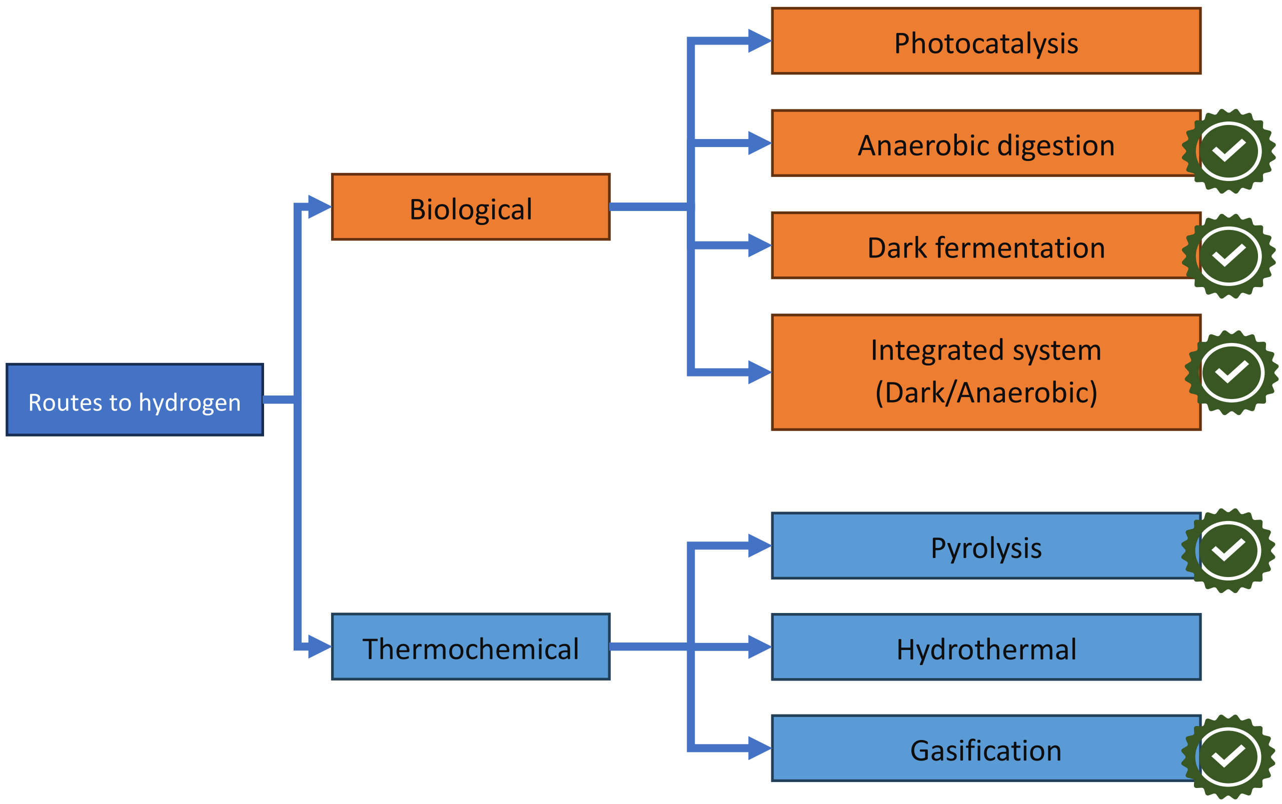


Figure 3 - Simplified routes to biohydrogen production showing the process types.

System boundaries

A challenge that arises when considering and comparing different biogenic hydrogen options is the definition of a system boundary. For this project, the system boundary is defined as “gate-to-gate” as shown in Figure 4. Analysis focuses on the production and conversion efficiency of the process itself, excluding upstream (e.g., feedstock cultivation or transport) and downstream (e.g., hydrogen distribution or end-use) stages. For many of these technologies, the type of feedstock, technology availability, and final use case will dictate the efficiencies of the process as well as the level of purity required and final levelised cost.

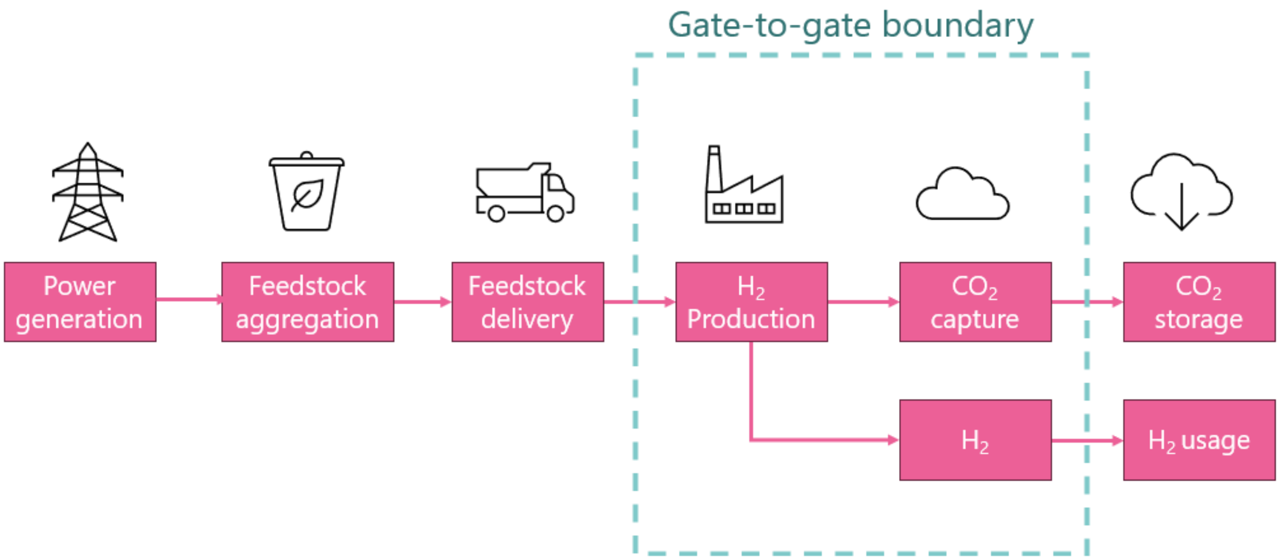


Figure 4 - System boundary definition for the H2BECCS project.

This project was intended to update the technical assumptions for the DESNZ version of the UK TIMES model. UK TIMES is a least-cost optimisation model of the whole UK energy system. The model is intended to meet projected energy demand within emissions constraints (set by Carbon Budgets and Net Zero) whilst minimising total system cost. The model provides insights into technological pathways to achieve net zero. The model includes representations of both feedstock inputs and outputs, which vary depending on different scenarios used to generate results. To ensure the technologies were input into the system correctly, four feedstock types were identified, and the changing efficiencies captured within the final assumptions workbook, the properties used within this study are defined in Table 5.

Table 5 - Feedstock types, moisture content, and lower heating value (dry basis)(LHV) [11], [12], [13]

Feedstock Type	Moisture content	Lower heating value (LHV)
Woody energy crops	25 wt%	18 MJ/kg
Grassy energy crops	15 wt%	18 MJ/kg
Pre-treated dry agricultural	15 wt%	15.5 MJ/kg
Pre-treated waste wood	10 wt%	18.7 MJ/kg

The purpose of this work was not to conduct a like-for-like comparison between different biogenic hydrogen production routes. Instead, each technology was assessed using the most appropriate or optimal feedstock for that specific process, as expected in real-world applications. The best feedstocks for thermochemical production routes (gasification, pyrolysis) are those with a low moisture content, such as wood chips. For biochemical production routes (AD, wastewater ammonia), a “wet” feedstock, such as agricultural residues and organic waste, is preferred.

Another challenge in defining the system boundary is standardising gas characteristics, specifically hydrogen and carbon dioxide. The critical factors to address are the offtake pressure and the purity of these gases. The composition and pressure of the output gases will vary depending on the hydrogen production method, feedstock type, and feedstock pre-processing. Guidance from the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) recommends a functional unit for the life cycle analysis of hydrogen to be 300 bar pressure and 99% purity [14]. Most hydrogen production methods require a purification step to meet this standard. While the reported purity levels vary depending on the process and feedstock used, all production methods considered in this study include a purification step that exceeds the minimum industrial purity requirement of 99%. It is important to note that for some applications, such as fuel cell usage, an additional purification step is required to reach the standard of 99.99% [15].

In addition to purification, compression of the gas is essential to make it usable for most applications. This step is factored into all of the hydrogen production processes. Additional compression stages will be necessary for applications requiring higher pressures, such as the 700 bar standard for vehicle hydrogen storage.

Similarly, carbon capture and storage (CCS) processes require both purification and compression of carbon dioxide to meet the requirements for transportation and storage. For effective pipeline transport or geological sequestration, carbon dioxide must typically be compressed to a supercritical state and purified to meet quality standards. These steps are critical for ensuring compatibility with infrastructure and minimising environmental impacts; however, they are outside of the process system boundaries considered within this report.

Summary and headlines

The landscape review was completed to understand the evidence base used by DESNZ in the current assumptions for the UK TIMES representation of H2BECCS technologies. This review aimed to evaluate the existing research and identify gaps in knowledge to support the following work packages in defining updated and reliable inputs for the UK TIMES model.

The initial review highlighted several key findings:

- The original assumptions on the H2BECCS technologies were focused on biomass gasification, with previous literature highlighting limited data availability for both cost and performance estimates, particularly for CCS integration with the plants.
- Cost data for the technology varied significantly due to original cost estimates being based on studies that did not differentiate first-of-a-kind and nth-of-a-kind projects, resulting in higher uncertainty in economic data.
- Existing reports relied heavily on modelling and assumptions due to limited real-world demonstrators of the technologies. There was a clear need for more robust data from operational plants and demonstrators. and ongoing stakeholder input.

Following the landscape review, the technologies considered within this project as hydrogen production methods with carbon capture and storage potential were identified. The key technologies were identified using the information provided within phase 1 of the Hydrogen BECCS Innovation Programme alongside desk-based research. This research also contributed to the system boundary definition to ensure that the assumptions and processes considered for the technology metrics were comparable between the technologies.

Technology assessment

Biomass gasification with carbon capture and storage

In gasification, biomass is heated to high temperatures (usually 700–1000°C) in a controlled environment with limited oxygen or air. The gasifier may be heated directly, by using the biomass itself to provide the heat of reaction, or indirectly by an external heat source. The thermochemical process converts biomass into syngas, a mixture of gases that includes carbon monoxide (CO), hydrogen (H_2), carbon dioxide (CO_2), and methane (CH_4). From the gasifier, the product gas is sent for syngas clean-up to remove unwanted contaminants. A water-gas shift reactor is typically included to increase the production of hydrogen. The water gas shift reaction is followed by pressure swing adsorption (PSA) or other separation technologies to remove the hydrogen. A generalised process flow diagram is shown in Figure 5.

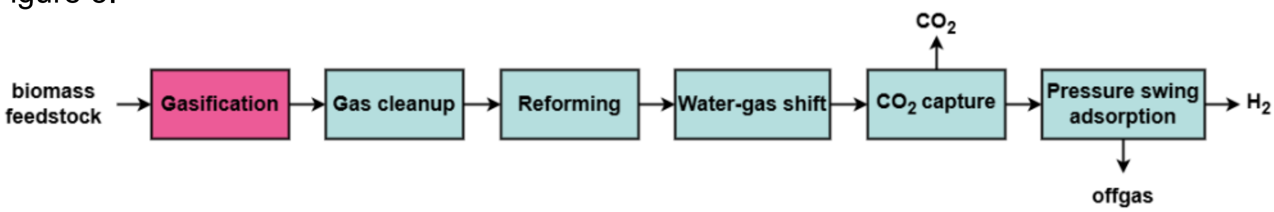


Figure 5 - Process flow diagram for biomass gasification with carbon capture and storage.

There are several commercial gasification plants that produce syngas, which is primarily used for heating and power generation [16]. At least 1700 are operational in Europe. Gasification is a well-established process, offering high energy conversion efficiency and the ability to utilise a variety of feedstocks. However, there are still technical barriers that need to be overcome, specifically the limited continuous running hours and the ability to handle heterogenous feedstocks. In addition to these technical challenges, wider commercial barriers prevent faster deployment. It is critical that the Government continues to develop initiatives such as the Greenhouse Gas Removal (GGR) and Hydrogen Production Business Models to appropriately incentivise investment into these technologies, fostering growth and reducing investment uncertainty.

Table 6 - Technical assumptions for biomass gasification with carbon capture and storage. Assumptions formed from peer reviewed academic papers, NREL assumptions, industry data and outputs from the H2BECCS workshop [17], [18], [19]**.**

Technical Assumptions	
Energy conversion efficiency – biomass to hydrogen *	44 %
Availability Factor**	91 %
Emissions (kg CO_{2eq}/kg H_2)	-22
Technology Readiness Level (TRL)	7 - 8
*Using LHV (MJ/kg), the amount of energy in the product hydrogen divided by the energy in the biomass feedstock	
**Percentage of time that the plant is operational per year. It is below 100% due to scheduled and unscheduled maintenance, breakdowns, and operational issues.	

The technical assumptions for gasification are shown in Table 6. The high carbon sequestration rate is associated with the high energy conversion efficiency of the process. PSA represents a pinch point due to its high energy consumption. More feedstock is necessary when the feedstock originates from waste biomass, as this feedstock tends to have a lower energy conversion efficiency compared to purpose-grown feedstocks.

Despite this, competition for bio-based feedstocks is expected to be high, making the transition to waste feedstocks potentially beneficial, particularly considering commercial factors such as feedstock gate fees. Based on stakeholders' discussions, improvements in overall energy conversion efficiency are dependent upon the level of investment. Further modelling assumptions are shown in Table 7

Table 7 - Modelling assumptions for biomass gasification with carbon capture and storage. Assumptions formed from workshop outputs, industry data, and peer-reviewed academic papers [20]**.**

Modelling Assumptions	
First year available	2030
Technical lifetime of new capacity	25 years
Investment lead time	3 years

The economic assumptions are shown in Table 8 and H_2 infrastructure, along with the provision of gap funding. TRL 9 is anticipated to be achieved before 2035.

Table 8 - Economic assumptions for biomass gasification with carbon capture and storage. Assumption formed from one Hydrogen Europe report and two academic peer-reviewed papers [19], [20], [21]**. Values in 2023 pounds per kg of hydrogen plant production capacity.**

Economic Assumptions[5]	
Investment cost for new capacity	4.00 $£_{2023}$/kg H_2
Fixed operational and maintenance cost	1.10 $£_{2023}$/kg H_2
Activity cost	1.00 $£_{2023}$/kg H_2

Summary and outlook

Biomass gasification represents a technology with a high TRL, evidenced by the operation of commercial plants (excluding CCS). Integrating the plants with CCS has yet to be demonstrated within a commercial plant; however, there are pilot plants in development.

The hydrogen yield from biomass is inherently lower than methane (the conventional route to hydrogen), and an even higher feedstock input is required when waste biomass serves as the feedstock. Nevertheless, the primary advantage of the technology lies in the thermodynamic conditions of the process, resulting in high energy conversion efficiency. This technology is projected to account for the majority of H2BECCS capacity implemented by 2050.

Anaerobic digestion to steam methane reforming

Anaerobic digestion is a commercially available and widely used biological process that uses microorganisms to break down organic matter, such as agricultural residues, bio-waste, and sewage sludge, in the absence of oxygen, producing biogas. Biogas is a mixture of methane (45-75%) [22], carbon dioxide, and trace amounts of other gases such as hydrogen sulphide. The feedstock type and the production pathway dictate the composition of the biogas. Upgrading technologies, such as water scrubbing and membrane separation, can be used to separate the biogas into its constituent parts, producing bio-methane. Biomethane is chemically indistinguishable from natural gas and, therefore, can be injected into the existing gas grid with minimal changes in infrastructure necessary.

[5] Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included.

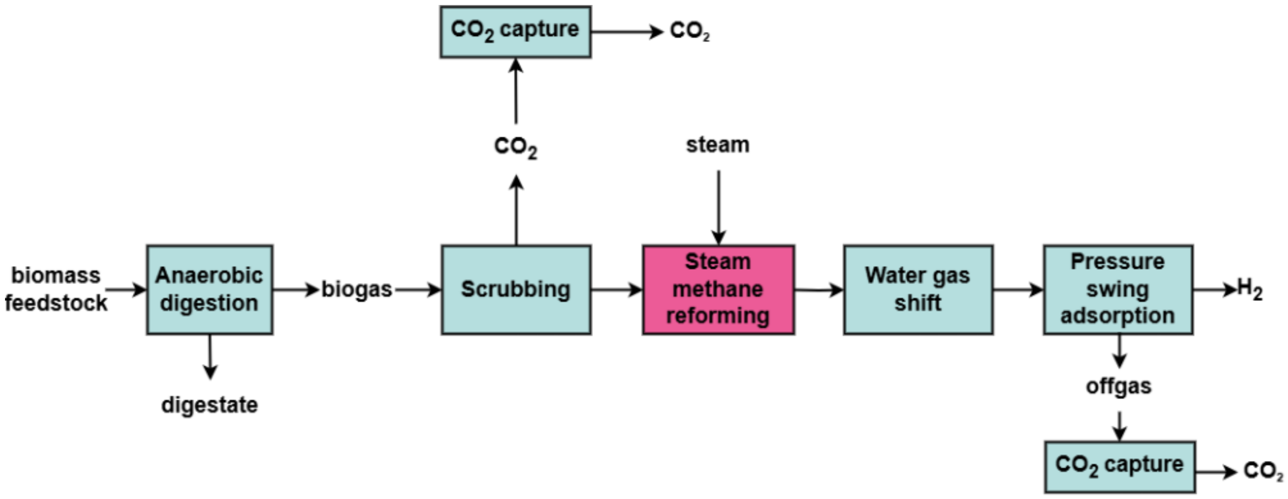


Figure 6 - Process flow diagram for anaerobic digestion with steam methane reforming and carbon capture and storage

Steam methane reforming (SMR) is a thermochemical process in which steam is reacted with methane under high temperatures (800 – 900ºC) and pressures (20 – 30 bar) in the presence of a catalyst to form syngas (a mixture of hydrogen, carbon monoxide, and carbon dioxide). The syngas is upgraded using a water gas shift reaction, where the carbon monoxide is further reacted with steam to produce higher yields of hydrogen and convert the carbon monoxide to carbon dioxide. The hydrogen is then separated using membranes or pressure swing adsorption to output high-purity hydrogen and a carbon dioxide stream that can be captured. This carbon dioxide stream represents 60% of the carbon dioxide emissions from the process; the remaining 40% is produced from the combustion of a fuel – typically a mixture of natural gas and process derived gases – to supply the high temperature heat needed for reforming. The off-gas consists of CO_2, small amounts of unconverted methane and other impurities such as hydrogen sulphide (H_2S) and ammonia. Capturing the remaining 40% from the diluted furnace flue gas remains costly and challenging. However, there are some alternatives to this, including using autothermal reformation (ATR) instead of SMR or electrification of the process heat, but these production methods were not considered in this project. A generalised process flow diagram is shown in Figure 6 and technical assumptions are shown in Table 9. Further modelling and economic assumptions can be found in Table 10 and Table 11.

Table 9 - Technical assumptions for anaerobic digestion with steam methane reforming and carbon capture and storage. Assumptions formed from workshop outputs and peer-reviewed literature [23], [24], [25], [26], [27]**.**

Technical Assumptions	
Energy conversion efficiency – biomass to hydrogen	35 - 45 %
Availability Factor	90 %
Emissions (kg CO_{2eq}/kg H_2)	-11.6 to -8.6
Technology Readiness Level (TRL)	5 - 7

The fundamental advantage of this process is the technical maturity of each step in isolation. Anaerobic digestors are a common technology with 75,000 Nm^3/hr biomethane production capacity in the UK shared across biomethane to grid and combined heat and power plants [28]. This is equivalent to 600 MW of capacity. Steam methane reforming accounts for approximately 95% of the hydrogen produced in the UK; this, however, is without CCS [29].

Table 10 - Modelling assumptions for anaerobic digestion with steam methane reforming and carbon capture and storage. Assumptions formed from workshop outputs and peer-reviewed literature [30], [31], [32]**.**

Modelling Assumptions	
First year available	2030
Technical lifetime of new capacity	25 years
Investment lead time	2 - 5 years

One of the challenges of this approach is the distributed model of biogas production, which is linked to the centralised model of steam methane reforming with carbon capture. Anaerobic digestion plants are typically on a smaller scale and used to valorise waste products to produce heat and power for the local sites alongside a partial decarbonisation gain. Prioritising biomethane production to be redirected to steam methane reformation plants would mean the direct emission savings are not captured locally. This would mean the commercial model would have to exceed current benefits to farmers and other AD plant users.

Table 11 - Economic assumptions for anaerobic digestion with steam methane reforming and carbon capture and storage. Assumptions formed from workshop outputs and peer-reviewed literature [20], [25], [33]**. Values in 2023 pounds per kg of hydrogen plant production capacity.**

Economic Assumptions[6]	
Investment cost for new capacity	0.60 - 0.74 $£_{2023}$/kg H_2
Fixed operational and maintenance cost	0.47 - 0.55 $£_{2023}$/kg H_2
Activity cost	2.1 - 2.7 $£_{2023}$/kg H_2

The UK Biomass Strategy (2023) highlights that around 30-40 TWh of biomethane production in 2050 would help the UK achieve Net Zero cost-effectively based on best utilisation of available feedstocks [6]. As an illustrative example, assuming a conversion efficiency of the SMR process at 70%, we can estimate that the total hydrogen yield from 30 TWh of biomethane is 630,000 tonnes of hydrogen. This represents between 5 and 10% of hydrogen demand in 2050 based on the CB6 central scenario [34]. It is important to note that this might not be the best application of biomethane, especially considering the current domestic reliance on the natural gas grid. Further work should be undertaken to prioritise the use of biomethane in the most impactful way.

[6] Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included.

Summary and outlook

Anaerobic digestion and steam methane reforming are commercially established technologies (TRL 9) with operating plants in the UK. Coupling SMR with carbon capture and storage is a key focus within the hydrogen sector to enable existing plants to decarbonise their operations and meet the low-carbon hydrogen standard. While the maturity of these technologies supports near-term deployment, challenges remain, particularly in developing CCS systems and enabling the integration of the distributed AD facilities with SMR plants. Addressing these barriers will require coordinated efforts to consider the strategic prioritisation of biomethane to maximise its decarbonisation impact.

Wastewater ammonia conversion

Anaerobic digestate – a byproduct of wastewater treatment – is rich in ammonia (NH_3). In wastewater ammonia conversion, ammonia is first removed from the digestate by air stripping, where air is forced through the water to remove volatile organic compounds, and distilled. The ammonia is then passed into a single reactor along with steam and biomethane, where H_2 is produced by steam methane reforming (SMR), with the yield subsequently increased via the water-gas shift reaction. This is a low-TRL technology in that the reactor has been demonstrated at a laboratory scale, and the wider system has been extensively modelled but not yet implemented. A generalised process flow diagram is shown in Figure 7.

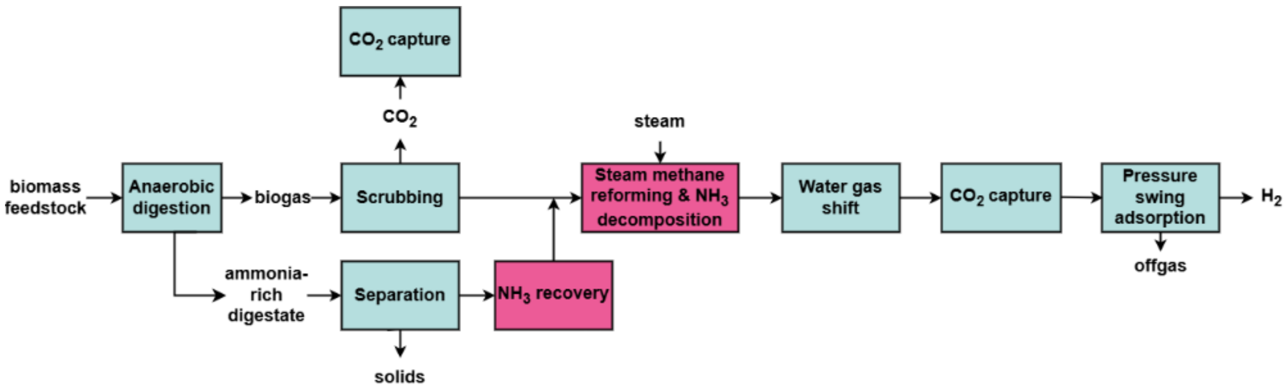


Figure 7 - Process flow diagram for wastewater ammonia conversion.

If implemented at wastewater treatment plants (WWTPs), this process reduces the need for conventional wastewater treatment, representing energy and cost savings. A significant supply chain advantage is the use of a waste product produced on-site as the feedstock.

The technology is relatively unproven, and there are questions about whether cracking in a combined reformer is more economically desirable than other possible uses for NH_3. Most of the investment required is capital expenditure, which may be a barrier for WWTP operators. In addition, the application is limited to existing WWTPs and only those whose size merits the capital expenditure. The technical assumptions are shown in Table 12.

Table 12 - Technical assumptions for wastewater ammonia conversion. Assumptions formed from workshop outputs and peer-reviewed literature [35]**.**

Technical Assumptions	
Energy conversion efficiency – biomass to hydrogen	3 - 5%
Availability Factor	50 %
Emissions (kg CO_{2eq}/kg H_2)	-3.5 to -6.4
Technology Readiness Level (TRL)	2 – 3

In a typical WWTP, about 27% of overall energy demand goes towards removing nitrogen from wastewater [36]. This step can be removed by extracting the ammonia and using it to produce hydrogen in combination with steam methane reformation (SMR), thus theoretically increasing the hydrogen yield of SMR while saving on energy use, cost and greenhouse gas emissions for the WWTP. The technical innovation is the use of a single reactor for both the ammonia cracking and SMR using biomethane.

The reactor is kept at about 700-800 °C, which is around 100 °C lower than normal SMR [36]. The optimal temperature for ammonia cracking is about 400 °C [37]. Therefore, neither process occurs at optimal conditions, hence the relatively low overall conversion efficiency. In addition, high ammonia content in the feedstock (which should be desirable for justifying the implementation of this process) reduces the efficiency of anaerobic digestion and, therefore, the hydrogen yield from SMR.

Table 13 - Modelling assumptions for wastewater ammonia conversion. Assumptions formed from workshop outputs and peer-reviewed literature [36]**.**

Modelling Assumptions	
First year available	2035
Technical lifetime of new capacity	20 years
Investment lead time	2 - 3 years

Given the savings made by avoiding conventional nitrogen removal from wastewater, this process is projected to be a cost-effective method of producing hydrogen. The economic assumptions are shown in Table 14

Table 14 - Economic assumptions for wastewater ammonia conversion. Assumptions formed from workshop outputs and peer-reviewed literature [38]**. Values in 2023 pounds per kg of hydrogen plant production capacity as a bolt on technology to an existing water treatment plant.**

Economic Assumptions[7]	
Investment cost for new capacity	1.26 - 2.33 $£_{2023}$/kg H_2
Fixed operational and maintenance cost	0.75 - 1.40 $£_{2023}$/kg H_2
Activity cost	0.29 - 0.54 $£_{2023}$/kg H_2

Some aspects of the process are unproven (for example, the ammonia separation technology). Even more pressingly, given the demand for ammonia, which has elicited a drive to generate ammonia using green hydrogen there is a case to be made for whether the ammonia separated from the digestate in this process could be better utilised [39].

Summary and outlook

Wastewater ammonia conversion has a low TRL and is mostly an unproven technology. The novel aspect, which is a combined reactor for both ammonia cracking and SMR, operates at suboptimal conditions for either process, limiting the overall energy conversion efficiency. Research is underway to inhibit ammonia production in situ, thus increasing the production of biogas, which may be a more efficient outcome for AD plants than hydrogen production [40]. Buildout is limited by the number of WWTPs large enough to merit the investment. Nevertheless, the technology could interest water companies as it eliminates the need for conventional nitrogen treatment of wastewater, representing significant energy and cost savings.

Pyrolysis

Biomass pyrolysis is a thermochemical process that heats organic materials to temperatures between 400 and 500°C under an oxygen-free atmosphere, converting them into products that are in solid, liquid, and gaseous forms, namely biochar, bio-oil, and syngas, respectively [41]. The process can produce renewable hydrogen while allowing carbon sequestration through biochar and captured carbon dioxide. The parameters that increase hydrogen yield include temperature, catalytic efficiency, and feedstock quality. Various reforming technologies can be applied to extract hydrogen from syngas. However, recent research has often prioritised bio-oil and biochar as the primary outputs, with limited focus on hydrogen production. Shifting the focus towards prioritising hydrogen production could better align the technology to future decarbonisation goals. The pathway's flexibility enables the technique to use a wide range of biomass inputs, resulting in a more resilient process suitable for diversification and scale-up. A generalised process flow diagram is shown in Figure 8.

[7] Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included.

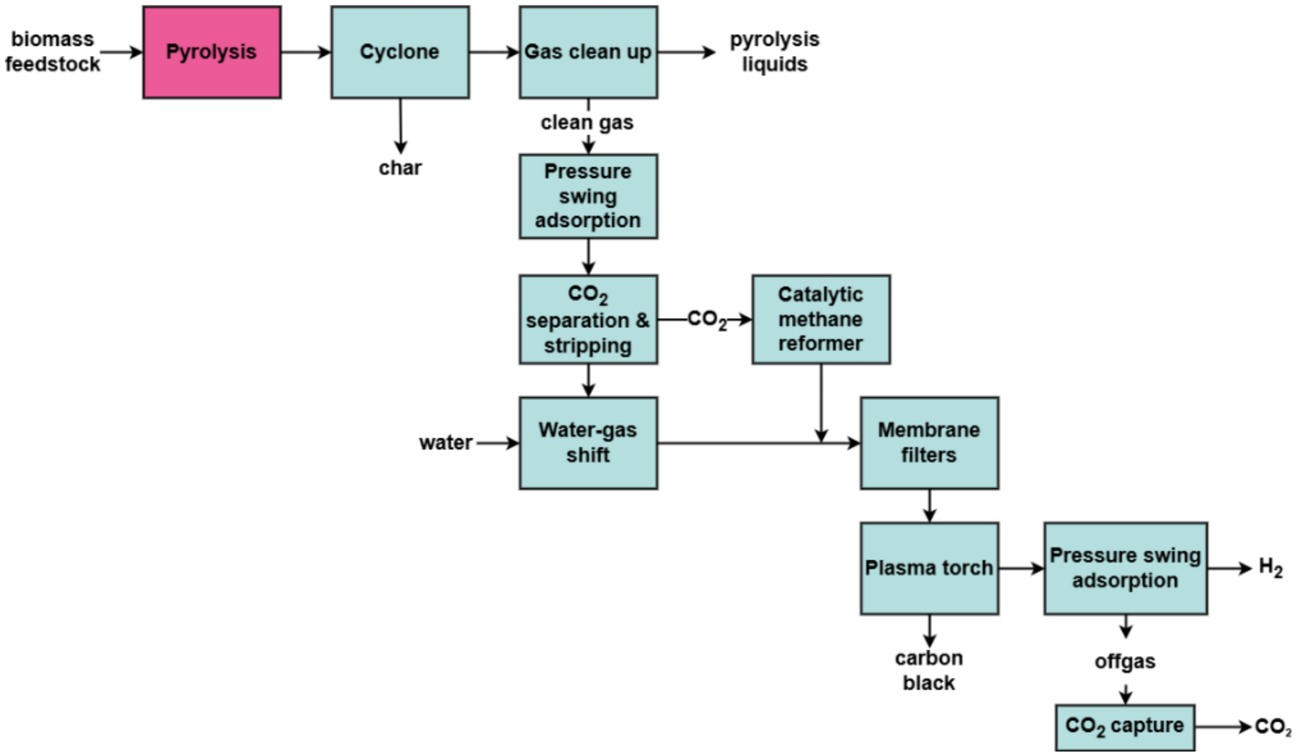


Figure 8 - Process flow diagram for biomass pyrolysis with carbon capture and storage.

While the core pyrolysis technology itself is more mature depending on the specific application and feedstock, the integration of pyrolysis with hydrogen reformation and purification remains at a lower TRL of 3–4 meaning it is still in the demonstration phase [42]. The key challenges are to optimise hydrogen yield, manage tar formation to increase syngas purity and achieve economic competitiveness against mature hydrogen production technologies such as electrolysis and steam methane reforming (SMR). Being a carbon-negative process, it presents opportunities to help contribute to climate change mitigation, subject to overcoming the described technical and economic challenges through further research and development. The technical assumptions are shown in Table 15 and further modelling assumptions in Table 16.

Table 15 - Technical assumptions for biomass pyrolysis with carbon capture and storage. Assumptions formed from workshop outputs and peer-reviewed literature [43], [44], [45]**.**

Technical Assumptions	
Energy conversion efficiency – biomass to hydrogen	30 - 41%
Availability Factor	85%
Emissions (kg CO_{2eq}/kg H_2)	-13.8 to -3.8
Technology Readiness Level (TRL)	3 - 4

Biomass pyrolysis demonstrates considerable potential for hydrogen production, with an efficiency ranging between 30 – 41% and an end-of-life carbon profile of -13.8 to -3.8 kg CO_2eq/kg H_2 due to biochar carbon sequestration. However, the current TRL of 3 to 4 indicates that it is still in the early stages of development, and substantial work remains to be completed to allow commercial-scale use by 2040. Much of the focus of the research now is on developing new catalysts, e.g. fluidised reforming catalysts, and on developing new types of reactors that would enhance efficiency while integrating carbon capture more effectively.

Table 16 - Modelling assumptions for biomass pyrolysis with carbon capture and storage. Assumptions formed from workshop outputs and peer-reviewed literature [46]**.**

Modelling Assumptions	
First year available	2040
Technical lifetime of new capacity	20 years
Investment lead time	5 years

From an operational point of view, LCOH (Levelised Cost of Hydrogen) of biomass pyrolysis for hydrogen production remains more expensive than conventional methods like steam methane reforming due to the operational complexity of pyrolysis technologies. The economic assumptions are shown in Table 17. Other commercial barriers include high upfront capital costs, a need for more supportive policies, and competition from existing hydrogen technologies. Addressing these commercial challenges through targeted investments, R&D allocations, policy shifts, and stakeholder consultations will significantly improve biomass pyrolysis as a key hydrogen production route.

Table 17 - Economic assumptions for biomass pyrolysis with carbon capture and storage. Assumptions formed from workshop outputs and peer-reviewed literature [46]**. Values in 2023 pounds per kg of hydrogen plant production capacity.**

Economic Assumptions[8]	
Investment cost for new capacity	2.33 - 4.33 $£_{2023}$/kg H_2
Fixed operational and maintenance cost	0.79 - 1.47$£_{2023}$/kg H_2
Activity cost	0.25 - 0.46 $£_{2023}$/kg H_2

Summary and outlook

Biomass pyrolysis, while a potential pathway for sustainable hydrogen production, remains a low-TRL technology with significant challenges. Key issues include unresolved technical barriers such as catalyst degradation, and carbon capture integration, alongside high production costs and limited market readiness. Achieving a competitive levelised cost of hydrogen (LCOH) will require sustained public and private investment, as well as supportive policies. Despite its potential role, its practical role in the hydrogen economy remains uncertain, but innovation could accelerate if a more hydrogen-centric approach were adopted.

[8] Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included.

Dark fermentation hydrogen production

Dark fermentation (DF), which is a biological process that occurs without light, carried out by anaerobic bacteria that are either strict (grow only in the absence of oxygen) or facultative (can grow with or without free oxygen). These bacteria convert biomass into H_2 and other valuable biobased molecules in the form of digestate [47].

Dark fermentation has a relatively simple reactor design and operation, keeping costs relatively low. Dark fermentation is a well-understood, and when combined with AD, there is minimal waste product [48]. However, H_2 yields are limited by thermodynamics, so research is directed towards optimising the metabolic pathways involved. The synthesis pathway is known to be critically sensitive to H_2 partial pressure, meaning that H_2 gas must be removed as it is generated, as must CO_2 to maintain pH control [49].

A generalised process flow diagram is shown in Figure 9.

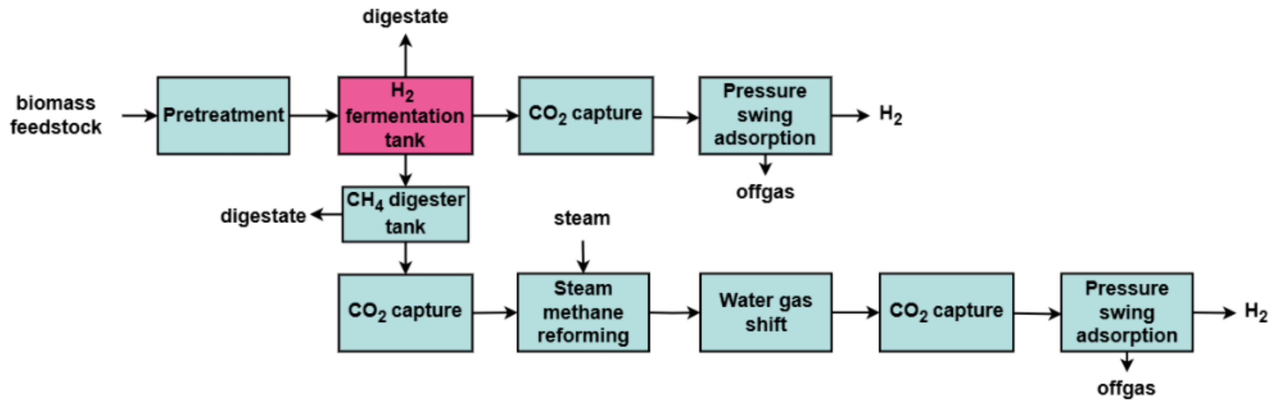


Figure 9 - Process flow diagram for dark fermentation.

The H_2Boost project is a research initiative focused on converting food waste into hydrogen using dark fermentation and AD, along with microbial carbon capture and storage and enzyme pretreatment. Specific areas of development for H2Boost, are optimising its feedstock pre-treatment process, analysing novel enzymes, and optimising bacteria for the feedstock type [50]. This demonstration project was delivered under Phase 2 of the H2BECCS Innovation Programme and led by the Biorenewables Development Centre[51].

Table 18 - Technical assumptions for dark fermentation. Assumptions formed from workshop outputs and peer-reviewed literature [52]**.**

Technical Assumptions	
Energy conversion efficiency – biomass to hydrogen	2 – 4 %
Availability Factor	60 %
Emissions (kg CO_{2eq}/kg H_2)	-1.6 to -1.0
Technology Readiness Level (TRL)	5 - 8

The main advantage of dark fermentation is its simplicity; the fermenter has few moving parts and operates close to room temperature and pressure. A wide range of feedstocks can be used, which are abundant and usually waste products from other processes (for example, agricultural, food and water waste). The carbon sequestration rate remains relatively low due to the low efficiency of the process and is especially affected by methane producing bacteria present in the feedstock. For example, the acetate production pathway produces four moles of H_2 per mole of glucose, while the butyrate pathway produces two moles of H_2 per mole of glucose; the total yield can comprise more than 80% acidic components [53]. Research focuses on inhibiting these secondary reactions, which will improve the hydrogen yield. The technical assumptions are shown in Table 18 and modelling assumptions in Table 19.

Table 19 - Modelling assumptions for dark fermentation. Assumptions formed from workshop outputs and peer-reviewed literature (Dinesh et al., 2018).

Modelling Assumptions	
First year available	2030
Technical lifetime of new capacity	20 years
Investment lead time	6 years

Certain feedstocks, such as food waste, may introduce undesirable, hydrogen-consuming, and methanogenic bacteria [55]. Careful pretreatment is required to remove these bacteria while breaking complex carbohydrates into more digestible sugars. Feedstock pretreatment remains an active area of research [56].

Table 20 - Economic assumptions for dark fermentation. Assumptions formed from workshop outputs and peer-reviewed literature [57]. **Values in 2023 pounds per kg of hydrogen plant production capacity.**

Economic Assumptions[9]	
Investment cost for new capacity	0.26 - 0.41£$_{2023}$/kg H_2
Fixed operational and maintenance cost	1.32 - 2.06 £$_{2023}$/kg H_2
Activity cost	0.45 - 0.70 £$_{2023}$/kg H_2

Despite the low energy conversion efficiency, the simplicity of this process means that the levelised cost of hydrogen can be as low as £2.60 GBP per kg (see Table 20). Planning and funding approval dominate the investment lead time, as the build time is only about two years. Scale-up is constrained by biological limitations and space requirements for feedstock transport and fermentation infrastructure. Engineering innovations in supply chains are needed to enable larger deployments. A smaller scale combined with modularisation could be one way to decrease the delivery time and reduce logistical challenges.

[9] Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included.

Summary and outlook

Dark Fermentation is a simple and well-understood process that uses cheap equipment and operates close to room temperature and pressure. A wide range of possible feedstocks, often from waste sources, are used. However, these feedstocks may harbour undesirable bacteria, further limiting what is already an inefficient process due to the acidic byproducts from the hydrogen-producing bacteria. Lead times are relatively short, but scale-up may be a challenge due to the space required and the needs of the bacteria. Modularisation is a promising way to address these scale-up issues. Current research aims to refine the pretreatment process for optimal yield, and to combine the process with AD for biomethane production.

Workshop outputs

Workshop 1

The aims of workshop 1 were as follows:

- **Output 1:** Present H2BECCS assumptions gathered during WP1.
- **Output 2:** Critical evaluation of the assumptions by the stakeholders.
- **Output 3:** Identify data gaps.
- **Output 4:** Discuss TRL and commercial implementation timeline of H2BECCS.
- **Output 5:** Establish clear lines of communication for data collection.

In Workshop 1, the assumptions gathered during WP1 were presented to the stakeholders, who were then invited to participate in structured discussions to critically evaluate the validity of those assumptions. In general, but especially for this validation stage, it proved immensely valuable to have approximately equal representation from the Catapult, DESNZ, academia, and industry (Figure 10) as a range of perspectives and interests could be voiced and discussed.

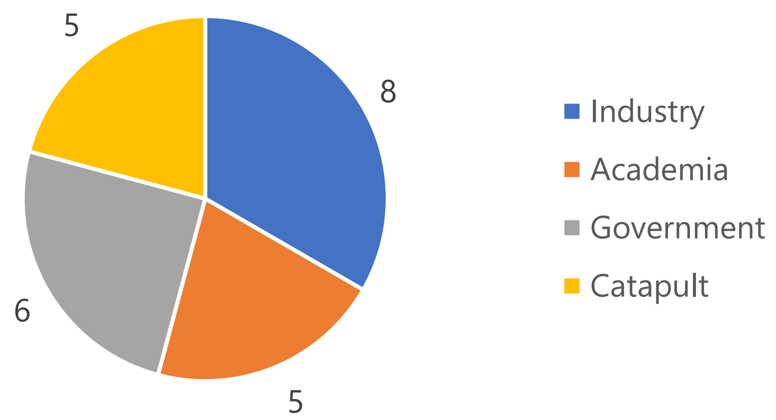


Figure 10 - Pie chart to show the distribution of attendees at workshop 1.

This diversity in areas of expertise facilitated Output 3, as the organisers could be confident that all reasonable measures had been taken to ensure that data gaps could be identified and addressed. As part of the discussions, stakeholders were asked to provide predictions and justifications for the implementation timeline of each technology, which were subsequently assessed and incorporated into this report. A final direct result of workshop 1 was access to commercial data, representing another reliable data collection method.

The common themes from the workshop 1 discussions were as follows:

- **Scale and efficiency:** Large scales are required, for example, to provide hydrogen for dispatchable power during peak periods. A recurring goal is to improve conversion efficiency and capture efficiency.
- **Economic viability:** High initial costs (CAPEX) and long development periods are significant barriers. The LCOH needs to be reduced for competitiveness. Alternative economic metrics like return on investment (ROI) or internal rate of return (IRR) were suggested over LCOH.
- **Technical barriers:** Energy-intensive processes represent pinch points in the H_2 production chain. Technological advancements are required to reduce energy use and increase efficiency. CO_2 capture and storage could be driven by incentives, which would then justify the investment. Feedstock availability and management are ongoing challenges.
- **Commercialisation challenges:** Location and infrastructure (H_2 storage, CO_2 infrastructure) are crucial. Government intervention and incentives are needed to improve TRLs. Planning and permitting delays hinder timely project execution.
- **Environmental impact:** Emissions reduction is a key focus, with targets for negative CO_2 emissions. By-products like biochar and graphene can reduce emissions and add value. Exploring different feedstocks for optimisation and economic strategy was recommended, as was full lifecycle analysis (LCA).
- **Market and offtake uncertainty:** Uncertainty in hydrogen offtake markets affects revenue predictions and investment decisions. Concern over competition for bio-based feedstocks raised the need for a biomass usage hierarchy.
- **Future projections and improvements:** Improvements in efficiency, availability, and capture rates are expected over time. Projections were expressed to achieve higher TRLs and increase annual build rates.

Overall, workshop 1 produced a comprehensive assessment of the assumptions gathered during WP1, validating the data where appropriate and, in other cases, steering future data collection efforts. In addition, lines of communication were established for further discussion and sharing of commercial data.

Workshop 2

The aims of workshop 2, which was held online, were as follows:

- **Output 1:** Present updated H2BECCS assumptions following workshop 2 and further data collection.
- **Output 2:** Critical evaluation of the updated assumptions by the stakeholders.
- **Output 3:** Facilitated discussion to fill any remaining gaps.

- **Output 4:** Facilitated discussion to gauge policy suggestions for enabling the rollout of H2BECCS technologies.

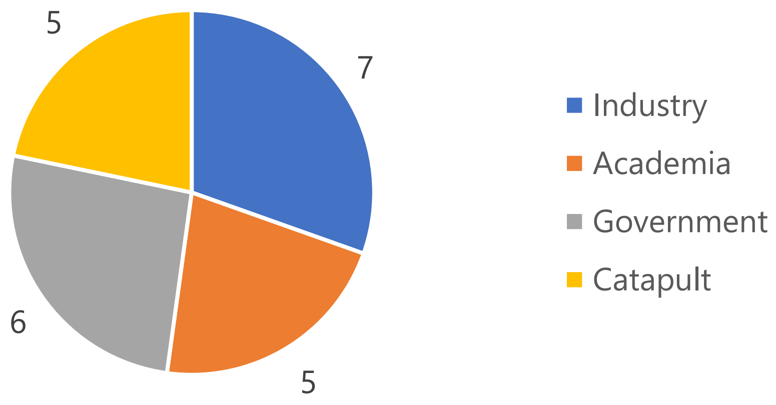


Figure 11 - Pie chart to show the breakdown of attendees at workshop 2.

As per workshop 1, there was a diverse range of attendees (Figure 11). Workshop 2 attendees agreed with the updated assumptions and no changes were made to the data. A series of questions were posed to the attendees via an online polling tool. This allowed answers to be collected anonymously and encouraged the participants to be open and honest with their answers. It is important to keep in mind that the participants' opinions may shift towards the technology they prefer. One also must bear in mind the potential influence of confirmation bias, as the participants could see how the majority were voting. Therefore, the results presented below are purely indicative and highlight areas for further investigation. To overcome this limitation, it would be necessary to increase the sample size and conduct more targeted questions of the researchers.

To gauge general perspectives, the attendees were asked to vote for their answers to the question, ***"What percentage of the UK 10 GW [10]target from H2BECCS will be achieved by 2030?"*** the results are shown in Figure 12. No participants believed that more than 31% of the 10GW target would arise from H2BECCS. This target was set under a previous UK Government and is therefore not reflective of current UK Government policy.

[10] Assuming a hydrogen lower heating value (LHV) of 120 MJ kg^{-1}, a 10 GW hydrogen capacity corresponds to approximately 2.37 Mt H_2 per year at a 90 % capacity factor.

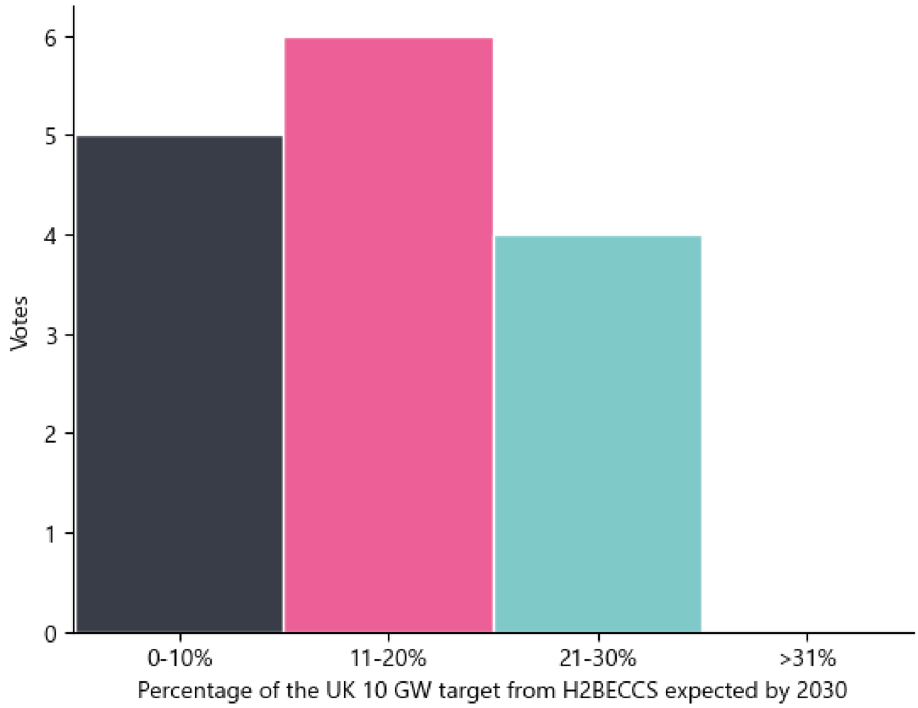


Figure 12 - Histogram to show results to the question "What percentage of the UK 10 GW target from H2BECCS will be achieved by 2030?".

The general opinion was that ~1-2 GW[11] would be delivered from H2BECCS by 2030. This indicates that attendees viewed most of the low-carbon hydrogen as being produced by other production routes. Next, the attendees were asked to ***rank the barriers to H2BECCS commercialisation identified during workshop 1 by importance***. The results are shown in Figure 13.

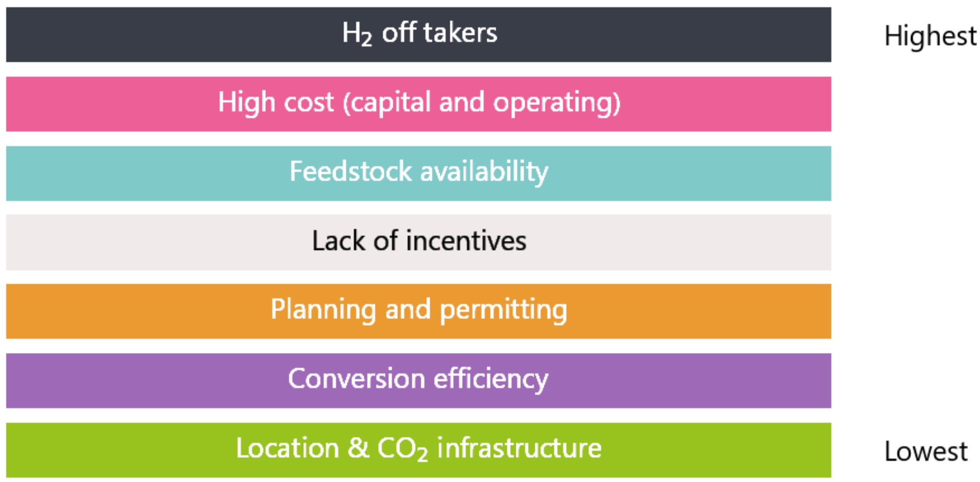


Figure 13 - Results of the barrier ranking exercise during workshop 2.

[11] Assuming a hydrogen lower heating value (LHV) of 120 MJ kg^{-1}, a 1–2 GW hydrogen capacity corresponds to approximately ~0.24–0.47 Mt H_2 per year at a 90 % capacity factor.

Every barrier received either 13 or 14 votes. The overall trend is that the availability of H_2 off-takers and feedstocks, in addition to high costs and lack of financial incentives, are more important than technical barriers.

The attendees were then asked for their 50MW-scale plant deployment predictions for the five technologies. ***The attendees were asked to indicate when they thought there would be deployment of 1s, 10s or 100s of each technology at a scale of 50MW H_2 production between now and 2050****[12]. If they did not think this would happen, they should not answer. A total of 18 attendees participated in the activity, with the results displayed in Figure 14. From the responses, it was clear that there was a level of confidence that gasification and anaerobic digestion with SMR would be implemented before 2050. In contrast, there was much less confidence in the other routes. This aligns with the level of uncertainty and TRL levels for these routes.

There were between 10 and 15 votes in total for each question. As the most mature technology, gasification is expected to be deployed most rapidly, with tens of 50MW plants expected around 2035. The AD rollout is expected to be five to ten years slower at first. Nevertheless, progress from tens to hundreds of plants is predicted to be faster than for gasification. This result may be associated with the stakeholders' belief that the main barriers to commercialisation relate to H_2 off-takers, cost, and feedstock availability rather than technological considerations, delaying the early buildout of greater numbers of gasification plants.

Given its relative simplicity, dark fermentation is expected to be deployed at about the same rate as AD. Pyrolysis and wastewater ammonia conversion both possess low TRLs and are unproven, so the deployment rates are predicted to be low, with no expectation of hundreds of 50MW-scale plants by 2050 for either technology. Prediction uncertainty is generally high for ammonia wastewater conversion; however, there is a strong consensus that FOAK 50MW-scale pyrolysis plants will appear around 2040.

[12] A 50 MW production capacity plant equates to 12000 tonnes per annum with a 90% capacity factor.

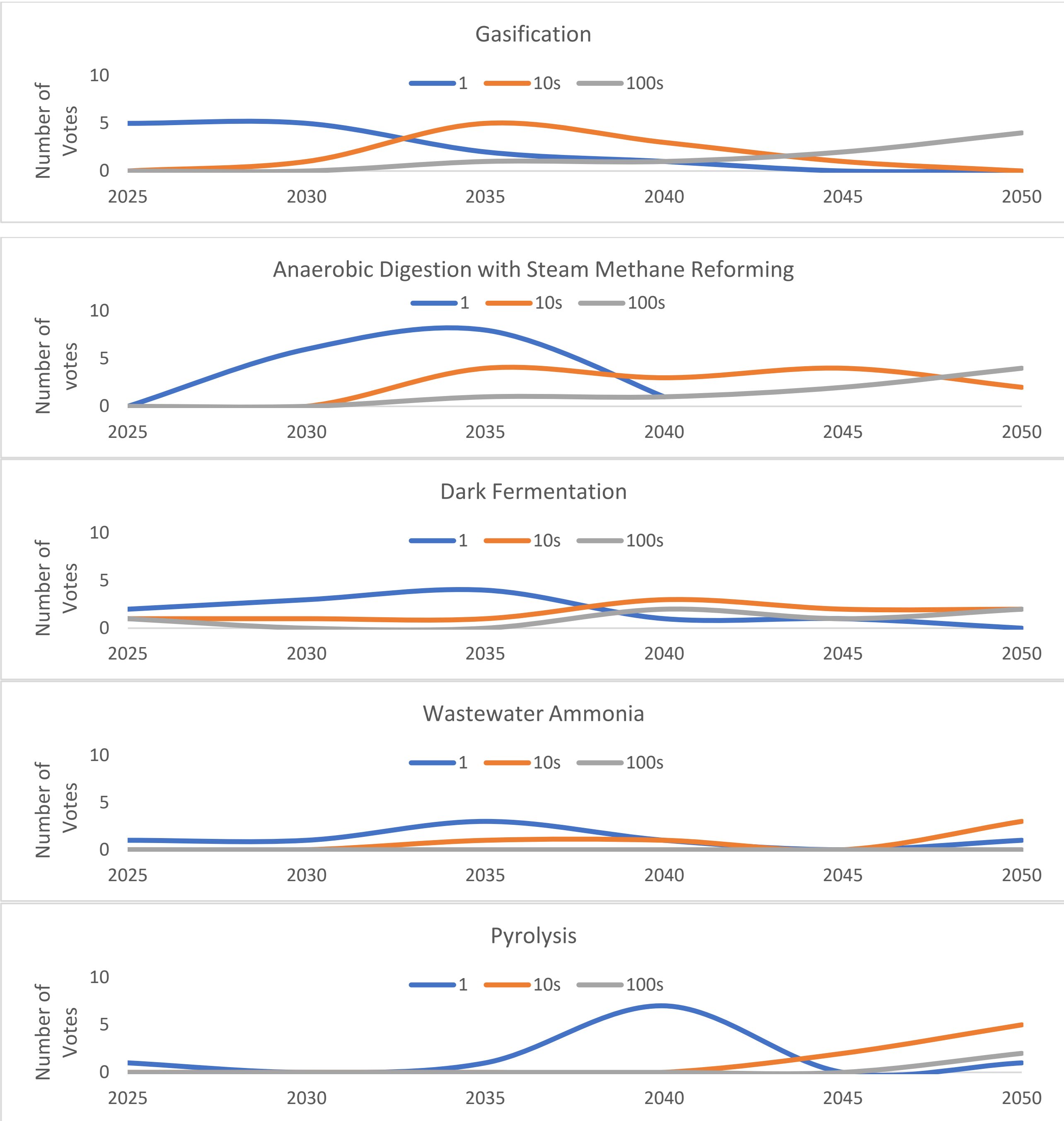


Figure 14 – Technology deployment potential between now and 2050 of 50MW plants.

The most notable theme of the policy discussion was reducing investor uncertainty. For example, the requirement for longer-term support for trials and large-scale demonstrations (possibly in the form of loan guarantees) and greater clarity on the overall hydrogen strategy were discussed. In addition, favourable views were expressed towards increased regulation and support for carbon capture on all biogenic materials for energy.

When asked, ***"Are there any other barriers to implementation?"*** the attendees provided many other comments. The commercialisation of H2BECCS faces a multifaceted set of challenges spanning technical, economic, policy, and social dimensions. Key barriers include competition for feedstocks, site availability, and public acceptance of biomass use.

Regulatory frameworks, particularly concerning domestic energy crops and end-of-waste policies, remain underdeveloped, adding complexity to project approval and operation.

The attendees viewed supply chain logistics as critical bottlenecks for feedstocks and hydrogen distribution. Geographic mismatches between feedstock sources and hydrogen offtake points further complicate deployment. Additionally, the alignment of H2BECCS with energy, agricultural, and biochemical industry policies is needed to ensure system-wide integration and circular economy benefits.

Economic hurdles, such as securing financing for first-of-a-kind technologies and managing investment competition with more established alternatives, also hinder progress. Uncertainty surrounding the value of outputs, carbon markets, and government commitments to hydrogen amplifies the risk for investors.

To address these barriers, some workshop participants suggested targeted strategies such as, government support for innovators through technical warranties, enhanced alignment of policies, and robust supply chain development. Land use optimisation and feedstock prioritisation should also be considered to ensure sustainability and scalability.

When asked, "***We know that the main barrier is financial. Do you have any suggestions about how to enable innovation from a financial point of view?"*** the attendees suggested various policy approaches and financial strategies to drive innovation.

Among the key recommendations is a direct government intervention programme, such as bonded capital for SMEs, targeted funding for key technical challenges, and a hydrogen scale-up funding programme based on equity collateral to enable the innovators to build an early-stage investment market. Additionally, ensuring price stability for low-carbon hydrogen and offering tax breaks for innovation in low-carbon technologies were suggested to enhance market certainty and incentivise private sector engagement.

Policy measures were highlighted to support innovation incentives with broader system goals. These included incentives for the utilisation of wastes, alignment of policies supporting hydrogen pathways, and government guarantees around performance, particularly for innovative technologies, to build investor confidence.

Other suggestions focused on transparency and support mechanisms, such as open-source cost data to reduce information asymmetry, improved techniques for evaluating technical risk, and mapping existing resources by TRL to support investment decisions. Attendees also emphasised the importance of developing markets for co-products such as biochar and leveraging public sector investment via schemes like Hydrogen Allocation Round (HAR) plus.

When asked, "***What other things could policy do to enable H2BECCS innovation?"*** attendees emphasised the critical role of organised and progressive policies in creating a supportive environment for H2BECCS development.

It was noted that a clear strategy for hydrogen market development should be integrated into the market development plan to provide direction and confidence for stakeholders. This includes greater clarity about the overall hydrogen strategy by sector, addressing the current disconnect between energy and biomass production, particularly in the waste and farming sectors.

Attendees highlighted the need for longer-term support for technology trials and publicly funded frameworks to facilitate large-scale demonstrations. These measures would de-risk innovation and accelerate the commercialisation of H2BECCS technologies. They would also demonstrate feasibility, build private and public confidence, and reduce the cost of FOAK projects.

Improving infrastructure access and alignment was another key point suggested by the stakeholders. Suggestions included better access to and confidence in carbon storage and enhanced transport and storage networks to support the end-to-end deployment of H2BECCS systems. Policies that regulate carbon capture for all uses of biogenic material for energy were also seen as critical to promote sustainability and align practices with decarbonisation goals.

Financial enablers, such as loan guarantees for H2BECCS projects, were proposed to de-risk investments and attract private sector participation. Combined with a robust policy framework, these guarantees could construct the basis for scaling the technology.

Summary

Workshops 1 and 2 were essential for gathering insights, validating assumptions, and addressing barriers to H2BECCS deployment. Workshop 1 focused on critically evaluating assumptions from WP1, identifying data gaps, and discussing technology readiness and commercialisation timelines. The diverse stakeholder representation ensured comprehensive feedback and established communication channels for ongoing data collection, including access to commercial datasets. Key themes included the need for large-scale deployment, improved efficiency, cost reduction, and addressing feedstock and market uncertainties.

Workshop 2 activities included updating assumptions, ranking barriers to commercialisation and exploring policy enablers. Stakeholders agreed that H2BECCS faces significant challenges, including financial risks, feedstock competition, and infrastructure needs. Discussions emphasised reducing investor uncertainty through targeted government support, policy alignment, and robust financial incentives. Predictions indicated that gasification and AD with SMR are the most likely technologies to scale by 2050, while lower-TRL routes require further development.

Both workshops provided critical input for accelerating H2BECCS deployment and integrating technical, economic, and policy considerations.

Data Uncertainty

Previous work [58] has shown Net Zero heavily depends on the UK's ability to produce negative emissions. However, there has not been a systematic review of H2BECCS since 2021's Element Energy report. A key purpose of this project has therefore been to update the evidence base. Given the low TRL of many H2BECCS technologies, there is significant uncertainty in the available data, stemming from limited demonstration-scale projects and variable assumptions about performance and scalability. As a result, while assessments of the low-TRL technologies provide valuable insights to inform modelling and research, they are not robust enough for use as modelling assumptions yet. For this reason, only the data for biomass gasification with CCS is considered reliable enough for inclusion in UK TIMES modelling at this stage. This approach ensures a balance between leveraging reliable data and informing long-term innovation and development in H2BECCS technologies.

Table 21 indicates the status of four key metrics for each of the five technologies to highlight uncertainties and areas for future work.

- Red – low certainty, singular workshop output or singular paper.
- Amber – medium certainty: multiple papers but no workshop output, strong workshop output but no papers, or singular workshop output combined with singular paper.
- Green – high certainty, based on both stakeholder workshop outputs with desk-based research from multiple peer-reviewed journals.

Table 21 – Data uncertainty

Technology	TRL	First year available	Energy conversion efficiency (%)	LCOH (£$_{2023}$/kg)
Biomass Gasification with CCS	7 - 8	2030	44	3.7
Anaerobic Digestion with Steam Methane Reforming and CCS	5 - 7	2030	35-45	4.7 – 5.9
Wastewater ammonia conversion	2 - 3	2035	3-5	2.9 – 5.3
Biomass Pyrolysis with CCS	3 - 4	2040	41	4.1 – 5.5
Dark fermentation	5 - 8	2030	2-4	2.0 - 3.2

Discussion

A review of the current literature, as provided by DESNZ, highlighted challenges with the evidence base used in previous modelling. The cited reports highlighted uncertainties related to the low TRLs of the technologies leading to challenges with data availability and limited commercial demonstrator data. Since this reporting, the Hydrogen BECCS Innovation Programme has supported key technologies through feasibility studies and has now moved on to enable the commercialisation and deployment of these technologies. This programme, along with updated literature and stakeholder engagement, provides an opportunity to update the evidence base with robust assumptions.

The analysis identified five key H2BECCS technologies with varying maturity levels, which were taken forward into the technology assessment. Within this assessment, technical, modelling, and economic assumptions were developed using desk-based research from peer-reviewed sources alongside the stakeholder engagement activities.

- **Biomass gasification with CCS** was identified as the most mature, with established commercial operations excluding CCS.
- **Pyrolysis** is a lower-TRL technology with promising commercial developments, however there are limited examples of the technology being used in the context of hydrogen production.
- **Anaerobic digestion** is already commercially established with clear market applications, but challenges remain around H_2 and CO_2 transport and storage because of decentralised and dispersed AD plant locations.
- **Dark fermentation**, while showing promise for hydrogen production, is at a lower TRL and faces additional hurdles in commercialisation and scaling.
- **Wastewater ammonia conversion** was also identified; however, it is an emerging technology with limited deployment potential constrained by the availability of larger-scale water treatment plants.

Two workshops played a pivotal role in validating the desk-based research findings and refining the project's insights. In the first workshop, the research outputs around the technologies were shared with industry, academia, and government stakeholders. Discussions were focused on each technology, steering subsequent data collection efforts and enhancing communications with industry. The process resulted in valuable contributions from commercial plants, further strengthening the evidence base.

The updated outputs and assumptions for each technology were presented in the second workshop. Discussions centred around broader commercialisation challenges such as financial barriers, policy and regulation, and infrastructure needs. Stakeholders emphasised the importance of reducing investor uncertainty through targeted government support, policy alignment, and robust financial incentives.

Phase 2: Modelling study evaluating the role of H2BECCS in achieving Net Zero emissions by 2050

Introduction

In 2025, DESNZ will conduct whole-systems modelling using UK TIMES to help inform the Seventh Carbon Budget (CB7). In the 2021 Net Zero Strategy modelling, UK TIMES favoured hydrogen bioenergy with carbon capture and storage (H2BECCS) above all other available GGRs, deploying the maximum technical potential in 2035 and 2050. This heavy reliance on H2BECCS to provide negative emissions and help meet Net Zero targets highlights the importance of ensuring the latest assumptions reflect a realistic and achievable deployment pathway.

The Catapult used its whole-energy systems model, Energy Systems Modelling Environment (ESME), to evaluate the role of H2BECCS in UK decarbonisation pathways. This modelling was built upon Phase 1 activities, which provided an engineering assessment of H2BECCS technologies. For the purposes of Phase 2 modelling, only biomass gasification with CCS was taken forward for further investigation. This decision reflects the relative maturity of the technology in comparison to the other H2BECCS technologies where data limitations and lower TRLs reduced confidence in the data. The modelling will complement future UK TIMES work, providing the opportunity to compare the outcomes of similar scenarios with different modelling approaches, thereby improving confidence in the conclusions drawn.

Phase 2 used updated technical-economic assumptions about H2BECCS technologies developed in Phase 1 to provide modelling insights for DESNZ and to support future UK TIMES modelling. The Hydrogen Innovation Initiative (HII) scenarios, previously developed in collaboration with DESNZ, formed the basis of four plausible yet distinct pathways for the UK's hydrogen landscape. Each scenario reflects different combinations of policy choices and technological characteristics, describing various levels of coordination and innovation related to the hydrogen economy. Additional sensitivities regarding the impact of changing biomass availability, carbon capture rates, and costs were also examined. These scenarios and sensitivities were used to assess the deployment potential of H2BECCS.

The outputs from this phase provide insights into how H2BECCS technologies can contribute to the UK’s Net Zero strategy. The main outputs include high/medium/low deployment profiles for H2BECCS to 2050, alongside an analysis of key drivers and barriers to deployment.

Research questions

Phase 2 aims to address the following research questions, which were defined in collaboration with DESNZ.

RQ 4: What is the maximum technological deployment potential (MTP) and build rate limit for scaled removals (in 5-year increments from 2030-2050) for biomass gasification H2BECCS plants?

To address this, an updated pathway of deployment limits was necessary to guide UK TIMES modelling for CB7. The revised constraints were defined using evidence previously identified in Phase 1 of the project, along with learnings from the stakeholder engagement outputs. Alongside the Phase 1 outputs, further analysis of equivalent historical plant deployments provided an additional validation measure.

RQ5: Applying the MTP, what is the "realistic" scaling potential for H2BECCS, factoring in constraints on biomass availability, CCUS storage availability, demand from hydrogen offtakers, and delays to rollout?

To address this, Hydrogen Innovation Initiative scenarios were updated with new technology assumptions, deployment rates, and biomass feedstock availability and then modelled in ESME. Analysis of how variation in these factors impacts H2BECCS deployment was performed. The outputs of this analysis will deliver insights into the impact of biomass availability and hydrogen innovation investment on the potential future deployment of H2BECCS.

Methodology

The methodology for this study was designed to evaluate the potential deployment of H2BECCS within the UK energy system and assess its contribution to meeting future carbon targets. The analysis builds on insights from phase 1 of the project, incorporating updated technical and feedstock assumptions into the Energy Systems Modelling Environment (ESME). Four distinct scenarios based on the Hydrogen Innovation Initiative scenarios were modelled to assess the role of H2BECCS under different conditions. Additional sensitivities related to biomass feedstock availability, CCS capture rate, and cost were also performed.

The following is an outline of the steps taken:

1. **Identification of Maximum Technological Deployment Potential (MTP):** The potential for H2BECCS deployment was assessed based on engineering constraints and insights from the deployment of comparable biomass power plants in the UK.
2. **H2BECCS Assumptions Update:** Assumptions related to biomass-to-hydrogen conversion efficiency, availability factor, and costs have been updated to reflect the latest technological and market developments.
3. **Scenario Development and Modelling:** The HII scenarios—Policy-Led, Industrial Cluster Propagation, Hydrogen Optimism, and Hydrogen Pessimism—were modelled to evaluate how different strategic and market conditions, particularly around hydrogen innovation, could influence the deployment of H2BECCS.
4. **Sensitivity Analysis:** Additional sensitivities were performed to assess the impact of variations in biomass feedstock availability (informed by the UK Biomass Strategy [6]), CCS capture rate, and cost on H2BECCS deployment pathways.

The following sections outline the details of the modelling process, including the definition of the Maximum Technological Deployment Potential, derivation of input assumptions and a description of the scenarios analysed.

Maximum Technological Deployment Potential (MTP)

The Maximum Technological Deployment Potential (MTP) represents the engineering constraints on building and operating H2BECCS plants. It defines the upper limit of deployment based purely on technological and engineering capacity, excluding factors such as biomass availability or hydrogen demand. MTP is a model input derived from a combination of engineering assessments and expert/stakeholder judgment. Specifically, it informs assumptions about the feasible build rates of H2BECCS plants within the UK's energy system. The following section directly addresses **Research Question 4 (RQ4)**, which explores the extent to which H2BECCS can be deployed within the UK energy system.

To estimate MTP for H2BECCS technologies, a comparable technology—biomass-fired generation plants—was used. These plants have been shown to encounter similar constraints relating to engineering, deployment, and broader systemic factors, such as supply chain immaturity [59]. Tracking the deployment of this more mature technology within the UK offers valuable insight into these challenges as well as a representative technology adoption curve to help predict the deployment of H2BECCS technologies [1].

The UK's Biomass Energy Development Path, published in 2010 (when the UK's biomass power generation capacity was around 300 MW, 7% of today's installed capacity), reported 7GW of planned capacity in development [59]. Today, the current installed biomass capacity is approaching 5 GW. The report highlighted multiple barriers to deployment including:

- Supply chain challenges
- Public awareness
- Complex grant schemes
- Government policy and support challenges

These barriers are very similar to those highlighted within the stakeholder workshop outputs from phase 1 of the project.

To estimate the MTP, data from the Renewable Energy Planning Database (REPD) was analysed to track the deployment of biomass electricity plants over time. Specifically, the Renewable Energy Planning Database: quarterly extract (Renewable Energy Planning Database (REPD): October 2024 (quarter 3)), was used to map the deployment curve of biomass power plants greater than 10 MWe. This deployment curve was then adjusted using assumptions about biomass-to-hydrogen conversion efficiency to model hydrogen production capacity. The resulting curve formed the basis for defining the MTP, providing a data-driven projection of how H2BECCS technologies might scale under similar engineering and systemic constraints. It is important to note that using historical deployment trends as a guide does not fully account for the urgency of Net Zero targets or the different constraints shaping future deployment.

In the case of H2BECCS, however, MTP is a model input and acts as a direct constraint on build rates within the model. This distinction means that while the scenario-based approach explores broader systemic factors, the MTP constraint reflects the underlying engineering and deployment feasibility (albeit an optimistic view), rather than resource availability, which is evident in the model outputs.

Numerous global examples exist where innovation, once considered constrained, has achieved significant breakthroughs, overcoming deployment barriers. Notable cases include the rapid advancements in solar energy and offshore wind, demonstrating how perceived limitations can be surpassed with the right focus, policy mix and innovation. This highlights the potential risk of over-constraining the model when applying maximum deployment limits to a technology.

Deriving the MTP for H2BECCS

The following steps were undertaken to develop the deployment curves presented in the charts.

1) Derive Stakeholder Workshop Curve: This curve was derived directly from the stakeholder workshop outputs, representing the expert view of the deployment trajectory.

2) Derive Biomass Powerplant Deployment Curve: The yearly deployment of biomass power plants (>10MW_e) was extracted from the Renewable Energy Planning Database. From this, the deployment curve for biomass-based industrial plants in the UK (the s-curve) was generated. Based on this deployment curve, the corresponding hydrogen production capacity was determined using the efficiency assumptions outlined in Table 22. This was then offset to a 2035 first commercial deployment start.

Table 22 - Conversion efficiencies used in the biomass conversion calculations.

	Efficiency (%LHV)	Reference
Biomass to electricity conversion	30%	[61]
Biomass to hydrogen conversion	44% - 50%	H2BECCS phase 1 outputs

3) Determine Technological Deployment Potential: This curve was calculated from the biomass power plant deployment potential and the outputs from the stakeholder workshop. The two sets of projections were averaged to provide a middle-ground estimate.

Additionally, a ±50% range was applied to the derived deployment curve to represent the high level of uncertainty in this predictive analysis due to various influences (policy, economic, and societal). The upper bound (+50%) of this range is referred to as the **Maximum Technological Deployment Potential (MTP).**

H2BECCS technological deployment

Considering the Hydrogen BECCS innovation programmes and the deployment rate of projects supported within the hydrogen allocation rounds (HAR), a 2035 initial deployment was recommended as a reasonable assumption. This timeline also aligns closely with the deployment suggested by stakeholders during the phase 1 workshop. Figure 15 presents the projected Maximum Technological Deployment Potential (MTP) of H2BECCS, while Table 23 outlines the H2BECCS MTP in terms of hydrogen production capacity (GW) over time. The deployment projections reflect a combination of engineering assessments, expert/stakeholder input, and lessons from the biomass power sector.

The analysis establishes a realistic technological deployment pathway for H2BECCS within the UK. The derived MTP values will serve as key model inputs within UKTIMES and ESME, providing a basis for scenario testing and policy development.

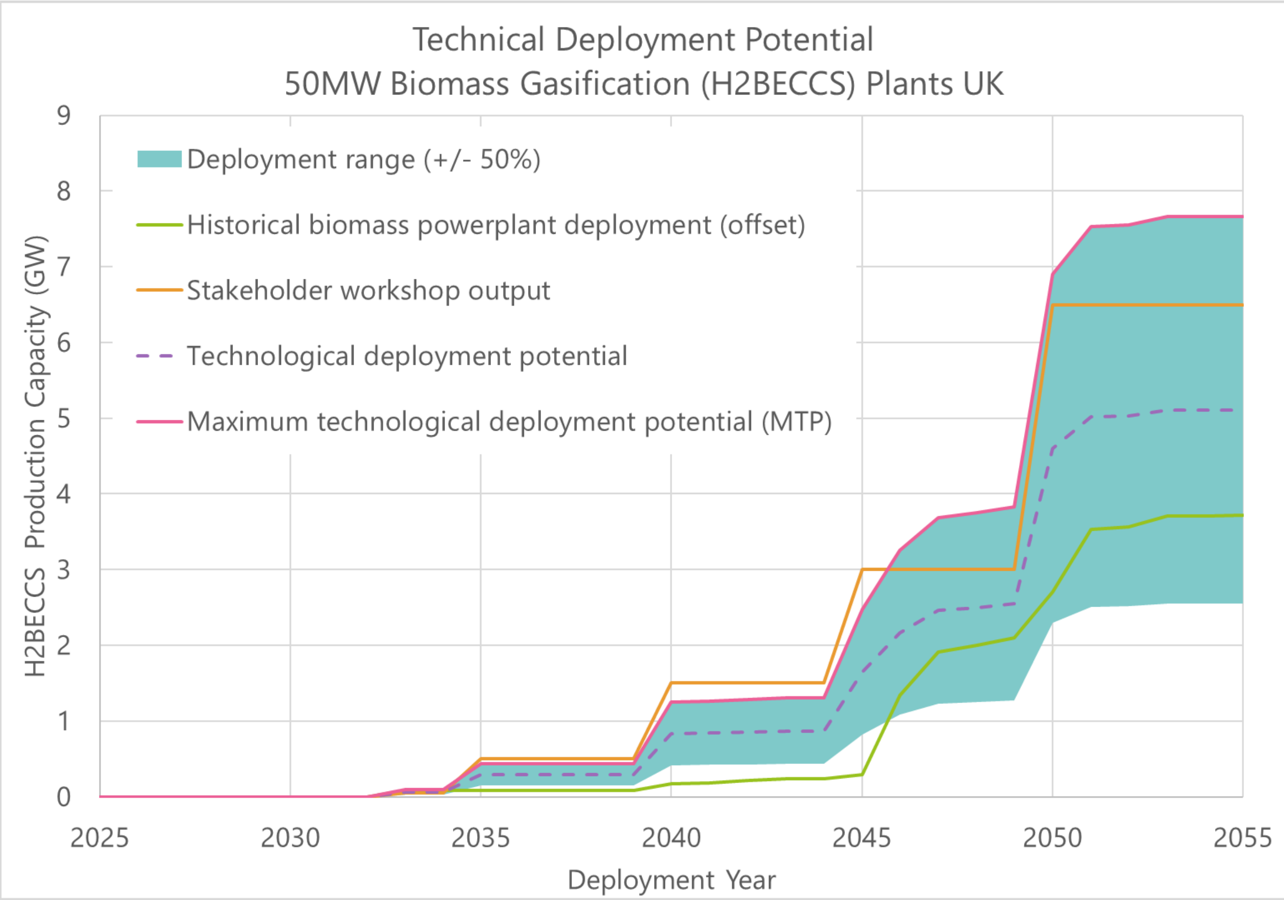


Figure 15 - Maximum Technological Deployment Potential of H2BECCS - Biomass Gasification Plants.

Table 23 - H2BECCS Maximum Technological Deployment Potential – GW Hydrogen production capacity.

Deployment Year		2025	2030	2035	2040	2045	2050
Historical biomass powerplant deployment (GW) (Offset)		0.00	0.00	0.09	0.17	0.29	2.70
Stakeholder Workshop Outputs (GW)		0.00	0.05	0.50	1.50	3.00	6.50
Technological deployment potential (GW)	Upper Range (MTP) (+50%)	0.00	0.00	0.44	1.25	2.47	6.90
	Median	0.00	0.00	0.29	0.84	1.65	4.60
	Lower Range (-50%)	0.00	0.00	0.15	0.42	0.82	2.30

Scenario Modelling

Energy Systems Modelling Environment (ESME)

The Energy Systems Modelling Environment (ESME) is an in-house, whole energy system model developed by the Energy Systems Catapult. It was originally designed to evaluate the role of innovation in UK energy system decarbonisation, covering energy resources, conversion, and end use across buildings, transport, and industry.

As an optimisation model, ESME determines the least-cost combination of energy resources and technologies that meet UK energy service demands up to 2050. Key constraints within the model include emissions targets, resource availability, and technology deployment rates, as well as operational factors that ensure adequate system capacity and flexibility. The model focuses on physical system components, including infrastructure, energy flows, and costs, without incorporating commercial aspects or interactions between energy system stakeholders, such as government, regulators and consumers.

A distinguishing feature of ESME is its multi-regional UK representation, allowing assessment of infrastructure requirements to connect resources, technologies, and demands nationwide. This includes transmission and distribution networks for electricity and gas, as well as CO_2 pipelines and storage. The model assumes the UK functions as an "energy island," meaning it does not rely on international cross-border electricity imports or exports. Additionally, ESME maintains a policy-neutral approach, avoiding assumptions about how policies might de-risk future investments.

Limitations of the model

Given the complexity of energy systems and computational limitations, ESME incorporates certain simplifications that introduce constraints to its outputs. These simplifications, along with other considerations such as data availability, introduce practical limitations to the modelling. Recognition of these limitations is crucial to select the most appropriate model for the questions being answered. Some key limitations to be aware of include the following:

- **Data**: ESME is a data-driven model, with projections for demands, technologies and resources being central to its decision-making. These projections are, by their nature, uncertain, and results should be assessed carefully in this context. Notably, decisions made in one sector can radically affect the timing or extent of decarbonisation in others.
- **Linearity:** Like many similar models (e.g., UK TIMES), ESME adopts a linear representation for technology and resource costs, as well as constraints affecting the energy system, meaning that the costs are assumed to scale proportionally with deployment levels. Such a representation overlooks “lumpy investment”, where

technologies are deployed in blocks of minimum size, and neglects any cost scaling of technologies. This has particular impacts on key sectors, as outlined below.

- **Spatial resolution:** ESME is a multi-regional model, allowing the broad features of transmission and distribution of energy across the UK to be assessed. However, only limited information at finer granularity is integrated. Demand centres are not spatially positioned, and local challenges of transmitting energy within a region are not substantively modelled. Where physical limitations are key (for example, where there are permitted locations for particular power stations), these are implemented as regional constraints within the model.
- **Sector representations:** Within ESME, each current and future emission point is not modelled independently. Instead, a set of coarse archetypes is used to characterise users of energy and sources of emissions across the whole system. In each case, sector representations are chosen to retain as much operational flexibility as possible, ensuring that innovations in technology properties and control do not impose overly constraining routes.

H2BECCS technology update

Following phase 1 of the project, the technical assumptions for H2BECCS were updated, including biomass-to-hydrogen conversion efficiency, TRL levels, availability factor, capital costs, and fixed and variable operational and maintenance costs. Further details about the costing update can be found in Appendix 1.

Feedstock assumptions update

Feedstock assumptions were updated using the 2024 UK and Global Bioenergy Resource model, informed by discussions with DESNZ [62]. The baseline UK domestic biomass production remains constant across all scenarios, while biomass import levels vary under the restricted, moderate, and ambitious scenarios. This allows for an assessment of how changes in global biomass availability could impact UK feedstock imports and therefore H2BECCS deployment. DUKES (the Digest of UK Energy Statistics) was used to provide real values for 2015 and 2020 [63], ensuring consistency with historical data.

The ambitious and restricted scenarios are aligned with the Biomass Strategy (2023) [6]. Figure 16 shows the biomass availability for the three scenarios.

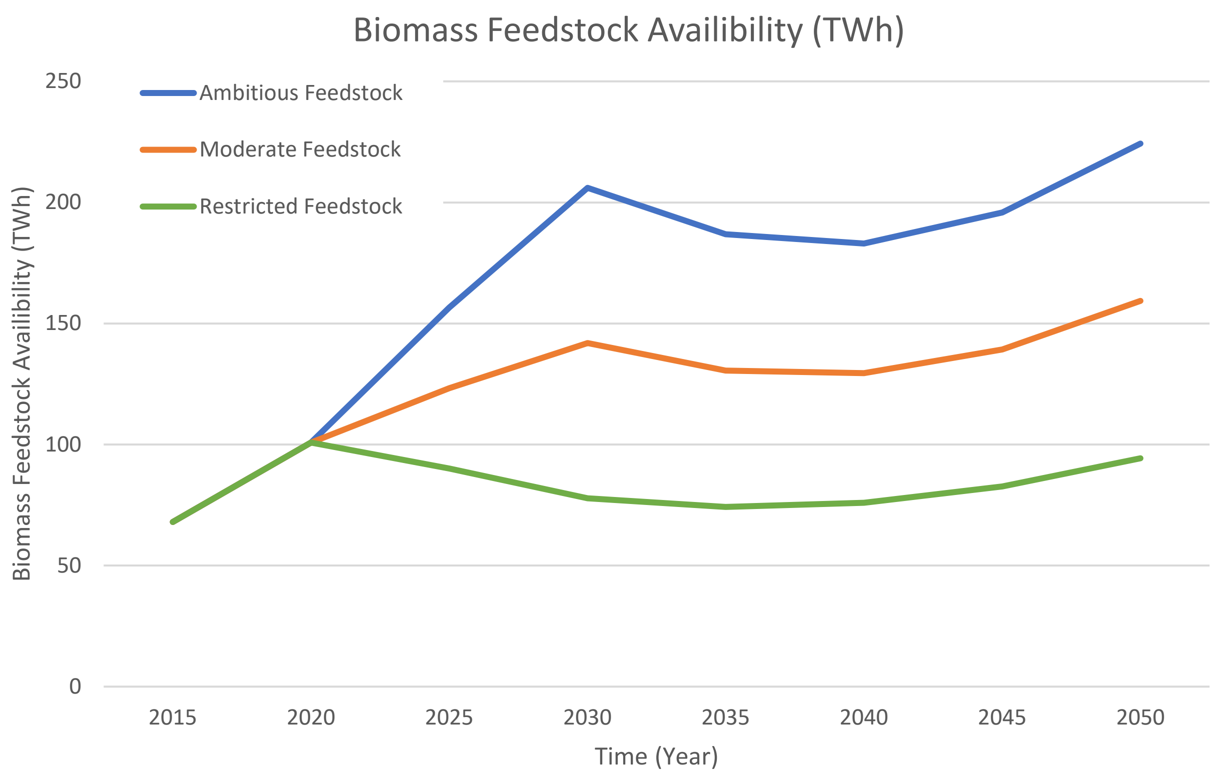


Figure 16 - Graph depicting the various feedstock scenarios used in the H2BECCS study.

Hydrogen Innovation Initiative scenarios

The initial reference cases used in this investigation were originally developed within the Hydrogen Innovation Initiative project [64]. Four scenarios were developed to explore different potential futures for the UK hydrogen landscape:

- **Policy-Led** reflects a strategy driven by strong government intervention and support.
- **Industrial Cluster Propagation** represents a geographically focused approach, with hydrogen deployment concentrated around key industrial clusters.
- **Hydrogen Optimism** envisions accelerated innovation, achieving commercial viability five years earlier than anticipated.
- **Hydrogen Pessimism** reflects a future where hydrogen innovation stalls, delaying commercial viability by five years beyond current expectations.

The scenarios are designed to test potential decarbonisation pathways and the role of various energy vectors. They are not intended to be equally probable; rather, they are explored to highlight the challenges of certain pathways, helping to identify potential barriers and inform more effective decision-making. Hydrogen demand is calculated by the model through system optimisation, reflecting how different scenarios influence hydrogen production and consumption patterns.

To align with previously set government targets (not reflective of current UK Government policy), three of the scenarios (Policy-led, Industrial Cluster Propagation, and Hydrogen Optimism) impose a constraint requiring 5 GW of electrolytic hydrogen and 5 GW of thermal hydrogen with CCS capacity by 2030. However, the Hydrogen Pessimism scenario takes a more cautious outlook, applying only half these targets (2.5 GW per technology).

Across all scenarios, carbon capture and storage (CCS) deployment is limited to locations where a current CCUS project has been identified, such as export terminals or pipelines to geological storage. In the Industrial Cluster Propagation scenario, the absence of Project Union results in the formation of "Hydrogen Islands" around industrial clusters, limiting hydrogen production outside these areas and restricting broader network connections.

See the Sectors and Scenarios report for additional information on the scenario definitions - https://hydrogeninnovation.co.uk/reports/sectors-and-scenarios/.

Policy-Led

The Policy-Led scenario is fundamentally driven by alignment with government policy across the energy sector. Policies set out within UK Government strategies and policy papers, such as the Net Zero Strategy (2021), Powering Up Britain (2023), and the British Energy Security Strategy (2022) create a clear framework for investment and development. Government-backed hydrogen production business models and supportive regulations facilitate coordinated national deployment.

Industrial Cluster Propagation

The Industrial Cluster Propagation scenario constrains hydrogen deployment to industrial clusters with limited coordinated propagation beyond. Investment in hydrogen is moderate, driven by the strategic importance of decarbonising heavy industry and transport hubs in specific regions.

Hydrogen Optimism

The Hydrogen Optimism scenario represents a future in which both the UK and global markets invest in innovation to bring costs down sooner and accelerate technology to commercial viability. The scenario assumes favourable market conditions, reducing financial and technical barriers to large-scale hydrogen adoption across multiple sectors, including hydrogen production, industry, transport, and other hard-to-abate end-use sectors.

Hydrogen Pessimism

The Hydrogen Pessimism scenario depicts a future in which hydrogen is viewed with caution in the UK, resulting in limited investment and slow commercialisation of hydrogen technologies.

Results and Discussion

This section presents a detailed analysis of the HII scenarios, focusing on the deployment profiles of H2BECCS technologies under different market and policy conditions.

The Policy-Led scenario was selected as a basis to test sensitivities to the H2BECCS technology update, biomass availability on H2BECCS deployment, and H2BECCS plant costs as it imposes fewer technological constraints, allowing for a more flexible evaluation. This scenario demonstrates the highest deployment of H2BECCS, reflecting a strategic focus on scaling hydrogen as a key decarbonisation tool across industry and transport.

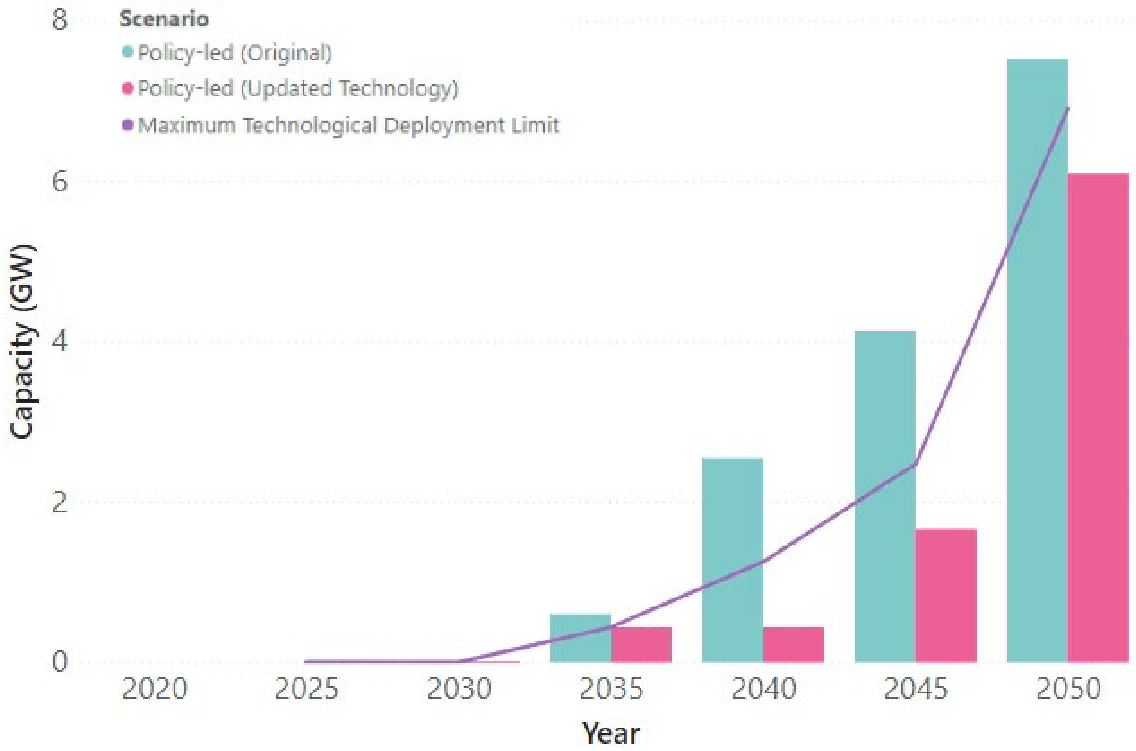
The impact of updating the H2BECCS technology parameters is assessed by comparing the original and updated deployment profiles. This analysis considers the maximum technological deployment potential within the Policy-Led scenario. Additionally, it examines the share and distribution of biomass-consuming technologies up to 2050.

A sensitivity analysis was conducted to assess the impact of varying biomass availability levels, including ambitious, moderate, and restricted scenarios. Insights were drawn from comparing H2BECCS deployment profiles, biomass consumption, and captured CO_2. Additional sensitivities were explored to assess the impact of varying capital cost and economies of scale, and carbon capture rates to build a more complete picture of the drivers of H2BECCS deployment.

Finally, key insights were drawn by comparing the influence of different UK hydrogen landscapes on the deployment of H2BECCS technologies using the HII scenarios. The updated H2BECCS technology assumptions were applied consistently across the scenarios. The findings provide valuable insights into how policy, technology costs, and resource constraints shape the future of the UK's hydrogen economy and the role of H2BECCS within it.

Impact of updated H2BECCS technology parameters

The original HII Policy-led scenario serves as a benchmark for the analysis, enabling the assessment of the impact of updating the H2BECCS gasification technology parameters. Figure 17 compares H2BECCS deployment capacity (in GW hydrogen) under the Policy-led (Original) and Policy-led (Updated Technology) scenarios alongside the new Maximum Technological Deployment Potential. The original scenario is not restricted by the new MTP.



(Please note, these are ESME modelled results and are not direct DESNZ projections or policy)

Figure 17 - H2BECCS capacity (GW) under the Policy-led (Original) and Policy-led (Updated Technology) scenarios, compared with the Maximum Technological Deployment Limit from 2020 to 2050.

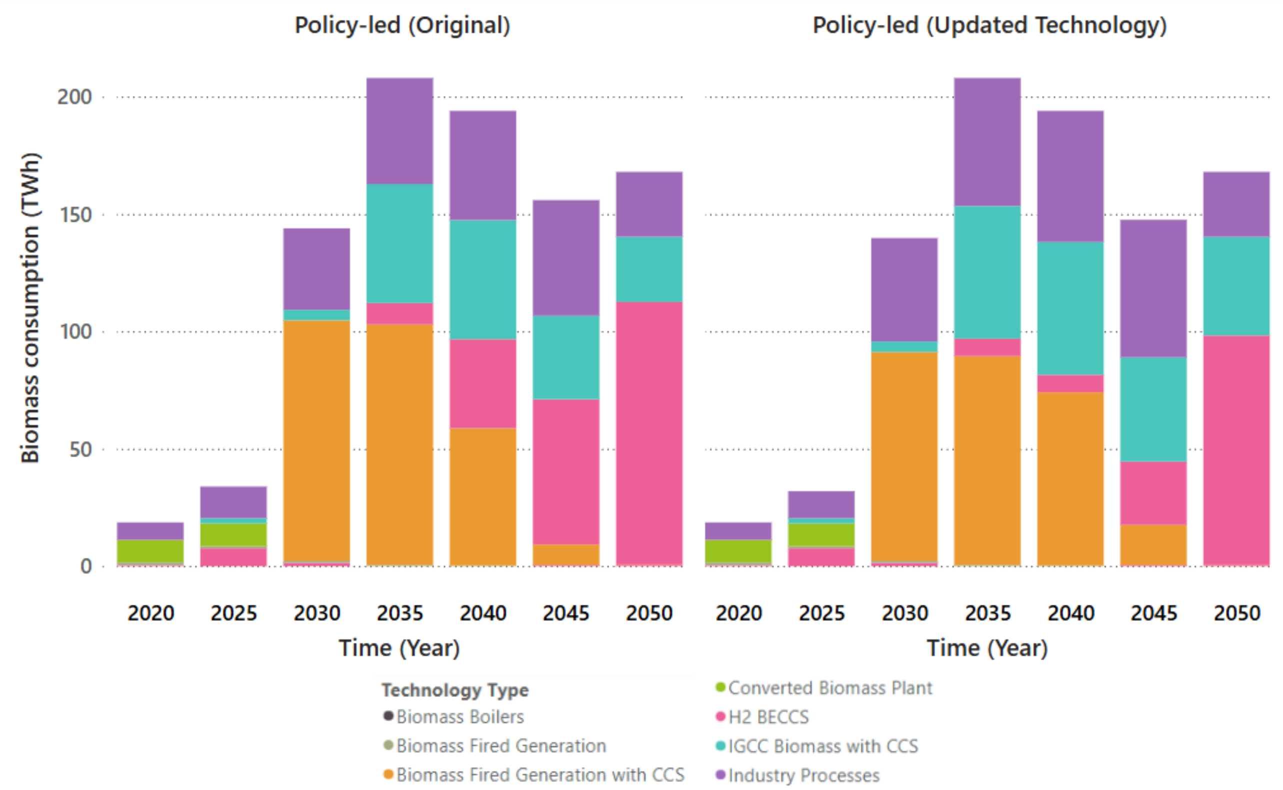
The original scenario projects steady growth from around 2030, reaching approximately 7 GW by 2050, which is close to the newly defined maximum deployment limit. In contrast, the updated technology scenario reflects slower initial deployment following the updated build rate constraints in 2035. Capacity lags behind the original scenario, with no new capacity built in 2040 as a result of increased technology costs between the scenarios. However, deployment accelerates after 2045, reaching approximately 6 GW by 2050.

The step change in deployment is a characteristic of both MTP and the least-cost optimisation modelling for Net Zero. This modelling approach is driven by two primary criteria: (1) meeting the Net Zero target, and (2) doing so at the lowest possible cost, based on constraints such as technology availability, resource limitations, and associated costs. Least cost optimisation models have perfect foresight of costs, meaning they understand what the future costs will be and as a result can sometimes delay deployment of technologies to later in the time horizon when costs are lowest.

H2BECCS deployment is impacted by both costs and build rates. (There are other energy system interactions that also impact deployment in 2040, which are discussed later in the report).

Figure 18 illustrates the impact the new H2BECCS parameter update has on biomass consumption for the Policy-Led scenario. Within both scenarios, early biomass consumption is primarily dominated by biomass power generation and industry usage to support near-term decarbonisation and an increase in electrification of other sectors such as transport and heat.

"Industry Processes" encompass a range of industrial technologies that use biomass both as a feedstock—for the production of biofuels and chemicals—and for energy, particularly heat. These processes also include configurations with carbon capture and storage (CCS), where applicable. Technologies falling under this category include biodiesel, biokerosene, biopetrol and biopetrol with CCS.



(Please note, these are ESME modelled results and are not direct DESNZ projections or policy)

Figure 18 - Stacked bar chart showing the biomass consumption in terawatt-hours (TWh) for biomass technologies within ESME for the original policy-led scenario – Policy-led (Original) and the updated technology policy-led scenario - Policy-led (Updated Technology) from 2020 to 2050.

As CO_2 targets tighten towards 2050, there is a clear shift toward more advanced technologies like integrated gasification combined-cycle (IGCC) biomass with CCS and H2BECCS. This highlights both the importance of negative emissions and the increasing role of hydrogen production in decarbonising industry, transport and dispatchable power applications.

Both Policy-Led scenarios consume similar amounts of biomass in total in each time period. Typically, models like ESME will consume all available biomass, especially when it can be combined with (CCS) to deliver valuable negative emissions. However, the scenarios reveal differences in the sectors where this is consumed. Notably, there is a slower uptake of H2BECCS in the Policy-Led (Updated Technology) scenario. This is a direct result of higher capital costs and less optimistic build rates. The upshot is higher consumption in the power sector and industry in the 2040s. By 2045, H2BECCS deployment accelerates, reflecting an increased demand for hydrogen.

With the updated technology constraints, the deployment of H2BECCS is primarily constrained by the build rate assumptions reflecting the maximum technological potential. The increased technology cost is also impacting deployment.

Further analysis of the impact of technology costs revealed that reducing CAPEX, based on assumptions aligned with a 500 MW plant size, led to an increase in overall deployment. This demonstrates that deployment is sensitive to the assumed scale of plant used to define CAPEX, where a cost reduction of 30% has resulted in an increase in deployment of 15-40% depending on the baseline. While the cost reduction made deployment more attractive, the resulting increase in capacity was ultimately constrained by the MTP across all years. **Increasing the scale of plants enabled CAPEX reductions that unlocked greater deployment, but once costs were no longer the limiting factor, the MTP became the binding constraint imposed on the model.** This suggests that although cost and scale assumptions are important levers, further capacity growth is fundamentally limited by system-wide factors such as deployment caps, rollout pace, and integration challenges.

Impact of biomass feedstock availability

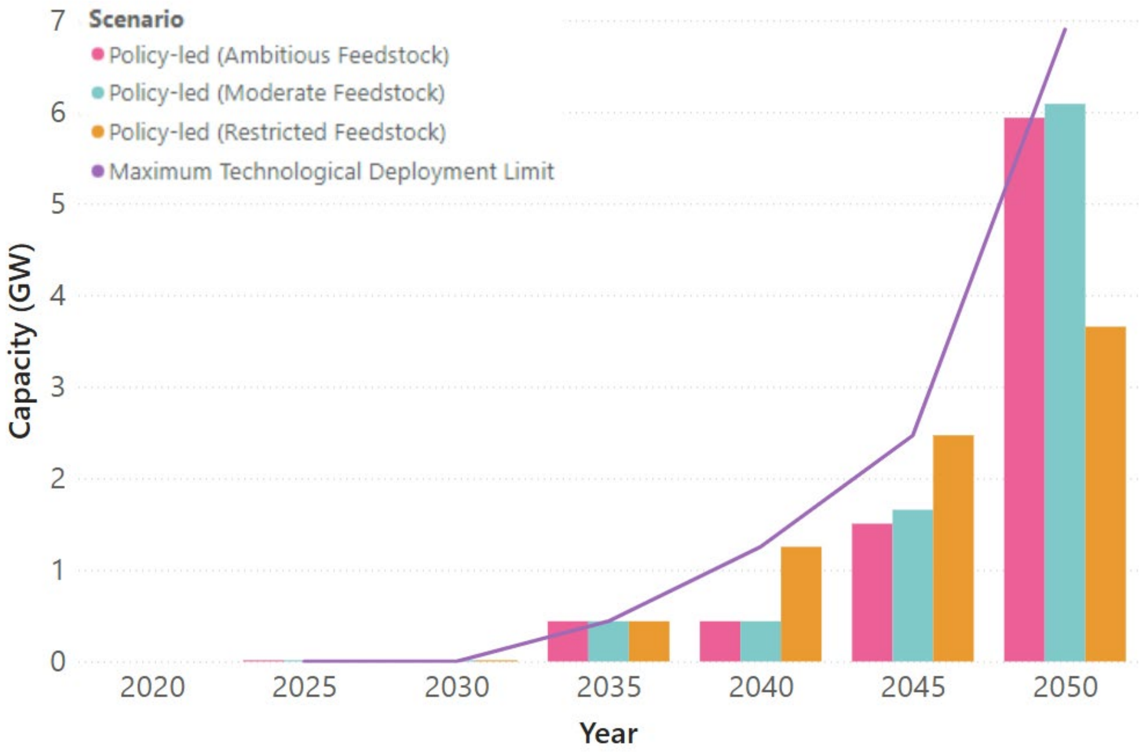
Biomass feedstock availability in these sensitivities is primarily driven by variations in biomass imports. These have been adjusted using the UK and Global Bioenergy Resource Model 2024 [62] to reflect changing biomass markets and policy shifts, with the Ambitious and Restricted availability scenarios aligned to the Biomass Strategy (2023) [6]. These variations directly impact the feasibility of H2BECCS and the overall role of biomass in the UK's energy system. The biomass sensitivities are described below:

- **Ambitious Feedstock Availability** – Highest biomass consumption, exceeding 200 TWh by 2050, driven by increased biomass imports and greater availability in global biomass markets.
- **Moderate Feedstock Availability** – Biomass consumption follows a middle ground trajectory, with domestic production constant and a moderate amount of biomass imports.

- **Restricted Feedstock Availability** – Lowest biomass consumption, below 100 TWh in 2050, with lower biomass imports.

An important point to note is that the moderate and restricted scenarios do not reach Net Zero by 2050.

Figure 19 shows the projected capacity (in GW) of H2BECCS under the policy-led scenario with varying on feedstock availability from 2020 to 2050 compared against the Maximum Technological Deployment Limit. The chart indicates a gradual increase in capacity until 2045, after which there is a sharp acceleration, particularly with the moderate and ambitious feedstock variations. It is important to note that linear cost optimisation models may delay the deployment of certain technologies to take advantage of lower costs that may arise as technologies improve or become cheaper over time.

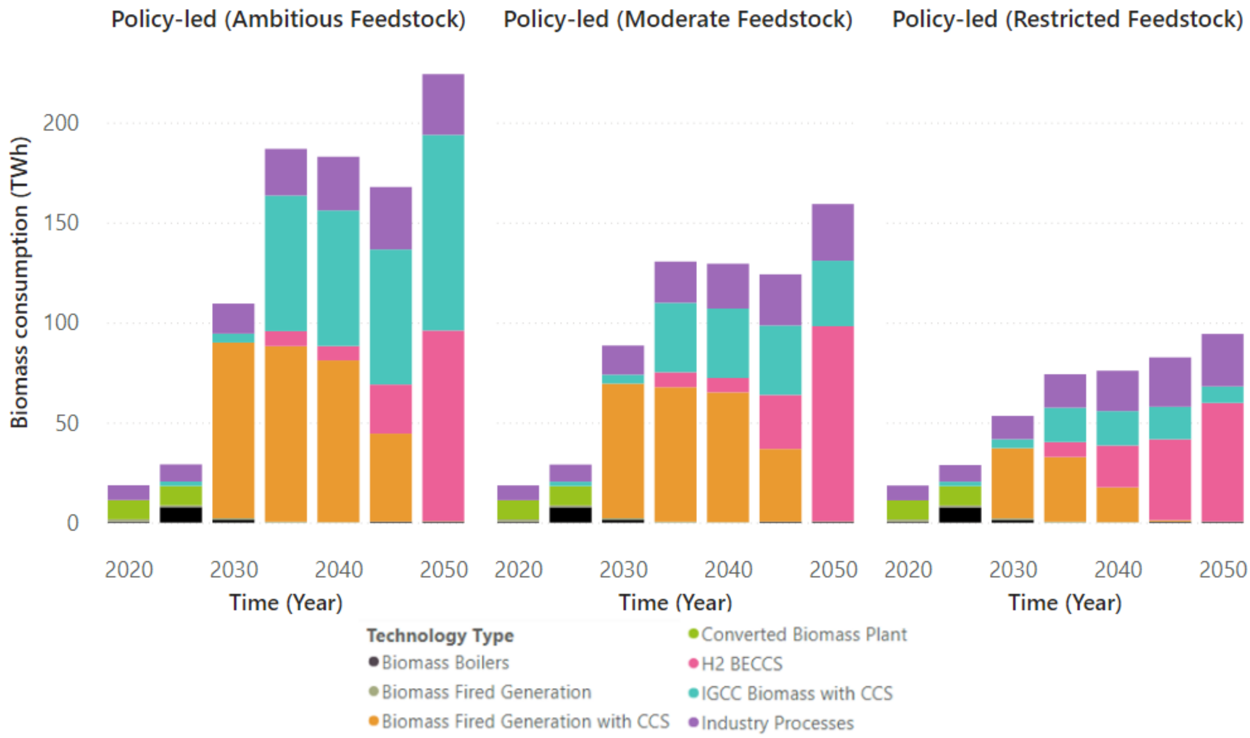


(Please note, these are ESME modelled results and are not direct DESNZ projections or policy)

Figure 19 - Projected H2BECCS capacity (GW) under the Policy-led scenario with Ambitious, Moderate, and Restricted Feedstock availability, compared to the Maximum Technological Deployment Limit from 2020 to 2050. All variations are with the updated H2BECCS technology.

The restricted feedstock scenario closely tracks the maximum technological deployment potential to 2045. After 2045, the total capacity is just under 4GW. This is a result of the limited availability of biomass feedstock, which constrains the potential for further H2BECCS deployment. The restricted scenario is fundamentally limited by resource availability rather than technological capability. **The divergence between scenarios highlights the importance of feedstock availability in scaling up H2BECCS capacity to meet long-term decarbonisation targets.**

Figure 20 shows biomass consumption for the biomass sensitivities from 2020 to 2050, highlighting the impact of feedstock availability on overall biomass consumption. Varying biomass availability provides insight into how the model prioritises the deployment of biomass-consuming technologies.



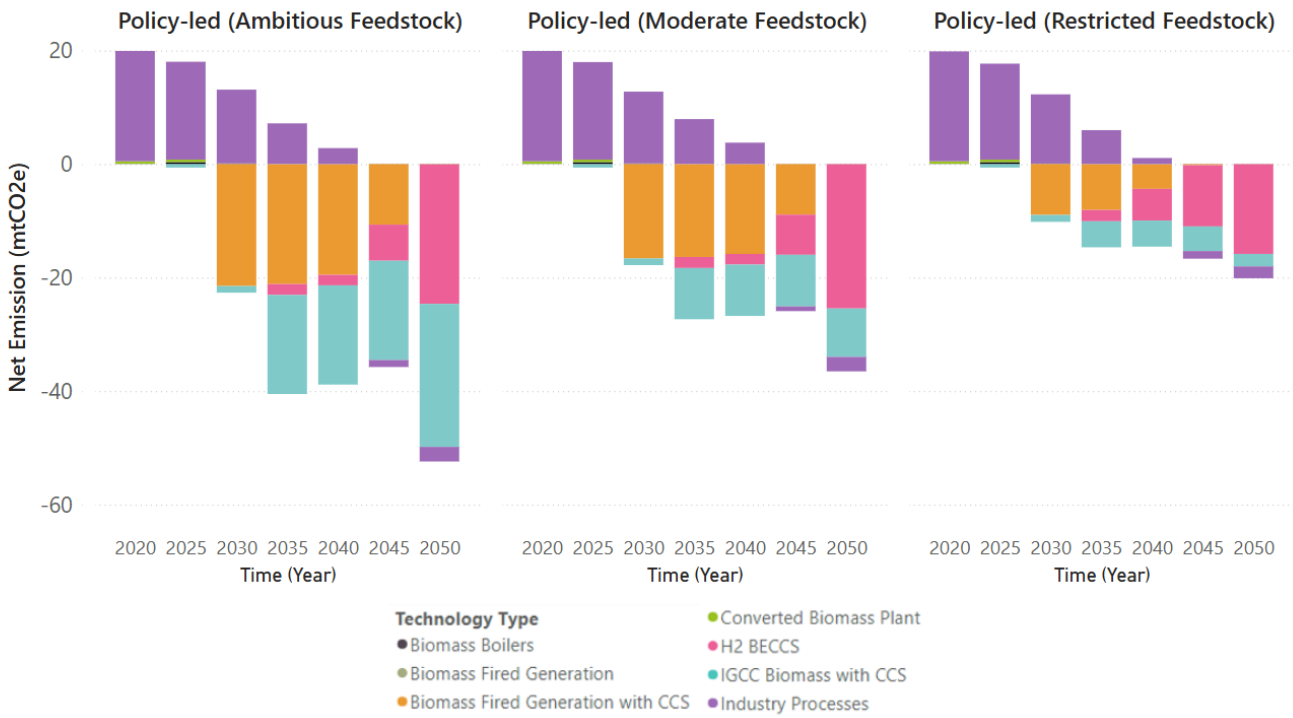
(Please note, these are ESME modelled results and are not direct DESNZ projections or policy)

Figure 20 - Biomass consumption by technology type across varying feedstock availability assumptions within the policy-led scenario. All variations are with the updated H2BECCS technology.

Across all sensitivities, by 2050, H2BECCS is the single biggest consumer of overall biomass. However, in the earlier years, power BECCS technologies, such as IGCC and Biomass Fired Generation, are the dominant contributors across all scenarios, with H2BECCS becoming more prominent in the later years. **Industrial demand for biomass is consistent across all sensitivities,** even in the restricted variation. This reflects the limited options for deep decarbonisation in industry (for high temperature process heat and as a non-fossil feedstock) reinforcing the importance of biomass for reducing emissions in hard-to-abate sectors.

Under restricted biomass availability, a greater share of the limited biomass is directed towards H2BECCS compared to other technologies. During the 2030s, the power sector, being the cheapest and easiest to decarbonise, is largely addressed first, with residual biomass mainly used to maximise negative emissions. In the 2040s, as overall power demand increases, H2BECCS deployment remains relatively steady, with most biomass continuing to support power generation. Over time, however, the generation mix increasingly shifts towards renewable and nuclear energy providing base load, reducing the reliance on BECCS for power. Due to evolving conditions in the electricity system, this whole-system outcome reflects the greater value of producing hydrogen rather than electricity from biomass. Meanwhile, rising hydrogen demand drives a significant expansion of H2BECCS capacity, explaining the sharp increase in deployment towards 2050. **When biomass availability is constrained, the system shifts priority towards H2BECCS, highlighting the strategic role of hydrogen production and carbon capture in decarbonising the energy system under resource-limited conditions.**

Figure 21 highlights the impact of changing biomass availability on net negative emissions potential through various technologies.



(Please note, these are ESME modelled results and are not direct DESNZ projections or policy)

Figure 21 - Projected net emissions (MtCO2e) by biomass consuming technology type across policy-led scenarios with varying feedstock levels (2020-2050). All variations are with the updated H2BECCS technology. Note: Moderate and Restricted Feedstocks did not reach Net Zero by 2050.

Given build constraints on individual power BECCS and H2BECCS technologies, a diverse range of BECCS applications emerges to maximise biomass utilisation. **The amount of biomass feedstock available directly impacts the amount of CO_2 captured and negative emissions.**

With ambitious feedstock assumptions, CO_2 capture reaches its highest level between the scenarios that involve extensive deployment of power BECCS and H2BECCS technologies. In contrast, the moderate and restricted feedstock scenarios result in less CO_2 capture and, in particular, fewer negative emissions. The deployment of the CO_2 backstop technology in 2050 signals that these scenarios fell short of the Net Zero target.

All the sensitivities modelled maximise biomass consumption in BECCS applications, whether for power generation, industry, or hydrogen production. BECCS, along with

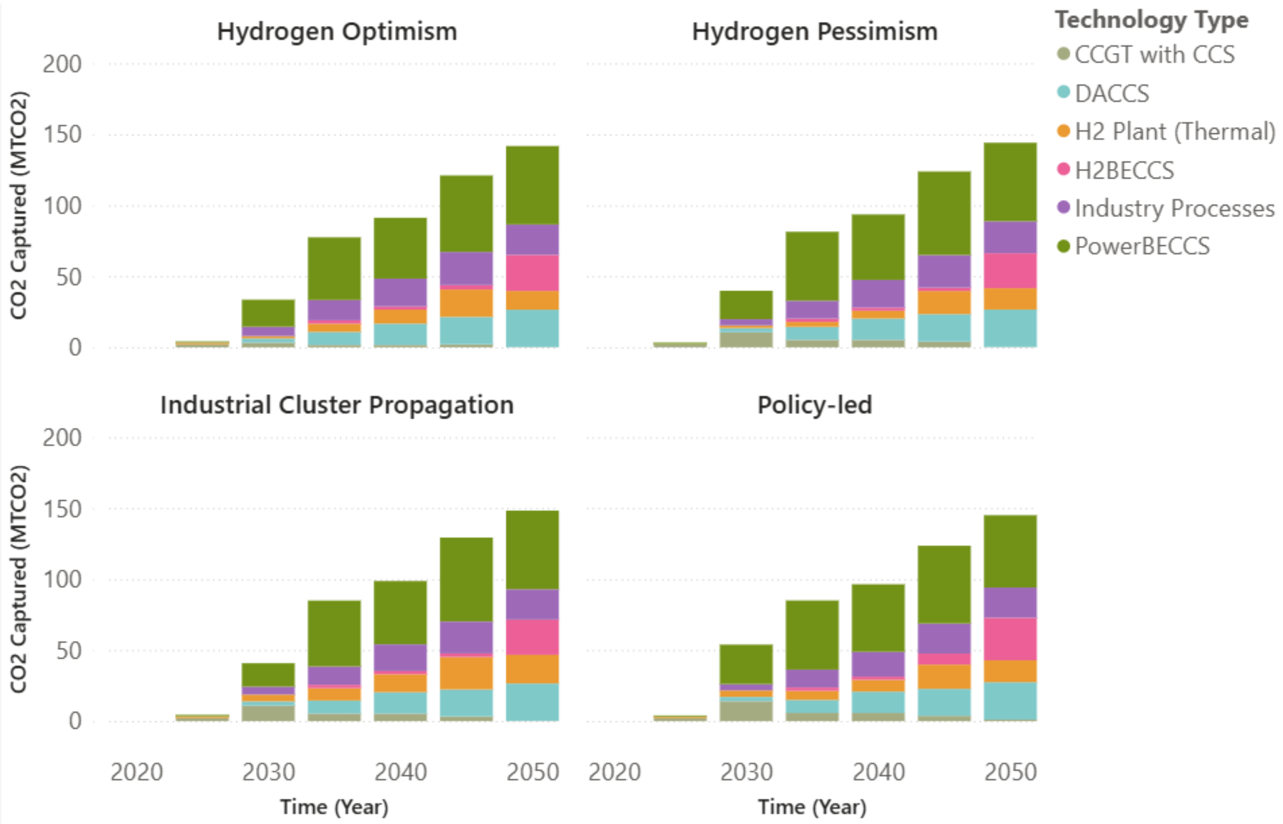
DACCS, delivers valuable negative emissions that are used to offset residual emissions in sectors such as industry, aviation, and agriculture. **Large supplies (multiple hundred TWh in 2050) of sustainable biomass and CCS technologies underpin negative emissions technologies such as BECCS and DACCS which are critical for meeting Net Zero.**

Impact of changing the UK hydrogen landscape

This section examines how varying levels of technological progress and innovation, policy support, and market conditions (specific to the UK's hydrogen economy) influence the deployment of H2BECCS technologies. The analysis is based on four scenarios created for the HII project, applying the updated technology assumptions for H2BECCS and ambitious feedstock availability. This provides insight into the strategic role of H2BECCS within the UK's decarbonisation strategy and the contribution of H2BECCS to long-term carbon reduction goals.

All scenarios deploy H2BECCS up to the MTP in 2035. No new capacity is built until 2050, except in the Policy-Led scenario, which builds around 1.5 GW in 2045. By 2050, all scenarios build as much as build rates allow but total installed capacity is limited by the decision not to build in the 2040s.

Before 2050, most scenarios use biomass in power BECCS applications to support increased electrolyser capacity, reflect government targets, or because hydrogen demand can be met more cost-effectively by steam methane reformers with CCS. By 2050, an increase in demand for hydrogen, particularly in shipping and industry, combined with tighter CO_2 targets, will make hydrogen and negative emissions produced by H2BECCS valuable to the system.



(Please note, these are ESME modelled results and are not direct DESNZ projections or policy)

Figure 22 – CO_2 captured across different hydrogen deployment scenarios. All scenarios are with the updated H2BECCS technology.

Figure 22 shows projected CO_2 capture ($MtCO_2$) from different CCS technologies under four HII scenarios from 2020 to 2050.

The Policy-led scenario exhibits the highest CO_2 captured by H2BECCS, projecting H2BECCS deployment to reach 2.4 Mt/year by 2035, followed by a sharp increase to 7.7 Mt/year by 2040 and 30 Mt/year by 2050. In the Hydrogen Pessimism and Industrial Cluster Propagation scenarios, thermal hydrogen production with CCS satisfies most of the hydrogen demand through the 2040s, which reduces the need for H2BECCS deployment during this period. In contrast, the other scenarios (Hydrogen Optimism and Policy-led) show a stronger production from electrolysers, which drives higher electricity demand. In these cases, power BECCS plays a more prominent role in supporting this increased electricity demand for electrolysis. The scenarios highlight the strategic importance of H2BECCS in meeting an increasing hydrogen demand, as well as reliance on negative emissions to achieve Net Zero.

Project Conclusions

Hydrogen-BECCS could be a key contributing technology in meeting the UK's GGR and low-carbon hydrogen production goals. This has been identified in modelling studies completed by DESNZ, National Grid, and the Energy Systems Catapult. Recognising the potential uptake of this technology, DESNZ commissioned this work to update the assumptions around the technology potential to support future seventh carbon budget (CB7) modelling.

Phase 1: Technical assessment of H2BECCS

The six-month first phase of the project combined desk-based research and stakeholder workshops to validate assumptions and provide updated insights. It has provided a detailed evaluation of the H2BECCS technologies, their deployment potential, and barriers to scaling.

The literature review and stakeholder engagement highlight both progress and challenges in the development of H2BECCS technologies. While efforts such as the Hydrogen BECCS Innovation Programme have strengthened the evidence base and moved key technologies closer to commercialisation, significant hurdles remain. Stakeholders identified several key challenges to H2BECCS deployment, including high financial risk and investor uncertainty. Feedstock competition and supply chain uncertainties were other key concerns, with infrastructure gaps for CO_2 transport and storage, and underdeveloped hydrogen networks also highlighted. Stakeholders emphasised the need for improved process efficiency, cost reduction and policy alignment, including financial incentives and clear carbon accounting frameworks to reduce market uncertainty. The assessment of five H2BECCS technologies revealed varying levels of maturity, with biomass gasification with CCS being the most commercially advanced. Pyrolysis, anaerobic digestion, dark fermentation, and wastewater ammonia conversion face challenges related to deployment, scalability, and data availability.

A major limitation in previous modelling was the lack of reliable data due to the low Technology Readiness Levels (TRLs) of certain technologies. However, updated literature, feasibility studies, and stakeholder engagement have provided new insights, strengthening the assumptions used in modelling.

Stakeholder discussions emphasised the need for clear policy support, regulatory alignment, and financial incentives to accelerate commercialisation and attract investment. Addressing these barriers through targeted government intervention and industry collaboration will be important to scaling up H2BECCS technologies and enabling their role in the UK's decarbonisation strategy.

Phase 2: Whole system modelling of H2BECCS

Phase 2 of the study assessed the deployment of H2BECCS technologies under varying policy, market, and feedstock availability scenarios, providing key insights into the role that H2BECCS could play in delivering greenhouse gas removals (GGRs) whilst supporting decarbonisation targets. Workshops 1 and 2 were essential for gathering insights, validating assumptions, and understanding barriers to H2BECCS deployment. Workshop 1 focused on critically evaluating assumptions from WP1, identifying data gaps, and discussing technology readiness and commercialisation timelines. The diverse stakeholder representation ensured comprehensive feedback and established communication channels for ongoing data collection, including access to commercial datasets. Key themes included the need for large-scale deployment, improved efficiency, cost reduction, and addressing feedstock and market uncertainties.

Workshop 2 activities included updating assumptions, ranking barriers to commercialisation and exploring policy enablers. Stakeholders agreed that H2BECCS faces significant challenges, including financial risks, feedstock competition, and infrastructure needs. Discussions emphasised reducing investor uncertainty through targeted government support, policy alignment, and robust financial incentives. Predictions indicated that gasification and AD with SMR are the most likely technologies to scale by 2050, while lower-TRL routes require further development.

Both workshops provided critical input for accelerating H2BECCS deployment and integrating technical, economic, and policy considerations.

The Maximum Technological Deployment Potential (MTP) of H2BECCS was assessed using updated engineering constraints and insights from the deployment of comparable biomass power plants in the UK. The revised MTP reflects more realistic build rates and alignment with industry expectations, ensuring that modelling scenarios align with achievable deployment trajectories. The findings show that while cost reductions can enhance deployment, build rate limitations (see section: Maximum Technological Deployment Potential (MTP)) remain the key factor influencing long-term capacity growth.

Key assumptions related to biomass-to-hydrogen conversion efficiency, availability factor, and capital and operational costs were revised to reflect the latest technological advancements and market developments. The updates were informed by literature reviews (including recent feasibility studies), and stakeholder engagement, providing a stronger evidence base for future energy system modelling.

The Hydrogen Innovation Initiative Policy-Led scenario was used for the initial technology update comparison and feedstock availability sensitivity study, as it imposes fewer technological constraints. Policy-Led reflects a strategy driven by strong government intervention and support. This scenario also demonstrates the highest H2BECCS deployment. The analysis highlighted the impact of revised capital costs and build rate constraints on deployment patterns. While the original Policy-Led scenario projected steady growth, the updated technology assumptions resulted in slower initial deployment due to higher capital costs and more conservative build rate constraints. However, deployment accelerated post-2045, driven by increasing hydrogen demand and tightening CO_2 targets, ultimately reaching approximately 6 GW by 2050, slightly below the newly defined Maximum Technological Deployment Limit.

The analysis highlights that build rate constraints, rather than capital costs, act as the primary limitation on H2BECCS deployment. While cost reductions, such as scaling to 500 MW plants, were seen to moderately increase deployment, system-wide constraints not presented in the modelling analysis above, such as the availability of CCS, will also impact real-world deployment outcomes. This emphasises the importance of addressing deployment barriers and infrastructure readiness alongside technological advancements to unlock the full potential of H2BECCS in the UK's Net Zero pathway.

The feedstock sensitivity analysis demonstrated the critical role of biomass resource availability in scaling H2BECCS deployment and the future energy system. Despite a strong variation in the biomass supply, the model showed H2BECCS remained the dominant consumer of biomass by 2050, with power BECCS prioritised in the earlier years. Industrial biomass demand remained consistent across all scenarios, demonstrating its essential role in decarbonising hard-to-abate sectors. In two of the sensitivities, the latest understanding of MTP was the primary limitation for H2BECCS deployment, rather than biomass availability alone. Under restricted biomass availability, the system reallocated a larger share of the limited biomass to H2BECCS.

The HII scenarios—Policy-Led, Industrial Cluster Propagation, Hydrogen Optimism, and Hydrogen Pessimism—were modelled to explore how changing the UK hydrogen landscape could impact H2BECCS deployment. Across all scenarios, H2BECCS reached its Maximum Technological Deployment Potential (MTP) by 2035, after which deployment stagnated until the late 2040s. The Policy-Led scenario exhibited the highest deployment, adding an additional 1.5 GW in 2045 and reaching 6GW by 2050.

Other scenarios, particularly Hydrogen Pessimism and Industrial Cluster Propagation, demonstrate a stronger reliance on fossil-based hydrogen production with CCS in the 2030s and 2040s, reducing the need for early H2BECCS deployment, allowing it to scale later when technologies are more mature, or biomass is more available. Conversely, Hydrogen Optimism and Policy-Led scenarios saw more electrolytic hydrogen production, which drove up electricity demand and reinforced the role of power BECCS to offset associated emissions. Based on the modelling results, the deployment of H2BECCS is sensitive to broader hydrogen strategy choices. Whether hydrogen is produced via electrolysis or thermally with CCS affects electricity systems, biomass allocation and the timing of carbon removal technologies. This emphasises the importance of system-level planning and policy alignment across sectors to ensure that strategies support both decarbonisation and negative emissions objectives.

By the late 2040s, H2BECCS could play a critical role in the UK's energy system by producing a flexible, storable, zero-carbon energy vector essential for decarbonising hard-to-abate sectors such as industry, shipping, and road freight. Alongside hydrogen production, negative emissions remain a primary driver of H2BECCS deployment, as they are crucial for offsetting residual emissions in sectors where full decarbonisation is challenging.

All 2050 scenarios deploy as much H2BECCS capacity as possible, constrained only by the MTP. This consistent and significant deployment results from least-cost optimisation modelling, which introduces technologies at the latest viable point to meet emissions targets cost-effectively. The strong uptake by 2050 highlights H2BECCS's critical role in meeting rising hydrogen demand and achieving Net Zero through negative emissions.

Accelerating H2BECCS implementation will require targeted policy support, cost reduction, regulatory facilitation, infrastructure development, and integrated whole-systems planning. Ensuring its deployment aligns with broader energy system needs will maximise its contribution to hydrogen availability, emissions reduction, and overall system efficiency—ultimately supporting the UK's Net Zero objectives.

Potential Future work

Future work should prioritise the opportunities and challenges associated with H2BECCS, as indicated by the findings from phase 1 and phase 2 of this project. Future research should focus on the following areas:

Competition for biomass resources: Evaluating the optimal use of biomass, considering competing demands such as Sustainable Aviation Fuel (SAF), power-BECCS, and bioproducts, is crucial to understanding the limits and trade-offs in resource allocation. As biomass is a finite resource, clarifying these trade-offs will guide effective policy and investment decisions. *Integrate the Biomass Value Chain Model (BVCM) with future hydrogen production siting work to create a comprehensive H2BECCS roadmap to 2050. Use this framework to predict deployment potential, align with decarbonisation pathways, and evaluate site-specific considerations.*

Policy and strategy alignment: Aligning H2BECCS with the broader UK Net Zero goals is crucial for ensuring coherent development across sectors and government departments (DESNZ, Defra, DfT). Without this alignment, progress could be obstructed by fragmented or contradictory policies. *Develop predictive models to show how future policy adjustments can support deployment.*

Enabling conditions of H2BECCS technologies: Current routes of funding and policy support of hydrogen projects focus on the cost of the hydrogen produced as a standalone metric. Taking into account the wider systems level interactions of these bio-based technologies, the additional benefits of negative emissions are not considered. Therefore, on a pure cost basis H2BECCS is not competitive for current funding mechanisms. Further work is needed to understand how H2BECCS projects can access funding based not only on the cost of hydrogen produced and a limit of carbon intensity but also recognising the added value.

Advanced conversion technologies: Investigating emerging biomass conversion technologies (e.g., pyrolysis, biochemical methods) could improve the efficiency, scalability, and sustainability of H2BECCS systems. These technologies may hold the key to overcoming existing barriers to large-scale deployment. *Compare H2BECCS with alternative hydrogen production routes to highlight benefits, focusing on lifecycle emissions, cost, and scalability*.

Aside from these priority areas, other future work of interest:

Systems view and modelling scenario development. Investigate modelling scenarios that account for:

- **Carbon credit dynamics**: Assess how emerging carbon credit markets will shape the economic feasibility of H2BECCS.
- **Economic risk assessment**: Conduct a more comprehensive economic risk assessment, particularly regarding cost uncertainties, technological learning curves, and market fluctuations in feedstock prices or hydrogen demand.

Hydrogen demand and feedstock availability

- Conduct a sector-specific review of hydrogen demand to identify off-takers and prioritise applications with the highest impact.
- Address biomass supply challenges by mapping sustainable feedstock sources and proposing strategies to optimise availability.

Appendix 1: H2BECCS CAPEX and OPEX Values

Following discussions with DESNZ we have looked into the values of CAPEX for Gasification plants that we provided within the Draft Assumptions Workbook. The values provided were components of a calculation of LCOH taken from various papers including the Hydrogen Europe report [65].

In order to provide a more confident value, we have investigated specific CAPEX figures for biomass gasification plants using non annualised/levelised costs to provide a £$_{2010}$/kW CAPEX figure. Costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included. This is due to the model representing these costs elsewhere.

There is a clear indication that the scale of plant influences the CAPEX of the plant due to economies of scale. An indicative plant size of 500 MW hydrogen production capacity has been used, so the values have been scaled using the six-tenths rule [66]. Figure 23 shows the range of capital costs identified in the literature and scaled to 500MW. Table 24 provides the sources of the capital costs.

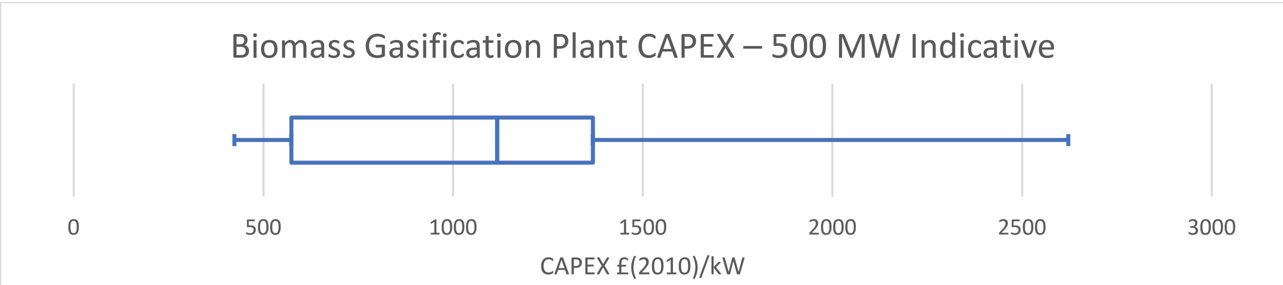


Figure 23 - Plot of the distribution of 2025 CAPEX in £$_{2010}$/kW. References in Table 24. 500 MW scaled indicative plant size.

There is an important point to note around the impact of the indicative plant size. Within the literature the average plant size was 182 MW. If we use a closer indicative plant size of 200 MW there is an increase in the CAPEX costs as shown in Figure 24.

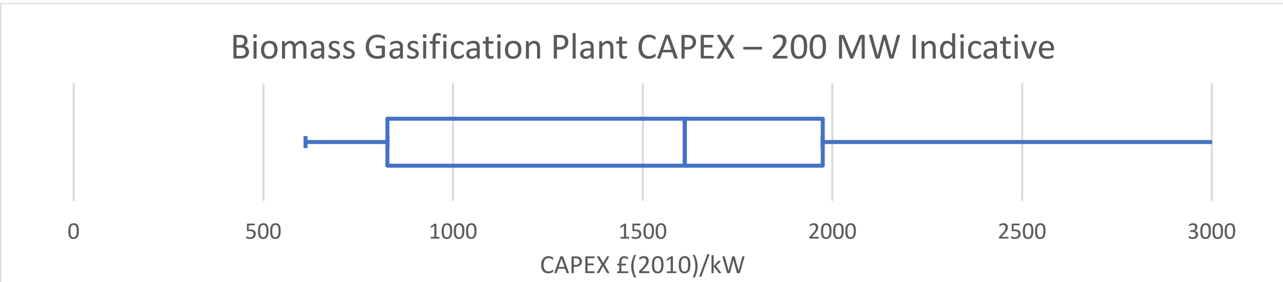


Figure 24 - Plot of the distribution of 2025 CAPEX in £$_{2010}$/kW. References in Table 24. 200 MW scaled indicative plant size.

Table 24 - Table of H2BECCS Gasification Plant Capacity, 2025 Overnight CAPEX and CAPEX per kW Capacity. Adjusted using the 0.6 rule to a 500 MW indicative plant capacity.

Reference		500 MW Indicative Capacity		200 MW Indicative Capacity	
	Plant Capacity MW	Overnight CAPEX £2010m	CAPEX £2010/kW	Overnight CAPEX £2010m	CAPEX £2010/kW
[65]	39	769	1538	444	2219
ESC ESME v5.0	500	602	1204	347	1737
[67]	197	407	814	235	1175
	285	281	562	162	810
	285	274	549	158	792
[68]	1	213	427	123	616
	1	533	1067	308	1539
[69]	59	555	1109	320	1600
	473	555	1110	320	1601
[70]	67	606	1211	350	1747
	384	679	1358	392	1960
[29]	50	239	478	138	690
	1	212	424	122	611
[71]	200	466	932	269	1345
	200	699	1398	403	2017
	200	583	1165	336	1681
	200	874	1748	504	2522
	200	655	1311	378	1891
	200	1078	2156	622	3110
	200	757	1515	437	2185
	200	1311	2622	757	3782
[72]	129	276	552	159	797
	119	289	577	167	833
AVERAGE	**182**	**561**	**1123**	**324**	**1620**

Learning rates have then been applied to the technology to show the reduction in cost over time as improvements in understanding, process optimisation and economies of scale take effect. These cost reductions stem from improvements in the construction process, enhanced manufacturing techniques, and supply chain efficiencies. Additionally, refinements in design contribute by increasing performance, reducing material waste, and streamlining assembly. Learning rates capture the expected cost trajectory as you move from first of a kind plant, to nth plant. A value of 20% reduction between 2025 and 2050 has been applied and then extrapolated back to 2015 using a linear reduction [71]. The Fixed OPEX is calculated as 5% of the CAPEX, this follows the approach seen in the literature [65]. Table 25 gives the recommended centralised cost projection for biomass gasification with CCS for use in ESME / UK TIMES.

Table 25: Cost projections for biomass gasification plant with CCS. *Median value from references.

	Units	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
500 MW Indicative Plant Capacity									
CAPEX	£$_{2010}$/kW	1206	1161	1116*	1072	1027	982	938	893
Fixed OPEX	£$_{2010}$/kW/yr	60	58	56	54	51	49	47	45
200 MW Indicative Plant Capacity									
CAPEX	£$_{2010}$/kW	1740	1675	1611	1546	1482	1417	1353	1289
Fixed OPEX	£$_{2010}$/kW/yr	87	84	81	77	74	71	68	64

Further investigation has been undertaken to ensure the Variable Operation and Maintenance (O&M) costs are not annualised or levelised for input into the UK TIMES model and into ESME. It is important to note that with these models the variable O&M costs do not include feedstock costs, electricity costs, carbon capture and storage costs as these are applied elsewhere. Across literature there is a significant variation around the assumptions that have been made around what constitutes a variable operation and maintenance cost. As a result, a wider range of prices are expected.

Table 26 - Table presenting references used for variable operation and maintenance costs.

Reference	Value £2010/MWh
[67]	2.32
[73]	26.57
(Department for Business Energy and Industrial Strategy, 2021)	10.25
[65]	15.29
[68]	0.42 2.91
Case 1: Biomass (sawdust) gasification without CO2 capture; [76]	15.39
Case 2: Biomass (sawdust) gasification with CO2 capture by MDEA-based gas-liquid absorption; (Cormos et al., 2022)	18.78
Case 3: Biomass (sawdust) gasification with CO2 capture by membrane technology; (Cormos et al., 2022)	16.82
Case 4: Biomass (sawdust) gasification with CO2 capture by hybrid solvent (MDEA) - membrane (Cormos et al., 2022)	18.62
Average	12.74

Table 27 - Calculation of Levelised Cost of Hydrogen from Biomass Gasification with CCS.

Variable	Unit	Value	Note
CAPEX	£2010/kW	1116	Table 25
Fixed OPEX	£2010/kW/yr	56	5% CAPEX
Variable OPEX	£2010/MWh	12.74	Table 26
Economic Base Year		2010	Modelling Base
Capacity 500MW	MW	500	Indicative Capacity
	KW	500000	
Capacity Factor		0.9	Assumed 90% Capacity factor
	Hours	8760	Hours in a year
Annual H2 Production	KWh H2	3942000000	
Annual H2 Production	kg/year	100050761	HHV H2 – 39.4
Conversion Efficiency	%	44	Table 6
Fuel Input	kWh biomass	8959090909	
Fuel Cost	£/kWh	0.018329	Calculated from [75], [76], [77].
Annual Fuel Cost	£	164210154	
Lifetime	years	25	Table 7
Economic lifetime	years	25	Table 7
Construction time		3	Table 7
Weighted average cost of capital	%	8	Assumed
CAPEX	2010 £/kW	1116	
Fixed OPEX	2010 £/kW/yr	55.8	
Variable OPEX	2010 £/kW/yr	100.4	
Fuel costs	2010 £/kW/yr	0	
Annualisation factor		0.09	
Interest during construction		1.12	
NPVeco		17.06	
NPVtec		17.06	
CAPEX	2023 £/kW	1616.66	
Fixed OPEX	2023 £/kW/yr	80.83	
Variable OPEX	2023 £/kW/yr	145.50	
Fuel costs	2023 £/kW/yr	328.42	
Annual capex payment	2023 £/kW/yr	170.31	
Total annual cost (discounted) CAPEX	2023 £/yr	3242.07	
Total annual cost (discounted) OPEX	2023 £/yr	9463.23	
Annual generation	kWh/kW/yr	134488.17	
LCOH	2023 £/kWh	0.09	
	£/kg	3.72	

Appendix 2: Feedstock Aggregation

This appendix provides details on the categorisation and aggregation of feedstock sources from the UK and Global Bioenergy Resource Model [62]. The feedstock sources are classified into three primary categories based on their origin and processing pathway: UK Biomass, Dry Waste, and Wet Waste. This classification aligns with the bioenergy conversion technologies used within the UK Times Model.

Table 28 - Classification of biomass types into ESME feedstock.

Label	UK TIMES Technology	ESME Assignment
Straw	Biomass boiler (chips or bales)	UK Biomass
Agricultural field residues		UK Biomass
Forestry harvesting residues		UK Biomass
Small roundwood		UK Biomass
Short rotation forestry		UK Biomass
Sawmill co-products		UK Biomass
Arboricultural arisings		UK Biomass
Waste wood		UK Biomass
Residual biogenic waste	EfW with CHP (residual MSW)	Dry Waste
Food waste	Biomethane to gas grid (maize and 'wet' wastes)	Wet Waste
Landfill gas		Wet Waste
Sewage sludge		Wet Waste
Cattle slurry		Wet Waste
Pig slurry		Wet Waste
Tallow	Biodiesel (UCO or Tallow)	UK Biomass
UCO		UK Biomass
SRC willow	Biomass boiler (chips or bales)	UK Biomass
Miscanthus		UK Biomass
Maize	Biomethane to gas grid (maize and 'wet' wastes)	Wet Waste
Wheat	Bioethanol (crops)	UK Biomass
Sugar beet		UK Biomass
Brown Grease	Biodiesel (UCO or Tallow)	Wet Waste
Waste tyres biogenic fraction	Advanced biofuel (solid biomass/waste as pellets/rdf)	Dry Waste
Microalgal Oils	Biodiesel (UCO or Tallow)	Wet Waste
Agricultural Residues	BECCS (pellets)	UK Biomass

Appendix 3: Defining Technology Readiness Levels (TRL)

Technology Readiness Level (TRL) indicates the maturity level of a given technology, ranging from 1 through 9. TRL does not indicate the quality of technology implementation in the design. We assess the TRLs based on the following:

- Assessment of the current status of technologies and their deployment.
- Previous TRL estimates within the literature.
- Discussions with expert stakeholders.

Reported TRLs within the literature might have a level of variation between the definitions used. As a result, the study will utilise the following scale which is adapted from the US DOE definition and consistent with other frameworks.

Table 29 - Technology Readiness Levels

	Definition	Description
TRL 9	System proven and ready for full commercial deployment	Actual application of technology is in its final form - technology proven through successful operations
TRL 8	System incorporated in commercial design	Technology is proven to work - actual technology completed and qualified through test and demonstration.
TRL 7	Integrated pilot system demonstrated	Prototype near or at planned operational system, requiring demonstration of an actual system prototype in an operational environment.
TRL 6	Prototype system verified	Representative model or prototype system is tested in a relevant environment.
TRL 5	Laboratory testing of integrated/semi-integrated system	The basic technological components are integrated with reasonably realistic supporting elements so it can be tested in a simulated environment.
TRL 4	Laboratory testing/validation of component(s)/process(es)	Basic technological components are integrated to establish that the pieces will work together.
TRL 3	Critical function or proof of concept established	Active research and development is initiated. This includes analytical and laboratory studies to physically validate analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative.
TRL 2	Applied research	Basic physical principles are observed, practical applications of those characteristics can be 'invented' or identified. At this level, the application is still speculative: there is not experimental proof or detailed analysis to support the conjecture.
TRL 1	Basic research	Scientific research begins to be translated into applied research and development.

Appendix 4: Hydrogen Consumption across scenarios

This appendix presents a breakdown of hydrogen demand by major energy system sectors; industry, transport, power generation, and other uses. As shown, industry and transport account for the majority of hydrogen consumption in most scenarios, reflecting their limited alternatives for deep decarbonisation. However, power sector hydrogen demand also reaches high levels in a subset of scenarios, particularly those with high variable renewable penetration and a greater role for long-duration storage and dispatchable low-carbon generation.

Table 30 - Breakdown of hydrogen consumption across HII Scenarios.

SCENARIO	TOTAL HYDROGEN CONSUMPTION (TWH)				
	Industry	Transport	Power	Buildings	Total
Policy Led	41.1	23.6	10.7	3.8	19.8
Hydrogen Optimism	41.8	26.9	2.6	5.2	19.1
Industrial Cluster Propagation	40.7	23.5	3.9	2.6	17.7
Hydrogen Pessimism	29.3	20.7	1.9	0.0	17.3

Appendix 5: Derivation of LCOH

The following section details the derivation of levelised costs from the literature. The costs reported are gate-to-gate, this means no gate fee is considered for the biomass input, CO2 compression, transport and storage costs are not included where reported.

H2BECCS Technology	LCOH £$_{2023}$/kg	Confidence Level	
Biomass Gasification with CCS	**3.7**	**High**	Due to updating values for Biomass Gasification with CCS in the phase 2 of the project, the following LCOH has been calculated from the values in Appendix 1 – Table 27.
Anaerobic Digestion with Steam Methane Reforming and CCS	**4.7 – 5.9**	**Medium**	There were limited studies that covered the entire lifecycle, usually drawing the line at biogas. It is possible to find studies covering AD to biogas and separate studies for biogas to SMR + CCS hydrogen production. The following references were used with values uplifted using CEPCI/CPI. [78] - No AD included just biogas to Biomethane to SMR and CCS. [79] – AD to SMR with no CCS [80] - Biogas to SMR with no CCS The wider range is due to the uncertainties associated with the literature. Costs were broken down from each paper and then combined to form a final value. ***Assumptions:*** *EURO to £ conversion – 0.85* *$ to £ conversion – 0.738* *MWh to kg H_2 conversion – 0.055*

Wastewater ammonia conversion	**2.9 – 5.3**	**Low**	[81] Adjusted from 2019 to 2023 using CEPCI for CAPEX, assumption from paper of 90% availability and 20 year lifetime. OPEX 3% of CAPEX assumption from paper. +/- 15% range applied due to low confidence. [82] Adjusted to 2023 using CEPCI and CPI, Ammonia decomposition - A major contribution of up to 62.2% to LCOH comes from the price of feed Ammonia. The wider range is due to the uncertainties associated with the literature. This is a low confidence value due to the low TRL and limited literature. ***Assumptions:*** *EURO to £ conversion – 0.85* *$ to £ conversion – 0.738* *MWh to kg H_2 conversion – 0.055*
Biomass Pyrolysis with CCS	**4.1 – 5.5**	**Low**	[46] Adjusted to 2023 using CEPCI and CPI, 20 year lifetime used, 10% discount rate. +/- 15% uncertainty range used.
Dark Fermentation	**2.0 - 3.2**	**Medium**	[47] Converted from 2021 to 2023. Range provided in paper.

Acronyms

Acronym	Description
AD	Anaerobic digestion
ATR	Autothermal reformation
BVCM	Biomass Value Chain Model
CAPEX	Capital Expenditure
CB6	6th Carbon Budget (2033 – 2037)
CB7	7th Carbon Budget (2038 – 2042)
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation, and storage
CHP	Combined heat and power
CO_2	Carbon Dioxide
CO_2eq	Carbon Dioxide Equivalent
DACCS	Direct Air Carbon Capture and Storage
DF	Dark fermentation
DUKES	Digest of UK Energy Statistics
EfW	Energy from Waste
ESME	Energy Systems Modelling Environment
FOAK	First-of-a-kind
GGRs	Greenhouse Gas Removals
GHG	Greenhouse Gas
GW	Gigawatt
H2BECCS	Hydrogen Production with Bioenergy and Carbon Capture and Storage
HAR	Hydrogen Allocation Round
HII	Hydrogen Innovation Initiative
IEA	International Energy Agency

IGCC	Integrated Gasification Combined Cycle
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
LCA	Life Cycle Analysis
LCOH	Levelised Cost of Hydrogen
LHV	Lower Heating Value
MDEA	Methyl Diethanolamine (a solvent used in gas absorption)
$MtCO_2$	Megatonnes of Carbon Dioxide
MTP	Maximum technological deployment potential
MW	Megawatt
MWe	Megawatt Electrical
NOAK	$N^{th-}$of-a-kind
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
OPEX	Operational Expenditure
PSA	Pressure Swing Adsorption
REPD	Renewable Energy Planning Database
ROI	Return on Investment
SAF	Sustainable Aviation Fuel
SMR	team methane reforming
SRC	Short Rotation Coppice
TRL	Technology readiness level
TWh	Terawatt
UCO	Used Cooking Oil
UK TIMES	UK TIMES Energy System Model
WWTP	Wastewater treatment plant

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