NEGATIVE EMISSIONS TECHNOLOGIES (NETS): FEASIBILITY STUDY

Technical Appendices

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ACRONYMS & UNITS USED

ACT	Advanced Conversion Technology
ATR	Auto thermal reforming
BECCS	Bioenergy with Carbon Capture and Storage
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CDRs	Carbon dioxide removals
CCC	Climate Change Committee
CCPu	Climate Change Plan Update
CXC	ClimateXChange
CfDs	Contracts for Difference
DAC	Direct Air Capture
DACCS	Direct Air Carbon Capture and Storage
GJ	gigajoules
GWh	gigawatt-hours
GWP	Global warming potential
GGR	Greenhouse gas removal
ha	hectare
kWh	kilowatt-hours
LPG	Liquid petroleum gas
Mt	mega tonnes
MJ	megajoules
MWh	megawatt-hours
NETs	Negative emission technologies
RDF	Refuse Derived Fuel
SRC	Short Rotation Coppicing
SRW	Small Round Wood
SRF	Solid Recovered Fuel
SMR	Steam methane reforming
SAF	Sustainable Aviation Fuel
t	tonnes
yr	year

PART 2: TECHNICAL APPENDIX AND SUPPORTING EVIDENCE

Disclaimer

The commentary/narrative in the interim report was developed at an earlier point in the project and may not be consistent with the main report. If there are any inconsistencies between the main report and interim report, the main report should be treated as the authoritative source of information'.

1. CURRENT STATUS OF GLOBAL NETS PROJECTS

1.1 INTRODUCTION

As outlined in chapter 1 of the main report document, it is now well established that NETs are needed to reach global Net Zero targets. Significant efforts are therefore underway to develop and deploy NETs, with several advancements, feasibility studies and deployment of pilot and commercial scale NETs plants.

To achieve the NETs deployment rates necessary, the UK Government has funded £31.5M for the Greenhouse Gas Removal Demonstrators Programme and £70M for the GHG R&D Programme and Direct Air Capture and Greenhouse Gas Removal technologies competition in 2020[1]. The purpose of the funds is to help improve the technological maturity of NETs[2].

Under the £70M fund, funding was split into two segments: 1.) Phase 1 delivering £250,000 of funding per project; 2.) Phase 2 utilising funding to help construct 15 facilities, 13 of which fall into our criteria of being an engineered NET[3,4]. Only one of these projects will be partially situated in Scotland, led by Black Bull Biochar Ltd, who plan to utilise waste biomass residues from a site in Fort William to produce biochar in Cumbria[4]. Please see Table 57 in Appendix 8 for further information.

There were two additional Scottish projects that did not pass Phase 2 funding: Storegga Dreamcatcher, a 0.5 $MtCO_2$/year DACCS project investigating the replacement of natural gas used in Carbon Engineering's prototype with an alternative heat source (e.g. hydrogen)[6,5]; and the University of Edinburgh's DACCS project, investigating the use of solar energy to capture 50$ktCO_2$/year of atmospheric CO_2 using an activated carbon adsorbent[6].

1.1.1 Examples of NETs facilities

This section presents NETs facilities currently operational and in planning in the UK and globally. The list presented here is not exhaustive and is intended to provide examples of the various technologies being implemented worldwide.

1.1.1.1 Carbon Capture Scotland

Carbon Capture Scotland (previously known as Dry Ice Scotland) operate a dry ice production facility at Crocketford, Dumfries & Galloway, commissioned in 2021 and costing £4m. The company operate a combined capture capacity of 22 $ktCO_2$ per year from biogenic sources such as biogas upgrading and fermentation in distilleries. The propriety equipment is modular and can be scaled up and applied across multiple sites and industries. The captured CO_2 is used to produce dry ice for the health, and food and drink sectors. The

[1] BEIS, 'Direct Air Capture and other Greenhouse Gas Removal technologies competition': Direct Air Capture and other Greenhouse Gas Removal technologies competition - GOV.UK (www.gov.uk)

[2] The Climate Change Committee (2020), 'Policies for the Sixth Carbon Budget and Net Zero': Sixth Carbon Budget - Climate Change Committee (theccc.org.uk)

[3] National Infrastructure Commission (2021), 'Engineered greenhouse gas removals': Engineered greenhouse gas removals - NIC

[4] BEIS (2022), 'Projects selected for Phase 2 of the Direct air capture and greenhouse gas removal programme': Projects selected for Phase 2 of the Direct air capture and greenhouse gas removal programme - GOV.UK (www.gov.uk)

[5] Carbon Engineering (2021), 'Engineering begins on UK's first large-scale facility that captures carbon dioxide out of the atmosphere': Engineering begins on UK's first large-scale facility that captures carbon dioxide out of the atmosphere (carbonengineering.com)

[6] BEIS (2022), 'Projects selected for Phase 1 of the Direct air capture and greenhouse gas removal programme': Projects selected for Phase 1 of the Direct air capture and greenhouse gas removal programme - GOV.UK (www.gov.uk)

company also intend to provide NETs removals and future storage potential, with a stated aim of greater than 200 ktCO_2 per year by 2030[7].

Carbon Capture Scotland has recently announced Project NEXUS which has received funding from the Scottish Government and private investment. The £120m investment will consist of a series of infrastructure and supply chain projects that allow for a sustainable and commercial means of carbon dioxide removal, starting in 2023 with projects in central and northern Scotland. Note that whilst not definitively NET projects (due to the question over the permanence of the captured CO_2 (at least in the interim period before geological storage is available)), the project will support the development and advancement of NETs in Scotland.

1.1.1.2 BECCS Power

1.1.1.2.1 Drax Power Station, UK

Drax Power Station is currently operating two pilot scale BECCS facilities in North Yorkshire, with plans for commercial scale capture in 2027. The pilot scale facilities became operational in 2019 and 2020, capable of capturing a total of approximately 1.3 tonnes of CO_2 per day[8]. One of the facilities is demonstrating the use of chemical absorption (based on an innovative solvent developed by C-Capture, a spin off from Leeds University) for capturing CO_2 from a stream of one of the Drax biomass boilers while the other is demonstrating Molten Carbonate Fuel Cell technology for CO_2 capture.

1.1.1.2.2 The Stockholm Exergi BECCS facility in Sweden

Stockholm Exergi is demonstrating BECCS on their biomass CHP site in Stockholm. The BECCS plant will be capable of capturing 800,000 tCO_2/year[9]. Heat is recovered from the CHP system as well as the capture unit (potassium carbonate-based chemical absorption) and is used and is fed into the district heating system leading to improved efficiencies. The 120 MWe project received funding from the European Commission under the EU Innovation Programme and is expected to become operational by 2026.

1.1.1.2.3 Toshiba Mikawa Power Plant, Japan

In 2009, Toshiba Energy Systems and Solutions (ESS) began an initial pilot to capture 10 tCO_2/day from the Toshiba Mikawa power plant in Japan, a 50kW biomass-fired power plant. As of 2020, Toshiba ESS announced the operation of a large-scale carbon capture facility, building on the findings of the initial pilot in 2009. The large-scale facility is capable of capturing up to 500 tCO_2/day and is now one of the largest operational BECCS plant worldwide[10].

1.1.1.3 BECCS EfW

The list of EfW sites considered is in Table 46 of Appendix 2.

1.1.1.4 BECCS biofuels

1.1.1.4.1 Operational

Carbon capture from fermentation is common areas with widespread bioethanol industry, such as Europe and North America. Table 1 shows a selection of the largest bioethanol with capture facilities currently operating. Also shown in the table is the total CO_2 captured from bioethanol production in Europe in 2021 and the USA in 2022.

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[7] Carbon capture Scotland (2022): Dry Ice Scotland

[8] BECCS and negative emissions, Drax, Accessed at: https://www.drax.com/about-us/our-projects/bioenergy-carbon-capture-use-and-storage-beccs/

[9] Stockholm Exergi carbon capture scheme gets EU support, Accessed at: Stockholm Exergi carbon capture scheme gets EU support - DCD (datacenterdynamics.com)

[10] Toshiba starts operation of large-scale carbon capture facility, October 2020, Accessed at: https://www.global.toshiba/ww/news/energy/2020/10/news-20201031-01.html?utm_source=www&utm_medium=web&utm_campaign=since202202ess

Table 1: Selection of existing carbon capture equipped bioethanol plants in Europe and USA in 2021/22

Includes total recorded CO_2 capture

Site	CO_2 destination	Location	Year	CO_2 Captured ($MtCO_2$/year)
Alco Bio Fuel[11]	Food and drink Refrigerated transport	Ghent, Belgium	2016 – 2022	0.1
Alco Energy[12]	Horticulture	Rotterdam, Netherlands	2016	0.4
Total capture from European bioethanol producers[13]			2021	1.05
Illinois industrial CCS[14]	Geological storage	Illinois, USA	2017	1
Arkalon CO_2 compression facility[14]	Enhanced Oil Recovery	Kansas, USA	2009	0.29
Bonanza bioenergy[14]	Enhanced Oil Recovery	Kansas, USA	2012	0.1
Red Trail Energy CCS[14]	Geological storage	Dakota, USA	2022	0.18
Total capture from USA bioethanol producers[15]			2022	2.55
Husky Energy CO_2 Injection[16]	Enhanced Oil Recovery	Saskatchewan, Canada	2012	0.1

1.1.1.4.2 Projects in planning

Projects in planning are those either with granted permission to construct their CCS facility or in the process of obtaining such permission.

The CCS institute lists 37 bioethanol CCS projects in development[14]. 36 of the planned projects are in the USA with the majority (35 of 36) ranging from 90-570 $ktCO_2$ per year in capture capacity, amounting to a total capacity of 9.32 $MtCO_2$ per year. The only planned project at mega tonne scale in the USA is the **Aemetis ethanol plant** in California, with a planned capacity of 2 Mt. However, only 400 $ktCO_2$ per year capture is planned from Aemetis' ethanol production facility, the remainder will be provided by third party facilities[17]. In Canada, a further 3 $MtCO_2$ of capture capacity from ethanol production is expected to be operating by 2024[14].

Table 2: Planned CO_2 capture at bioethanol production sites[14]

Site	Location	CO_2 destination	Year	Capture capacity
35 bioethanol facilities throughout USA		Geological storage	2024-2025	9.32 $MtCO_2$ total. Ranging from 0.09 to 0.57 $MtCO_2$, averaging 0.266 $MtCO_2$

[11] Alco Bio Fuel Ghent: GHG emission savings
[12] Alco Energy Rotterdam: Greenhouse Gas Emission Saving
[13] ePure, (2022): European renewable ethanol – key figures 2021
[14] Global CCS Institute, (2022): Global Status of CCS 2022
[15] Renewable Fuels Association: Feedstocks and Co-Products
[16] Global CCS Institute, (2022): Bioenergy and Carbon Capture and Storage
[17] Aemetis (2022): Carbon Capture and Sequestration

Site	Location	CO_2 destination	Year	Capture capacity
Aemetis	California, USA	Geological storage	2024	2 $MtCO_2$. 0.4 $MtCO_2$ from own production facility. 1.6 $MtCO_2$ from third parties.
Federated co-operatives	Saskatchewan, Canada	Enhanced Oil Recovery	2024	3 $MtCO_2$

In terms of potential UK pilot plants there are three that were being considered for Phase 2 CCUS funding[18], but failed to pass.

Table 3: List of UK-based biofuel projects that failed to pass Phase 2 of the CCUS fund

Project	Technology	Location	Capacity			Operational Date
			Mt,waste/year	Ml,fuel/year	$MtCO_2$/year	
Alfanar's Lighthouse Green Fuels plant[19]	Waste-to-SAF plant using gasification and Fischer Tropsch	Teesside, England (East Coast Cluster)	1	180	N/A	2027
Altalto Immingham waste to jet fuel[20]	Waste-to-fuel plant	Immingham, England (East Coast Cluster)	0.5	60	0.08	2027
Protos Biofuels Ltd[21]	Waste-to-fuel plant	Northwest England (HyNet)	150,000	N/A	0.16	2025

1.1.1.5 BECCS Industry

The list of industry sites considered is in Table 43 of Appendix 2.

1.1.1.6 BECCS Hydrogen

1.1.1.6.1 Operational

There are currently no operating BECCS Hydrogen plants in Scotland. However, there are circa 20 existing biomethane sites which could be used to produce hydrogen via SMR or auto thermal reforming (ATR)[22].

Outside of the UK, there are some existing biohydrogen and bio-syngas production plants, with Table 4 summarising key projects identified from the IEA's Clean Energy Demonstration Projects Database[23] and Bioenergy ExCo database[24].

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[18] BEIS (2021), 'October 2021 update: Track-1 clusters confirmed': October 2021 update: Track-1 clusters confirmed - GOV.UK (www.gov.uk)

[19] Biofuels International, 'alfanar's £1 billion Teesside SAF plant enters FEED engineering phase': alfanar's £1 billion Teesside SAF plant enters FEED engineering phase - Biofuels International Magazine | Biofuels International Magazine (biofuels-news.com)

[20] Altalto, 'Immingham, the site of our first waste-to-fuels plant': Immingham | Altalto

[21] Covanta, 'Protos Energy Recovery Facility': Protos Energy-from-Waste Facility (covanta.com)

[22] Element Energy, 'Review of international delivery of negative emission technologies': Review of international delivery of negative emission technologies (climatexchange.org.uk)

[23] IEA, 'Clean Energy Demonstration Projects Database': Clean Energy Demonstration Projects Database – Data Tools - IEA

[24] ETIP Bioenergy, 'Production Facilities': Production Facilities (etipbioenergy.eu)

Table 4: List of currently operational bio-gasification and bio-syngas plants

Project	Hydrogen Technology Type	CCS Installed	Location	Year	Capacity
AquaGreen PCE	Fast Pyrolysis of wet sludge and waste streams to produce syngas with CCS	Yes	Denmark	N/A - operational	N/A
Tokyo Sewage-to-H_2 plant	Waste-to-hydrogen gasification plant with CCS	Yes	Japan	2021	15-18 t/year of hydrogen
BayoTech H_2-1000 hydrogen + carbon clean pilot	Methane reforming of syngas or biogas plant with CCS	Yes	USA	2022	3 ktCO_2/year,
Waste2Value, Bioenergy and Sustainable Technologies GmbH	Gasification of lignocellulosics to produce H_2 rich syngas without CCS	No	Austria	2022	1MW
AquaGreen/Farevejle wastewater facility	Fast Pyrolysis of wet sludge and waste streams to produce syngas without CCS	No	Denmark	2022	N/A
DTU Chemical engineering LT-CFB	Fast Pyrolysis to produce syngas without CCS	No	Denmark	2002	N/A
DTU Chemical engineering Viking Gasifier	Gasification of organic residues and waste streams to produce syngas without CCS	No	Denmark	2002	N/A
Hazer Process Demonstration Plant	Methane pyrolysis-cracking of biogas from sewage treatment without CCS*	No	Australia	2020	100 t/year of hydrogen

*Novel technology which stores carbon in the form of graphite

Key things to note from the above is that existing projects appear to favour the use of waste feedstocks (5 out of 8 projects) over more traditional biomass feedstocks, and that gasification and fast pyrolysis are the favoured routes of production (7 out of 8 projects). Furthermore, the majority of projects do not utilise CCS (5 out of 8 projects), and hence do not deliver negative emissions.

Several pilot projects producing syngas and/or biohydrogen without CCS also exist:

- **LTU Green Fuels, DP1+DME pilot:** Operating from 2011 to 2016, this Swedish pilot plant produced 2MW of clean syngas by gasifying black liquor and bio-oil. DME and methanol were also produced and sold as by-products.
- **BIONICO pilot plant:** Operating from 2015 to 2019, this Italian pilot plant produced 100kg/day of hydrogen using waste feedstocks that were anaerobically digested and converted to biohydrogen via membrane reactor technology[25]. The project was funded by the EU's Horizon 2020 programme.

  These have now closed down.

1.1.1.6.2 Projects in planning

There appears to be considerable scope for biohydrogen and bio-syngas within the next decade, with 32 projects being identified: 23 projects within the rest of the UK and 9 projects outside of it. Please note that some of the listed projects do not utilise CCS, and hence are considered as biohydrogen/bio-syngas projects instead of BECCS hydrogen.

[25] European Commission, 'BIONICO: A pilot plant for turning biomass directly into hydrogen': BIONICO: A pilot plant for turning biomass directly into hydrogen | BIONICO Project | Results in brief | H2020 | CORDIS | European Commission (europa.eu)

1.1.1.6.3 *Non-UK projects*

Projects that are under development were discovered using the IEA's Clean Energy Demonstration Projects Database[23] and the Bioenergy ExCo database[26].

Table 5: List of planned BECCS Hydrogen projects outside of the UK

Project	Hydrogen Technology Type	Location	Year	Capacity
FUREC[23]	Waste gasification without CCS	Netherlands	2022*	54 ktH_2/year
Wabash Valley Resources (IN)[23]	Waste gasification with CCS	USA	2024	1,700 ktCO_2/year
Mote biomass-to-hydrogen plant (CA)[23]	Waste gasification with CCS	USA	2024	150 ktCO_2/year
OMNI CT – California[23]	Waste gasification without CCS	USA	2023	5 ktH_2/year
Solena Group Plasma enhanced gasification[23]	Waste gasification without CCS	USA	2023	4 ktH_2/year
Yosemite Clean Energy - Oroville[23]	Waste gasification without CCS	USA	2024	4.5 ktH_2/year
Eni, Waste to Hydrogen[26]	Gasification of solid waste without CCS	Italy	N/A	0.1tH_2/year
Stiesdal, SkyClean[26]	Fast pyrolysis of agricultural residues to produce syngas	Denmark	Mid 2020s	N/A
Springkildeprojektet, Frichs Pyrolysis ApS[26]	Fast pyrolysis of manure without CCS	Denmark	2021*	100 m^3/hr syngas

*Project delayed and still under development

The majority of projects appear to be situated within the USA (5 out of 9 projects), which in turn promise to deliver the most significant carbon savings of 1.85 MtCO_2/year by 2024. These carbon savings will be attributed to the **Wabash Valley Resources (IN) plant** and **Mote biomass-to-hydrogen plant**. The choice of feedstock is also heavily weighted towards waste (8 out of 9 projects), which will likely not deliver negative emissions due to the lack of CCS being installed (7 out of 9 projects).

1.1.1.6.4 *UK Projects*

The UK specific projects were identified by referring to BEIS's list of Phase 2 projects under the Direct air capture and greenhouse gas removal programme[1] and the list of Phase 1 projects under the Hydrogen BECCS Innovation Programme[27]. Both programmes form part of the UK's Net Zero Innovation Portfolio. These projects all cover feasibility and FEED studies, which aim to investigate ways to improve the economics, energy efficiency and broaden the range of biomass feedstocks that can be utilised to produce biohydrogen.

Table 6: List of planned BECCS Hydrogen projects within the UK

Project	Company	Hydrogen Technology Type
Biohydrogen Greenhouse Gas Removal Demonstration	Advanced Biofuel Solutions Ltd[1]	Waste gasification with CCUS

[26] Projects Bioenergy ExCo: Projects | Bioenergy ExCo (best-research.eu)

[27] BEIS, 'Hydrogen BECCS Innovation Programme Phase 1: successful projects': Hydrogen BECCS Innovation Programme Phase 1: successful projects - GOV.UK (www.gov.uk)

Project	Company	Hydrogen Technology Type
CCH_2: Carbon Capture and Hydrogen	KEW Projects Ltd[22, 1]	Gasification of biomass and refuse derived fuels (RDF) with CCS
Ince Bioenergy Carbon Capture & Storage (INBECCS) - Phase 2	Ince Bio Power Ltd[1]	Gasification of waste wood with CCS
Development of Biomass Gasification Tar Reformation and Ash Removal	Advanced Biofuel Solutions Ltd[27]	Biomass gasification with tar reformation and ash removal
Micro-H_2 hub utilising biogenic feedstock for hydrogen and CO_2 production	Compact Syngas Solutions Ltd[27]	Gasification
Bio-hydrogen Produced by Enhanced Reforming (Bio-HyPER)	Cranfield University[27]	Gasification and biogas with the HyPER process
RiPR (Rising Pressure Reformer) using SCWG (Super Critical Water Gasification)	Helical Energy Ltd[27]	Gasification and RWGS
Enhancement of KEW biomass gasification technology performances through optimisation of the H_2/CO_2 separation process stage	Kew Projects Ltd[27]	Gasification
Northeast Waste Wood Hydrogen Demonstrator (NEW2H_2)	Northumbria University[27]	Hydrogen production using waste wood
Novel plasma reforming technology for tars reduction in BECCS	Queen Mary University of London[27]	Plasma reforming
H_2 production via Biomass gasification Integrated with innovative one-step Gas shift reforming and separation (BIG-H_2)	Translational Energy Research Centre - The University of Sheffield[27]	Gasification
Hydrogen from Cyanobacteria - a biological route to zero-carbon or carbon-negative hydrogen	17Cicada Ltd[27]	Cyanobacteria
Eco Dark Fermentation	Alps Ecoscience UK Ltd[27]	Fermentation
Production of biohydrogen from waste biomass	CATAGEN Ltd[27]	Hydrogen production using recirculating-gas reactor
Pure Pyrolysis Refined	Environmental Power International (UK R&D) Limited[27]	Pyrolysis
HAROW – Hydrogen by Aqueous-Phase Reforming of Organic Wastes	ICMEA-UK Ltd[27]	Aqueous-Phase Reforming
Biohydrogen from Dark and Photo Fermentation	Phoebus Power Limited[27]	Fermentation
Thermal Catalytic Conversion of Syngas to Carbon Nanotubes	The Cool Corporation Ltd[27]	Thermal Catalytic Conversion

Project	Company	Hydrogen Technology Type
The Sustainable Biogas, Hydrogen, Graphene LOOP	United Utilities Water[27]	Biogas reforming
Hydrogen from organic waste with an integrated biological-thermal-electrochemical process	University of Aberdeen[27]	Thermal-electrochemical process
H_2-Boost	University of Leeds[27]	Advanced wet oxidation and dark fermentation of organic waste
BIOHYGAS	University of South Wales[27]	Two-stage biohydrogen / biomethane AD system
Bio Hydrogen Demonstrator	Wood Group UK Ltd[27]	SMR of liquid biological feedstocks

Several key projects producing syngas and/or biohydrogen with CCS include:

- ***Advanced Biofuel Solutions Ltd:*** This UK company already has a plant in Swindon that is expected to become the world's first facility to convert household waste into grid-quality biomethane (1,500 t/year) and hydrogen (500t/year)[26,28]. The funding from the Direct air capture and greenhouse gas removal programme will be utilised to expand hydrogen production, similar to that of the Swindon plant, with the aim to capture 1MtCO_2/year by 2030.
- ***KEW Projects Ltd:*** This midlands-based company is developing the world's first pressurised advanced gasification plant with CCS, with works expected to be completed by 2023-2024. The plant will produce a combination of renewable fuels and bio-hydrogen using waste. The aim is to produce 50 ktCO_2/year during 2025-2030 and 24 MtCO_2/year in the subsequent decade[22,29]
- ***Ince Bio Power Ltd:*** The largest waste wood gasification plant in the UK, providing 22MW of power to local households. The aim of the project is to install CCS to the existing site, which will deliver 7 ktCO_2/year of negative emissions by 2027 and be the first of its kind in the UK.[30]

1.1.1.7 Biomethane BECCS

The list of biomethane sites considered is in Table 41 of Appendix 2.

1.1.1.8 Direct Air Capture (DAC)

1.1.1.8.1 Operational

There are 20 DAC pilot plants in operation worldwide at the moment, capturing less than 0.01 MtCO_2/year. These are detailed in Table 7 below.

Table 7: Breakdown in DAC pilot plants currently operational

DAC Technology Type	Company	Location	Year	Capacity (t/year)	Utilisation or Storage
Solid sorbent DAC	Climeworks[31]	Germany	2014	1	Utilisation for diesel
		Switzerland	2016	50	Utilisation for fuels
		Switzerland	2017	900	Utilisation for horticulture
		Iceland	2017	50	Storage

[28] Absl, 'Swindon Plant': Swindon Plant | Advanced Biofuel Solutions Ltd (absl.tech)

[29] Kew Technology, 'Our commercial scale plant': Our commercial plant • KEW Technology • Delivering a world beyond fossil fuels (kew-tech.com)

[30] Bioenergy Infrastructure Group, 'Ince Bio Power secures funding for carbon capture demonstration project, in win for Net Zero ambitions in North West': Ince Bio Power secures funding for carbon capture demonstration project, in win for Net Zero ambitions in North West - Bioenergy Infrastructure Group

[31] IEA (2022), 'Direct Air Capture Direct Air Capture a key technology for Net Zero': Direct Air Capture 2022 – Analysis - IEA

DAC Technology Type	Company	Location	Year	Capacity (t/year)	Utilisation or Storage
		Switzerland	2018	600	Utilisation for beverage carbonation
		Switzerland	2018	3	Utilisation for fuels
		Italy	2018	150	Utilisation for fuels
		Germany	2019	3	Utilisation for fuels
		Netherlands	2019	3	Utilisation for fuels
		Germany	2019	3	Utilisation for fuels
		Germany	2019	50	Utilisation for fuels
		Germany	2020	50	Utilisation for fuels
		Germany	2020	3	Utilisation for fuels
		Germany	2020	3	Utilisation for fuels
		Iceland	2021	4,000	Storage
	Global Thermostat[31]	United States	2010	500	N/A
		United States	2013	1,000	N/A
	Hydrocell[32,52]	Finland	N/A	1.387	Utilisation for e-fuels
Liquid solvent DAC	Carbon Engineering	Canada[31]	2015	365	Utilisation for e-fuels
		Canada[33]	2021	1,000	Utilisation for e-fuels

1.1.1.8.2 Projects in planning

On a global scale, Iceland, Saudi Arabia, and Scotland are all ideal locations for DAC, due to the proximity of cheap and abundant excess renewable energy (the average auction price of Saudi-Arabian solar projects awarded in 2020 was \$18.3/MWh (£14.3/MWh[34])[22,35]. However, as detailed below, only 2 projects are being built in these locations at present. There are 11 DAC facilities under development at the moment, capable of capturing 5.5 $MtCO_2$/year by 2030[36], as well as five pilot projects funded by the UK's Direct Air Capture and Green House Gas Removal technologies competition. A breakdown of these projects is illustrated in Table 8.

The key projects in the pipeline cover both CO_2 storage and utilisation. For storage, Climeworks' **Mammoth project**[37] will build upon their existing DAC technology to capture 36,000 tCO_2/year, and Carbon Engineering aims to capture 1.5-2.5 $MtCO_2$/year through their DAC1[38], Storegga[4] and Norwegian Carbon Removal[39] projects. In terms of utilisation, both Climeworks and Global Thermostat are aiming to produce e-fuels for

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[32] Hydrocell (2018), 'Direct Air Capture (DAC) appliances': Direct Air Capture (DAC) appliances - Hydrocell Oy

[33] Carbon Engineering (2021), 'Carbon Engineering Innovation Centre Update': Carbon Engineering Innovation Centre Update - Carbon Engineering

[34] Using an average exchange rate of 0.7798 USD/GBP in 2020

[35] Haszeldine et al (2019), 'Greenhouse Gas Removal Technologies – approaches and implementation pathways in Scotland': Greenhouse Gas Removal Technologies – approaches and implementation pathways in Scotland

[36] IEA (2022), 'Direct Air Capture technology deep dive': Direct Air Capture – Analysis - IEA

[37] Climeworks (2022), 'Climeworks takes another major step on its road to building gigaton DAC capacity': Groundbreaking on Climeworks' newest facility has started

[38] IEA (2021), 'DAC1': DAC 1 – CCUS around the world – Analysis - IEA

[39] Carbon Engineering (2021), 'New partnership to deploy large-scale Direct Air Capture in Norway': New partnership to deploy large-scale Direct Air Capture in Norway (carbonengineering.com)

Norsk e-fuels[40] and **HIF Haru Oni e-fuels**[41]. There are also plans for 1PointFive and Carbon Engineering to collaborate and deploy up to 70 large scale DAC projects by 2035, each of which could capture 1MtCO_2/year[42].

If successful, the pilot projects funded under the UK's DAC competition could capture up to 1.6 MtCO_2/year. In particular, the NNB Generation Company (SZC) Ltd and Rolls Royce Plc projects show the most potential; with the former aiming to utilise 400MWth of waste heat from Sizewell C power station to capture 1.5MtCO_2/year, and the latter aiming to capture circa 0.1 MtCO_2/year.

Table 8: Breakdown in DAC projects that are under development

DAC Technology Type	Company	Project	Location	Year	Capacity (t/year)	Utilisation or Storage
Solid sorbent DAC	Climeworks	Norsk e-fuel[40]	Norway	2026	80,000*	Utilisation in e-fuels
		Mammoth[37]	Iceland	2024	36,000	Storage
	Global Thermostat	HIF Haru Oni e-fuels[41]	Chile	N/A	2,190**	Utilisation in e-fuels
	NNB Generation Company (SZC) Limited	Sizewell C[4]	England, UK	N/A	1,500,000	Storage
	CO_2CirculAir B.V.	SMART-DAC[4]	Northern Ireland, UK	N/A	100	Storage
Liquid solvent DAC	Carbon Engineering	DAC1[38]	Unites States	2024	500,000	Storage
		Storegga[4]	Scotland, UK	2026	500,000-1,000,000	Storage
		Carbon Removal Project[39]	Norway	N/A	500,000-1,000,000	Storage
	Rolls-Royce plc	Environmental CO_2 Removal[4]	England, UK	N/A	100,000	Storage
	Mission Zero Technologies Ltd	DRIVE[4]	UK	N/A	120	Storage and utilisation
Mineralisation DAC	Cambridge Carbon Capture Ltd	Direct air CO_2 capture and mineralisation[4]	England, UK	N/A	100	Utilisation in construction

* Producing 25 Ml/year by 2026. Converted to CO_2 utilisation by assuming a fuel density of 800 kgm-3 and 100% conversion of CO_2 to fuel.

** Utilising 250 kgCO_2/day and assuming 24/7 operation throughout the year

1.1.1.9 Biochar

There are currently no operating biochar plants in the UK. However, there are a considerable number of demonstration plants situated in Western Europe, Australia, Canada, and China. The table below summarises these projects using data taken from the IEA's Clean Energy Demonstration Projects Database[43] and

[40] Nosrk e-fuel (2022), 'Accelerating the transition to renewable aviation': Norsk e-Fuel - Sustainable aviaton (norsk-e-fuel.com)

[41] Global Thermostat (2021), 'Global Thermostat to Supply Equipment Needed to Remove Atmospheric CO_2 for HIF's Haru Oni eFuels Pilot Plant': Global Thermostat to Supply Equipment Needed to Remove Atmospheric CO2 for HIF's Haru Oni eFuels Pilot Plant - Global Thermostat (archive.org)

[42] 1PointFive (2022), '1PointFive and Carbon Engineering Announce Direct Air Capture Deployment Approach to Enable Global Build-Out of Plants': PointFive and Carbon Engineering Announce Direct Air Capture Deployment Approach to Enable Global Build-Out of Plants (1pointfive.com)

[43] IEA, 'Clean Energy Demonstration Projects Database': Clean Energy Demonstration Projects Database – Data Tools - IEA

Bioenergy ExCo database[26]. Note that projects which dispose of or burn biochar have been included in this table.

Table 9: List of global planned biochar projects

Project	Biochar Technology Type	Location	Year	Capacity/ products
Loganholme Wastewater Treatment Plant Gasification Facility Demonstration Project[23]	Biochar and biofuel production from wastewater	Australia	2019	N/A
Renergi, Bioenergy, Collie, Waste to Energy through Pyrolysis[23]	Biodiesel, biokerosene and biochar production via pyrolysis of waste	Australia	2020	13kt/year of pyrolysis products
PCH Alberta	Produces SNG from fast pyrolysis of biomass. Biochar produced is burnt onsite	Canada	2018	0.1 m^3/year of syngas
DALI COUNTY FACILITY	Pyrolysis of rice husks to produce bio-oil, biochar, and non-condensable gases	China	N/A - operational	4,500 m3/year of bio-oil
AquaGreen PCE	Pyrolysis of wet sludge to produces syngas, solid fuels, and biochar	Denmark	N/A - operational	N/A
AquaGreen Farevejle wastewater facility	Pyrolysis of wet sludge to produces syngas, solid fuels, and biochar	Denmark	2022	N/A
Susteen TCR300	Pyrolysis of sewage sludge to produce bio-oil and biochar	Germany	2018	0.1t/year of pyrolysis oil
Empyro Enschede	Fast pyrolysis to produce bio-oil and char. Char is burnt onsite.	Netherlands	1998	1,000 t/year of pyrolysis oil
EMPYRO	Fast pyrolysis of organic residues to produce pyrolysis oil, steam, power and biochar	Netherlands	2015	3,200 kg/hr pyrolysis oil
Karlsruhe Institute of Technology (KIT), Bioliq	Fast pyrolysis of straw to produce bio-oil, solid fuels, and biochar	Germany	2010	0.3 t/h bio-oil

Unlike BECCS Hydrogen, the source of feedstock appears to be evenly distributed between the use of waste, woody biomass, and other organic products (i.e., straw and rice husks). Furthermore, the majority of these projects only produce biochar as a by-product, which is either burnt onsite, disposed of, or utilised in other industries.

1.1.2 Pathways for global NETs (capacity)

As of April 2021, the European Union as well as 44 countries have pledged to meet a Net Zero emissions target, accounting for approximately 70% of global CO_2 emissions. The use of NETs feature in the pledges, albeit with varying approaches and scale of deployment. The Climate Change Act commits the UK to an 80% reduction in GHG emissions by 2050 relative to 1990 levels. To achieve this reduction of NETs emissions to a value of 160 $MtCO_2$/year in 2050, NETs, particularly DACCS and BECCS, will contribute significantly.

The IEA published its "Net Zero by 2050: A Roadmap for the Global Energy Sector"[44] in 2021, outlining a pathway for the global energy sector to achieve Net Zero emissions by 2050. The Net Zero Emissions (NZE) Scenario developed states that a total of 7.6 $GtCO_2$ is to be captured in 2050; 30% of which comes from BECCS and DACCS, 50% from fossil fuel combustion, and 20% from industrial processes. Currently, there are approximately 35 commercial CCUS facilities in operation globally, with a collective CO_2 capture capacity of 45 Mt CO_2/year.

To meet the targets outlined in the NZE Scenario, global capture capacity needs to increase to 1.2 $GtCO_2$/ year in 2030 and 7.6 $GtCO_2$/ year in 2050. .

[44] IEA (2021), "Net Zero By 2050: A Roadmap for the Global Energy Sector": https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf

1.2 TECHNOLOGY OPTIONS

Several options existing for engineered NETs including BECCS, DACCS and biochar.

A key indicator of a technology's maturity, and hence likelihood of deployment, is known as its Technology Readiness Level (TRL). Each technology and project will be assigned a TRL level, ranging from 1-9, with a TRL of 1 being the lowest and TRL 9 the highest. Definitions of each TRL level are detailed in Table 10 below.

Table 10: Breakdown in TRL description

Phase	TRL Level	Description
Research	1	Basic principles
	2	Concept and application formulation
	3	Concept validation
Development	4	Experimental pilot
	5	Demonstration pilot
	6	Industrial pilot
Deployment	7	First implementation
	8	A few records of implementation
	9	Extensive implementation

1.2.1 BECCS

BECCS refers to technologies which combine bioenergy applications with CCS. BECCS processes consist of biomass production, biomass conversion, CO_2 capture, CO_2 transport and CO_2 utilisation or storage. There are a wide range of available biomass conversion and CO_2 capture technologies, which are introduced within this section. The final output will depend on the technologies used, ranging from the generation of electricity and heat to the production of hydrogen, biofuels or biomethane. A more detailed review of BECCS applications is given in section 2.

1.2.1.1 Biomass conversion

Biomass conversion refers to the process in which biomass feedstocks are converted into energy. There are several different methods and technologies available, consisting of combustion, gasification, pyrolysis, fermentation and anaerobic digestion. A summary of the various technologies is outlined in Table 11 below.

Table 11. Biomass conversion technologies

Conversion technology	Description	Products
Combustion	Combustion with oxygen	Electricity, heat
Gasification	Partial combustion of biomass or waste feedstocks	Syngas, electricity, heat
Pyrolysis	Thermal degradation of a solid fuel in the absence of oxygen to produce char	Biochar, syngas
Fermentation	Organic material is broken down by micro-organisms with low oxygen levels	Bioethanol and other biofuels
Anaerobic digestion	Organic material is broken down by micro-organisms in the absence of oxygen	Biogas

All of the listed technologies are at TRL 9 (without CO_2 capture) but not are all well-established with CO_2 capture. CO_2 capture on combustion of biomass has been demonstrated by Drax and Stockholm Exergi as well as other operators worldwide. The capture of CO_2 from process emissions in fermentation and AD sites has also been demonstrated. The capture of CO_2 from biomass gasification and pyrolysis processes is less established and still at TRLs below 7.

Biomass combustion technologies are substantially advanced and have been demonstrated commercially in the UK and globally at large capacities up to 300MWe. All other biomass conversion technologies have been demonstrated on a smaller scale. More detail on the various conversion techniques is shown in Appendix 2

1.2.1.2 CO_2 capture Options

There are many carbon capture options including post-combustion carbon capture, pre-combustion carbon capture, oxy-fuel combustion, chemical looping, carbonate looping and supercritical CO_2 (the Allam cycle). Different approaches are applicable to the different biomass conversion technologies listed above. Table 12 provides a summary of the three most-developed carbon capture approaches (post-combustion capture, pre-combustion capture and oxyfuel combustion are discussed below) applicable to power plants (including CHP and DH) and industrial sites. For each approach, there are also several different technologies available as shown in Table 13. The TRL levels in the last column refers to biomass plants with carbon capture with post-combustion capture being the most advanced in terms of large-scale technology demonstration while gasification systems with pre-combustion capture are still in the pilot testing phase (Assessing the cost reduction potential and competitiveness of novel (Next Generation) UK carbon capture technology, Benchmarking state-of-the-art and next generation technologies, Wood)[45].

Table 12. Types of carbon capture methods

Carbon capture technology	Description	Advantages	Disadvantages	CO_2 capture rate	TRL
Post-combustion capture	Removal of CO_2 from a flue gas stream. Chemical absorption	- Can be retrofitted to existing sites -Commercially proven in some industries	High energy penalty for solvent regeneration	~90%	TRL 7-8
Pre-combustion capture	Capture of CO_2 from syngas, where the syngas is produced through gasification. Can utilise physical absorption due to relatively high pressures, thus reducing costs.	Results in a high CO_2 concentration and high partial pressure	High capital and operating costs	~90%	TRL 5-6
Oxy-fuel combustion capture	Combustion with a stream of oxygen, resulting in a flue gas with higher CO_2 concentration and hence easier CO_2 separate	Reduced downstream processing of CO_2	High energy requirement for air separation unit (ASU)	~90%	TRL 7

[45] Benchmarking State-of-the-art and Next Generation Technologies (publishing.service.gov.uk)

Pre-combustion capture

Pre-combustion carbon capture systems are applied to biomass gasification processes. CO_2 is extracted from the syngas prior to combustion, where specific options included biomass integrated gasification combined cycle plants (BIGCC) with solvent absorption, sorbent enhanced reforming using carbonate looping and membrane separate of hydrogen from syngas[46].

Post-combustion capture

Post-combustion capture systems are applied at the end of biomass conversion processes, where CO_2 is separated from the flue gas stream from biomass combustion or incineration.

Table 13. Types of CO_2 capture technologies

CO_2 capture technology	Description	Variations
Membrane separation	Separation of CO_2 across a selective membrane	Inorganic membranes, Polymeric membranes, hybrid membranes
Adsorption	Molecular sieves or activated carbon are used to adsorb CO_2. Desorption of CO_2 is then carried out by pressure swing adsorption, or temperature swing adsorption	Molecular sieves, activated carbon
Chemical absorption	Reaction of CO_2 with a chemical solvent to form an intermediate compound. The original solvent and CO_2 can be regenerated upon application of heat	Solvents include amines, ammonia, ionic liquids
Physical absorption	Physical absorption of CO_2 into a solvent	Solvents include methanol and glycol based
Cryogenic separation	Separation of CO_2 by condensation at low temperatures and separation by boiling point difference.	

Oxy-fuel combustion capture

Oxy-fuel combustion involves the combustion of a fuel in a high purity oxygen stream, rather than air, resulting in the production of a flue gas with a much higher CO_2 concentration. This allows for a much easier CO_2 separation process when compared to combustion with air, as the CO_2 can be cleaned, compressed, and stored with less downstream processing when compared to combusting fuel with air[46].

Although oxy-fuel combustion capture systems have several advantages, a key disadvantage relates to the energy requirements of the Air Separation Unit (ASU) to produce the oxygen required, and the CO_2 purification unit.

1.2.2 Direct Air Carbon Capture and Storage (DACCS)

DACCS works by drawing in ambient air using fans and contacting the CO_2 present with specialist sorbents, where the CO_2 is subsequently captured via adsorption or absorption. CO_2-depleted air is produced as an output. The sorbent is then regenerated by altering the process conditions, typically by elevating temperatures and/or reducing pressures, which in turn releases the CO_2 as a pure stream ready for capture.

As the CO_2 concentration in air is significantly lower than compared to BECCS and biochar flue gas streams (between 3-8 vol%)[47], then DACCS exhibits a higher energy penalty and hence is more expensive. Despite this, researchers have suggested that DACCS shows the most immediate promise in Scotland out of all

[46] Analysis the potential of bioenergy with carbon capture in the UK to 2050, Ricardo, 2020

[47] Rodin et al (2020), 'Assessing the potential of carbon dioxide valorisation in Europe with focus on biogenic CO_2': Assessing the potential of carbon dioxide valorisation in Europe with focus on biogenic CO_2 - ScienceDirect

engineering NETs[22], as it can achieve considerable carbon removal efficiencies (85.4%-97%)[48], is flexible in location[49,50], and is not constrained by the availability of limited resources (e.g. biomass)[35]. Furthermore, DACCS does not require complex MRV and carbon accounting methods, as it is a closed system technology achieving permanent removal[35].

Existing DACCS systems are predominantly based on liquid solvent CO_2 capture or solid sorbent-based carbon capture[51]. The liquid solvent process is pioneered by Carbon Engineering, whilst the solid sorbent process is led by Climeworks and Global Thermostat. There are also new technologies being developed which offer promises of reduced energy demands and cost[52]. The energy demands of these alternative configurations, along with their carbon removal potential, are detail in Table 14 below. The costs of these configurations are broken down in Table 33, page 68. More detail on the specific DACCS technology aspects is given in Appendix 3.

Table 14: Breakdown in energy demands and carbon removal for each DACCS technology

Company	Heat (MWh/tCO_2)*	Electrical (kWh/tCO_2)	Carbon removal efficiency
Carbon Engineering	1.46[23]-2.45**	0[23]-1,535[52]	10-92%[49]
Climeworks	1.5-2.0[52]	200–300[52]	9-97%[50]
Global Thermostat	1.17-1.41[52]	150–260[52]	N/A
Antecy	2.08[52]	694[52]	N/A
MSA	0[52]	316-326[52]	N/A
Molecular filters	N/A	333[52]	N/A

*Units transposed to MWh from varying sources

** In this instance natural gas is burnt in a NGCC unit and electricity is generated onsite.

When compared to BECCS, DACCS is less effective in terms of carbon removal, as it requires large quantities of heat and power per tCO_2; BECCS on the other hand act as a NETs producer[53]. However, the potential for DACCS scale up is technically unlimited, as CO_2 is sourced directly from the atmosphere and is not constrained by biomass feedstocks that can exhibit supply chain, price, and transport issues.

1.2.3 Biochar

Biochar is a charcoal-like product formed during pyrolysis, where a biomass feedstock is thermally decomposed in the absence or at very low oxygen levels[54]. This process is similar to gasification, despite exhibiting lower efficiencies, and can be achieved through slow or fast pyrolysis[55].

Slow pyrolysis is favoured when producing biochar and can be achieved following a batchwise or continuous process configuration. During batchwise pyrolysis, heat is sourced from burning a portion of the biomass

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[48] An et al (2022), 'The impact of climate on solvent-based direct air capture systems': The impact of climate on solvent-based direct air capture systems

[49] de Jonge et al (2019), 'Life cycle carbon efficiency of Direct Air Capture systems with strong hydroxide sorbents': Life cycle carbon efficiency of Direct Air Capture systems with strong hydroxide sorbents - ScienceDirect

[50] Terlouw et al (2022), 'Life Cycle Assessment of Direct Air Carbon Capture and Storage with Low-Carbon Energy Sources': Life Cycle Assessment of Direct Air Carbon Capture and Storage with Low-Carbon Energy Sources | Environmental Science & Technology (acs.org)

[51] McQueen et al (2021), 'A review of direct air capture (DAC): scaling up commercial technologies and innovating for the future': A review of direct air capture (DAC): scaling up commercial technologies and innovating for the future - IOPscience

[52] Fasihi et al (2019), Techno-economic assessment of CO_2 direct air capture plants': Techno-economic assessment of CO_2 direct air capture plants - ScienceDirect

[53] Cooper et al (2022), 'The life cycle environmental impacts of negative emission technologies in North America': The life cycle environmental impacts of negative emission technologies in North America

[54] Novais et al (2017), 'Mitigation of Greenhouse Gas Emissions from Tropical Soils Amended with Poultry Manure and Sugar Cane Straw Biochars': Mitigation of Greenhouse Gas Emissions from Tropical Soils Amended with Poultry Manure and Sugar Cane Straw Biochars (scirp.org)

[55] Matusik et al (2020), 'Life cycle assessment of biochar-to-soil systems: A review': Life cycle assessment of biochar-to-soil systems: A review - ScienceDirect

feedstock, whilst continuous pyrolysis initially sources heat externally, before switching to burning the combustible gases released during pyrolysis. Fast pyrolysis is favoured when maximising biofuel production, with yields of up to 80% being achievable under the right conditions. The heat used in fast pyrolysis is typically delivered using an inert solid material that acts as the energy carrier (i.e., a fluidised bed) [56].

The choice of feedstock to produce biochar is broad, with organic wastes, forestry residues and mixed plastic all being possible[57,58]. The biochar product can subsequently be applied to soils, where the original carbon sequestered during biomass feedstock growth (via photosynthesis) is retained in a stable form that is resistant to decomposition, and thus enables negative emissions[59]. Typically, slower biochar application rates are prefered[54]. Pyrolysis temperatures typically range from 350degC to 650degC, below which the process is considered to be "toast" rather than pyrolysis, and above leads to significant material loss. Varying these temperatures also has a direct impact on the structure, composition, and physical characteristics of the biochar, which in turn contribute towards the biochar's recalcitrancy. In particular, temperature impacts the number of aliphatic chains and aromatic rings, the proportion of fulvic and humic acids, the concentration of nutrients (e.g., phosphorous and nitrogen), ash content, pH, porosity and surface area. Typically, higher temperatures are favoured[54].

An alternative production method is via hydrothermal carbonization (known as wet mild pyrolysis), where biomass is anaerobically decomposed at 180degC to 280degC in the presence of subcritical liquid water. The advantage of this process is its ability to process biomass with a high moisture content (i.e., wetter waste feedstocks)[60].

1.3 POLICY & REGULATORY EVIDENCE REVIEW

1.3.1 Existing Scottish policies and regulations

Under an amended Climate Change Act, Scotland set out an ambitious target to achieve a 75% reduction in emissions by 2030 compared to 1990 levels[61]. This will be funded through the Industrial Strategy Challenge Fund[3]. However, according to the CCC[62] this would not be possible even under the most optimistic scenario (the 'tailwinds' pathway), which predicts a 69% reduction in emissions.

Under the '*Developing Scotland's circular economy'* paper[63], the Scottish Government proposes to reduce landfill waste to 5%, by achieving a recycling rate of 70%, reducing 15% of total waste compared to 2011, and reducing food waste by 33% (compared to 2023) by 2025. This reduction in waste could significantly impact feedstock supplies going towards EfW, gasification and biomethane sites.

1.3.2 Existing UK policies, regulations and recommendations

The UK Government has announced over £100M in funds to help develop GGRs and screen them on their potential to deliver negative emissions, reduce costs and scalability[2]. £31.5M of these funds will be delegated to five land based GGR demonstrator projects (including biochar and perennial bioenergy crops) under the Strategic Priorities Fund. The development of CCUS clusters is also underway, with the UK Government announcing £1B worth of funds[59]. To help further encourage the deployment of NETs and formation of a CO_2 utilisation market, the UK Government is planning to invest £15M in a new grant-funding competition for SAF

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[56] WikiBiomass (2022), 'Pyrolysis': Pyrolysis – European Biomass Industry Association (eubia.org)

[57] Ricardo, 'Synergies and Potential of the Scottish Bioeconomy' (2020)

[58] Freer et al (2022), 'Putting Bioenergy With Carbon Capture and Storage in a Spatial Context: What Should Go Where?': (PDF) Putting Bioenergy With Carbon Capture and Storage in a Spatial Context: What Should Go Where? (researchgate.net)

[59] Vivid economics (2019), 'Greenhouse Gas Removal (GGR) policy options – Final Report': Greenhouse gas removal policy options - GOV.UK (www.gov.uk)

[60] Krysanova (2019), 'Properties of biochar obtained by hydrothermal carbonization and torrefaction of peat' :Properties of biochar obtained by hydrothermal carbonization and torrefaction of peat - ScienceDirect

[61] The CabiNETs Secretary for Net Zero, Energy and Transport (2022), 'Climate Change Plan: monitoring reports 2022': Climate Change Plan: monitoring reports 2022 - gov.scot (www.gov.scot)

[62] The Climate Change Committee (2020), 'The Sixth Carbon Budget – The UK's path to Net Zero': Sixth Carbon Budget - Climate Change Committee (theccc.org.uk)

[63] Scottish Government (2020), 'Developing Scotland's circular economy - proposals for legislation: analysis of responses': Executive summary - Developing Scotland's circular economy - proposals for legislation: analysis of responses - gov.scot (www.gov.scot)

production and introduce SAF blending mandates by 2025[2]. SAFs typically comprise of biofuels and e-fuels, that latter of which is manufactured via the Fischer Tropsch process using captured CO_2[64].

In 2021, the National Infrastructure Commission (NIC) made 8 key policy suggestions for the UK Government to enact[3], the majority of which the UK Government agreed with[65]. Firstly, the UK Government has reiterated that they are committed to achieving at least 5 $MtCO_2$/year of GGRs by 2030, by delivering on their £100M GGR innovation fund and wishing to develop GGRs incentives. Secondly, the UK Government has confirmed they will obligate polluting sectors to offset their emissions, covering 100% of emissions by 2050. Lastly, they have reiterated that CO_2 T&S infrastructure will be delivered by the end of this decade[65]. However, the UK Government only partially accepts to have polluting sectors pay for removals in order to reach carbon targets[65], which can undermine the viability of implementing policies that penalise heavy emitting polluters, such as the GGR Obligation Scheme (please see Section 1.3.3 for further detail).

The UK is expecting to issue a Biomass Strategy in 2023, which will review the amount of sustainable biomass in the UK to source biochar[59].

Stakeholders wish for a combination of price and quantity instruments to promote GGR deployment. Price mechanisms will be vital to attracting investment in early GGR projects and quantity mechanisms will play a larger role in reaching targets for removals once technologies have matured. Also, technology-neutrality should be a long-term goal once technologies mature, and a market-led mechanism becomes feasible[59].

UK Government must ensure that new policies complement existing ones, such as the 25 Year Environment Plan and Sustainable Development Goals[59].

1.3.3 Potential policy or regulatory levers

1.3.3.1 Expand support for GGRs via additional funds

The CCC[2] recommends that the UK Government should expand upon its existing UK Greenhouse Gas Removal Demonstrators programme, in order to further develop field experiments, pilots, and demonstration and commercialisation projects. For less mature GGRs, government support is necessary to enable innovation and demonstration, before the private sector deploys them in response to £/tCO_2 incentives[59]. As for large-scale NETs, public funding provides a chance to develop and test the technology without the risk of private investment being retracted[66]. Continued government support for pilot projects helps improve understanding of a technology's risks, so that appropriate safeguards can be put in place, as well as help provide financial certainty through long term contracts[59]. Analysis by Vivid economics further builds upon this and suggests that research councils can fund research and innovation into low-carbon technologies through the Natural Environment Research Council (NERC), Economic & Social Research Council (ESRC), and Engineering and Physical Sciences Research Council (EPSRC) [59]. **Furthermore, the Government should help coordinate opportunities between GGRs and wider CCUS deployment, to help share the cost of CO_2 T&S infrastructure[59].**

Despite the benefit of Government funds, it is also necessary that fiscal incentivises are put in place. Without them the high capital and operating costs of GGRs makes private investment unattractive and there is lack of a stable revenue stream for the provision of negative emissions[59]. Furthermore, pilot projects are needed to more fully understand the environmental impacts, negative emissions potential, and can help establish repeatable and effective practices in deploying land-based GGR[59].

1.3.3.2 Expand the Contracts for Difference (CfD) scheme

The CfD scheme is the UK Government's main mechanism for supporting low-carbon electricity generation. CfDs incentivise investment in renewable energy by providing developers of projects that have with high upfront costs and long lifetimes with direct protection from volatile wholesale prices, and they protect consumers from paying increased support costs when electricity prices are high. This is done by having a pre-

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[64] Dieterich et al, 'Power-to-liquid via synthesis of methanol, DME or Fischer–Tropsch-fuels: a review': Power-to-liquid via synthesis of methanol, DME or Fischer–Tropsch-fuels: a review - Energy & Environmental Science (RSC Publishing)

[65] BEIS (2022), 'Government Response to the National Infrastructure Commission's Report on Engineered Greenhouse Gas Removals': National Infrastructure Commission report on greenhouse gas removals (GGRs): government response - GOV.UK (www.gov.uk)

[66] Element Energy (2021), 'Review of International Delivery of Negative Emissions Technologies': Review of international delivery of negative emission technologies (climatexchange.org.uk)

agreed price for the low carbon electricity that the generators produce, for the duration of the contract – this is known as the 'strike price'.

The CfD scheme could be expanded to include GGR or CCUS facilities. This approach could prove attractive to investors, as it secures a revenue stream for the GGR developers and reduces financial risk associated with upfront capital investment[59]. Furthermore, it has proven to be successful in the past for renewable energy, which experienced significant cost reductions and scale up once initial CfDs were issued.

Analysis by Ricardo[67] highlights that a CfD auction could be easily adjusted to target BECCS specifically, and be applied to the three main biomass conversion/CHP sites in Scotland: Markinch CHP (55 MWe), Steven's Croft power station (44 MWe), and Westfield Biomass Plant (10 MWe). These sites have potential to achieve 0.8MtCO_2/year of negative emissions[67], which is equivalent to 15% of the CCPu's 2032 target[68] Further analysis by Vivid economics[59] suggests that the 'strike price' for BECCS Power could be linked to the electricity price, whilst for BECCS Industry and DACCS the 'strike price' could be linked to the ETS price.

1.3.3.3 UK ETS

Prior to Brexit, the UK had adopted the EU-ETS. This policy allowed operators that undertook CCS to not have to surrender allowances where emissions had been verified as captured and permanently stored. The UK now has its own ETS, which follows a similar cap and trade scheme that caps the total level of GHG emissions a at a reserve price of £22/t. This cap will reduce in line with the UK's Net Zero commitments (i.e., reaching zero by 2050), increasing the price. This scheme does not cover any GGRs[69].

The Government can link contracts with GGR providers (i.e., CfDs) for revenue to the UK ETS, allowing offsets to be traded. This will act as an additional revenue source for GGR providers, helping us reduce the initial volatility of GGR revenues. The inclusion of GGRs in the UK ETS will help provide market-based solutions for stimulating investment, and move us towards a single, integrated compliance market for carbon, with negative emissions supporting liquidity as the ETS allowance cap falls over time[59, 62,]. However, the UK ETS won't be a sufficient incentive on its own[59].

1.3.3.4 GGR Obligation Scheme

As an alternative to including negative emissions within the UK ETS, a negative emissions obligation scheme could be implemented instead. This is viewed as a good alternative, as it avoids the risk of potentially undermining the UK ETS due to the uncertain nature of GGRs[59, 62]. Companies would be required to secure negative emission certificates to meet their obligations, focussing on fossil fuel suppliers (calculated as a percentage of the carbon content of fuels) and wholesale distributors of agricultural products (calculated as a percentage of GHG emissions associated with agricultural activities). These certificates can be traded with other obligated emitters[59, 62]. Additional benefits of the system include focussing on a "polluter pays principle", which will be more politically acceptable, and the fact that the heaviest emitting sectors would be covered[59, 62]. However, one key risk is pass through costs impacting low-income households disproportionately. Another key disadvantage is the initial limited GGR market size, which could lead to volatile certificate prices during the early stages of deployment, and risk weaking the incentives. Furthermore, the trading of these certificates would require rigorous accounting standards (please see the MRV section above) [59, 62].

1.3.3.5 GGR tax credit/carbon levy

This is a scheme where energy intensive industries receive a reduction in tax liabilities (£/tCO_2) if they adopt GGRs and/or CCS, which can then be traded to allow realisation of their true value[59]. There two main options available: 1.) provide tax credits paid for in £/tCO_2 of GHGs removed, modelled after the 45Q tax credit for CCS; 2.) provide a tax credit for initial (capital) investment for GGRs, similar to the 48a/b tax code in the US[62]. It has been proven in the past that high carbon prices/carbon taxes/tax credits have created markets where NETs are more commercially viable (e.g., the California carbon tax credit)[66]. Please note that stakeholders believe tax credits should be available to everyone, and not just be limited to heavily polluting industries[59].

The benefits of this tax credit are that it provides a strong incentive to develop capital intensive GGRs (e.g. BECCS Power), has a lower MRV accounting requirement compared to the GGR Obligation Scheme, and

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[67] Ricardo, Comparing Scottish bioenergy supply and demand in the context of Net-Zero targets: [Comparing Scottish bioenergy supply and demand in the context of Net-Zero targets (climatexchange.org.uk)]

[68] The CCPu (2018), 'Update to the Climate Change Plan 2018 - 2032: Securing a Green Recovery on a Path to Net Zero': [Supporting documents - Securing a green recovery on a path to Net Zero: climate change plan 2018–2032 - update - gov.scot (www.gov.scot)]

[69] Scottish Government (2022), 'UK emissions trading scheme': [UK emissions trading scheme - Climate change - gov.scot (www.gov.scot)]

incentivises both emission reductions and GGR deployment simultaneously[59]. However, a key risk is that tax credits can easily change overtime, which exposes investors to risk, and hence the Government needs to provide additional guarantees to ensure that tax credits will pursue over time. Furthermore, the monetary benefits of this scheme will go to corporations, which is less politically favourable than compared to the other options discussed. Finally, similar to the GGR Obligation Scheme, there is a risk of pass-through costs impacting low-income households[59, 62].

Analysis on the necessary carbon and negative emission prices needed to make BECCS and EfW-CCS competitive with coal-CCS and coal was conducted by Pour et al[70]:

- For BECCS to be competitive with coal-CCS, the carbon price will need to be between £107/tCO_2* to £160/tCO_2 *
- For BECCS to be competitive with coal-CCS the negative emission price will need to be between £17/tCO_2 - £68/tCO_2 *
- For BECCS to be competitive with coal the negative emissions price needs to be between £68/tCO_2* to £135/tCO_2* respectively.
- For EfW-CCS to be competitive with coal-CCS, the negative emissions price needs to be £68/tonne* to complete with coal-CCS.
- For EfW-CCS to be competitive with coal, the carbon price will need to be between £110- £169/tCO_2*

We could also input a fertiliser tax to incentivise the application of biochar to soils[59].

**Values converted from USD to GBP using conversion of 1 USD = 0.83 GBP.*

1.3.3.6 GGR Subsidies

Subsidies from the Government are another option, which are categorised into:

1.) Targeted grants aimed at individual landowners who deploy small-scale GGR projects (e.g., biochar).
2.) Service contracts aimed at businesses that deploy large-scale GGRs.

In both instances, a government body responsible for the programme would screen the proposals based on feasibility and enter into contracts with successful bidders[59].

Some key benefits associated with this incentive are its lower risk, its cost being progressively distributed across the tax base, and greater Government control over GGR locations. This latter point is important, as it enables targeted GGR deployment to maximise co-benefits. However, this choice of incentive is expensive (costing £6B-£20B/year by 2050) and leads to less efficient allocation of resources compared to market-based policies[59]. These levers have not been included in the pathway analysis but could aid deployment, particularly in scenario 1).

1.3.3.7 Monitoring, verification and reporting (MVR)

Across the literature reviewed, a frequently cited barrier to GGR deployment is the lack of a MRV protocol[2]. To ensure BECCS is low carbon, biomass feedstocks need to be sourced locally and sustainably. However, at present the IPCC's Guidelines for National Greenhouse Gas Inventories does not account for removals reported in the jurisdictions producing the biomass or storing the CO_2[2], and there are no UNFCCC accounting guidelines for most GGRs[59]. A robust MVR protocol would fill in these gaps; reducing the risk of relying on carbon-intensive biomass imports and accommodate for varying GHG accounting accuracies between different GGRs[66]. This latter point is key, as it facilities an environment where negative emission certificates can be traded whilst maintaining certificate equivalence[59]. Furthermore, an appropriate Certificate Authority (CA) should be established, who can issue negative emission certificates and hold the power to guarantee removals are verifiable and quantifiable[59]. There is also a risk associated with the 'mitigation deterrence' effect of GGRs[66], which refers to the risk of incentives making GGRs more attractive than compared to developing/adopting other low-carbon technologies[2]. The Government has confirmed that they understand this risk, and will design an appropriate GGR monitoring scheme to combat it accordingly[59] Please note that the Government has only partially accepted putting in place a MRV regime by 2024[65].

[70] Pour et al (2018), 'Opportunities for application of BECCS in the Australian power sector': Opportunities for application of BECCS in the Australian power sector - ScienceDirect

Biochar carbon accounting is still under development and depends on the potential for mobilisation of the stored carbon and its possible return to atmosphere. Carbon permitting and regulations that prevents such releases will be necessary[35].

1.3.3.8 Other policy options

The permanent land use change requirement could be relaxed to help support production of biomass for BECCS, so that farmers can more flexibly switch back to agricultural land use after an initial rotation, and biochar could be incentivised through inclusion in the Agriculture Reform Programme (ARP) [59]. Furthermore, BECCS Hydrogen deployment could be scaled up if included in the Renewable Transport Fuels Obligation (RTFO) [59].

1.3.3.9 Potential policy issues

The Climate Change Committee highlighted potential policy issues[2]:

- Who has responsibility for accounting of GHG removals, does it lie with the producer or consumer?
- Setting a negative emission threshold may only lead to inefficient GGR technologies being deployed (e.g., a BECCS Power plant without heat recovery). This is counterintuitive, and policy should include a minimum NETs efficiency alongside any negative emissions thresholds.
- Public support for NETs is necessary, with analysis by the Climate Assembly highlighting the public's negative view on engineered GGRs compared to natural solutions. Building early on with sequential small-scale deployment could help build a social license for engineered GGRs.
- Policy must ensure strong governance so that biomass is harvested sustainably. Biomass cannot be harvested if it is detrimental to the surrounding area and impacts natural CO_2 sequestration.

1.3.4 Existing International policies

In recent years, there have also been several global advancements in incentives that have been developed to promote the accelerated deployment of NETs. NETs policy support to date has predominantly focused on direct grant support, aimed at addressing financial barriers with deployment of NETs due to high upfront capital costs and potential high operating costs. However, efforts are underway to develop further incentives for NETs through regulations and mandatory standards.

In November 2022, the European Commission adopted a proposal for an EU-wide voluntary framework for certification of carbon removals[71]. The proposal is now under review by EU countries and lawmakers to determine if it will be approved. The certification process must be credible, hence the proposal sets out proposed rules for independent verification of CO_2 removals, as well as proposed rules to recognise certification schemes that can be used to demonstrate compliance[71]. The certification of carbon removals from NETs can help support future inclusion of NETs in carbon markets, hence providing a direct incentive to invest in the technologies.

An overview of existing global support mechanisms is outlined in Table 15 below.

Table 15. International NETs policy support

Policy support	Location	Year
BECCS reverse auction	Sweden	2021 (announced)
NETs tariff	Luxembourg	2022
Direct Air Capture combined with long-term carbon storage, coupled to existing low-carbon energy	US	2021
Bipartisan Infrastructure Law	US	2021

[71] European Green Deal: European Commission proposes certification of carbon removals to help reach Net Zero emissions, EC, November 2022

1.3.4.1 BECCS Reverse auction, Sweden

The Swedish Government has announced a reserve auction, covering bio-CCS projects with a total budget of £3.2 billion. The reverse auction will determine who can deploy BECCS at the lowest cost, with companies bidding on the quantities of CO_2 that can be captured[72]. Winners of the auction will then receive support in the form of subsidies. The support will cover CO_2 capture, transport and storage fees over a period of 15 years. The Swedish Energy Agency hope to hold the first round of the auction in 2023, followed by storage occurring in 2026[73].

1.3.4.2 NETs Tariff, Luxembourg

NETs have been concluded as being required to reach Net Zero targets for the EU and many of the member states, as part of the strategy identified in the European Green Deal and the 2021 European Climate Law. The EU commission has therefore proposed to develop the certification of carbon removals (CCR) which will be discussed in the first quarter of 2023. The aim of the CCR is to support the scale-up of atmospheric carbon removal with the use of engineered GGR technologies, such as BECCS and DACCS, as well as improved forestry and agriculture practises.

Luxembourg has developed and introduced national legislation to support engineered GGR, known as the Luxembourg Negative Emissions Tariff (LNET). The LNETS is designed as a support scheme to CCR based upon the German renewable energy feed-in tariff, providing a premium per tonne of removed carbon through five-year contracts assured by the government.

1.3.4.3 Direct Air Capture combined with long-term carbon storage, coupled to existing low-carbon energy, USA

This funding opportunity in the US aims to support front-end engineering design (FEED) studies for DACCS projects, capable of capturing a minimum of 5,000 tCO_2/year. Covering a total of £11.8 million*, 5 DACCS projects have received funding through this policy mechanism as of August 2022.

1.3.4.4 Bipartisan Infrastructure Law, USA

Beginning in 2021, the Bipartisan Infrastructure Law (BIL) aims to commercialise carbon management, industrial decarbonisation technologies and associated infrastructure, containing a total of £10.2 billion* to be provided over a five-year period. As part of the BIL, the Department of Energy (DOE) in the US will provide up to £3 billion* support to regional DAC hubs, with the aim of establishing four regional hubs capable of capturing 1 million tCO_2/year. The BIL is made up of several additional programmes, with a focus on carbon capture technologies, as well as transport and storage infrastructure.

**Values converted from USD to GBP using conversion of 1 USD = 0.83 GBP.*

1.4 NON-ENGINEERED NETS

Non-engineered NETs are out of scope of this report; however, we have summarised these in chapter 1.4 of the main report and Appendix 9 for reader reference.

1.5 BIORESOURCES

Carbon capture technologies discussed in section 1.2, with the exception of DACCS, can only be considered NETs when combined with a feedstock which has absorbed carbon from the atmosphere. The negative emissions that can be achieved is therefore dependent on sourcing such feedstocks, ensuring sustainable supply and avoiding indirect land use change.

Ricardo studied the availability of bioresources in Scotland in 2022, for ClimateXChange (CXC)[67]. The project subdivided feedstocks into directly combustible biomass and those more appropriate for anaerobic digestion or liquid biofuel production. This report has divided feedstock into solid and non-solid biomass.

The tables in sections 1.5.1 and 1.5.2 show the currently utilised biomass resource, and the available resource currently (latest available data), in 2030 and 2045. The available resource accounts for biomass that should be left in-situ (for maintenance of soil condition, for example) and those that remain after competing uses have

[72] Support scheme for bio-ccs, IEA, Accessed at: https://www.iea.org/policies/14843-support-scheme-for-bio-ccs

[73] Bio-CCS as a policy measure to achieve climate goals – the pioneering support scheme in Sweden, Svante Soderholm, Nicki Carnbrand Hakansson, 2022

been satisfied. Where the available resource equals the currently used resource, there is neither excess resource nor is the resource overused. **Where the available resource exceeds the currently used resource, there is potential to increase the amount of biomass used for energy.** Where the future available resource is lower than the currently used resource, the amount of biomass used for energy must decrease in the future or potentially use biomass at an unsustainable rate.

If biomass is sourced from forests, concerns may centre on woodland loss and degradation, and if sourced from dedicated energy crops there's a risk of competition for land to grow food[59]. The large-scale of biomass required can cause additional pressure on land, water and biodiversity[74].

Table 16 shows some typical energy and density criteria for bioresources. Non-biogenic resources are also included in this table for reference.

Table 16: Chemical and energy properties of biogenic and non-biogenic fuels

Note non-biogenic fuels included in this list for reference

Type	Moisture content (%)	NCV (GJ/t)	Bulk density Kg/m^3	Energy density GJ/m^3
Biogenic				
Miscanthus (balled)	25%	13	140-180	1.8-2.3
Wood chip	30%	13	250	3
Wood pellet	10%	18	650	11
Torrefied wood pellets[75]	0%	22	720	16
Non-biogenic				
Natural gas	N/A	38	0.9	0.035
LPG	N/A	46	510	24
Heating oil	N/A	43	845	36
Coal (Anthracite)	N/A	33	1100	36
SRF*/RDF[76]	Site specific, up to 23 GJ/tonne depending on composition. Biomass content variable.			

*Note that the acronym SRF can stand for solid recovered fuel or short rotation forestry, here we are talking about solid recovered fuel. We have not used the acronym for forestry in this report to minimise confusion.

1.5.1 Solid biomass

The largest source for solid biomass in Scotland is from the forestry industry. Use of roundwood suitable for timber for bioenergy is not considered viable. Therefore, the available resource includes only residues: Portions of small roundwood (SRW) and brash. Arboriculturally arising (tree felling in parks, verges and gardens) have also been included in the resource, assuming this is less likely to enter sawlog supply chains.

A secondary by-product of forestry are sawmill residues. These are predominantly woodchip (60%), with smaller quantities of sawdust (28%) and bark (11%). Wood processing industries take the largest share of this resource (54%), in woodchip and sawdust for purposes such as panel board production. 26% of sawmill residues are already used for bioenergy, including wood pellet production. Most bark is sold for other purposes, not used in wood production or energy.

[74] Jeswani et al, 'Environmental sustainability of negative emissions technologies: A review': Environmental sustainability of negative emissions technologies: A review

[75] Biomass pre-treatment for bioenergy: https://www.ieabioenergy.com/wp-content/uploads/2018/10/CS1-Torrefaction.pdf

[76] Trends in the use of solid recovered fuels: https://www.ieabioenergy.com/wp-content/uploads/2020/05/Trends-in-use-of-solid-recovered-fuels-Main-Report-Task36.pdf

Due to the long maturation time of traditional forestry plantations, the current level of forestation in Scotland is indicative of the availability of forestry and sawmill residues in the medium term. Future afforestation will not increase the availability of residues until after 2045. The availability of SRW for bioenergy (constituting the greatest part of the forestry residue resource) is expected to decline to 2045, whilst brash and arboricultural arisings may increase. However, the availability of large roundwood is expected to increase to 2037-41, resulting in greater production of sawmill residues. The estimate assumes half of the sawmill residue increase will be directed to bioenergy, increasing the proportion for this purpose from 26% currently to 34% in 2030. Beyond 2041, the supply of large roundwood (and therefore sawmill residues) is expected to decline.

Emerging sources for biomass, specifically intended for energy uses, are short rotation forestry (commonly referred to as SRF, but not in this report due to acronym used elsewhere), short rotation coppicing (SRC) and perennial energy crops. There is currently no largescale resource, however, the report estimates a potential SRF resource of 100kt/year by 2045 and a perennial energy crop resource (including short rotation coppice) of 150kt/year per year by 2030, rising to 640kt/year by 2045.

Previous work by Ricardo, for CXC, indicated a theoretical potential of 5.78, 1.75 and 0.52 Mt/year for short rotation forestry, SRC and miscanthus respectively[67]. This work accounted for physical constraints on land suitability (such as access, soil type and climate). The later work for CXC (resulting in estimates presented in Table 17) assumed limits on planting rates for each type of energy crop. For short rotation forestry and Miscanthus this was fixed at 1000ha per year. For SRC this started at 1000 ha per year, increasing by 20% with each passing year. The planting area for SRC was limited to 5% of permanent grassland (amounting to 57,113 ha). This limit was imposed to comply with Greening rules at the time of the study and, at the assumed planting rate, is reached by 2036. SRF and Miscanthus planting is allowed up to the area of suitable land identified in the 2020 Ricardo study (912,600 ha and 51,800 ha, respectively), however neither limit is reached within the timeline of the model due to the restricted planting rate. It should also be noted that a rotation of 15 years was applied to short rotation forestry, therefore even if widespread planting begins by 2025, resource is not available until 2040.

Table 17: Solid biomass resource; current, 2030 and 2045 projections

Feedstock	Currently used for bioenergy (Mt)	Current available resource (Mt)	2030 available resource (Mt)	2045 available resource (Mt)
Forestry residues and arb arisings	1.12	1.2	0.94	0.95
Sawmill residues	0.45	0.45	0.98	0.81
Short rotation forestry	0	0	0	0.1
Perennial energy crops	0	0	0.15	0.64
Straw	0	0.29	0.29	0.29
Waste wood	0.29	0.29	0.29	0.29
Residual waste (biogenic component)	0.56	0.56	0.14	0.14

Straw is an agricultural residue of cereal crops, which may be directly combusted. There is currently no widespread use of straw for bioenergy in Scotland, straw also has a large number competing uses, such as: Animal bedding, feed and horticulture. These uses consume around 80% of the current production. Leaving a potential resource of 290kt, which is not expected to change to 2045.

Wood waste arises from a number of sectors. Cleaner wood comes from packaging, pallets and joinery, whilst dirtier waste wood arises from construction and demolition, civic amenity sites. Wood from fencing, railways and telegraph poles may be classed as hazardous waste due to use of preservatives. 290kt is currently used for bioenergy and the available resource is not expected to change throughout the time period.

Residual waste is the waste left after recyclables and food waste have been removed. The organic component of the residual waste for combustion is expected to decline from current levels, both from policies aimed at waste prevention (decoupling population and economic growth from waste quantities) and greater recovery of food waste for anaerobic digestion. The specific mix of fuel used in EfW sites determines the biogenic CO_2 that can be captured – our assumptions for future sites use an equivalent CO_2 capture potential per unit fuel input as the existing sites in operation – but if this mix changes, then the CO_2 capture potential will also vary.

1.5.2 Non-solid biomass

Non-solid wastes are those either entirely liquid or with comparatively low solid content. They are generally not suitable for direct combustion, without first drying to remove the liquid content, but are ideal for anaerobic digestion or some methods of liquid biofuel production. Table 18 and Table 19 both show the same resources, however, Table 19 expresses the quantity of resource as the energy content (MWh) of their assumed products, which is biodiesel for used cooking oil (UCO) and tallow, and biogas for all other resources. Comparison of the two tables highlights the large range in energy content across the resources, from 0.003 MWh/t for spent lees/wash (from whisky production), to 10.1 MWh/t for UCO to biodiesel.

Table 18: Non-solid biomass resource; current, 2030 and 2045 projections

Feedstock	Currently used for bioenergy (Mt)	Current available resource (Mt)	2030 available resource (Mt)	2045 available resource (Mt)
Food waste	0.18	0.18	0.27	0.27
Whisky by-products	0.74	2.49	2.75	3.16
Brewery by-products	0	0	0	0.01
Dairy by-products	0.03	0.04	0.04	0.04
Animal processing by-products	0	0.07	0.07	0.07
Sewage sludge	0.35	1.53	1.56	1.56
Farm slurries	0.07	10.26	10.26	10.26
Used cooking oil	0.01	0.02	0.02	0.02
Tallow	0.04	0.06	0.06	0.06

Table 19: Non-solid biomass resource; current, 2030 and 2045 projections, table presented in MWh

Quantities expressed in MWh (biogas or biodiesel for UCO and tallow).

Feedstock	Currently used for bioenergy (MWh)	Current available resource (MWh)	2030 available resource (MWh)	2045 available resource (MWh)
Food waste	202	202	299	299
Whisky by-products	145	319	379	479
Brewery by-products	0	0.57	1.14	2.06
Dairy by-products	5.80	8.64	8.64	8.64
Animal processing by-products	0	51.4	51.4	51.4

Feedstock	Currently used for bioenergy (MWh)	Current available resource (MWh)	2030 available resource (MWh)	2045 available resource (MWh)
Sewage sludge	90.4	392	398	400
Farm slurries	8.66	1,187	1,187	1,187
Used cooking oil	138	210	213	214
Tallow	330	500	500	500

Food wastes arises from domestic and commercial sectors. Scotland has a target to reduce food waste by 33% by 2025. However, the Ricardo study assumed an increase in the rate of food waste collection, up to 70% by 2030. Therefore, there is a NETs increase in the available food waste resource.

Whisky by-products include draff, pot ale, spent lees/wash and distillers' dark grains (DDG). Brewery by-products (spent grain, hops and yeast) provide a much smaller potential resource (both in weight and energy). These sectors have been identified as having growth potential. The CXC study has assumed a growth in production (and therefore by-products) of 7.5% by 2030 and 20% by 2045. Draff and DDGS have the greatest energy potential per tonne, but also have value as animal feed. The largest potential by weight and total energy is pot ale, a by-product of the first distillation process with sold content of only 4%, most of which is disposed of as waste-water.

The main dairy by-product is Whey (the liquid remains of cheese making). The current total production of 500kt is primarily located in Dumfries and Galloway, where it is mainly used for animal feed. However, a small amount of the resource (25.5kt) in Argyll and Bute is used for anaerobic digestion. The available resource is not expected to change from the current level to 2045.

Animal processing by-products include fish, shellfish and abattoir wastes (primarily blood and bones, and some fat). By energy content, shellfish waste (undersized shellfish or parts not suitable for consumption) has the greatest potential (81.6% of the available resource) and is not considered to have any competing uses. Animal blood and bones comprises 14.8% of the available resource, the total resource is greater than shellfish waste but is primarily used for fertiliser or animal feed, leaving a smaller resource available for bioenergy. The available resource is not expected to change.

Sewage sludge arises from waste treatment plants, the availability of the resource is expected to increase in proportion to Scotland's population. An increase of 1.5% by 2030 and 2% by 2045. Some sewage sludge is dried for direct combustion and a larger amount already sent for AD, amounting to around 350kt. The available resource is estimated to be 4 times the currently utilised resource. These are naturally concentrated in areas of high population concentration.

Farm slurries constitute the largest non-solid biomass resource, by weight and total energy, it is also largely underutilised. These arise from dairy, beef and pig farms which may present difficulties for economic use as the resource is dispersed. The study has assumed that 75% of the resource may be available to bioenergy. The size of the resource is not expected to change from the present day to 2045.

Used cooking oil (UCO) and tallow are assumed to be used to produce biodiesel in Table 19. In comparison to other non-solid biomasses, the energy potential is out of proportion to the total mass due to their relatively high energy densities (10.1 and 9.1 MWh/t, respectively). UCO arises from catering premises, food factories and households. As with sewage sludge, the scale of the resource is expected to increase in proportion to Scotland's population (increasing by 1.5% by 2030 and 2% by 2045). 70% of UCO is assumed to be available for bioenergy, alternative uses include lubricants and manufacturing additives.

Tallow is a by-product of meat processing, produced by rendering fat. Tallow, in common with many animal products, is categorised for permissible uses. Category 3 tallow, suitable for use is soap and cosmetics, is a high value product and unlikely to be used for energy. Category 2 tallow can be used for industrial applications. Category 1 may only be used for burning or fuel production, production is estimated as 55 kt per year, of which two thirds is already used for bioenergy. The current size of the resource is not expected to change to 2045.

1.6 CO_2 TRANSPORTATION AND STORAGE (T&S)

The main methods of CO_2 transportation are via pipeline, shipping, rail or truck. Pipelines are favoured when transporting in large quantities (1–5 Mt) and over moderate distances (100–500 km), whilst shipping is better suited to longer journeys (>2,400 km). Shipping does have the advantage of being more flexible and scalable; however, it also requires well-developed hubs, terminals, and a pressurisation station to de-liquify compressed CO_2, all of which are expensive[52].

Haszeldine et al[35] estimated the cost of CCS implementation to be between £70-200/tCO_2 for capture and £20/tCO_2 for storage, which are expected to reduce by 50% by 2050 if deployed at scale (meaning capturing, transporting and storing CO_2 at capacities >400 ktCO_2/year)[22].

The deployment of all NETs is dependent on CO_2 T&S and hydrogen infrastructure. In Scotland, the Acorn site shows the most promise, which plans to repurpose the Feeder 10 gas pipeline to transport CO_2 from Peterhead port to St Fergus gas terminal at a capacity of 12 MtCO_2/year and be sequestered in the North Sea. The site plans to be operational until 2060[22]. In the instance that the Acorn site is not developed in time, the Scottish Government can utilise alternative CCUS clusters (e.g., East Coast Cluster) that aim to be in operation by the close of this decade. Table 20 shows a breakdown in typical CO_2 transport and storage costs.

Table 20: Breakdown in typical CO_2 transportation and storage costs

Category	Method	Cost (£/tCO_2) *
CO_2 Transport	Truck	11.8
	Train	6.8
	Onshore Pipeline	1.7 – 40.5
	Offshore Pipeline	3.4 – 48.5
	Shipping	10.1 – 18.6
Storage	Geological storage	9.3

**Values converted from USD to GBP using conversion of 1 USD = 0.83 GBP.*

Additional costs found from IEAGHG Paper[77]:

Table 21: Breakdown in typical CO_2 transportation and storage costs according to the IEAGHG

Category	Method	Capacity (MtCO_2/year)	Cost range (£/tCO_2)
CO_2 transport	Onshore pipeline	3	3.32 - 9.12
		10	1.66 - 3.32
		30	1.08 - 1.66
	Offshore pipeline	3	5.81 - 12.44
		10	2.49 - 4.15
		30	1.66 - 2.07
CO_2 Storage	Depleted Oil-Gas field onshore- reusing wells onshore	N/A	1.33 - 9.12
	Depleted Oil-Gas field no reusing wells onshore	N/A	1.33 - 13.02
	Saline formation	N/A	2.49 - 14.93

77 IEAGHG, 'CCS on Waste to Energy': New IEAGHG report: 2020-06 CCS on Waste to Energy - BLOG

Category	Method	Capacity ($MtCO_2$/year)	Cost range (£/tCO_2)
	onshore		
	Depleted Oil-gas field offshore- reusing wells offshore	N/A	2.49 - 11.61
	Depleted Oil-Gas field offshore- no reusing wells offshore	N/A	3.9 - 18.25
	Saline formation offshore	N/A	7.46 - 25.71

*Costs are in per 250km of pipeline constructed. All costs quoted above were converted to sterling using a conversion factor of USD to 0.83 pounds.

Revised costs used in the LCOC Analysis

Table 22: Transport costs used in the LCOC analysis

Transport Mode	Distance (km)	Cost ($/$tCO_2$)	Cost (£/tCO_2/km)
Truck	100	13	0.126
Rail	598	7.3	0.013
Pipe (onshore)	250	5.5	0.015
Pipe (offshore)	100	4	0.033
	500	18	0.029
	>1000	30	0.024
Shipping	100	20	0.163
	500	24	0.039
	>1000	27	0.022

Figure 1: Transport costs used in the LCOC analysis

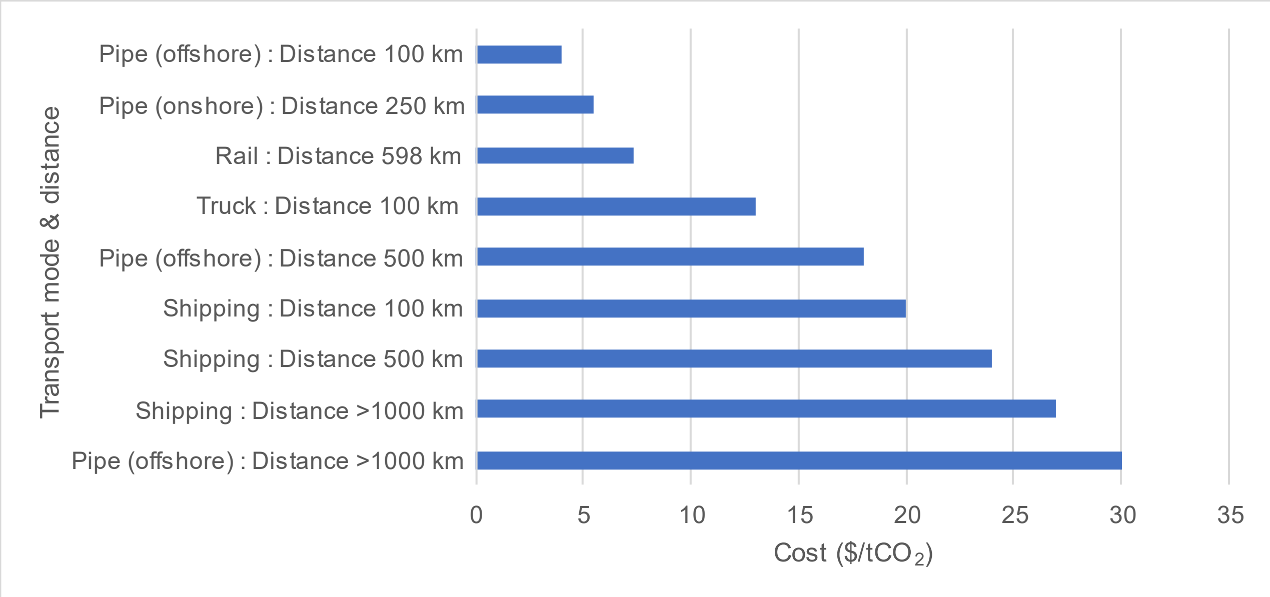
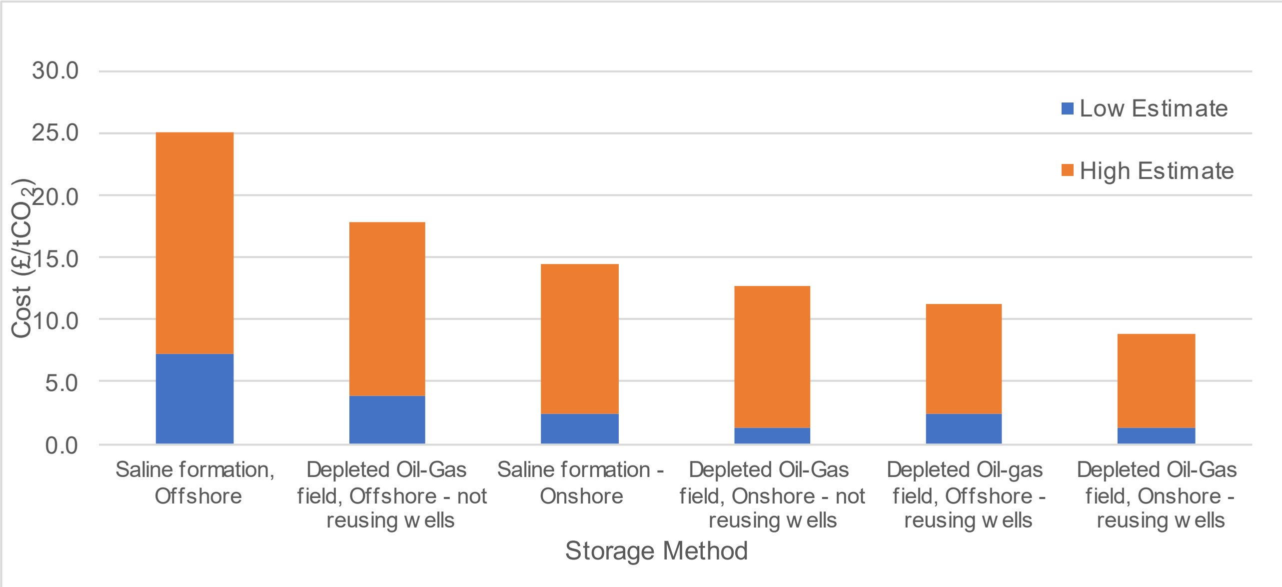


Table 23: Storage costs used in the LCOC analysis

Storage Method	Cost (£/tCO_2)	
	Low	High
Depleted Oil-Gas field onshore- reusing wells onshore	1.292256972	8.884266682
Depleted Oil-Gas field no reusing wells onshore	1.292256972	12.68027154
Saline formation onshore	2.422981822	14.53789093
Depleted Oil-gas field offshore- reusing wells offshore	2.422981822	11.3072485
Depleted Oil-Gas field offshore- no reusing wells offshore	3.796004855	17.76853336
Saline formation offshore	7.268945467	25.03747883

Figure 2: Storage costs used in the LCOC analysis



2. DETAILED SECTOR SPECIFIC TECHNOLOGIES

This section provides a detailed description of each of the NETs technologies, considering the final applications. These consist of BECCS power, BECCS energy from waste, BECCS hydrogen, BECCS biofuels, BECCS biomethane, BECCS industry, biochar and DACCS. These technological solutions are all outlined in the follow sub-sections. Common limitations and barriers to implementation are outlined in section 2.1.

2.1 COMMON LIMITATIONS AND BARRIERS

Although the deployment of NETs is accelerating, there are still a number of challenges and barriers that need to be faced. These can be broadly categorised into economic, technical, infrastructure, supply chain, environmental, social and regulatory barriers. There are several that are specific to NETs as a whole, which are detailed in this section, as well as technology-specific barriers that are discussed within the technology sub-sections.

CCUS has an important role to play in achieving negative emissions and ultimately Net Zero targets and is part of a globally accepted suite of technological solutions to combatting rising carbon dioxide emissions. Experts do not see CCUS as the approach that will solve the climate crisis alone, but as part of a portfolio of technologies that are needed to get to net-zero. CO_2 capture, transport, and storage are well-established and have been used for decades worldwide. However, the full CCS chain for purposes of achieving carbon reduction targets have only been fully demonstrated on large scale in a few places worldwide. This is because there are still a wide range of challenges and barriers which still need to be overcome as discussed below.

Several pilot programmes and projects for CCUS have emerged over the past ~20-25 years – with varying levels of success. Appendix 4 outlines existing CCUS projects (including pilot projects) in the UK. It does not however outline the various success (or lack-thereof) rates for these and other pilot projects or the barriers that have led many of these schemes to fail to capture the volumes of carbon that had been originally aimed for. A key criticism of CCUS is the fact that many of the projects proposed and planned over the years have been focused in storing the carbon dioxide in oil and gas fields for enhanced oil and enhanced gas recovery (EOR and EGR) thus leading to increased use of fossil fuels. In the last decade, however, many proposals for CO_2 utilisation have emerged including for sustainable aviation fuels (to replace fossil fuels) and in green cement, concrete curing and mineral carbonation where the carbon can remain permanently trapped. In EOR applications, it is essential that life cycle impacts including CO_2 leakage and additional consumption of oil and gas are taken into account in evaluating carbon savings. Many CCS projects propose to store the CO_2 in saline aquifers rather than in oil and gas fields (e.g., the Sleipner project in Norway which has been storing 1 Mt CO_2/year in saline aquifers in the North Sea since 1996)

A study by the Institute for Energy Economics and Financial Analysis (IEEFA) [78] in 2022 highlighted that the current global CCS industry is around 39 Mt CO_2/year (with no major NETs projects contributing to this at the time). A sample of 13 sites was analysed to learn lessons about the emerging CCS sector. The study showed that many of these CCS demonstrations failed or underperformed with successful CCUS projects existing mainly in the natural gas processing sector where CO_2 removal has been deployment for natural gas sweetening for many decades.

In the US, many planned CCS demonstrations failed due to factors affecting their economic viability such as market competition, uncertainty in the carbon market/tax incentives or high expected project costs. Many of the failed projects were based on integrated gasification combined cycle (IGCC) technology which was found to be very capital-intensive. A report by the United States Government Accountability Office[79] report calculated that the US Department of Energy had invested ~$1.1 Bn in eleven CCS demonstration projects (8 coal-CCS and 3 industrial CCS). Of the three industrial projects, two were completed and remain in operation.

In a paper by Wang et al[80], their model of 263 CCUS projects undertaken between 1995-2018 showed that the key cause for concern was that existing support mechanisms were not sufficient in mitigating the risks associated with CCUS project upscaling. One of the key findings was that larger plant sizes increase the risk

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[78] IEEFA study on applications and conceptualisations of CCUS: https://ieefa.org/resources/carbon-capture-crux-lessons-learned

[79] US Department of Energy had investment in CCUS demonstration projects: https://priceofoil.org/2022/01/13/us-government-wastes-1-billion-on-failed-ccs-projects/

[80] Wang et al (2021): "What went wrong? Learning from three decades of carbon capture, utilization and sequestration (CCUS) pilot and demonstration projects": https://www.sciencedirect.com/science/article/pii/S030142152100416X

of CCUS projects being terminated or put on hold, **with increasing a plant capacity by 1 Mt CO_2/year leading to a 45.5% increase in project hazard rate.**

Despite these failures, the evidence is clear that CCUS and NETs are needed if Net Zero targets are to be achieved. If CCUS and NETs are to become a reality in the future, lessons learned from the planning and operation of many CCUS projects should be considered. The following sections discuss challenges and barriers associated with CCUS deployment.

A 2022 Public policy project report[81] recommended that immediate plans for CCS especially including infrastructure must be delivered to support CO_2 pipeline transport and offshore geological storage infrastructure development for the Track 1 CCS clusters. It was stated that *"unless a reasonable return can be expected on investments, industry cannot be expected to commit to the construction and long-term operation of these facilities."*

2.1.1 Technical

The most cited barrier for NETs is the need to develop CO_2 transport and storage infrastructure; once developed there will be competition for storage. Storage capacity must be prioritised if NETs are to be successfully deployed at large scale in the short timeframes necessary. The high energy requirements of NETs are another common limitation, with oxy-combustion capture and DACCS being particularly energy intensive; oxy-combustion requires an Air Separation Unit (ASU) whilst DACCS must process dilute concentrations of CO_2 from the atmosphere. Pre-combustion capture has an advantage over post-combustion capture in that physical absorption instead of chemical absorption can be used for the capture process due to the higher pressures involved. As a result, pre-combustion capture is associated with lower energy penalties due to the lower energy needed for physical solvent regeneration. Similar to post-combustion capture, the cleaning of syngas from biomass gasification (e.g., SOx and NOx removal) is necessary to ensure optimal performance of the CO_2 capture process.

The timing of future BECCS and DACCS operation is limited to when CCS networks are deployed[3, 35]. This is a genuine concern for Scotland, since the Acorn CCS site has not been awarded Phase 1 or 2 cluster funding[18, 82], and there remains some uncertainty over its future. This uncertainty remains in place, whilst £20Bn of funding for CCUS was announced in the 2023 spring budget, there was no explicit reference to progressing with the Scottish Cluster[83].Competing uses of geological storage for CO_2 between various NETs technologies could limit technology scale up[84]. The timescales of innovating, developing, and deploying NETs are also lengthy, taking between 10 to 15 years[35]. This limits the deployment of NETs within this decade, meaning the negative emissions targets set out by the CCPu and CCC are realistically likely going to be missed. Finally, guaranteeing public acceptance for engineered NETs is an unexpected barrier, with an approval rating of 42% only being achieved for BECCS and DACCS, due to the perception that higher CO_2 leakage risks are exhibited compared to nature-based solutions[66].

2.1.2 Economic

Economic barriers to NETs exist due to the high capital cost associated with upfront investment. Additionally, several NETs technologies possess high operating costs. This is most prevalent for DACCS, which requires the construction of large capture units to process and extract the dilute concentrations of CO_2 in the air (~400 ppm) and consumes significant heat and power. The large energy penalty associated with solvent regeneration in post combustion capture is another example of high Variable OPEX costs.

According to stakeholders, a key barrier to GGR deployment is financial[59]. They see a clear lack of an established market or customer demand for engineered removals, a lack of policy incentives to make the high capital and operational costs of GGRs attractive, and a lack of a stable revenue streams for the provision of negative emissions.

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[81] Public Policy Projects report on CCUS infrastructure: https://web.archive.org/web/20221123112225/https://publicpolicyprojects.com/wp-content/uploads/sites/6/2022/11/PPP-Carbon-Capture-Report.pdf

[82] BEIS (2022), 'Cluster sequencing Phase-2: shortlisted projects (power CCUS, hydrogen and ICC), August 2022': Cluster sequencing Phase-2: shortlisted projects (power CCUS, hydrogen and ICC), August 2022 - GOV.UK (www.gov.uk)

[83] UK Government Spring Budget 2023: https://www.gov.uk/government/publications/spring-budget-2023/spring-budget-2023-html

[84] Terlouw et al (2022), 'Life Cycle Assessment of Direct Air Carbon Capture and Storage with Low-Carbon Energy Sources': Life Cycle Assessment of Direct Air Carbon Capture and Storage with Low-Carbon Energy Sources | Environmental Science & Technology (acs.org)

2.1.3 Policy and Regulatory

Currently the costs of NETs are prohibitively high, resulting in economic barriers to their widescale deployment. The UK Government are proactively considering the most appropriate support to limit such barriers; however, support has been limited to date. Therefore, further financial incentives are necessary in order to provide stakeholders with greater long-term clarity and revenue certainty.

Additionally, the requirement to have effective monitoring, reporting and verification (MRV) standards in place is another key challenge. Most notably, to be classed as negative emissions, the total quantity of CO_2 permanently removed and stored must be greater than the total quantity of CO_2 emitted to the atmosphere. These rules and methodologies will be different depending on the choice of NET. The implementation of robust procedures to account for permanence of storage of CO_2 is also necessary.

Analysis undertaken by the UK Climate Assembly shows the public to be highly in favour of nature-based GGRs (only 4% disagree or strongly disagree with implementing nature-based solutions), whilst engineered NETs are much less favourable (42% approval rate). This is due to a perceived CO_2 leakage risk compared to nature-based solutions. This lack of public acceptance will be a barrier for engineered NETs, which can be combated if the Government introduces NETs at a small scale and sequentially builds up capacity over time[66].

The high resource requirements, lack of CO_2 T&S infrastructure, and lack of policy incentives for GGRs are some of the main constraints towards deployment[59, 62]. Most notably, without a price or reward for negative emissions, GGR deployment may not be financially viable for the private sector[59].

Our pathway analysis aims to provide some site-based calculations to support potential negative emission credit calculations. This will work from an economic payback point of view and using the estimated CAPEX and OPEX for the NETs solutions to determine what economic value on the captured carbon could have at a site in order to achieve a specific payback period. This analysis is meant as a guide and will be based only on the available literature on CAPEX and OPEX (specific to a given sector where CCS is applied) to determine a levelised cost (£/tCO_2). The costs for transport and storage of the CO_2 will also be included in the levelised cost calculation. Further details of this methodology will be described in the Final Report. The high project costs[79] of some CCUS projects in the past has been a key reason for their failure, meaning that there is a risk that this analysis uses CAPEX costs that are lower than potential real-life project costs (providing low carbon prices (or low paybacks if the analysis was done in reverse)

2.1.4 Environmental

A major environmental challenge relates to the changes in land use to accommodate the large amounts of feedstock required for BECCS and biochar, which may result in species loss and reduced biodiversity. Furthermore, land use changes may affect the price of agricultural commodities, such as food, which will negatively impact the poorest households. The high-water requirements of BECCS, related to the production and processing of the biomass fuel, may also negatively impact wildlife and raise water prices.

Our pathway analysis will evaluate the overall costs associated with a given pathway as well as the carbon savings and NETs potential. As part of the discussion, potential life cycle impacts arising from the full CCS chain (capture, transport and storage), associated externalities and risks will also be discussed qualitatively for the various pathways.

2.1.5 Social

Public perception is an important aspect to ensure the successful wide-scale deployment of NETs; however, the unfamiliar nature of novel technologies may pose as a risk to gaining public support. To date, prior studies have shown that public acceptance varies across different NETs, with nature-based solutions having higher acceptance rates and engineering NETs being seen as a risk.

A study on the perception of BECCS was recently undertaken in the UK, where a large majority (79%) of participants stated that prior to the experiment they knew little to nothing about BECCS. It was also concluded that after learning about BECCS, there were no participants who were strongly opposed to it, with more overall support shown. The unfamiliar nature of GGRs may cause apprehension to its wide scale deployment [85].

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[85] Perceptions of bioenergy with carbon capture and storage in different policy scenarios, https://www.nature.com/articles/s41467-019-08592-5

Bioenergy feedstock is typically of lignocellulosic nature, for example wood and agricultural residues, which are unlikely to compete with food supply; however, they may cause issues relating to land-use change. Energy crops on the other hand, have already caused serious socio-economic problems in several countries, in particular over land tenure and loss of ecosystem services. There are also societal concerns relating to land-use change, especially in cases where energy crops are grown on agricultural land or existing woodland is used for biomass supply. A study released by Traverse stated that participants felt uncomfortable about the burning of trees for use in BECCS, essentially finding BECCS complex and difficult to assess. However, participants found the concept of DACCS easier to evaluate, despite expressing concerns regarding its proven effectiveness at scale[86].

2.1.6 Supply chain

The increased demand for negative emissions will result in an increase in the demand for carbon capture equipment. It can therefore be expected that the number of suppliers will need to increase to meet this demand in order to avoid significant supply chain barriers. In recent years, the number of companies offering carbon capture solutions is rapidly increasing, with major companies including Aker Carbon Capture, Climeworks, Carbon Engineering, Carbix, Carbon Clean, amongst others.

America and Canada appear to be leading the way with number of companies providing carbon capture equipment, as illustrated by Carbon Engineering, LanzaTech and Svante. Whilst in Europe, countries such as Norway, Denmark, Switzerland, and the Netherlands are dominating, with companies including Aker Carbon capture, Climeworks, and CO_2 Capsol[87].

At present, there is lack of a carbon capture equipment supply chain within the UK, as there are a limited number of companies locally manufacturing such equipment. Carbon Clean Solutions is a notable company headquartered in the UK providing modular DAC systems, however, it is unclear whether their equipment is manufactured in the UK. Other noteworthy companies in the UK include Carbogenics and Carbon Infinity, both start-ups that have developed biochar and DAC technologies, respectively[88].

Another significant supply chain limitation is the lack of skills within this industry, resulting in an inability to develop the market in line with the demand. Typical industry skill-sets will be similar to those found in the oil & gas industries, where direct and indirect employment in the industry has dropped from 260,000 in 2019 to 213,000 in 2022[89]. This compounded with the lack of suppliers, creates consequential barriers for deployment.

Finally, there are also issues around the supply chain for CO_2 storage, including lack of suitable fabrication yards in Scotland/ the UK, and competition for skilled workers with other major projects that are likely to happen at the same time as CCS deployment, such as offshore wind, oil and gas decommissioning and hydrogen transport and storage.

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[86] Carbon Capture Usage and Storage: Public Dialogue, 2021, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1005434/ccus-public-perceptions-traverse-report.pdf

[87] Carbon Herald," The Top 10 Carbon Capture Companies in 2022", https://carbonherald.com/top-10-carbon-capture-companies/

[88] ClimAccelerator, "Five European start-ups selected to scale carbon removal innovations", https://climaccelerator.climate-kic.org/news/5-european-start-ups-selected-to-scale-carbon-removal-innovations/

[89] Statisticss and economic data on Oil & Gas in the UK: https://www.ukeiti.org/oil-gas

2.2 BECCS POWER

2.2.1 Overview of technology

2.2.1.1 TRL

The TRL of BECCS power varies depending on the specific pathway, where biomass combustion with post-combustion CO_2 capture has the highest TRL, at TRL 8-9. Oxyfuel capture via the steam-based Rankine cycle has a TRL of 7, as this has been developed at pilot scale however is not yet commercially available[46]. Pre-combustion capture with gasification is at TRL 3[90].

2.2.1.2 Costs

The costs of BECCS power will vary depending on the specific technologies used. Table 24 provides an overview of costs, estimated in a 2020 study[46], as well as providing key assumptions on the operational parameters of the plants related to the final costs.

Table 24. Costs of different BECCS power technology types

Technology type	**Gross plant capacity, MWe**	**NETs plant capacity, MWe**	**Capital cost, £/kW**		**Operating cost (fixed), £/kW**	**LCOE, £/MWh**	**CO_2 avoided, £/tCO_2**
			Plant and CCS	CCS			
Post-combustion	498	396	2,793	698*	146	181	410 - 720
Oxy-fuel combustion	598	402	3,209	N/A	164	189	420 - 730
Pre-combustion IGCC	493	356	3,664	N/A	198	204	440 - 805

*A CCS investment cost of 25% was taken from the IEAGHG report[91]

2.2.1.3 Inputs / outputs

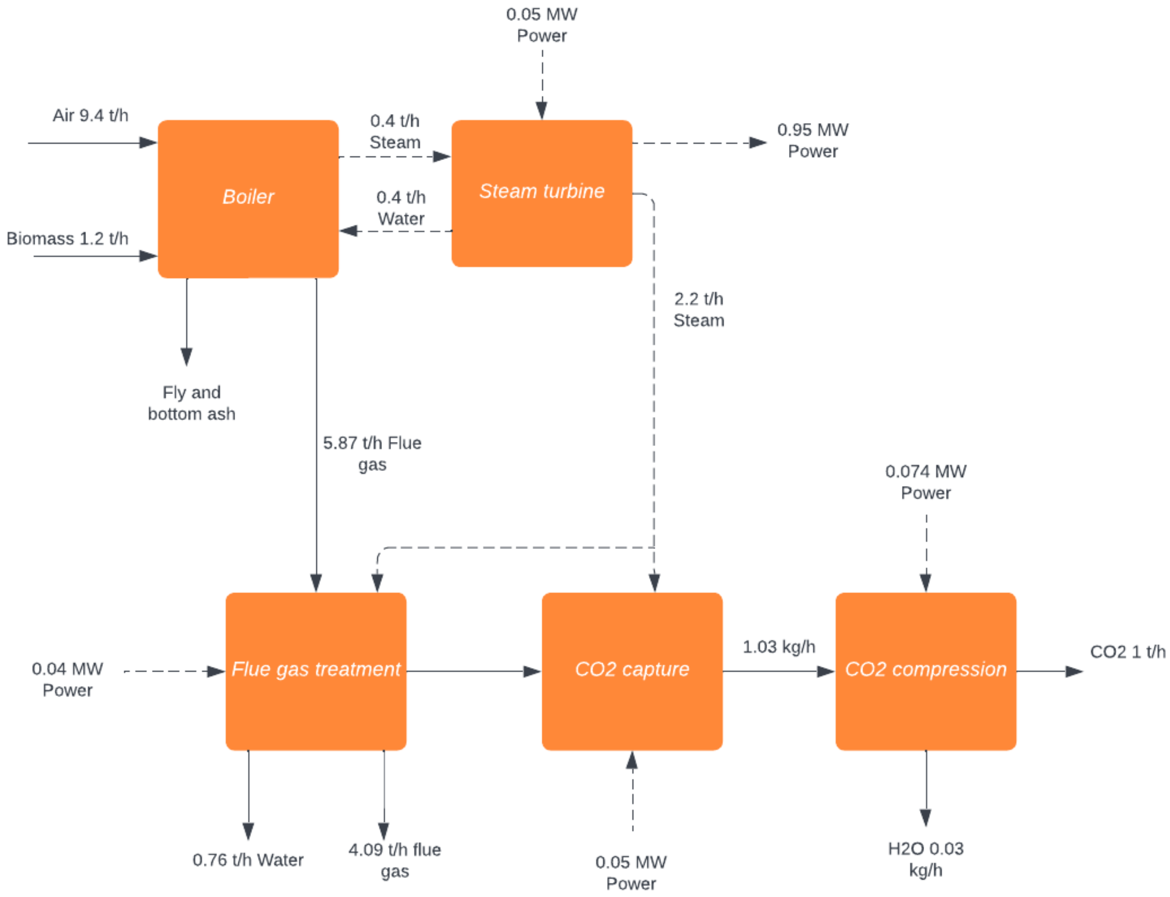
A wide range of feedstocks can be used for BECCS power applications. The most common feedstocks include sugar/starch crops, forestry products, by-products and residues and energy crops. Energy crops include woody crops such as short rotation coppice, and grassy energy crops such as miscanthus. These feedstocks can all be converted via combustion or gasification, the two conversion processes utilised in BECCS power applications. The outputs consist of electricity and sometimes heat, as well as the CO_2 that is captured.

2.2.1.4 Schematics

Data for all three schematics below was taken from the Wood BECCS report[45]. The schematic for the post-combustion capture typology is shown in Figure 3, Oxyfuel combustion and pre-combustion capture are shown in Appendix 11.

[90] Bioenergy with carbon capture and storage, Technology deep dive, IEA, 2022
[91] IEAGHG, 'Biomass CCS Study': Microsoft Word - 00_General Index - Rev.2.doc (ieaghg.org)

Figure 3: BECCS post combustion capture



The above schematic shows that to capture and store one tonne of CO_2 using BECCS post-combustion capture, 1.2t of woody biomass is needed to be fed to the boiler(s) alongside a power input of 0.214 MW. These power demands can be met through a steam turbine located onsite, which converts 0.4t steam exiting the boiler(s) to 0.95MW of power.

2.2.2 Potential Carbon impact

As shown in the above schematic, and schematics shown in Appendix 8, the carbon capture potential of BECCS Power varies between 0.83-1.59 tCO_2/t biomass. This does not account for lifecycle emissions associated with upstream processing and transportation of biomass, which are discussed in more depth below.

For the pathways modelling, performance data for a reference BECCS Power plant is needed to calculate the CO_2 capture potential in Scotland. For the electrical efficiency, a value of 34.9% has been assumed based on performance data from Steven's Croft biomass power station[92], with an assumed CO_2 capture rate of 90% (see Section 1.2.1 for further detail). The utilisation factor of the power plant is taken to be 90%, based on work by SCCS[92] and Pour et al[70], and the biogenic content of the captured CO_2 is assumed to be 100%. Finally, the CO_2 emission factor for the biomass fuel is taken to be 0.35 $kgCO_2$/kWh or 1433.89 $kgCO_2$/t, based on an average for wood logs, chip, pellets, and grass/straw taken from the BEIS conversion factors database[93].

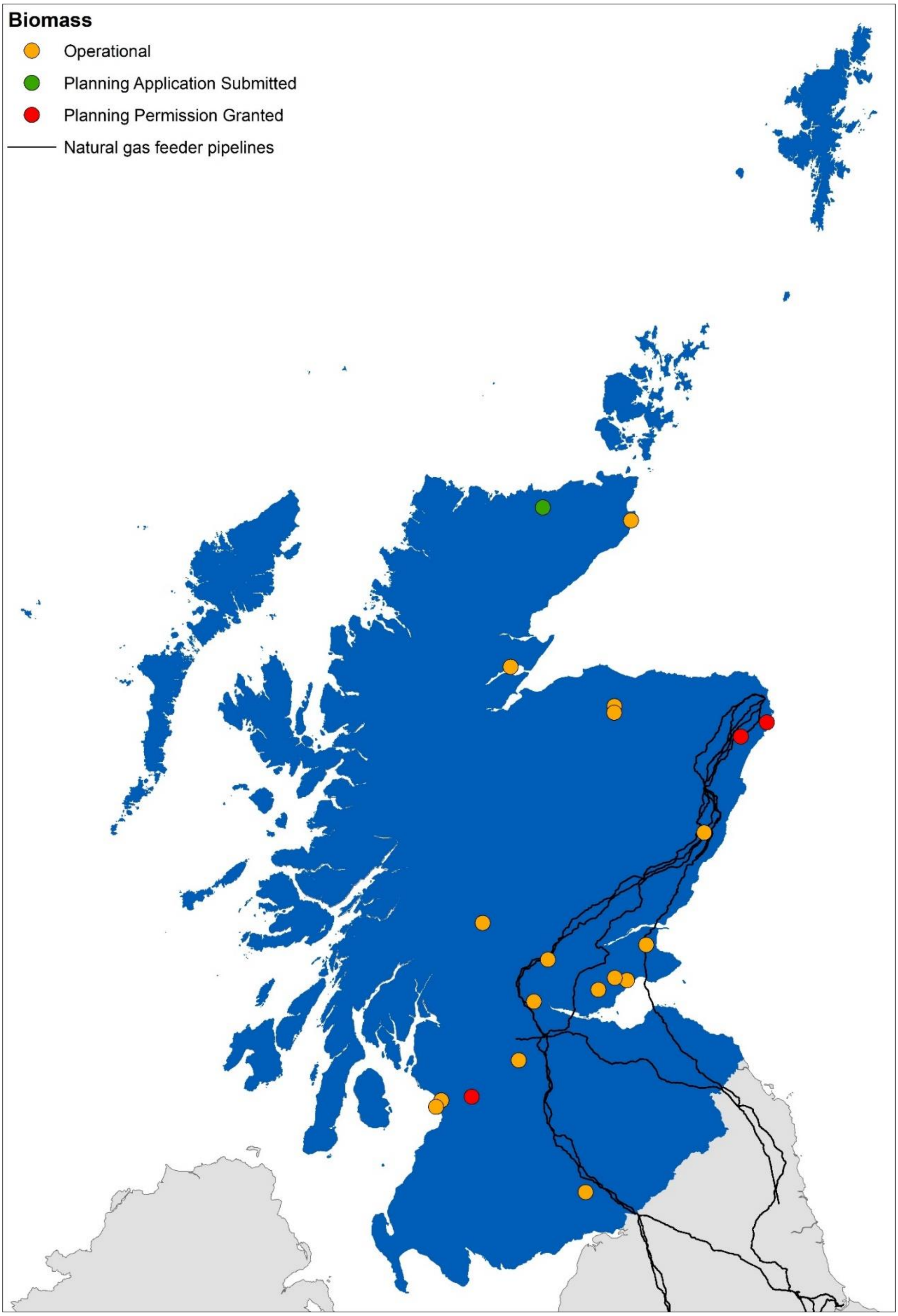
[92] Scottish Carbon Capture & Storage (SCCS), 'Negative Emission Technology in Scotland: carbon capture and storage for biogenic CO_2 emissions'

[93] DESNZ and BEIS, 'Greenhouse gas reporting: conversion factors 2022': Greenhouse gas reporting: conversion factors 2022 - GOV.UK (www.gov.uk)

2.2.3 Potential locations in Scotland (map)

Data from the October 2022 Renewable Energy Planning Database (REPD) was filtered through, and relevant projects categorised into different NETs applications. A GIS map was then constructed. The development status was also taken note of, which fell under already operational, awaiting construction, planning permission granted, and planning permission submitted. In this instance, biomass power and biomass used in industry (section 2.4) are included in Figure 4.

Figure 4: Map of biomass fuelled Power and Industry plant locations, that may be suitable for BECCS



With regards to biomass sites that could be future candidates for a BECCS Power site there are 16 projects in total. The majority are located around Grangemouth, Fife, Angus and Aberdeenshire which could in theory utilise existing gas pipeline infrastructure to transport captured CO_2 to Peterhead if they were to be upgraded accordingly. The remaining projects are in the south, near Dumfries and Ayr (3 projects), and the north (4 projects), which would have to rely on truck and rail transportation to CCS hubs to store captured CO_2, if not utilised.

For the existing sites which can be retrofitted with CCS, a capture potential of 1.24 $MtCO_2$/year is possible at an investment and operational cost of £30M and £6M/year respectively. Once the proposed new-built sites are also considered, the total capture potential reaches 3.1 $MtCO_2$/year at a CAPEX and OPEX of £593.8M and £35.7M/year. Compared to Element Energy's analysis (0.944 $MtCO_2$/year)[22], our estimates appear to be more optimistic.

Further analysis by Haszeldine et al[35] estimates that BECCS potential within Scotland could reach 5.7 - 23 Mt CO_2/year. Any potential future BECCS plant would require dedicated bioresource supplies, particularly those that are spatially dense, high yield, and observe a high biomass tonnage ratio. The location of any potential future large-scale BECCS sites will need to consider and the proximity of the site to the available bioresources due to the high demand this would place on the resource, and the proximity to transport switching locations such as the rail terminals and ports. Ideal locations for future BECCS sites would be either adjacent to the feeder 10 pipeline for transportation to permanent storage, or adjacency to the Acorn facility in Peterhead.

2.2.4 Technology specific limitations & barriers

2.2.4.1 Technical

Several technological barriers exist across each of the different BECCS power generation options, however efforts are underway to further develop the technologies, hence increasing scale and reducing costs. For solvent-based post-combustion capture systems, which are the most advanced post-combustion capture technologies, the largest challenge relates to the high energy penalty associated with solvent regeneration. The approach usually consists of diverting steam from the power generation process to be utilised for solvent regeneration, hence the addition of the carbon capture unit will reduce the total electricity generated on site that can be exported. Capture of CO_2 through post-combustion capture from flue gases poses additional challenges due to the low concentration of CO_2 in the flue gas stream, at around 3-4%.

For oxy-combustion capture, the largest challenge arises from the high-power requirement of operating an Air Separation Unit (ASU), which is utilised to produce a pure stream of oxygen utilised for combustion. However, the energy penalty for oxy-combustion capture systems is much less than for post-combustion capture, as the CO_2 in the flue gas stream is at a significantly higher concentration, due to the absence of nitrogen during biomass combustion.

There are also significant challenges with pre-combustion capture systems associated with BECCS power. The predominant challenge relates to the required cleaning of syngas from biomass gasification on a large scale, as most gas cleaning methods are not substantially efficient on a large scale.

2.2.4.2 Economic

As previously outlined, the large energy penalty of solvent-based post-combustion capture systems reduces the total electricity that can be exported. Operation of the carbon capture unit therefore has high operating costs and reduced the revenue that can be obtained through sales of electricity. The capital costs of CO_2 systems are also high, hence reducing the attractiveness of the technology.

2.2.4.3 Infrastructure

As with all BECCS applications, the successful storage of the captured CO_2 is intrinsically linked to the availability of CO_2 transport and storage infrastructure. Analysis by Pour et al[70] highlights that locating a BECCS plant near a Biomass Hub over a CO_2 Storage Hub will lead to cheaper costs but at the price of higher carbon emissions.

2.2.4.4 Environmental

A major environmental challenge relates to the possibility of changes in land use to accommodate the large amounts of feedstock required as input to a BECCS plant. As well as increasing the potential for species loss and reduced biodiversity, land use change may directly affect the price of agricultural commodities, including food, due to increased demand for land.

Operation of a BECCS plant also results in adverse effects due to increased freshwater consumption, related to producing and processing the biomass fuel[94]. Increased water demand also has the potential to increase the price of water.

2.3 BECCS ENERGY FROM WASTE

2.3.1 Overview of technology

2.3.1.1 TRL

Post-combustion carbon capture technology is the most conducive for effective CO_2 capture from EfW facilities, and as such has a TRL of 7, according to Element Energy[22]. A TRL of 7 indicates that there are operational prototypes or planned operational systems, requiring demonstration in an actual operational environment. This technology is mature and has been successfully deployed for many years, however, it has yet to be integrated within a commercial scale EfW facility in the UK.

2.3.1.2 Inputs / outputs

Inputs

Municipal solid waste (MSW) as well as commercial or industrial waste is typically utilised at EfW plants. Waste can be classified as either biogenic or non-biogenic material; biogenic being biological in nature, such as wood, food, or paper. Non-biogenic materials are those which have fossil fuel origins, for example plastics and synthetics. Exact composition of MSW is unknown as there is yet to be a detailed study undertaken in the UK, furthermore, the composition and proportions of biogenic/non-biogenic material vary over time and with location. This variation is due to consumption habits, waste management practices, and waste policies[95]. However, it can be stated that in developed countries biogenic materials make up approximately 40-60% of waste utilised in EfW facilities[96]. This relatively significant proportion of biogenic materials means that CCS implemented on EfW sites can be classified as BECCS, as negative emissions can be achieved.

Outputs

The outputs produced varies depending on the configuration of the EfW facility. For thermal treatment facilities where the waste is incinerated, along with heat, bottom ash and combustion gases are produced. The bottom ash is a heterogeneous material comprised of concrete, glass, ceramics, brick etc., and has long been regarded as a waste product. However, incinerator bottom ash can be used as aggregate once processed to remove any contaminants. The aggregate is predominately used in construction, namely as a sub-base for roads or car parks, or it can be bound with cement[97]. This practice is widely accepted and frequently carried out in the UK and Europe. By utilising incinerator bottom ash in construction, it has the potential to displace the use of raw materials, thus contributing to a more circular economy.

Heat produced from the combustion of waste is used to generate electricity, however, the remaining heat, i.e., steam, is rejected to the atmosphere, which not only significantly reduces the efficiency of the plant but also wastes useful heat. For combined heat and power (CHP) EfW facilities, this low-grade steam is extracted from the steam turbine to produce hot water that is subsequently distributed via insulated pipework to provide heat to buildings. By employing CHP at EfW plants instead of recovering only electricity, the overall efficiency increases to over 70%.

The main products of pyrolysis include biochar, pyrolysis oil, and syngas; syngas being the desired product as it can be further converted into a range of energy products, including electricity as well as gaseous or liquid high-quality fuels, which can be used as transport fuels. Pyrolysis oil has the potential to be utilised for combustion in CHP systems or further refined into diesel oil, although this is not common practice[98].

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[94] The life cycle environmental impacts of negative emissions technologies in North America, Cooper et al, 2022

[95] The climate change impacts of burning municipal waste in Scotland - Technical Report, 2021, Zero Waste Scotland, Accessed at: mf-a-fhszvb-1678196543d (zerowastescotland.org.uk)

[96] Material and Energy Valorisation of Waste in a Circular Economy, 2022, IEA Bioenergy, Accessed at https://www.ieabioenergy.com/wp-content/uploads/2022/05/T36_Waste_Circuar_Economy_final_report.pdf

[97] Incinerator Bottom Ash, Day Group Ltd, Accessed at: https://www.daygroup.co.uk/our-group/recycling/incinerator-bottom-ash/

[98] Zaman et al (2017), "Pyrolysis: A Sustainable Way to Generate Energy from Waste", Accessed at: https://www.intechopen.com/chapters/56034

Both pyrolysis and gasification processes create biochar, which is a solid residue rich in carbon that is the direct product of thermal decomposition of biomass. Further information about biochar can be found in section 2.8.

2.3.1.3 Costs

A breakdown in CAPEX for two operating EfW plants with CCS installed is detailed in Table 25 below. These plants are based in the Netherlands, utilise post-combustion capture via MEA solvent, and provide considerable heat and power to local residents and businesses[77]. Further analysis by Element Energy indicates that EfW-CCS levelised costs range between £60-£140/tCO_2[22].

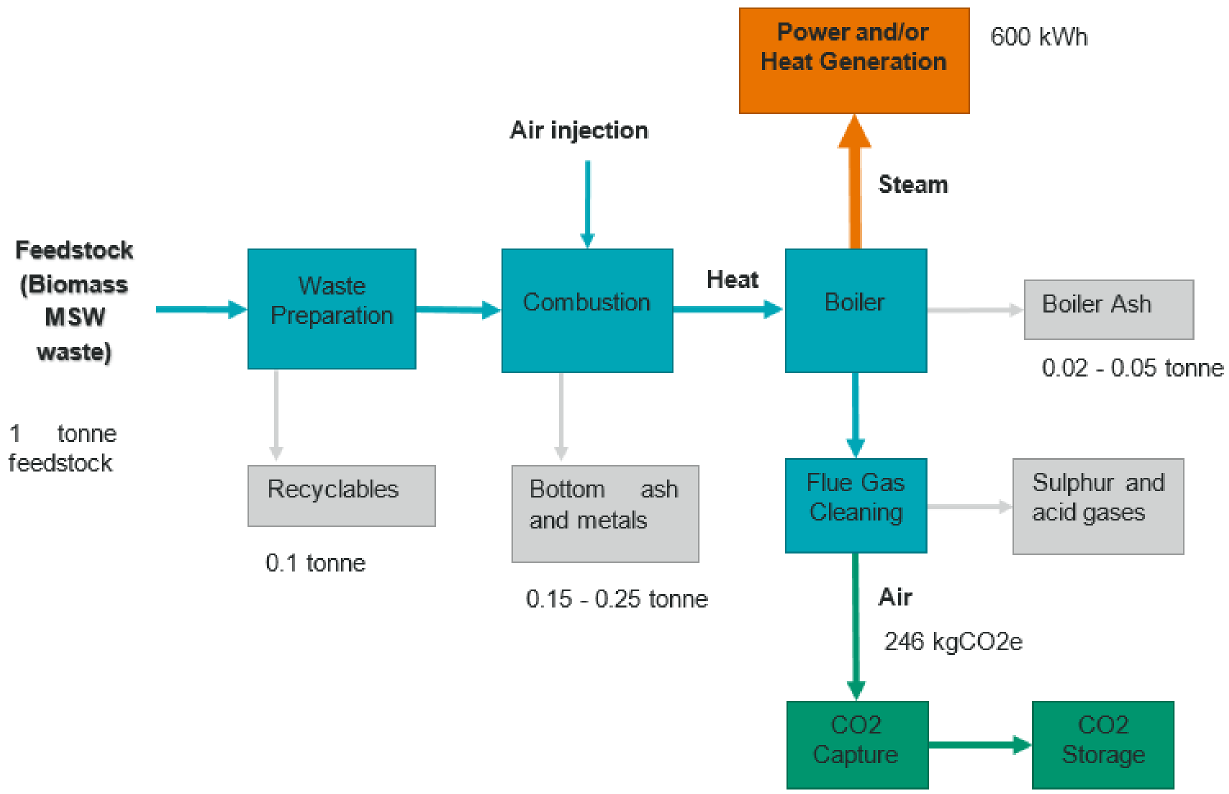
Table 25: Breakdown in CAPEX for two EfW-CCS combustion plants in the Netherlands[77]

Plant	Total waste (t/year)	Power (MWh_e)	CO_2 captured (tCO_2/year)	Investment costs*(M£)		CAPEX	
				EfW plant	CCS installation	EfW plant (£/t,waste)	CCS installation (£/tCO_2)
AEB Amsterdam	1,284,164	888,000	450000	403.19	107.52	314	240
AVR-Duiven	360,635	147,000	50000-60000	N/A	17.92	N/A	299.7-360

* Using a conversion factor of euros to 0.9 pounds sterling[99]

2.3.1.4 Schematics

Figure 5: Post Combustion Carbon Capture from EfW incineration[100]



[99] Xe, 'Xe Currency Converter': 1 EUR to GBP - Euros to British Pounds Exchange Rate (xe.com)

[100] Gary C. Young, "Municiple Solid Waste to Enery Conversion Process, Economic, Technical and Renewable Comparisons", Accessed at http://energy.cleartheair.org.hk/wp-content/uploads/2012/01/Municipal-Solid-Waste-to-Energy-Conversion-Processes-Economic-Technical-And-Renewable-Comparisons-0470539674-Wiley-1.pdf

2.3.2 Potential Carbon impact

The EfW industry are a significant component of industrial emissions in the UK, emitting approximately 11 Mt CO_2/year CO_2; this value is almost 3% of total UK emissions[95]. In Scotland, the average carbon intensity of EfW plants operating in 2018 was 509 gCO_2/kWh, which was notably higher than the carbon intensity of the marginal electricity grid in the UK during the same year (270 gCO_2/kWh). Incinerator facilities that export electricity only have the highest carbon intensity due to their inefficiency, whilst CHP and heat only EfW facilities have particularly lower values[95]. By upgrading electricity-only EfW facilities (which are the majority in Scotland) to CHP, this not only reduces their carbon intensity by approximately 200 gCO_2/kWh, but it also allows for a more effective deployment of retrofit carbon capture technologies.

The potential carbon impact is dependent on the future capacity and hence number of EfW facilities that are suitable for retrofitting CCS. Furthermore, the composition, particularly the fossil content, of the MSW plays a significant role. Nevertheless, the installation of carbon capture technology reduces the emissions intensity of the electricity exported to Net Zero. Additionally, approximately 1.06-1.14 tCO_2 are avoided per tCO_2 gross removed; however this is very dependent on the biogenic fraction of waste[101].

For the pathways modelling, performance data for a reference EfW-CCS plant is needed to calculate the CO_2 capture potential in Scotland. For the electrical efficiency, a value of 23.8% has been assumed based on benchmark data provided by the IEAGHG[77], with an assumed CO_2 capture rate of 90% (see Section 1.2.1 for further detail). The utilisation factor of the power plant is taken to be 92%, based on performance data from Runcorn EfW and Riverside Resource Recovery Facility, and the biogenic content of the captured CO_2 is assumed to be 50.3%[77]. Finally, the CO_2 emission factor for the waste is taken to be 0.10005 $kgCO_2$/MJ or 0.36018 $kgCO_2$/kWh[77].

Global Warming Potential (GWP) Emissions

Analysis by Pour et al[70] indicates that EfW via MSW-CCS exhibits a negative emission potential -0.89 tCO_2/MWh and a GWP of -1.48 $kgCO_2$/kWh[70].

2.3.3 Potential locations in Scotland (map)

Similar to BECCS Power, the GIS Mapping for energy from waste in Scotland was taken from the REPD (see Section 2.2.3 for more detail). At present the mapping is split into two separate categories: EfW and Advanced Conversion Technologies (ACT). The EfW map considers incineration facilities only, whilst ACT considers waste gasification sites.

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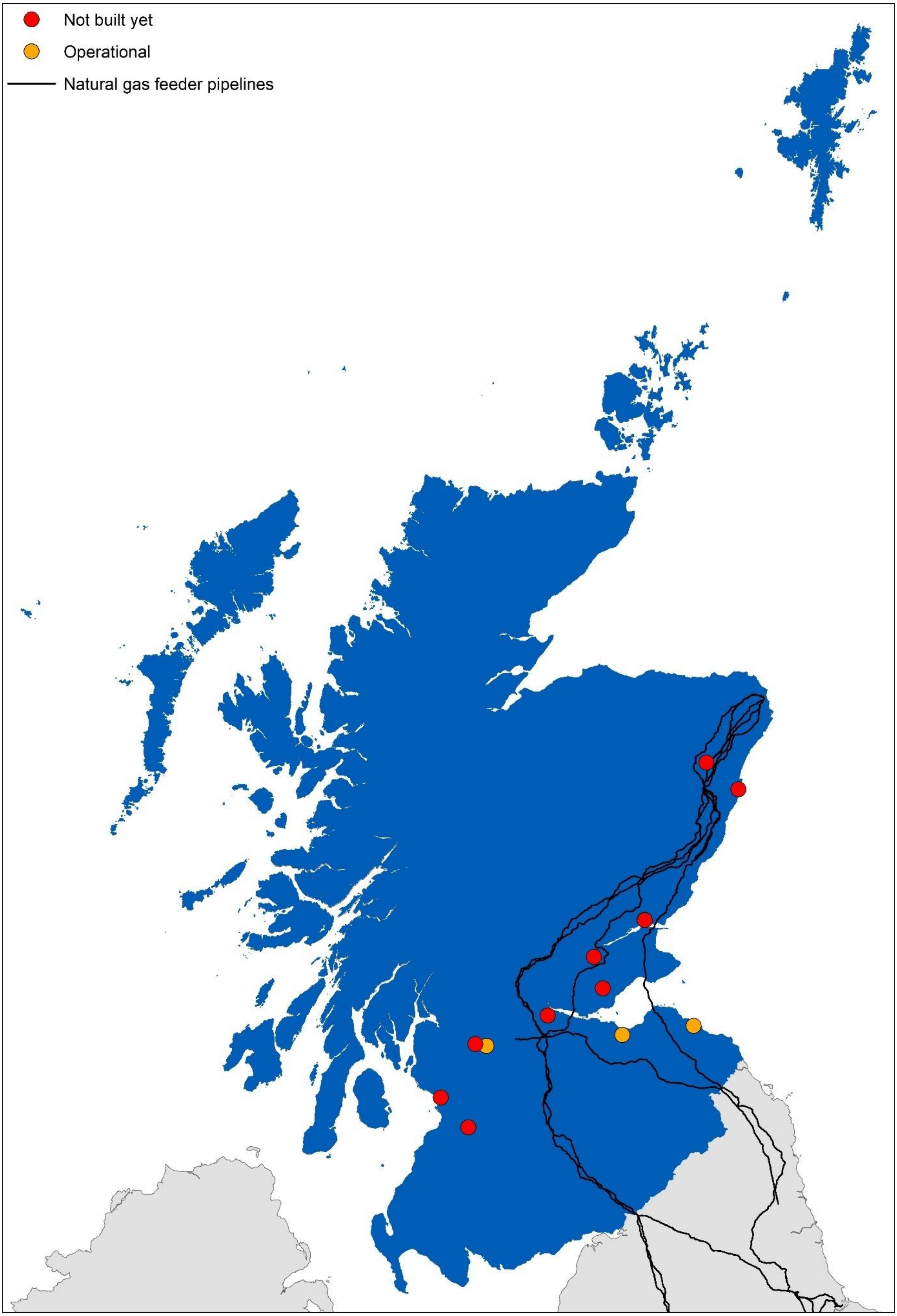
[101] Greenhouse gas removal methods and their potential UK deployment, Element Energy, Accessed at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1026988/ggr-methods-potential-deployment.pdf

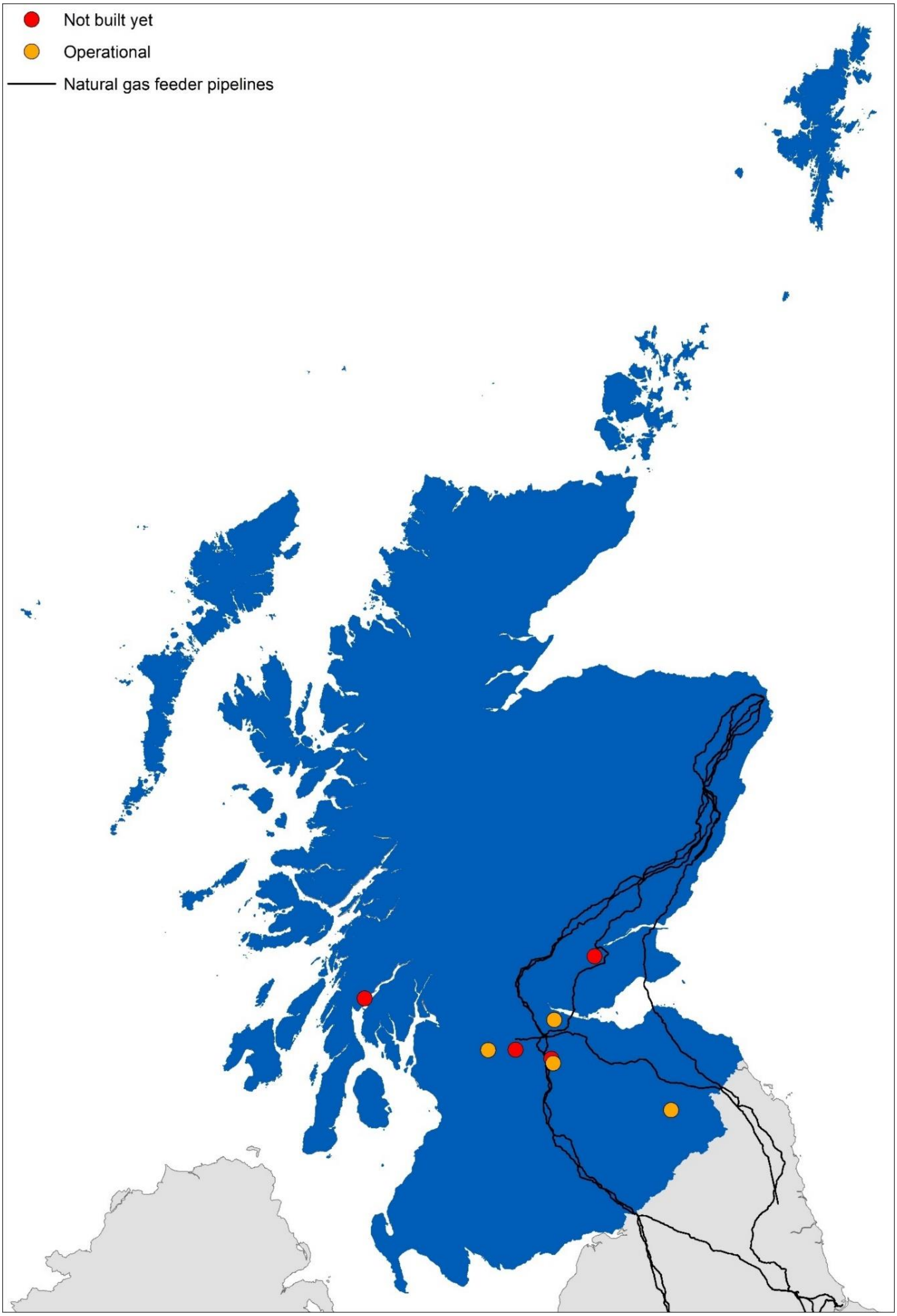
Figure 6: GIS Map of Energy from Waste plants in Scotland



With regards to EfW there are 13 projects in total. Similar to BECCS Power, the majority are located around the central belt and eastern Scotland; sites on the east side of the country could in theory utilise existing gas pipeline infrastructure to transport captured CO_2 to Peterhead if they are upgraded accordingly. The remaining projects are in the south-west (2 projects), which will have to rely on truck and rail transportation to CCS hubs to store captured CO_2.

For the existing sites which can be retrofitted with CCS, and provide 374 GWh/year of electricity, a capture potential of 0.51 $MtCO_2$/year is possible at an investment cost of £63.9M. Once the proposed new-built sites are also considered, the total electricity generation reaches 1628 GWh/year at a capture potential of 2 $MtCO_2$/year, costing £408.8M in CAPEX. These values are similar to the literature, with Element Energy estimating present day EfW-CCS potential of circa 1 $MtCO_2$/year[22].

Figure 7: GIS map of Advanced Conversion Technologies (ACT)



With regards to ACT there are 8 projects in total. They are predominantly located around the central belt and Fife which could in theory utilise existing gas pipeline infrastructure to transport captured CO_2 to Peterhead if they are upgraded accordingly. Of the remaining projects, one is located on the west coast, and is likely to be unpractical to transport any stored CO_2 from this site by road; the other is in the Scottish Borders. BECCS EfW plants require a sustained supply of waste, hence they are best located near both population centres and CO_2 T&S infrastructures, which may not always be an option.

For the existing sites which can be retrofitted with CCS and capture 0.65 $MtCO_2$/year at an investment cost of £173.6M. Once the proposed new-built sites are also considered, the total capture potential reaches 1.68 $MtCO_2$/year, costing £1.8B in CAPEX.

2.3.4 Technology specific limitations & barriers

A barrier to the deployment of CCS to EfW facilities in Scotland is the Scottish biodegradable municipal waste ban that is due to come into effect in 2025, including the effective ban on new incinerators. Both bans were implemented as part of Scotland's Zero Waste Strategy, meaning that a larger proportion of waste will be diverted away from incineration facilities in favour of recycling or alternate pathways, directly affecting the quantity of feedstock available for EfW plants. Moreover, policies to divert biogenic waste to other routes such as biomass combustion or anaerobic digestion may significantly reduce the percentage of feedstock of biogenic origin, thus reducing the negative emissions potential of BECCS EfW. However, these alternative waste treatment plants can still be operated with CCS to help mitigate against fossil emissions.

Although post combustion carbon capture technologies are mature, for BECCS EfW specifically it is not yet known how impurities in the flue gas resulting from contaminants in the waste feed, affect the CCUS solvent over long periods of time. The solvent is susceptible to degradation from contaminants which may be present in the flue gas, negatively impacting the performance of the technology[102].

2.3.4.1 Economics

Economic factors pose a significant issue to the deployment of CCS at EfW facilities. The addition of CCS increases capital investment required, which could be seen as increasing investment risk, particularly due to the uncertainties surrounding current policy and lack of transport infrastructure. Moreover, CCS utilises energy produced from the EfW facility that would otherwise be sellable, consequently creating a financial barrier for sites that would rather invest in other opportunities that would increase their revenue[102].

Furthermore, EfW facilities are subject to particular economic exposure due to gate price fluctuations and plant throughput. There are uncertainties surrounding how these factors may evolve in coming years, and how adding CCS may increase exposure to both gate prices as well as other policy driven value streams[102].

2.4 BECCS INDUSTRY

2.4.1 Technology overview

BECCS industry relates to the use of biomass as an energy source for industrial applications and the capture of CO_2 from the process and subsequent CO_2 storage. Typical industrial applications include wood-based products (paper & pulp industries), distillation & fermentation processes and steel production. As there are no steel manufacturing industries in Scotland, we have added detail on the typical BECCS applications for this industry to Appendix 10.

One-quarter of industrial emissions arise from the physical or chemical processes[103], which cannot be reduced through fuel switching. Additionally, approximately one third of industrial energy demand is for high-temperature heat, hence limiting the potential decarbonisation options available. BECCS therefore provides a key opportunity to reduce emissions for industrial processes, while still maintaining the high-temperature heat for the processes. Conversion technologies will mostly consist of biomass combustion; therefore, CO_2 will be captured via oxyfuel combustion or post-combustion capture (as outlined in section 1.2.1)

2.4.1.1 TRL

Due to the differences in industrial processes, as described above, the TRL of applying CCS varies between industrial sectors.

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[102] Energy from Waste Plants with Carbon Capture - A preliminary Assessment of Their Potential Value to the Decarbonisation of the UK, 2020, Catapult Energy Systems, Accessed at: https://esc-production-2021.s3.eu-west-2.amazonaws.com/2021/10/20200513-Energy-from-Waste-Plants-with-Carbon-Capture-Final.pdf

[103] Transforming industry through CCUS, IEA, 2019

Table 26. TRL of applying CO_2 capture to industrial sectors

Industry	Technology type	TRL
Cement	Fuel firing in rotary kilns with CO_2 capture	TRL 7[90]
Steel	Blast furnace with CO_2 capture	TRL 5[90]
	Torrefied biomass in steel furnace with CO_2 capture	TRL 7[90]
Wood-based products	Combustion of biomass fuel or process waste, to provide power and/or heat for production process	TRL in-line with readiness for post-combustion CCS for BECCS power or CHP. See section 2.2.
Fermentation (Brewing and whisky industries)	Membrane capture from fermentation process	TRL 9[104]

2.4.1.2 Costs

Table 27: Breakdown of costs for cement, wood-based products, and fermentation with CCS

Industry	Technology type	CO_2 Captured, $MtCO_2$/year	Capital cost, £M	Operating cost (fixed), £/tCO_2	CO_2 avoided, £/tCO_2
Cement	Amine post-combustion capture[253]	0.293*	87.6	8.2	102.49 (FOAK) 85.13 (NOAK)
Wood-based products	Amine post-combustion capture for onsite power and heat generation	CAPEX, OPEX and cost of carbon in-line with costs for post-combustion CCS for BECCS power or CHP. See section 2.2.			
Fermentation (Brewing and whisky industries)	Membrane bio reactor plant	All vary with capacity of alcohol produced. Tennent's Lager aims to capture 4.2kt/year at an investment of £2.6M[105]; North British Distilleries claim to capture ~ 4 t/day[104]			

*Units relate to CO_2 captured and stored/utilised

Note that for sites which do not currently use biomass fuel sources, additional costs for fuel switching would need to be considered – these costs will vary considerably depending on the process and plant capacity required.

2.4.1.3 Inputs / outputs

Cement

The manufacturing of cement involves the calcination of sources of calcium, silica, and alumina, such as limestone, clay, and sand, which are typically sourced locally. These raw materials undergo several successive operations, including quarrying, homogenisation, preheating, calcination, clinkerisation, cooling, blending, storage, and dispatch.

The clinker is produced in high temperature kilns, requiring operating temperatures of 1400-1500degC. The necessary high temperatures are predominantly provided by the combustion of fuel, such as coal, petroleum

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[104] Carbon capture in the heart of the city (archive.org)

[105] Tennent's Brewery installs CCUS: https://www.foodmanufacture.co.uk/Article/2020/07/20/Tennent-s-Brewery-launches-carbon-capture-facility

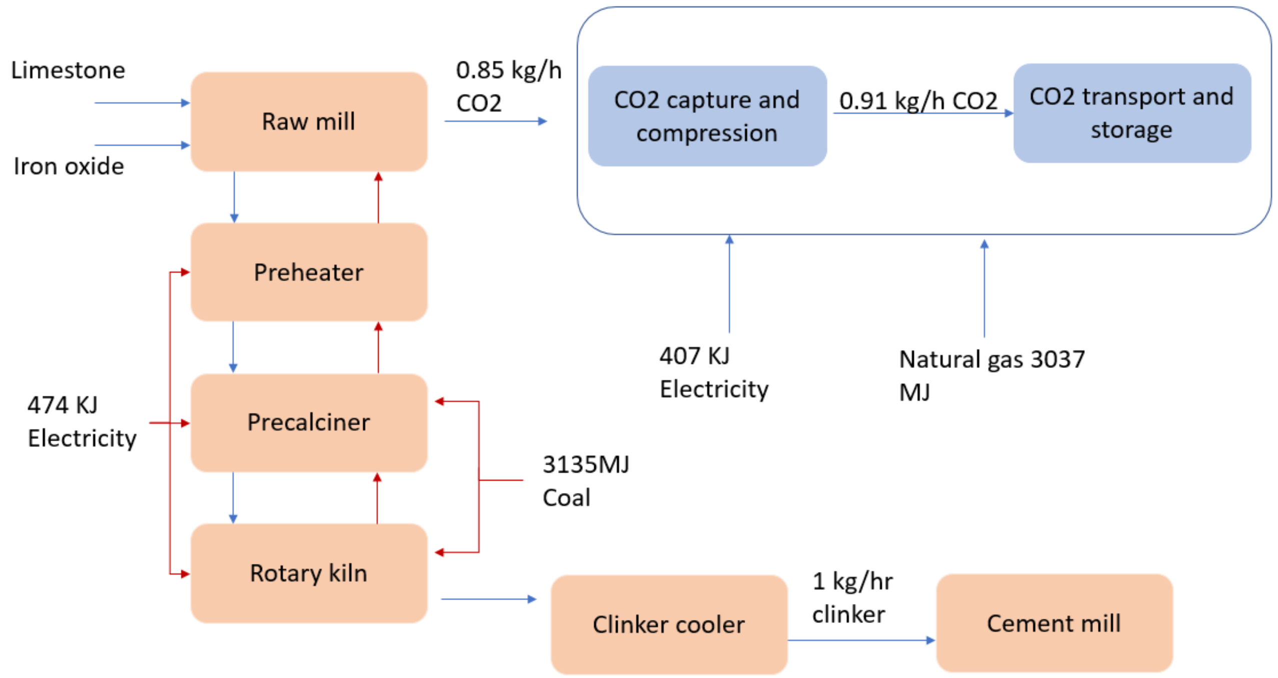
coke and natural gas. However, the rotary kilns are able to make use of a wide range of fuel types, therefore efforts are already underway to shift to alternative, low-carbon sources of fuel.

2.4.1.4 Schematics

Mass and energy balances were taken from Voldsund et al[106], assuming that MEA post-combustion capture is retrofitted to a reference European clinker plant. This was deemed reasonable for the purposes of this report, since there is only one cement plant within Scotland (Dunbar) which will require CCS retrofit[22]. There appears to be no plans in the pipeline to build a new cement plant in Scotland, and so there is no further discussion on alternative clinker production routes (e.g., calcium looping, oxyfuel capture, etc).

Cement

Figure 8: Schematic of standard clinker production with post-combustion capture



Pulp and paper

The raw materials used in the production of pulp and paper consist of fibrous plant materials from trees and plants. Waste materials can also be utilised, such as waste-paper. The main form of fibrous plant materials used in the paper manufacturing process consists of wood from sawmills, which can be in the form of wood chips, logs or sawdust. Chemical or mechanical pulping is then used to breakdown lignin in the plant materials, producing a pulp. The pulp is then cleaned before going through the paper production process, involving stretching, pressing and drying.

The paper industry also utilises significant volumes of water throughout the manufacturing process. The production process also requires significant amounts of heat and electricity, with the vast majority arising from the pulping process.

Process wastes (considered by-products), in the form of biomass wastes which cannot be used in the pulp and paper production process, are often utilised on site to generate electricity and heat to power the paper mills. The chemical pulping process (known as the Kraft process) results in by-products of hog fuel (solid wastage from the raw material input), black liquor and crude tall oil. The arising black liquor from the Kraft

[106] Voldsund et al, 'Comparison of Technologies for CO_2 Capture from Cement Production—Part 1: Technical Evaluation': [PDF] Comparison of Technologies for CO2 Capture from Cement Production—Part 1: Technical Evaluation | Semantic Scholar

pulping process provides the majority of the BECCS potential from the process[107]. However, the only pulping process in Scotland is mechanical pulping, using the Pressurised Groundwood (PGW) process[108]. Whilst some wastage is generated, in the form of bark or paper sludge, mechanical pulping is more efficient at converting wood to pulp, resulting in less potential for BECCS from by-products[109]. The greatest potential for CCS arises from providing the required process power and heat, only if this is provided by bioenergy CHP.

Wood-based products

Products such as paper, medium-density fibre board (MDF), particle board, oriented strand board (OSB) and wood pellets require wood-based raw material as the main input. Natural wastage from the process can be used to partially provide the required power and heat for the production processes. The wastage may also be supplemented by virgin wood fuel. According to Renewables Obligation annual sustainability reporting for 2019/2020, the only pulping plant in Scotland (UPM Caledonian) consumed 280 kt of fuel, sourced from virgin roundwood, aboricultural arisings, forestry and sawmill residues, bark, recycled wood and paper sludge[110]. Similarly, Balcas Invergordon (a wood pellet manufacturer) consumed 108 kt of bark and woodchip from roundwood and forestry residues.

Process heat and power at sites such as UPM Caledonian, Balcas Invergordon, and the West-Fraser (previously Norbord) Cowie and Morayhill is provided by biomass CHP. The potential, in relation to fuel input, and associated costs of CCS at these sites will be similar to those described for BECCS power in section 2.2.

Fermentation (brewing and whisky industries)

CCUS is also applicable to the brewing and whisky industries where process emissions from fermentation can be easily captured with technologies which are already available[111]. Around 0.5Mt/year of carbon dioxide is produced by Scottish breweries and distilleries. Usually, carbon dioxide is extracted from such operations but is not collected and is released into the atmosphere. The recovery of CO_2 process emissions from such sites and storing it permanently provides a real and easy opportunity for achieving NETs in Scotland.

2.4.2 Potential Carbon impact

2.4.2.1 Cement

Cement is used as a key input to concrete, which is the most widely used construction material in the world[112]. The cement sector is a large contributor to global emissions; hence it is crucial to determine effective methods of reducing emissions from the sector. Emissions from the cement sector arise from combustion of fuels, the conversion of limestone to calcium oxide, as well as other downstream plant operations. It is estimated that approximately 60-70% of emissions arise from the conversion of limestone to calcium oxide, and about 30-40% from the use of fuel inputs to the industrial process[112].

2.4.2.2 Pulp and paper

The pulp and paper industry cogenerates heat and electricity, where biomass is a typical fuel source. It is estimated that biogenic emissions account for approximately 75% of on-site CO_2 emissions[113], through the combustion of process wastes, hence there is great potential to result in negative emissions with the addition of a CO_2 capture unit.

2.4.2.3 Brewing and whisky industries

Brewing and whisky sites are string candidates to deliver negative emissions in Scotland at an early stage and prior to 2030 with readily available technology. The negative emission potential arises from capturing and

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[107] Onarheim et al. (2017): Performance and costs of CCS in the pulp and paper industry part 1: Performance of amine-based post-combustion CO2 capture

[108] UPM Caledonian (2022): upm-emas-report-ettringen-2021_en.pdf

[109] Martin et al. (2000): Opportunities to improve energy efficiency and reduce greenhouse gas emissions in the U.S. pulp and paper industry

[110] Ofgem (2021): Biomass Sustainability Dataset 2019-20

[111] Ardgowan Distillery to pilot novel CO2 capture technology | Scottish Financial News

[112] Deployment of bio-CCS in the cement sector: an overview of technology options and policy tools, IEA Bioenergy, 2021

[113] Decarbonising Industry via BECCS: Promising sectors, challenges and techno-economic limits of negative emissions, S.E Tanzer et al, 2021

permanently storing process emissions as well as combustion emissions. On the combustion side, a strong competitor will be hydrogen which is being considered by many distilleries across Scotland.

2.4.3 Potential locations in Scotland (map

2.4.3.1 Cement

There is only one cement plant in Scotland at Dunbar, which releases 570 ktCO_2/year emissions (mostly fossil based)[22]. The site produces 867 t/d of clinker with a heat consumption of 0.91 kWh/kg[114].

2.4.3.2 Pulp and paper

Scotland has three paper or board mills in total: Caledonia paper mill (located in Ayr), Cowie MDF and particleboard facility (located near Stirling), and Invergordon Pellet Mill (north of Inverness). These are all existing sites, with the Cowie facility having the closest proximity to access to existing pipelines that could be used for CO_2 transport (if upgraded accordingly). The remaining projects would require truck or rail transportation to CCS hubs. The only pulp production plant is the UPM Caledonian mill, with the remaining 2 facilities being panel board and pellet manufacturers. CCS from the pulp-to-paper production is not mentioned and is not considered as a decarbonisation option by the confederation of paper industries (CPI), due to the small size of most sites[115].

These existing sites which can be retrofitted with CCS can capture up to 0.363 MtCO_2/year at an investment cost £248.3M and operational cost of £51.9M/year. If the West Fraser Morayhill Mill plant is also considered, then the total CO_2 capture potential rises to 0.469 Mt/year, which closely matches the value of 0.676 Mt/year calculated by Element Energy[22].

2.4.4 Technology specific limitations & barriers

2.4.4.1 Technical

Several technical barriers from application of CO_2 capture in the power sector are also applicable to the industrial sector. A key example is the low concentrations of CO_2 which are likely to be present in the flue gas stream, as well as the high energy required for solvent regeneration in post-combustion capture plants. Additionally, the emissions at industrial plants are more likely to be dispersed and hence additional challenges arise from the need to capture emissions from multiple point sources located around the entire plant.

There are also additional technical barriers that relate to the specific industrial application in the production of cement, steel and pulp and paper. Currently, many cement production plants around the world are utilising a mixture of fossil fuels and low-carbon fuels, as there are currently some concerns associated with only burning alternative fuels in the kiln, due to variations in combustion temperatures. There are therefore current technical barriers to the potential for utilising biomass in the cement production process, where co-firing of biomass with fossil-based fuels occurs at up to 35-40% biomass. This leads to technical limitations with the amount of biogenic CO_2 that can be captured to result in negative emissions.

The current dominant energy carrier in the cement industry is coal, constituting approximately 70% of the total energy consumption with biomass and other alternative fuels accounting for ~5%[116]. The introduction of biomass as a fuel source requires increased thermal and electrical energy input due to the inherent characteristics, which necessitate increased processing and pre-treatment requirements, such as high moisture content, particle size and a possible need for elevated oxygen levels. To meet the thermal energy demand in the calciner burners, which account for 60% of the total thermal load of a cement plant alternative fuels such as refuse-derived fuels and agricultural waste can be used to substitute up to 100% of its thermal demand. It has been demonstrated that up to 20% substitution rate is achievable, whilst minimising process modification and increased capital expenditure. In the UK, an estimated 17% total thermal input substitution is seen[117].

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[114] Cement kilns, 'Dunbar': Cement Kilns: Dunbar

[115] CPI (2022). Position paper: http://thecpi.org.uk/library/PDF/Public/Publications/Position%20Papers/PP_2050Roadmap_March2023.pdf

[116] IEA.Technology , "Roadmap - low-carbon transition in the cement industry," International Energy Agency, Paris, 2018.

[117] Department for Business Energy and Industrial Strategy, "Options for switching UK cement production sites to near zero CO_2 emission fuel: Technical and financial feasibility.," 2019.

However, limitations to further adoption and substitution of biomass as a fuel source is attributable to the technical complexities associated with solid biomass co-firing in the kiln and calciner burners, which create operational complications in maintaining suitable temperature profiles and combustion velocities. Although the cement kilns exhibit a high degree of fuel flexibility, the minimum calorific value required for efficient kiln operation exceeds the energy content of a majority of alternative biomass fuels.

In selecting a suitable biomass fuel for cement production, it is important to consider its availability and the specific energy requirements of the kiln and calciner burners, which typically require a minimum calorific value of 3.89kWh/kg and 2.22kWh/kg, respectively[118]. Furthermore, accounting for the typical non-homogeneity of biomass fuel physical and chemical characteristics are of relevance, including moisture content, size distribution, volatile matter, and ash content.

2.4.4.2 Economic

As with CO_2 capture applied to the power sector, the addition of CO_2 capture to industrial processes results in a large increase in the energy demand and hence high associated costs. In sectors where the current fuel use is predominantly fossil fuel based, the costs of achieving negative emissions are also likely to be higher than in sectors which already make use of a large share of biomass, such as in the production of pulp and paper.

2.5 BECCS HYDROGEN

2.5.1 Technology overview

2.5.1.1 TRL

The technological maturity of biohydrogen is broad, with BEIS[119] and Element Energy[66] estimating a TRL of 4-6 (meaning that the technology is within its innovation/prototype phase), whilst the University of Edinburgh estimates a larger TRL of 5-9 (meaning the technology is closer to full commercial application)[35]. Biohydrogen's TRL has potential to improve if confidence in biomethane and gasification technologies continues to grow[57].

2.5.1.2 Costs

Analysis by Element Energy estimates future BECCS hydrogen costs to be £50-120/tCO_2 (by 2030) and £30-100/tCO_2 (by 2050)[119], whilst the CCC highlights gasification-CCS costs to be £106/MWh (by 2025) and £64-127/MWh (by 2040) [120]. Further work by BEIS provides a thorough breakdown in gasification-CCS costs, SMR-CCS and ATR-CCS, as detailed below in Table 28 and in Table 29[121,122]. The cost of SMR-CCS and ATR-CCS cover the installation of new hydrogen plants and CCS, with CCS costs not being disaggregated from total costs.

Table 28: Breakdown of gasification costs to produce hydrogen.

Technology type	Capacity (t/year)			CAPEX (M£)		OPEX (M£/year)	
	Fuel input	CO_2 output	Hydrogen	Plant	CCS	Plant	CCS
Wood gasification	330,000	303,400	12,600	304	63	60	6
Pellet gasification	1,000,000	1,712,500	72,600	982	191	327	30
MSW gasification	100,000	93,900	3,900	171	31	9	3
	550,000	519,000	22,00	499	93	19	11

[118] M. R. M. K. S. S. A. Rahman, "Cement kiln process modeling to achieve energy efficiency by utilizing agricultural biomass as alternative fuels," *Thermofluid Modeling for Energy Efficiency Applications,* pp. 197-225, 2016.

[119] Element energy (2021), 'Greenhouse gas removal methods: technology assessment report': Greenhouse gas removal methods: technology assessment report - GOV.UK (www.gov.uk)

[120] Climate Change Committee (2018), 'Hydrogen in a low-carbon economy': Hydrogen in a low-carbon economy - Climate Change Committee (theccc.org.uk)

[121] BEIS, 'Advanced Gasification Technologies – Review and Benchmarking': Advanced Gasification Technologies – Review and Benchmarking: Technical assessment and economic analysis - task report 5 (publishing.service.gov.uk)

[122] BEIS, 'Hydrogen production costs 2021': Hydrogen production costs 2021 - GOV.UK (www.gov.uk)

Table 29: Breakdown in SMR-CCS and ATR-CCS costs

Technology type	Year	CAPEX (£/MWh, HHV*)		OPEX		CO_2 T&S and carbon cost	
		300MW	1000MW	300MW	1000MW	300MW	1000MW
SMR-CCS	2025	10	7	3	3	8	8
	2030	9	7	3	3	10	10
	2035	9	7	3	3	11	11
	2040	8	6	3	3	12	12
	2045	8	6	3	3	13	13
ATR-CCS	2025	12	8	3	3	7	7
	2030	11	7	3	3	8	8
	2035	10	7	3	3	8	8
	2040	10	6	3	3	9	9
	2045	9	6	3	3	9	9

*High Heating Value

2.5.1.3 Inputs/outputs

Inputs

Feedstocks and land requirements: Bioresources from the food and drink sector, and slurries and farmyard manure from the agricultural sector, are favoured in anaerobic digestion and gasification, due to their abundance and low environmental impact[57,74]. The availability of these waste feedstocks will increase in the future, due to the proposed Scottish ban on biodegradable MSW going to landfill, as well as the utilisation of these feedstocks being incentivised through the green gas support scheme[57]. However, there is potential competition with other BECCS technologies and the fact that biohydrogen exhibits large land requirement (0.8-2.5 m^2/kW H_2 versus 0.07-0.14 m^2/kW,H_2 for blue hydrogen)[120]. Furthermore, to ensure negative emissions, the source of biomass must maintain low supply chain and process emissions, meaning biomass imports should be limited and feedstocks that do not require intensive pre-processing steps should be favoured[123].

Water demands: The production of biohydrogen through SMR will require supplementary natural gas/biomethane firing in order to meet onsite energy demands. To provide this heat, high temperature steam must be produced using demineralised water, which is also utilised as feedstock within the reforming and RWGS reactions. This water demand is similar for both SMR and ATR (11.52 kgH_2O/kWh$_{H2}$)[127]. In terms of bio-gasification, the water demands are similar to conventional blue hydrogen production (0.2-0.6 l/kWh)[120]. Please note that these water demands will vary depending on the choice of feedstock, operating conditions, and CO_2 capture method, as highlighted in the schematics below.

Energy demands: Please see Figure 9 and Appendix 12.

Outputs

Biohydrogen and negative emissions: The key benefit of BECCS hydrogen is its ability to simultaneously provide low-carbon H_2 and negative emissions[124]. The growth in biohydrogen is expected to be driven by the UK Government's plan to prioritise biomass use for hydrogen production in heavy industry, with capacities ramping up from 1GW in 2025 to 7-20 GW by 2035. On this trajectory, 250-460TWh of hydrogen could be utilised by 2050, 20% of which would be sourced by biomass gasification[124]. This growth in biohydrogen

[123] Cumicheo et al, 'Natural gas and BECCS: A comparative analysis of alternative configurations for negative emissions power generation': Natural gas and BECCS: A comparative analysis of alternative configurations for negative emissions power generation - ScienceDirect

[124] BEIS (2021), 'Biomass policy statement: a strategic view on the role of sustainable biomass for Net Zero': Biomass policy statement: a strategic view on the role of sustainable biomass for Net Zero - GOV.UK (www.gov.uk)

production will be fuelled by the £240m Net Zero Hydrogen Fund[124], the BEIS NZIP Innovation Programme[124], and the Scottish Government's £100M hydrogen investment programme[68].

Biohydrogen and negative emissions: Analysis by Element Energy estimates that between 2.3-3.5 MWh/tCO_2 of biohydrogen is produced when utilising 3-3.1 MWh of biomass[119], where high purities of 99.8%[120] and 99.9%[127] are possible. The biohydrogen could be used to provide low-carbon heating, be used in industry to produce green fertilisers and high temperature heat, or in freight transport and aviation[125]. The captured CO_2 can be stored to achieve negative emissions or be utilised in a range of sectors: such as fertiliser production, food and beverages, low carbon concrete, e-fuels, and aggregates[126].

Waste: The by-products of anaerobic digestion and gasification include ash removal, tar removal, particulate and heavy metal removals, and acid gas removal. All of which are treated and disposed of accordingly.

2.5.1.4 Schematic

Figure 9 shows Hydrogen produced via SMR of biomethane with MDEA CO_2 capture, potentially the most "common" form of biohydrogen production. For the biomethane reforming schematics (including those in Appendix 9), mass and energy balances were taken from Antonin et al[127].

For the gasification schematic, energy/mass balances were taken from Materazzi et al[128], which is in turn taken from a 62MW hydrogen plant. This considers an initial bubbling fluidised bed gasifier operated at 700–800degC, in which steam and oxygen are used to partially oxidise the waste feedstock, and a plasma converter to refine the syngas. Please note that all heating demands are met onsite via a steam system and by imported power.

Additional schematics for BECCS Hydrogen are included in Appendix 12 and include:

- Hydrogen produced via SMR of biomethane with VSPA CO_2 capture (Figure 22)
- Hydrogen produced via ATR of biomethane with MDEA CO_2 capture (Figure 23)
- Hydrogen produced via ATR of biomethane with VSPA CO_2 capture (Figure 24)
- Hydrogen production via gasification and subsequent reformation of the syngas (Figure 25)

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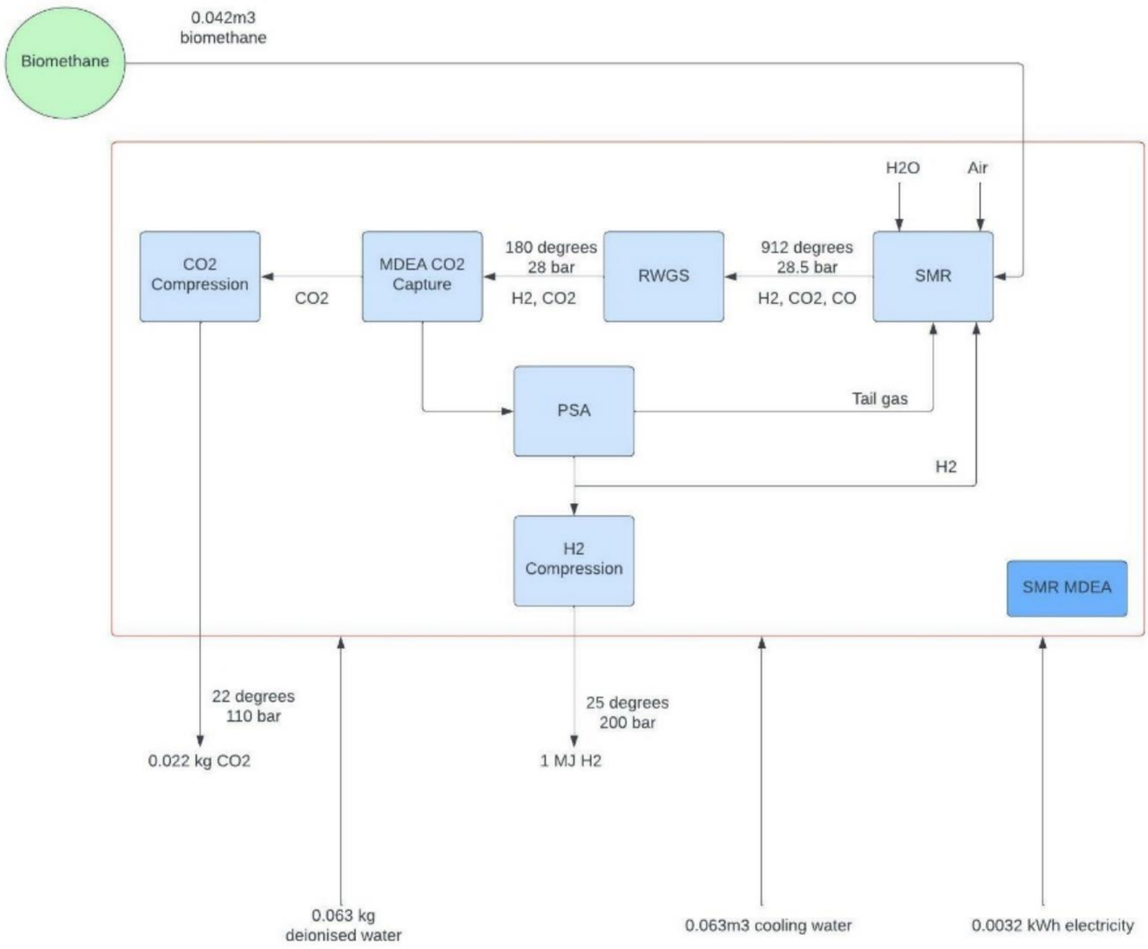
[125] BEIS (2021), 'UK Hydrogen Strategy': UK hydrogen strategy - GOV.UK (www.gov.uk)

[126] IEA (2019), 'Putting CO_2 to Use': Putting CO_2 to Use – Analysis - IEA

[127] Antonin et al (2020), 'Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis'': Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis - Sustainable Energy & Fuels (RSC Publishing)

[128] Materazzi et al (2019), 'Production of biohydrogen from gasification of waste fuels: Pilot plant results and deployment prospects': Production of biohydrogen from gasification of waste fuels: Pilot plant results and deployment prospects - ScienceDirect

Figure 9: Hydrogen produced via SMR of biomethane with MDEA CO_2 capture



2.5.2 Potential carbon impact

For the pathways modelling, performance data for a reference BECCS Hydrogen plant is needed to calculate the CO_2 capture potential in Scotland. The carbon conversion factors were taken to be 0.0792kgCO_2/kWh,H2 for biomethane SMR, 0.248 to 0.256kgCO_2/kWh,H2 for biomethane ATR, 0.72 kgCO_2/kWh,H2 for gasifying wood, and 1.764kgCO_2/kWh,H2 for gasifying MSW. These factors are taken directly from the mass balances of the schematics (including those in appendix 9), since no BECCS Hydrogen plants were available in the literature to refer to. The CO_2 capture rate was assumed to be 90% (see Section 1.2.1 for supplementary details) and the utilisation factor of the plant is taken to be 85%, based on modelling carried out by BEIS[121]. The biogenic content of the captured CO_2 is assumed to be 100% if biomass feedstocks are utilised and 50.3% if MSW is used (see Section 2.3.2 for more information).

Carbon footprint

A key benefit of BECCS hydrogen is the provision of both hydrogen and negative emissions. The use of waste biomass appears to maximise negative emissions (-2.88kgCO_2/kWh,H_2 to -0.45kgCO_2/kWh,H_2)[120,127] compared to non-waste feedstocks[74]. In fact, negative emissions can be achieved without the use of CCS (-1.44kgCO_2/kWh), if AD digestate is applied to the soil as a fertiliser[127]. It must also be noted that BECCS H_2 exhibits an inverse relationship between carbon negativity and process efficiency; meaning the inclusion of CCS reduces process efficiencies, which prompts greater biomass consumption, and hence increases capture of biogenic carbon[123]. Please note that negative emissions are only possible if supply chain emissions remain low, which can be achieved by focussing on decarbonising biomass transport (shipping and rail in particular)[58].

The blending of biohydrogen with fossil-derived natural gas can also lead to negative emissions; most notably, biomass integrated gasification combined cycle (BIGCC-CCS) and hydrogen thermal combined cycle (HTCC-CCS) achieve emissions of 220 to -650 kgCO_2/MWh and 300 to -750 kgCO_2/MWh respectively. Carbon neutrality is achieved at blending proportions of 15-40%[123].

Non-GWP emissions

However, despite the benefit of reduced carbon emissions, biohydrogen production leads to a 72-162% increase in non-GWP emissions. This is directly linked to the inclusion of CCS, which has an energy penalty that must be compensated for by greater biomass use and electricity imports, which increases electricity demand, eutrophication potential (EP), fossil depletion potential (FDP), ozone depletion potential (ODP), photochemical oxidant formation potential (POFP) and terrestrial acidification potential (TAP)[74].

2.5.3 Potential locations in Scotland

Future hydrogen clusters include Acorn H_2 (located in St Fergus), where blue H_2 will be produced to heat homes, power transport and be used in industry; Aberdeen City Council; and H100 Fife, where green H_2 will be used to heat domestic households[120]. CO_2 produced during H_2 production can be captured, transported, and stored in the North Sea using existing oil and gas infrastructure, which the Acorn site plans to utilise. However, there are currently no BECCS H_2 plants in operation, with only circa 20 existing biomethane sites in Scotland which could be used to produce H_2 via steam reforming[66].

Spatial analysis undertaken by Freer et al[58] concluded that optimal biomass residue locations for hydrogen production are dependent on biomass, energy end-user and low carbon infrastructure. In particular, emissions are tethered to the location of the BECCS H_2 facility, with the lowest emissions being exhibited in rural areas with strong access to biomass resources. This is highlighted by the fact that transport emissions can increase by 8.6% to 13.1% if the BECCS location is shifted 10km away from an optimal location.

2.5.4 Technology-specific limitations & barriers

As highlighted in the TRL section, there remains to be a lack of demonstration of advanced biomass gasification technologies, with further demonstration and commercialisation needed alongside pilot projects for CO_2 capture[119]. The timescales required to develop a CCUS facility are 5-8 years, from commencing detailed engineering work to building and operating the facility[22], so works needs to begin now if BECCS H_2 is to reach the capacities necessary.

To overcome these barriers, the UK Government aims to support both low carbon H_2 and CCUS providers by incentivising the adoption of low carbon H_2 production through the Government's hydrogen business model, which will provide revenue via CfDs to overcome the operating cost gap between low carbon hydrogen and high carbon counterfactual fuels[22]. This business model does not explicitly value negative emissions; however, it will provide support to cover the costs of installing and operating CCS technology. The Government has also developed a Low Carbon Hydrogen Standard, which sets a maximum threshold for GHG emissions allowed in the production process for hydrogen to be considered 'low carbon hydrogen', and hence be eligible for certain government funding[22]. The rewarding of biohydrogen fuel certificates via the Renewable Transport Fuel Obligation (RTFO) could also provide a potential route[22].

With regards to biomethane production, which in turn could be utilised to produce biohydrogen, the key constraints are on low pressure gas networks, increased regulatory scrutiny on the management of digestate use, and limited availability of biogenic waste depending on future regulations[57,127]. During AD and gasification, the additional demands of feedstock preparation and syngas cleaning, which are expensive to install and run, lead to uncertainties over the true scalability of BECCS H_2[124,]

2.6 BECCS BIOMETHANE

2.6.1 Technology overview

There are multiple pathways to produce biomethane, the first being thermochemical conversion routes which covers gasification and pyrolysis. Other methods include anaerobic digestion, whereby biogas (syngas) or biohydrogen are produced and then converted to biomethane. The two common practices of converting biogas to biomethane are upgrading, a process that removes any CO_2 and other contaminants present in the biogas, and methanation which makes use of a catalyst to promote reaction between the hydrogen and CO or CO_2 to produce methane.

2.6.1.1 TRL

Biomethane can be produced through multiple routes, namely anaerobic digestion followed by upgrading of biogas; the removal of CO_2 is an inherent part of the process and consequently "upgrading" technologies are already well established as they have been refined over the last 20 years. The TRL ranges between 8 - 9 for anaerobic digestion and biomethane/CO_2 separation, as the technology is commercially mature.

2.6.1.2 Economics

Costs associated with biomass and waste gasification to produce biomethane are detailed below based on analysis conducted by Element Energy[66].

Table 30: Breakdown in biomass and waste gasification costs to produce biomethane

Technology type	Capacity			CAPEX*		OPEX*	
	Fuel input (t/year)	CO_2 output (t/year)	Biomethane (t/year)	Plant (£M)	CCS (£M/year)	Plant (£M)	CCS (£M/year)
Wood gasification	330,000	131,500	30,300	293	54	59	5
Pellet gasification	1,000,000	1,289,200	175,200	946	163	325	24
MSW gasification	100,000	71,100	9,800	164	26	9	2
	550,000	385,700	55,100	481	76	18	9

*All CAPEX and OPEX costs rounded to the nearest £M

Costs associated with biomethane production via AD upgrading were taken from a IEAGHG paper, which provides a breakdown in plant investment, operation and CCS costs for different feedstocks[129]. These costs are based off a plant utilisation factor of circa 91%.

Table 31: Breakdown in biomass and waste anaerobic digestion costs produce biomethane

Feedstock	Year	Capacity (MW)	CAPEX (£/kW)*		OPEX (£/kW)*	
			Plant	CCS	Plant	CCS
Energy crops and agricultural residues	2030	10	855	92.7	76.5	11.7
	2050	15	855	83.7	76.5	10.8
MSW	2030	10	1485	92.7	162	11.7
	2050	15	1485	83.7	162	10.8
Sewage/manure	2030	10	1035	121.5	76.5	16.2
	2050	15	1035	109.5	76.5	16.2

*Assumes a euro to pound conversion ratio 0.9

2.6.1.3 Inputs / outputs

Inputs

Biomethane is formed from the methanation or upgrading of biogas. To produce biogas, various feedstocks can be utilised depending on the pathway. Manure, sewage sludge, municipal solid waste, specifically food waste, and crop residues are frequently employed as feedstock for the production of biogas by anaerobic digestion. The gasification and pyrolysis routes to biomethane make use of MSW and energy crops, in addition to woody biomass which consists of residues from forest management and wood processing.

Outputs

Regardless of the biomethane production pathway (gasification, pyrolysis, or AD), a combustible gas, known as biogas, is produced with a varying composition depending on feedstock as well as technology. This biogas

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[129] IEAGHG, 'Potential for Biomethane production with carbon dioxide capture and storage': Technical Reports - Files - IEAGHG Document Manager

contains differing quantities of methane, carbon dioxide, water, hydrogen sulphide, nitrogen, oxygen, ammonia, tars, and particles[130]. The upgrading process serves two goals: to increase the concentration of methane from approximately 50% to >90% and remove CO_2 along with other contaminants[131]. Oftentimes, the separated CO_2 stream needs to be cleaned before it can be compressed, transported, and stored.

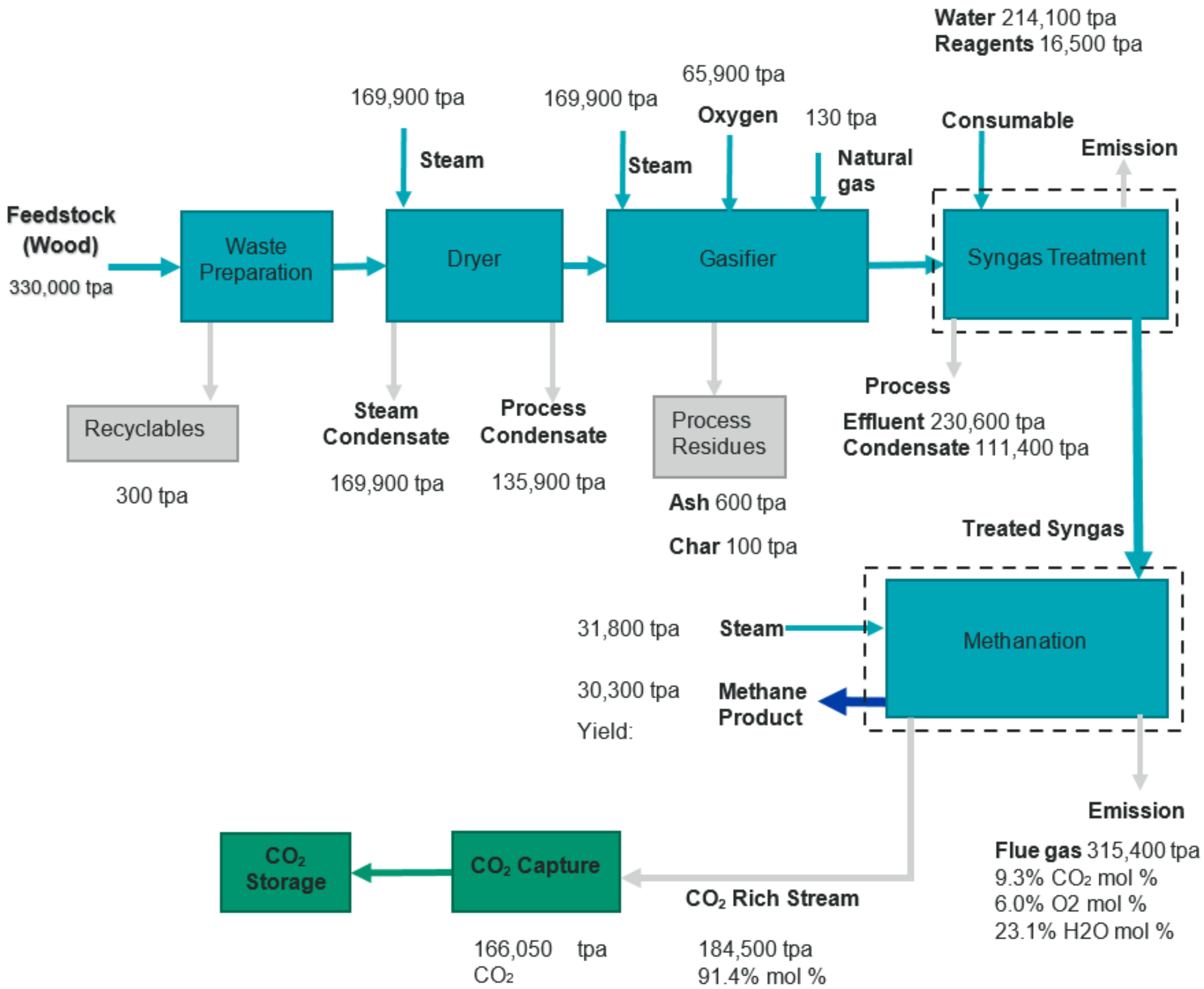
Table 32: Composition of gas pre- and post- biogas upgrading

Molecule	Biogas	Biomethane
Carbon Dioxide	40 - 50 %	2 - 6 %
Methane	50 - 60 %	93 - 97 %
Other (Hydrogen Sulphide, Nitrogen, etc.)	< 5 %	Trace

The production of biogas results in the creation of several other waste products, such as biochar, pyrolysis oil and bottom ash. Further details on the waste products of pyrolysis and gasification of biomass can be found in 2.2 BECCS Energy from Waste.

2.6.1.4 Schematics

Figure 10: Biomethane Production Through Gasification

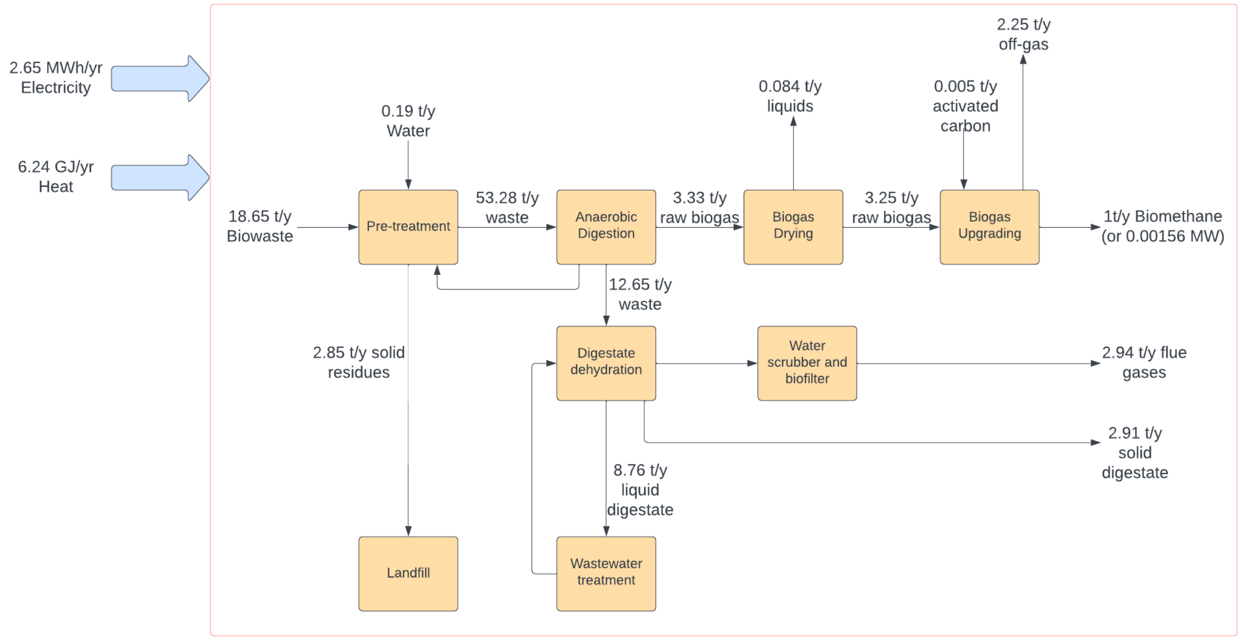


[130] Koornneef et al (2013), "Global potential for biomethane production with carbon capture, transport and storage up to 2050": https://www.sciencedirect.com/science/article/pii/S1876610213007765

[131] Biomethane/ RNG, Clarke Energy, Accessed at: https://www.clarke-energy.com/applications/biomethane-renewable-natural-gas-rng/

The mass and energy balance for waste anaerobic digestion and biogas upgrading was taken from a LCA paper conducted by Ardolino and Arena[132].

Figure 11: Biomethane production through anaerobic digestion and biogas upgrading



2.6.2 Potential Carbon impact

Biomethane is fully substitutive of both natural gas and biogas. The production and utilisation of biomethane results in over 80% less GHG emissions in comparison to conventional fossil fuels, and therefore can play an important role in the decarbonisation of the energy sector[133].

BECCS biomethane has the potential to produce negative emissions, although this is dependent on residual biogenic carbon being captured and stored, resulting in a final fuel largely free of CO_2. Moreover, the quantity of CO_2 captured must exceed that associated with the input power and lifecycle emissions of the feedstock, which varies depending on the source. Default GHG emissions for rye, grass silage, and maize are between 126 to 158.4gCO_2e/kWh biomethane; values that are significantly higher than other bioenergy routes, and as such will consequently result in a notably lower amount of gross biogenic CO_2 being captured regarding NETs negative emissions[22]. Post biomethane upgrading, there will still exist trace amounts of CO_2 (2-6%), therefore, when the fuel is combusted CO_2 will be released, but these emissions would be deemed carbon neutral[131].

According to the International Energy Agency, if natural gas is replaced by biomethane production with CCS, annual GHG emission savings could be approximately 8 Gt in 2050. Furthermore, BECCS biomethane has the technical potential to remove upwards of 3.5 Gt of GHG emissions in 2050[134].

For the pathways modelling, performance data for a reference BECCS Biomethane plant is needed to calculate the CO_2 capture potential in Scotland. The carbon conversion factors were taken to be 4.34 tCO_2/tCH_4 for woody biomass and 7.26 tCO_2/tCH_4 for MSW gasification[121], and 199.02 tCO_2/GWh from the BEIS conversion factors database[93]. If the biomethane is subsequently combusted, and the CO_2 captured, then an additional conversion factor of 183.7 tCO_2/GWh is used when assuming stoichiometric reaction. The CO_2 capture rate was assumed to be 90% (see Section 1.2.1 for further detail) and the utilisation factor of the plant is taken to be 85% for gasification[121] and 80% for AD upgrading[92]. The biogenic content of the captured CO_2 is assumed

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[132] Ardolino and Arena, 'Biowaste-to-Biomethane: An LCA study on biogas and syngas roads' (2019): Biowaste-to-Biomethane: An LCA study on biogas and syngas roads - ScienceDirect

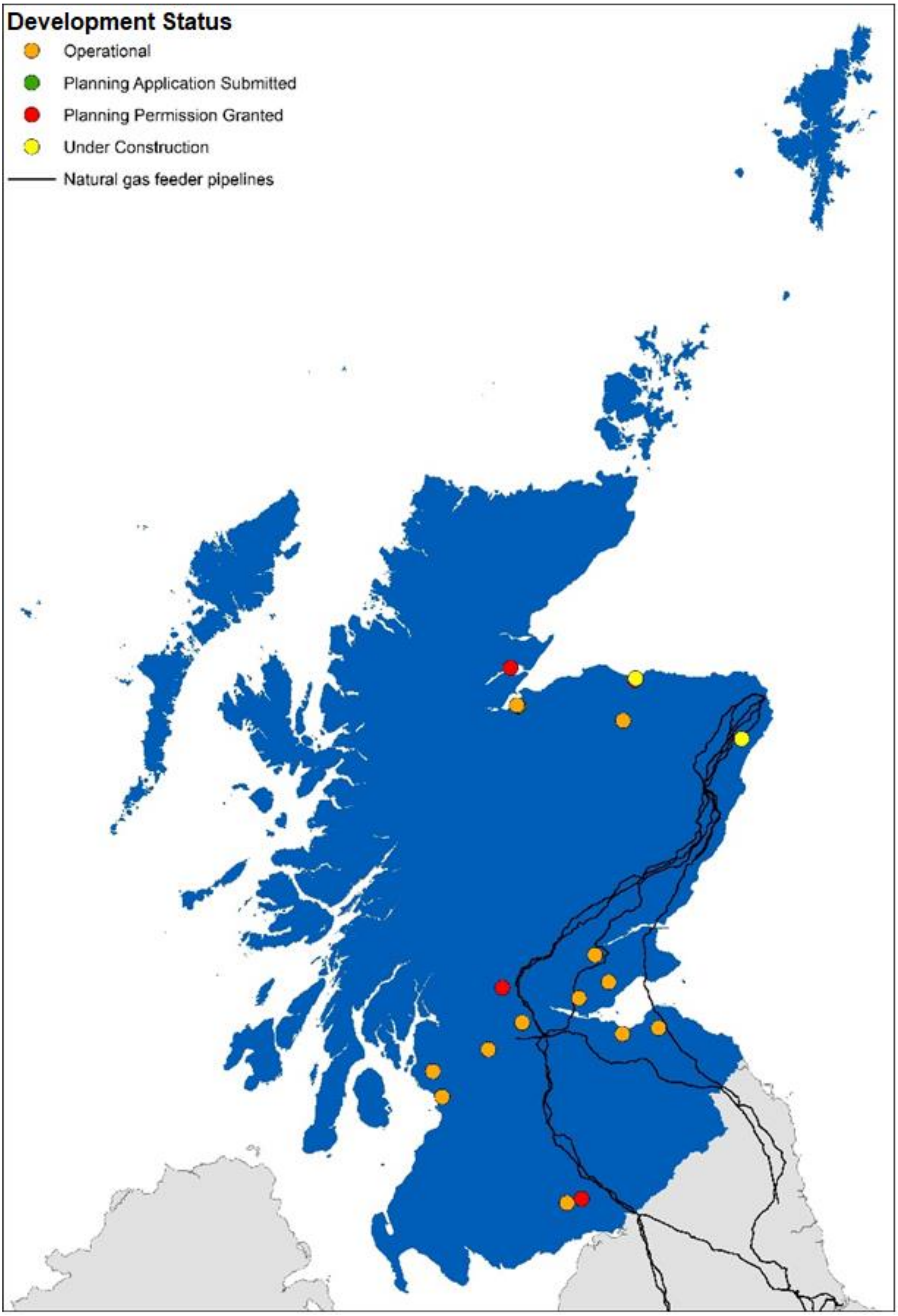
[133] Ardolino et al (2021), "Biogas-to-biomethane upgrading: A comparative review and assessment in a life cycle perspective": https://www.sciencedirect.com/science/article/pii/S1364032120308728

[134] Potential for Biomethane Production with Carbon Dioxide Capture and Storage, 2013, The International Energy Agency, Accessed at: https://ieaghg.org/docs/General_Docs/Reports/2013-11.pdf

to be 100% if biomass feedstocks are utilised and 50.3% if MSW is used (see Section 2.3.2 for more information).

2.6.3 Potential locations in Scotland (map)

Figure 12: GIS map of Biomethane and Anaerobic Digestion sites



2.6.3.1 Biomethane

As the REPD Database only considers projects that operate at a capacity greater than 1MW, then the majority of small-scale AD plants will have not been included in the above mapping. In the above map only 3 biomethane projects are included, which have a potential of producing 98.1 GWh/year of electricity and capture 0.05 $MtCO_2$/year. This will come at an investment cost of £0.81M.

Further analysis by Element Energy highlights that there are approximately 84 AD facilities in Scotland, most of which have been built in recent years. Though, it should be noted that of the 84 sites, only 20 are confirmed to be upgrading biogas into biomethane, with a production of 716 GWh/year of biomethane and 140$ktCO_2$/year[22]. Upwards of 290 $ktCO_2$/year could be captured if half of the AD plants in Scotland are retrofit with biomethane upgrading, however, this is dependent on the number of AD plants where this is feasible. Biomethane is already injected into the gas grid or trucked, depending on plant location, however, one of the factor's affecting applicability is the remaining AD sites' proximity to gas grid connections[22].

The Scottish biomethane sector is predicted to triple in size from 2019 to 2030, as presented by the CCC in the sixth carbon budget, suggesting that BECCS biomethane is plausible and has the potential of contributing significantly to Scottish NETs[22]. It should be noted that this contribution is highly reliant on the establishment of downstream CO_2 distribution chains and integration of new facilities into a national CCS network.

2.6.4 Technology specific limitations & barriers

There are several barriers to the large-scale deployment of biomethane BECCS, mainly due to economic factors and existing CO_2 distribution infrastructure. The economic potential for biomethane BECCS is limited by natural gas and CO_2 prices, despite the fact that lower capture costs are observed due to the high concentration of CO_2 present in the output stream[22]. Additional barriers include high biomass transport costs; this limits the plant size which consequently leads to higher costs (per tonne of biomethane produced) for connecting to CO_2 and natural gas infrastructure[134].

Furthermore, there are uncertainties surrounding the sale of biogenic CCS credits, as these factors are all yet to be confirmed. Schemes such as the UK ETS do not currently award negative emissions, and other UK policies regarding negative emission support are still in development[22].

2.7 DIRECT AIR CAPTURE

2.7.1 Technology overview

2.7.1.1 TRL

The TRL ranges from 4-6, meaning the technology is at the bench scale research to large scale deployment phase[59,22]. However, stakeholders are more optimistic, and estimate a TRL of 6-7 (indicating the technology is ready for inactive commissioning)[22].

2.7.1.2 Economics

Table 33: Breakdown in DACCS costs for different configurations

Company	Configuration	Capacity (Mt/year)	CAPEX (M£) *	OPEX (£/tCO_2) *	Levelised cost (£/tCO_2) *
Carbon Engineering[227]	1st Plant	0.98	951.4	35.5	142 – 196
	Nth plant	0.98	658.2	25	106 – 143.5
	Grid electricity – Nth plant	0.98	574.3	22	95.4 – 137.6
	No CO_2 compression and free O_2	0.98	503.9	19.4	79.4 – 109.8
	Fully electrified	0.98	N/A	N/A	66.7 – 68.4
Climeworks[51]	Solid sorbent	0.0009	2.5 – 3.4	N/A	422 – 506.6

Company	Configuration	Capacity (Mt/year)	CAPEX (M£) *	OPEX (£/tCO_2) *	Levelised cost (£/tCO_2) *
Antecy[52]	Solid sorbent	0.36	246.3*	N/A	165.5 – 126.7 **

*Assumed that Antecy plant operates over a 25-year lifetime and using a Euro to Great British Pounds conversion rate of 0.89.

Liquid solvent DACCS

According to Carbon Engineering their levelised cost of capture is estimated to be 79.3 £/tCO_2* - 196 £/tCO_2[227,52] *. This range in cost considers FOAK costs, Nth plant costs, and potential to replace the existing NGCC with lower carbon alternatives. This is similar to analysis by Element Energy[135], who indicates that a first of a kind (FOAK) plant hybrid liquid DACCS plant could cost 318 £/tCO_2.

Analysis by Fasihi et al[52] shows that if learning rates are taken into consideration, then it is expected levelised costs of the fully electrified liquid DACCS system will reduce from 267.7 – 250.8 £/tCO_2* to 68.4 – 66.7 £/tCO_2*, which is somewhat aided by the reduction in electricity demand from 1535 to 1316 kWh/tCO_2. The NIC concurs[3], with DACCS experiencing large cost reductions driven through learning by doing, economies of scale, and efficiency improvements.

Solid adsorbent DACCS

According to McQueen et al[51] the Climeworks Hinwil pilot plant exhibits a levelised cost of £422 – 506.6 £/tCO_2*, with an estimated CAPEX of 2,814 – 3,752 £/tCO_2*. Analysis by Element Energy[22] agrees, where a FOAK hybrid solid sorbent plant costing 453 £/tCO_2. These costs are significantly higher than compared to Carbon Engineering's liquid solvent DACCS plant; however, once Learning Rates are accounted for, then the levelised costs could drop to 127 – 169 £/tCO_2[51]*. Furthermore, Fasihi et al[52] anticipates more optimistic projections of reducing costs to 75 – 24.5 £/tCO_2* by 2050, depending on whether heat is sourced via waste heat or heat pumps, and is in line with Climeworks' aim of achieving production costs of 70 £/tCO_2* in the future.

The other major solid sorbent DACCS company, Global Thermostat, expect their costs to drop to as low as 10 – 35.5 £/tCO_2[52]*, whilst a smaller scale company based in the Netherlands named Antecy exhibits a present day levelised cost of 165.5 – 126.7 £/tCO_2[52]*.

Moisture Swing Adsorption DACCS

According to Fasihi et al[52], the CAPEX of MSA is estimated to be 394 £/tCO_2* with a levelised cost of 135 £/tCO_2*. This is based off rather old data from 2009, which hasn't been updated since. However, it is expected that future levelised costs could reduce significantly to 22 £/tCO_2* by 2050, and hence be able to compete directly with liquid solvent and solid sorbent DACCS. This is driven by higher sorbent capture surface areas, higher CO_2 uptake capacity per kg of sorbent, economies of scale and decreases in the costs of other materials.

**Values converted from USD to GBP using conversion of 1 USD = 0.83 GBP.*

2.7.1.3 Inputs/outputs

Inputs

Solvent/adsorbent: According to Carbon Engineering, their pellet reactor requires a $CaCO_3$ makeup stream of 0.03 t/tCO_2 to account for material lost during disposal. Furthermore, it is assumed that all of the KOH solvent is regenerated and recycled back to the pellet reactor. As for Climeworks, the solid adsorbent used has a lifetime of <1 year, which averages to an adsorbent depletion rate of 7.5 kg/tCO_2[51].

Land requirement: At first the land requirements of DACCS appear to be very low, with the construction of a capture facility only requiring ~0.01m^2/tCO_2[52]. However, once lifecycle land requirements are considered, such as the provision of low carbon heat/power[84] and maintaining adequate spacing between capture units to reduce local CO_2 depletion[35,52], do we see land demands rise dramatically. For example, powering solid sorbent DACCS with solar PV requires 1.87 m^2/tCO_2[84], whilst maintaining adequate spacing between capture units for liquid solvent DACCS requires ~1.5 km2/MtCO_2[52].

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[135] Element Energy (2022), 'Policy Mechanisms for First of a Kind Direct Air Carbon Capture and Storage (DACCS) and other Engineered Greenhouse Gas Removals (GGRs)': BEIS - Engineered GGR policies - Final Report - Element Energy (element-energy.co.uk)

Heat and electricity: As highlighted in Section 1.2.2, the heat and electricity demand of DACCS is significant, ranging from 1.46 to 2.45 MWh/tCO_2 and 0 to1,535 kWh/tCO_2 (please see Table 14). The nature of solid sorbent DACCS only requires low temperature heat (between 80-120degC), and so can be sourced from a variety of low carbon options: waste industrial heat, Fresnel solar-thermal heat collectors, and heat pumps[84]. This flexibility in design is a key advantage of solid sorbent DACCS, with the optimal configuration being the use of waste heat and onsite solar PV, where waste heat is characterised as 'burden-free'[84]. On the other hand, liquid solvent DACCS requires high temperatures (in excess of 900degC), which can only realistically be sourced from natural gas combustion[23]. The energy penalty of DACCS can be reduced by a fifth if a less pure stream of CO_2 is captured; however, this compromises the carbon capture efficiency of the facility[84].

Water and CO_2 absorption rates: For liquid solvent DACCS, the condition of the ambient air has a significant impact on CO_2 absorption and water losses[48]. Under hot and dry conditions, there is a benefit of higher CO_2 absorption rates, due to the exponential relationship between temperature and chemical reaction rate; but at the expense of rising water consumption (19.8 t/tCO_2). Cooler conditions can help reduce this water consumption to 7.3t/tCO_2; but with the CO_2 capture rate halving. The impact of humidity is also key, with higher humidity reducing water consumption whilst reaction rates remain reasonable. Therefore, it is best to locate a liquid DACCS plant in a warm and humid climate, whilst avoiding arid conditions[48]. For Carbon Engineering, their plant consumes a moderate 4.7 t/tCO_2 under mild conditions (20degC and 64% RH)[23]. During solid sorbent DACCS the moisture in the air is captured during adsorption, and hence acts as a NETs producer of water that is utilised onsite[52]. This is another key benefit of using solid sorbents.

Natural gas: For liquid solvent DACCS, the energy demands of the system are inversely proportional to the carbon capture efficiency. This is highlighted by An et al[48], where increasing the capture rate from 40% to 85% results in a reduction of natural gas demand from 1.39 MWh/tCO_2 to 0.86 MWh/tCO_2 (a 38% decrease). This is in accordance with onsite demands being solely met by a NGCC unit. If instead electricity demands are met through the grid, then carbon capture efficiency becomes tethered to the carbon intensity of the grid. In fact, grid carbon intensity must be below 62 gCO_2e/kWh to compete with NGCC[48]. Upstream fuel emissions are also significant, with capture efficiencies significantly dropping to 32%-49% if natural gas leakage rates rise to 6%, resulting in an energy consumption of 3.08 MWh/tCO_2[48].

Outputs

CO_2: The key output of all DAC technologies is a pure stream of CO_2, which can either be sequestered to achieve negative emissions (known as DACCS) or be utilised. Existing markets for utilisation include the fertiliser and food & beverage industries, whilst new markets expect to grow significantly in the near future for the production of e-fuels, low carbon concrete, and aggregates[126].

However, the act of reducing GWP through DACCS can come at the expense of increased non-GWP emissions (also known as burden shifting), depending on the source of electricity and heat. Namely acidification, eutrophication, ozone layer depletion and respiratory effects are the most heavily impacted[84].

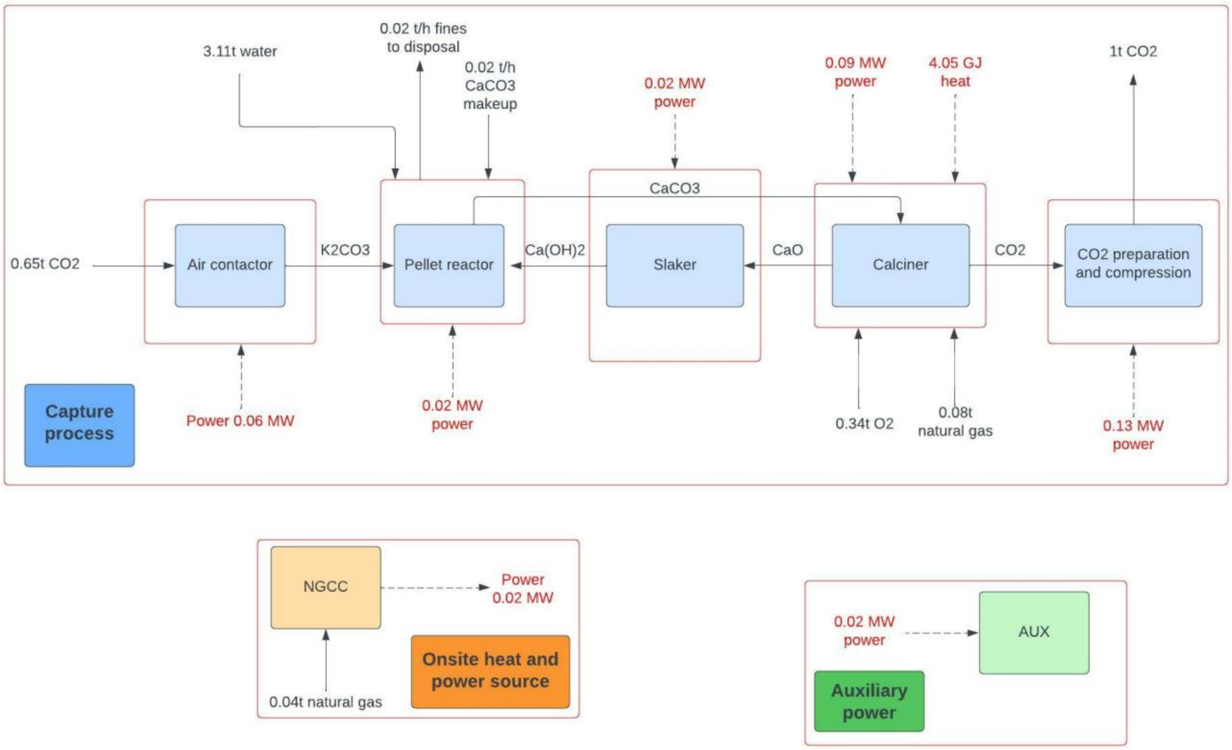
<u>Wastes:</u> During liquid solvent DACCS, waste from $CaCO_3$ fines exiting the pellet reactor must be disposed of within landfill[23]; whilst for solid sorbent DACCS, adsorbents at their end of life must be dealt with appropriately[59].

<u>Water:</u> It has already been established that solid sorbent DACCS is a NETs producer of water, with Climeworks producing 0.8–2 t/tCO_2, which can be used to meet onsite demands or be utilised for electrolysis to produce e-fuels[52].

2.7.1.4 *Schematic*

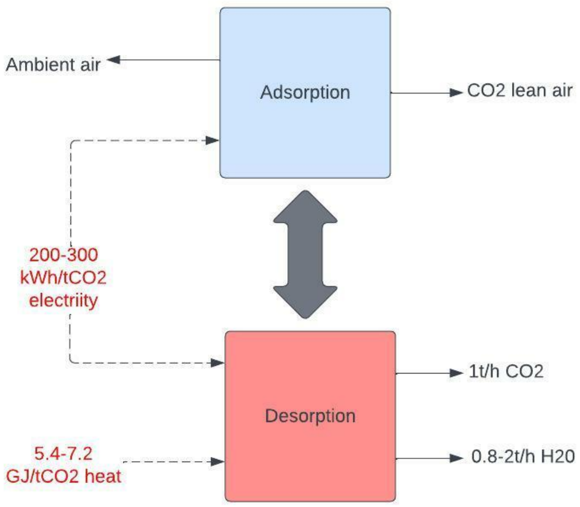
Liquid solvent DACCS

Figure 13: Liquid solvent DACCS schematic



Solid sorbent DACCS

Figure 14: Solid sorbent DACCS schematic



2.7.2 Potential carbon impact

In all instances, both liquid solvent and solid sorbent DACCS exhibit negative emissions, where the source of electricity and heat act as the key emissions hotspots. In the case of liquid solvent DACCS, carbon removal efficiency ranges from 10%-92%, depending on whether the system is powered with coal electricity or by renewables and heat recovery[49]. Similarly, solid sorbent DACCS exhibits removals of 9% - 97%; depending on whether a carbon-intensive grid supplies electricity and heat demands (via heat pumps), or if waste heat and low carbon electricity are used. Please note that to maintain negative emissions the carbon intensity of the grid must remain below 0.87 kg CO_2-eq./kWh[84]. Once sourced with low carbon heat and power, the emissions associated with construction, sorbent consumption and CO_2 T&S become hotpots[84]. These key findings are consistent with the remaining literature reviewed[48,74].

2.7.3 Potential locations in Scotland

As discussed previously, the choice of location will greatly impact the operability of a liquid solvent DACCS facility[48]. For Scotland, the climate is typically mild and access to water is plentiful, so any risks associated with water loss are minimal; however, it is likely that CO_2 absorptions rates will reduce during the winter months. This limitation is not exhibited for solid sorbent DACCS.

As DACCS is flexible in terms of its deployment, then it can be built close to cheap abundant energy and geological storage sites[74]. This is the reasoning behind why Carbon Engineering's Storegga plant will be located close to the Acorn site, which aims to utilise existing oil and gas infrastructure to remove 0.5-1.0 $MtCO_2$/year by 2026[22]. Scottish DACCS deployment could further expand if residual waste heat from industrial hubs, such as Grangemouth, is utilised for solid sorbent DACCS, or if low-grade heat is upgraded via heat pumps and used directly. One such DACCS project funded under the GGR Development Programme proposes utilise 400MWth of waste heat from the Sizewell C nuclear plant to capture 1.5 Mt/year[4]. There is also potential to pair Scotland's offshore wind energy with DACCS facilities[22].

2.7.4 Technology specific limitations & barriers

As the economy continues to decarbonise, there will be competing uses of low carbon electricity which may gain priority over DACCS, such as heating and transport. This will in turn hamper the scalability of the technology. To get around this, DACCS could be powered by fossil fuels; however, this would compromise carbon removal efficiency and go against Net Zero pledges. This is in contrast to BECCS and biochar, which are NETs producers of heat and power[74].

The land demands of DACCS are significant, as sufficient space between the capture units needs to be guaranteed to limit the effects of local CO_2 depletion, which impacts vegetation, wildlife, and capture efficiency[52,135]. This calls into question the practicality of scaling up DACCS to the capacities suggested by the NIC, CCPu and CCC.

When compared to BECCS, DACCS is more energy and materially intensive, and so exhibits higher non-GWP environmental impacts and costs. This in turn leads to Jeswani et al[74] rating DACCS, alongside EW, as the least effective NET. However, electricity costs may be reduced if DACCS facilities are co-located or powered by constrained renewables. Low carbon energy sources, such as heat pumps, geothermal, and solar thermal, could potentially provide heat to solid adsorbent DACCS facilities, although, this is not possible for liquid solvent DACCS facilities due to the high temperature requirements[136].

Liquid solvent DACCS:

- The fabrication of the PVC packing materials and specialty process equipment, such as the contactor and fluidized bed calciner, may pose issues for rapid, large-scale implementation[51].
- The constraint of high-water requirements, depending on location, could limit the locational flexibility of DACCS plants, particularly in dry and remote desert regions where both water demand and its transportation cost could be high[52].

Solid sorbent DACCS:

- During initial plant iterations the adsorbent will likely be consumed at a rate of 7.5 $g/kgCO_2$, which leads to a sorbent lifetime of <1 year. The supply chain for such adsorbents is still in development, indicating that supply chains will need to expand substantially to meet the needs of gigatonne-scale DACCS deployment. One way to get around this is to recycle spent adsorbents, which creates a circular sorbent production process and simultaneously reduces GHG emissions[51].
- Waste heat sources will reduce as economies decarbonise, due to reduced fossil fuel combustion, lack of waste heat in remote locations, and competing uses of waste heat[84].

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[136] Direct Air Capture, technology deep dive, 2022, https://www.iea.org/reports/direct-air-capture

2.8 BIOCHAR

2.8.1 Technology overview

2.8.1.1 TRL

According to the Royal Society, biochar is within a TRL of 3-6, suggesting the technology is within the 'proof of concept' and 'large [pilot plant] scale' phase. It is expected that readiness for implementation at large scale is anticipated within a decade. Additional analysis by Vivid economics[59] and BEIS agree, with TRL ranging from 5 to 7. However, according to the CCC, there is uncertainty over biochar's TRL, as it is not yet demonstrated at scale and there remains some scepticism over its deployment[59].

2.8.1.2 Economics

A breakdown in biochar costs for various plant sizes is provided below in Table 34, which is sourced from research conducted by Shackley et al[137]. OPEX includes the cost of feedstock, transport and storage; the use of natural gas in kick-starting the pyrolysis reaction; labour; plant operational costs; and the application of biochar to the soil. These costs can be used as benchmarks, where the sixth-tenth rule is used to extrapolate CAPEX and OPEX based off biochar production rates.

Further analysis by Ricardo estimated that the gross value added (GVA) of biochar within Scotland could be circa £24.3M, which is significant, and the levelised cost of capture is lower than DACCS and BECCS at 13 – 120 £/tCO_2[67]. These costs are in line Vivid economics, who estimated a capture cost £14-130/tCO_2[59], whilst Haszeldine et al determined a provisional abatement cost of £144-208/tCO_2[35]. In all cases the choice of feedstock, pyrolysis technology, and scale are key.

Table 34: Breakdown in biochar costs provided by Shackley et al[137]

Scale $t_{biochar}$/year	Feedstock	Revenues (£/$t_{biochar}$)			CAPEX (£/$t_{biochar}$)	OPEX (£/$t_{biochar}$)
		Sale of electricity	ROC	Avoided Gate fee		
2,000-16,000	Straw	-37	-74	0	87	260
	SRC	-37	-74	0	87	315
	Arboriculture arisings	-37	-74	0	87	167
16,000-184,800	Straw	-37	-74	0	101	308
	SRC+FRs	-37	-74	0	101	334
	Miscanthus	-37	-74	0	101	377
	Sawmill Residues	-37	-74	0	101	288
	SFR	-37	-74	0	101	354
	Canadian FR	-37	-74	0	101	399
	Waste wood	-37	-74	-124	101	151
	Green waste and sewage sludge	-37	-74	-89	101	151
	C&I veg and animal waste	-37	-74	-96	101	151
>184,800	Straw	-37	-74	0	45	201

137 Shackley et al, 'The feasibility and costs of biochar deployment in the UK': Full article: The feasibility and costs of biochar deployment in the UK (tandfonline.com)

Scale $t_{biochar}$/year	Feedstock	Revenues (£/$t_{biochar}$)			CAPEX (£/$t_{biochar}$)	OPEX (£/$t_{biochar}$)
		Sale of electricity	ROC	Avoided Gate fee		
	SRC+FRs	-37	-74	0	45	233
	Miscanthus	-37	-74	0	45	282
	Sawmill Residues	-37	-74	0	45	173
	SFR	-37	-74	0	45	254
	Canadian FR	-37	-74	0	45	296
	Waste wood	-37	-74	-124	45	42
	Green waste and sewage sludge	-37	-74	-89	45	42
	C&I veg and animal waste	-37	-74	-96	45	42

2.8.1.3 Inputs/outputs

Inputs

Feedstocks: The most promising feedstock source for biochar production is waste, as it eliminates the need for additional land, gives value to waste and exhibits the lowest life cycle emissions[138,55]. These waste feedstocks can be sourced from a variety of suppliers, such as sewage companies and farmers. Energy crops and woody feedstocks can also be utilised; however, these will directly compete with other BECCS technologies and do not exhibit the same benefits as waste.

Land: In terms of land requirements, biochar requires circa 1 ha/tCO_2, which is significantly higher than compared to BECCS (0.03-0.07 ha/tCO_2), due to the lower efficiencies of biochar technology[67].

Outputs

Apart from providing negative emissions, biochar can also be utilised in the agricultural, horticultural, construction, water treatment and environmental remediation sectors[35]. Most notably, the application of biochar to soil can help improve soil health by absorbing heavy metals (e.g., arsenic and copper), increase water and nutrient retention, and stabilise pH and microbial populations, which in turn improve crop yields and help remove pollutants within the food chain[139]. The use of biochar as a form of activated carbon within waste treatment processes[139], act as a substitute for charcoal and coal for the provision of low-carbon heat[139]. The by-products of condensable gases and vapours (i.e. syngas and bio-oil) produced during pyrolysis can also be combusted to provide heat and electricity or be utilised within heavy industry[53,56].

Biochar is a NETs energy producer, producing circa 1.39 to 3.89 MWh/tCO_2[138].

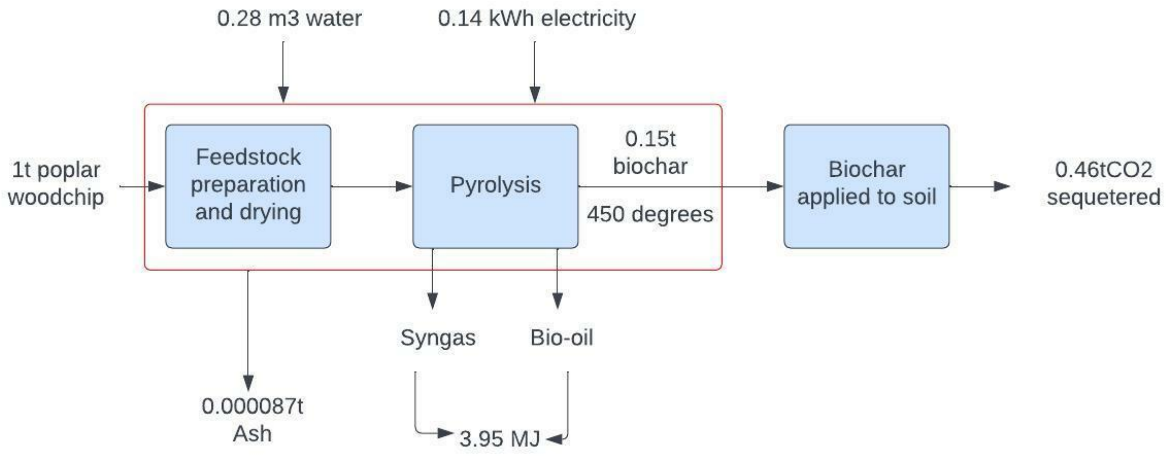
[138] The Royal Society (2018), 'Greenhouse gas removal': https://royalsociety.org/-/media/policy/projects/greenhouse-gas-removal/royal-society-greenhouse-gas-removal-report-2018.pdf

[139] Peters et al (2015), 'Biomass Pyrolysis for Biochar or Energy Applications? A Life Cycle Assessment': Biomass Pyrolysis for Biochar or Energy Applications? A Life Cycle Assessment | Environmental Science & Technology (acs.org)

2.8.1.4 Schematic

The schematic for biochar production via poplar woodchip is from Peters et al[139].

Figure 15: Biochar production using poplar woodchip feedstock



2.8.2 Potential carbon impact

For the pathways modelling, performance data for a reference biochar plant is needed to calculate the CO_2 capture potential in Scotland. The carbon sequestration potential was taken to be 3 tCO_2/tbiochar, based on the mass balance from the above schematic. The utilisation factor of the plant is taken to be 85%[121], assuming that the pyrolysis plant operates to a similar degree to a gasification plant, and the biogenic content of the captured CO_2 is assumed to be 100% if woody biomass feedstocks are utilised and 50.3% if MSW is used (see Section 2.3.2 for more information).

A literature review by Jeswani et al[74] identified biochar as exhibiting the lowest GWP potential when used as a soil amendment, whilst Matusik et al[55] highlighted that biochar production reduces GHG emissions in all cases; with life cycle emissions ranging from -2561 kg CO_2/t,biochar to 3.85 kgCO_2/kg,rice. In instances where carbon emissions are positive, these emissions are still lower than compared to business as usual. This is reflected by the fact that biochar offsets agricultural emissions onsite, with 80-90% of this carbon remaining in a stable condition for hundreds of years[55].

Typically waste derived biochar exhibits the lowest lifecycle emissions, due to waste production and management emissions being discounted[138]; however, this is counteracted by waste derived biochar exhibiting the lowest carbon removal potential. In this case woody biomass and perennial grasses provide the optimal carbon removal potential.

Despite the benefits, biochar production does lead to an increase in non-GWP emissions (known as burden shifting). In particular, acidification, eutrophication and ecotoxicity all increase, due to higher demands for fertiliser and grid electricity[55]. The co-benefits of biochar for soil health are also uncertain, with potential irreversible impacts regarding heavy metals and organic contamination[22,59].

2.8.3 Potential locations in Scotland

In the UK, 66% of land use is agricultural, which acts as a NETs CO_2 source due to farming intensive practices that have disturbed the soil (emitting c. 16MtCO_2/year in 2009). Soil pH levels have also increased because of this[140]. For Scotland, around 30% (2.3 Mha) of land use is agricultural, which emitted 7.7 Mt CO_2/year in 2007, whilst 17% is forest (1.3 Mha). These forests are capable of sequestering 10MtCO_2/year and have potential to sequester 11 MtCO_2/year by 2050[140].

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[140] Ahmed et al (2011), 'The potential role of biochar in combating climate change in Scotland: An analysis of feedstocks, life cycle assessment and spatial dimensions': https://www.tandfonline.com/doi/abs/10.1080/09640568.2011.608890?journalCode=cjep20

The biochar plant should be located close to supplies of suitable biomass and transport infrastructure (for virgin feedstocks). The most important factors for biochar location are proximity to woodlands, grasslands and on lower sloping land to reduce risk of erosion. Areas in the south, south-eastern and eastern regions of Scotland are most suitable for installing a biochar facility (e.g., Glasgow, Central Scotland, Lothian region and Fife). This is due to close proximity to roads, and hence are more likely to minimise transport costs between sources of feedstocks and sinks for biochar[140].

Analysis by Haszeldine et al[35] highlights potentials for emission abatement within Scotland of 0.6-3.9 Mt C/year when using domestic feedstocks at a land requirement of 5,200 km^2.

2.8.4 Limitations/barriers

The application rate of biochar must be limited to 30-60 t/ha, to ensure soil surface reflectivity does not decrease significantly and damage crops. This limits the deployment of biochar. BECCS does not exhibit this constraint, and is also more energy efficient[138], has a higher negative emission potential, and is a more mature technology[67]. On this basis, it could be argued that BECCS be prioritised when allocating biomass resources and public funding. Furthermore, like other NETs, biochar may be denied public licence if scaled up, as it is viewed as “incineration in disguise”[138].

From a policy perspective, stronger regulation on waste[22] and the issuing of environmental permits[59] will be necessary if biochar capacity grows significantly within the next few decades. Furthermore, in order to verify that biochar has been applied to the soil, an appropriate MRV procedure will need to be outlined which accounts for uncertain storage permeances[59] and the varying decomposition rates of biochar depending on the choice of feedstock and temperature[138]. These will in turn require improvements in modelling biochar spread, which is complex[59].

2.9 BIOFUEL PRODUCTION WITH CCS

2.9.1 Technology overview

2.9.1.1 TRL

Biofuel production encompasses a large range of technologies. First generation biofuels, such as bioethanol from sugar or starch crops are commercially established, with an estimated UK capacity of 927 Mlt per year, producing 326 Mlt is 2020[141]. Production of biodiesel from crop-derived feedstocks (Rapeseed oil) has declined entirely within the UK in favour of waste feedstocks such as used cooking oil (UCO) and tallow, of which 421 Mlt was produced in the UK from an estimated capacity of 557 Mlt per year[141]**. Of these established technologies, no bioethanol production takes place in Scotland**, whilst biodiesel fatty acid methyl ethers (FAME) production consists of a 70 Mlt capacity plant in Motherwell. Although not present in the UK, there is a significant capacity of biodiesel HVO (Hydrotreated Vegetable Oil), classed as a 2nd generation biofuel, production facilities in the EU, with a total capacity of 5,280 Mlt per year[142]. Similarly, to FAME production in the UK, these are derived from feedstocks such as: UCO, animal fats and palm oil.

Second generation bioethanol, from feedstocks other than food crops, is less established than diesels. The USDA estimate that 50 Mlt of cellulosic ethanol, from a capacity of 200 Mlt per year, was produced in the EU in 2021[142]. Feedstocks include wheat and rice straw, saw dust and forest residues. These advanced bioethanol production processes include a fermentation stage, in common with 1st generation crop-based bioethanol[143,144].

Drop-in biofuels may also be produced from forest residues and kraft pulp process by-products (including black liquor, black liquor lignin and crude tall oil) by hydrotreatment or gasification pathways. These may produce both drop-in gasoline and drop-in diesels. Capacity of these plants amounts to 341 Mlt per year, of which the vast majority (all production excluding 6 Mlt per year) is tall oil to drop-in diesel production, attached to pulp production facilities in Finland and Sweden[142].

2.9.1.2 Economics

Table 35 presents associated costs and GHG footprints for a selection of biomass to biofuel pathways, provided by Jafri et al[146]. The levelised cost of production (LCOP) with and without CCS fitted is given, showing

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[141] DEFRA, (2021), Area of crops grown for bioenergy in England and the UK: 2008-2020. Section 1: Biofuels

[142] US Department of Agriculture, (2021): European Union: Biofuels Annual

[143] Beta Renewables: What is Proesa™?

[144] St1 Nordic Oy, (2018): St1 Cellunolix® process – Lignocellulosic bioethanol production and value chain upgrading

the additional cost of capturing carbon on the final product. It should be noted that all CO_2 streams are assumed to be captured. Therefore, fermentation processes (for example) are fitted with capture equipment for both concentrated and dilute streams, costs with only fermentation capture were not modelled. Capture costs are also inclusive of transport and storage. GHG footprints were calculated on a well-to-wheels basis, the table provides GHG emissions for CCS fitted plants, negative numbers represent a NETs removal of CO_2. The cost of carbon presented in the final column is the additional LCOP for CCS equipped plant compared to without, per tonne of carbon captured.

Table 35: Costs and GHG footprints associated with biofuel production

GHG emissions from production with CCS and additional cost of captured carbon for a selection of biofuel pathways[146].

Main process	Pathway	LCOP £'21/MWh	LCOP with CCS £'21/MWh	GHG footprint $kgCO_2/MWh$	Cost of carbon £'21/tCO_2
Fermentation	Wheat grain to bioethanol	60	91	-88	349
	Sawdust to bioethanol	128	162	-200	173
Hydrotreatment	Tall oil to drop-in fuels	55	58	6	N/A
	Tallow to drop-in fuels	107	108	43	N/A
	Forest residues to drop-in fuels	113	179	-351	189
Gasification	Bark to drop-in fuels	115	130	-420	35

Drop-in fuels from tall oil and tallow are two advanced biofuel processes currently at commercial scale. Adding carbon capture to these plants results in very little increase in production costs. However, even with carbon capture, the GHG footprint of these pathways remain positive. This is not because the upstream emissions of these pathways are particularly high, the GHG footprint without CCS for the six pathways in Table 35 range from 17 to 63 $kgCO_2/MWh$, with tall oil and tallow at 28 and 51 $kgCO_2/MWh$ respectively. However, a larger amount of the carbon embodied in the feedstock is either converted into fuel or a valued by-product and is not considered capturable. For these two processes, around 84-89% of the process carbon input is realised in biofuel or tradeable by-products. In comparison, the gasification pathways result in only 29-36% of the carbon input is output as biofuel or by-product. The two hydrotreatment pathways, therefore, have reduced opportunity to capture CO_2 by being more "carbon efficient".

Wheat grain to ethanol and forest residues to drop-in fuels have similar uplifts in LCOP from fitting and operating CCS, by around 50-60%. However, a combination of high upstream emissions and relatively high conversion of feedstock carbon to fuel or tradeable by-products (63%) result in wheat grain to bioethanol having the highest cost of carbon. However, of the options providing negative emissions wheat grain to bioethanol has the lowest fuel production cost with or without CCS, making it the most commercially viable NETs option in the absence of negative emissions payments. Conversely, bark to drop-in gasoline has the lowest carbon capture cost due to a small uplift in production cost, relatively low upstream emissions and low conversion of feedstock carbon to fuel. However, production costs are higher than wheat grain to bioethanol making the process less commercially viable on revenue from fuel alone.

2.9.1.3 Inputs / outputs

First generation bioethanol production relies on a fermentation process. This produces a highly concentrated stream of CO_2 that is easily captured. As discussed in 2.9.1, the primary inputs to 1st generation bioethanol production are food-based crops. In the UK these are predominantly wheat grain and sugar beet, however, corn, barley, rye and triticale are also commonly used in other countries[141,142].

Taking sugar beet to ethanol as an archetypical biofuel plant for Scotland, per 1 kg of sugar beet input, 0.104 kg of carbon dioxide may be captured from the fermentation process[145]. Process heat is required throughout the plant, whether this can contribute to negative emissions or not is dependent on how the heat provision is fuelled. There is potential to provide this by anaerobic digestion of distillation waste (vinasse) to produce

[145] NNFCC, (2019): An Assessment of the Opportunities for Re-establishing Sugar Beet Production and Processing in Scotland

biogas. Capturing post-combustion CO_2 could provide 0.05kg CO_2 of negative emissions, and upgrading any residual biogas for biomethane injection a further 0.015kg CO_2. An alternative feedstock common in Europe is wheat grain. In this case, per 1 kg of carbon input, 0.224 kg of capturable carbon could be expected from the fermentation process (approximately 0.41 kg CO_2 per kg of wheat grain input)[146]. Heat input is required at the distilling stage, whether this can contribute to negative emissions or not is dependent on how the heat provision is fuelled. In an example where biomass CHP is used, an additional 0.38 kgCO_2 could be captured via post-combustion capture technology.

As with 1st generation bioethanol production, many of the established production pathways for cellulosic ethanol involve a fermentation processes, resulting in easily captured concentrated CO_2. An example sawdust to ethanol plant produces 0.28kg of concentrated CO_2 during the fermentation stage, for each kg of sawdust input. An additional concentrated CO_2 stream may be produced by anaerobic digestion of the liquid phase resulting from steam pre-treatment of the sawdust. Upgrading the resulting biogas could contribute a further 0.034 kgCO_2 per kg of sawdust input. Additionally, combustion is required to generate the required heat for the process. Providing this, using lignin pellets resulting from the process, could contribute a further 0.27kgCO_2 captured via post-combustion capture technology[146].

Drop-in diesel and gasoline by hydrolysis pathways do not generally result in any intrinsic production of capturable biogenic CO_2. However, they require heat input to the process, and this may be provided by biomass combustion, either directly via an additional biofuel input or by combustion of off-gases from the process. Alternatively, the required heat could be provided by fossil fuel, in which case there would be no negative emissions potential. In all cases, a dilute CO_2 stream is produced which must be captured using post-combustion capture technology. Per kg of feedstock, potential negative emissions ranges from 0.017kgCO_2 per kg (for meat industry by-products to diesel using hydrodeoxygenation) to 0.47kgCO_2 (for forest residues to gasoline via fast pyrolysis). One of the most common hydrolysis pathways, raw tall oil to drop-in diesel, results in a potential 0.44kgCO_2 per kg of tall oil input. Although this assumes capture of combusted biofuels required for process heat.

Gasification pathways result in intrinsic emissions of concentrated CO_2 during the syngas conditioning phase (acid gas removal). The negative emissions potential (per kg of feedstock input) from syngas conditioning ranges from 0.312kgCO_2 via fluidized-bed gasification of bark, up to 0.528kgCO_2 from entrained-flow gasification of black liquor (a pulp production by-product). Black liquor to drop-in gasoline does not have the potential for a large amount of additional CO_2 capture. However, combustion of syngas, char, RME and tars during the bark to drop-in gasoline process results in a large potential for additional CO_2 capture (0.59kgCO_2 per kg of bark). Both concentrated and dilutes CO_2 streams give bark to drop-in gasoline the highest potential negative emissions (per kg of feedstock input) of any biofuel option.

[146] Jafri et al. (2022): Double Yields and Negative Emissions? Resource, Climate and Cost Efficiencies in Biofuels With Carbon Capture, Storage and Utilization

2.9.1.4 Schematics

Figure 16: Mass balance schematic for sugar beet to bioethanol process.

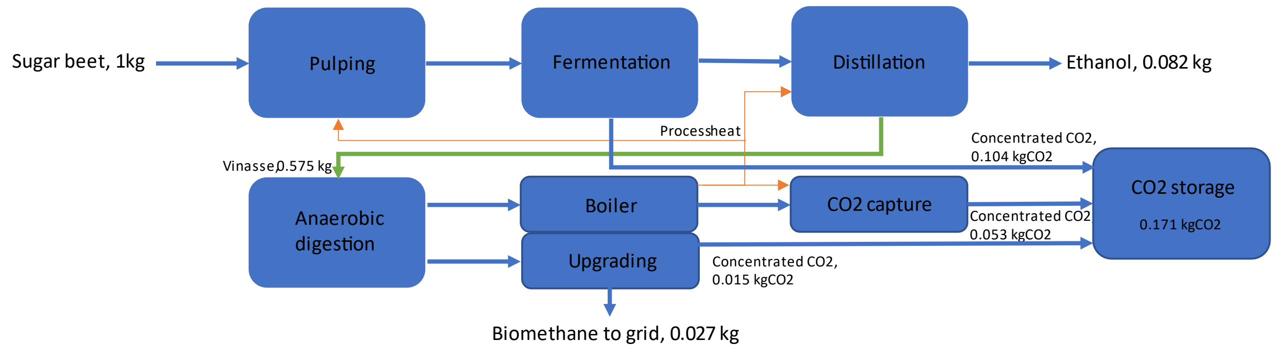


Figure 17: Mass balance schematic for sawdust to bioethanol process.

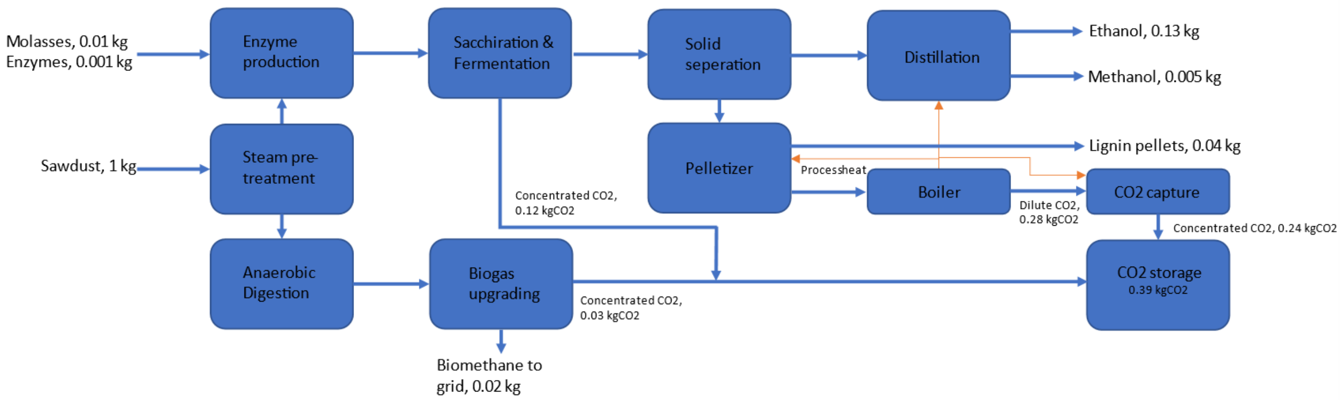
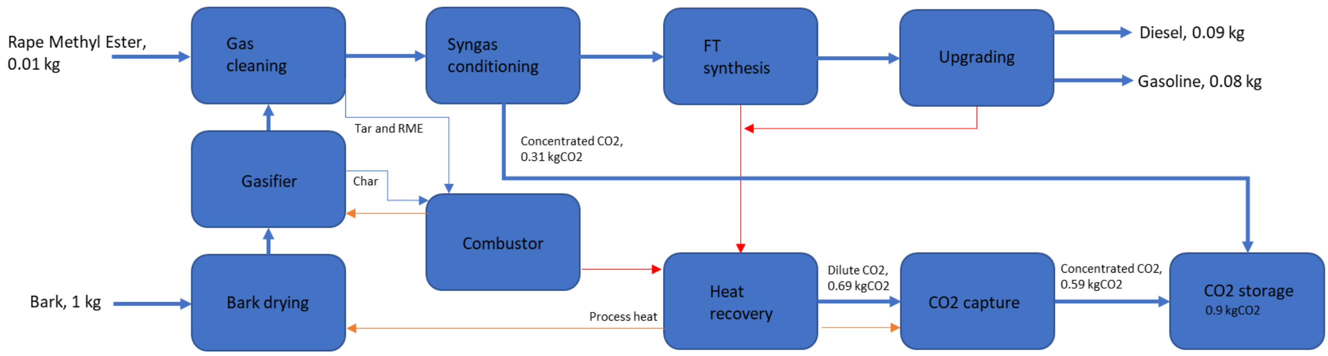


Figure 18: Mass balance schematic for bark to drop-in biofuels using gasification.



2.9.2 Potential carbon impact

NNFCC studied the potential of a sugar beet to bioethanol industry in Scotland[145]. Three scenarios were explored, including an E4 (petrol mandated to contain 4% bioethanol), E10 and “most likely” scenario, producing 57, 145.2 and 171.8 million litres of bioethanol per year, respectively. Sugar beet input required ranges from 551 k tonnes to 1.6 M tonnes, equating to 1.1% to 3.2% of Scotland’s arable land (in comparison to 2.3% of arable land currently used to cultivate sugar beet in England). The negative emissions potential for each of these scenarios are 59, 150 and 177.4 kt of concentrated CO_2 from fermentation alone. Adding co-production, onsite combustion and upgrading of biogas, a total potential of 97, 247.5 and 292.8 kt CO_2 could be captured.

Similar processes to the sawdust to bioethanol plant (as illustrated in Figure 17) can be used for a number of feedstocks, including whisky industry by-products (DDGS, pot-ale and draff)[147] and agricultural by-products such as straw. Section 1.5 discussed the availability of these resources in Scotland. There is estimated to be an excess of sawmill residues of 0.53 Mt by 2030 but falling to 0.36 Mt by 2045. Of this, approximately 28% (0.15 Mt and 0.1 Mt) is sawdust. There is a surplus of whisky by-products of 1.75 Mt currently, which is expected to increase to 2.01 Mt and 2.42 Mt in 2030 and 2045 respectively. Of straw, there is a current excess supply of 0.29 Mt which is not expected to change out to 2045.

Table 36: Fermentation and other capturable CO_2 from bioethanol production

Adapted from sawdust to bioethanol process in Figure 17, on that basis of feedstock carbon content. May not reflect differences in process due to change in feedstock. Feedstock quantities based on 2030 estimates. All figures presented in kilo tonnes (kt)

	Sawdust	Draff	Pot-Ale	DDGS	Straw
Available feedstock	148.7	51.7	1,610.9	19.2	293.7
Fermentation CO_2	17.5	3.7	94.6	5.3	58.7
Other CO_2	40.0	8.3	215.8	12.0	134.0

2.9.3 Potential locations in Scotland

Typical locations include abattoirs (tallow), sawmills (forest residues), ports (UCO), pulp mill (UPM Caledonian) and sugar beet, ideally sourced within 60 miles. Excess transport distances increase the cost of feedstock beyond economic viability.

2.9.4 Technology specific limitations & barriers

Fermentation produces a concentrated stream of CO_2. Little equipment is required to capture the CO_2 from fermentation. Production of bioethanol via sugar and starch crops is widespread throughout Europe and presents the technologically easiest route to capturing biogenic carbon. According to ePure, renewable ethanol producers in Europe captured 0.87Mt of CO_2 in 2020[148] However, no bioethanol plants currently exist in Scotland. The NNFCC studied the potential of creating a sugar beet to bioethanol industry in Scotland, although there are a number of barriers to introducing this industry to Scotland.

Firstly, although generally viewed as a low carbon alternative to fossil fuels, production of biofuels from food crops raises concerns of food production being displaced to land not previously cultivated, therefore causing emissions through indirect land use change (ILUC). In response, current policy generally favours development of second-generation biofuels derived from wastes and residues. RED II placed restrictions on the increasing use of first generation (1G) biofuels within member countries, and both RED II and RTFO allow double counting of advanced biofuels to encourage development. Secondly, bioethanol is most applicable to light duty vehicles (passenger cars and light commercial vehicles), a sector of road transport seeing increasing penetration of electric vehicles. Accordingly, studies into future fuel demand often include scenarios which see a reduction in demand liquid fuels as a whole, and 1G biofuels in particular[149].

Although demand for liquid transport fuel may decline overall, there remains opportunities for advanced biofuel production to grow by displacing fossil fuels and 1G biofuels. As discussed in section 2.9.1, options for production of advanced biofuels are already deployed commercially in Europe, but at much smaller scale than more conventional biofuel production routes. Establishing biofuel production as a significant source of negative emissions within Scotland will be dependent on first establishing large-scale production in the country. Processes for advanced biofuels including a fermentation step, such as ABE fermentation, will present the technologically easiest route for negative emissions. Hydrotreatment pathways do not generally produce a concentrated CO_2, negative emissions from this technology will be dependent on deployment of post-combustion capture technology described in section 1.2.1. Gasification processes to liquid biofuels are at lower

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[147] Celtic Renewables: About us
[148] ePure, (2021): European Renewable Ethanol – key figures 2020 (www.epure.org)
[149] Concawe, (2021): Transition towards Low Carbon fuels by 2050: Scenario analysis for the European refining sector

TRL than other processes but present an opportunity to capture a concentrated stream of CO_2 from syngas separation process (acid gas removal).

APPENDICES

APPENDIX 1. TCO2, CAPEX & OPEX FOR PATHWAYS

MTCO2 PER YEAR

Table 37: NETs potential per year; all values are in $MtCO_2$

Carbon emissions - ALL SITES	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Pathway 1: No Action	**-**	**-**	**-**	**-**	**-**	**0.6**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**
Pathway 2: SG Action	**-**	**-**	**-**	**-**	**-**	**0.8**	**0.9**	**1.1**	**1.2**	**1.2**	**1.2**
Pathway 3: UKG & SG Action	**-**	**-**	**-**	**-**	**0.1**	**2.2**	**2.8**	**3.2**	**3.7**	**4.0**	**4.5**

Carbon emissions - ALL SITES	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
Pathway 1: No Action	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	
Pathway 2: SG Action	**1.2**	**1.2**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	
Pathway 3: UKG & SG Action	**4.7**	**4.8**	**4.9**	**4.9**	**6.1**	**6.2**	**6.3**	**6.3**	**6.3**	**6.8**	

CAPEX PER YEAR

Table 38: CAPEX per year, all values are in £M

Carbon emissions - ALL SITES	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Pathway 1: No Action	-	-	-	-	-	702	0	0	6	-	-
Pathway 2: SG Action	-	-	-	-	-	823	-	-	-	-	-
Pathway 3: UKG & SG Action	-	-	-	-	49	1,314	88	59	224	258	292

Carbon emissions - ALL SITES	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
Pathway 1: No Action	-	-	-	-	-	-	-	-	-	-	
Pathway 2: SG Action	-	-	-	-	1	-	-	-	-	-	
Pathway 3: UKG & SG Action	206	31	76	-	1,568	-	-	-	-	157	

OPEX PER YEAR

Table 39: OPEX per year, all values are in £M

Carbon emissions - ALL SITES	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Pathway 1: No Action	-	-	-	-	-	-	25	26	49	51	53
Pathway 2: SG Action	-	-	-	-	-	-	25	26	49	51	52
Pathway 3: UKG & SG Action	-	-	-	-	-	12	131	167	171	224	317

Carbon emissions - ALL SITES	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
Pathway 1: No Action	54	55	57	58	60	61	63	64	66	68	
Pathway 2: SG Action	53	55	56	57	59	64	66	68	69	71	
Pathway 3: UKG & SG Action	363	396	412	433	444	521	534	548	562	576	

APPENDIX 2. LCOC ANALYSIS

Data sources

Disregarded sites

The following sites were disregarded due to a lack of data in the literature, the site is fossil fuel powered, and/or the site is located on an island. In the instance that the site is an island, the capture carbon would have to be shipped and then transported by road to one pf our chosen CO_2 injection points, which is unrealistic given that the site will offer low CO_2 capture potentials.

Table 40: A list of sites disregarded from our analysis

Site	Owner	Type of Technology	Reason
North British Distillery	Lothian Distillers	Grain whisky	Already deploys CCS
Caol Ila	Diageo	Malt whisky	Island based
Laphroaig	Beam Suntory	Malt whisky	
Bunnahabhain	Burn Stewart Distillers (Distell International)	Malt whisky	
Highland Park	The Edrington Group	Malt whisky	
Jura	Whyte & Mackay (Emperador)	Malt whisky	
Lagavulin	Diageo	Malt whisky	
Bowmore	Beam Suntory	Malt whisky	
Bruichladdich	Rémy Cointreau	Malt whisky	
Scapa	Chivas Brothers Ltd. (Pernod Ricard)	Malt whisky	
Ardbeg	The Glenmorangie Co. (LVMH)	Malt whisky	
Arran	Isle of Arran Distillers	Malt whisky	
Tobermory	Burn Stewart Distillers (Distell International)	Malt whisky	
Lagg	Isle of Arran Distillers	Malt whisky	
Ardnahoe	Hunter Laing & Co.	Malt whisky	
Kilchoman	Kilchoman Distillery Co.	Malt whisky	
Harris	Isle of Harris Distillers Ltd.	Malt whisky	
Isle of Raasay	R&B Distillers	Malt whisky	
Abhainn Dearg	Mark Tayburn	Malt whisky	
Lerwick Energy Recovery Plant	Shetland Islands Council	BECCS EfW (Heat only)	
Western Isles Integrated Waste Management Facility	Western Isles Waste Management	BECCS AD (CHP)	
Pulp Mill House[150]	Pulp-tec	BECCS Industry (pulp)	Lack of data
Cullen[151]	Robert Cullen Ltd	BECCS Industry (pulp)	
Sapphire Mill	Fourstones Paper Mill Co Ltd	BECCS Industry (paper towel)	A gas-powered site. No potential for NETs

[150] Pulp-Tec - the leading producer of moulded pulp in Europe: pulp-tec
[151] Cullen - Manufacturer of moulded pulp and corrugated packaging | UK

BECCS Biomethane

The following sites considered were identified using the NNFCC database and REPD.

Table 41: BECCS Biomethane data point summary

Extracted from the literature and used in the calculations for the NETs Model

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Feedstock Capacity (t/year)	Biomethane produced (m^3/hr)	Data source
Portgordon Maltings Beyside	Grissan Energy	Operational	Biomethane grid injection & CHP	5	837,500	800	NNFCC
Brae of Pert Farm	Qila Energy	Operational	Biomethane grid injection & CHP	0.25	35,000	550	NNFCC
Charlesfield Industrial Estate	Charlesfield First	Operational	Biomethane grid injection & CHP	0.249	24,995	550	NNFCC
Cumbernauld AD	Shanks	Operational	Biomethane grid injection & CHP	3.6	100,000	495	NNFCC
Downiehills Farm	Buchan Biogas	Operational	Biomethane grid injection & CHP	0.5	55,000	550	NNFCC
Girvan Distillery	Grissan Energy	Operational	Biomethane grid injection & CHP	7.2	300,000	2,750	NNFCC
Glenfiddich Distillery	William Grant & Sons	Operational	Biomethane grid injection	3.5	80,000	2,000*	NNFCC
Hatton Farm AD	Grissan Energy	Operational	Biomethane grid injection & CHP	0.5	38,000	450	NNFCC
Inchdairnie Farm	Qila Energy	Operational	Biomethane grid injection & CHP	2	40,000	500	NNFCC
Invergordon Distillery	Whyte & Mackay	Operational	Biomethane grid injection & CHP	0.25	36,500	500	NNFCC
Keithick Farm	Keithick Biogas	Operational	Biomethane grid	0.249	36,000	605	NNFCC

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Feedstock Capacity (t/year)	Biomethane produced (m^3/hr)	Data source
			injection & CHP				
Lockerbie Creamery	Lockerbie Biogas Ltd	Operational	Biomethane grid injection	0.5	98,250	768	NNFCC
Morayhill AD	Qila Energy	Operational	Biomethane grid injection & CHP	0.25	40,000	495	NNFCC
Peacehill Farm	TD Forster & Son	Operational	Biomethane grid injection & CHP	0.237	30,450	550	NNFCC
Rosskeen Farm	Qila Energy	Operational	Biomethane grid injection & CHP	0.25	36,000	450	NNFCC
Savock Farm	Qila Energy	Operational	Biomethane grid injection & CHP	0.25	40,000	600	NNFCC
Tambowie Farm	Tambowie Biogas	Operational	Biomethane grid injection & CHP	0.973	24,000	220	NNFCC
TECA AD	Aberdeen City Council	Operational	Biomethane grid injection & CHP	0.35	81,012	425	NNFCC
Portgordon Maltings – Anaerobic Digestion Facility	Grissan Engineering Services Limited	Permission Granted	Biomethane	0	0	2,000**	REPD
Lockerbie Creamery – Anaerobic Digester	Lockerbie Biogas Limited	Permission Granted	Biomethane	0	0	916***	REPD
Mains Of Boquhan - Anaerobic Digester Facility	Grahams Family Dairy	Permission Granted	Biomethane	0	21,500	274****	REPD
Millerhill AD	Biogen	Operational	BECCS Biomethane (grid injection & CHP)	1.5	35,000	445.6	NNFCC

* Regarding the Glenfiddich Distillery site, it is split into two installations. The first consists of two 11.5m high by 30m diameter reactors with a 3.5 MW biogas-fuelled CHP[152], and the second installation includes two 14.7m high by 28m diameter reactors[153]. Assuming a standard medium-sized anaerobic digestor tank produces around 500m3/hr of biomethane, the estimated biomethane production potential is approximately 2000 m3/hr.

** The information provided in the REPD Database regarding the operational capacity of the Portgordon Maltings site was insufficient. To obtain more comprehensive details, we conducted a thorough examination of the planning application submitted to the council. [154] Our investigation revealed that the project had been divided into two phases, which were represented separately in the REPD. The complete project consists of four primary digester plant tanks, each measuring 28m in diameter and 16.9m in height, along with three smaller feedstock tanks measuring 22.5m in diameter and 10m in height. The primary source of feedstock for the project will be waste from the malting plant and nearby distilleries. Considering that both project phases are located on the same site, we have chosen to merge them. Based on the assumption that an average biomethane tanker has a capacity of 500 m3/hr, we have determined a total site capacity of 2,000 m^3/year.

*** The information provided in the REPD Database regarding the operational capacity of the Lockerbie Creamery site was insufficient. To obtain more comprehensive details, we conducted a thorough examination of the planning application submitted to the council. [155] The application for the project exhibited several variations, and according to the SEPA permit, the installation will comprise of two 1.5MWth input natural gas CHP units and inject around 54,965 MWh of biomethane into the grid. This injection rate is equivalent to ~5,496,500 m3/year, which we have utilised in our analysis.

$$Biomethane\ injection\ rate = \frac{54{,}965\ MWh}{yr} \times \frac{m^3}{36\ MJ} \times \frac{3.6\ MJ}{kWh} \times \frac{10^3\ kWh}{MWh} = 5{,}496{,}500\ m^3/yr$$

**** The information provided in the REPD Database regarding the operational capacity of the Mains of Boquhan site was insufficient. To obtain more comprehensive details, we conducted a thorough examination of the planning application submitted to the council.[156] According to the application, the site is designated as an AD Upgrading facility utilizing the water scrubbing method. The proposed feedstock inputs for the facility include whey (20,000t), sludge from milk pasteurization (500t), manure (500t), and grass silage (500t), totalling 21,500 tonnes per year. Since the provided data only pertains to feedstock inputs, it was necessary to employ calculations specific to BECCS AD Upgrading to determine the biomethane production capacity and associated costs. This approach differs from the methodology used for other BECCS Biomethane sites.

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[152] 13/01781/EIA | Anaerobic digestion facility energy plant and associated infrastructure at | Glenfiddich Distillery Castle Road Dufftown Keith Moray AB55 4DH

153 19/00988/APP | Extension to Anaerobic Digestion Facility Energy Plant and associated infrastructure at | Grissan Riverside Ltd Glenfiddich Distillery Castle Road Dufftown Keith Moray AB55 4DH

154 Moray Council: Planning Application: 21/01605/APP

155 SEPA: draft_decision_document.pdf (sepa.org.uk)

[156] Strathclyde County: Planning Application: 21/00686/FUL

https://pabs.stirling.gov.uk/online-applications/applicationDetails.do?activeTab=documents&keyVal=QX7BJCPIG0N00

BECCS Power

The following sites considered were identified using the REPD.

Table 42: BECCS Power data point summary

Extracted from the literature and used in the calculations for the NETs Model

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Data source
Markinch Biomass CHP Plant	RWE	Operational	BECCS Power (CHP)	65	REPD
Stevens Croft	E.ON	Operational	BECCS Power	50.4	REPD
Westfield Biomass Power Station	EPR Scotland	Operational	BECCS Power	12.5	REPD
Speyside Biomass CHP Plant	Speyside Renewable Energy Partnership	Operational	BECCS Power (CHP)	12.5	REPD
Rothes Bio-Plant	Scottish Bio-Power	Operational	BECCS Power (CHP)	8.3	REPD
Sustainable Power and Research Campus	University of St Andrews	Operational	BECCS Power (CHP)	6.5	REPD
Acharn Forest Killin Biomass Plant	Northern Energy Developments	Operational	BECCS Power (CHP)	5.6	REPD
Diageo Biomass Energy Project	Diageo	Operational	BECCS Power	5.5	REPD
Harbour Road	Glennon Brothers Troon	Operational	BECCS Power (CHP)	2.6	REPD
Gleneagles Hotel Biomass Boiler Plant Room	AMP Energy Services Limited	Operational	BECCS Power	1.2	REPD
Macphie of Glenbervie	Macphie Ltd.	Operational	BECCS Power	1.2	REPD
Co-Op, Polwarth Street - Biomass boilers	Gold Energy Limited	Permission Granted	BECCS Power	0.44	REPD
Hillhead Of Coldwells, Longhaven - Biomass Boilers	Private Developer	Permission Granted	BECCS Power	0.26	REPD
Little Broomfield - Biomass boiler	Private Developer	Permission Granted	BECCS Power	0.21	REPD

BECCS Industry

The sites considered were identified using the REPD, HNPD, SPRI, and CHPQA databases. The Morayhill Mill site was identified through the REPD, but site-specific data was obtained through stakeholder engagement.

Table 43: BECCS Industry data point summary

Extracted from the literature and used in the calculations for the NETs Modell

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Data source
Caledonian Papermill	Caledonian Paper	Operational	BECCS Industry CHP (paper - coated magazine)	26	REPD and CHPQA
Cowie Biomass Facility	Norbord	Operational	BECCS Industry CHP (Particle & MDF)	15	REPD and CHPQA
Invergordon Pellet Mill	Balcas	Operational	BECCS Industry CHP (wood pellets)	5	REPD and CHPQA
Morayhill Mill	Norbord	Operational	BECCS Industry (Oriented Strand Board)	100*	Stakeholder engagement
Barony Road, Auchinleck	EGGER BARONY LTD (particle)	Operational	BECCS Industry CHP (Chipboard and wood recycling)	5.5	HNPD
Dunbar Cement	Tarmac	Operational	BECCS Industry (Cement)	N/A	SPRI and websites[114, 108]

Please note that the REPD mistakenly states that the following sites are not CHPs: Caledonian Papermill, Cowie Biomass Facility, Invergordon Pellet Mill, and Barony Road, Auchinleck. We understand that these sites are CHPs based off previous CHPQA submissions and additional information found in the literature.

No data on the heat and power usages of the Dunbar Cement site could be found in the literature; therefore, the carbon capture capacity of the site was determining using data submitted to SEPA under the SPRI Database. This in turn was used to determine the costs. The only data that was found was the production of 867 t,clinker per day[114] and that the site aims to use a fuel mixture that consists of 45% SRF [108].

Caledonian Paper Mill

This paper mill has been in production since April 1989 and has the capacity to produce 250,000 tonnes of lightweight coated paper (LWC) specifically designed for printing magazines, catalogues, and brochures[157]. The mill operates a 26 MWe CHP plant that exclusively uses 100% biomass as fuel, derived from both virgin and recycled sources, including solids sourced from a primary effluent treatment plant.

Cowie Biomass Facility

The site produces Caberfloor[158], a specially processed and compressed woodchip material. The site operates both a large biomass boiler that produces steam as well as two high-pressure natural-gas turbines to produce

[157] caledonian_2021_en.pdf (upm.com)
[158] How is CaberFloor made? - West Fraser

hot exhaust gas and to supply on-site power. The SPRI database indicates emissions with a biomass content of 72.4%, but it is unclear whether this includes sources outside of the CHP plant.

Invergordon Pellet Mill

This site produces wood pellets[159]. Again, there is limited data on site heat and power demands, with the planning application[160] and REPD mentioning that a biomass fired CHP is present onsite.

Morayhill Mill

This site manufactures Oriented Strand Board (OSB) using timber chips sourced from nearby sawmills. Any timber residue from the plant is used to fuel a biomass boiler. This includes bark stripped from the logs at the start of the manufacturing process, wood dust extracted from various production processes around the plant, along with any timber residue and non-specification timber flakes. The burner generates heat for use in the drying and curing stages in board production. The SPRI database confirmed that emissions from this site are 100% biogenic.

After some stakeholder engagement we learnt that there are two biomass burners present onsite, one 57 MW_{th} and the other 43 MW_{th}.

Egger Barony

This site manufactures approximately 400,000 m^3 of raw chipboard per annum[161], which can then either be used in its raw form or be upgraded for use in the furniture and interior design markets or building market. In 2021 Egger stated that they wish the Barony plant to be powered 100% through a new biomass CHP (5.5 MWe output) and generate hot gas to be used in drying wood material[162]. This CHP has now been completed and features in the Heat Networks Planning Database[163], where heat is sold to an industrial customer nearby consisting of three buildings. The SPRI database confirmed that emissions from this site are 100% biogenic.

Dunbar Cement

The site produces 867 t/d of clinker with a heat consumption of 3.26 MJ/kg[114].

Dunbar cement plant by agreeing a contract with leading Scottish resource management company, Hamilton Waste and Recycling, to begin using Solid Recovered Fuel (SRF) at the plant[164]. Combined with other waste-derived fuels, this new supply of SRF at Dunbar will support our aim to replace up to 45% of its traditional fossil-based fuels with alternatives which are fully or partially classed as carbon neutral.

Disregarded sites

Sapphire Mill was initially considered, since it manufactures paper towels. However, upon further investigation, we found that the site sources heat and power demands via natural gas. This was reflected in the SPRI database which shows no mention of biogenic emissions.

The sites Pulp Mill House and Robert Cullen Ltd were all considered due their work in manufacturing moulded pulp. However, since no information was available on their site operations then they were removed from the analysis.

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[159] Balcas Energy - Timber Merchant (business.site)

[160] 06/00944/FULRC | Combined heat and power and wood pelleting plant | Cromarty Firth Industrial Estate Invergordon Highland 06/00944/FULRC

[161] Barony Plant | EGGER

[162] EGGER's Barony expansion to create more jobs in Auchinleck | Cumnock Chronicle

[163] Heat Networks Planning Database - data.gov.uk

[164] Tarmac, 'Tarmac boosts cement plant sustainability': Tarmac boosts cement plant sustainability | Dunbar Quarry

BECCS AD

The sites considered were identified using the NNFCC database and REPD.

Table 44: BECCS AD data point summary

Extracted from the literature and used in the calculations for the NETs Model

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Feedstock Capacity (t/year)	Data source
Rainton Farm	D Finlay & Son	Operational	BECCS AD (CHP)	0.025	2,500	NNFCC
Loanhead Farm	N Poett	Operational	BECCS AD (CHP)	0.05	2,000	NNFCC
Carterhaugh Farm	BQ Farming Partnership	Operational	BECCS AD (CHP)	0.195	2,000	NNFCC
Genoch Mains Farm	Mr J McIntosh	Operational	BECCS AD (CHP)	0.225	17,500	NNFCC
Genoch Mains Farm (Extension)	Mr J McIntosh	Operational	BECCS AD (CHP)	0.237	17,500	NNFCC
Kirkton Farm	Kirkton Farm	Operational	BECCS AD (CHP)	0.475	2,000	NNFCC
Wester Clockeasy Farm	AGTEC	Operational	BECCS AD (CHP)	0.125	5,000	NNFCC
Dronley Farm AD	Dronley Farming Ltd	Operational	BECCS AD (CHP)	0.0623	3,000	NNFCC
East Reston Farm AD	RH & DH Allan	Operational	BECCS AD (CHP)	0.076	3,500	NNFCC
Mains of Fortrie AD	D Bartlet & Son	Operational	BECCS AD (CHP)	0.076	3,500	NNFCC
Old Ballikinrain House AD	M Percy Ltd	Operational	BECCS AD (CHP)	0.076	3,500	NNFCC
Forthar Farm AD	J&C Wilson	Operational	BECCS AD (CHP)	0.1275	5,000	NNFCC
Meinside AD	Mein Farming Ltd	Operational	BECCS AD (CHP)	0.088	4,500	NNFCC
Baltier Farm	Baltier Farm	Operational	BECCS AD (CHP)	0.5	10,000	NNFCC
Girvan Road AD	AGTEC	Operational	BECCS AD (CHP)	0.098	7,000	NNFCC
Lemington Farm AD	Greenshields Agri Ltd	Operational	BECCS AD (CHP)	0.18	8,000	NNFCC
Mayfield Farm	PALL	Operational	BECCS AD (CHP)	0.2	7,000	NNFCC

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Feedstock Capacity (t/year)	Data source
Balmangan Farm	Mathers Dairy Utensils	Operational	BECCS AD (CHP)	0.124	5,500	NNFCC
Crofthead farm	W Callander	Operational	BECCS AD (CHP)	0.124	3,000	NNFCC
Slacks Farm	D Kincaid	Operational	BECCS AD (CHP)	0.124	3,000	NNFCC
Standingstone Farm	Mathers Dairy Utensils	Operational	BECCS AD (CHP)	0.124	5,500	NNFCC
East Denside Farm	M Forbes	Operational	BECCS AD (CHP)	0.243	5000	NNFCC
Knockrivoch Farm	Knockrivoch Farm	Operational	BECCS AD (Heat only)	0.15*	480	NNFCC
East Knockbrex AD	Iain Service & Co Ltd	Operational	BECCS AD (CHP)	0.154	12,800	NNFCC
Littleton Farm (2)	Mathers Dairy Utensils	Operational	BECCS AD (CHP)	0.19	5,500	NNFCC
Harpers Transport AD	Harpers Transport	Operational	BECCS AD (CHP)	0.197	10,000	NNFCC
Ignis Wick AD	Ignis Wick Ltd	Operational	BECCS AD (CHP)	0.197	6,000	NNFCC
Balmachie Farm AD	JF Lascelles	Operational	BECCS AD (CHP)	0.086	4,000	NNFCC
Slains Park Farm	J Forbes	Operational	BECCS AD (CHP)	0.399	8,000	NNFCC
Standhill Farm	JG Shanks & Son	Operational	BECCS AD (CHP)	0.185	11,000	NNFCC
Woodside Farm	AGTEC	Operational	BECCS AD (CHP)	0.1792	5,228	NNFCC
Balmenach Distillery	Inver House Distillers	Operational	BECCS AD (CHP)	0.25	5,000	NNFCC
Auchencheyne AD	Auchencheyne Ltd	Operational	BECCS AD (CHP)	0.1275	5,000	NNFCC
Girvan Mains Farm	AB Young	Operational	BECCS AD (CHP)	0.238	8,000	NNFCC
Allerbeck Farm	Wyseby Hill Ltd	Operational	BECCS AD (CHP)	0.093	5,770	NNFCC
Camieston Farm AD	Camieston Renewables Ltd	Operational	BECCS AD (CHP)	0.485	18,000	NNFCC
Kinknockie Farm	Yorston & Sinclair	Operational	BECCS AD (CHP)	0.457	9,500	NNFCC
Gask Farm	J Rennie & Son	Operational	BECCS AD (CHP)	0.46	15,000	NNFCC

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Feedstock Capacity (t/year)	Data source
Broadwigg Farm	N Forsyth & Son	Operational	BECCS AD (CHP)	0.465	28,000	NNFCC
North British Distillery AD	North British Distillery	Operational	BECCS AD (CHP)	0.479	9,855	NNFCC
Bendochy Farm	ET Bioenergy	Operational	BECCS AD (CHP)	0.44	9,500	NNFCC
Claylands Farm	Strathendrick Biogas	Operational	BECCS AD (CHP)	0.499	30,000	NNFCC
Dailuaine Distillery	Diageo	Operational	BECCS AD (CHP)	0.5	15,000	NNFCC
Edge Farm Composting	GP Green Recycling	Operational	BECCS AD (CHP)	0.5	12,000	NNFCC
Glendullan Distillery	Diageo	Operational	BECCS AD (CHP)	0.5	15,000	NNFCC
Levenseat Recycling facility	Levenseat	Operational	BECCS AD (CHP)	0.5	25,000	NNFCC
Pure Malt Products	Pure Malt Products	Operational	BECCS AD (CHP)	0.5	25,000	NNFCC
Roseisle Speyside Whisky Distillery	Diageo	Operational	BECCS AD (CHP)	0.5	47,450	NNFCC
Charlesfield Farm	Hoddom & Kinmount Estates	Operational	BECCS AD (CHP)	0.475	11,200	NNFCC
Glenmorangie Distillery	Glenmorangie	Operational	BECCS AD (Heat only)	940	0	NNFCC
Wester Alves Farm	Wester Alves Biogas	Operational	BECCS AD (CHP)	0.8	25,000	NNFCC
Wester Kerrowgair Farm	Qila Energy	Operational	BECCS AD (CHP)	0.45	20,650	NNFCC
GSK Irvine	GlaxoSmithKline	Operational	BECCS AD (CHP)	0.98	10,000	NNFCC
Deerdykes Composting and Organics Recycling Facility	Scottish Water Horizons	Operational	BECCS AD (CHP)	1	30,000	NNFCC
Auchentoshan Distillery	Morrison Bowmore Distillers	Operational	BECCS AD (CHP)	0.5	20,000	NNFCC

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Feedstock Capacity (t/year)	Data source
West Roucan Farm	J Cunnigham-Jardine	Operational	BECCS AD (CHP)	0.95	20,000	NNFCC
Lochhead Landfill (Dry-AD)	Fife Council	Operational	BECCS AD (CHP)	1.14	45,000	NNFCC
Binn Farm AD	TEG Biogas	Operational	BECCS AD (CHP)	1.4	30,000	NNFCC
Barkip AD	SSE	Operational	BECCS AD (CHP)	2.2	75,000	NNFCC
Charlesfield Industrial Estate (2)	Iona Capital	Operational	BECCS AD (CHP)	3	36,000	NNFCC
Glenfiddich Distillery AD (Extension)	William Grant and Sons Distillers	Permission Granted	BECCS AD (CHP)	2	0	REPD
Skeddoway Farm	RM Brown & Son	Operational	BECCS AD (CHP)	2	0	NNFCC
Energen biogas Cumbernauld	Bio Capital Limited	Operational	BECCS AD (CHP)	2.4	0	REPD
Balmcassie Commercial Park - Anaerobic digestion plant	Brewdog Limited	Under Construction	BECCS AD (CHP)	3.5	0	REPD
Academy Road - Energy Centre & Anaerobic Digestion Facility	Grissan Engineering Services Limited	Permission Granted	BECCS AD (CHP)	4	0	REPD
Glasgow Renewable Energy and Recycling Centre	Viridor	Operational	BECCS AD (CHP)	4	100,000	NNFCC
Cameron Bridge Distillery	Diageo	Operational	BECCS AD (CHP)	5.5	90,000	NNFCC

*Heat only site so units are kW_{th}

BECCS Fermentation

This data from whisky distilleries was taken from Whisky Invest Direct[165,166] and for beer producing sites from the Scottish Carbon Capture Storage (SCCS)[92].

Table 45: BECCS Fermentation data point summary

Extracted from the literature and used in the calculations for the NETs Model

Plant	Owner	Operational Status	Type of Technology	Alcohol production Capacity (MLPA)	Data source
Cameronbridge	Diageo	Operational	Grain whisky	110	Whisky Invest Direct
Girvan	William Grant & Sons	Operational	Grain whisky	110	Whisky Invest Direct
Invergordon	Whyte & MacKay	Operational	Grain whisky	36	Whisky Invest Direct
Strathclyde	Chivas Brothers	Operational	Grain whisky	39	Whisky Invest Direct
Starlaw/Glen Turner Distillery	La Martiniquaise	Operational	Grain whisky	25	Whisky Invest Direct
Loch Lomond (Grain)	Loch Lomond Group	Operational	Grain whisky	18	Whisky Invest Direct
Reivers	Mossburn Distillery Co.	Operational	Grain whisky	0.1	Whisky Invest Direct
Glenlivet	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	21	Whisky Invest Direct
Glenfiddich	William Grant & Sons	Operational	Malt whisky	21	Whisky Invest Direct
Macallan	The Edrington Group	Operational	Malt whisky	15	Whisky Invest Direct
Ailsa Bay	William Grant & Sons	Operational	Malt whisky	12	Whisky Invest Direct
Glen Ord	Diageo	Operational	Malt whisky	11.5	Whisky Invest Direct
Roseisle	Diageo	Operational	Malt whisky	10.8	Whisky Invest Direct
Dalmunach	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	10.5	Whisky Invest Direct
Teaninich	Diageo	Operational	Malt whisky	10.2	Whisky Invest Direct

165 Whisky Invest Direct, ‘Malt whisky distilleries in Scotland’: Malt whisky distilleries in Scotland | WhiskyInvestDirect
166 Whisky Invest Direct, ‘Grain whisky distilleries in Scotland’: Grain whisky distilleries in Scotland | WhiskyInvestDirect

Plant	Owner	Operational Status	Type of Technology	Alcohol production Capacity (MLPA)	Data source
Glenmorangie	The Glenmorangie Co. (LVMH)	Operational	Malt whisky	6.5	Whisky Invest Direct
Glen Grant	Campari Group	Operational	Malt whisky	6.1	Whisky Invest Direct
Glen Moray	Glen Turner (La Martiniquaise)	Operational	Malt whisky	6	Whisky Invest Direct
Dufftown	Diageo	Operational	Malt whisky	5.9	Whisky Invest Direct
Miltonduff	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	5.8	Whisky Invest Direct
Glen Keith	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	5.7	Whisky Invest Direct
Auchroisk	Diageo	Operational	Malt whisky	5.7	Whisky Invest Direct
Balvenie	William Grant & Sons	Operational	Malt whisky	5.6	Whisky Invest Direct
Glenrothes	The Edrington Group	Operational	Malt whisky	5.5	Whisky Invest Direct
Tomatin	Tomatin Distillery Co.	Operational	Malt whisky	5	Whisky Invest Direct
Ardmore	Beam Suntory	Operational	Malt whisky	4.9	Whisky Invest Direct
Tormore	Elixir Distillers	Operational	Malt whisky	4.9	Whisky Invest Direct
Dailuaine	Diageo	Operational	Malt whisky	4.9	Whisky Invest Direct
Loch Lomond (Malt)	Loch Lomond Group	Operational	Malt whisky	4.75	Whisky Invest Direct
Longmorn	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	4.7	Whisky Invest Direct
Clynelish	Diageo	Operational	Malt whisky	4.7	Whisky Invest Direct
Allt-a-Bhainne	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	4.5	Whisky Invest Direct
Braeval	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	4.5	Whisky Invest Direct
Kininvie	William Grant & Sons	Operational	Malt whisky	4.4	Whisky Invest Direct

Plant	Owner	Operational Status	Type of Technology	Alcohol production Capacity (MLPA)	Data source
Glenburgie	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	4.3	Whisky Invest Direct
Dalmore	Whyte & Mackay (Emperador)	Operational	Malt whisky	4.3	Whisky Invest Direct
Speyburn	Inver House Distillers (Thai Beverages plc)	Operational	Malt whisky	4.2	Whisky Invest Direct
Craigellachie	John Dewar & Sons (Bacardi)	Operational	Malt whisky	4.2	Whisky Invest Direct
Tamnavulin	Whyte & Mackay (Emperador)	Operational	Malt whisky	4.2	Whisky Invest Direct
Glentauchers	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	4.1	Whisky Invest Direct
Royal Brackla	John Dewar & Sons (Bacardi)	Operational	Malt whisky	4.1	Whisky Invest Direct
Tamdhu	Ian Macleod Distillers	Operational	Malt whisky	4	Whisky Invest Direct
Glenfarclas	J. & G. Grant	Operational	Malt whisky	4	Whisky Invest Direct
Glenallachie	The Glenallachie Distillers Co.	Operational	Malt whisky	4	Whisky Invest Direct
Aberlour	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	3.8	Whisky Invest Direct
Mortlach	Diageo	Operational	Malt whisky	3.8	Whisky Invest Direct
Linkwood	Diageo	Operational	Malt whisky	3.7	Whisky Invest Direct
Benrinnes	Diageo	Operational	Malt whisky	3.6	Whisky Invest Direct
Glendullan	Diageo	Operational	Malt whisky	3.6	Whisky Invest Direct
Macduff [Glen Deveron]	John Dewar & Sons (Bacardi)	Operational	Malt whisky	3.4	Whisky Invest Direct
Tomintoul	Angus Dundee Distillers	Operational	Malt whisky	3.3	Whisky Invest Direct
Cardhu	Diageo	Operational	Malt whisky	3.3	Whisky Invest Direct
Aberfeldy	John Dewar & Sons (Bacardi)	Operational	Malt whisky	3.3	Whisky Invest Direct

Plant	Owner	Operational Status	Type of Technology	Alcohol production Capacity (MLPA)	Data source
Laphroaig	Beam Suntory	Operational	Malt whisky	3.275	Whisky Invest Direct
Inchgower	Diageo	Operational	Malt whisky	3.2	Whisky Invest Direct
Aultmore	John Dewar & Sons (Bacardi)	Operational	Malt whisky	3.2	Whisky Invest Direct
Talisker	Diageo	Operational	Malt whisky	3	Whisky Invest Direct
Tullibardine	Picard Vins & Spiriteaux	Operational	Malt whisky	2.9	Whisky Invest Direct
BenRiach	Benriach Distillery Co. (Brown Forman)	Operational	Malt whisky	2.8	Whisky Invest Direct
Glenlossie	Diageo	Operational	Malt whisky	2.8	Whisky Invest Direct
Balmenach	Inver House Distillers (Thai Beverages plc)	Operational	Malt whisky	2.8	Whisky Invest Direct
Deanston	Burn Stewart Distillers (Distell International)	Operational	Malt whisky	2.7	Whisky Invest Direct
Glen Elgin	Diageo	Operational	Malt whisky	2.6	Whisky Invest Direct
Mannochmore	Diageo	Operational	Malt whisky	2.6	Whisky Invest Direct
Strathisla	Chivas Brothers Ltd. (Pernod Ricard)	Operational	Malt whisky	2.5	Whisky Invest Direct
Blair Athol	Diageo	Operational	Malt whisky	2.5	Whisky Invest Direct
Glenkinchie	Diageo	Operational	Malt whisky	2.5	Whisky Invest Direct
Fettercairn	Whyte & Mackay (Emperador)	Operational	Malt whisky	2.3	Whisky Invest Direct
Cragganmore	Diageo	Operational	Malt whisky	2.2	Whisky Invest Direct
Dalwhinnie	Diageo	Operational	Malt whisky	2.2	Whisky Invest Direct
Auchentoshan	Beam Suntory	Operational	Malt whisky	2.15	Whisky Invest Direct
Ben Nevis	Ben Nevis Distillery Ltd (Nikka, Asahi Breweries)	Operational	Malt whisky	2	Whisky Invest Direct

Plant	Owner	Operational Status	Type of Technology	Alcohol production Capacity (MLPA)	Data source
Strathmill	Diageo	Operational	Malt whisky	2	Whisky Invest Direct
Inchdairnie	Inchdairnie Distillery Ltd	Operational	Malt whisky	2	Whisky Invest Direct
Glendronach	Benriach Distillery Co. (Brown Forman)	Operational	Malt whisky	1.8	Whisky Invest Direct
Balblair	Inver House Distillers (Thai Beverages plc)	Operational	Malt whisky	1.8	Whisky Invest Direct
Knockdhu [AnCnoc]	Inver House Distillers (Thai Beverages plc)	Operational	Malt whisky	1.8	Whisky Invest Direct
Borders	The Three Stills Co. Ltd	Operational	Malt whisky	1.8	Whisky Invest Direct
Glen Spey	Diageo	Operational	Malt whisky	1.6	Whisky Invest Direct
Bladnoch	Bladnoch Distillery Ltd	Operational	Malt whisky	1.5	Whisky Invest Direct
Glencadam	Angus Dundee Distillers	Operational	Malt whisky	1.4	Whisky Invest Direct
Knockando	Diageo	Operational	Malt whisky	1.4	Whisky Invest Direct
Pulteney	Inver House Distillers (Thai Beverages plc)	Operational	Malt whisky	1.4	Whisky Invest Direct
Glen Garioch	Beam Suntory	Operational	Malt whisky	1.3	Whisky Invest Direct
Glengoyne	Ian Macleod Distillers	Operational	Malt whisky	1.1	Whisky Invest Direct
Glenglassaugh	Benriach Distillery Co. (Brown Forman)	Operational	Malt whisky	1	Whisky Invest Direct
Ardross	Greenwood Distillers	Operational	Malt whisky	1	Whisky Invest Direct
Oban	Diageo	Operational	Malt whisky	0.8	Whisky Invest Direct
Brora/Clynelish Distillery	Diageo	Operational	Malt whisky	0.8	Whisky Invest Direct
Falkirk	Falkirk Distilling Co.	Operational	Malt whisky	0.75	Whisky Invest Direct
Glengyle	J & A Mitchell	Operational	Malt whisky	0.75	Whisky Invest Direct

Plant	Owner	Operational Status	Type of Technology	Alcohol production Capacity (MLPA)	Data source
Springbank	J & A Mitchell	Operational	Malt whisky	0.75	Whisky Invest Direct
Glen Scotia	Loch Lomond Group	Operational	Malt whisky	0.75	Whisky Invest Direct
Aberargie	The Perth Distilling Co.	Operational	Malt whisky	0.75	Whisky Invest Direct
Burn o'Bennie	Mike Bain & Liam Pennycook	Operational	Malt whisky	0.69	Whisky Invest Direct
Speyside	Speyside Distillers Co.	Operational	Malt whisky	0.6	Whisky Invest Direct
Royal Lochnagar	Diageo	Operational	Malt whisky	0.5	Whisky Invest Direct
Benromach	Gordon & MacPhail	Operational	Malt whisky	0.5	Whisky Invest Direct
Bonnington	John Crabbie & Co.	Operational	Malt whisky	0.5	Whisky Invest Direct
Glenturret	Lalique Group	Operational	Malt whisky	0.5	Whisky Invest Direct
Clydeside	Morrison Glasgow Distillers	Operational	Malt whisky	0.5	Whisky Invest Direct
Torabhaig	Mossburn Distillers	Operational	Malt whisky	0.5	Whisky Invest Direct
Ardnamurchan	Adelphi Distillery Ltd	Operational	Malt whisky	0.45	Whisky Invest Direct
Glasgow	The Glasgow Distillery Co.	Operational	Malt whisky	0.44	Whisky Invest Direct
Eden Mill	Paul Miller	Operational	Malt whisky	0.3	Whisky Invest Direct
Edradour No.2	Signatory Vintage Scotch Whisky Co. Ltd	Operational	Malt whisky	0.27	Whisky Invest Direct
Annandale	Annandale Distillery Co.	Operational	Malt whisky	0.26	Whisky Invest Direct
Arbikie	Arbikie Distilling Ltd	Operational	Malt whisky	0.25	Whisky Invest Direct
Holyrood	Holyrood Distillery Ltd.	Operational	Malt whisky	0.25	Whisky Invest Direct
Lindores Abbey	The Lindores Distilling Co.	Operational	Malt whisky	0.25	Whisky Invest Direct
Kingsbarns	Wemyss Vintage Malts	Operational	Malt whisky	0.205	Whisky Invest Direct

Plant	Owner	Operational Status	Type of Technology	Alcohol production Capacity (MLPA)	Data source
Lone Wolf	Brewdog plc.	Operational	Malt whisky	0.2	Whisky Invest Direct
Lochlea	Lochlea Distilling Co.	Operational	Malt whisky	0.18	Whisky Invest Direct
Wolfburn	Aurora Brewing Ltd	Operational	Malt whisky	0.175	Whisky Invest Direct
GlenWyvis	GlenWyvis Distillery Ltd	Operational	Malt whisky	0.15	Whisky Invest Direct
Strathearn	Douglas Laing	Operational	Malt whisky	0.14	Whisky Invest Direct
Edradour	Signatory Vintage Scotch Whisky Co. Ltd	Operational	Malt whisky	0.135	Whisky Invest Direct
Nc'nean	Drimnin Distillery Co.	Operational	Malt whisky	0.1	Whisky Invest Direct
Ballindalloch	MacPherson-Grant	Operational	Malt whisky	0.1	Whisky Invest Direct
Daftmill	Francis Cuthbert	Operational	Malt whisky	0.065	Whisky Invest Direct
Dornoch	Phil & Simon Thompson	Operational	Malt whisky	0.025	Whisky Invest Direct
Tennent Caledonian	Wellpark Brewery	Operational	Beer production	8.36	SCCS
Belhaven	Belhaven	Operational	Beer production	0.51	SCCS

BECCS EfW/ACT

The sites considered were identified using the REPD and relevant websites/blog posts.

Table 46: BECCS EfW/ACT data point summary

Extracted from the literature and used in the calculations for the NETs Model

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Fuel source	Data source
Thainstone Energy Park Project ERF	Agile Energy Recovery	Application Submitted	BECCS EfW	35	MSW	REPD
Dunbar EfW (previously Oxwellmains EfW)	Viridor	Operational	BECCS EfW	25.6	MSW	REPD
Westfield (former Opencast Coal Mine)	Brockwell Energy	Under Construction	BECCS EfW	23.7	MSW	Website[167] Blog post[168]
CalaChem Fine Chemicals (Grangemouth) - Earlsgate Energy Centre	Brockwell Energy, Covanta and Green Investment Group	Under Construction	BECCS EfW (CHP)	21.5	MSW	REPD
South Clyde Energy Centre	Fortum (formerly Peel Environmental)	Under Construction	BECCS EfW	20	MSW	REPD
Oldhall Industrial Estate	Dover Yard	Permission Granted	BECCS EfW	15	MSW	REPD
Millerhill EfW	FCC Environment	Operational	BECCS EfW	12.5	MSW	REPD
Barr Killoch Energy Recovery Park	Barr Environmental Limited	Application Submitted	BECCS EfW	12	RDF	REPD
Ness Energy Project	Aberdeen / Aberdeenshire / Moray Councils	Under Construction	BECCS EfW (CHP)	11.1	MSW	REPD
Baldovie Industrial Estate (Forties Road)	MVV Environment	Under Construction	BECCS EfW (CHP)	10	MSW	REPD

[167] HZI confirmed for another UK-based EfW plant build | ENDS Waste & Bioenergy (endswasteandbioenergy.com)

[168] Hitachi Zosen Inova Appointed to Design, Build and Operate the Westfield Energy Centre in Scotland - Hitachi Zosen Inova (hz-inova.com)

Plant	Owner	Operational Status	Type of Technology	Gross Electrical Capacity (MWe)	Fuel source	Data source
Baldovie	Dundee Energy Recycling	Operational	BECCS EfW	8.3	MSW	REPD
Binn Farm EfW	Binn Group	Permission Granted	BECCS EfW	7.3	MSW	REPD
Polmont landfill site EfW	NPL Group	Planning application submitted	BECCS EfW	7.4	MSW	News paper[169]
Drumgray Energy Recovery Centre (DERC)	FCC	Planning granted	BECCS EfW (CHP)	25.5	MSW	Blog post[170]
Charlesfield Biomass CHP Plant	Charlesfield First LLP & Biogas Power	Operational	BECCS EfW ACT (CHP)	10	MSW	REPD
Coatbridge Material Recovery and Renewable Energy Facility	Golder Associates (UK) Ltd/ Shore Energy	Under Construction	BECCS EfW ACT (CHP)	25	MSW	REPD
Levenseat Waste Management Facility	Levenseat	Permission Granted	BECCS EfW ACT (CHP)	17	RDF	REPD
Levenseat EfW	Levenseat	Operational	BECCS EfW ACT	12.5	RDF	REPD
Glasgow Renewable Energy and Recycling Centre (ACT)	Viridor	Operational	BECCS EfW ACT (CHP)	10	MSW	REPD
Achnabreck	Northern Energy Developments	Permission Granted	BECCS Power ACT (CHP)	5.5	Wood pellets	REPD
Binn Eco Park	SITA UK/Binn Group	Permission Granted	BECCS EfW ACT	4.6	RDF	REPD
Avondale Quarry (Pilot)	Grangemouth Generation Ltd	Operational	BECCS EfW ACT	2	MSW	REPD

169 EFW plant approved at Polmont landfill: https://www.falkirkherald.co.uk/news/environment/green-light-for-waste-energy-plant-at-polmont-landfill-site-3034062

170 FCC Drumgray RERC Energy Recovery Centre (fccenvironment.co.uk)

Carbon Capture Calculations

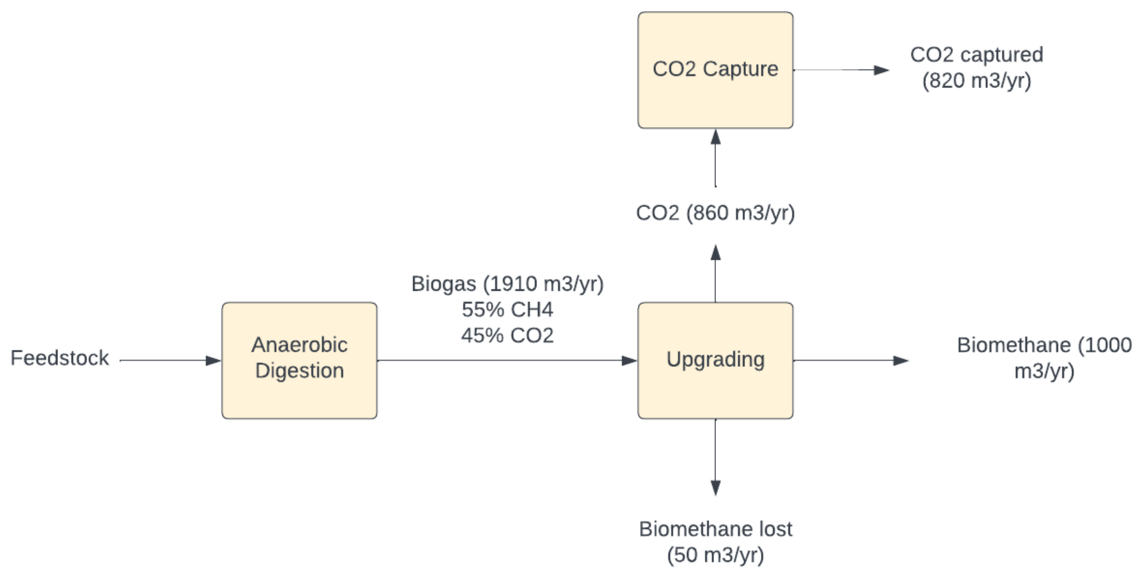
The following section provides an overview of the modelling parameters and methodology used to estimate the CO_2 capture potential of each NET.

BECCS Biomethane

We utilised a simple mass balance to determine the CO_2 capture potential of a biomethane facility (see Figure 19 below). The methodology used was as follows:

1.) Since we know the amount of biomethane produced hourly, taken from the NNFCC or estimated using the REPD, then we can estimate the annual biomethane production rate by assuming standard operating hours of 6,000 hr/year (this is equivalent to a utilisation factor of 68%).
2.) The amount of methane directed to the upgrading facility, from the anaerobic digestor, can be determined by assuming that 4.7% of the methane entering the upgrader is lost to the surroundings[171].
3.) The amount of biogas and CO_2 directed towards the upgrading facility can be determined by assuming a biogas composition of 55:45 methane to CO_2 (on a volumetric basis)[171].
4.) By assuming that the biogas exiting the anaerobic digestor is under normal conditions (i.e., at 25 degC and 1 atm) then the mass of CO_2 entering the CO_2 capture unit can be determined using a density of 1.795 kg/m^3.
5.) The CO_2 production potentials determining using this mass balance method were compared to mass balance benchmarks found in a LCA paper (0.00161 tCO_2/m^3,biomethane)[132]. The values were found to be very close to one another and hence confirms our assumptions and calculations are valid.
6.) The capture potential was finally determined by applying a CO_2 capture efficiency of 95%.

Figure 19: A simple mass balance of a BECCS biomethane reference facility



The comparison of CO_2 production potentials through our mass balance method and that of the LCA mass balance benchmarks are shown below in Table 47. The values are very close, deviating by +- 0.002 $MtCO_2$/year, validating our assumptions and calculations.

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[171] Mattia De Rose, 'Economic assessment of producing and selling biomethane into a regional market': Economic assessment of producing and selling biomethane into a regional market (sagepub.com)

Table 47: Fermentation CO_2 production rates comparison

Calculated using our mass balance method, compared against an LCA paper.

Site	CO_2 generated from upgrading (Mt/year)	
	General Mass Balance	LCA Mass Balance
Portgordon Maltings Beyside	0.007	0.008
Brae of Pert Farm	0.005	0.005
Charlesfield Industrial Estate	0.005	0.005
Cumbernauld AD	0.005	0.005
Downiehills Farm	0.005	0.005
Girvan Distillery	0.025	0.027
Glenfiddich Distillery	0.018	0.019
Hatton Farm AD	0.004	0.004
Inchdairnie Farm	0.005	0.005
Invergordon Distillery	0.005	0.005
Keithick Farm	0.006	0.006
Lockerbie Creamery	0.007	0.007
Morayhill AD	0.005	0.005
Peacehill Farm	0.005	0.005
Rosskeen Farm	0.004	0.004
Savock Farm	0.006	0.006
Tambowie Farm	0.002	0.002
TECA AD	0.004	0.004
Portgordon Maltings - Anaerobic Digestion Facility, Phase 2	0.018	0.019
Lockerbie Creamery - Anaerobic Digester	0.008	0.009

BECCS Power and Industry (Wood)

As described in the Data Sources section, all the BECCS Industry (Wood) sites considered in our study employ biomass boilers or CHPs on-site. These units are the focus for potential CCS implementation, enabling negative emissions similar to BECCS Power sites. Consequently, our carbon and cost calculations will adopt the same methodology and utilise identical parameters for BECCS Power and Industry (Wood).

To determine the CO_2 capture potential of a power only, CHP or heat only site, we carried out the following:

1.) The fuel input rate going into the CHP or power plant was determined by back-calculating from the gross electrical capacity, quoted in the REPD, using an assumed electrical efficiency of 38.7% for power only sites and 25% for CHPs[46]. If the site is heat only then a heat efficiency of 80% is used.
2.) The CO_2 production rate was then determined by applying a conversion factor of 0.35 $kgCO_2$/kWh,fuel using the BEIS greenhouse gas reporting conversion factors[93], taken from the 'Outside of Scopes' tab.
3.) The CO_2 capture potential of the site was then determined using an assumed capture efficiency of 90%.

An example calculation for Caledonian Papermill is provided in Box 1 below.

Box 1: CO_2 capture potential, BECCS Power calculation

Caledonian Papermill (26 MWe CHP).

$$Feedstock\ input = \frac{26\ MJ,e}{s} \times \frac{3600\ s}{h} \times \frac{8760\ h}{yr} \times \frac{1}{25\%} \times 90\% \times \frac{kWh}{3.6\ MJ} \times \frac{GWh}{10^6\ kWh} = 819.9\ GWh, \frac{fuel}{yr}$$

$$CO2\ Capture\ Potential = \frac{819.9\ GWh, fuel}{yr} \times \frac{0.35\ kgCO2}{kWh, fuel} \times \frac{10^6\ kWh}{GWh} \times \frac{1\ MtCO2}{10^9\ kgCO2} \times 90\% = 0.258\ MtCO2/yr$$

To ensure the validity of our assumptions and data sources, the CO_2 production potential of the BECCS Power and Industry (Wood) sites were compared to values from the SPRI Database[172]. The comparison revealed a general alignment between the values, as demonstrated in below. It is worth noting that data for most BECCS Power sites was unavailable in the SPRI Database due to their low gross capacities. This further supports the reasonableness of our assumptions and data sources.

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[172] SEPA, 'Scottish Pollutant Release Inventory': SPRI | Scottish Environment Protection Agency (SEPA)

Table 48: BECCS Power and Industry (wood) CO_2 production rates comparison

Compared using two data sources: our own calculations based on REPD data and the values quoted in the SPRI database.

Site	NET	REPD ($MtCO_2$/year)	SPRI ($MtCO_2$/year)
Markinch Biomass CHP Plant	BECCS Power (CHP)	0.717444	0.371911
Stevens Croft	BECCS Power	0.359363721	0.388518964
Westfield Biomass Power Station	BECCS Power	0.089127907	0.108348
Caledonian Papermill	BECCS Industry CHP (paper - coated magazine)	0.2869776	0.3012053
Cowie Biomass Facility	BECCS Industry CHP (Particle & MDF)	0.165564	0.264579705
Invergordon Pellet Mill	BECCS Industry CHP (wood pellets)	0.055188	N/A
Morayhill Mill	BECCS Industry (Oriented Strand Board)	0.344925	0.19257725
Barony Road, Auchinleck	BECCS Industry CHP (Chipboard and wood recycling)	0.0607068	0.020513208

BECCS Cement

Due to limited data availability for calculating the CO_2 capture potential, we relied on the CO_2 emissions rate provided by the SPRI database to estimate our own CO_2 capture potential. To determine the portion of emissions considered biogenic, we assumed that approximately 40% of cement emissions result from the combustion of fossil fuels[173]. Additionally, considering that Dunbar Cement intends to utilise a fuel mix composed of 45% RDF/SRF waste, with a biogenic content of 17%[174], we determined the quantity of emissions classified as biogenic.

BECCS AD

For the AD sites, we assume that all generated biogas is converted into biomethane, with a small portion being utilised by an onsite CHP to meet onsite requirements. With these assumptions, we can determine the maximum CO_2 capture potential for each site.

To determine the CO_2 capture potential, we carried out the following:

1.) The feedstock input data, provided via the NNFCC Database, was utilised to determine the biogas production rate using a feedstock to biogas mass balance benchmark taken from an LCA paper (0.17 kg,biogas/kg,feedstock).
2.) The volume of biogas produced is then determined using an assumed biogas density of 1.2 kgm^{-3}.
3.) The CO_2 and biomethane production rate are calculated using the assumed biogas composition of 55:45 methane to CO_2 on a volumetric basis. The mass of CO_2 produced can then be determined using the density of CO_2 under standard conditions (1.795 kgm^{-3}).

[173] CarbonBrief, 'Q&A: Why cement emissions matter for climate change': Q&A: Why cement emissions matter for climate change - Carbon Brief
[174] IEA Bioenergy, 'Municipal Solid Waste and its Role in Sustainability': 40_IEAPositionPaperMSW.pdf (ieabioenergy.com)

4.) Finally, the CO_2 capture potential is determined using a CO_2 capture efficiency of 95%.

Six of the sites listed in Table 44 lacked data on feedstock input rates, making it difficult to calculate their carbon capture potential. Consequently, additional research was required. Among them, five sites had gross power capacities available in either the REPD or NNFCC databases. For these sites, a similar methodology to that used for BECCS Power/Industry (Wood) could be applied, although with different efficiencies, utilisation factors, and emission conversion factors. As for the remaining heat-only site ('Glenmorangie Distillery'), its planning application documents indicated a biogas production rate of 8000 m^3/day, enabling the determination of its CO_2 capture potential using the same methodology as BECCS Biomethane.

An example calculation for the '*Glenfiddich Distillery AD (Extension)*' site is shown below.

Box 2: AD CO_2 capture potential example

The annual electricity production potential is calculated using our utilisation factor of 68%, derived from the assumption that a standard AD site operates at 6000hr/year.

$$Power\ out = \frac{2.4\ MJ,e}{s} \times \frac{8760\ hr}{yr} \times \frac{3600\ s}{hr} \times 68\% \times \frac{1\ kWh}{3.6\ MJ} \times \frac{1\ GWh}{10^6\ kWh} = 14.4\ GWh,e/yr$$

Determine biogas fuel input rate going into the CHP by assuming an CHP electrical efficiency of 25%. The volumetric rate of this input can then be determined by assuming a biogas energy density of 26 MJ/m^3.

$$Biogas\ input = \frac{11.9\ GWh,e}{yr} \times \frac{1}{25\%} \times \frac{1\ m^3}{26\ MJ} \times \frac{3.6\ MJ}{kWh} \times \frac{10^6\ kWh}{GWh} = 7{,}975{,}385\ m^3/yr$$

To determine biomethane production and CO_2 capture potential, we assume that all biogas is now upgraded. Using a typical biogas composition of 55:45 methane and CO_2 (volume basis), that we exhibit a 5% biomethane losses during upgrading, and a CO_2 capture potential of 95%.

$$Biomethane\ output = \frac{7{,}975{,}385\ m^3}{yr} \times 55\% \times 95\% = 4{,}195{,}499 \frac{m^3}{yr}$$

$$CO2\ capture\ potential = \frac{7{,}975{,}385\ m^3}{yr} \times 45\% \times \frac{1.795\ kg}{1\ m^3} \times 95\% \times \frac{1\ MtCO2}{10^9\ kg} = 0.0061\ MtCO2/yr$$

BECCS Fermentation

For the brewery sites, we have estimated CO_2 capture potentials as well as costs by assuming that the sites operate like industrial bioethanol plants.

To determine the CO_2 capture potential, we carried out the following:

1.) The litres of pure alcohol (LPA) produced by each site is provided[92]. We can utilise a CO_2 conversion factor of 754.7 tonnes per Ml of alcohol to determine the quantity of CO_2 produced.
2.) The CO_2 capture potential can then be determined using a capture efficiency of 90%

BECCS EfW/ACT

For EfW/ACT sites, we can apply the same methodology as BECCS Power and Industry (Wood), but with variations in efficiencies, utilisation factors, and emission conversion factors. Another possible approach is to directly calculate CO_2 capture potentials by gathering waste input rates from literature. However, we chose not to use this method in order to maintain consistency in our methodology, as well as to reduce errors and discrepancies in assumptions and data sources, enabling a more accurate and meaningful comparison of different NETs on a like-for-like basis.

To determine the CO_2 capture potential, we carried out the following:

1.) Firstly, we calculate the waste input rate. For this purpose, we employed a back-calculation approach utilising the electrical gross capacities provided in the REPD data and assuming a plant utilisation factor of 85%[175]. The power-only sites utilised an electrical capacity of 22%, calculated based off data sourced from AECOM and a MSW energy capacity of 10 MJ/kg[77], while an assumed value of 15% was used for CHP sites and 80% heat efficiency for heat only sites.
2.) Based on the waste input rate we can determine the CO_2 production potential using conversion factors. Depending on the choice of waste used, which can be either MSW or RDF/SFR, then the CO_2 capture potential will change. This is due to three factors: 1.) SRF/RDF is a more energy dense fuel, 2.) MSW is a more carbon intense fuel, and 3.) SRF/RDF has a higher biogenic carbon content (on a mass basis).
3.) A standard 90% capture rate is then employed to determine CO_2 capture potential.

An example below for the '*Thainstone Energy Park Project ERF'* site is provided in Box 3.

Box 3: BECCS EfW example CO_2 capture calculation

Determine EfW power efficiency based off AECOM data:

- Waste input = 350,000 t/year
- MSW LHV = 10 MJ/kg (taken from IEAGHG)
- Net power output (pre-CCS) = 25MWe
- Convert net to gross efficiency using a standard industrial scaler of 1.11

$$Net\ efficiency = \frac{25\ MJ,e}{s} \times \frac{3600\ s}{yr} \times \frac{8760\ hr}{yr} \times 85\% \times \frac{yr}{0.35\ Mt, MSW} \times \frac{1\ kg}{10\ MJ} \times \frac{1\ Mt}{10^9\ kg} = 19\%$$

$$Gross\ efficiency = \frac{19\%}{1.11} = 22\%$$

Determine waste input using electrical efficiency

- $Waste\ input = \frac{35\ MJ,e}{s} \times \frac{3600\ s}{hr} \times \frac{8760\ hr}{yr} \times \frac{1}{22\%} \times 85\% = 4{,}264{,}527{,}273\ MJ, fuel/yr$

Convert waste input into units of mass using the waste energy densities (10 MJ/kg for MSW and 13 MJ/kg for SFR/RDF)

- $Waste\ input = \frac{4{,}264{,}527{,}273\ \ MJ,fuel}{yr} \times \frac{1\ kg}{10\ MJ} \times \frac{1\ Mt}{10^9\ kg} = 0.43\ Mt, waste/yr$

[175] AECOM, 'Next Generation Carbon Capture Technology': Next generation carbon capture technology: technoeconomic analysis work package 6 (publishing.service.gov.uk)

Determine CO_2 captured

- $$CO2\ captured = \frac{0.43\ Mt{,}waste}{yr} \times \frac{1.0005\ Mt{,}CO2}{1\ Mt{,}waste} \times 90\% = 0.40\ Mt{,}CO2/yr$$

To double check our calculations, we compared our determined values for waste input against that quoted in the literature (see Table 49 below).

Table 49: Waste input rate comparison of EfW/ACT sites

Comparing REPD data (utilised in our calculations) against literature values

Site	REPD feedstock input (t/year)	Literature feedstock input (t/year)	Reference
Thainstone Energy Park Project ERF	422,414	200,000	[176]
Dunbar EfW (previously Oxwellmains EfW)	308,966	300,000	[177]
Westfield (former Opencast Coal Mine)	286,034	200,000	[178]
CalaChem Fine Chemicals (Grangemouth) - Earlsgate Energy Centre	384,214	162,000	[179]
South Clyde Energy Centre	241,379	350,000	[180]
Oldhall Industrial Estate	181,034	180,000	[181]
Millerhill EfW	150,862	152,500	[182]
Barr Killoch Energy Recovery Park	111,406	166,000	[183]
Ness Energy Project	198,361	150,000	[184]
Baldovie Industrial Estate (Forties Road)	178,704	110,000	[185]
Baldovie	100,172	90,000	[185]
Binn Farm EfW	88,103	85,000	[186]
Lerwick Energy Recovery Plant	19,549	26,000	[187]
Polmont landfill site EfW	89,310	150,000	[188]

[176] Agile Energy Recovery (Inverurie) Ltd | IRF

[177] Dunbar ERF (viridor.co.uk)

[178] Brockwell Energy | Wetsfield Energy Centre

[179] About Us - Earls Gate Energy Centre (egecl.com)

[180] South Clyde Energy Centre

[181] About – OldhallERF (oldhallenergy.co.uk)

[182] Our facility – Millerhill (fccenvironment.co.uk)

[183] s3179-0310-0003sdr_supporting_information_r2_redacted_redacted-1.pdf (sepa.org.uk)

[184] Ash from Aberdeen incinerator will be stored and processed near Portlethen (pressandjournal.co.uk)

[185] 2022_01_25_PR_MVV_Environment_Baldovie_Full_Service_Commencement.pdf

[186] Developer and operator appointed for Perthshire Energy from Waste facility - Binn Group

[187] https://www.tolvik.com/published-reports/view/uk-energy-from-waste-statistics-2021/

[188] Tolviklkirkherald.co.uk/news/environment/green-light-for-waste-energy-plant-at-polmont-landfill-site-3034062" Green light for waste energy plant at Polmont landfill site | Falkirk Herald

Site	REPD feedstock input (t/year)	Literature feedstock input (t/year)	Reference
Drumgray Energy Recovery Centre (DERC)	455,695	300,000	[189]
Charlesfield Biomass CHP Plant	178704	70,000	[190]
Coatbridge Material Recovery and Renewable Energy Facility	446760	160,000	[191]
Levenseat Waste Management Facility	233689.8462	315,000	[192]
Levenseat EfW	116047.7454	215,000	[192]
Glasgow Renewable Energy and Recycling Centre (ACT)	178704	222,000	[193]
Achnabreck	38413.95275	N/A	N/A
Binn Eco Park	42705.57029	60,000	[194]
Avondale Quarry (Pilot)	24137.93103	n/a	N/A

Please note that for the '*Achnabreck'* site, we could not utilise the above calculations, since this site plans on gasifying wood. Again, we used the REPD method to determine CO_2 production potential, using the same CO_2 conversion factor as BECCS Power/Industry (Wood). The feedstock input rate was then calculated using a wood pellet energy density of 4.8 kWh/kg, using that the fuel has a moisture content of 10%[195].

We compared our CO_2 production values to the benchmark values provided by Tolvik[196], using a waste to CO_2 benchmark of 0.992 kg CO_2/kg waste. Our calculations using the REPD method closely aligned with the Tolvik benchmark (refer to Table 50), reinforcing our confidence in our assumptions and methodology. The only site which had significant deviation were: Barr Killoch Energy Recovery Park, Levenseat Waste Management Facility, Levenseat EfW, and Binn Eco Park. and which is planning to burn RDF/SFR fuel instead of MSW. Please note that the Achnabreck site gasifies wood pellets - not waste, and hence cannot be compared against the Tolvik benchmark.

Table 50: EfW/ACT CO_2 production potential comparison

Compared using our REPD method and Tolvik benchmarks

Site	NET	CO_2 production (Mt/year)		Difference (%)
		REPD Method	Tolvik benchmark	
Thainstone Energy Park Project ERF	BECCS EfW	0.423	0.419	1%
Dunbar EfW (previously Oxwellmains EfW)	BECCS EfW	0.309	0.306	1%

[189] FCC Drumgray RERC Energy Recovery Centre (fccenvironment.co.uk)

[190] 09/01020/OUT | Erection of Biomass Combined Heat Power Plant and Wood Pellet Plant and formation of access road | Land East Of G A White Motors Charlesfield Industrial Estate St Boswells (scotborders.gov.uk)

[191] Media Release: Shore Energy secures planning approval for £50m waste recycling and renewable energy generation facility at Carnbroe - allmediascotland…media jobs, media release service and media resources for all

[192] Levenseat Announce new plans for Phase 2 of its Energy from Waste Power Plant - Levenseat

[193] Glasgow RRE (viridor.co.uk)

[194] Binn Ecopark - Binn Group

[195] Typical calorific values of fuels - Forest Research

[196] UK Energy from Waste Statistics - 2021 - Tolvik

Site	NET	CO_2 production (Mt/year)		Difference (%)
		REPD Method	Tolvik benchmark	
Westfield (former Opencast Coal Mine)	BECCS EfW	0.286	0.284	1%
CalaChem Fine Chemicals (Grangemouth) - Earlsgate Energy Centre	BECCS EfW (CHP)	0.384	0.381	1%
South Clyde Energy Centre	BECCS EfW	0.242	0.239	1%
Oldhall Industrial Estate	BECCS EfW	0.181	0.180	1%
Millerhill EfW	BECCS EfW	0.151	0.150	1%
Barr Killoch Energy Recovery Park	BECCS EfW	0.124	0.111	11%
Ness Energy Project	BECCS EfW (CHP)	0.198	0.197	1%
Baldovie Industrial Estate (Forties Road)	BECCS EfW (CHP)	0.179	0.177	1%
Baldovie	BECCS EfW	0.100	0.099	1%
Binn Farm EfW	BECCS EfW	0.088	0.087	1%
Lerwick Energy Recovery Plant	BECCS EfW (Heat only)	0.020	0.019	1%
Polmont landfill site EfW	BECCS EfW	0.089	0.089	1%
Charlesfield Biomass CHP Plant	BECCS EfW ACT (CHP)	0.179	0.177	1%
Coatbridge Material Recovery and Renewable Energy Facility	BECCS EfW ACT (CHP)	0.447	0.443	1%
Levenseat Waste Management Facility	BECCS EfW ACT (CHP)	0.261	0.232	11%
Levenseat EfW	BECCS EfW ACT	0.130	0.115	11%
Glasgow Renewable Energy and Recycling Centre (ACT)	BECCS EfW ACT (CHP)	0.179	0.177	1%
Achnabreck	BECCS Power ACT (CHP)	0.098	N/A	N/A
Binn Eco Park	BECCS EfW ACT	0.048	0.042	11%

Site	NET	CO_2 production (Mt/year)		Difference (%)
		REPD Method	Tolvik benchmark	
Avondale Quarry (Pilot)	BECCS EfW ACT	0.024	0.024	1%

Table 51 on the subsequent pages provides summary of the NETs parameters used in the analysis.

Summary of NETs parameters

Table 51: A breakdown in parameters used to model NETs carbon capture potential

NET	Gross Power Efficiency (power only)	Net Power Efficiency (CHP)	Net Heat Efficiency (CHP)	Gross Heat efficiency (heat only)	Utilisation Factor	Conversion Factor (kg/kWh)	Lifespan (years)	CO_2 Capture efficiency	Biogenic content of carbon (%mass)	Reference
BECCS Biomethane	N/A	N/A	N/A	N/A						Not used
					68%					Assumed
						N/A*				Not used
							20			[197]
								95%		Assumed
									100%	Assumed
BECCS Power & Industry (Wood)	38.7%									BEIS, Wood (2018)[45]
		25%								Assumed
			37.5%							
				80%						Assumed
					90%					Assumed
						0.35				BEIS, GHG Reporting[93]**
							25			BEIS, Wood (2018) [45]
								90%		BEIS, Wood (2018) [45]
									100%	Assumed
	N/A	N/A	N/A	N/A	N/A	N/A				Not used

[197] Lars-Julian Vernersson, 'Bio-LNG and CO_2 liquefaction investment for a biomethane plant with an output of 350 Nm3/h': FULLTEXT01.pdf (diva-portal.org)

NET	Gross Power Efficiency (power only)	Net Power Efficiency (CHP)	Net Heat Efficiency (CHP)	Gross Heat efficiency (heat only)	Utilisation Factor	Conversion Factor (kg/kWh)	Lifespan (years)	CO_2 Capture efficiency	Biogenic content of carbon (%mass)	Reference
BECCS Cement							30			IEA
								90%		BEIS, Wood (2018) [45]
									3%***	
BECCS Fermentation	N/A	N/A	N/A	N/A	N/A					Not used
						754.7*****				SCCS Paper[92]
							30			I
								90%		Assumed
									100%	Assumed
BECCS EfW/ACT	22%******									AECOM[175]
		15%								Assumed
			31%							
				80%						Assumed
					85%					AECOM[175]
						0.36 (MSW) 0.31 (RDF/SFR)				IEAGHG[77]
							20			AECOM[175]
								90%		BEIS, Wood (2018) [45]
									50% (MSW) 17% (RDF/SFR)	IEAGHG[77] and IEA

*Mass balance used instead

**The greenhouse gas reporting conversion factors used were taken from the 'Outside of Scopes' tab.

***We understand that 40% of cement emissions are from combustion, with Dunbar Cement aiming to utilise 45% SFR in their fuel mix which has a biogenic content of 17%.

****This corresponds to the amount of biogas output per tonne of feedstock anaerobically digested. The units are t/t.

*****Units of tonnes of CO_2 produced per mega litre of alcohol produced (MLA)

******See calculations above in EfW section to see how this efficiency is derived.

LCOC Methodology

The Levelised Cost of Carbon (LCOC) will serve as a filtering mechanism for potential NETs sites. It supports the determination of whether these sites should be included in subsequent pathway analysis or not; the higher the LCOC the less economically attractive the site.

Sites located on islands were excluded from further analysis due to the complexities involved in transporting the CO_2 to a suitable storage location.

LCOC calculation of existing sites

$$LCOC_{existing} = \frac{(CAPEX \times CRF) + OPEX_{fix} + OPEX_{var} + C_{transport} + C_{storage}}{CO2_{captured}}$$

LCOC of future sites

$$LCOC_{new} = \frac{(CAPEX \times CRF) + OPEX_{fix} + OPEX_{var} + C_{transport} + C_{storage} - C_{revenue}}{CO2_{captured}}$$

Table 52: A breakdown in the definitions of the various parameters used to determine LCOC

Variable	Meaning	Units
$LCOC_{existing}$	This figure serves as a summary of the economic viability of a particular Negative Emission Technology (NET), acting as an indicator to aid in the selection process among different NETs options.	£/tCO_2,captured
CAPEX	This figure accounts for the investment cost associated with purchasing, installing, and commissioning plant equipment.	M£
Capital Recovery Factor (CRF)	This figure represents the fraction of the initial capital investment that needs to be recovered each year to cover the cost of the investment. It is used to annualise the investment cost.	N/A, this is a dimensionless quantity
$OPEX_{fix}$	This figure accounts for expenses that remain relatively constant regardless of the level of production. This figure is typically in proportion with the capital expenditure.	£M/year
$OPEX_{var}$	This figure accounts for expenses that vary in proportion to the level of production. For industrial sites this cost is typically heavily linked to energy costs.	£M/year
$C_{transport}$	This figure represents the cost associated with transporting the CO_2 to the designated storage site(s). In this report, we have made the assumption that the CO_2 can be transported either entirely by truck to St Peterhead, or partially by truck to an injection point, where it is then injected into a pipeline.	£M/year
$C_{storage}$	This figure represents the cost of storing the CO_2 in the North Sea. In this report, our assumption is based on the utilisation of depleted oil and gas wells, which aligns with the proposed approach of the Acorn project.	£M/year
$C_{revenue}$	This figure represents the gain in revenue associated with selling heat and power from BECCS Power, BECCS Industry and BECCS EfW sites. It's important to note that the analysis does not include revenues derived from the	£M/year

Variable	Meaning	Units
	sale of biomethane for future BECCS Biomethane and AD Upgrading sites.	
CO_2,captured	This figure depicts the quantity of CO_2 captured by the NETs site. Please note that this is not the same as the negative emission potential, which does not account for emissions from fossil sources.	$MtCO_2$/year

Cost Analysis

Capital Expenditure (CAPEX)

In estimating the CAPEX, we employed the widely used sixth-tenths rule, which is a method for approximating costs. According to this rule, the cost of a project can be estimated by taking the cost of a comparable completed project and scaling it by the exponent 0.6, based on the capacity of the reference plant. This scaling can be done by considering various factors such as CO_2 capture potential, heat or power production, biomethane production, or any other relevant parameter. An example calculation is provided below.

$$CAPEX = \; Cost\;(M£) \times \left(\frac{Capacity\; site\; of\; NET}{Reference\; capacity}\right)^{0.6}$$

It's important to note that this method provides a quick and rough estimate of costs. However, it should be used with caution, as it may not encompass all the unique aspects and complexities of each specific project. It's worth mentioning that we do not intend to conduct a detailed cost analysis for each NETs site in our current scope, making this method sufficient for our purposes.

Operational Expenditure (OPEX)

The OPEX is divided into two categories: Fixed costs and Variable costs. Fixed OPEX encompasses ongoing expenses that tend to remain consistent regardless of the production or operational level. Examples include salaries, benefits, equipment maintenance, repairs, and insurance. On the other hand, Variable OPEX includes costs that fluctuate based on the level of production or operation. These costs can include raw materials, fuel, maintenance supplies, and energy consumption.

For existing sites, we assumed that the fixed OPEX would amount to 5% of the CAPEX (a typical industrial benchmark), while the variable OPEX would account for increases in fuel/electricity usage alone as this is typically the main source of variable OPEX cost. We could account for additional variable costs; however, this would to a complex cost analysis for each site which is outside of the scope of this project. Although cost benchmarks for Variable and Fixed OPEX were available in the literature, we chose not to utilise them due to significant discrepancies in assumptions and parameters included in the costs, depending on the specific NETs being discussed. As a result, the costs for existing NETs would not be comparable on a like-for-like basis. The exception was the '*Dunbar Cement*' plant, where site-specific data on heat and power demands was unavailable in the literature, and so we had to rely on benchmarks to determine Variable OPEX.

When evaluating future sites, it was necessary to consider the overall costs associated with both installing and operating a NETs site. To accomplish this, cost benchmarks were employed in their entirety and then scaled up using the sixth-tenths rule. This approach ensured that the complete range of costs were considered for accurate cost estimation. Although this approach may lead to potential cost overestimation, it is not a concern since our objective does not necessitate comparing future sites on a like-for-like basis.

We tested our assumption of fixed OPEX being equivalent to 5% CAPEX, for existing sites, by comparing the respective costs to industrial benchmarks. The overall estimation was reasonably close, as shown below in Table 53. Please note that all cost benchmarks have been scaled to 2023 costs via inflation and converted to pounds sterling.

Table 53: OPEX and CAPEX comparison used in modelling

A comparison between the assumption of fixed OPEX for existing projects, estimated to be equivalent to 5% of CAPEX, and the fixed OPEX benchmarks cited in the literature

NET	5% assumption (£/tCO_2)	Cost benchmark
BECCS EfW (combustion and ACT)	16.1	15.7[175]
BECCS Biomethane	11.4	7[197]
BECCS AD Upgrading	263.3*	N/A, not broken down into fixed and variable OPEX[171]
BECCS Fermentation	2.3	3.1[198]
BECCS Power and BECCS Industry (Wood)	4.1	3.3[45]
BECCS Industry (Cement)	0.0041**	0.0037[175]**

*Please note that AD Upgrading is in units of £/m^3/year

**Please note that BECCS Industry (Cement) is in units of £/tclinker/day

BECCS Biomethane

For existing sites, the costs associated with CCS installation encompassed CO_2 liquefaction only. This is because biomethane sites already separate out CO_2 into a pure stream during the biogas upgrading process, and hence the CO_2 capture is more efficient, less energy intensive, and cheaper. The resulting liquefication process takes the capture carbon and removes water and impurities, where the clean CO_2 stream is then compressed to high pressures in preparation for transport.

CO2 Liquefication

The initial step of liquefication is to compress the gas to the desired pressure (circa 130 bar) and help it reach its critical temperature. Water is then removed by condensation to prevent hydration and the gas is subsequently cooled (e.g., using a set of heat exchangers or expansion cooling) to transition the gas into a liquid. An impurity removal unit is used to remove impurities when the delivered CO_2 needs to meet a high purity requirement.

CAPEX

To determine the CAPEX of liquefication a benchmark was taken from a 2022 techno-economic analysis paper investigating the costs associated with CO_2 capture for AD Upgrading sites. The paper considers a reference case of an AD Upgrading facility producing 4400 tCO_2 at a CAPEX of 1MEUR.

To determine the CAPEX for future sites, we also have to account for the costs associated with constructing the AD Upgrading and AD plant. These costs were taken from a techno-economic analysis paper that investigates biomethane upgrading via the water scrubbing method, which accounts for investment costs in constructing the biogas plant, silage pit, AD upgrading plant, gas grid connection, and CNG service station. For simplicity, we have assumed the water scrubbing technique is used in all biogas AD Upgrading sites in Scotland, so that this paper can be applied to all biomethane sites. This assumption is reasonable, given the fact that around one third of AD Upgrading sites in the UK use water scrubbing technology, according to the EBA Statistical Report of 2020. However, an improvement opportunity of the analysis is to consider membrane separation costs in the analysis instead.

OPEX

As previously mentioned, the Fixed OPEX for existing sites was taken to be 5%. This assumption was also applied to future sites since the CCS OPEX benchmarks from the 2022 AD Upgrading paper was not clearly broken down.

198 National Energy Technology Laboratory, 'Cost of Capturing CO_2 from Industrial Sources': Energy Analysis | netl.doe.gov

The Variable OPEX for existing sites was calculated by determining the power demands of CO_2 liquefication (i.e., powering the compressors and chiller). This method was also used for new sites, again due to an unclear breakdown in CCS OPEX from the 2022 Upgrading paper. The liquefication power demands were taken from a 2019 paper which details a thorough breakdown in cooling and compression power requirements, with compression requiring 12.5 MW and cooling 40.48 MW in order to capture 1 $MtCO_2$/year. We are assuming to compress CO_2 to 130 MPa in preparation for transport, which is a standard industrial benchmark.

An example calculation is shown in Box 4 below for the '*Portgordon Maltings Beyside*' site.

Box 4: Example Variable OPEX calculation process

We use the liquefication power demand of 52.98 MW, in order to capture 1 $MtCO_2$/year, and convert to MJ/kg. We assume standard operating hours of 6000 hr/year for an AD Upgrading site.

$$Liquefication\ demand = \frac{52.98\ MJ}{s} \times \frac{yr}{1\ MtCO2} \times \frac{3600s}{hr} \times \frac{6000\ hr}{yr} \times \frac{1\ MtCO2}{10^9\ kg} = 1.14\ MJ/kgCO2$$

To convert to MJ/year, we multiply the energy demand by the CO_2 capture potential and scale up using the sixth tenths rule.

$$Liquefication\ demand = \frac{1.14\ MJ}{kgCO2} \times \frac{0.00697\ MtCO2}{yr} \times \frac{10^9\ kg}{Mt} \times \left(\frac{0.00697}{1}\right)^{0.6} \times \frac{1\ kWh}{3.6\ MJ} = 112{,}144\ kW/yr$$

To determine the cost of this power demand, an electricity price of 14.6 p/kWh was used based off Ofgem's wholesale electricity price. This final cost is taken as the Variable OPEX.

$$Liquefication\ Variable\ OPEX = \frac{112{,}144\ kWh}{yr} \times \frac{14.6\ p}{kWh} \times \frac{£}{100p} \times \frac{M£}{10^6£} = 0.02M£/yr$$

When considering future sites, the Variable OPEX associated with the AD and Upgrading plants was taken from a 2018 paper. The total OPEX was quoted as a single figure, including both fixed and variable OPEX, which accounts for maintenance and overheads, electricity demands, thermal demands, feedstock and disposal costs, plant OPEX, depreciation, and gate fee(s).

Revenue

We did not include revenue sources from biomethane in our analysis because they fall outside the mass/energy balance boundary that we established.

<u>BECCS Power and Industry Wood</u>

The costs for BECCS Power and BECCS Industry (Wood) were taken from the same source. This is because BECCS Industry (Wood) sites either have biomass boilers or biomass powered CHPs onsite that meet onsite demands (as described earlier in Data Sources). The reference is a 2018 BEIS paper (BEIS Wood 2018). This paper examines the costs associated with installing CCS on a 498 MWe bioenergy power station capturing circa 4.2 $MtCO_2$/year.

CAPEX

The sixth tenths rule is applied, where the costs associated with constructing the bioenergy plant and installing the CCS equipment are £813.7M and £322M respectively.

OPEX

Fixed OPEX was taken to be 5% of CAPEX.

To determine Variable OPEX of existing sites, we had to determine the impact installing CCS would have on the NETs power export of a site. In particular, installing CCS requires heat demands of circa 3.4 MJ/kg,CO_2, which are sourced by extracting low-pressure steam from the turbine at circa 3 bar. As a result, the overall efficiency of the site decreases by approximately 5%. In our analysis, we have used these drops in NETs efficiency to determine losses in revenue, which is equivalent to an increase in Variable OPEX.

If a site is in fact a CHP, then we have to account for the impacts on both power and heat export. To make this analysis simpler, and avoid the need to undertake multivariable optimisation, we assumed that the power export of a site will remain the same, but the heat export potential is impacted by the CCS heat requirements. This results in NETs power efficiencies remaining constant and heat efficiencies dropping. An electrical efficiency of 25% was assumed for CHP sites, based off CHPQA knowledge, and the resulting heat efficiency (pre-CCS) was determined using a z ratio of 3.5. The price of heat was taken to be 4 p/kWh.

The assumed low price of heat is justified by the fact that we are considering the heat price at the export point rather than the price at which heat is sold directly to the customer, such as 12p/kWh through a third party. In this scenario, the generator sells heat to a third party at 4p/kWh. The third party is responsible for constructing and operating the heat network, which incurs significant costs. Subsequently, the third-party charges the customer for the heat supplied.

Box 5 below is a summary of how Variable OPEX was calculated for "*Markinch Biomass CHP Plant*"

Box 5: Further example of variable OPEX calculation process

Using the assumed NETs power efficiency of 25%, we can calculate the heat efficiency using the CHP zed ratio of 3.5. This results in a NETs heat efficiency of ~37.5%.

$$heat\ efficiency = 3.5 \times (35.7\% - 25\%) = 37.5\%$$

Taking the feedstock input rate, we can determine the heat export potential pre-CCS.

$$Heat\ export\ (pre - CCS) = \frac{2050\ GWh, fuel}{yr} \times 37.5\% = 768.8\ GWh, th/yr$$

Using a standard CCS heat demand of 3.4 MJ/kg, CO_2, we can determine the resulting heat demand of CCS using the annual CO_2 capture potential. This enables us to check whether the site can meet CCS demands without the need for the installation of an additional boiler.

$$CCS\ heat\ demand = \frac{3.4\ MJ, th}{kg, CO2} \times \frac{0.65\ MtCO2}{yr} \times \frac{10^9\ kg}{Mt} \times \frac{1\ kWh}{3.6\ MJ} \times \frac{GWh}{10^6\ kWh} = 610\ GWh, th/yr$$

$$Heat\ efficiency\ (post - CCS) = \frac{(768.8 - 610)\ GWh, th}{yr} \times \frac{yr}{2050\ GWh, fuel} = 8\%$$

Using a heat price of 4p/kWh, we can determine the variable OPEX.

$$Variable\ OPEX = \frac{610\ GWh, th}{yr} \times \frac{4\ p}{kWh, th} \times \frac{10^6\ kWh}{GWh} \times \frac{£M}{10^8\ p} = £24.4M/yr$$

For the Morayhill Mill industrial site, which is a heat only site, we have assumed that the gross boiler efficiency is 80%. The same methodology to CHP sites is then applied, where a heat efficiency post-CCS was found to be 50%.

For future sites, we directly applied the bioenergy and CCS benchmarks quoted in the 2018 BEIS paper to determine fixed and variable OPEX. One key thing to note is that the benchmarks used do not account for fuel usage within the Variable OPEX benchmark. Therefore, a wood pellet price of £24/MWh was applied and scaled up according to the feedstock demands of the site.

Revenue

For future sites, the same methodology described above was applied to determine the revenue stream potential of each site, using the expected heat and/or power export potential post-CCS and multiplying it by the respective energy costs (14.6 p/kWh and 4 p/kWh for power and heat respectively).

BECCS Cement

The only site associated with BECCS Cement is Dunbar Cement, which is already operational. As there are no other cement sites expected to be constructed in Scotland, that we have only considered the costs associated with installing and operating CCS.

CAPEX

The investment cost of CCS was taken from the reference site used as the cost benchmark assumed a clinker production rate of 1 Mt/year and a carbon capture potential of 0.8 $MtCO_2$/year, as well as utilising some waste as a fuel feedstock. This last point is ideal for our calculations of Dunbar cement, which plans to implement a 45% blend of SRF/RDF into their fuel feedstock.

The investment cost of CCS, obtained from the AECOM Next Generation Carbon Capture Technology techno economic analysis paper, for a reference site producing 1 Mt/year of clinker and capturing 0.8 $MtCO_2$/year is £192.5M. This reference site also utilises waste as a fuel feedstock, which aligns with our calculations for Dunbar cement due to the site aiming to incorporate a 45% blend of SRF/RDF into their fuel feedstock. The capital expenditure covers EPC and Project Development costs.

OPEX

The Fixed OPEX was taken to be 5% of the CCS Capex.

As there was no data available on the heat and power usages of the Dunbar Cement site in the literature, then the Variable OPEX was determined by applying cost benchmarks directly, despite the site being operational. This does go against the methodology applied to all other existing NETs sites; however, no other options were available to us. This will lead to the LCOC of the Dunbar Cement site being overestimated compared to other existing industrial sites. An improvement point for this work is that the Variable OPEX of the Dunbar Cement site is recalculated based on potential increases in heat and power demands for the site, as well as the impact CCS has on potential losses in revenue sales from clinker, heat and power. The variable OPEX was taken to be £72.7M/year for the reference site.

Due to the lack of available data on the heat and power usages of the Dunbar Cement site, the Variable OPEX was determined by directly applying cost benchmarks, despite the site being operational. This deviates from the methodology used for other existing sites, but no other options were available. The Variable OPEX for the reference site was £72.7M/year. An improvement for this study is to recalculate the Variable OPEX of the Dunbar Cement site considering the impacts CCS will have on heat and power demands, as well as potential revenue losses from clinker, heat, and power sales.

<u>BECCS AD</u>

For existing sites, the costs associated with BECCS AD were taken to be that associated with constructing and operating an AD Upgrading and liquefication plant. As for future sites, the costs associated with constructing and operating an AD facility also had to be accounted for. The calculations, as well as the cost benchmarks used, are discussion previously in the BECCS Biomethane cost section.

<u>BECCS Fermentation</u>

For existing sites, the costs associated with BECCS Fermentation were taken to be that associated with constructing and operating the CCS plant. As potential future sites were not listed in the literature, please see the Data Sources section, then costs associated with future sites (e.g., cost of building a whisky distillery or brewery) were not investigated into. Similar to BECCS Biomethane sites, the mechanism for capturing carbon will be similar to the CO_2 liquefication process, since the stream of CO_2 exiting the distillery is pure. In our case, we used a 2014 paper published by the US Department of Energy which investigated the cost of capturing carbon from a bioethanol plant, which is a reasonable approximation to a whisky distillery and/or brewery. The paper in question considers a reference bioethanol plant that produces 50 Mgal/year of ethanol and 0.145045 $MtCO_2$/year.

CAPEX

The investment cost associated with capturing 0.145045 $MtCO_2$/year is £7.846M. This cost was then scaled up accordingly using sixth tenths rule and the alcohol production rate.

OPEX

The fixed OPEX was again taken to be 5% of CCS Capex.

Similar to BECCS Biomethane, the electricity requirements associated with processing this pure CO_2 are similar to that of CO_2 liquefication. Regarding this 2014 bioethanol paper, a power demand of 1.9 MWh/hr is needed to capture the carbon, which is equivalent to 14147.4 MWh/year based off the fact that the reference bioethanol plant operates at a utilisation factor of 85%. Now assuming a standard carbon capture efficiency of 90%, we can achieve a power demand of 109.9 $GWh/MtCO_2$.

Please see Box 6 below for a breakdown in this calculation.

Box 6: Example of fixed OPEX calculation for BECCS fermentation, power demand

A power demand of 1.9 MWh/hr is needed to capture the carbon, which is equivalent to 14147.4 MWh/year based off the fact that the reference bioethanol plant operates at a utilisation factor of 85%.

$$CCS\ Power\ Demand = \frac{1.9\ MWh}{hr} \times \frac{8760\ hr}{yr} \times 85\% = 14147.4\ MWh/yr$$

Assuming a standard carbon capture efficiency of 90%, we can achieve a power demand of 109.9 GWh/MtCO_2

$$CCS\ Power\ Demand = \frac{14147.4\ MWh}{yr} \times \frac{1\ yr}{(0.143 \times 90\%)MtCO2} \times \frac{1\ GWh}{10^3\ MWh} = 109.9\ GWh/MtCO2$$

Using the sixth tenths rule, we can then scale up the power demand depending on the alcohol production rate. The final cost associated with power usage can then be calculated using an electricity price of 14.6 p/kWh.

Please see the calculations in Box 7 relating to '*Cameronbridge*' grain whisky distillery

Box 7: Example of fixed OPEX calculation, cost implication

The CCS power requirement is scaled using the sixth-tenths rule

$$\frac{109.9\ GWh}{MtCO2} \times \frac{0.075\ MtCO2}{yr} \times \left(\frac{0.075}{0.143 \times 90\%}\right)^{0.6} = 5924\ MWh/yr$$

The power requirement is costed

$$\frac{5924\ MWh}{yr} \times \frac{14.6\ p}{kWh} \times \frac{10^3\ kWh}{MWh} \times \frac{M£}{10^8 p} = £0.86M/yr$$

<u>BECCS EfW/ACT</u>

The paper used to source our CCS cost benchmarks is from the AECOM Next Generation Carbon Capture Technology paper, which quotes a reference site that processes 350,000 t/year of waste, has a gross power output 29 MWe and captures 0.3 MtCO_2/year. Costs associated with constructing and operating a EfW facility were taken from a Catapult Energy Systems paper that focussed on UK deployment of EfW facilities, considering a 'Core EfW Plant' where 350,000 t/year of waste is burnt under a gross capacity of 32MWe.

CAPEX

The investment cost of capturing 0.3 MtCO_2/year from a EfW site is quoted to be £96.8M, which is then scaled accordingly using sixth tenths and the CO_2 capture potential of each site. When considering future sites, the investment cost associated with constructing an EfW facility is taken to be £224M, when not scaled for inflation.

OPEX

For existing sites, the fixed OPEX is again taken to be 5% of CAPEX.

The methodology behind calculating Variable OPEX for existing EfW/ACT sites is similar to that of BECCS Power and Industry (Wood). The key difference is the choice around the electrical and heat efficiencies used, which are calculated below using parameters described in the AECOM paper.

<u>The NETs power efficiency pre and post CCS is 19% and 11% for power only sites</u>

Given the fact that the reference case consumed 350,000 t/year of MSW and that the site operates 7446 hr/year, then we can determine the fuel energy input rate based on the fact that MSW has an energy density of 10 MJ/kg.

$$Waste\ input = \frac{350{,}000\ t}{yr} \times \frac{10\ MJ}{kg} \times \frac{10^3\ kg}{t} \times \frac{yr}{7446\ hr} \times \frac{1\ hr}{3600s} = 130.6\ MW, fuel$$

We know that the gross power is 29 MWe, NETs power output (pre-CCS) is 25 MWe, and NETs power output (post-CCS) is 14 MWe. Furthermore, we know that the Therefore, we can determine the power efficiencies.

$$Gross\ power\ efficiency = \frac{29\ MWe}{130.6\ MW, fuel} = 22\%$$

$$Net\ power\ efficiency\ (pre - CCS) = \frac{25\ MWe}{130.6\ MW, fuel} = 19\%$$

$$Net\ power\ efficiency\ (post - CCS) = \frac{14\ MWe}{130.6\ MW, fuel} = 11\%$$

The choice of NETs power and heat efficiencies (pre-CCS) of a EfW CHP was determined based off CHPQA data. The power and heat efficiencies were taken to be 15% and 31% respectively.

The NETs heat efficiency of a EfW CHP was determined to be 0.4% once CCS was installed (i.e., all heat output from the CHP is utilised onsite to meet CCS demands). An example calculation for the "*Charlesfield Biomass CHP Plant*" site is shown in Box 8.

Box 8: BECCS EfW OPEX calculation example

Taking the feedstock input rate, we can determine the heat export potential pre-CCS.

$$Heat\ export\ (pre - CCS) = \frac{496.4\ GWh, fuel}{yr} \times 31\% = 153.9\ GWh, th/yr$$

Using a standard CCS heat demand of 3.4 MJ/kg,CO_2, we can determine the resulting heat demand of CCS using the annual CO_2 capture potential. This enables us to check whether the site can meet CCS demands without the need for the installation of an additional boiler.

$$CCS\ heat\ demand = \frac{3.4\ MJ, th}{kg, CO2} \times \frac{0.16\ MtCO2}{yr} \times \frac{10^9\ kg}{Mt} \times \frac{1\ kWh}{3.6\ MJ} \times \frac{GWh}{10^6\ kWh} = 152\ GWh, th/yr$$

$$Heat\ efficinecy\ (post - CCS) = \frac{(153.9 - 152)\ GWh, th}{yr} \times \frac{yr}{496.4\ GWh, fuel} = 0.4\%$$

Using a heat price of 4p/kWh, we can determine the variable OPEX.

$$Variable\ OPEX = \frac{152\ GWh, th}{yr} \times \frac{4\ p}{kWh, th} \times \frac{10^6\ kWh}{GWh} \times \frac{£M}{10^8\ p} = £6.1M/yr$$

For the only heat only site, Lerwick Energy Recovery Plant, the heat efficiency pre-CCS was taken to be 76.7%. This is based off calculations using data from the Tolvik 2022 EfW statistics paper, where the site is labelled as Gremista. The total heat export from this site was 49 GW_{th} in 2022, the waste input rate 23,000 t/year, and the energy density of the fuel was assumed to be 10 MJ/kg (MSW equivalent). This calculated heat efficiency is reasonable compared to industrial benchmarks of a typical boiler efficiency being ~80%.

For future sites, we directly applied the EfW plant and CCS benchmarks quoted in the AECOM and Catapult Energy Systems papers. This includes the proposed Achnabreck site, which plans on gasifying wood pellets in a CHP. The reasoning behind why we used these benchmarks is because the technology is the same and hence costs are unlikely to differ significantly if we switch the biomass source. However, it is still worth noting that an improvement point to this work is to update the Achnabreak cost calculations so that they are more closely aligned to woody biomass gasification, since the fuel density and gasification efficiencies will differ compared to waste, which in turn will impact the variable OPEX costs slightly.

CO_2 Transport

The costs associated with carbon transport were determined in a separate Excel tool compared to the LCOC Tool.

In this case, the X and Y coordinates identified during the literature review of each site were taken and mapped against potential CO_2 injection points across Scotland using GIS Mapping.

The key CO_2 injection points considered were all along the St Fergus gas pipeline, which is proposed to be upgraded to enable CO_2 transport cross country as part of the Acorn project. **The injection points were Bathgate, Kirriemuir, Garlogie, and Peterhead.** The distance between all four injection points and the proposed NETs site were calculated in km using GIS Mapping by assuming that all sites will initially transport CO_2 by truck to an injection point unless they are physically located next to one of the four proposed injection points. **The shortest possible road distance was then selected**.

The onshore pipeline distances from each of the four injection points to the St Peterhead gas terminal was then calculated using GIS mapping and are shown in Table 13 of the main report.

The final offshore pipeline distance from the Peterhead to the Acorn site is 80km for all sites.

The resulting costs associated with each mode of travel: road, onshore pipeline, and offshore pipeline, are then calculated using the benchmarks outlined in Table 20, page 36 following benchmarks taken from the IEAGHG EfW-CCS paper. The benchmarks can then be used to scale linearly scale up transport costs based on CO_2 production capacity and transport distance.

CO_2 Storage

Storage costs were taken directly from the IEAGHG EfW CCS paper, where the high-end costs were utilised in order to ensure that costs are conservative. As these costs are quoted in a £/tCO_2 basis, with no reference to plant size, then costs are linearly scaled up based on CO_2 capture capacity.

Inflation

To ensure all cost benchmarks are within the correct format, they are adjusted for inflation and converted to pounds sterling using indexes from the World Bank and exchange rates from the OECD. Please note that inflation indexes were only available up to 2021. An improvement point of this analysis is to utilise updated inflationary figures, when they are available, to determine the difference in costs based on the fact that the British economy is going through a period of very high inflation.

Table 54: Figures used to convert costs into British Pounds Sterling and scaled for inflation

Parameter	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
GDP deflator index (2010 =100) to 2021 for US	91.86	93.77	95.52	97.19	99.01	100.00	101.00	102.92	105.40	107.29	108.69	113.57
GDP deflator index (2021 =100) to 2021 for US	0.81	0.83	0.84	0.86	0.87	0.88	0.89	0.91	0.93	0.94	0.96	1.00
Exchange rate USD to GBP	0.65	0.62	0.63	0.64	0.61	0.65	0.74	0.78	0.75	0.78	0.78	0.73
Exchange rate USD to Euro	0.75	0.72	0.78	0.75	0.75	0.90	0.90	0.89	0.85	0.89	0.88	0.85
Exchange rate Euros to GBP	0.86	0.87	0.81	0.85	0.81	0.73	0.82	0.88	0.89	0.88	0.89	0.86

APPENDIX 3. STAKEHOLDERS FEEDBACK: KEY MESSAGES

There are several factors which need to be considered when evaluating the feasibility of NETs and developing NETs pathways for Scotland. These were based on information and data gathered via a comprehensive stakeholder consultation which was undertaken as part of the study. The stakeholder engagement is used to complement data gathering and to identify which stakeholders have a real intention to consider and develop NETs projects, to what extent, how would they seek to do this, and on what timescale. The engagement with stakeholders enabled a greater understanding of the drivers for the development of NETs projects and identified specific existing facilities that would be suitable or unsuitable for retrofit with CCUS. A comprehensive account of discussions with stakeholders is provided in this part of the report.

STAKEHOLDER ENGAGEMENT PROCESS

The stakeholder engagement was based on a pre-developed online survey and interview questionnaire followed by targeted semi-structured interviews. Three different versions of the interview questionnaire, tailored to different groups of stakeholders – technology providers, industries with biogenic emissions, and industries without biogenic emissions – were developed. Key stakeholders were identified for further discussions. Key stakeholder interviews are described in this appendix.

We developed online survey and interview questionnaire in discussion with Scottish Government steering group. The aim was to use the online survey to gain initial information followed by targeted, semi-structured interviews to gather further information. Three different versions of the interview questionnaire were produced, tailored to different groups of stakeholders: technology providers, industries with biogenic emissions, and industries without biogenic emissions. We identified key stakeholders in discussion with Scottish Government, drawing on existing contacts and new suggestions. The survey was piloted with a selected group of stakeholders and the questionnaire and interview script adapted accordingly. From a shortlist of 48 stakeholders, 42 were formally approached to participate in this study. Of these, 14 participated in the online survey and 22 were formally interviewed.

STAKEHOLDERS ENGAGED WITH

The 22 stakeholders that were formally interviewed as part of this process are as follows:

• E-on (Steven's Croft power station)	BECCS Power (inc. CHP)
• RWE (Markinch CHP plant)	BECCS Power (inc. CHP)
• Drax Group (Drax Power Station)	BECCS Power (inc. CHP)
• Shetland Heat and Power	BECCS EfW
• FCC (Baldovie EfW, Dundee)	BECCS EfW
• MVV (Millerhill EfW, Midlothian)	BECCS EfW
• West Fraser (Norbord Europe Ltd, Cowie)	BECCS Industry
• INEOS	BECCS Industry
• Diageo	BECCS Industry
• Carbon Capture Scotland	BECCS Industry
• Scottish Water	BECCS Industry
• Forth Green Freeport	BECCS Industry
• Dunbar Cement	BECCS Industry
• PetroINEOS	BECCS Industry / BECCS Biofuels
• Future Biogas	BECCS Biomethane
• Anaerobic Digestion & Bioresources Assoc.	BECCS Biomethane
• University of Glasgow	BECCS Hydrogen
• Carbogenics	Biochar
• Climeworks	DAC
• CO2CirculAir	DAC

• Bellona	DAC
• CCS Association	Trade Associations/Other

KEY OUTPUTS FROM STAKEHOLDER ENGAGEMENT

The following sub-sections summarise the key findings from the various stakeholder groupings: industry, EfW, power, biomethane, biochar and DAC. The different sub-sections report on the specific questions outlined in the interview script and which were asked in the same way to different stakeholder groups. For the different types of NETs options, respondents highlighted similar issues and aspects which need to be taken into account and so some of the sections below (categorised by type of NET) are repetitive and emphasise the same message.

BECCS Industry

BECCS Industry – summary

Industry respondents came from the refining and petrochemicals, water treatment, pulp, paper and board, and food and drinks sectors. All with operating centres in Scotland, they included the following 5 organisations:

- INEOS
- PetroINEOS
- Scottish Water
- West Fraser (Norbord Europe Ltd, Cowie)
- Diageo

Of these, 4 of 5 were working to Net Zero targets with dates ranging between 2030-2050 for different aspects of business operations.

While there were no NETs projects either currently underway or planned in Scotland, overall perceptions of NETs were generally positive, with all respondents reporting that carbon removal was necessary to offset hard-to-abate sectors and was an area where they felt they either had an important role to play or could implement certain technologies, depending on a range of related developments and supporting measures.

All respondents expressed a preference for on-site BECCS as opposed to DAC (likely due to the relatively high costs and low TRL associated with DAC).

For 3 of the 5 respondents, using biomass for energy is already a well-established part of their business model. For the refining and petrochemicals sector, fuel switching to biomass is acknowledged as being possible at some point in the future, but preference is given to switch to low-carbon (blue) hydrogen.

Deployment of NETs for industry was projected to be a credible option from around 2030 onwards, with the Acorn CCS CO_2 transport and storage infrastructure project cited as a key enabler.

BECCS Industry - studies and projects

There were a number of complementary studies and projects that had either already been undertaken or were currently underway that could easily feed into future NETs activity. These included prefeasibility studies looking into: fuel switching to biomass, crop regeneration, DAC and biorefining options in the refining and petrochemicals sectors; CO_2 capture and upgrade to food standard, CCU for low-carbon building materials and biochar production in the water treatment sector; CO_2 capture in the pulp, paper and board sector; and bioenergy deployment in the food and drinks sector.

In terms of future plans and potential, too, there were a number of projects either in the pipeline or being considered that would also be well aligned with any future NETs activity. The refining and petrochemicals sector is focused of reducing emissions and low-carbon (blue) hydrogen production from natural gas but also sees potential in BECCS for either energy or fuel production, bioethanol and for CCU whereby CO_2 is sequestered in polymers. The water treatment, pulp, paper and board and food and drinks sectors see potential in BECCS from existing operations across a combination of bioenergy CHP and AD processing facilities.

BECCS Industry - NETs deployment timeline

While feedback on timelines varied, there was a general consensus that 2030 could mark the point at which NETs could begin to take root in Scotland. Timelines were influenced by a range of variables, including long lead in times for projects of around 4-5 years from conception to operational status, uncertainty around business models and support mechanisms, a general feeling that it would take around 10 years to see a positive return on any NETs project (which is also comparable to other industries of this scale), and the projected timeline for the Acorn CCS project to become operational. Thoughts on the timing of full feasibility studies differed, with the refining and petrochemicals sector suggesting that it was still too early for this while the water treatment sector indicated that these could be up and running by 2024.

BECCS Industry – support needed for NETs

Suggested supporting and facilitating measures to incentivise NETs for BECCS Industry were as follows:

- CCS and NETs
- Acorn CCS transport & storage infrastructure is a key enabler
- Policy changes to incentivise deployment of CCS, CCU and NETs including for example inclusion under the ETS, supporting the development of CCS infrastructure, etc.
- Clear policy to incentivise carbon capture on EfW and to ensure that new EfW are capture-ready
- Financial support from Government
- CAPEX and OPEX support
- Long-term financial support for CCS
- Credible and verifiable negative emissions standards
- Carbon markets
- Long-term confidence in carbon pricing mechanisms and timelines
- Other
- Strong research base (e.g., research needs in innovative CO_2 capture processes relevant to specific industries, e.g., chemical loping)

BECCS EfW

BECCS EfW – summary

All EfW respondents were active EfW plant operators in Scotland. They included the following 3 organisations:

- Shetland Heat & Power
- FCC (Millerhill EfW, Midlothian)
- MVV (Baldovie EfW, Dundee)

Of these, 2 of 3 were working to Net Zero targets of 2045.

While there were no NETs projects either currently underway or planned in Scotland, overall perceptions of NETs were generally positive, with most (2 of 3) respondents reporting that NETs were necessary to offset hard-to-abate sectors and all respondents agreed that it was an area where they felt they either had an important role to play or could implement certain technologies, depending on a range of related developments and supporting measures.

Most (2 of 3) respondents expressed a preference for on-site BECCS.

For 2 of the 3 respondents, using biogenic feedstock is already a well-established part of their operations. For the third respondent, this was not relevant as they did not have any biogenic feedstock and therefore no biogenic CO_2 emissions.

Deployment of NETs for EfW plants was projected to be a credible option from around 2030 onwards, with the Acorn CCS CO_2 transport and storage infrastructure project cited as a key enabler.

BECCS EfW - studies and projects

There were a number of complementary studies and projects that had either already been undertaken or were currently underway that could easily feed into future NETs activity. One respondent reported NETs feasibility studies on EfW plants in Germany and a biomass plant in England, but nothing for Scotland. Two respondents intimated that they were currently involved in district heating network schemes (albeit at different stages of development) and, with CCS very much in mind, both were very aware of the potential to align with the Acorn CCS project and related projects and initiatives to better exploit the potential from EfW CHP plants. One of these respondents also reported that they had already spoken with a commercial CO_2 capture technology provider.

In terms of future plans and potential, the respondents were again split into two camps. Two of them have a strong preference for on-site BECCS and both are interested in revenues from negative emissions offsets. As mentioned above, both are involved in district heating schemes, with deployment of one of these imminent. One of the respondents also alluded to the potential for a small-scale CO_2 capture plant with a leading UK academic institution in the near future. The third respondent reported plans to explore CCU potential for agriculture (growing algae) and exploiting renewable sources for heat and power generation, including sea water heat pumps and wind.

BECCS EfW - NETs deployment timeline

Between the two respondents considering on-site BECCS, there was a consensus that 2030 could mark the point at which NETs could begin to take root in Scotland. Timelines were influenced by a range of variables, including long lead in times for projects (2 years for planning and permitting alone, to be followed by construction) and issues pertaining to plant ownership, and therefore future plans, e.g., one plant is co-owned by the City of Edinburgh Council under a Public-Private Partnership model. The projected 2030 timeline was influenced by the projected timeline for the Acorn CCS project to become operational.

BECCS EfW – support needed for NETs

Suggested supporting and facilitating measures to incentivise NETs for BECCS EfW were as follows:

- CCS and NETs
- Acorn CCS transport & storage infrastructure is a key enabler
- Policy changes re. CCS, CCU and NETs
- Financial support from Government
- CAPEX and OPEX support
- Long-term financial support for CCS
- Credible and verifiable negative emissions standards
- Carbon markets
- Long-term confidence in carbon pricing mechanisms and timelines, i.e., UK ETS
- Other
- Strong research base (need for R&D on new solvents to reduce energy requirements and optimise CO_2 capture performance and costs when deploying on EfW. Also, R&D needs to integrate EfW plants with CHP and DH systems to maximise efficiency.

BECCS Power

BECCS Power – summary

All power respondents were renewable energy providers. All were biomass power plant operators: 2 of them with operating centres in Scotland and 1 in England. They included the following 3 organisations:

- E-on (Steven's Croft power station)
- RWE (Markinch CHP plant)
- Drax Group (Drax Power Station)

All respondents were working to Net Zero targets with dates ranging between 2030-2050.

While there were no NETs projects on currently underway in Scotland, the respondents reported being involved in a number of scoping/feasibility studies covering BECCUS applications. Overall perceptions of NETs were positive, with all respondents reporting that NETs will be necessary to offset hard-to-abate sectors and all agreeing that it was an area where they felt they either had an important role to play or could implement certain technologies, depending on a range of related developments and supporting measures.

All respondents acknowledged the importance of BECCS Power, with 2 of 3 expressing a preference for on-site BECCS.

Deployment of NETs for biomass power plants was projected to be a credible option from around 2030 onwards, with the Acorn CCS CO_2 transport and storage infrastructure project cited as a key enabler.

BECCS Power - studies and projects

There were a number of complementary studies and projects that had either already been undertaken or were currently underway that were either designed to or could easily feed into future NETs activity. Two respondents reported scoping/feasibility studies on BECCUS applications, including assessment of unspecified CCU, BECCS hydrogen production and CCU for sustainable aviation fuel (SAF). For the other respondent, NETs wis a core part of its business both in the UK and globally and it had been involved in numerous feasibility and pilot studies and demonstration projects with a view to large-scale NETs deployment.

In terms of future plans and potential, the respondents all see NETs as an important part of continued business operations, and all were interested in potential revenues from negative emissions offsets. Two of them had a strong preference for on-site BECCS Power while the preferred options for the other site were maximising/exploring renewable heat and BECCS hydrogen production opportunities, followed by BECCS Power. The two Scotland-based facilities were open to third-party testing and pilot-scale demonstration projects.

BECCS Power - NETs deployment timeline

The two Scotland-based facilities suggested 2030 as an indicative timeline for NETs deployment, although neither gave details of any concrete project plans. This timeline was implied from their acknowledgements that a business-as-usual approach would simply not work and statements around the perceived longevity of the facilities, which were also aligned with the projected timeline for the Acorn CCS project to become operational. The England-based facility was operating to a very similar timeline, with concrete project plans in place for UK deployment by 2027 and feeding into geological storage provided as part of other UK-based CCS clusters, but not in Scotland. The US Inflation Reduction Act (IRA) was cited as a key enabler of NETs activity because it makes the business case clear, suggesting that something similar for Scotland/the UK would make a real difference.

BECCS Power – support needed for NETs

Suggested supporting and facilitating measures to incentivise NETs for BECCS Power were as follows:

- CCS and NETs
- Acorn CCS transport & storage infrastructure is a key enabler
- Policy changes re. CCS, CCU and NETs
- Clear policy on EfW + CCS
- Planning permission
- Financial support from Government
- CAPEX and OPEX support
- Long-term financial support for CCS
- Replacement for ROCs (ROCs preferred to CfD)
- Credible and verifiable negative emissions standards
- Industry grouping/collective
- Carbon markets
- Long-term confidence in carbon pricing mechanisms and timelines, i.e., UK ETS
- Other
- Strong research base

BECCS Biomethane

BECCS Biomethane – summary

Biomethane respondents were comprised of a UK-wide AD/biomethane producer with 1 facility in Scotland and the UK-wide trade body for AD and bioresources. While both are active in Scotland, they are both headquartered in England. They included the following 2 organisations:

- Future Biogas

- Anaerobic Digestion & Bioresources Association (ADBA)

Future Biogas was working with auditors to assess entire company emissions, i.e., scopes 1-3, and was following the Science-Based Targets Initiative (SBTI).

While there were no NETs projects currently underway in Scotland, the respondents reported a very tangible prospect of future growth in this area, with new AD plants very likely to have CO_2 capture technology designed in from the start and existing plants very likely to retrofit. Reasons given included a pressing need for NETs, increased recognition of the value of the additionality of capturing and sequestering biogenic CO_2 and a projected steady rise of the value of biogenic CO_2 over time compared to fossil CO_2. The issue of value was repeatedly mentioned in terms of the rise of the price of CO_2 in recent months, partly due to the situation in Ukraine. Both CCS and CCU were mentioned. Although, financial support was still deemed necessary to facilitate wider deployment.

Both respondents acknowledged the current roll out of CO_2 capture technology on new build plants, as well as retrofit to existing plants. It was also suggested that early movers could be in a position to offer a service for collecting biogenic CO_2 from other biomethane facilities in Scotland.

Future Biogas intend to develop 25 of their existing biomethane sites in England into NETs projects where the CO_2 is captured and transported for permanent storage not the Norther Lights storage hub. Deployment of NETs for AD/biomethane plants was projected to be a credible option for certain UK locations from 2024 onwards, such as Future Biogas' to-start-construction-in-2023 plant. This example shows that domestic CO_2 transport and storage infrastructure is not a prerequisite for such projects to be considered financially viable.

BECCS Biomethane - studies and projects

In terms of future plans and potential, the respondents reported a healthy amount of activity for the sector which simply made good business sense. Underpinned by the current high value of CO_2 and a projected premium for biogenic CO_2 specifically, the sector is seeing new plants CCS-equipped from day 1 and retrofit for existing plants. An estimated 10% of biomethane facilities have CO_2 capture technology installed and this is expected to grow. One example given was a new build Future Biogas facility in an unspecified location in the north-east of England that will capture its CO_2, to then be transported from the Humber area to Norway for permanent offshore geological storage as part of the Northern Lights project.

BECCS Biomethane - NETs deployment timeline

While the Future Biogas example shows that projects may be considered financially viable as early as 2024 even in the absence of domestic CO_2 transport and storage infrastructure, international shipment of CO_2 was not deemed to be a sustainable long-term option for the sector or indeed for Scotland-based facilities, given the added cost of transport to the Humber area. An indicative sector-level timeline for NETs deployment was therefore suggested to be closer to the late 2020s and aligned with the UK's CCUS cluster sequencing programme. For Scotland – and the Acorn CCS project – this means an implied timeline of around 2030.

BECCS Biomethane – support needed for NETs

Suggested supporting and facilitating measures to incentivise NETs for BECCS Biomethane were as follows:

- CCS and NETs
- Acorn CCS transport & storage infrastructure is a key enabler
- Policy changes re. CCS, CCU and NETs
- Financial support from Government
- CAPEX and OPEX support
- Long-term financial support for CCS
- **Replacement for Green Gas Support Scheme (GGSS) : should consider incentivising CO_2 capture and permanent storage of the captured CO_2. For example, through providing higher payments for sites which become NETs.**
- Power BECCS CfDs
- Regulated carbon removals market
- Credible and verifiable negative emissions standards backed by Government
- Carbon markets

- Long-term confidence in carbon pricing mechanisms and timelines, i.e., UK ETS
- Other
- Strong research base to identify innovative capture technologies

Biochar

Biochar – summary

Biochar respondents were comprised of a single organisation: Carbogenics. Carbogenics is a Scotland-based producer of specialist bio additive charcoal called *cre-char* for AD processes and is currently without any direct competitors.

- Carbogenics

While there were no NETs projects – or indeed even a market - currently underway in Scotland, the respondents reported a very tangible prospect of future growth in this area, with over 700 AD plants across the UK that could use their product to improve efficiency and increase biogas yield. Reasons given for anticipated growth included a general pressing need for NETs aligned to the climate imperative and significant levels of support across Europe. Certified, verifiable negative emissions credits were considered vital for the sector. Other char products and AD additives such as carbon black are part of a wider nascent char market that Carbogenics aims to develop.

Biochar - studies and projects

Carbogenics reported ongoing trials with around 10 different AD companies. In what is a highly specialised, niche sector with no extant market, activity is aimed at demonstrating the efficacy of the product and creating a biochar market in the UK. Selling carbon credits is considered another important potential revenue stream for the sector.

Biochar – NETs deployment timeline

Carbogenics is currently building a new 400t biochar/year production facility, which would serve between 10-20 individual AD plant customers. It is expected to be operational by early 2024. While the timeline for delivery of this facility might be near term, no date was suggested as to when the UK sector might be able to support a functioning NETs market. In addition to firstly having to prove the concept through trials, barriers to development included policy (i.e., policies currently do not support development), regulation (regulation is needed to facilitate use of biochar) and finances (projects are not viable without financial support).

AD and biogas sites are target customers for biochar and growth of the AD sector will affect development of biochar plants. Currently, biogas production targets (as a % of total gas demand) across Europe are much more ambitious than in the UK, which currently has no mandated target (and sits at 1% of total gas demand), e.g., Denmark, Poland (100%) and Germany (25%). Despite a favourable wind in Europe, the outlook for the UK, and Scotland, is therefore uncertain. Carbogenics, however, project that the UK biochar sector will double in the next 3 years and that the UK biogas sector will double in less than 10 years. Taking this projected growth as a proxy for establishing a market, a timeline of around 2030-2035 could be proposed for NETs development.

Biochar – support needed for NETs

Suggested supporting and facilitating measures to incentivise NETs for Biochar were as follows:

- Access to capital to facilitate growth (public sector capital could be matched by private sector)
- Regulation: Scotland's permitting system is restrictive even compared to England
- Targets: establish mandatory targets for biogas production as % of total gas demand to 10% or 25%
- Biomass classification: formal classification of secondary biomass for biochar
- Allow biochar created from sewage sludge to be returned to the soil (like Sweden and Denmark)
- Support farming communities
- Strong research base (education, training & skills)

DAC

DAC – summary

DAC respondents included two DAC developers and an environmental NGO:

- CO2CirculAir (developer)
- Climeworks (developer)
- Bellona (NGO)

There is currently no operational DAC sector in Scotland. The respondents' comments, while often in agreement in principle, were very often diametrically opposed to each other. For example, all agreed that DAC would not play a significant role in helping to meet Net Zero or any other major near-mid-century climate targets. They also agreed that DAC would probably be better used for CCU rather than CCS as this is likely to provide a better and more viable economic case. On the principle of whether or not Scotland could support a DAC sector, they agreed that it technically could but disagreed that DAC would actually be the best use of (renewable) resources where other and better alternative uses for those resources existed'. Neither of the developers have actively researched DAC in Scotland but were aware of the fast-tracked nature of the Acorn project with geological storage being the most important factor for future deployment of DAC operating as a NETs facility.

DAC - studies and projects

CO2CirculAir reported that a pilot plant facility trialling its novel Smart-DAC technology, a natural wind-based technology using membrane gas absorption, was currently under construction in Northern Ireland and that it would soon be operational. Climeworks operates project Orca in Iceland[199] which can capture ~4,000 tCO_2/year and has plans to scale this up to have a ~0.4 $MtCO_2$ plant operational by the late 2020s and a mega-tonne project operational by the mid-2030s.

DAC - NETs deployment potential

Both respondents reported that DAC would most likely play only a very limited role in helping to meet Net Zero and/or any other significant climate targets. There was therefore no discussion about a timeline for NETs deployment on DAC. Rather, their responses were focused on the pros and cons of DAC deployment in Scotland, the key themes from which are outlined below.

- Themes/Issues on which respondents agreed included:
    - Scotland could in principle support a DAC sector
    - Scotland's surplus renewables from wind could in principle be used for DAC
    - Scotland's spare land could in principle be used for DAC
    - Waste industrial heat could in principle be used for DAC
        - The heat requirements for the various technologies varies significantly – whilst using waste heat is always advantageous – Climeworks indicated that the vast majority of the energy demands required are in the form of power (carbon neutral / renewable electricity)
    - DAC will not contribute meaningfully to 2045/2050 net-zero targets
    - DAC is scalable (In theory, the plant set up can be replicated and scaled up by adding several smaller plants in series but the main issue is the cost associated with scaling up the technology and identifying and resolving integration issues to maximise performance)
    - DAC is better applied to CCU than CCS (that is, it makes more sense to use CO_2 from DAC to produce sustainable aviation fuels, SAF, e-kerosene or other fuels where green hydrogen is also available. If the right incentives are available, it may also become attractive to permanently store CO_2 from DAC)
    - NETs on DAC will require large-scale CO_2 transport and storage infrastructure
    - DACCS makes sense if there's an economic return on geological storage of CO_2
    - Plans for 1Mt/year DAC facilities are very unclear

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[199] Roadmap of orca DAC facility: https://climeworks.com/roadmap/orca

- Themes/Issues on which respondents disagreed included:
    - Scotland's surplus renewables would be best used for DAC
    - Scotland's spare land would be best used for DAC
    - Waste industrial heat would be best used for DAC
    - DAC is expensive
    - DAC can be scaled up sufficiently to make a meaningful contribution to decarbonising air travel via CCU for sustainable aviation fuel (CO_2 from DAC is a focus for the aviation industry (for example, this study). Using CO_2 for making SAF or e-kerosene (rather than storing it in geological formations) provides a route for the aviation industry to decarbonise. Scaling up DAC is possible in theory as the designs can be modular, but systems need to be integrated and optimised. These additional build-up costs can be offset by creating additional revenue streams from SAF production

DAC – Support needed for NETs

Suggested supporting and facilitating measures to incentivise NETs for DACCS were as follows:

- CCS and NETs
- Acorn CCS transport & storage infrastructure is a key enabler
- Policies to facilitate granting planning for new projects
- Policies to prioritise incentivises for permanent storage of CO_2 from DAC rather than using it for making sustainable aviation fuels

APPENDIX 4. CCUS IN THE UK

The UK Government is in the process of allocating £1B of funding to CCUS projects, in a bid to decarbonise heavy industry. There is an expectation that this funding will help reduce CCUS costs by 50% by 2050[22], helping spur further deployment and investment from the private sector into CCUS.

Previous CCUS UK pilot projects

In the UK there were three previous CCS pilot projects: the Aberthaw CCS Facility operating between 2013-2014, capturing 50tCO_2/day from a coal power plant in South Wales[200]; the Ferrybridge Carbon Capture Pilot plant operating between 2011-2013, capturing 100tCO_2/day from a 5MW coal-biomass plant located in Leeds[201]; and the 40MWth Renfrew oxy-fuel coal-CCS project operating between 2007-2011.

Projects under Phase 2 CCUS Funding

After the East Coast and HyNETs Clusters received Track 1 funding under the CCUS Fund[18], BEIS allocated Phase 2 funding to projects categorised under Power CCUS, Hydrogen, and Industrial carbon capture (see for further information). Please note that none of these projects are located within Scotland.

Power CCUS

Funding has been allocated to one oxyfuel and two post-combustion natural gas fired power plants, located in Teeside and Scunthorpe, which will provide a combined power output of 2.12 GW and capture 4.3 MtCO_2/year[82]. These will help form part of the East Coast Cluster.

Hydrogen CCUS

Six projects are dedicated to blue hydrogen production via SMR-CCS of natural gas, four of which are located in the East Coast Cluster and the remaining two near the HyNETs Cluster. Combined, these will provide at least 2 GW of hydrogen and capture 14 MtCO_2/year by 2030.

Industrial carbon capture (ICC)

Thirteen projects are dedicated to industrial capture, two of which are hydrogen focussed and hence have been included in the above section. The sites covered include an ammonia production facility owned by CF Fertilisers; four EfW-CCS sites, half of which are located in the East Coast Cluster and the other half near HyNet, providing at least 148 MW of power and capturing 1.4 Mt/year by 2030; three cement facilities, one of which produces lime using low carbon hydrogen, one that utilises lime to capture CO_2 directly from the air, and the other a post-combustion cement-CCS plant capturing 0.8Mt/year; and two oil-refineries located in the East Coast Cluster, performing post-combustion capture to sequester 1.6 Mt/year by 2030. There is one project named 'Norsea Carbon Capture' which lacks any supporting information to expand upon.

Additional Scottish CCUS projects (Not funded by phase 2 CCUS fund)

Power CCUS

There are two natural gas fired CCS plants aiming to capture a combined 4.5 MtCO_2/year by 2026; the Caledonia Clean Energy plant located in Grangemouth (3MtCO_2/year) and Peterhead Power Station (1.5MtCO_2/year). The Caledonia project has potential to co-produce blue hydrogen[202], whilst the Peterhead Power Station will utilise the Acorn CCS T&S infrastructure.

Hydrogen and Industrial carbon capture (ICC)

The Acorn CCS and hydrogen site is planning to repurpose the St Fergus Gas Terminal and pipeline with the aim to transport CO_2 by 2025. Within the first phase, 200MW of hydrogen will be produced and capture 0.4 MtCO_2/year, whilst CO_2 transport via the Feeder 10 pipeline will enable 10MtCO_2/year of capture by 2030[203].

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[200] MIT (2016), 'Aberthaw Fact Sheet: Carbon Dioxide Capture and Storage Project': Carbon Capture and Sequestration Technologies @ MIT

[201] MIT (2016), 'Ferrybridge CCSPilot100+ Fact Sheet: Carbon Dioxide Capture and Storage Project': Carbon Capture and Sequestration Technologies @ MIT

[202] Global Energy Monitor Wiki, 'Caledonia Clean Energy Project': Caledonia Clean Energy Project - Global Energy Monitor (gem.wiki)

[203] Technip Energies (2022), 'Acorn Hydrogen Project': Acorn Hydrogen Project | Technip Energies

In terms of green hydrogen, the Fife Hydrogen Hub[204] is working towards expanding their hydrogen network to supply domestic households. There is also potential for a future hydrogen Hub near Aberdeen, named H_2 Aberdeen, which is seeking to develop a hydrogen economy through hydrogen fuel HGVs, hydrogen district heating and national gas grid replacement[205].

Non-Scottish additional CCUS projects

The projects discussed below were either not shortlisted for Phase 2 funding, are receiving other forms of public funds, or are relying on private investment.

Power CCS

The UK's largest power station, Pembroke Power Station (2.2MW), is considering installing post-combustion capture and blending their natural gas feedstock with low-carbon hydrogen by 2030, whilst an additional two natural gas post-combustion plants are expected to be developed in the East Coast Cluster by 2027, producing at least 1.24 GW of power. In the southeast of England, it is planned that CO_2 T&S infrastructure will be installed in the Medway Hub, with CO_2 from the Grain Power Station, Damhead Power Station, and Isle of Grain LNG terminal be captured and stored in the North Sea[47].

Hydrogen

Two sites located in the East Coast Cluster aim to produce at least 720 MW of blue hydrogen by 2027; the Northern Gas Network $H_2$1 in Hull and Killingholme CCS in Immingham, capturing a combined 1.6 $MtCO_2$/year[20]. Project Cavendish located in the Isle of Grain (Kent) is planning to produce 700MW of blue hydrogen by 2026, leading to 1.2$MtCO_2$/year being captured.

Biofuels

All three biofuel projects eligible for Phase 2 CCUS funding were not shortlisted; nevertheless, these projects still appear to be going ahead with the proposed works. All projects are waste-to-fuel plants, two of which will be located in Teesside and Immingham (East Coast Cluster) and one in the Northwest (HyNETs Cluster). When completed, up to 1.65 Mt/year of waste will be processed to produce at least 240Ml/year of fuel and capture 240$MtCO_2$/year by 2027.

Table 55: proposed CCUS projects located in the UK

Type	Project	CCUS Fund	Technology	Location	Capacity	Operational date
Power CCUS	Aberthaw CCS[200]	No	Coal Power CCS	Aberthaw, Wales	50 tCO_2/day	2013-2014
	Ferrybridge Carbon Capture Pilot[201]	No	BECCS Power (co-firing with coal)	Ferrybridge, England	100tCO_2/day	2011-2013
	Doosan Babcock (Renfrew)[18]	No	Coal Power CCS	Renfrew, Scotland	40MWth	2007-2011
	Net Zero Teesside Power[82,206]	Yes	Natural gas power with post combustion CCS	Teeside, England (East Coast Cluster)	860 MW 2 $MtCO_2$/year	2025
	Whitetail Clean Energy[82,207*]	Yes	Natural gas power with	Teeside, England	350 MW	N/A

[204]SGN H100 Fife, 'A world-first green hydrogen gas network in the heart of Fife': A world-first green hydrogen project from SGN | H100 Fife

[205] Net Zero Aberdeen, 'H2 Aberdeen Hydrogen is Here': H2 Aberdeen Hydrogen is Here | Aberdeen City Council

[206] Net Zero Teesside Power, 'Net Zero Teesside Power': Net Zero Teesside | About NZT Power

[207] Whitetail Clean Energy, 'Clean Power Clean Air Clean Jobs Teesside, UK' '': Whitetail Energy – Clean Power, Clean Air, Clean Jobs, The Whitetail Energy Project

Type	Project	CCUS Fund	Technology	Location	Capacity	Operational date
			oxy-fuel combustion CCS	(East Coast Cluster)	0.8 $MtCO_2$/year	
	Keadby 3 Carbon Capture Power Station,[82,208]	Yes	Gas fired-CCS power plant (post combustion)	Scunthorpe, England (East Coast Cluster)	910 MW 1.5 $MtCO_2$/year	N/A
	Pembroke Power Station[82]	No	Blended natural gas and hydrogen power with post combustion CCS	South Wales	2.2 GW	2030
	UKCCSRC pilot scale CCS[82]	No	N/A	Sheffield, England	N/A	N/A
	DRAX BECCS Pilot[82,]	No	BECCS Power post-combustion	Selby, England	1 tCO_2/day	2019
	DRAX BECCS Project[82]	No	BECCS Power post-combustion	Selby, England	8 $MtCO_2$/year 16 $MtCO_2$/year by 2035	2027
	VPI Immingham CCS[82,]	No	Natural gas fired CHP CCS	Immingham, England	1.24 GW	Mid-2020s
	Net Zero Teeside – NETS Power Plant[82]	No	Natural gas fired power CCS	Middlesborough, England	N/A	N/A
	Caledonia Clean Energy[202]	No	Natural gas fired power CCS	Grangemouth, Scotland	3 $MtCO_2$/year	N/A
	Peterhead CCS Power Station[82]	No*	Natural gas fired power CCS	Peterhead, Scotland	910 MW 1.5$MtCO_2$/year	2026
Hydrogen	bpH_2Teesside,[82,209]	Yes	Blue hydrogen	Tees Valley, England (East Coast Cluster)	0.5GW by 2027 1GW by 2030 2$MtCO_2$/year	2027-2030
	H_2NorthEast[82,210]	Yes	Blue hydrogen	Teeside, England (East Coast Cluster)	355 MW by 2027 1GW by 2030	2027-2030

[208] SSE Thermal, 'Keadby 3 carbon capture station capturing the potential of the Humber': Keadby 3 Carbon Capture Power Station | SSE Thermal
[209] BP, 'bp plans UK's largest hydrogen project': bp plans UK's largest hydrogen project | News | Home
[210] Kellas Midstream, 'Introducing a New Video about the Low Carbon Blue Hydrogen H2NorthEast Project on Teesside': Kellas Midstream

Type	Project	CCUS Fund	Technology	Location	Capacity	Operational date
	Hydrogen to Humber (H_2H) Saltend[82,211]	Yes	Blue hydrogen	Humber, England (East Coast Cluster)	Hydrogen blended with the natural gas supply to decarbonise chemical production and the Triton Power plant. 0.9-1.2 $MtCO_2$/year Reforming 600 MW of natural gas Operating by 2026-2027	2026-2027
	HyNETs Hydrogen Production Project (HPP), Vertex Hydrogen[82,212]	Yes	Blue hydrogen	Stanlow, England	10$MtCO_2$/year	2030
	Northern Gas Network H_2[82]	No	Blue hydrogen	Hull, England	N/A	2026
	Uniper Humber Hub Blue Project, Killingholme CCS[82]	No	Blue Hydrogen	Immingham, England	720 MW 1.6 $MtCO_2$/year	2027
	Acorn Hydrogen[82]	No*	Blue Hydrogen	St Fergus, Scotland	N/A	2025
Industrial carbon capture (ICC)	CF Fertilisers Billingham[82]	Yes	Ammonia CCS	Billingham , England (East Coast Cluster)	N/A	2023
	Tees Valley Energy Recovery Facility Project (TVERF)[213]	Yes	EfW CCS	Redcar, England (East Coast Cluster)	0.45 Mt,waste/year 49.9 MW	2026
	Norsea Carbon Capture[82]	Yes	N/A	Hull, England (East Coast Cluster)	N/A	N/A
	Redcar Energy Centre[82,214]	Yes	EfW CCS	Redcar, England (East Coast Cluster)	49 MW of energy (heat and power) by 2025 0.4$MtCO_2$/year	2027
	Teesside Hydrogen CO_2 Capture[82]	Yes	Blue H_2	Teeside England (East Coast Cluster)	N/A	N/A

[211] Power Technology, 'Hydrogen to Humber Saltend: will it kickstart the UK's hydrogen economy?': Hydrogen to Humber Saltend: will it kickstart the UK's hydrogen economy? - Power Technology (archive.org)
[212] Vertex Hydrogen, 'Building a Low Carbon Future': Vertex Hydrogen - Building a low carbon future
[213] Tees Valley Energy Recovery Facility, 'About the Project': About the project – Tees Valley Energy Recovery Facility (tverf.co.uk)
[214] Redcar Energy Centre, 'About Redcar Energy Centre': About Redcar Energy Centre - Redcar Energy Centre

Type	Project	CCUS Fund	Technology	Location	Capacity	Operational date
	Humber Zero Phillips 66 Humber Refinery[82,215]	Yes	Fluidised Catalytic Cracker (FCC) Blue H_2	Humber, England (East Coast Cluster)	0.5 $MtCO_2$/year	2027
	Prax Lindsey Oil Refinery Carbon Capture Project[82,216]	Yes	Oil refining CCS	Immingham, England (East Coast Cluster)	1.1$MtCO_2$/year	2027-2029
	ZerCaL250[82,217]	Yes	Lime production	Singleton Birch, England (East Coast Cluster)	Utilising Origen's zero-carbon tech and Singleton Birch's lime production expertise	N/A
	Hanson Padeswood Cement Works carbon capture and storage project[82,218]	Yes	Cement CCS	Mold, Wales (HyNet)	0.8$MtCO_2$/year	N/A
	Viridor Runcorn Industrial CCS[82,219]	Yes	EfW CCS	Runcorn, England (HyNet)	1$MtCO_2$/year	N/A
	Protos Energy Recovery Facility[21,82]	Yes	EfW CCS	Ellesmere Port, England (HyNet)	0.4 Mt,waste/year 49 MW	N/A
	Buxton Lime Net Zero[82,220]	Yes	Utilising H_2 from HyNETs to produce lime, which requires temperatures of >1000 degrees	Buxton, England (HyNet)	N/A	N/A
	Carbon Dioxide Capture Unit, Essar Oil[82,221]	Yes	H_2 production	Stanlow, England (HyNet)	0.81 $MtCO_2$/year	N/A
	Alfanar's Lighthouse Green Fuels plant[19]	No*	Waste-to-SAF plant using gasification and Fischer Tropsch	Teesside, England (East Coast Cluster)	1Mt,waste/year 180Ml,SAF/year	2027
	Altalto Immingham waste to jet fuel[20]	No*	Waste-to-fuel plant	Immingham, England (East Coast Cluster)	0.5 Mt,waste/year 60Ml,fuel/year	2027

215 HumberZero, 'Documents, Technology Selection Report': Documents - Humber Zero

216 Argus, '' UK's Lindsey refinery joins Humber carbon capture plans: UK's Lindsey refinery joins Humber carbon capture plans | Argus Media

217 Origen, 'Origen's decarbonisation plans receive UK Government boost': Origen's decarbonisation plans receive UK Government boost - Origen Carbon Solutions

218 Hanson, 'Our CCS feasibility study at Padeswood gets green light as HyNETs North West receives funding': Our CCS feasibility study at Padeswood gets green light as HyNETs North West receives funding | Hanson UK

219 Viridor, 'Runcorn ERF': Runcorn EFW (viridor.co.uk)

220 Tarmac, 'UK lime kiln in world first Net Zero hydrogen trial': UK lime kiln in world first Net Zero hydrogen trial | Tarmac

221 Gasworld, 'Essar Oil UK to build £360m carbon capture plant at Stanlow refinery': Essar Oil UK to build £360m carbon capture plant at Stanlow refinery (gasworld.com)

Type	Project	CCUS Fund	Technology	Location	Capacity	Operational date
					Saving 80 ktCO_2/year	
	Protos Biofuels Ltd[222]	No*	Waste-to-fuel plant	Northwest England (HyNet)	150,000 t,waste/year Avoid 160,000tCO_2/year	2025

**Was an eligible project under Phase 2 but not shortlisted*

[222] Greenergy, 'Protos Biofuels' first commercial scale municipal waste to biofuels plant progresses to FEED stage': [Protos Biofuels' first commercial scale municipal waste to biofuels plant progresses to FEED stage (greenergy.com)]

APPENDIX 5. BIOMASS CONVERSION TECHNIQUES

Thermal Treatment (Combustion)

Thermal treatment, more often referred to as incineration or combustion, involves the combustion of biomass to produce useful heat. Combustion is a complex interaction of chemical and physical processes, highly dependent on the quality of fuel source and quantity of air. Biomass feedstocks are rich in biogenic carbon, hydrogen, and oxygen, which are all essential in the combustion process. There are several systems available, however, the principle of biomass combustion is essentially the same for each.

The three main stages of combustion, in order, are heating and drying, pyrolysis, and char combustion. Biomass contains moisture, which must be released prior to the latter stages of the process. This is achieved through supplying heat produced by radiation from the flames, as well as the stored heat in the combustion unit. Once the biomass has been dried, it is then able to undergo pyrolysis, where it is subject to temperatures between 200degC and 350degC. At these temperatures volatile gases are released, including CO, CO_2 and CH_4, that react with the O_2 present in the incinerator, thus resulting in a self-sustaining process, ceasing when all the O_2 has been consumed or all volatile gases released. Pyrolysis results in the deposition of a residue known as biochar in the incinerator, once all the volatiles have been combusted. Biochar is a material consisting of carbon and ash. The final stage of the combustion process involves the injection of O_2 and subjecting the biochar to temperatures more than 800degC, allowing the biochar to oxidise and thus fully combust, i.e., for all the energy present in the biomass to be fully extracted. Longer residence times and sufficient air in the chamber allows for complete combustion to occur, and results in a flue gas containing lower concentrations of CO. It should be noted that all the above stages can occur subsequently as well as simultaneously[223].

The heat generated from combustion is used in a boiler to produce high pressure steam that is passed through a turbine, which in turn, generates electricity.

Gasification

Biomass can be gasified to produce syngas and eventually hydrogen using a range of different feedstocks: woody biomass, energy crops and waste[106]. During gasification, biomass is partially oxidised at 800degC to produce syngas, which is subsequently cooled down to enable the removal of particulates, heavy metals, tars, and acidic gases. The cleaned syngas is then processed in a similar manner to the SMR/ATR configurations; however, the process efficiency is lower (46-60% for bio gasification versus 74% for SMR/ATR) [106]. The keys methods of biomass gasification are autothermal and allothermal gasification, where fluidised bed gasifiers are favoured due to their flexibility and robustness[106]. Hydrogen can also be produced via pyrolysis or hydrothermal carbonisation[35].

Autothermal gasification

In order to maximise hydrogen production via autothermal gasification, pure oxygen and steam are used as the gasifying agents. This is because they increase the syngas H_2:CO ratio, which in turn encourages the conversion of CO to H_2 and improves hydrogen yields. The moisture content of the feedstock should be limited to 15% wt, which leads to feedstocks having to be pre-treated and dried beforehand[110].

Allothermal gasification

During allothermal gasification, steam is typically used as the gasifying agent and fluidised beds are the favoured choice of reactor. Fluidised bed technology is typically split into the categories of externally heated reactors, fast internally circulated fluidised beds (FICFB), and dual fluidised beds (DFB). More recently attention has been focussed on plasma allothermal gasification[128].

"The process functions in a similar way to coal gasification, but there are additional requirements for pre-processing the feedstock (e.g., drying), and more effort is required to clean the syngas to remove contaminants before upgrading it to hydrogen. Therefore, there remains some uncertainty around whether biomass gasification can be deployed at scale in a commercially viable way.[224]" Efficiencies of 46-60% are achievable

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[223] Biomass Combustion, University of Arkansas System, Accessed at: https://www.uaex.uada.edu/environment-nature/energy/docs/FSA-1056.pdf

[224] Climate Change Committee (2018), 'Hydrogen in a low-carbon economy': Hydrogen in a low-carbon economy - Climate Change Committee (theccc.org.uk)

and the production of biohydrogen is seen as a high value use of sustainable bioenergy; however, the feasibility of technology is uncertain at present due to the lack of demonstration plants.

Advanced Thermal Treatment (Pyrolysis)

Advanced thermal treatment technologies are those that employ pyrolysis and/or gasification to recover energy present in biomass. Both are thermochemical reactions, the difference being that pyrolysis is carried out in the absence of oxygen, i.e., anaerobically, whereas gasification utilises a controlled amount of oxygen.

The biomass feedstock the pyrolysis unit where it undergoes thermal degradation at temperatures between 250 – 900degC. Three main products are formed during this process, namely, char (solid residue rich in carbon), pyrolysis oil, and syngas. Of the three outputs, syngas, which is a combustible gas, is utilised for power generation. Exact chemical composition of syngas is highly dependent on that of the biomass inputs, nevertheless, the composition of syngas produced from pyrolysis is composed primarily of carbon dioxide, carbon monoxide, methane, and hydrogen. The main application of syngas is typically the generation of power and heat; this can be realised either in stand-alone CHP plants, or through co-firing of the product gas in large-scale power plants. This combustible gas can be used for production of power in several types of equipment, such as gas engines and turbines, both of which employ steam cycles. Syngas does not typically require extensive gas treatment before use in the previously mentioned steam cycles, however, when it is utilised in gas engines, it requires a higher degree of purification and preparation[225].

Biological Treatment (Anaerobic Digestion)

The two main biological treatment techniques of biomass are anaerobic digestion and aerobic digestion. Biological treatment is based on the decomposition of biodegradable waste by living microbes, namely bacteria and fungi, which use the feedstock as a food source for growth and proliferation. The process occurs either aerobically or anaerobically, although anaerobic digestion is more prevalent in the biomass context as this method produces useable, combustible gases.

The biomass is mixed and macerated, with water added to create the required moisture and flow conditions. As the process is anaerobic, the digestors are sealed, and mechanical stirring devices continuously mix the contents of the unit. Biodegradable material present in the digestor under these conditions is ultimately converted into a biogas containing high concentrations of methane (50 - 75%) and carbon dioxide. Additionally, water is produced due to the fermentation that occurs within the vessel, resulting in a wet organic mixture also being present. Anaerobic digestion takes approximately three to six weeks to complete depending on the exact biomass feedstock and is carried out at temperatures of 30 – 40degC[226].

There are several methods in which the energy present in the biogas can be recovered, either in a CHP generator unit to produce electricity and heat, or in boiler where it is combusted to produce hot water and/or steam. In some cases, treatment of the biogas is required to remove contaminants such as hydrogen sulphide, or moisture.

Biomethane reforming

Steam methane reforming (SMR)

Methane reforming is the conventional method of hydrogen production, where natural gas is the typical feedstock source. However, a low carbon alternative is to use upgraded biogas ('biomethane'), produced from anaerobically digested waste/residues, as a direct substitute to natural gas.

SMR is the reaction of methane with high temperature steam, at 912degC and 28.5 bar, to produce syngas (a mixture of H_2, CO and CO_2). This syngas is subsequently passed through a reverse water gas shift (RWGS) reactor, where excess CO is converted to CO_2 and H_2 to improve hydrogen yields. Typically, either a sequence of one or two RWGS reactors are used; a single high temperature reactor (HT) or both a high temperature and low temperature reactor (HTLT). The HT reactor operates at temperatures in excess of 300degC, whilst the LT reactor operates at circa 180degC. The gas stream exiting the RWGS reactor(s) is passed through a CO_2 capture unit and a pressure swing adsorption (PSA) column, where CO_2 and H_2 are recovered at purities of 99.97%. The CO_2 and H_2 are then compressed to 110 bar and 200 bar receptively, ready for transport. A

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225 Department for Environment Food & Rural Affairs, "Advanced Thermal Treatment of Municiple Solid Waste", https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/221035/pb13888-thermal-treatment-waste.pdf

226 International Flame Research Foundation, "Energy-from-Waste technologies – Biological Treatment: Anaerobic Digestion", https://ifrf.net/ifrf-blog/energy-from-waste-technologies-biological-treatment-anaerobic-digestion/

combustible by-product exiting the PSA unit, known as 'tail gas', is recovered and burnt within a fired heater to partially meet onsite energy demands. This maximises process efficiencies to 74%, with the remaining onsite demands being met through supplementary firing of natural gas. To ensure that all process emissions are captured, post-combustion capture must be used[120,127].

The choice over the HT or HTLT configuration does not have an impact on NETs process efficiency. In the case of HTLT, the higher H_2 yields lead to greater upstream efficiencies; however, these are counteracted by the tail gas exhibiting a lower heating value, and hence more supplementary natural gas must be burnt onsite to compensate. The opposite is true for the LT configuration. A proportion of the H_2 product can also be recycled back to the reaction vessel to increase H_2 yields; however, this again leads to a reduction in heating value for the tail gas, and hence reduces NETs efficiencies[127].

Auto thermal reforming (ATR)

Unlike SMR, the ATR configuration partially oxidises methane using pure oxygen sourced from an Air Handling Unit (AHU). The heat from this exothermic reaction is sufficient to meet the reactor's energy demands, and hence no external heat source is needed. The subsequent processing steps relating to RWGS, CO_2 capture, and PSA are the same as SMR. The tail gas exiting the PSA unit is also burnt in a fired heater to meet onsite energy demands, with no need for supplementary natural gas firing. Therefore, pre-combustion capture can be utilised. Please note that the purity of H_2 is lower than compared to SMR (99.9%)[127].

Unlike SMR, the HTLT configuration is favoured, as it increases NETs efficiency by 7%. The HTLT configuration does again lead to increased hydrogen yields and a reduction in tail gas heating value; however, as no supplementary natural gas firing is needed onsite, then the reduced heating value does not compromise the gains in upstream process efficiencies. The impact of H_2 recovery is negligible[127].

APPENDIX 6. DACCS

Liquid Solvent DACCS

Configuration

Carbon Engineering's process is split into 4 key stages[23,52]: 1.) the air contactor unit, where ambient CO_2 absorbs into the hydroxide KOH solvent to form a K2CO3 salt; 2.) the pellet reactor, where the carbonate salt reacts with another solvent (Ca(OH)2) in a fluidised bed to form CaCO3, which in turn regenerates the KOH solvent; 3.) the calciner, where CaCO3 is heated to 900degC and thermally decomposes to release the captured CO_2, which is subsequently compressed to 150 bar ready for storage; 4.) the slaker, where the Ca(OH)2 solvent is regenerated by hydrating the CaO exiting the calciner. This cyclic configuration enables continued operation. The process heat and power demands are met through onsite natural gas combustion within a NGCC unit, where the CO_2 emissions are captured.

There are alternative process configurations where the NGCC unit has been replaced with grid electricity[23], with the most ambitious being a fully electrified system which meets all heat and power demands. This comes at the expense of a high electricity penalty (1,535 kWh_{el}/tCO_2)[52], but at the benefit of downsizing several process units.

Loading capacity

The CO_2 loading capacity on the solvent must be limited to a maximum concentration of 30%, due to the corrosive nature of hydroxide bases. This in turn reduces the CO_2 flux potential for absorption. This is reflected by the fact that the CO_2 flux of a strong NaOH base is ~0.52 $molCO_2.min^{-1}.m^{-3}$, which is an order of magnitude lower than compared to solid amine adsorbents. In order to maximise this loading capacity, Brentwood XF12560 packing is used to increase surface contact area[51].

Temperature

The sorbent regeneration temperature is considerably high (at 900degC), which can at present only be achieved through natural gas combustion[23]. However, there is scope to investigate alternative low carbon fuels via the Dreamcatcher project[4,5].

Energy requirement

In the baseline case, where all energy demands are met through the NGCC unit, 2.45 MWh/tCO_2 of natural gas is required. If instead electrical demands are met through the grid, then natural gas usage drops to 1.46 MWh/tCO_2 coupled with heat recovery and 366 kWh/tCO_2 of electricity[23]. The majority of this power demand (70%) is allocated to the CO_2 compressors[48]. There is also the instance of having a fully electrified system, which requires 1,535 kWh/tCO_2 of electricity[52].

Modularity

Compared to solid absorbent DACCS, the modularity of Carbon Engineering's capture units is poor, with capture capacities having to be greater than 10 $ktCO_2$/year[51]. Therefore, it is preferential to deploy liquid solvent DACCS at larger scales.

New research

The reaction kinetics of the solvent are being improved through biomimetic catalysts (e.g., using carbonic anhydrase, which hydrate and dehydrate CO_2 orders of magnitude faster than amines or water) [51].

Solid Adsorbent DACCS

Configuration

When regenerating the sorbent bed to release CO_2, either Temperature Swing Adsorption (TSA), Pressure Swing Adsorption (PSA), or Vacuum Swing Adsorption (VSA) is used. The benefit of TSA is that it exhibits lower steam requirements (0.2–0.4 kg steam/$kgCO_2$) and is cheap, whilst PSA experiences quicker CO_2 adsorption/desorption times, but at the expense of higher costs and safety[51]. VSA provides similar benefits to PSA and is safer; however, it is the most expensive option[51].

Climework's pilot plant is described in Fasihi et al's work[52]. Ambient air is drawn into modular contactor units using fans, where CO_2 and moisture adsorb onto the solid surface of a special cellulose fibre that is supported by amines; thus enabling CO_2 capture and providing sufficient water for onsite use (0.8–2 t/tCO_2). The remaining air in the adsorbent bed is then purged by reducing pressures or inserting steam into the system. The CO_2 is then released by heating to temperatures of 80-120degC, compressed, and is ready for storage or utilisation. Finally, the sorbent bed is cooled to ambient conditions before re-use. A whole adsorption/desorption cycle takes between 4-6hrs[52]. A key benefit of this process is its ability to use a wide range of sorbents and low temperature heat sources, such as waste heat, geothermal energy, and heat pumps. However, there are also drawbacks associated with building the large surface area structures that exhibit low-pressure drops, as they exhibit high capital costs[48].

Global Thermostat follows a similar process, with the key differences being a lower regeneration temperature requirement (85–95 degC), the adsorbent being an amino-polymer, and the full cycle time being shorter (~100s)[52]. The heat and electricity requirements are also lower (please see Table 14).

Loading capacity

Compared to liquid hydroxide solvents, the use of solid adsorbents enables much higher CO_2 loading by weight (3.53 mol CO_2 $min^{-1}.m^{-3}$). Therefore, the flux of CO_2 adsorption is less limited[51]. A hierarchical adsorbent pore structure of micro and mesopores is used to maximise adsorption[51].

Temperature

The temperatures required to regenerate the sorbent (80-120degC) are significantly lower than compared to liquid DACCS[51]. This is due to adsorbent bonds formed between CO_2 and the sorbent surface being weaker than the chemical bonds formed during absorption.

Energy requirement

For the Climeworks process, the electrical demands are lower than that of Carbon Engineering (200–300 kWh/tCO_2), to supply the fan and control systems. However, heat demands are greater (1.5 -2.0 MWh/tCO_2)[52]. Despite this, the temperature of the heat is much lower and hence is easier to source.

Modularity

Climeworks' technology is provided in small modular units, with the maximum potential of one unit being 50 tCO_2/year. This modularity helps the technology be manufactured and deployed at scale[51].

New research

There's bountiful research investigating alternative adsorbents that show potential in reducing thermal energy demands. This includes metal–organic frameworks (MOFs), zeolites, activated carbons, etc. In terms of design, a moving bed adsorber is being considered over the more traditional fixed bed, which helps reduce pressure drops and cycle times[51].

Other DACCS

Cryogenic DACCS

Takes advantage of the sublimation point of CO_2. The CO_2 extracted from the air is converted into a solid or sublimated to produce a high purity gas stream[51].

Moisture/humidity swing adsorption (MSA)

MSA uses anionic exchange resins to capture and evolve CO_2. These sorbents will bind to CO_2 in arid conditions and evolve CO_2 when contacted with water, which has the potential to decrease energy requirements but at the expense of increased water consumption[51]. After CO_2 is removed, the system is heated to 45 degC to dry the resin sheets. The electrical energy demands range from 316-326 kWhel/tCO_2, depending on whether a fan is used to draw in ambient air within the contactor[52].

Electro-swing adsorption

In this process CO_2 binds to a polyanthraquinone-carbon nanotube composite upon charging and is released upon discharge, eliminating the need for thermal energy, and producing a high purity CO_2 stream[51].

Molecular filters

Nano sized molecular filters are used to capture CO_2 from the air powered by solar energy. The technology is expected to only require 333 kWhel/tCO_2 of electricity, where pure CO_2 is delivered at 100 bar, at a cost of 14 €/tCO_2[52].

Alternative feedstocks

Manufactured alkaline feedstocks (e.g., MgO) and aqueous amino acids could absorb CO_2, where CO_2 is regenerated by crystallization of an insoluble carbonate salt with a guanidine compound[51].

DAC pilot projects

Liquid solvent DAC

Carbon Engineering is the only company active in liquid solvent-based DAC, who use an aqueous KOH solvent to capture carbon. At present, they have a demonstration and pilot plant capturing a combined 1,365 tCO_2/year, which costs 132-191 £/tCO_2[227]*. The company's goal is to establish broad commercial deployment of synthetic fuels produced from captured carbon and green hydrogen.

Solid sorbent DAC

Climeworks is the most well-known solid sorbent-based DAC company, who use an adsorbent made of special cellulose fibre supported by amines to capture carbon[52]. Their first demonstration project was in 2014, in collaboration with Audi and Sunfire, where ambient CO_2 was captured and converted to synthetic diesel[52]. Since then, an additional 14 projects have been undertaken, most of which utilise the captured carbon to either produce e-fuels, aid plant growth in horticultural sites, or carbonate beverages. Their first CO_2 storage project was a pilot plant located in Iceland, capturing 50tCO_2/year in 2017. This site was scaled up in capacity in 2021, to provide 4,000 tCO_2/year of negative emissions at a cost of 411-494 £/tCO_2[51]*. This latest project is named Orca and is the largest operating DACCS facility in the world.

Global Thermostat uses an amino-polymer adsorbent to capture CO_2[52]. The company has pilot and commercial demonstration plants operating since 2010 in the United States, which provide a combined capture capacity of 1500 tCO_2/year.

Smaller scale DAC companies include Antecy, a Netherlands based company who have developed a detailed DAC design in collaboration with Shell that utilises a K2CO3 adsorbent, and Hydrocell Ltd, a Finnish company that has built a 1.387 tCO_2/year pilot unit that exhibits low regeneration temperatures (70–80 degC) and is a NETs producer of water (1.9 t/tCO_2)[52].

Moisture Swing Adsorption (MSA)

MSA DAC is less developed, and only has two small-scale companies developing the technology: Skytree (founded in the Netherlands) and Infinitree (founded in the United States). Skytree are building upon electrostatic absorption and moisturising desorption, and Infinitree utilise an ion exchange sorbent. Early markets for both companies are urban farming projects, for which captured CO_2 is used to assist in plant growth[52].

**Values converted from USD to GBP using conversion of 1 USD = 0.83 GBP.*

[227] Keith et al (2018), 'A Process for Capturing CO_2 from the Atmosphere': [A Process for Capturing CO_2 from the Atmosphere: Joule (cell.com)]

APPENDIX 7. ENERGY FROM WASTE SITES

Table 56: List of existing and proposed EfW sites in Scotland

Technology	Status	Projects	Location	Year	Capacity	
					Waste (t/year)	MWe
Waste incineration	Operational	Baldovie	Dundee, Scotland	1994	120,000	8.3
		Millerhill EfW	Edinburgh, Scotland	2019	155,000[228]	12.5
		Dunbar EfW	Haddington, Scotland	2019	300,000[229]	25.6
		Barclays Glasgow Campus, Plot 4 - Energy Sustainability Centre[230,231] *see note	Glasgow, Scotland	N/A	N/A	N/A
		Lerwick Energy Recovery Plant	Lerwick	2000	26,000[196]	N/A
		Baldovie Industrial Estate (Forties Road)	Dundee	2022	110,000[232]	10
Waste incineration	Under construction or under planning phase	Ness Energy Project	Aberdeen, Scotland	2023	150,000[233234]	11.1
		Thainstone Energy Park Project ERF	Aberdeen, Scotland	N/A	200,000[235]	35
		Barr Killoch Energy Recovery Park	Ochiltree	N/A	Potential NETs savings of 18,000 tCO_2/year[236]	12
		Binn Farm	Perth	2024	85,000[237]	7.3
		Westfield (former Opencast Coal Mine)	Cardenden	N/A	200,000[238]	23.7
		Oldhall Industrial Estate	Irvine	2025	180,000[239]	15

[228] Our facility – Millerhill (fccenvironment.co.uk)
[229] Dunbar ERF
[230] Ron Coghill on building Barclays' world-class Glasgow campus | Culture | Barclays (home.barclays)
[231] ENERGY Centre And 'Ambitious' Landscaping Plan Submitted For Barclays Glasgow Campus - reGlasgow
[232] 2022_01_25_PR_MVV_Environment_Baldovie_Full_Service_Commencement.pdf
[233] NESS Energy From Waste - Aberdeen - Indaver
[234] Ash from Aberdeen incinerator will be stored and processed near Portlethen (pressandjournal.co.uk)
[235] Agile Energy Recovery (Inverurie) Ltd
[236] Home - Killoch EFW
[237] Developer and operator appointed for Perthshire Energy from Waste facility - Binn Group
[238] Brockwell Ener gy | Wetsfield Energy Centre
[239] About – OldhallERF (oldhallenergy.co.uk)

Technology	Status	Projects	Location	Year	Capacity	
					Waste (t/year)	MWe
		Earls Gate Energy Centre	Grangemouth	N/A	216,000[240]	21.5
		South Clyde Energy Centre	Glasgow	2025	350,000[241]	20
Biogas production via advanced conversion technology	Operational	Charlesfield Biomass CHP Plant[242]	Melrose	2015	N/A	10
		Avondale Quarry (Pilot)[243]	Grangemouth	N/A	N/A	2
Gasification or pyrolysis	Operational	Levenseat EfW	Lanark	N/A	100,000[244][245]	12.5
		Glasgow Renewable Energy and Recycling Centre (ACT)	Glasgow	2019	222,000[246][247]	10
	Under construction or under planning phase	Coatbridge Material Recovery and Renewable Energy Facility[248]	Glasgow	N/A	160,000	25
		Levenseat Waste Management Facility[249]	Forth	2025	215,000	17
		Achnabreckcar[250]	Lochgair	N/A	N/A	5.5
		Binn Eco Park	Perth	N/A	60,000[251]	4.6

*note: This site appeared on the REPD but no technical data was found, it was therefore removed from our list of existing sites for the analysis stage.

240 About Us - Earls Gate Energy Centre (egecl.com)
241 https://www.power-technology.com/marketdata/south-clyde-energy-centre-uk/
242 United Kingdom Power Plants - Open Infrastructure Map (openinframap.org)
243 Avondale Quarry (Pilot) - UK Electricity Production
244 Energy from Waste - Levenseat energy from waste
245 Levenseat EfW Plant and MRF, Forth (riddellpm.co.uk)
246 Glasgow Recycling & Renewable Energy Centre (GRREC) - Glasgow City Council
247 Glasgow RRE (viridor.co.uk)
248 Partnership to develop Scottish EfW plant - letsrecycle.com
249 Levenseat Announce new plans for Phase 2 of its Energy from Waste Power Plant - Levenseat
250 Simple Search (argyll-bute.gov.uk)
251 Binn Ecopark - Binn Group

APPENDIX 8. ENGINEERED GGR PROJECTS COVERED BY THE DIRECT AIR CAPTURE AND GREEN HOUSE GAS REMOVAL TECHNOLOGIES COMPETITION

Table 57: Projects covered by the DAC and GHG Removal technologies competition

Project	Technology	Pilot plant location	Funding	Other?
Biohydrogen Greenhouse Gas Removal Demonstration, Advanced Biofuel Solutions Ltd	Biohydrogen production via gasification of waste and biomass with CCS	Northwest (located near HyNet)	£4,750,429.16	Aims to optimise the production of biohydrogen with CCS using a demonstration plant capturing 1.8 kt/year Aim to roll out 10 plants in 2030 to capture 1Mt/year
Bio-waste to biochar (B to B) via Hydrothermal Carbonisation and Post-Carbonisation, Coal Products Limited (CPL)	Biochar production using biowaste and bio residues	At CPL's site in Immingham (near Humber)	£4,997,822.00	Aim to capture 6.36 ktCO_2/year by 2030
Mersey Biochar, Severn Wye Energy Agency	Biochar production using virgin woodchip, whole tree chip/arb arising, miscanthus, short rotation coppice (willow), and short rotation forestry (eucalyptus)	Lingley Mere business park, Warrington	£4,994,312.28	Each pyrolysis unit will capture 5kt/year Aiming to capture 50kt/year
CCH_2: Carbon Capture and Hydrogen, KEW Projects Ltd[66]	Biohydrogen production via gasification using biomass or refuse derived fuels (RDF) blended with biomass	Birmingham	£4,998,409.19	Can access lower-quality forms of biomass which currently can go unutilised by EfW schemes Estimated that a 70 MWt Kew plant has a CAPEX of ~ £73m By 2024 KEW technology anticipates to upscale to units that can produce 1.3 t,H_2/hr

Project	Technology	Pilot plant location	Funding	Other?
				Aiming for 50ktCO_2/year during 2025-2030 and 24 MtCO_2/year in the subsequent decade.
DAC powered by Nuclear Power Plant, NNB Generation Company (SZC) Limited	Waste heat from Sizewell C nuclear plant powers solid sorbent DAC	Suffolk	£3,000,000.00	Potential to remove 1.5 Mt/year if scaled up using c.400MWth of heat from Sizewell C
The Biochar Platform, Black Bull Biochar Ltd	Biochar production using woodchip, pinchip residues, and dairy farm manure	Cumbria/Southwest Scotland	£2,997,622.15	Residues from BSW's site in Fort William will be shipped across the border and be used in the Biochar Demonstrator Hub in Cumbria. Potential to remove 50 kt/year by 2030. Aim to develop the world's first integrated biochar system
Project DRIVE (Direct Removal through Innovative Valorisation of Emissions), Mission Zero Technologies Ltd	Solvent DAC	Co-located at OCO's Wretham site	£2,997,822.16	Aim to capture 120t/year Will be more energy efficient, heat free, and continually operable compared to existing DAC technologies Potential to reduce the costs and energy consumption of DAC by 3-5 times
BIOCCUS, Ricardo UK Ltd	Biochar production using undried waste wood from sustainably sourced domestic timber with integrated CHP and CCS	Icknield Farm, Reading	£2,986,349.43	Forecast to capture between 310-820 kt CO_2/year by 2030
SMART-DAC, CO_2CirculAir B.V.	DAC using Membrane Gas Absorption (MGA) via KOH solvent and regeneration by electrodialysis bi-polar membranes (EDBP)	Port of Larne, Northern Ireland	£2,941,301.44	Aim to design a pilot plant capturing 100 t/year

Project	Technology	Pilot plant location	Funding	Other?
Direct Air CO_2 Capture and Mineralisation (DACMIN), Cambridge Carbon Capture Ltd	DAC	Thornton Science Park, Chester	£2,999,964.00	Aims to deliver a fully costed plan for a demonstrator capable of capturing CO_2 from air and converting it directly into a mineral by-product used in construction Aims for a pilot plant capturing 100 t/year Aim to scale up to 50 kt/year
Reverse Coal, Lapwing Energy Limited	Biochar production using short willow coppice grown on rewet degraded peat soils.	Lapwing Estate, Doncaster	£2,999,822.60	Energy released is used to power a highly productive vertical farm. Captures 670kgCO_2/year.ha Can be scaled up to remove >1Mt/year CO_2
ENCORE (ENvironmental CO_2 REmover), Rolls-Royce plc	Liquid based absorbent DAC	Derby	£2,812,704.12	Aiming to develop a plant that captures 100kt/year
Ince Bioenergy Carbon Capture & Storage (INBECCS), Ince Bio Power Limited	Gasification of waste wood from IBP's plant	Cheshire (near HyNet)	£4,992,408.30	Aim to capture of 10t/day Aim to deliver the first operational BECCS plant in the Northwest and the first instance of integrated BECCS-gasification in the UK. Aim to produce BECCS negative power in the future.
		TOTAL =	**£48,468,966.83**	

APPENDIX 9. NON-ENGINEERED NETS

Greenhouse Gas Removals (GGRs) can be divided into two categories, land-based and engineered removals. The focus of this report is engineered removal technologies; however, an overview of several land-based GGRs is provided in the section below, including reforestation, soil carbon sequestration, peatland restoration and wood in construction.

Although land-based GGRs have the potential to make a major contribution to meeting carbon reduction targets, such as the 2050 Net Zero target, they alone are not sufficient. This is due to competing land, as well as societal resistance to land-use changes on the scale that would be required. Whilst impacts vary greatly between each land-based GGR option, they collectively may negatively affect biodiversity, alter water/land use, or result in reversibility of carbon store, e.g., due to improper long-term management.

Forests and forestry management

Afforestation, reforestation, and forest management are various land-based GGRs that consider carbon removals through woodland expansion and forest management. They are based on the principle that by increasing forest area, the amount of CO_2 absorbed from the atmosphere increases. The maximum technical potential of this GGR is 26.5 $MtCO_2$/year by 2050, which is the highest of the land-based GGRs, however, still notably lower than engineered GGRs[101].

The technology readiness level (TRL) of afforestation is 9 as it is robust, well evidenced, and already widely practiced throughout the world[101].

Deployment of afforestation and reforestation has several limiting factors; these include land availability, the supply of tree seed and saplings, and capacity to plant large areas. Further, there are sustainability issues associated with this GGR, such as risk of biodiversity loss, greater water demand, and land competition with food production. Afforestation is already commercially deployed in the UK, and there is potential to grow existing capacity with afforestation targets. However, to meet these targets, early deployment is required, along with appropriate selection of tree species, planting age, and yield class, as these factors directly affect carbon sequestered.

It should be noted that carbon can move from this GGR to others, due to biomass supply for biochar, BECCS and wood in construction. Additionally, GGR afforestation competes with biochar and bioenergy feedstock (for BECCS) for land.

Peatland/ peatland restoration

There has been notable damage to UK peatlands, through forestry, drainage, agriculture, and burning, which has caused significant emissions of greenhouse gases due to the depletion of the carbon store. Peatland habitat restoration as a GGR method involves the re-establishment of functional, and hence carbon-accumulating, peatland ecosystems in areas that have been degraded to the extent they no longer sequester CO_2. The maximum technical potential of this GGR in 2050 is 4.7$MtCO_2$/year; this figure is based on restoration of 750 kha of the most degraded peatlands in the UK[101]. This value is one of the lowest of all land-based GGR methods, and noticeably lower than engineering GGRs. However, based on modelling, very high rate of GGR per unit year are attainable in the period following effective peat restoration.

The technology readiness of peat restoration has been assessed to be TRL 9 as it is well established and widely implemented across the UK[101].

According to the Sixth Carbon Budget Balanced Pathway (under the Climate Change Committee), 39 $MtCO_2$/year of nature-based sinks will be required in the UK by 2050, meaning that the UK will need to plant 300,000 hectares of mixed woodland by 2030, accelerating to 850,000 hectares by 2050[252]. The Scottish Government has committed to funding the restoration of 250,000 hectares of peat by 2030 with funding of £100 million to Scottish Forestry as well as £30 million to Forestry and Land Scotland to expand Scotland's national forests by 18,000 hectares per year until 2024[252].

Peatland restoration brings additional benefits such as biodiversity and improved habitat restoration, however, there are uncertainties associated with the GGR method. Flood regulation, water supply, and drinking water

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[252] The Sixth Carbon Budget: The UK's Path to Net Zero, Committee on Climate Change, Accessed at: https://www.theccc.org.uk/wp-content/uploads/2020/12/The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf

quality may be affected by various degrees depending on area, causing significant impact. Furthermore, as peat restoration has not yet been demonstrated at the large field scale, there is a risk that the restoration is not successful, meaning that CO_2 uptake and methane suppression is not as predicted.

Soil carbon sequestration

Soil carbon sequestration is a GGR method that considers how the carbon content of soil can be increased through land-use or land-management change. It is more relevant to agricultural land use, and hence has greater impact on cropland and grassland. The maximum technical potential of this GGR is 15.7 $MtCO_2$/year by 2050, which again is considerably lower than engineered GGRs[101].

The technology readiness of soil carbon sequestration as a GGR was assessed to be TRL 8[101]. There are several reasons as to why the TRL is not higher, and this is mainly due to a lack of consensus on the magnitude and effectiveness of land use and management change. Furthermore, this GGR encompasses a complex range of potential management practices that are dependent on socio-economic and environmental context.

The deployment of soil carbon sequestration takes place predominantly on agricultural land used for food production, as well as temporary and permanent grassland. It involves either applying compost/crop residues to fields, reducing soil disturbance by switching to low-till or no-till practice, changing planting schedules, or managing grazing of livestock. Due to the existing farming infrastructure and technology that already exists, uptake of soil carbon sequestration can be immediate and widely deployed in the 2020s.

However, there are uncertainties and limitations to deployment of this GGR, such as the reversibility risk. After approximately 20 years soil becomes saturated, and once saturated, it is assumed that land will require indefinite maintenance to avoid CO_2 being re-emitted. Another key challenge of soil carbon sequestration is the Measurement, Reporting, and Verification (MRV) aspect, as cost-effective measurement of changes in soil carbon is difficult at the field and farm scale. Lastly, there is limited evidence of efficacy in the UK context.

Wood in construction

Wood in construction as a GGR method is defined as the increased use of domestically produced wood in buildings to permanently store carbon. This has the potential to increase the amount of biogenic carbon stored in harvested wood products (HWP). Due to several limitations, the maximum technical potential in the UK of this land-based GGR is 3.3 $MtCO_2$/year by 2050, which is significantly less than any other engineered GGR[101].

The technology readiness of wood in construction has been assessed at TRL 9, despite the variation seen between different products and applications, as there are significant commercially available and mature options within this GGR[101].

To achieve an increase in the HWP carbon pool whilst only utilising the existing UK capacity for HWP production, the lifetime of HWP must be increased through diverting wood use to long-life applications. Long-life products are those which are still in the pool after 20 years, and ideally, 70 years, and applications include uses in construction, such as timber carcassing.

The UK harvests approximately 4 million oven dried tonnes (M odt) per year of softwood, 90% of which gets used in shorter life applications, and the remaining 10% for construction. The use of timber-frames in construction has increased over the years, with 50,000 homes being built per year with timber in the UK and figures suggest that the total demand for HWP in construction could reach 4.7 M odt/year in 2050[101].

The uncertainties associated with this GGR are limited, however, mostly surround its feasibility. There are uncertainties in the UK's ability to source enough domestic timber of appropriate quality, as well as consumer preference. Additionally, utilising more wood in construction requires adjustments to building requirements, safety, and quality assurance to enable sufficient scale.

APPENDIX 10. BECCS FOR STEEL MAKING

TRL

Due to the differences in industrial processes, as described above, the TRL of applying CCS varies between industrial sectors.

Table 58. TRL of applying CO_2 capture to steel sector

Industry	Technology type	TRL
Steel	Blast furnace with CO_2 capture	TRL 5[90]
	Torrefied biomass in steel furnace with CO_2 capture	TRL 7[90]

Costs

Table 59: Costs associated with steel industry BECCS

Industry	Technology type	NETs plant capacity, MWe	Capital cost, £/kW	Operating cost (fixed), £/kW	CO_2 avoided, £/tCO_2
Steel	Amine post-combustion capture[253]	0.71*	167.64**	9.50***	52.82-86.83[255]
	Cost of constructing a new UK steel mill[254]	6.13*	592.77** (cost of steel mill) 124.08** (cost of installing CCS)	241.02 (cost of steel mill)*** 33.84 (cost of CCS)***	67.31

*Units of CO_2 captured in MtCO_2/year

Units of £/tCO_2/year

***Units of $/t$CO_2$

The CCS Institute conducted a thorough cost analysis on the existing the Abu Dhabi CCS Project, which is a blast furnace facility that produces 40 tsteel/hr and captures 0.71 MtCO_2/year of point source emissions. The total CAPEX is $173M ($243.7/tCO_2/year) and the total O&M is $9.8M/year ($13.8/tCO_2)[253]. In terms of the cost to construct an entirely new Steel Mill that can install a CO_2 capture unit, this amounts to $4382M whilst producing 4Mtsteel/year ($1095.5/tsteel/year). The CAPEX of refitting a CO_2 capture plant adds an additional $917M to capture 6.13 Mt$CO_2$/year ($149.6/tCO_2/year) [254]. These costs have been converted into pounds sterling and been included in the table above.

Inputs / outputs

The first step of steel production involves production of liquid iron. The main raw materials required to produce liquid iron include iron ore, limestone, and coke (a type of coal), which is used to obtain the levels of carbon required in the final steel product. The raw materials are combined in blast furnaces to produce liquid iron.

The liquid iron is then converted to steel, which can occur through different production processes. A predominantly used method is through the Basic Oxygen Steelmaking (BOS) process, where high purity oxygen is blown onto the liquid iron, as well as additional of lime. An additional method is the use of an Electric Arc Furnace (EAF), where the required temperatures are achieved through the use of electricity.

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[253] Global CCS Institute, 'Global Costs of Carbon Capture and Storage': Global Costs of Carbon Capture and Storage - Global CCS Institute

[254] IEAGHG, 'Iron and Steel CCS Study (Techno-economics integrated steel mill)': IEAGHG Document Manager

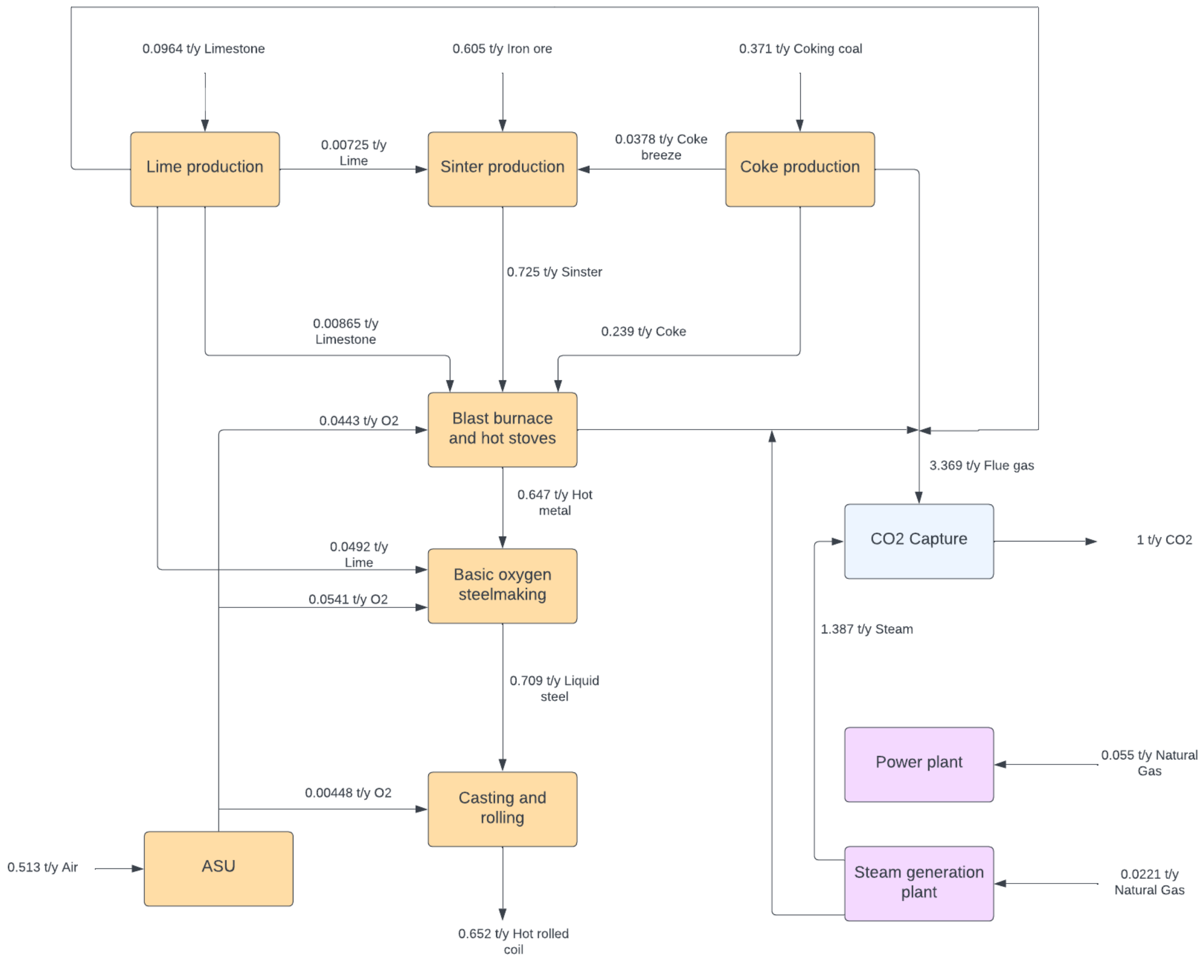
The production of steel also requires fuel inputs to provide heat to the coke oven and blast furnaces, which can be provided through natural gas, oil, or coal. To classify as a BECCS plant, fuel inputs will need to be provided through biomass sources.

Outputs of the process include steel, which can be adjusted to result in different properties, as well as the CO_2 that is captured from the CO_2 capture process.

Schematics

Data on biomass fuelled steel-CCS was limited, and hence data from fossil powered steel-CCS has been used as a compromise.

Mass and energy balances were taken from a IEAGHG report[254], who modelled the existing Tata Steel plant in South Wales which operates as a traditional Blast Furnace Basic Oxygen Steam (BF-BOS) facility. The data was taken from a 'high CCS' scenario, where CO_2 is captured from the flue gases exiting the blast furnace hot stoves, the steam generation plant, the coke oven batteries, and the lime kilns using post combustion capture via MEA solvent (90% efficiency). The resulting CO_2 avoidance was calculated to be ~60%, and the site energy demands are 1 MWh/tCO_2 for natural gas and 405 kWh/tCO_2 for electricity.



Potential Carbon impact

The heat required for steel production is predominantly provided through blast furnaces utilising the BOS process, which rely on the properties of coal as a control mechanism. This method of steel production accounts for over 70% of steel produced globally[113]. There is the potential for fuel switching to biomass, however it is estimated that this is likely limited to around 30% of current coal use[113]. In more recent years, coal blast furnaces are being switched out for EAFs as a means of reducing emissions from the steel making process. This therefore demonstrates the limited potential of achieving negative emissions through the most common steel production routes. However, alternative steel making methods, including direct reduction of iron ore (DRI), and smelt reduction steel making routes, provide greater flexibility in the fuel used when compared to blast furnace steel production, hence creating the potential to achieve negative emissions. For example, DRI makes use of natural gas to reduce iron. Switching natural gas for a biogenic gas source, such as biogas, when combined with CCS, could allow for the potential to achieve negative emissions.

Traditional steel making via BF-BOS has a high carbon intensity of 2-3 tCO_2/t,steel. This can be abated through the integration of biomass to help reduce point source emissions by 50-60%, which in turn lowers the emission intensity to 1.04-0.828tCO_2/t,steel. The utilisation of charcoal can help further reduce point source emissions by up to 80%, which is already being practiced in Brazil through mini blast furnaces[255].

GWP Emissions

On a life cycle basis, emissions associated with traditional steel making (i.e., not utilising biomass or CCS) range from 1.3-2.4 tCO_2/t,steel; whilst utilising biomass with CCS can achieve NETs negative emissions of 0.1 to -0.5 tCO_2/t and capture 1.2-2.1 tCO_2/t of point source emissions. Also, the use of CCS and bioenergy separately still reduce emissions considerably, leading to low NETs emissions of 0.8-1.7 tCO_2/t,steel[256]. The results demonstrate the potential of BECCS in helping decarbonise the steel industry and potentially act as a NETs carbon sink (please see Table 60 below for a breakdown in lifecycle emissions for various steel manufacturing methods).

Table 60: Life cycle GWP emissions of various steel manufacturing methods

Scenario*		BF-BOF	BF-BOF and TGR	HIsarna-BOF	MIDREX DRI-EAF	ULCORED GRI-EAF
High CCS (no bioenergy)	CO_2 produced (tCO_2/t,steel)	3.0	2.3	2.5	1.7	1.3
	CO_2 removed from atmosphere (tCO_2/tsteel)	0	0	0	0	0
	CO_2 captured and stored (tCO_2/tsteel)	1.8	1.4	1.5	0.7	0.6
	NETs CO_2 produced (tCO_2/tsteel)	**1.2**	**0.8**	**1.0**	**1.0**	**0.7**
High bioenergy (no CCS)	CO_2 produced (tCO_2/t,steel)	2.7	2.2	2.6	2.5	2.0
	CO_2 removed from atmosphere (tCO_2/tsteel)	-1	-0.9	-1.3	-1.6	-1.2
	CO_2 captured and stored (tCO_2/tsteel)	0	0	0	0	0
	NETs CO_2 produced (tCO_2/tsteel)	**1.7**	**1.3**	**1.3**	**0.9**	**0.8**
High bioenergy (with CCS)	CO_2 produced (tCO_2/t,steel)	3.7	2.7	3.1	3.0	2.1

[255] Mandova et al, 'Achieving carbon-neutral iron and steelmaking in Europe through the deployment of bioenergy with carbon capture and storage': Achieving carbon-neutral iron and steelmaking in Europe through the deployment of bioenergy with carbon capture and storage - ScienceDirect

[256] Tanzer et al, 'Can bioenergy with carbon capture and storage result in carbon negative steel?': Can bioenergy with carbon capture and storage result in carbon negative steel? - ScienceDirect

Scenario*		BF-BOF	BF-BOF and TGR	HIsarna-BOF	MIDREX DRI-EAF	ULCORED GRI-EAF
	CO_2 removed from atmosphere (tCO_2/tsteel)	-1.6	-1.1	-1.5	-1.9	-1.2
	CO_2 captured and stored (tCO_2/tsteel)	2.1	1.7	1.9	1.6	1.2
	NETs CO_2 produced (tCO_2/tsteel)	**0.1**	**-0.1**	**-0.3**	**-0.5**	**-0.3**

**Please note that the optimistic scenario options were considered only*

Note: we can justify assuming post combustion MEA as the reference plant for our pathway modelling since this is the most common method of steel manufacturing, has the most abundant CCS data available in the literature, and is most cost effective since it does not require significant CCS retrofit to existing plants.

Potential locations in Scotland (map)

The majority of steel works within Scotland are metal product manufacturers, with the last crude steel plant (Ravenscraig) being closed down in 1992. What remains is two heavy fabrication facilities, Clydebridge and Dalzwell, which were purchased by Liberty House Group in 2016[257]. Clydebridge acts as a plate heat treatment works, whilst Dalzwell (the sister plant to Clydebridge) acts as a heavy plate mill plant. It must be noted that Dalzwell uses an existing biomass plant to produce 17 MW of electricity that is used onsite; however, the likelihood of this site being retrofitting with CCS is low, due to the uncertain future of the Scottish steel industry.

Technology specific limitations & barriers

2.9.4.1 Technical

Several technical barriers from application of CO_2 capture in the power sector are also applicable to the industrial sector. A key example is the low concentrations of CO_2 which are likely to be present in the flue gas stream, as well as the high energy required for solvent regeneration in post-combustion capture plants. Additionally, the emissions at industrial plants are more likely to be dispersed and hence additional challenges arise from the need to capture emissions from multiple point sources located around the entire plant.

There are also additional technical barriers that relate to the specific industrial application in the production of cement, steel and pulp and paper. Currently, many cement production plants around the world are utilising a mixture of fossil fuels and low-carbon fuels, as there are currently some concerns associated with only burning alternative fuels in the kiln, due to variations in combustion temperatures. There are therefore current technical barriers to the potential for utilising biomass in the cement production process, where co-firing of biomass with fossil-based fuels occurs at up to 35-40% biomass. This leads to technical limitations with the amount of biogenic CO_2 that can be captured to result in negative emissions.

2.9.4.2 Economic

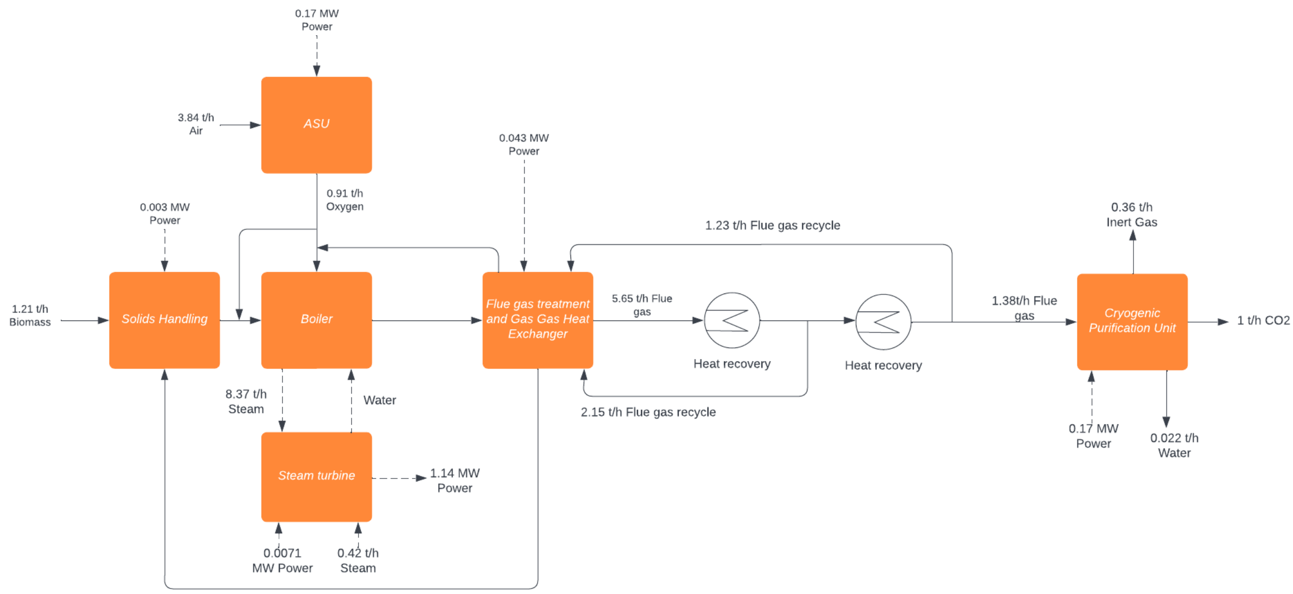
As with CO_2 capture applied to the power sector, the addition of CO_2 capture to industrial processes results in a large increase in the energy demand and hence high associated costs. In sectors where the current fuel use is predominantly fossil fuel based, the costs of achieving negative emissions are also likely to be higher than in sectors which already make use of a large share of biomass, such as in the production of pulp and paper.

[257] BBC, 'Dalzell and Clydebridge steel plants to make metal for wind turbine towers': Dalzell and Clydebridge steel plants to make metal for wind turbine towers - BBC News

APPENDIX 11. ADDITIONAL BECCS COMBUSTION CAPTURE SCHEMATICS

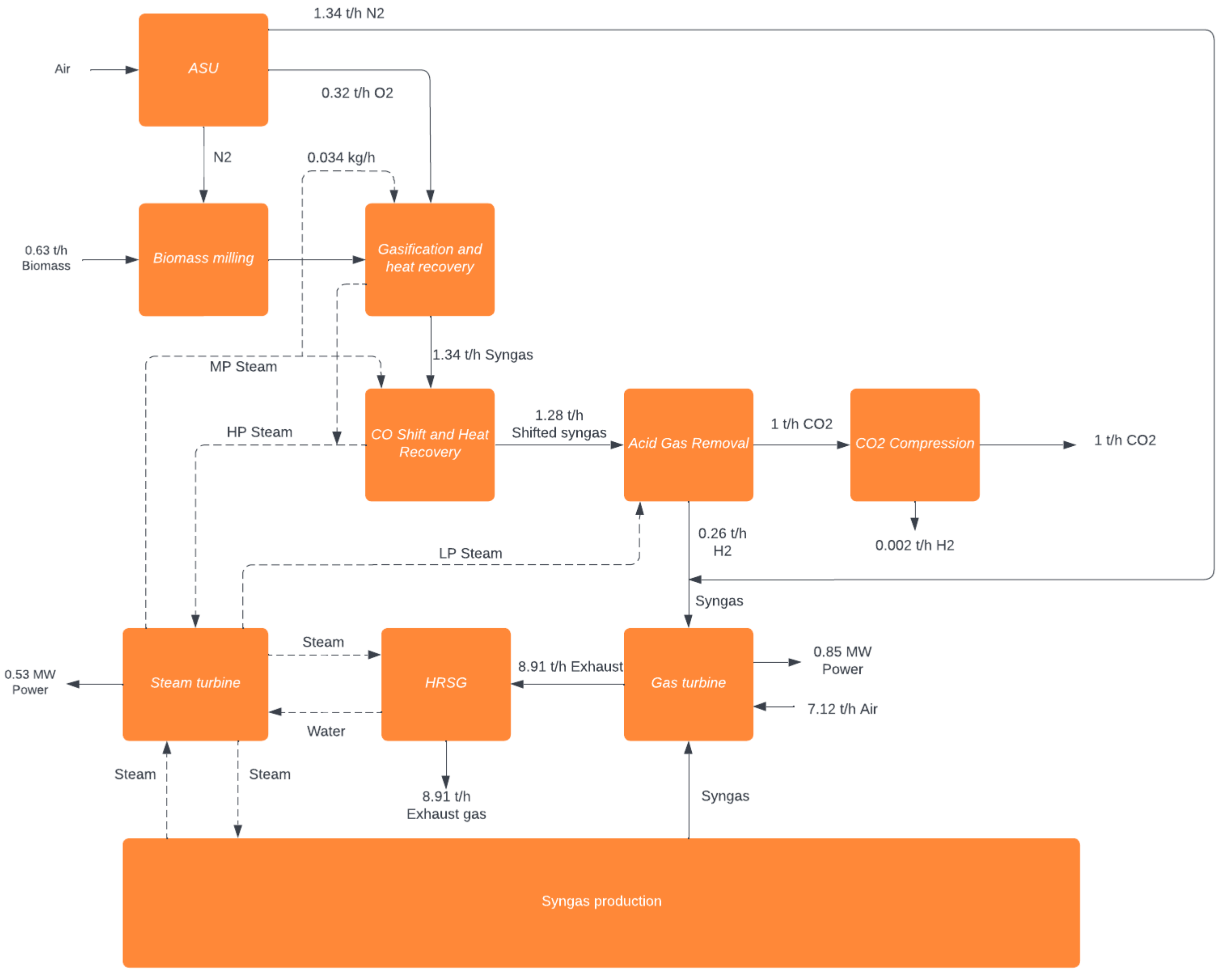
Oxyfuel combustion capture

Figure 20: Schematic of BECCS Power with oxy-combustion capture



Pre combustion capture

Figure 21: Schematic of BECCS Power with pre-combustion capture



APPENDIX 12. BECCS HYDROGEN ADDITIONAL SCHEMATICS

Figure 22: Hydrogen produced via SMR of biomethane with VSPA CO_2 capture

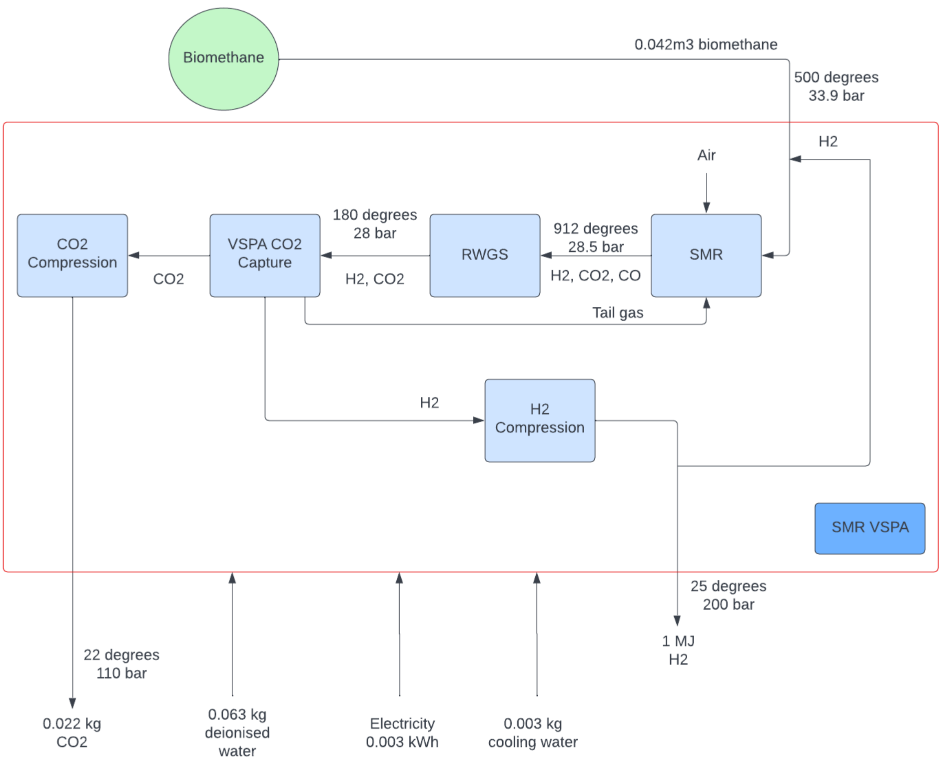


Figure 23: Hydrogen produced via ATR of biomethane with MDEA CO_2 capture

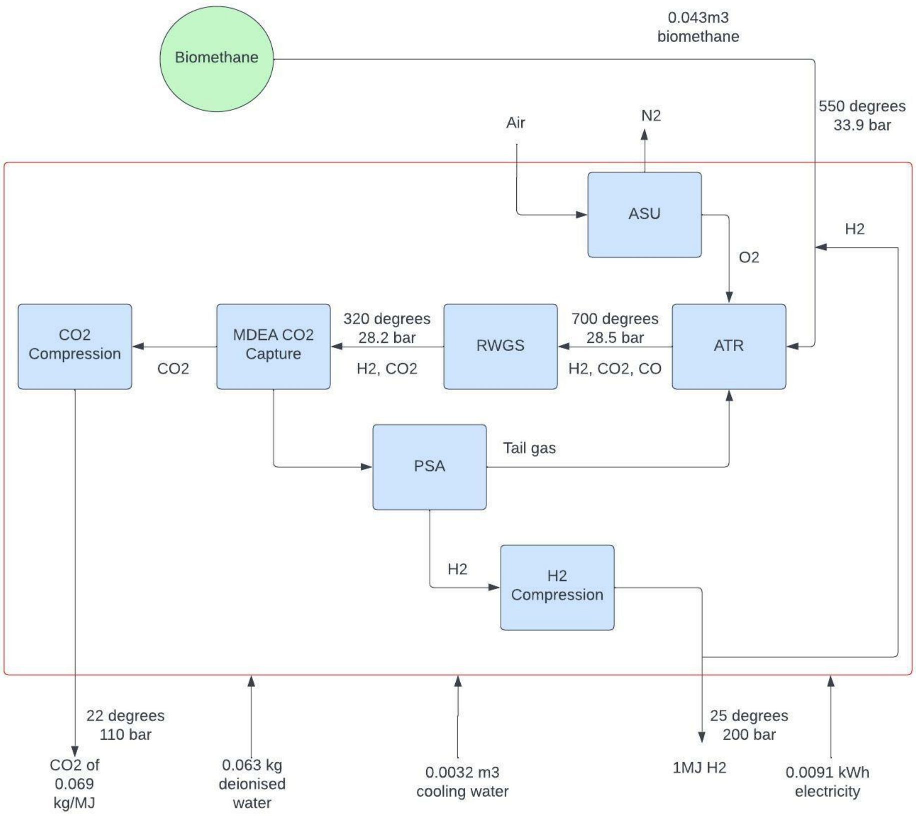


Figure 24: Hydrogen produced via ATR of biomethane with VSPA CO_2 capture

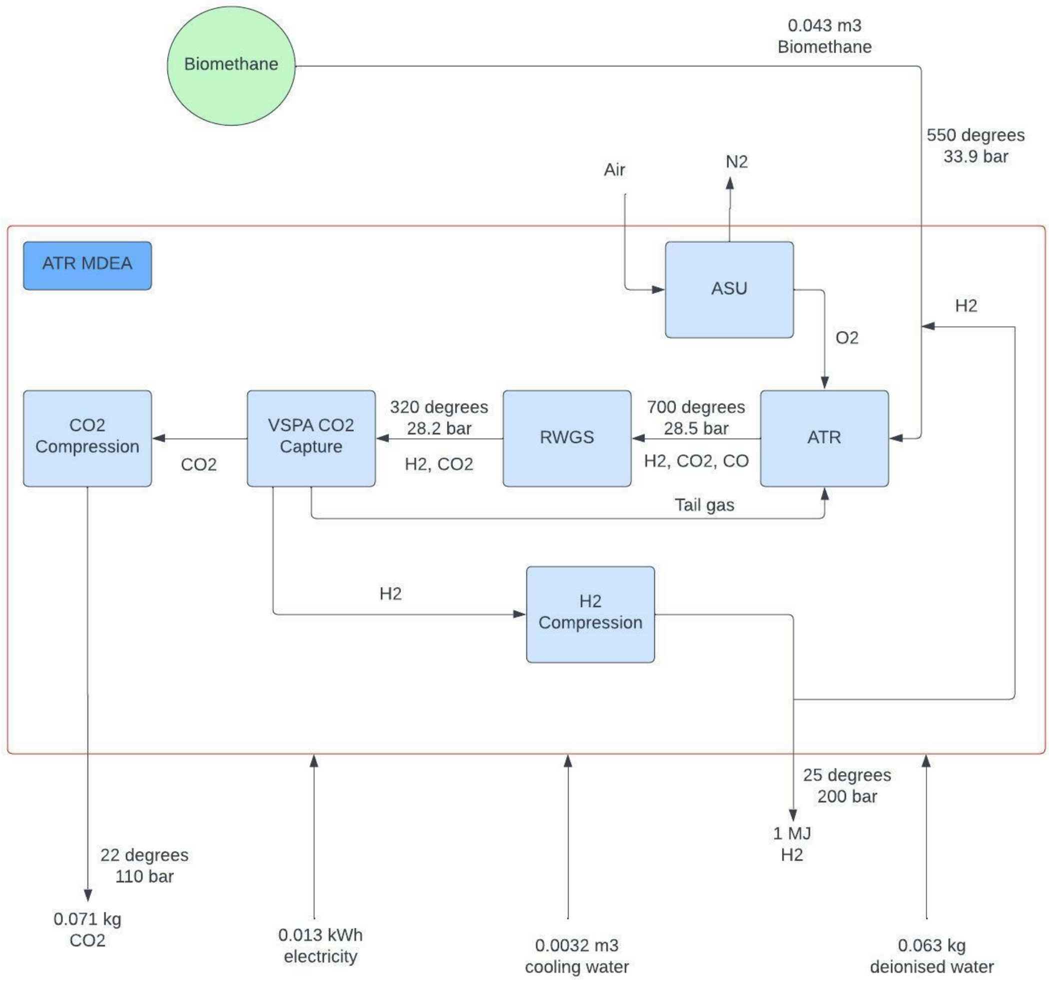
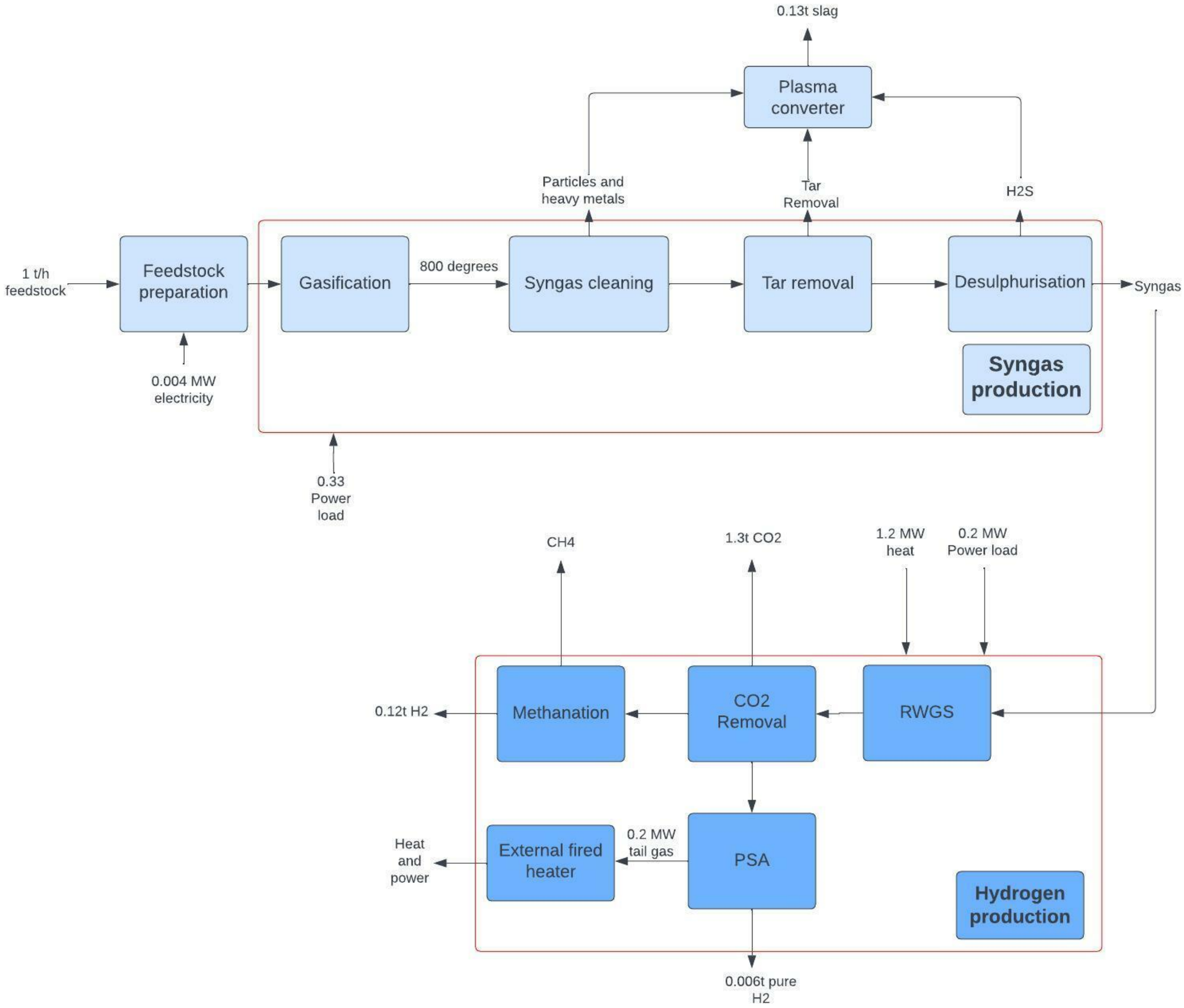


Figure 25: Hydrogen production via gasification and subsequent reformation of the syngas



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