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HICP
HUMBER INDUSTRIAL CLUSTER PLAN

Market, Policy, and Regulatory Studies for the Humber Industrial Cluster Plan

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Executive summary

The Humber industrial cluster is looking to fully decarbonise by 2040

The UK has set 2050 as the target year for its ‘Net Zero’ statutory goal. By then, all sectors of society will need to fully decarbonise, including the industry and power sectors. The selection of the East Coast Cluster as one of the two ‘Track 1’ Industrial Clusters positions the Humber as one of the potential early ‘SuperPlaces’ leading the transformation to a net-zero economy. **The Humber Industrial Cluster Plan (HICP) aims to set out the optimal route to fully decarbonise the Humber cluster by 2040.**

The HICP was set up in January 2021 and is funded by UK Research and Innovation (UKRI) and industrial partners. The project team includes Membership organisation CATCH, the Hull and East Yorkshire Local Enterprise Partnership (HEY LEP) plus 8 industry partners. Partners will work together to develop the Humber Industrial Cluster Plan that aims to set out the strategic roadmap for the Humber Cluster to follow in order to achieve net zero by 2040. This study aims to inform the Humber cluster of the decarbonisation options available for the industrial emitters within the region.

The Humber is UK’s largest industrial cluster, based on both emissions and economic activity. Industrial sites in the Humber emitted 14.6 $MtCO_2$ in 2018, or 20 $MtCO_2$ if local power generators are included. Emissions are likely to only reduce 10-20% by 2040 under business-as-usual scenarios, underlining the need for large-scale deployment of deep decarbonisation technologies and methods such as **carbon capture and storage (CCS), fuel switching, and greenhouse gas removals** in the Humber.

Deep decarbonisation of the Humber industrial cluster may unlock greater environmental benefits than can be observed by solely considering local industries. The deployment of CO_2 storage in the Humber can also serve other regions. Through the development of **CO_2 import infrastructure**, the Humber would be well placed to receive CO_2 from emitters in other parts of the UK and Europe who may rely on CCS for their decarbonisation but do not have access to CO_2 storage locally. Similarly, large-scale production of negative emissions via greenhouse gas removals could unlock a new **market for the export of CO_2 removal credits** to entities who have residual emissions that must be balanced out to reach their own net zero goals.

While the need to deploy decarbonisation technologies is clear, there are several market, policy, and regulatory risks and barriers that currently impede the uptake of these novel technologies, hindering regional decarbonisation and economic transformation. **The core objective of this study is to identify the most important risks and barriers and discuss ways to mitigate and overcome them to enable the Humber cluster to reach net zero by 2040**.

This study considers electrification, fuel switching and carbon capture decarbonisation pathways for industry

This study aims to identify the risks and barriers hindering the deployment of low-carbon technologies in the Humber across the market, policy and regulatory (MPR) dimensions. An initial list of market, policy, and regulatory risks and barriers was developed based on a review of publicly available literature, with perspectives from over 25 stakeholders from industry, academia, and policy also integrated into the study. Risks are defined as long-term uncertainties, where uncertainty levels vary, and mitigation measures are far-sighted. Barriers are defined as known problems which are likely to require upfront solutions to progress with market participation in the shorter-term.

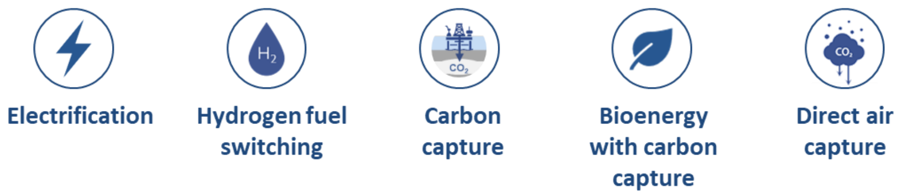

Figure 1: Technologies considered for detailed MPR analysis

Fuel switching

Fuel switching replaces the energy supply from fossil fuels with alternative low carbon fuels or electricity. This enables a reduction in **combustion emissions** from industrial heating, responsible for a large proportion of the Humber industrial emissions. There are multiple options for fuel switching across each industrial sector. Broadly, three main classes of low-carbon energy sources are considered for fuel switching. These are **electrification**, **hydrogen fuel switching**, and switching to bioresources, which include **biomass and waste-derived fuels**. This assessment primarily focuses on electrification and hydrogen fuel switching, since they have the largest deployment potential and will be less constrained by future supply.

Electrification of industrial processes

Fuel switching through electrification results in **no on-site emissions** and can be highly efficient compared to combustion. This is especially the case for heat pumps in low-temperature applications. Electrification comprises **various technologies**. The most suitable electrification technology will depend on the **process that is being switched** and, for direct heating applications, on the **product's characteristics**.

Provided all electricity comes from renewable resources, electrification has the potential to fully eliminate Scope 2 emissions. The effect of electrification on all other indirect emissions not related to purchased energy (Scope 3) can be varied, depending on the level of embodied emissions relating to renewable generation assets and electrical appliances.

Electricity generation from non-renewable sources may reduce the net decarbonisation benefit of fuel switching via electrification pathways because the UK electricity grid has not been fully decarbonised yet. The total emissions are only reduced if the **carbon intensity of the grid** is lower than the carbon intensity from processes burning fossil fuels on site. Hence, for a site switching via electrification, Scope 2 emissions could represent a larger share of total emissions. This presents both an opportunity and a risk: industries can leverage on the grid decarbonisation efforts without additional capital investments, but they will have less control on the speed and level of decarbonisation of the grid. As the electric grid becomes increasingly decarbonised, electrification allows industrial emitters to reduce their Scope 2 emissions without additional capital investments.

Electrification is potentially applicable to most heating processes in the Humber that currently use fossil fuels. However, the potential for electrifying each heating process differs. For **low-temperature heating**, commercially available electrification technologies can generally lead to a complete fuel switching. For **high-temperature heating,** the maximum attainable level of switching may be constrained in the short and medium term and *partial* electrification can be an option instead. For instance, electric furnaces can be used to decarbonise glass furnaces at the Guardian Industries site, although the energy cost will be prohibitive under current prices. **Electrification could also potentially replace natural-gas-fired Combined Heat and Power (CHP) units**; electricity would in this case be directly sourced from the grid while heat pumps and/or electric steam boilers would deliver the required heat.

Hydrogen for industrial heating

Hydrogen fuel switching allows for the conversion of equipment whilst maintaining similar processes and site set up, as it shares broad similarities with natural gas. Because of this, hydrogen fuel switching has a high potential to decarbonise industrial heating processes notably for **high temperature heating** applications. There are various hydrogen fuel switching technologies under development for a range of industrial processes.

As in the case of electrification, **hydrogen combustion results in no on-site CO_2 emissions, fully eliminating Scope 1 emissions** for industrial users, apart from any global warming potential (GWP) associated with releases of H_2 itself (e.g. via leaks). The abatement potential of hydrogen fuel switching is thus solely linked to the level of emissions associated with hydrogen production and supply and with the upstream supply chain (Scope 3, also known as "embodied").

Different types of low-carbon hydrogen include electrolytic hydrogen, produced from the electrolysis of water powered by dedicated renewable energy sources (referred to as "green hydrogen"), and CCS-enabled hydrogen, produced via the reforming of natural gas in combination with CCS (referred to as "blue hydrogen"). Alternatively, hydrogen produced from biomass can be considered carbon neutral, with the potential to achieve negative emissions when combined with CCS. Electrolytic hydrogen is generally assumed to be carbon neutral so long as it is produced with zero-carbon electricity, though the relatively higher embodied emissions from electrolysers and the associated infrastructure should be carefully considered when assessing the net decarbonisation benefit.

As was the case with electrification, hydrogen fuel switching is potentially applicable to most heating processes in the Humber that currently rely on fossil fuels, including low- and high-temperature heating, and both direct and indirect heating. Unlike electrification, hydrogen is expected to be able to offer the potential for **complete fuel switching** (rather than just partial) for high-temperature heating. Industrial power generation in the Humber can also be decarbonised through hydrogen fuel switching: **hydrogen-fired turbines** can decarbonise CHP generation, although the abatement cost may be significantly higher than for carbon capture-equipped CHP generation plants. However, compared to carbon capture-equipped GHP generation, hydrogen turbines can operate more flexibly and could provide cost savings at low-capacity factors. The announcement of several hydrogen production projects in the Humber, such as the H2H Saltend project and the Gigastack project, would provide a local supply of hydrogen for use in heat generation.

Carbon capture from local industries

Carbon capture, utilisation, and storage (CCUS) is a group of technological approaches that capture CO_2 and prevent it from entering the atmosphere through permanent storage, often geologically. In certain cases, the captured CO_2 can also be utilised (CCU) as a feedstock in the production of minerals, chemicals, or synthetic fuels. Due to the low volumes of CO_2 that can be treated via CCU and to the uncertainty over the carbon abatement potential of CCU, CCS with geological storage is likely to play a much greater role in the future decarbonisation of industry and power generation facilities. Hard-to-abate emissions streams produced as a by-product in industrial processes can also be decarbonised via the application of post-combustion carbon capture technology.

CCS deployment can result in deep decarbonisation, with modern CCS facilities capable of capturing well over 90% of CO_2 from emissions streams. Capture technologies enable industrial facilities to continue their usual operations whilst enabling the majority of direct CO_2 emissions (Scope 1) to be decarbonised from streams that it is applied to. However, CCS may lead to increased indirect emissions from purchased electricity or steam (Scope 2) or from other indirect sources (Scope 3), such as the manufacturing of necessary equipment and infrastructure (Scope 3). CCS is the only technology that enables the capture of process emissions and emissions from the combustion of internal fuels, without changing the industrial process. Process emissions are unavoidable in many Humber industrial sectors; therefore, CCS will be an essential technology for decarbonisation of the Humber industries.

For some industrial sectors, the complete deployment of carbon capture is unfeasible to fully abate emissions due to technological and economic reasons. This could be the case for industrial facilities that have multiple emissions sources with different process characteristics. In many cases, a hybrid decarbonisation approach will be required, where small point source emissions are electrified or switched to hydrogen and CO_2 capture is deployed at the remaining emitting streams. CCS deployment on fossil-fuelled power generation could also be used to complement the increased deployment of renewables, enabling dispatchable low-carbon power output at times of low generation from wind or solar sources.

Imports of CO_2 from outside the Humber

The Humber has the potential to enable emitters beyond its core industrial cluster to decarbonise by importing captured emissions for permanent geological storage. By developing capabilities to receive CO_2 imports, the Humber has the potential to provide storage as a service (SaaS) to emitters that will rely on carbon capture but are unable to connect to another transport and storage network. Approximately 80% of the UK's currently licensed CO_2 storage capacity is accessible from the Humber, with potential for further expansion. Given the Humber's broad access to ports and considering that many large UK and European emitters are also situated near ports – albeit without access to CO_2 storage – shipping is likely to emerge as the dominant transport method for importing CO_2 to the Humber over the coming decades. Accordingly, multiple emitters in the UK and across Europe are expected to have to rely on CO_2 ships to transport captured emissions as a precondition to implementing CCS. As of today, there is no operational market for CO_2 imports. Given the prospects for its rapid development over the next two decades, early movers are however likely to gain a competitive advantage as the market evolves.

Depending on the level of demand for CO_2 imports to the Humber, multiple shipping terminals could be developed both onshore at existing or new-build ports, or offshore, for direct injection at the storage site. The Humber region has access to ports with deep water capabilities enabling it to accommodate large CO_2 capacities (up to 50,000m^3) that are likely to be associated with the largest CO_2 carrying vessels. The development of terminals that process CO_2 imports from ships could unlock access to over 100+ MtCO_2/year from existing industry and power facilities in Europe. Large industrial clusters are located within 500km from the Humber in regions including the Netherlands, Belgium and France.

Options to remove atmospheric CO_2

According to the latest International Panel on Climate Change (IPCC) report methods for **removing CO_2 from the atmosphere are "unavoidable" if the world is to reach net-zero**. Carbon removals include engineered technologies and natural pathways that *actively remove carbon from the atmosphere*; the term does not include pathways that avoid future emissions. Removals will likely make a crucial contribution to reaching net-zero in 2050, by compensating unavoidable, residual emissions from hard-to-abate sectors that cannot be technologically and economically decarbonised. After 2050, carbon removals may be used to reverse any overshoot of atmospheric CO_2 beyond levels associated with a 'safe' limit and reduce concentrations back towards pre-industrial levels.

Bioenergy with carbon capture and storage (BECCS) combines the combustion or gasification of biomass to produce energy with carbon capture and storage (CCS) to prevent the CO_2 produced through combustion or gasification from reaching the atmosphere. Emissions are counted in the land use sector at the point of harvest and biomass is only considered carbon neutral when sourcing meets strict sustainability and regulatory requirements. Biomass is already employed globally as an energy source and is often considered carbon neutral for Scope 1 and 2 accounting purposes. However, incomplete capture and supply chain emissions mean bioenergy use does usually entail non-zero lifecycle emissions. Therefore, the capture of the CO_2 from biomass combustion only constitutes a net removal if it is greater than the combination of these supply chain (growing, harvesting, processing, transport, and storage) emissions. Drax is planning to retrofit two 645 MW biomass units with CCS by 2027 and 2030, respectively, and may consider retrofitting the other two units on the site by 2035. Once retrofitted with CCS the four units will have a combined potential of 16-18 MtCO_2/year of carbon capture.

Direct air capture with CCS (DACCS) provides negative emissions by capturing and storing atmospheric CO_2 (Scope 1). However, several sources of emissions exist in the DACCS value chain that will offset some of these negative emissions. The provision of heat may include emission from natural gas combustion (Scope 1), electricity demand may have associated emissions (Scope 2), and manufacturing, construction, and CO_2 transport, and storage all produce emissions to varying degrees (Scope 3). Therefore, to maximise the decarbonisation potential of DACCS projects, there is a need to utilise low emission electricity and heat, potentially from integration with sources such as curtailed renewables and industrial waste heat. The Humber may be an appropriate location for DACCS due to the large **availability of low-carbon, low-cost energy.** Secondly, there is an opportunity to **couple the heat requirement of DACCS processes to waste heat** produced within the industrial cluster alongside the vast **geological CO_2 storage options** available in the Humber region.

Exporting CO_2 removal credits

The UK will require removals within its territory to 'balance' territorial residual CO_2. Deployment of engineered CO_2 removals of between **75 and 81 MtCO_2/year** will be required to compensate residual emissions across all sectors. Within the national commitment to 'net zero' and the associated demand for CO_2 removal, there is also a range of sub-national commitments, including those from local governments, public bodies, industries, landowners, and private companies.

It is also important to note that there will be significant demand for CO_2 removal credits solely from within the Humber cluster, which is the highest-emitting industrial cluster in the UK. The UK is likely to need all possible removals produced in the Humber (which poses a potential barrier to selling CO_2 removal credits to international buyers). At present there is uncertainty over the ownership of CO_2 removal credits and how they will be claimed amongst the variety of interested stakeholders

Rapid, large-scale deployment of industrial decarbonisation technologies is hindered by existing risks and barriers

MPR risks and barriers were considered in detail for the technologies presented in Figure 1, across eight core categories as presented in Figure 2. These categories were utilised to group similar risks and barriers for each technology type, whilst also allowing key recommendations and actions to be identified for relevant stakeholder groups. The key risks and barriers preventing the Humber from achieving net-zero by 2040 are identified below. A detailed analysis of the market, policy and regulatory risks and barriers for each technology is provided in the subsequent chapters.

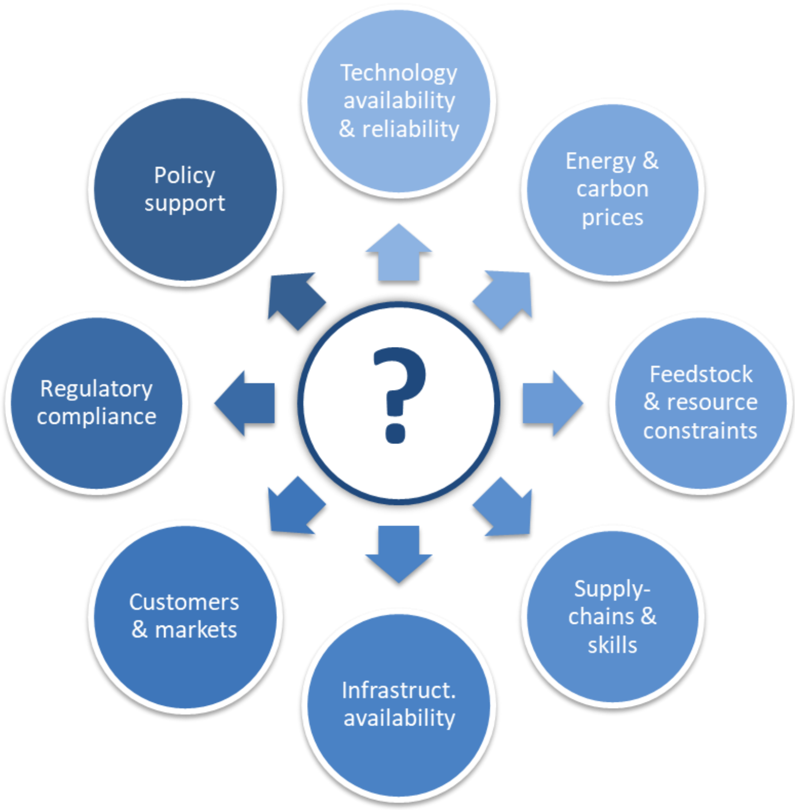

Figure 2: Core categories for MPR analysis

Technology availability and reliability

Key Barrier: Many promising technologies are still under development

- The ability to meet industry-specific heating profiles with electrical and hydrogen appliances often still needs to be demonstrated at scale.
- There is a lack of successful CO_2 capture demonstrators in sectors like glass, lime, and for certain emission sources in the refining, petrochemical, and iron & steel industries.
- Current CO_2 capture technologies are highly energy intensive, increasing site-level energy demands by 20-50%.
- CCU technologies may be able to accelerate early DAC opportunities but are hindered by insufficient standards for the use of their co-products in industry.

Key risks: Early movers may take higher risks only to then find themselves locked into sub optimal choices

ALL

- Industrial operators may question why they should invest now in less efficient & immature technologies when others can bear the higher initial risk.

Energy and carbon prices

Key barrier: The cost of energy increases when switching away from fossil fuels

- The price of electricity is still set by that of natural gas generation even though renewables are often cheaper, due to the structure of the UK electricity sector
- The price of hydrogen is intrinsically linked to and higher than electricity (if electrolytic) or natural gas (if CCS enabled).

Key barrier: CO_2 capture from flue gases or air is highly energy intensive

- CCS significantly increases industrial energy demands and the cost of power generation.
- DACCS is only viable if it can access vast amounts of low-cost heat and/or electricity.

Key barrier: Carbon prices are too low, so currently it is cheaper to emit than to abate CO_2

ALL

- An increase in the carbon price is required to ensure low carbon solutions are lower cost than fossil fuel solutions in the future.

Key risk: Long term carbon and energy prices are highly uncertain

ALL

- Investors willingness to invest in low-carbon projects is determined by the expected return on investment that they can expect to achieve.

Feedstock and resource constraints

Key barrier: Each decarbonisation pathway hinges on critical resources whose long term availability is not fully understood

- Large scale electrification necessitates copper to upgrade of the grid infrastructure, battery minerals, and multiple other materials.
- Hydrogen is not freely available in nature: CCS enabled production would increase demand for natural gas, while electrolysers today require critical minerals like platinum, iridium, and scandium.
- Bioenergy and BECCS rely on sufficient availability of sustainable sources of primary biomass or residues.
- For the iron and steel sector, transition to electric arc furnaces and/or hydrogen direct reduced iron may become constrained by limited availability of scrap and/or high-quality iron ore.

Supply chains and skills

Key barrier: New sectors will need to emerge and mature within less than 20 years

- The transition away from carbon intensive processes will require large numbers of skilled workers in new sectors.
- Local and national manufacturing capacity may require significant changes to meet the demand from low carbon technologies.

Key barrier: Early supply chain constraints have been identified for carbon capture and CO_2 imports

- Supply chain constraints of key components (e.g. CO_2 compressors) could result in delays in project delivery.
- Optimal CO_2 shipping conditions are likely to be project specific, resulting in added complexity for infrastructure developers. A range of specifications are likely to be utilised by industry, increasing the challenge for supply chains to reach maturity.

Infrastructure and availability

Key barrier: Each decarbonisation pathway relies on significant new infrastructure

- Electricity grid upgrades and build out of renewable generation underpins direct electrification of industrial heat, electrolytic hydrogen, DACCS, and CCS.
- Hydrogen production, storage, and distribution networks require development to supply low-carbon hydrogen for industrial fuel switching.
- Carbon capture projects will rely on the availability and operation of CO_2 T&S networks to handle captured emissions.

Key barrier: No private company can take certain counter party risks

- Individual industries cannot build infrastructure themselves.
- Infrastructure developers need credit worthy counterparties.
- High capital costs of infrastructure associated with transitioning to a low carbon pathway is inefficiently covered by current policy support.

Customers and markets

Key barrier: Industries facing declining market demand may struggle to access sufficient capital to finance multi decade investments

- Decarbonisation assets installed in 2030 must be operating in 2050.
- There are currently limited opportunities to obtain a “green premium” for industrial products.

Key barrier: Customer requirements may limit viability of fuel switching routes

- Customer demand for existing high-carbon products may act as a significant barrier to large scale investment in decarbonisation measures e.g., railways need blast furnace steel today.

Key risk: Demand for CO_2 removal credits is highly dependent on policy and/or emerging markets

- UK credits may be more expensive than foreign ones, and voluntary carbon markets may present prices that are too low and/or excessive volatility if not linked to overarching carbon policies.

Regulatory compliance

Key risk: Changing output streams requiring re-permitting

- Hydrogen combustion produces NO_x in higher amounts/concentrations than natural gas.
- Carbon capture may release new pollutants like nitrosamines that could result in complications in the permitting process.

ALL

Key barrier: The planning regime is not yet fully defined

- The consenting regime (DCO or TCPA) is poorly defined for hydrogen fuel switching, BECCS, DACCS, and electrification technologies.

Key risk: Water availability could constrain technology deployment

- Hydrogen production and carbon capture may require large volumes of water (between 4.9-81.8 million m^3/year depending on deployment), which might constrain deployment in water constrained regions like the South Humber.

Key risk: Alignment of supply chain regulation across sectors and geographies

- Supply chains will cut across different sectors and geographies, requiring policy alignment to allow scale and integrity.

Policy support

Key risk: Commodities produced in the Humber will not be competitive without policy support

- Carbon prices are currently too low to drive existing emitters to deeply decarbonise their processes and there are limited external incentives to produce green products.
- Without policy support, early adopters of new technologies would face higher costs than competitors who do adopt decarbonisation measures, reducing their competitiveness.
- Industry relocating offshore (i.e. carbon leakage) might occur if carbon prices increase without measures to level the playing field with unabated imports of industrial products (e.g. a Carbon Border Adjustment Mechanism).
- Without policy support, transitioning to low carbon technologies will be unviable for the majority of industrial operators.

Key barrier: Access to finance can be challenging to acquire without policy support

ALL

- Large upfront investments in novel technologies are unattractive to investors without guarantees of return on investment

Priority recommendations and actions are identified for each stakeholder

The Humber has the opportunity to achieve net-zero by 2040 and become the world's first net-zero industrial cluster. Emissions can be reduced through the deployment of carbon capture, hydrogen fuel switching and electrification technologies, combined with the potential of the Humber to deliver negative emissions via engineered removals. There are currently a range of market, policy and regulatory barriers that could restrict the Humber from reaching net-zero (detailed above), that will require co-ordinated action from a range of stakeholders. The most impactful actions for decarbonisation are highlighted based on the categories presented in Figure 3.

Figure 3: Primary action categories

Due to the scale of industrial activity in the Humber and the typically long lead times for large scale infrastructure projects, it is critical that detailed decarbonisation planning commences imminently. Delivering decarbonisation in the Humber region will rely on a co-ordinated approach across a range of stakeholders to ensure that optimal choices are made both on a site and a cluster level. Avoiding delays in this early planning stage will be critical to ensuring that the goal of net-zero emissions by 2040 remains in reach. The priority recommendations and actions for each stakeholder group are shown in Table 1 – these have been identified as crucial for ensuring the Humber reaches net-zero by 2040.

Table 1: Priority recommendations and actions for stakeholders

Stakeholder	Action Category	Recommendation / Action
Policy Makers		Finalise business models for carbon capture, H_2 production and greenhouse gas removals, specifically providing clarity on the level of financial support that will be made available.
		Develop a business model for electrification.
		Implement carbon border adjustment measures or equivalent instruments to enable carbon pricing to drive decarbonisation whilst not contributing to carbon leakage.
		Devise policies that stimulate and support demand for green products.
		Increase innovation funding for new technologies that will reduce the cost of decarbonisation.
Industry		Pursue opportunities for circularity starting with industrial symbiosis for using waste heat and other physical streams to air, water, or land.
		Identify easy wins for hydrogen fuel switching opportunities.
		Stimulate demand for green products through the development of increased Scope 1-3 emissions traceability across the full product supply chain.
		Focus on reducing energy and water consumption as well as minimising impacts on air quality and the environment.
Regulators		Ofgem should reform industrial electricity prices, decoupling the cost of electricity from fossil generation and the market price of natural gas.
		Environment Agency (EA) should investigate future water availability in the Humber region.
Local Authorities		Work alongside the government to update how planning consent is awarded for projects of national significance.
Local Leadership		Communicate the benefits of low carbon technology deployment to the wider public.
		Identify potential synergies between Humber industrial operators (e.g. to utilise waste streams).
Academia		Focus R&D efforts on reducing the cost of CO_2 capture, hydrogen production and electrification, alongside further analysis of promising alternative pathways.
Utilities and Networks		Identify constraints in the UK electricity grid and opportunities for electrification.
		Identify potential water constraints to industrial operators and project developers in the Humber region.

Contents

Acronyms

BAT Best Available Technique
BF Blast furnace
BOF Basic oxygen furnace
BECCS Bioenergy with CCS
BEIS UK Department for Business, Energy and Industrial Strategy
BREF Best Available Techniques Reference document
CAPEX Capital expenditure
CCC Committee on Climate Change
CCS Carbon Capture and Storage
CCUS Carbon capture, utilisation, and storage
CfD Contract for Difference
CHP Combined heat and power
CO_2 Carbon dioxide
CO_{2e} Carbon dioxide equivalent
CIF CCS Infrastructure Fund
DAC Direct air capture
DACCS DAC with CCS
DCO Development Consent Order
DRI Direct Reduced Iron
EA Environment Agency
EAF Electric Arc Furnace
EfW Energy from Waste
EIA Environmental Impact Assessment
EP Environmental Permit
EPR Environmental Permitting (England and Wales) Regulations 2016 (as amended)
ETS Emissions trading scheme
FCC Fluid catalytic cracking
FOAK First of a kind
GHG Greenhouse gas
GGR Greenhouse Gas Removal
GWP Global Warming Potential
H_2 Hydrogen
H-DRI Hydrogen-based Direct Reduced Iron
HBI Hot briquetted iron
HICP Humber Industrial Cluster Plan
HFO Hydrofluoroolefin
ICC Industrial Carbon Capture
IED Industrial Emissions Directive
IETF Industrial Energy Transformation Fund
LHV Lower Heating Value
LNG Liquefied Natural Gas
LPA Local Planning Authority
MRF Materials Recovery Facility
NbS Nature-based Solutions
NCS Natural Climate Solutions
NOx Nitrogen oxides
NPS National Policy Statements
NSIP Nationally Significant Infrastructure Project
NZIP Net Zero Innovation Portfolio
OPEX Operating expenditure
PINS Planning Inspectorate
RDF Refuse Derived Fuel
RFNBO Renewable fuels of non-biological origin
RTFC Renewable transport fuel certificate
SAF Sustainable aviation fuel
SDG Sustainable Development Goals
SMR Steam methane reforming
SOx Sulphur oxides
SRF Solid Recovered Fuel
T&S Transport and Storage
T&SCo Transport and Storage Company
TCPA The Town and Country Planning Act 1990
TRI T&S Regulatory Investment
TRL Technology Readiness Level
WDF Waste-Derived Fuels

1 Introduction

1.1 Context

The UK has set 2050 as the target year for its 'Net Zero' statutory goal. By then, all sectors in society will need to fully decarbonise, including the industry and power sectors. To support this high-level goal, the UK Government reiterated in its recent Net Zero Strategy its ambition to:

- Develop 10GW of low carbon hydrogen production capacity by 2030, supported by the £240 million Net Zero Hydrogen Fund.
- Develop Carbon capture, utilisation, and storage (CCUS) at least two industrial clusters by the mid-2020s, and four by 2030, underpinned by the £1 billion CCUS Infrastructure Fund (CIF).
- Deploy at least 5 MtCO2/year of engineered removals by 2030 and delivering £100 million of investment in innovation.
- Support deployment of other decarbonisation technologies power by renewable energy – and offshore wind – and future-proofing industrial sectors, and the communities they employ through the £315 million Industrial Energy Transformation Fund (IETF).

The selection of the East Coast Cluster as one of the two 'Track 1' Clusters positions the Humber as one of the potential early 'SuperPlaces' leading the transformation to a net-zero economy. The Humber Industrial Cluster Plan (HICP) aims to set out the optimal route to fully decarbonise the Humber cluster by 2040. The HICP was set up in January 2021 and is funded by UK Research and Innovation (UKRI). The steering group includes Membership organisation CATCH, the Hull and East Yorkshire Local Enterprise Partnership (HEY LEP) plus 8 industry partners. Partners will work together to develop the Humber Industrial Cluster Plan that aims to set out the strategic roadmap for the Humber Cluster to follow in order to achieve net zero by 2040. This study is a collaborative effort between Element Energy, ERM, Eunomia and HICP aiming to inform the Humber cluster of the decarbonisation options available for the industrial emitters within the region.

1.2 Scope, objectives, and approach

The Humber is UK's largest industrial cluster by emissions and economic activity. Humber industries emitted 14.6 MtCO_2 in 2018, or 20 MtCO_2 when including local power generators. This study also considers the Drax power station to be part of the core Humber cluster. Previous analysis by Element Energy for HICP found that industrial emissions are likely to only reduce 10-20% by 2040 under business-as-usual scenarios[1]. This underlines the **need for large-scale deployment of deep decarbonisation technologies and methods such as carbon capture and storage (CCS), fuel switching, and greenhouse gas removals** in the Humber.

Deep decarbonisation of the Humber industrial cluster may unlock greater environmental benefits than can be observed by solely considering local industries. The deployment of CO_2 storage in the Humber can also serve other regions. Through the development of **CO_2 import infrastructure**, the Humber would be well placed to receive CO_2 from emitters in other parts of the UK and Europe who require CCS to achieve their decarbonisation goals but do not have access to CO_2 storage locally. Similarly, large-scale production of negative emissions via Removals could unlock a new **market for the export of CO_2 removal credits** to entities who require these to reach their own net zero goals.

While the need to deploy decarbonisation technologies is clear, there are several market, policy, and regulatory risks and barriers that currently impede the uptake of these novel technologies, hindering regional decarbonisation and economic transformation. **The core objective of this study is to identify the most important risks and barriers and discuss ways to mitigate and overcome them to enable the Humber cluster to reach net zero by 2040**. A second, related objective is to formulate recommendations and clear actions for a broad range of stakeholders, including local industries, investors, local authorities, and national regulator and policy makers to unlock deployment of the necessary decarbonisation technologies.

[1] Element Energy for HEY LEP/CATCH 2021, Update to the Phase 1 Baseline Local Emissions Assessment.

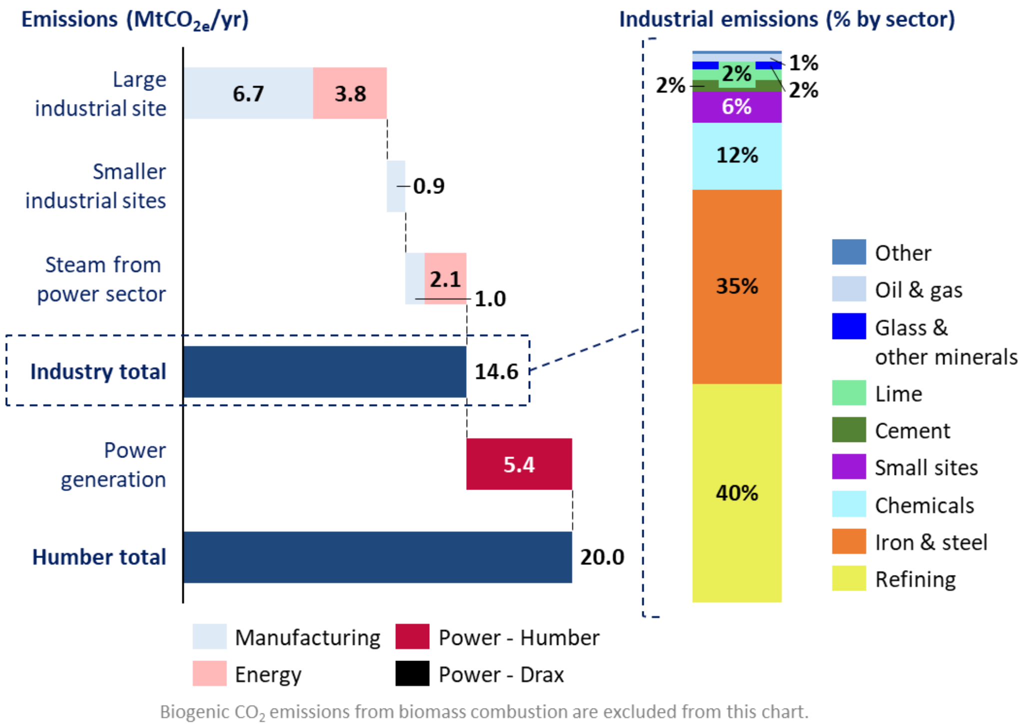

Figure 4: Emissions produced by industry and power generators in the Humber region[2]

To achieve these objectives, an initial list of market, policy and regulatory risks and barriers were developed based on the review of publicly available literature. These were subsequently **refined and validated through engagement with over 25 stakeholders from industry including representatives from local industries, project developers, local authorities, national regulators, and policy makers**. Stakeholder feedback was also used to establish potential risk mitigation measures and enablers to overcome the main barriers.

Prior to presenting this analysis, it is useful to define the following terms:

- **Risks**: longer-term uncertainties, where uncertainty levels vary, and mitigation measures are far-sighted.
- **Barriers**: known, shorter-term problems which are likely to require upfront solutions to progress with market participation.
- **Market** risks and barriers: associated with supply, demand, competition, and pricing.
- **Policy** risks and barriers: associated with the overall intended outcomes of the market system / depending on specific policy mechanisms.
- **Regulatory** risks and barriers: associated with the specific rules, requirements and certification methodologies which must be complied with to participate in the market.

These definitions will be used throughout the report. However, it should be noted that in many cases, risks and barriers do not fall exclusively into one category. The interlinking nature between market, policy and regulatory risks and barriers is shown in Figure 5.

[2] Data source: National Atmospheric Emissions inventory 2019, Emissions from NAEI large point sources.

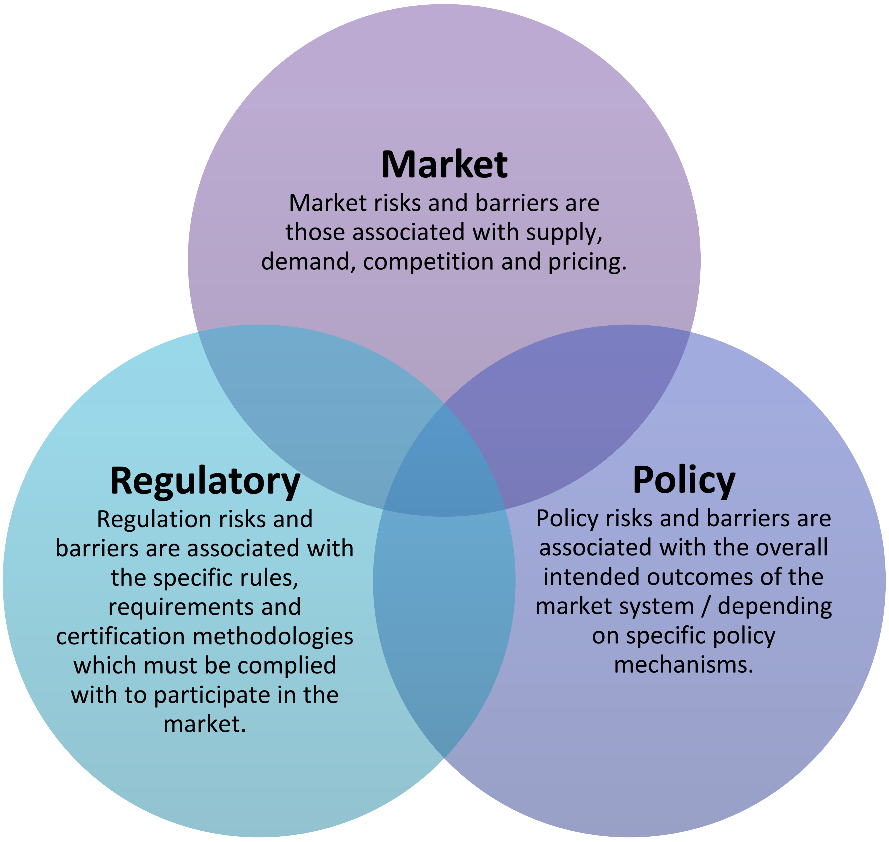

Figure 5: Definition of market, policy and regulatory risks and barriers

1.3 Structure of this report

The rest of this report is set out as follows:

- Chapters 0, 3, and 4 constitute the market, policy, and regulatory studies on the implementation of industrial fuel switching, carbon capture and storage, and CO_2 removals in the Humber. Each chapter follows an analogous structure, providing:
    - An **overview** of each technology, discussing its decarbonisation potential, status, cost, energy and resource implications, and infrastructure.
    - A **market** study looking at the local opportunities for deployment of each technology and highlighting the main market risks and barriers that will hinder uptake.
    - A **policy** study that, after defining the relevant policy context, outlines the main policy risks and barriers to address in order to unlock large-scale deployment.
    - A **regulatory** study that reviews the main known health, safety and environmental implications of technology development, summarises the emerging consenting (planning and permitting) requirements, and emphasises the main regulatory risks and barriers faced by project developer.
    - A summary of **recommendations and actions** by key stakeholders including local industry, government, and technology developers.

- Chapter 2 focuses on electrification and hydrogen fuel switching, but also briefly reviews other possibilities like biomass and waste-derived fuels.
- Chapter 3 further consider the possibility of developing the Humber into a **CO_2 imports hub**, whereas Chapter 4 also discusses how a market to **export CO_2 removal credits** generated in the region could emerge. These topics are also analysed from market, policy, and regulatory lenses, though the

corresponding sections follow a different structure that better suits these themes, which are less related to technology aspects or site-specific considerations.
- Chapter 5 offers a brief review of other approaches to decarbonise the industrial sectors in the Humber and specifically provides an overview of circular economy principles and other factors that could impact demand for carbon-intensive products in the long term.
- **Chapter 6** concludes the report by providing **recommendations** and defining **actions for different stakeholders** to enable deployment of the technologies discussed in the previous chapters.

Detailed supporting information is provided in the Appendix.

1.4 Overarching policy context

The introduction of new policies could have a pivotal role in enabling deep decarbonisation across the UK economy. Scale up of low-carbon technologies will be needed in all areas of the economy to set the conditions for mass rollout from the 2030s onwards. By the 2030s choices across all sectors should default to the low-carbon, rather than high-carbon, option. In 2020, the UK government released its *10 Point Plan for a Green Industrial Revolution* that was followed in 2021 by the *Net Zero Strategy*. This outlined the decarbonisation pathways that would be required to achieve net zero by 2050.

The UK Government is developing sector specific decarbonisation policies that are currently at various stages of development. These are summarised along with overarching industrial policies in Table 2. The UK Government will build on these policies in the coming years, aligning approaches to the UK's net zero target and introducing new policies to address any outstanding barriers to decarbonisation.

Table 2: Summary of key UK policies

Pathway		Key Policies and Strategies
	Industrial Carbon Capture	• Cluster Sequencing • Industrial Carbon Capture (ICC) Business Model • CO_2 T&S (TRI) Business Model
	Hydrogen	• Cluster Sequencing • UK Hydrogen Strategy • Low-carbon Hydrogen Business Model (Consultation) • Low-carbon Hydrogen Standard (Consultation) • CO_2 T&S (TRI) Business Model
	Electrification	• Industrial Decarbonisation Strategy
	Carbon removals	• Greenhouse Gas Removals: Summary of Responses to the Call for Evidence • Net Zero Strategy • Biomass Policy Statement • Business model for power BECCS
	CO_2 Imports	• London Protocol • CO_2 T&S (TRI) Business Model

1.4.1 Carbon pricing

UK Emissions Trading Scheme

Carbon pricing is a cost-effective and technology-neutral tool for ensuring industry accounts for its GHG emissions when formulating business decisions. The UK Emissions Trading Scheme (ETS) is a market-based policy that aims to support the UK in meeting its legally binding carbon reduction targets. The UK ETS acts as a cross-cutting policy lever to drive market-based abatement, incentivising industries to find the most cost-effective solutions to decarbonise. [3] The policy aims to provide a long-term carbon price signal for heavy industry, aviation and power sectors to incentivise sector decarbonisation. In January 2021, the UK ETS replaced the UK's participation in the EU ETS.

A cap on allowances represents the overall limit of emissions allowed in the system and the cap will gradually reduce over time, providing a long-term market signal so industries can invest in abatement technologies. The cap will be aligned with the UK's net zero ambition by January 2024, potentially earlier, to become the world's first net zero aligned ETS. A review of the UK ETS, including a review of a net-zero consistent emissions cap commenced in 2021. The initial cap has been set 5% below the UK's notional share of the EU ETS for Phase IV.

Energy-intensive industries are eligible to receive a volume of emissions allowances for free. The UK ETS aims to minimise the risk of industries being disadvantaged due to increased costs associated with the purchasing of allowances. Free allocation is the main policy instrument through which carbon leakage risk and competitiveness impacts are addressed under the UK ETS.

Carbon removal credits could function within an ETS market by allowing polluting sectors to meet their obligations through the procurement of negative emissions. The UK is investigating the role the UK ETS could have as a potential long-term market for carbon removals (engineered or nature-based solutions).

Carbon Border Adjustment Mechanisms

Carbon leakage refers to unintended consequences of policies targeting industrial decarbonisation, which can lead to industry and its emissions relocating to countries with less ambitious greenhouse gas emissions reduction policies to avoid the additional costs associated with decarbonisation. This can lead to an increase in overall global emissions, and a worse outcome for climate change. In the context of industrial decarbonisation in the Humber, there are two primary concerns: 1) Domestic producers losing market share to higher carbon imports as a result of higher carbon costs in the UK than those faced by international competitors, and 2) diversion of investment from countries with more ambitious carbon constraints to those with less ambitious ones, leading to increased emissions[4].

Carbon Border Adjustment Mechanisms (CBAMs) adjust the import and export price of industrial products based on the applied carbon price. This is proposed in the form of a tax, where import fees are issued on industrial goods produced in countries with a lower carbon price and carbon charges paid on exports to the same country can be claimed back. The EU have recently introduced CBAMs on a range of industrial commodities with plans to expand coverage to a greater number of products over time[5]. The EU CBAM policy also aims to phase out free allowances for all sectors by 2026 under the EU ETS. The UK aim to work with the EU to develop a mutually beneficial CBAM policy, however, the UK ETS is still the primary mechanism for addressing carbon leakage in the UK. The UK Environmental Audit Committee is currently conducting an inquiry into the role CBAMs could play in addressing carbon leakage and addressing the UK's environmental objectives[6].

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[3] BEIS 2021, Net Zero Strategy: Build Back Greener.
[4] BEIS 2021, Industrial Decarbonisation Strategy.
[5] Council of the EU 2022, Council agrees on the Carbon Border Adjustment Mechanism (CBAM).
[6] UK Environmental Audit Committee 2021, Carbon border adjustment mechanisms: Inquiry.

1.4.2 Cluster sequencing

The UK governments Ten Point Plan announced the commitment to deploy CCS in two industrial clusters by the mid-2020s (Track 1), and a further two clusters by 2030 (Track 2). This is enabled by a £1 billion CCS infrastructure fund (CIF) that will primarily support the capital expenditure requirements of the CO_2 Transport and Storage (T&S) networks. If the clusters represent value for money for the consumer and the taxpayer then subject to final decisions of Ministers, they will receive support under the Government's CCS Programme.

Within each *'track'* there are two *'phases'*:

Phase 1 is the process for identifying industrial clusters most suitable for CCS deployment[7]. A 'cluster' must include a CO_2 T&S network with the entity responsible for the network (the CO_2 T&S Company, T&SCo) identified as the cluster lead. The government receives submissions from the CO_2 T&SCo and provisionally sequences those most suited to deployment in the mid-2020s onto Track-1.

Phase 2 is the process for identifying individual capture projects to connect to the cluster selected for sequencing[8]. The government receives submissions from individual capture projects from industry, power and hydrogen production sectors. The Phase 2 submission process is eligible to all projects that could feasibly connect to one of the sequenced clusters by 2027.

Phase 1 of the Track 1 cluster sequencing process was completed in October 2021, in which the HyNet and East Coast Clusters were selected as Track 1 clusters and taken forward to the negotiation stage with BEIS. As of August 2022, BEIS have shortlisted 20 projects (power CCS, CCS-enabled hydrogen, and industrial carbon capture) as part of Phase 2 of the Track 1 process to proceed to the due diligence stage of the process. This shortlist does not imply availability of funding for any or all of the shortlisted projects. Power BECCS plants were invited to apply to the Track 1 process separately, with the deadline for submission October 2022. The outcome of the Track 1, Phase 2 projects is expected by late 2022 to early 2023.

Government will aim to conclude negotiations with projects within Track-2 clusters in time to enable them to take Final Investment Decisions (FIDs) from 2024 so that projects will then be operational from 2027. Phase 1 of the Track 2 cluster sequencing process is expected to commence in late 2022 or early 2023. An overview of the cluster sequencing timeline is shown in Figure 6.

Figure 6: Cluster sequencing timeline[9]

[7] BEIS 2021 - Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-1.
[8] BEIS 2021 - Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-2.
[9] CCSA 2022, CCUS Delivery Plan 2035.

1.4.3 Local policy context

Policy and actions available to local authorities

Local authorities work closely with Local Enterprise Partnerships (LEPs) in order to implement policies and plan support for low-carbon technologies. The policy and actions available to the Humber are shown in Table 3.

Table 3: Policy and actions available to Humber local authorities

Group	Description
Planning, infrastructure and land use	Act as the Local Planning Authority and develop plans for use of regional assets by industry
Innovation, demonstrations, and grants	Offer funds, raised regionally or by government, to promote R&D and business growth
Encourage private sector investment	Facilitate investment from private industries by supporting private sector initiatives
Partnerships and communication	Collaborate with private industries via LEPs and other jointly established bodies
Investment in employment and skills	Invest in the re-skilling and upskilling of the regional employee base to use low carbon technologies with support from local industries
Deployment of action plans & strategies	Exploit regional knowledge and work with stakeholders to develop industrial decarbonisation pathways with support from local industries
Green procurement	Use local authorities' purchasing power to encourage decarbonisation of industrial processes, for example by requiring disclosure of the carbon footprint associated with main supplies

Local authorities and Local Enterprise Partnerships

The policies and interventions identified are not usually targeted to one specific type of technology, but rather consider a holistic approach to decarbonisation framework for clean growth. In collaboration with Local Enterprise Partnerships, the four local authorities perform activities such as:

- **Administration and development of initiatives to direct investment towards decarbonisation,** which is often funded from national or supranational budgets. Such initiatives can include infrastructure to enhance connectivity in the industrial cluster or management of land shared by ecosystems and industry. A policy example is the South Humber Industrial Investment Programme[10].
- **Developing action plans and strategies with partners.** Local authorities and LEPs have recently been involved in developing cluster-wide plans which include actionable recommendations and initiatives to support decarbonisation technologies. However, full implementation of these recommendations for industry entails close collaboration with the national government. An example of this is the Yorkshire and Humber Climate Action Plan and the former Humber Local Energy Strategy.
- **Land management and use** of the region's natural and infrastructure assets, such as the Humber Estuary and ports, underpinned by strategic priorities of decarbonisation via growth of low-carbon technologies and climate change mitigation. An example of this is the Humber Estuary Plan and work of the Humber Leadership Board.

Local authorities and LEPs often act as the regional interface between private sectors and the UK government, along with providing vertical collaboration and regional stakeholder engagement and management through bodies such as the North East and Yorkshire Net Zero Hub.

Humber Freeport

The Humber Freeport is home to the UK's busiest port complex including the four major ports of Hull, Goole, Immingham and Grimsby which combined handle around 17% of the nation's trade. The freeport handles

[10] Greater Lincolnshire Local Enterprise Partnership 2022, South Humber Industrial Investment Programme.

materials that supply 10% of the nation's energy, 25% of the UK's road transport fuel and almost a third of national timber supply[11]. The Humber Freeport also underpins the farming, food, retail, construction, automotive and pharmaceutical sectors, which have a strong economic impact across the UK but especially in the Midlands and the North of England. The North East Lincolnshire Council was named the accountable body for the Humber Freeport in June 2021[12]. The role of the accountable body includes the management of funding and financial systems within the freeport.

Box 1 – *The Humber Freeport*

The Humber Freeport is under development and will provide diverse financial advantages to industry in the region. Normal tax and customs rules do not apply within Freeports; they function similarly to 'enterprise zones'[13] but are designed to specifically encourage businesses that import, process, and then re-export goods. Humber Freeport will take in a wide area, with a vision to realise the ambitions of the region by helping create high quality jobs, promote value-adding activities, deliver the levelling-up agenda, and build an innovative, resilient, and sustainable ecosystem. The Freeport has also undertaken a renewed focus on low-carbon and advanced manufacturing, underpinned by clean energy, to support government ambition on decarbonisation[14]. Freeport consist of two types of zones:

- Tax Zones: Expected to be the focus for the Humber Freeport due to their greater potential and financial incentive, these zones specifically attract new businesses and stimulate investment through accelerated capital allowances and relief from stamp duty, land taxes, business rates, and some employer's NI contributions. There are two tax zones approved already, Hull East and Humber Southbank, with the Goole site expected in the next wave of approvals[15].
- Customs Zones: Less important to the current Humber Freeport plans, inside these zones port operators and companies can defer tax and import VAT on goods unless they later enter the UK. A manufacturer can therefore use those goods to create their product for export to an international market without taxation.

The Freeport should help with the crucial task of building new infrastructure in the Humber to accelerate decarbonisation, especially for the maritime sector. Seed capital from the first phase of funding has been ringfenced to several identified projects and a second phase of funding, which will be derived from business rates and available in the next few years, will be much more significant. The process is ongoing to establish which projects to fund with the four focus streams to target being Offshore Wind, CCS, Hydrogen and EVs. It is thought that the Freeport may act more as a contribution to national decarbonisation than specifically for the Humber, for example, increased production of wind turbine blades will produce more renewable energy accelerating the decarbonisation of electricity generation across the UK. However, there will also be specific benefits for sites within the Humber. For example, the Hull East tax zone includes[16]:

- Equinor's proposed new CCS-enabled hydrogen plant.
- The Saltend plant and subsequent opportunity to create exportable hydrogen and low-carbon chemical products. The facility also includes the agreed 25-year lease site for Pensana, a rare earth processing plant, which will develop local supply chains for magnets in offshore wind and electric vehicles batteries.
- Siemens Gamesa's expanding wind blade manufacturing facility.

[11] Humber Freeport 2022, Humber Freeport.
[12] North East Lincolnshire Council 2022, NELC to become accountable body for the Humber Freeport projects.
[13] Enterprise Zones are designated areas across England that provide tax breaks and Government support. They are part of the Government's wider Industrial Strategy to support businesses and enable local economic growth.
[14] Freeports Report to the LEP Board, 2020
[15] Humber Freeport gets Budget go-ahead with two out of three tax sites set for November launch - Business Live 2021
[16] Humber Freeport Plan

2 Industrial fuel switching: electrification and hydrogen

Fuel switching replaces the energy supply from fossil fuels with alternative low carbon fuels or electricity. This enables a reduction in **combustion emissions** from industrial heating, responsible for a large part of the Humber industrial emissions. Fuel switching includes multiple options for each industrial sector. Broadly, three main classes of low-carbon energy sources are available for fuel switching. These are **electrification**, **hydrogen fuel switching**, and switching to bioresources, which include **biomass and waste-derived fuels**. This assessment primarily focuses on electrification and hydrogen fuel switching, since they have the largest deployment potential and will be less constrained by future supply. Additionally, this section includes an overview of options for switching to bioenergy relevant to the Humber industries.

Fuel switching is suitable for processes fired by purchased fossil fuels. However, some industrial processes are fired by internal fuels, which are industry by-products generally burnt on-site and with limited or no alternative use. Fuel switching is not a valid decarbonisation pathway for those processes, as internal fuels are co-produced in fixed proportions to the main output product. Abating the emissions from the combustion of internal fuels would require either CCUS or process changes for a deep decarbonisation.

Heating processes are the predominant source of industrial emissions. The technology options for fuel switching vary depending on the heating process; in direct heating processes, the material being heated is in direct contact with the burning fuel or its hot combustion products, whilst in indirect processes the material being heated is separated by a physical barrier, such as furnace tubes or a heat exchanger. Heating processes are shown in Table 4 and can be classified into three high-level groups:

- Indirect high-temperature heating processes employed in the oil and gas and petrochemical industries, most of which arise from internal fuel combustion.
- Indirect heating processes making use of steam (or other intermediate fluid).
- Direct heating processes, most of which relates to direct high-temperature process units such as furnaces, kilns, and equipment utilised for reduction processes.

Table 4: Direct and indirect heating processes[17]

Cross-sectoral heating process		Representative technology	Main sectors or subsectors relying on these processes
Indirect heating	High temperature	Furnaces (up to 1000 °C)	Refining, petrochemicals
	Steam-driven	Boilers and combined heat and power (CHP) plants (up to 240 °C)	Food & drink, chemicals, other energy intensive industries
Direct heating	High temperature	Kilns, smelters, and other furnaces (up to 2000 °C)	Glass furnaces, lime kilns
	Low temperature	Ovens, cookers, fryers	Food & drink

Among these three categories, fuel switching for **indirect heating with steam** has the fewest barriers to switch as it only requires modifications to the steam raising part of the plant, leaving the core industrial processes untouched. **Direct heating processes** need to be studied on a **case-by-case basis**, as process modifications are required, and fuel switching can impact the characteristics of end products. Indeed, specific requirements concerning the interaction of combustion gases with products, differences in flame characteristics or heating profiles represent a technical challenge for fuel switching high-temperature direct heating processes. In comparison, it is generally simpler to fuel switch low-temperature direct heating processes.

It is important to make a distinction between process emissions, combustion emissions from purchased fuels, and combustion emissions from internal fuels. This is critical, as fuel switching can mainly only abate combustion emissions from purchased fuels. Process emissions result from CO_2 generated as an intrinsic part of the

[17] Adapted from Element Energy, 2020, Deep Decarbonisation Pathways for Scottish Industries.

industrial processes and are not associated with energy inputs. As illustrated in Figure 7, fuel switching could be an attractive decarbonisation option for up to 39% of emissions, which includes most industrial sectors. However, 61% of CO_2 emissions in the Humber are either process emissions or from the combustion of internal fuels and cannot be abated with fuel switching. The Humber refineries and the integrated iron and steel site, responsible for over 70% of total emissions, use a large share of internal fuels. Decarbonisation pathways for these sectors are explored in Box 2 and Box 3.

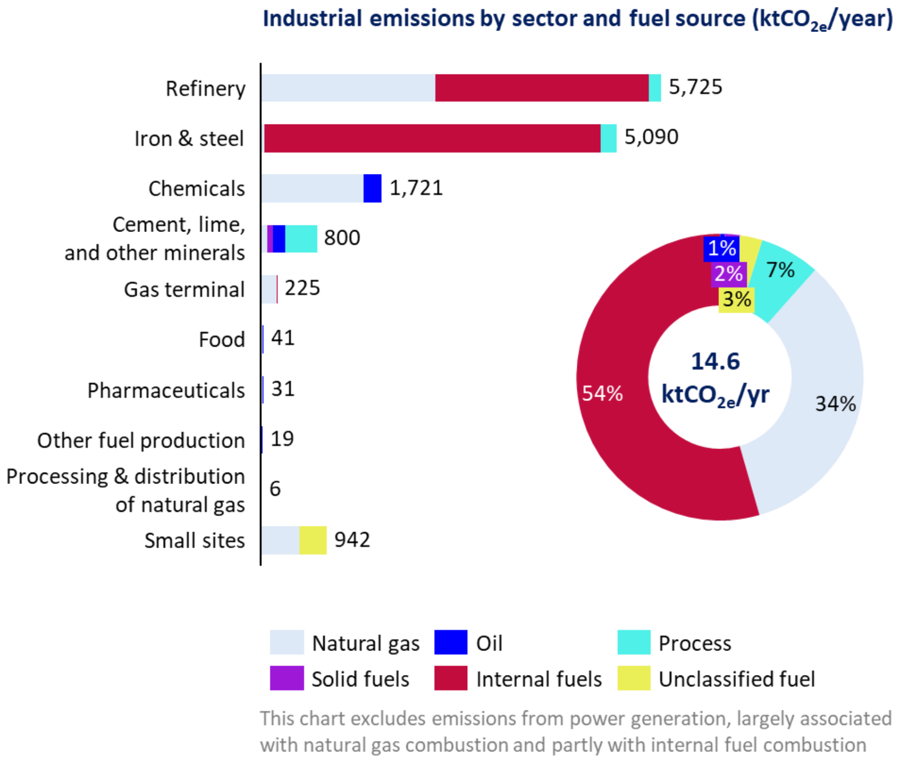

Figure 7: Industrial emissions by sector and fuel source ($ktCO_{2e}$/year) in the Humber[18]

[18] Element Energy, 2021, Update to the Phase 1 Baseline Local Emissions Assessment for the Humber Cluster.

Box 1 – Decarbonisation pathways for refineries

Refineries are characterised by highly integrated processes and the production of various products. Around 50% of emissions from Humber refineries arise from the burning of internal fuels. Emission sources vary by product line. The main emission sources in Humber refineries refinery include:

- **Fluid catalytic cracking (FCC)**: used to break the long-chain molecules from heavy gas oil to short-chain molecules.
- **Calciner**: calcining at very high temperature removes volatile hydrocarbons from pet coke. The calcined coke is then used to make anodes for electric arc furnaces (EAFs), for aluminium and titanium smelting, and for batteries in EVs. Phillips 66 is currently the only UK refinery producing graphite electrode coke.
- **Heaters**: used for high temperature process heating and to generate the high temperature steam used for the different internal processes.
- **Steam methane reforming (SMR)**: used to produce hydrogen by reacting natural gas with steam.

Pathways for the decarbonisation of refineries have CCS as a central element. There is some room for improving efficiency of both processes and utilities, with the remaining Scope 1 emissions to be abated by a combination of CCS and fuel switching. For streams like FCCs, where waste products on the catalyst can only currently be removed through combustion, CCS is the most attractive option. In the case of process heaters, both **CCS and fuel switching are feasible alternatives.** Using CCS to capture emissions from heaters could offer economies of scale when combined with capture for other processes such as the FCC. By contrast, fuel switching could prove more economical where heaters face logistical or space constraints to be integrated into a capture unit. Fuel switching to hydrogen (or through electrification) can be the preferable choice in such cases. Moreover, the increased use of internal fuels within CHP units or in nearby power stations offers the possibility of a further reduction of emissions, as it would help to further reduce flaring[19].

Refineries are actively pursuing the production of low-carbon fuels to lower the carbon footprint of their products. Whilst the production of low-carbon fuels only makes a small contribution to reduction in site emissions, it reduces Scope 3 emissions – linked to the combustion of the fuels by end users. Examples include **biofuels**, **renewable fuels of non-biological origin** (RFNBO), **low-carbon fossil fuels** from non-organic waste and **development fuels**. RFNBOs are fuels where the energy content of the fuel comes from renewable sources other than biomass, such as power-to-liquid or electrolytic hydrogen – hydrogen produced with renewable energy from the electrolysis of water. Recently, the production of sustainable aviation fuel (SAF) at the Humber Refinery has been announced[20]. **Hydrogen's importance in fuel production** is expected to grow with the manufacture of power-to-liquid fuels. Power-to-liquid fuels, or e-fuels, are made from electrolytic hydrogen, CO_2 captured from an industrial or power emitter, and their synthesis into liquid hydrocarbons. Whilst refineries have the option between CCS-enabled hydrogen production – reforming of natural gas combined with CCS – and electrolytic hydrogen, only when electrolytic hydrogen is used are synthetic fuels considered RFNBO. As such, they are eligible for Renewable Transport Fuel Certificates (RTFCs) which allows them to comply with the Renewable Transport Fuel Obligation – which sets a percentage of renewable fuels to be met.

[19] Flaring is the controlled combustion of waste gas, done to stabilise pressure and to prevent the risk of explosions.
[20] British Airways, 2021, British Airways and Phillips 66 agree first ever UK produced sustainable aviation fuel supply.

Box 2 – Decarbonisation pathways for iron and steel

Iron and steelmaking are responsible for over a third of the Humber's industrial emissions. The integrated nature of the processes - from iron ore preparation to the steel end product - and the use of internal fuels does not allow for a direct fuel switching. A better understanding of current and emerging production routes for iron and steel is required to effectively assess the options for decarbonising the sector.

The majority of British steel (81%)[21], and **all steel manufactured at Scunthorpe, is made via the primary route**. The iron ore consists of iron oxides – iron and oxygen atoms bonded chemically. To produce iron, the iron ore is reduced in the presence of carbon, emitting CO_2 from the chemical reaction between the iron oxides and the carbon. The primary route involves processing iron ore into pellets or iron ore sinter. Simultaneously, coal is processed into coke in coke ovens to provide a source of carbon. Iron ore sinter, pellets and coke are then charged into a blast furnace (BF), where they are melted to make pig iron. Coke is essential to the process, as it is used both as a fuel for heating and melting the iron ore and a reducing agent. Also, gas distribution through the furnace is enabled by its mechanical properties that result in a permeable support for the iron ore. Pig iron has a high carbon content, and it is further processed in a basic oxygen furnace (BOF) to lower its carbon content by blowing oxygen, obtaining as a result low-carbon steel. **Off-gases from each of these steps have a high carbon and hydrogen content and can be used as an energy source within the process unit**. Coke oven gas (COG), blast furnace gas (BFG), and basic oxygen furnace gas (BOFG) are either used as fuels within the integrated site, burnt for power generation, or flared. Figure 8 shows a simplified process diagram for the primary route.

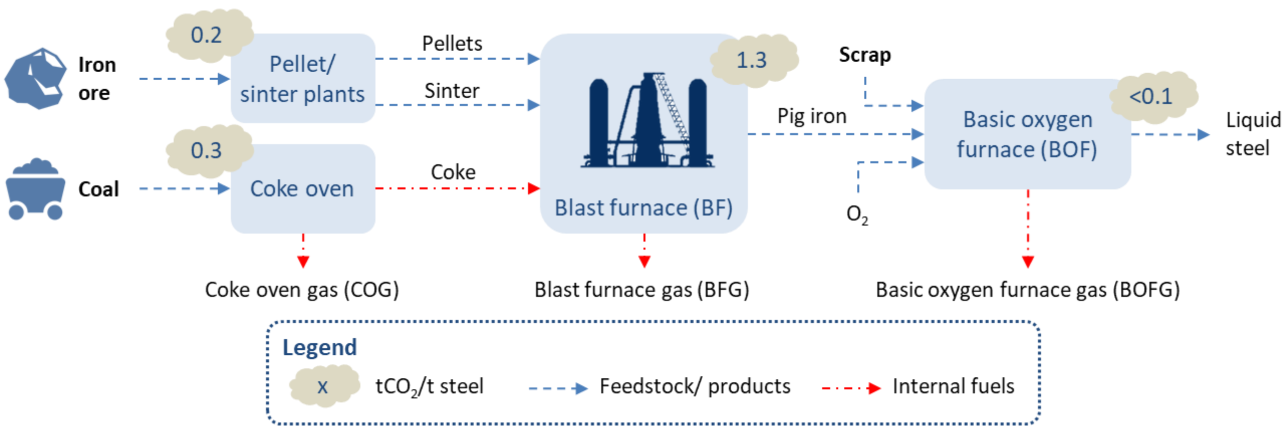

Figure 8: The primary route for steel production (simplified)[22]

The secondary production route uses electric arc furnaces (EAF) to melt scrap steel, as shown in Figure 9. CO_2 emissions from the secondary route are mainly indirect emissions from electricity production, although there are some process emissions from the carbon in the scrap steel, from carbon sources added to the EAF and from the electrodes. The emission intensity from the secondary route is significantly lower than for the primary route, and it can further decrease as power generation continues to decarbonise. Whilst EAFs can be charged with up to 100% scrap steel, pig or direct reduced iron (see below) can be charged for chemical balance and to dilute undesirable elements from scrap.

[21] UK Steel, 2021, UK Steel Key Statistics Guide 2021.
[22] Values correspond to average European Scope 1 and 2 tonnes of CO_2 emitted per tonne of crude steel. Material Economics 2019, Industrial Transformation 2050 – Pathways to Net-Zero Emissions from EU Heavy Industry.

Box 2 – Decarbonisation pathways for iron and steel

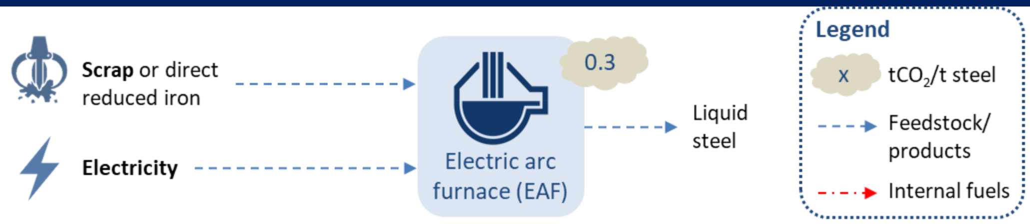

Figure 9: The secondary route for steel production (simplified)[23]

An alternative production route is the direct reduction of iron (DRI). DRI accounts for 6% of global steelmaking[24], but there are no DRI plants in the UK and it represents only 0.4% of European steel production[25]. This is because it is only cost-effective if there is easy access to cheap natural gas nearby. DRI uses natural gas, reformed into hydrogen and carbon monoxide, instead of coke to reduce iron ore pellets in a shaft furnace. The reaction occurs at moderate temperatures of around 800 °C and the iron is not melted. The resulting direct reduced iron or sponge iron is fed into an EAF to produce steel. Sponge iron can also be processed into hot briquetted iron (HBI), a compacted form designed for ease of shipping and storage that can be fed into an EAF or a BF.

Following the primary or the secondary production route, the crude liquid steel undergoes secondary steelmaking. Secondary steelmaking performed in ladles which are used to control and adjust the steel metallurgy to the desired grade of steel. Steel is then casted and rolled into the desired forms. The process results in indirect emissions from electricity production for the ladles and direct emissions from casting and rolling from the rolling mill furnaces (often fired with coke oven gas).

For the steel industry to reach net zero, **disruptive long-term decarbonisation strategies are required**, as improvements to existing processes can only reduce emissions up to a certain extent. Improving energy efficiency by implementation of best available technologies can lead to emissions reductions in the short term, but the potential for further reductions is limited due to the maturity of the BF-BOF route[26]. Use of biomass in the form of charcoal can partially replace coke, and some small steelmaking sites in Brazil fully operate with charcoal. However, the biomass stock availability in the UK and the mechanical properties of charcoal limit biomass's potential use for the large blast furnaces present in the Humber, with some degree of biomass injection to replace pulverised coal more likely than top charging to replace coke. Material efficiency, via the measures summarised in Chapter 5, can further decarbonise the steel industry, providing the same service using less material input as the steel production decreases.

There are **three main technological pathways** to decarbonise iron and steelmaking in the UK:

- Increasing the use of EAFs and recycling
- CCUS retrofitted on BF-BOF steelmaking
- Hydrogen-based direct reduction of iron

Despite not being technically fuel switching, as they involve process changes, increasing the use of EAFs and hydrogen-based direct reduction of iron (H-DRI) will be addressed within this chapter.

[23] Ibid.
[24] Global DRI production in 2019 was 111 MT and global steel production was 1,875 Mt, according to World Steel Association 2020, Steel Statistical Yearbook 2020.
[25] European DRI production in 2019 was 0.58 Mt and European steel production was 157 Mt. Ibid.
[26] Rechberger et al, 2020, Green Hydrogen-Based Direct Reduction for Low -Carbon Steelmaking.

Switching to other low-carbon fuels

Whilst electrification and hydrogen fuel switching hold the largest potential for deployment in the Humber, switching to other low-carbon fuels such as waste-derived fuels, biomass or biogas are alternative options that can result attractive for some industrial sites. Early deployment of fuel switching at larger sites is likely to influence the decisions made by smaller sites, which may adopt similar technologies and are likely to try to leverage opportunities to share infrastructure where possible. Box 3 presents an overview of those options.

Box 3 – Other low-carbon fuels

Other fuel switching alternatives are switching to waste-derived fuels (WDFs), biomass or biogas. WDFs are waste streams that can be used as a fuel source. As the portion of WDFs that have a biological origin is typically considered carbon neutral according to carbon accounting standards, use of WDFs can significantly lower the net emissions. However, it must be noted that the combustion of WDFs also includes plastics and other materials derived from fossil fuels. There are two main categories of WDFs:

- **Refuse derived fuels (RDFs)** are produced from non-hazardous waste stream, from individual or mixed stream of municipal solid waste, and commercial and industrial waste. They are the residue of the waste processed in materials recovery facilities (MRFs) that is not recovered. RDFs include biodegradable materials as well as plastics. In the UK, RDFs are typically burnt at energy-from-waste (EfW) power plants.
- **Solid recovered fuels (SRFs)** are a subset of RDFs, and they differ in that SRFs are made to meet specifications. SRFs generally present a higher portion of paper, cardboard, plastics, or textiles in their composition than RDFs, but the composition differs depending on the waste stream and the production process. Compared to RDF, SRF has a higher calorific value and a lower water content. SRF has a wide application in the cement industry, where it is used to co-fire cement kilns.
- Other types of waste-derived fuels include **end-of-life tyres** and **processed sewage pellets**.

Biofuels that are suitable for fuel switching include biogas and biomass. Biogas is a mixture of gases produced from the anaerobic digestion of biomass and contains methane and carbon dioxide.; because of its carbon dioxide content, it has a lower calorific value than biomethane, which is produced from the fermentation of organic matter. Biogas can be upgraded to a high percentage of methane using different carbon capture technologies that are commercially available. Switching to biomass can be attractive for sites without access to the local gas or electricity grid infrastructure. Biomass sources include woody biomass, such as wood logs, chips or pellets, and non-woody biomass, including agricultural residues, paper and pulp residues, or residues from the food processing industry. Some industrial heating appliances running on natural gas would require significant retrofits to be able to incorporate solid fuels – WDFs or biomass. In such cases, biogas can present switching advantages. Whilst the combustion of biofuels results in CO_2 emissions at a site level, they can be accounted as carbon neutral when sustainably sourced – without negatively influencing agricultural production or environmental quality. Moreover, forestry and agricultural waste are often bulky and expensive to transport so must be locally sourced. The UK Climate Change Committee (CCC) considers the most effective use of bioenergy is either in combination with CCS (BECCS) or where bioenergy displaces coal or coke[27].

As opposed to fossil fuels, WDFs and biomass have high water and oxygen content. Due to the energy penalty that this causes, they also have a relatively low calorific value. High quality SRFs mitigate this and are specified to higher heat values, but that is still lower than for fossil fuels. As a result, for high-temperature heating industrial applications the combustion of WDFs or biomass is typically complemented by fossil fuels– or electrification or hydrogen. EfW plants making use of WDFs represent a high local demand for these fuels. Long-term contractual obligations between the waste collection party, MRFs operators and EfW plants operators, many times integrated under one company, limit the availability of WDFs for industry. However,

[27] Committee on Climate Change, 2018, Biomass in a low-carbon economy, pp. 118-119.

Box 3 – Other low-carbon fuels

in order to avoid EfW plants' gate fees[28] the combustion of biogenic residues can result an economically attractive decarbonisation pathway for industrial sites that generate large volumes of these residues.

If unabated, the combustion of WDFs and biofuels can result in high air pollution, with emissions of particulate matter, NOx and SOx, among other contaminants. The combustion of WDFs is of particular concern. Switching to WDFs would require the post-combustion treatment of the raw flue gas to comply with emissions limits. The use of WDFs implies compliance with waste regulations in handling, storage, and use of the fuel.

Opportunities for deployment

Fuel switching to biofuels is particularly relevant for industries that generate organic process residues – food and drink, paper and pulp[29], wood processing. Out of these, there are only food and drink sites in the Humber. The sector is relatively small in the Humber. It includes three plants operated by AAK, Greencore Grocery, and Muntons, with total emissions of 41 ktCO_2/year as shown in Figure 7. Residues from these plants, or from forestry and agricultural residues from the Humber region, can be used to operate boilers in many industrial facilities. However, the supply chain limits the scale of biomass fuel switching, especially when it is not combined with CCS (see discussion of bioenergy with carbon capture and storage (BECCS) in Section 4.1.

The potential for increased use of WDFs in the Humber is limited. The use of SRFs for lime production, despite the broad similarities between lime and cement production processes, is not attractive. Whilst SRsF are extensively used in the cement sector, the only cement plant in the Humber ceased production in 2020. Although there are some examples of lime kilns burning biomass, retrofitting to switch to biomass would involve large investments. For instance, adapting the injection and the burners, or pre-treating the fuel, would be required. Contaminants and ashes from WDFs would be incorporated into the lime negatively affecting the purity requirements. The most efficient lime kilns – parallel flow regenerative lime kilns (PFRK) – burn mainly gas. The lime kilns operated by Singleton Birch in the Humber belong to this category. They could incorporate WDFs or biomass if it were pulverized or gasified, but significant modifications would be required to allow for the combustion of solid lumps. Biogas, on the other hand, can be burnt by PFRK without further modifications. Biogas is already being produced and used by Singleton Birch at low replacement rates.

WDFs are already used in the Humber in EfW plants. A new EfW power station in the Humber – the South Humber Bank Energy Centre – was granted a development consent order (DCO) in November 2021. The South Humber Bank Energy Centre will make use of over 2,000 tonnes of WDFs per day; with a UK average volume of household waste of 392 kg per person[30], it would process waste from almost 2 million people. Hence, it is likely to attract most of the local supply of WDFs and reduce availability for industry. The use of WDFs in EfW plants produces some electricity and heat and reduces waste sent to landfill. If combined with CCS, it could lead to net negative emissions as the biogenic emissions are sequestered.

2.1 Electrification of industrial heating

2.1.1 Overview

Fuel switching through electrification results in **no on-site emissions** and can be highly efficient compared to combustion. This is especially the case for heat pumps in low-temperature applications. Electrification comprises **various technologies**. The most suitable electrification technology will depend on the **process that**

[28] Gate fees are the charge paid by the holder or collector of waste to the operator of a waste processing facility.

[29] Although technically possible, fuel switching to biomass is expected to play only a marginal role in further decarbonising the UK paper industry. Confederation of paper industries 2021, Decarbonising the UK Paper Industry: Going beyond 80% to zero carbon – is it currently feasible to replace natural gas?

[30] Statista, 2022. Retrieved from: https://www.statista.com/statistics/322535/total-household-waste-volumes-in-england-uk-per-person/.

is being switched and, for direct heating applications, on the **product's characteristics**. Table 5 presents a non-exhaustive list of electrification technologies for industrial sites. Other options include microwave heaters, electric compressors, electric arc furnaces (EAFs), electric dryers etc.

Table 5: Electrification technologies and applicability to industrial heating processes

Potential technologies	Applicable processes/sectors
Electric boiler (immersion or electrode)	Steam driven processes
Electric process heater	Indirect low-temperature heating
Electric oven	Direct low-temperature heating
Electric kiln, electric plasma gas furnace	Direct high-temperature heating
Heat pump (open or closed loop)	Low temperature indirect heat (inc. steam)
Electric arc furnaces	Direct high-temperature heating

Considerations around the electricity supply for electrification technologies have a direct impact on the suitability of electrification as a fuel-switching option. The current **capacity of the electricity network** may not be sufficient to meet the increased demand for electrical power, potentially requiring **major upgrades to the grid infrastructure before** electrification of large heating processes can happen[31]. Upgrades can take up to 7 years to complete and costs can run into several millions for an individual industrial site. Also, electrification may expose industrial users to a **lower reliability of supply** as they become exposed to grid supply risks, unless accompanied by the parallel deployment of large-scale energy storage (which is currently a high-cost solution).

Decarbonisation potential

Electrification fully eliminates direct emissions within the site (Scope 1 emissions), shifting them to indirect emissions from the generation of electricity (Scope 2). Provided all electricity comes from renewable resources, electrification has the potential to fully eliminate Scope 2 emissions too. The effect of electrification on all other indirect emissions not related to purchased energy (Scope 3) can be varied, depending on the level of embodied emissions relating to renewable generation assets and electrical appliances.

Electricity generation from non-renewable sources may reduce the net decarbonisation benefit of fuel switching via electrification pathways because the electricity grid has not been fully decarbonised yet. The total emissions are only reduced if the **carbon intensity of the grid** is lower than the carbon intensity from processes burning fossil fuels on site. Hence, for a site switching via electrification, Scope 2 emissions will represent a larger share of total emissions. This presents both an opportunity and a risk: industries can leverage on the grid decarbonisation efforts without additional capital investments, but they will have less control on the speed and level of decarbonisation. As the electric grid becomes increasingly decarbonised, electrification allows industrial emitters to reduce their Scope 2 emissions without additional capital investments.

Technology status

The maturity of electrification technologies is generally higher than that of hydrogen technologies for low temperature heat. Electric boilers, process heater and ovens have a technology readiness level (TRL)[32] of 9, whilst large industrial heat pumps have a TRL 8–9 – although it can be lower for some high-temperature heat pumps. In contrast, technologies which provide direct high temperature heating are highly sector-specific and

[31] A comparable issue exists in the case of hydrogen fuel switching, due to unavailability of hydrogen infrastructure today.
[32] Technology readiness levels are used to estimate the maturity of emerging technologies on a scale from 1 (basic principles observed) to 9 (system proven in operational environment and is commercially available).

have a lower maturity. For instance, electric glass furnaces and electric ceramic tunnel kilns are considered to have a TRL of 7. Ongoing research and development efforts are focusing on high-temperature heat pumps and on the re-design of primary processes.

Cost considerations

For most electrification options, switching would cause an increase in the cost of energy that is hard to justify from a commercial perspective, even after including projected carbon prices and efficiency savings. Whilst the capital cost of electric boilers is equivalent to the cost of fossil fuel-fired appliances, appliances such as heat pumps have a much higher capital cost.

The operating cost depends on the unit cost of electricity and on the efficiency of the appliances. The cost of electricity faced by an industrial is largely a political choice, however, the UK currently faces some of the highest industrial electricity prices in Europe. Today, the unit cost of electricity is significantly higher than for natural gas. For electrification technologies like heat pumps, their higher efficiency compared to fossil fuelled appliances and their ability to provide demand-side response services to the grid could at least partly offset the greater cost of energy inputs, and hence make them more cost effective. Other electrification technologies will face higher energy costs than their fossil-fuel counterfactual, unless the cost of fossil fuels (inclusive of the cost of the associated carbon emissions) increases. The cost differential between electrification and the continued use of fossil fuels could strengthen the business rationale for investing in energy efficiency measures, or the development of hybrid technologies that can operate using both electricity and other fuels.

Additional conversion costs include grid reinforcement and scrappage costs. If grid reinforcement is required, the connection costs and the total capital requirement would climb further, however, Ofgem have announced that costs of these new connections will be shared in a fair and proportionate way amongst all network users with updated charging reforms set to come into effect from April 2023[33]. A site-by-site assessment to determine the spare capacity of the distribution grid is needed to better understand the impact of grid reinforcement costs on Humber industries. The scrappage cost of fossil fuel-fired appliances can be significant, as under electrification appliances cannot be retrofitted and need to be replaced. To reduce scrappage costs, industrial emitters could decide to wait until the end of life of their existing appliances.

Energy and resource implications

Electricity demand from industry would grow substantially following wide-spread electrification. Despite this, primary energy demand will instead likely *decrease* when compared to the continued use of fossil fuels due to the higher efficiency of electrical appliances (heat pumps in particular). Additionally, **primary energy demand under a direct electrification pathway will be lower compared to switching to electrolytic hydrogen**, since the end-to-end efficiency of the electricity supply chain is higher when compared to that for electrolytic hydrogen. For instance, over a quarter of the energy powering water electrolysers is lost in the processes, whereas electricity transmission and distribution losses amount to less than 10%[34].

Renewable electricity will typically be sourced from the grid with renewable power purchase agreements (PPAs) or in some cases via a private wire connected directly to renewable assets. Private wire connections can often enable electricity consumers to access electricity at well below market rate as transmission via the electrical grid and the associated system costs are completely avoided. Renewable PPAs allow the existing grid infrastructure to be utilised, therefore removing the barrier to renewable electricity access to many industrial sites that are located large distances from renewable sources. This also allows operation to be maintained 24-hours per day, as the supply of electricity is not dependent on local renewable generation.

In terms of demand on primary resources, electrification technologies rely on raw materials mined overseas. A global trend towards electrification across multiple sectors is expected to lead to a steep increase in the demand for some critical minerals[35]. These minerals include lithium, nickel and cobalt for lithium-ion batteries, rare earth

[33] Ofgem 2022, Changes to charging: How Ofgem is preparing for a very different grid.
[34] A comparable end-to-end energy efficiency can be estimated for CCS-enabled hydrogen, due to energy losses in the reforming and to operate the CO_2 infrastructure (including compressing or liquefying CO_2).
[35] IEA, 2022, The Role of Critical Minerals in Clean Energy Transitions.

elements for permanent magnets, copper for electricity networks and electric appliances, and graphite for electric arc furnaces and batteries. Increased demand can lead to higher prices and supply chain bottlenecks. For instance, growing demand from electric arc furnaces and for electric mobility has already led to a graphite electrode shortage and to a steep increase in copper prices[36]. Increased recycling of materials such as copper will be key for lowering costs and ensuring productive supply chains are maintained.

Infrastructure requirements

Electricity demand is expected to increase substantially in this pathway, and a corresponding expansion of low-carbon generation capacity will be required to guarantee the low-carbon credentials of electrification. Because the current capacity of the electricity network may not be sufficient to meet the increased demand for electrical power, electrification of large heating processes may require substantial upgrades to the grid infrastructure, especially in cases where industrial sites connect directly to the distribution network. High penetration of variable renewable energy sources may also result in an increased volatility in electricity supply, which may in turn necessitate large-scale deployment of energy storage or alternative flexibility measures such as demand-side response[37].

Land availability could potentially be an issue for some industrial sites. Heat pumps, for instance, are larger than their fossil-fuel alternatives. This issue is nevertheless less significant than for other decarbonisation pathways such as carbon capture. Behind-the-meter battery storage to replace back-up diesel generators can also be challenged by space constraints, although the stakeholder engagement process revealed this is not a major barrier for most Humber sites.

2.1.2 Market study

Opportunities for deployment

Electrification is potentially applicable to most heating processes in the Humber that currently use purchased fossil fuels. However, the potential for electrifying each heating process differs. For **low-temperature heating**, commercially available electrification technologies can generally lead to a complete fuel switching. For **high-temperature heating,** the maximum attainable level of switching may be constrained in the short and medium term and *partial* electrification is only possible. For instance, electric furnaces can be used to boost glass furnaces at the Guardian Industries site, although the energy cost can be prohibitive under current prices. **Electrification could also replace natural-gas-fired CHP units**; electricity would in this case be directly sourced from the grid while heat pumps and/or electric steam boilers would deliver the required heat.[38] Electrification can be pursued in iron and steel production with British Steel **switching from the primary to the secondary route**. Out of the 11 million tonnes of scrap steel the UK produced per year, only 23% is recycled in domestic steelmaking, with the remainder exported[39]. This contrasts with other markets, where use of scrap in electric arc furnaces (EAFs) is constrained by scrap supply, and it represents an opportunity for decarbonisation.

Market risks and barriers

The market risks and barriers associated with electrification are outlined in Table 6[40]. The main ones are:

[36] For news coverage of price increases, see for example Reuters, 2017, The graphite fix: Inside China's newest commodity addiction or North of 60 Mining News, 2021, A supercharged surge in copper prices.
[37] The potential of engaging in demand-side response may be limited to processes that do not require continuous operation or which operate with thermal buffers like steam.
[38] In this case, electricity supplied today by the CHP plant would need to be obtained from the grid. This could increase the cost of electricity compared to today's level. Further analysis would be required to establish the comparative cost of grid electricity with a CHP unit with CCS of fuelled by hydrogen.
[39] Hall et al, 2021, Domestic Scrap Steel Recycling – Economic, Environmental and Social Opportunities.
[40] See Section 1.2 for definitions of risks and barriers.

Table 6: Market risks and barriers for electrification

Risks	Description
Uncertainty on long-term electricity cost	The future price of natural gas, carbon, and electricity is very uncertain and depends on internal and external factors alike. This uncertainty is not currently addressed by policy instruments, hindering the business case for electrification.
Technology path dependency	If fossil fuel-fired appliances are upgraded in the next few years, the long lifetimes and low rate of capital stock turnover might lead to technology lock-in, as electrification would be delayed for at least one additional investment cycle.
Supply-chain constraints	Some technologies already face bottlenecks in the raw materials supply chain. There could also be a skilled labour shortage as the required skillset changes. For instance, local industries have identified a shortage of electrical engineers.
Uncertainty on most cost-effective pathway	It is not yet fully clear which approach (electrification, hydrogen fuel switching, or CCS) will be most cost-effective for each industrial sub-sector. The evaluation is susceptible to future factors such as changes in energy and carbon prices. Opting for an approach today can result in a suboptimal choice.
Grid reliability risks	Electrification exposes industrial users to the grid reliability risks. Alternatives to back-up diesel generators (like battery storage) would have low load factors and a high capital cost, which would likely defer investment on them to a later date.
Renewable generation capacity	There are concerns about the availability of electricity for industrial demand if low-carbon generation capacity does not ramp up as required. Also, many forms of industrial demand lack flexibility for demand-side response, which might be needed to cope with intermittent electricity sources. As a result, there may be limited 24-hour dispatchable capacity.
Scrap sorting and quality	Scrap sorting standards are insufficient to ensure scrap can be easily recycled into high grade steel. Even after improving sorting standards, the secondary route would still be unsuitable for some applications. The presence of undesirable elements in scrap such as copper, that are hard to remove from steel once incorporated, affects the final steel composition. The Scunthorpe site, for instance, manufactures steel rails with a low copper tolerance which can only be produced by the primary route.
Barrier	**Description**
High electricity cost	Switching to electrification could cause a substantial increase in the cost of energy, compared to the continued use of fossil fuels (even after including the cost of carbon). Local industries choosing to electrify today would face increased energy costs and reduced competitiveness, thus disadvantaging the Humber compared to other UK industries that choose not to decarbonise.
High capital costs for some technologies	Under electrification, current fossil-fuelled appliances need to be replaced. Capital costs remain high for some electric equipment, like heat pumps or equipment for high-temperature heating. While mass-production could reduce the cost of electrical equipment in the long term, policy support is likely to still be required in the shorter term.
Need for costly network reinforcements	Electrification of large heating processes may only be possible after major upgrades to the grid infrastructure, which is, in many cases, a costly operation both for the grid operator and for industrial end-users.
Requirement to meet specific heating profiles	In direct heating applications, the heating profile often directly impacts product quality and there might be a strict requirement to meet a specific heating profile. Some electrification technologies might be rendered unsuitable as they may not be able to reach the specific heating profile
Lack of knowledge of the technical possibilities	With electrical heating equipment not currently being mainstream yet, there is a lack of successful implementation examples in some sectors, particularly for high-temperature direct heating. Lack of knowledge and information about electrification technologies will hinder its application. Furthermore, the lack of pilot projects – and the consequent lack knowledge and information about the electrification technologies – results in limited awareness of and trust towards this pathway. Pilot projects and demonstrations in real applications can increase the perception of reliability.

2.1.3 Policy study

Policy status and future enablers

BEIS business model

There is currently no business model to support the electrification of industrial processes.

Funding mechanisms

To date, there has been limited development of policy that incentivises the electrification of industrial processes. The CCC's Policies for the 6th Carbon Budget identified that industrial electricity prices are well in excess of costs that would reflect the supply of extra inexpensive low carbon electricity from renewable sources such as offshore wind. The CCC recommend that electricity pricing should be reformed to reflect the much lower costs of supplying low carbon electricity in the future, incentivising fuel switching via electrification. In July 2022, Department for Business, Energy and Industrial Strategy (BEIS announced the 'Review of electricity market arrangements' consultation that ran until October 2022[41]. The consultation aims to review a range of options to deliver an enduring electricity market framework that will work for businesses, industry, and households.

Today, funding for fuel switching via electrification is only available via the BEIS's Industrial Fuel Switching Innovation Competition and Industrial Energy Transformation Fund (IETF). BEIS launched the Industrial Fuel Switching Innovation Competition in October 2021 as part of the Net Zero Innovation Portfolio (NZIP) with the aim to support innovation in the development of precommercial fuel switching to help industry switch from high to lower carbon fuels. Up to £20m of funding will be made available for electrification in two phases, with Phase 1 focusing on feasibility studies and Phase 2 considering demonstration projects with grant funding of up to £6m per project. The innovation competition aims to develop and test industrial electric technologies (electric boilers, kilns, furnaces and heat pumps), microwave, infrared or induction heating systems and storage systems or other infrastructure that supports fuel switching to renewable electricity.

The IETF has a total budget of £315m up to 2025[42], however, significant portions of this fund are expected to go to alternative decarbonisation technologies other than electrification. The IETF aims to support the development and deployment of technologies that allow industries to transition to low-carbon solutions such as the process electrification The fund aims to support late-stage innovation projects (TRL 7+) from feasibility studies to deep decarbonisation deployment. Although there is currently no business model for industrial electrification, electrification policy for industry is currently being considered by BEIS. As a result, it is possible but not guaranteed that a business model may be developed in the future.

Policy risks and barriers

Many of the market-specific risks shown in the above section represent an increase in manufacture cost that would likely need to be passed on to consumers via higher product prices. As the price of products increases, these will face uneven competition from unabated products imported from abroad and could therefore lead to carbon leakage, as discussed in section 1.4.1.

The policy risks and barriers associated with electrification are outlined in Table 7. Sector specific policies for electrification will work alongside overarching policies that cut across multiple sectors. Overarching policies are discussed in more detail in Chapter 1.4.

[41] BEIS 2022, Review of electricity market arrangements.
[42] BEIS 2022, Hydrogen Investor Roadmap

Table 7: Policy risks and barriers for electrification

Risks	Description
Lack of financial risk coverage	There are major financial risks, mainly from the uncertainty over future energy prices, and these risks are not covered by current policy instruments.
Uncompetitive commodities	Many industrial products from the Humber are commodities. The lack of suitable carbon border adjustment mechanisms could lead to carbon leakage and uneven competition from unabated imported products.
Barrier	**Description**
Tariff structure and flexible operation	Currently, companies pay a variable fee plus a fixed fee on contracted capacity. This can be prohibitive for electrification options with a flexible nature, where capacity fees apply for the whole year but there is a low load factor.
Lack of incentives and business model for electrification	Industrial electricity prices are well in excess of costs that would reflect the supply of extra low-carbon electricity from renewable sources[43]. In effect, industrial electricity prices in the UK are higher than those in continental Europe. The UK electricity market has a more even distribution of network costs across all consumers (and hence industrial end-users face high network costs), and an electricity system that does not promote long-term electricity contracts or collective negotiations[44]. While business models are being proposed by BEIS to support uptake of CCS and hydrogen, no business model for electrification has been proposed to date.

2.1.4 Regulatory study

Health, safety, and environment

Fuel switching faces additional regulatory barriers linked to the health, safety, and environment (HSE) risks posed by the technologies. For the electrification of industrial heating, there are few additional safety or environmental risks. One safety risk is the use **of refrigerants for heat pumps.** Mechanical heat pumps operating at above 80 °C use ammonia, n-butane, hydrofluoroolefins (HFOs) or CO_2 as refrigerants. The use of these refrigerants creates a safety risk to be addressed by regulations.

Demand on water resources is another key consideration for the Humber region when determining the optimum decarbonisation pathway. **Electrification pathways are likely to have significantly lower water demand** when compared to hydrogen fuel switching and CCUS alternatives on a life-cycle basis[45]. This is because electrification does not require water as a feedstock in the process whilst also requiring lower process cooling requirements. As the Humber is likely to be a water stressed area by 2050, electrification processes may be required to ensure water resources can be managed sustainably.

Electrification approaches also have the environmental **co-benefit of a reduction in air pollution**. In effect, not only does it tackle direct CO_2 emissions, but it also eliminates the emission of air pollutants such as particulate matter (PMs), nitrogen oxides (NOx), or sulphur oxides (SOx). However, there is a safety risk related to mechanical heat pumps that use ammonia or n-butane as refrigerants[46]. The hazards associated with these refrigerants call for extra safety measures.

Planning requirements

Please refer to the planning requirements discussed in Section 2.2.4 for hydrogen fuel switching, which also apply in the case of electrification. It is also worth noting that, as with any fuel switching, it would be necessary to assess whether any of the new infrastructure will require consent. Given that the size and scale of infrastructure can vary significantly, this would need to be assessed on a case-by-case basis.

[43] Committee on Climate Change, 2020, Policies for the Sixth Carbon Budget and Net Zero.
[44] Grubb & Drummond, 2018, UK Industrial Electricity Prices: Competitiveness in a Low Carbon World.
[45] Meldrum et al 2013, Life cycle water use for electricity generation: a review and harmonization of literature estimates.
[46] Berenschot, 2017, Electrification in the Dutch Process Industry.

Permitting requirements

Electrification is the process of replacing technologies that use combustion of fuels (such as coal, oil, natural gas, hydrogen) with technologies that run on electricity (e.g. electric furnaces, electric boilers). Switching to technologies to run on electricity could result in substantial changes to the equipment used and required on site. It is considered unlikely in this event that partial switching is an option, given the need for equipment changes.

In the event that activity is entirely electrified, then it would be necessary to assess whether there were any remaining emissions to air, water, land or sewer from the industrial site. The emissions from combustion will have been removed. A variation to an existing permit would be necessary for the changes and would remove combustion related elements (including the ELV requirements). New emissions, if relevant, from the electrified process would need to be added as part of the same variation.

The Large Combustion BREF and Medium Combustion Plant Directive relate to combustion activities as burning a fuel. These will not be applicable for appliances that have been changed to electrically powered. Other BREF/BAT requirement associated with the relevant sector may still be applicable.

Not all combustion processes are suitable for fuel switching and should be considered carefully to ensure that they can still operate effectively/still function for its primary purpose. There is no specific guidance for fuel switching via electrification, but the changes would need to comply with the relevant BREF(s)/Directive still applicable.

Regulatory risks and barriers

The regulatory risks and barriers related to electrification are presented in Table 8.

Table 8: Regulatory risks and barriers for electrification

Risks	Description
Lengthy consenting timelines for renewable generation	Large scale renewable energy projects can face lengthy consenting processes before construction can commence. For commercial wind farms, pre-application to final determination of the necessary consents, the process is estimated to take from between 3-5 years before construction can commence[47].
Barrier	**Description**
Inconsistent planning application	The consenting regime (DCO or TCPA) is poorly defined for electrification technologies. Gaining planning permission will be dependent on the clarity of the application.
Changing output streams	Electrification of existing processes will have design implications that would need to be considered to ensure that existing or new emission limit values can still be met.

2.1.5 Recommendations and actions

The risks and barriers outlined above cover the market, policy and regulatory dynamics of electrification. In considering actions to mitigate those risks and barriers, there is merit to considering actions in the context of all three of these dimensions, due to the overlapping benefits which arise.

Drawing on the stakeholder discussions held, reviews of the literature, and Element Energy's own market insights, the following set of action categories are recommended to help actors within the Humber cluster navigate what is a complex market. These actions would either be considered the responsibility of industries operating within the Humber cluster, policy makers, and regulators.

[47] Catapult 2021, Floating offshore wind development and Consenting process.

Action 1: Reform industrial electricity prices

The UK's energy intensive industries already face some of the highest industrial electricity prices in the world. Increased electrification could severely damage the competitiveness of industrials who decarbonise, as production is highly exposed to international competition, meaning additional costs cannot be transferred to customers. Industrial electricity pricing should be reformed to reflect the much lower costs of supplying low-carbon electricity in the future, hence incentivising fuel switching via electrification. The UK Government and Ofgem (the energy sector regulator) should look to address the industrial price disparity, levelling electricity prices in line with competition abroad to ensure that industry can invest in low-carbon electricity-based production methods. Ofgem recently introduced updated Distribution Use of System (DUoS) charges in April 2022, because of changes instigated by Ofgem's Targeted Charging Review (TCR). A greater proportion of distribution costs are to be recovered through fixed charges, resulting in an increase in daily standing charges and a reduction in unit rates. This could result in higher costs for energy intensive industries further disincentivising electrification. Price reform is therefore essential if electrification is to be considered at scale. The ongoing 'Review of electricity market arrangements' is an excellent opportunity to do so.

Action 2: Identify potential constraints on the existing electricity network

The development of new infrastructure could place significant additional loads on the electricity network. This is likely to be primarily from energy intensive equipment for electric heating processes, such as electric arc furnaces or from air separations units (ASUs). Electricity distribution networks should identify potential constraints in the existing electricity distribution infrastructure in different parts of the Humber, that could limit the deployment of electrification. Northern Powergrid are the electricity distribution network operator (DNO) in the Humber region and should conduct early feasibility studies that identify constraints in the existing infrastructure. These studies would inform a more accurate representation of the total system cost of the electrification pathway and highlight geographical differences. Constraints need to be identified early on, at the feasibility stage of large electrification projects.

Action 3: Ensure the cost of infrastructure is borne by those better able to do so

Distribution grid upgrades can be costly and may render electrification prohibitively expensive if the costs are to be borne by industrial operators. The upfront cost of infrastructure upgrades should be borne by Northern Powergrid, the DNO. Appropriate business models should be introduced by BEIS to facilitate investment in the local electrical infrastructure, in equivalence to how the TRI model facilitates investment in CO_2 transport and storage infrastructure.

Action 4: Incentivise the electrification of industrial processes

There has been limited development in policy incentivising the electrification of industrial processes. To date, policy support has focused primarily on CCS and hydrogen production in industry. Electrification of industrial processes should be supported / subsidised by government in a comparable manner to alternative pathways. Otherwise, market distortions can incentivise the adoption of the least cost-effective alternatives and, because of the technology path dependency, lock in sub-optimal decarbonisation options. This could come in the form of a new business model by BEIS for industrial processes. Again, the ongoing 'Review of electricity market arrangements' provides an opportunity to discuss potential incentives or business models.

Action 5: Increase innovation and deployment funding

Innovation projects are a key stage in advancing a technology to enable large scale deployment. To date, there have been limited innovation projects exploring how processes can be electrified in different industrial sectors. Increased funding should be allocated to innovation and pilot projects that demonstrate the electrification of industrial processes. Pilots and demonstrations in real applications can increase the perception of reliability. BEIS should develop a dedicated electrification fund that aims to support projects with significant potential for application at industrial scale (small, medium, and large). This could work in parallel with the existing Industrial Energy Transformation Fund (IETF) and Industrial Fuel Switching Innovation Competition. Increased focus should be placed on supporting electrification in industry immediately to avoid sub-optimal decarbonisation options being selected by some industrial sectors.

Action 6: Develop electricity tariffs that incentivise flexible operation

Currently, companies pay a variable fee plus a fixed fee on contracted capacity. This can be prohibitive for electrification options with a flexible nature, where capacity fees apply for the whole year but there is a low load factor. Electricity distribution network operator (DNOs) such as Northern Powergrid should develop tariffs that are designed for flexible operation. This should be done alongside Ofgem to incentivise electricity intensive low-carbon technologies. Project developers will be looking to conduct feasibility studies for electrifying processes from 2023. Clarification on the expected tariff structure will be required at FEED stage to ensure projects can reach FID.

Action 7: Support large-scale energy storage development

There are concerns about the availability of electricity for industrial demand if low-carbon generation does not ramp up as required. Also, many forms of industrial demand lack flexibility for demand-side response, needed to cope with intermittent electricity sources. Large scale energy storage could provide industry with the reliability of supply needed to operate when renewable generation is low. The UK government should continue to expand renewable generation capacity whilst simultaneously providing funding support (via BEIS) for large scale energy storage technology development. BEIS have already released £100 million in innovation funding for energy storage as part of the NZIP. However, further funding will need to be made available to develop promising technologies at commercial scale. This is likely to be required to support technologies up to FID.

2.2 Hydrogen for industrial heating

2.2.1 Overview

Hydrogen fuel switching allows for the conversion of equipment maintaining similar processes and site set up, as it shares broad similarities with natural gas. Because of this, hydrogen fuel switching offers a high potential, notably for **high temperature heating** applications. As shown in Table 9, there are various hydrogen technologies under development for each process and sector.

Table 9: Hydrogen fuel switching and applicability to industrial heating processes

Potential technologies	Applicable processes/sectors
Hydrogen boiler	Steam-driven processes
Hydrogen oven and hydrogen heater	Direct low-temperature heating
Hydrogen furnace and hydrogen kiln	Direct high-temperature heating
Hydrogen CHP	Replacing gas-fired CHP

Decarbonisation potential

Like in the case of electrification, **hydrogen combustion results in no on-site CO_2 emissions, fully eliminating Scope 1 emissions** for industrial users, apart from any global warming potential (GWP) associated with releases of H_2 itself.[48] The abatement potential of hydrogen fuel switching is thus solely linked to the level of emissions associated with hydrogen production and supply and with the upstream supply chain (Scope 3, also known as "embodied").

Different types of low-carbon hydrogen include electrolytic hydrogen, produced from the electrolysis of water powered by dedicated renewable energy sources (and often referred to as "green hydrogen"), and CCS-enabled

[48] Derwent et al. (2006) calculated an indirect 100-year GWP of 5.8. More recently, a GWP of 11 has been estimated by Warwick et al for BEIS, 2022, Atmospheric implications of increased hydrogen use.

hydrogen, produced via the reforming of natural gas in combination with CCS ("blue hydrogen"). Electrolytic hydrogen is generally assumed to be carbon neutral so long as it is produced with zero-carbon electricity, though the relatively higher embodied emissions from electrolysers and the associated infrastructure should be carefully considered when assessing the net decarbonisation benefit[49]. The UK has developed a low-carbon hydrogen standard that defines what constitutes low-carbon hydrogen at the point of production. Hydrogen producers proving compliance with the standard are required to meet a greenhouse gas emissions intensity of $20gCO_{2e}/MJ_{LHV}$ of produced hydrogen or less to be considered low carbon[50]. Today, the emissions intensity of natural gas-based steam methane reforming (without CCS) is approximately $80\text{-}90gCO_{2e}/MJ_{LHV}$[51]. Although electrolysis and natural gas-based production combined with CCS are likely to be the two primary production pathways for low-carbon hydrogen in the future, hydrogen can also be produced from biomass feedstocks as well as from the gasification of coal which can be deployed with CCS. Producing hydrogen from biomass in combination with CCS can lead to negative emissions hydrogen, as covered in Section 4.1.

Residual emission from CCS-enabled hydrogen can instead vary significantly depending on:

- The **CO_2 capture rate** (affecting Scope 2), which is expected to range from 90% to 95% or higher[52].
- **Upstream emissions** within the natural gas extraction and processing supply chain (Scope 3), which mainly depend on the source of natural gas and the associated methane leakage, meaning that hydrogen producers have limited control over these.
- Upstream emissions from natural gas production and transport varies significantly by source. Generally, upstream emissions from liquefied natural gas (LNG) transported over long distances are substantially higher than emissions from natural gas transported small distances by pipeline. Emissions from natural gas transported by pipeline show a strong regional variation and are subject to high uncertainty. Natural gas produced in the UK or Norway from the North Sea, which supply the Easington gas terminal in the Humber, show low fugitive emissions[53], estimated at below 0.5%[54]. The Committee on Climate Change (CCC) considers that CCS-enabled hydrogen can reduce emissions relative to unabated natural gas use by 60% to 85% on a lifecycle basis[55], provided the natural gas feedstock is not associated with a high methane leakage rate[56]. Methane leakage emissions exhibit large variability globally and selecting an average is difficult[57]. Consequently, **if the amount of LNG compared to domestically produced gas used in the UK increases in the future, then average upstream natural gas emissions will tend to increase** unless there is a parallel push to reduce natural gas supply chain methane emissions.

Table 10: Emissions associated with hydrogen fuel switching

	Scope 1	Scope 2	Scope 3
Electrolytic hydrogen	Fully eliminated	No emissions	Embodied emissions of electrolysers and renewable generation assets
CCS-enabled hydrogen	Fully eliminated	Dependence on the capture rate and the efficiency of the conversion	Methane leakage and other upstream emissions Embodied emissions of key assets, including reformer and CO_2 infrastructure

[49] Further information on embedded emissions (Scope 3) relating to the manufacturing of hydrogen production equipment can be found in previous work by E4Tech for BEIS, 2019, H_2 emissions potential: literature review.
[50] BEIS 2022, UK Low Carbon Hydrogen Standard
[51] BEIS 2021, Consultation on a UK Low Carbon Hydrogen Standard
[52] Higher capture rates are technically possible but may not be economically favourable.
[53] International Energy Agency, 2022, Methane Tracker Database.
[54] Bauer et al, 2022, On the climate impacts of blue hydrogen production.
[55] Committee on Climate Change, 2018, Hydrogen in a low-carbon economy.
[56] A methane leakage rate of 3.5%, considered more representative of natural gas supply from the United States, could result in significantly lower GHG savings, as reported by Howarth & Jacobson, 2021, How green is blue hydrogen?
[57] Bauer et al, On the climate impacts of CCS-enabled hydrogen production.

Technology status

The TRL of hydrogen fuel switching is highly process specific. As a generalisation, for high-temperature heating hydrogen fuel switching has a similar TRL as electrification, although it has a lower maturity for low temperature heating. Still, if the technical challenges are resolved hydrogen fuel switching technologies could find **fewer barriers to market** due to their likeness to gas-fired equipment. Conversely, the electricity grid infrastructure is already established whereas the hydrogen infrastructure development required for fuel switching is yet to commence. Despite the broad similarity, the differences in the combustion of hydrogen and natural gas present some technical challenges including higher flame temperature, lower heat transfer, higher NOx emissions, higher leakage potential, embrittlement of metals, and different flue gas composition.

There is strong R&D activity in burner design to address these issues. Hydrogen boilers and indirect dryers are considered to have a TRL 7. Direct heating technologies are less mature, with kilns and furnaces having TRL 5–6.

Cost considerations

Low carbon hydrogen is not yet available at commercial scale. Hence, while its current cost is much higher than the fossil fuels that it would replace, production costs are expected to substantially reduce with time and possibly achieve lower hydrogen retail fuel price per kWh than electricity. Hydrogen equipment has, in broad terms, a **higher capital cost** and a **lower operating cost** than electrification alternatives. The main variables that influence cost are:

- **Energy costs**: in summer 2021, BEIS estimated levelized production costs of 5.6-6.2 p/kWh for CCS-enabled hydrogen and 13.3-14.8 p/kWh for electrolytic hydrogen[58], at a time when the natural gas price for industrial users averaged 1.83 p/kWh[59,60]. It is generally expected that hydrogen cost will reduce substantially with time – the Hydrogen Council estimates that the production cost could drop below 2 p/kWh by 2050, for a natural gas price of 0.7-1.8 p/kWh[61]. Moreover, the proposed hydrogen business model would lower the retail price for hydrogen. The expectations in the early phases of market development are that electrolytic hydrogen will have a higher cost than CCS-enabled hydrogen, but under the hydrogen business model users would not face a price differential[62]. Electrolysers can operate flexibility, for example only operating when energy prices are lower and so reducing operational costs; however, this will mean that the capital cost is amortised over fewer operating hours as the load factor reduces[63]. Therefore, the sensitivity of the load factor on hydrogen cost will be dependent on the capital intensity of the project.
- **Retrofitting/replacement**: unlike electrification, most equipment can potentially be retrofitted and converted to run on hydrogen[64]. This allows for earlier switching for fossil fuel-fired appliances with a high remaining lifetime than for electrification. For steam-driven processes the conversion cost is lower than for direct-heating applications. Figure 10 shows the conversion cost for a sample of equipment types, which evidences the higher costs for direct heating applications. Also, a key issue in using hydrogen in furnaces will be around instrumentation, in particular safety systems such as flame out detection as hydrogen flames have a lower emissivity than natural gas flames.
- **Site conversion**: replacement of on-site pipework material as a result of stricter standards and an increased pressure requirement might be needed – as hydrogen has a lower volumetric energy density than natural gas the flow rate needs to increase. The capital requirement for the site conversion adds to the equipment cost.
- **Emissions reduction**: the NOx concentration in the raw flue gas may significantly increase because hydrogen burns at a higher temperature than hydrocarbons; tackling the increase of NOx emissions has

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[58] BEIS, 2021, Hydrogen production costs 2021.
[59] BEIS, 2022, Prices of fuels purchased by manufacturing industries.
[60] The natural gas price constitutes approximately 60% of the levelised cost of CCS-enabled hydrogen, whereas the electricity price accounts for approximately 80% of the levelised cost of electrolytics hydrogen. UK Energy Research Centre 2022, The impact of increased energy costs on decarbonising UK industry
[61] Hydrogen Council, 2021, Hydrogen Insights.
[62] For more detail on the hydrogen business model, see Section 7.3.2.
[63] Hydrogen Council, 2020, Path to Hydrogen Competitiveness, See Chapter 2
[64] However, other equipment like CHP engines encounter issues around ‘knock’ and ‘de-rating’ when running with high fraction hydrogen fuels and would need replacement.

cost implications. Various approaches exist, which include adding steam, recirculating the flue gas, lean combustion, or post-combustion selective non-catalytic reduction (SNCR). For high-temperature heating, the more capital-intensive selective catalytic reduction (SCR) process might be required, which would further increase the capital cost.

- **Infrastructure costs**: the development of infrastructure for transport, distribution, and storage of hydrogen will represent a large capital commitment. Storage losses and added technical challenges such as compression and conversion will likely increase the costs.

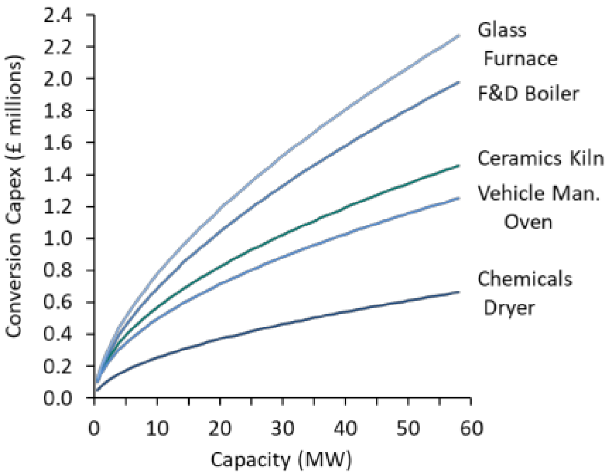

Figure 10: Conversion capital expenditure (CAPEX) for a sample of equipment types[65]

Energy and resource implications

Hydrogen production involves a transformation from hydrocarbons such as natural gas, or electricity into hydrogen. Although electrolysis and natural gas-based production with CCS are likely to be the two primary production pathways for low-carbon hydrogen in the future, hydrogen can also be produced from biomass feedstocks as well as from the gasification of coal which can be deployed with CCS. Because such a transformation will inevitably be accompanied by energy losses, **the primary energy demand from hydrogen combustion is higher than that of natural gas or switching via electrification**, irrespective of whether electrolytic hydrogen or CCS-enabled hydrogen are used. For processes switching from natural gas to **CCS-enabled hydrogen**, the primary **demand for natural gas would increase by 40-50%[66]**. Hence, there are energy security concerns associated to this pathway. There might be some exceptions where hydrogen fuel switching is accompanied by process changes, and the primary energy demand can fall as a result of that. For instance, switching to hydrogen-based direct reduction of iron (H-DRI) to replace blast furnaces, assuming that electrolytic hydrogen is used, would represent an electricity demand of 3.5 MWh of electricity per tonne of steel[67]. Although this is a very high electricity demand and switching all primary UK steel to H-DRI would demand 23% of all electricity supplied to industry[68], it is lower in primary energy terms than the BF-BOF route at 5.9 MWh per tonne of steel[69]. It should be noted, however, that electrical energy cannot be directly equated with the heating value of coal.

Infrastructure requirements

There is uncertainty around the magnitude of the infrastructure needs for hydrogen supply and storage and concerning the degree to which existing gas infrastructure could be repurposed. Early adopters of hydrogen fuel switching might need to store hydrogen above ground on site. CCS-enabled hydrogen production also relies

[65] Element Energy, 2019, Hy4Heat WP6: Conversion of Industrial Heating Equipment to Hydrogen.
[66] Assuming an average of 70% LHV fuel substitution efficiency gives 100/70 = 43% extra gas. Additional energy requirements for H_2 storage losses, or a lower conversion efficiency achieved in practice gives an approximate upper limit of 50%.
[67] Assuming all hydrogen is electrolytic hydrogen. Materials Processing Industry, 2021, Decarbonisation of the Steel Industry in the UK.
[68] Ibid.
[69] IEA, 2020, Iron and Steel Technology Roadmap.

on the development of a CO_2 transport network. As for electrolytic hydrogen, electrolysers need to be powered by additional renewable energy so that it is not diverted from the grid. The required rate of expansion of renewable energy generation and upgrades to the grid infrastructures are significant electric infrastructure challenges.

Concerning the need for CO_2 infrastructure associated for CCS-enabled hydrogen production, it should be noted that, for some industrial sectors, the total CO_2 captured when producing CCS-enabled hydrogen for fuel switching could be lower than when deploying carbon capture on existing processes. Taking the iron and steel sector as an example, if all hydrogen supplied to the H-DRI shaft furnace were to be blue, around 0.5 tCO_2 per tonne of steel would need to be captured[70], which is significantly lower than the volume injected into the CO_2 transport network if the coal-based carbon capture pathway was deployed (around 1.2 tCO_2/t steel from the blast furnace alone, as seen in Figure 8)[71].

2.2.2 Market study

Opportunities for deployment

As electrification, hydrogen fuel switching is potentially applicable to most heating processes in the Humber that currently use purchased fossil fuels, including low- and high-temperature heating, and both direct and indirect heating. Unlike electrification, hydrogen is expected to be able to lead to **complete fuel switching** (rather than partial) for high-temperature heating. Industrial power generation in the Humber can also decarbonise through hydrogen fuel switching: **hydrogen-fired turbines** can decarbonise CHP generation, although the abatement cost might be significantly higher than for carbon capture-equipped plants. Compared to carbon capture-equipped CHP generation, hydrogen turbines can operate more flexibly and could have an economic advantage at low-capacity factors, even though the end-to-end efficiency of producing hydrogen and then electricity would be fairly low. The announcement of several hydrogen production projects in the Humber, such as the H2H Saltend project[72] and the Gigastack project[73], would provide a local supply. In particular, Gigastack will allow the Phillips 66 Humber Refinery to switch hydrocarbons for hydrogen for a share of their process heaters. Moreover, the presence of **salt caverns** in the Humber allows for hydrogen storage, increasing the reliability of supply. The Rough reservoir located offshore in Humberside, stored natural gas safely for over three decades and has the potential to be repurposed provide around half of the UK's hydrogen storage[74]. If it is reopened for gas storage[75] it might not be available for hydrogen, though.

Hydrogen can be used to decarbonise the iron and steel sector, too. Conversations with local industry stakeholders highlighted that hydrogen fuel switching for secondary steelmaking is relatively straightforward as rolling mills in Scunthorpe currently run-on coke oven gas, which has a high hydrogen concentration. The decarbonisation of primary steelmaking can be achieved by switching the process to an alternative reduction of iron ore. The alternative reduction of iron ore includes hydrogen-based direct reduction of iron (H-DRI), smelting reduction, or electrolytic processes, and out of these H-DRI is the most advanced technology, being deployed across multiple sites in Europe. When hydrogen is used both as the fuel and the reductant for DRI, as an alternative to natural gas, it would produce only water as a by-product. A production route using electrolytic hydrogen could emit as little as 0.1 tCO_2 per tonne of steel[70]. Moreover, H-DRI presents transitional benefits as it can be developed in tranches, feeding sponge iron (or hot briquetted iron) to blast furnaces and basic oxygen furnaces while the capacity of the shaft furnace and EAF ramps up. Because EAFs are a key component of the H-DRI process, it allows for an increased use of scrap.

[70] Material Economics, 2019, Industrial Transformation 2050: Pathways to Net-Zero Emissions from EU Heavy Industry.
[71] However, the amount of carbon to be stored per tonne of steel would be similar if CCS-enabled hydrogen-based DRI was to be compared with natural gas-based DRI equipped with CCS.
[72] Equinor, 2020, H2H Saltend.
[73] Gigastack, 2020, Gigastack Phase 2: Pioneering UK Renewable Hydrogen.
[74] UK Parliament 2021, Written Evidence Submitted by Centrica plc (HNZ0073).
[75] Thomas, "Centrica aiming to reopen Rough gas storage at start of September", 16th August 2022, Energy Voice

Market risks and barriers

Market risks and barriers associated with hydrogen fuel switching are outlined in Table 11.

Table 11: Market risks and barriers for hydrogen fuel switching

Risks	Description
Price volatility	The price of CCS-enabled hydrogen will remain tied to that of natural gas, contributing to its volatility. This can limit uptake by industrial users aiming to reduce their risk exposure. Even if policy instruments link the hydrogen market price to that of natural gas or other fossil fuels, users would not be shielded from the energy price volatility.
Energy security concerns on CCS-enabled hydrogen	The use of CCS-enabled hydrogen leads to an increased primary demand for natural gas (or other fossil fuel feedstock)[76]. With a rising share of the gas mix being imported there are concerns over the energy security implications. It may also extend reliance on a non-renewable resource.
Sourcing of raw materials	Only high-grade iron ores are compatible with hydrogen-based direct reduction of iron (DRI). A global trend towards direct reduction might constrain access to high-grade iron ores and hence restrict the applicability of this pathway.
Technology path dependency	Industrial heating equipment typically have low replacement rates. If fossil fuel-fired appliances are upgraded in the next few years this might lead to technology lock-in, as fuel switching to hydrogen would be delayed by a full investment cycle.
Uncertainty on most cost-effective pathway	It is not yet fully clear which approach (electrification, hydrogen fuel switching, or CCS) will be most cost-effective for each sector. The evaluation is susceptible to future factors such as changes in energy and carbon prices. Opting for an approach today can result in a suboptimal choice.
Water availability limitations	An increase in local hydrogen production will result in a higher water demand, for both CCS-enabled and electrolytic hydrogen. With the Humber forecast to be a water stressed region in the future, hydrogen production could further exacerbate water supply concerns in the region. Water abstraction constraints placed on industry and public water companies may limit the capacity of available hydrogen in the Humber in order to maintain supplies of water and protect the environment.
Barrier	**Description**
Cost of hydrogen	It is expected that gas will remain cheaper than hydrogen for the foreseeable future and, unless economic incentives change, hydrogen fuel switching would cause a substantial increase in the cost of energy and a loss of competitiveness for early movers. However, in some cases industrial producers will be able to claim a price premium for green products, enabling a business case for decarbonising.
High capital costs	Capital costs for hydrogen equipment and the associated on-site infrastructure are high and are scantly covered by available funding. Until capital costs become comparable with those of equivalent fossil-fuelled appliances – for instance thanks to mass production – capital support may be required to encourage sites to switch. Although the Industrial Energy Transformation Fund provides some capital support for hydrogen fuel switching, certain industries see this as potentially insufficient due to the additional need to invest in on-site hydrogen infrastructure
Limited availability of low-carbon hydrogen	The limited availability of low-carbon hydrogen, and of hydrogen infrastructure, is a main barrier to the development of hydrogen technologies. End-users, hydrogen producers and network developers face a counterparty risk. National Grid are developing the hydrogen pipeline infrastructure in the Humber, however, they are awaiting the results of the Phase 2 cluster sequencing process before they can finalise their routing and design plans. This chicken-and-egg dilemma creates a counterparty risk and can hinder investment.
Additionality of renewable energy supply	For electrolytic hydrogen, unless the renewable energy capacity used to power the water electrolysers is *additional* to that built to support decarbonisation of the electricity grid, deployment of electrolysers may constrain the amount of renewable energy available to other grid users. This may result in slower substitution of fossil-fired electricity generation and lower reductions in carbon emissions.

[76] This is due to efficiency losses in the conversion from natural gas (or other fossil feedstock) to hydrogen, also including the energy requirements for CCS.

Conversion and retrofitting challenges	There are technical challenges related to retrofitting existing fossil-fuelled appliances and upgrading piping. Significant changes to the plant configuration may be required to enable fuel switching, especially in the case of integrated processes. Early adopters of hydrogen might need to deploy above ground storage on site, and as the required clearance around storage vessels can be significant, they might face space constraints.
Disruption from site conversion	Conversion of sites will require extended shutdown periods causing an inherent loss of revenue. Single sites with no capacity at other UK sites are likely to be hit hardest by this, as they have no ability to share load with other facilities. This, however, was identified as a minor barrier by Humber industries, as fuel switching would be programmed together with planned maintenance shutdowns
Requirement to meet specific heating profiles	In direct heating applications, there might be a strict requirement to meet a specific heating profile. Some fuel-switching technologies may be rendered unsuitable because of this.
Maturity and availability of hydrogen appliances	There is a limited number of suppliers offering hydrogen appliances, which may restrict availability of essential appliances in the short term. There are only a few manufacturers of hydrogen burners, a key part of making equipment conversion possible. Technologies that are not yet commercially available might also encounter obstacles on their way to market, which may restrict their commercial availability to industries in the Humber. This barrier is likely to be more pronounced for industries making use of very site-specific appliances.

2.2.3 Policy study

Policy status and future enablers

Three key policies for low-carbon hydrogen are expected to be finalised in 2022 including the hydrogen business model, low-carbon hydrogen standard and the design of the net zero hydrogen fund. These policies will all be key to delivering the UK hydrogen strategy, published in 2021. This strategy set out the approach for developing a thriving low-carbon hydrogen sector in the UK. Initially, this included a target of 5GW of low-carbon hydrogen capacity by 2030, however, this was doubled to 10GW as part of the Energy Security Strategy in 2022. BEIS are proposing a technology agnostic 'Twin Track' approach to hydrogen production that will support both CCS-enabled and electrolytic hydrogen production. However, the treasury will consider value for money to the taxpayer and affordability of produced hydrogen before authorising major investments.

Sector specific policies for hydrogen and electrification will work alongside overarching policies that cut across multiple sectors. Overarching policies are discussed in more detail in Chapter 1.4.

BEIS business model for hydrogen production

The UK government's hydrogen business model consultation[77] proposes a technology-neutral subsidy based on a Contracts for Difference (CfD) model, whereby Government will agree to pay the difference between the market value of hydrogen, and a pre-negotiated strike price. Revenue support is likely to be funded by passing on costs indirectly to consumers.

The UK government aims to manage some of the initial risks faced by first of a kind (FOAK) low-carbon hydrogen project, primarily:

- **Market price risk –** this is the risk that the price the producer is able to achieve for selling hydrogen does not cover the cost of producing it, as it is unable to compete against counterfactual fuels, such as natural gas or diesel.
- **Volume risk –** this is the risk that a hydrogen production facility is unable to sell enough volumes of hydrogen to cover costs with reasonable confidence.

A **variable premium model** is proposed by BEIS where a premium is paid as the difference between a 'strike price' and 'reference price' for each unit of hydrogen sold. BEIS proposes the reference price to be the higher of natural gas price and the achieved sales price as shown in Figure 11. At any one point, only one reference price would apply with the size of the subsidy expected to decrease over time as the market for low-carbon

[77] BEIS 2021, Low Carbon Hydrogen Business Model (Consultation).

hydrogen evolves. Producers would not receive additional subsidy for sales below the natural gas price, to deliver value for money for government and to avoid distorting energy markets.

BEIS proposes the strike price to be indexed and it is likely to reflect the input costs of the producer (e.g. electricity and natural gas costs). BEIS are conducting further analysis of indexation of the strike price for different production technologies. The indicative Heads of Terms agreement suggests that for CCS enabled hydrogen production, the strike price will be indexed in certain proportions to the market price of natural gas and the consumer price index (CPI). For electrolytic hydrogen production, the full strike price is likely to be indexed to the CPI.

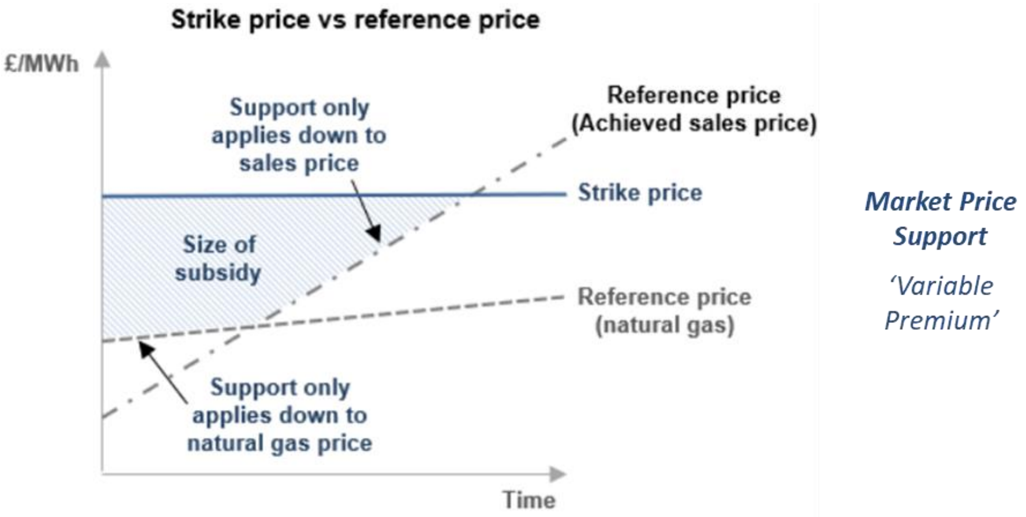

Figure 11: Variable premium model - low-carbon hydrogen market price support[77]

There are a number of policy gaps in the current business model that need to be addressed. Today, there is a lack of capital support for hydrogen fuel switching and funding for feasibility studies. **The business model currently supports the production of low-carbon hydrogen without considering the equipment upgrades that will be required to utilise it in industry.** The current model will only provide support for small scale hydrogen transport and storage as part of a projects overall production costs when bidding for a business model contract. Uptake of low-carbon hydrogen will require the development of transport infrastructure (such as pipelines) to connect low-carbon hydrogen producers with end users. Hydrogen storage may also be required to ensure supply matches demand requirements. Larger-scale hydrogen transport and storage infrastructure is highlighted by many stakeholders as essential for the growth of the hydrogen economy. In the recent Energy Security Strategy[78], the government has committed to designing a new business model to support the development of hydrogen transport and storage infrastructure by 2025. These barriers need to be addressed if industrial facilities are to consider switching to low-carbon hydrogen in the future.

Funding mechanisms

There are a range of funding mechanisms available for low-carbon hydrogen in the UK that BEIS are developing or have recently made active. These are shown in

[78] BEIS 2022, British Energy Security Strategy.

Table 12 with the timings summarised below in Figure 12. Some funding streams focus on supporting low maturity innovation projects and feasibility studies, whereas recently there has been increasing funds made available for bringing technologies to market at commercial scale via support for Front end engineering design (FEED). Today, funding support is focused primarily on low-carbon hydrogen production via the Net Zero Hydrogen Fund (NZHF) and the hydrogen business model. The Hydrogen Business Model is funded by the Industrial Decarbonisation and Hydrogen Revenue Support Scheme (IDHRS).

The Industry Fuel Switching (IFS) and Industrial Energy transformation Fund (IETF) are the primary funding mechanisms available for hydrogen fuel switching. The IFS has a budget for hydrogen of £20m while the IETF has a total budget of £315m up to 2025[79], however, significant portions of this fund are expected to go to alternative decarbonisation technologies other than hydrogen. Recent rises in the cost of natural gas could result in greater attention being placed on electrification pathways as the government looks to minimise reliance on natural gas imports.

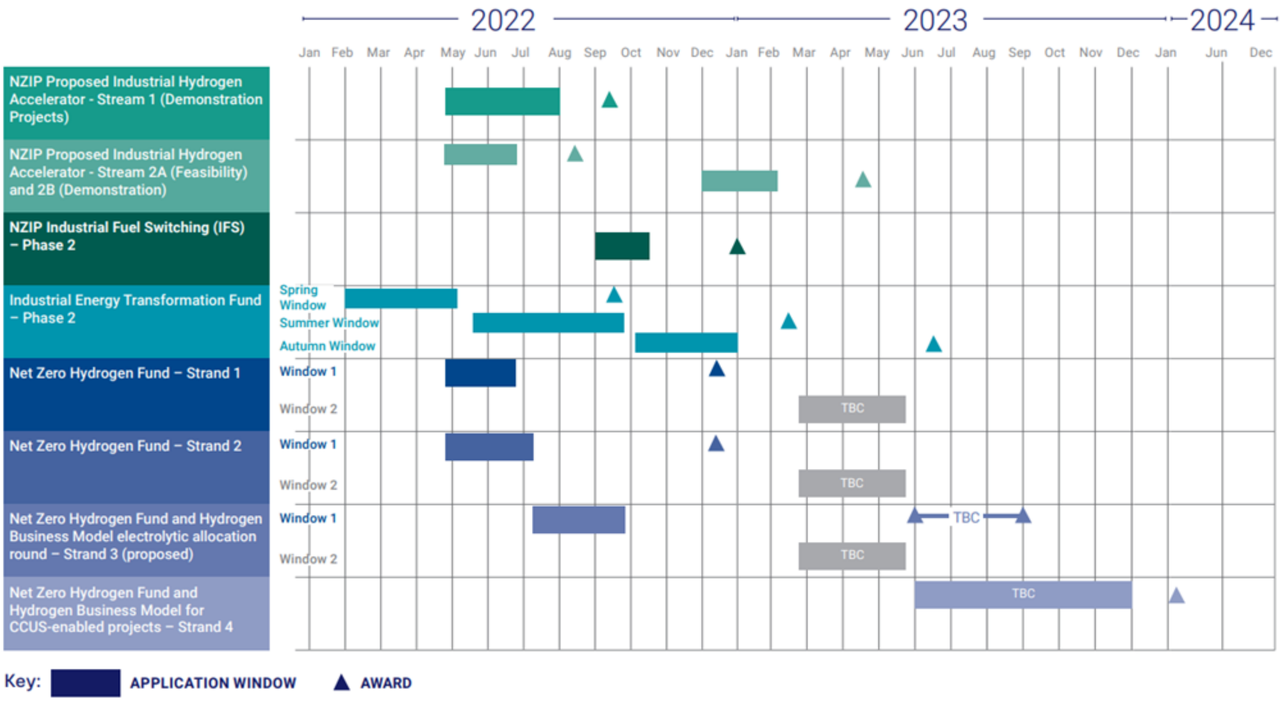

Figure 12: Competition timings for BEIS hydrogen funds launching in 2022 and 2023[80]

[79] BEIS 2022, Hydrogen Investor Roadmap
[80] BEIS 2022, Hydrogen investor roadmap: leading the way to net zero

Table 12: BEIS hydrogen funds launching in 2022 and 2023[81]

<table>
<tr><th colspan="2">Funding Stream</th><th>Aim</th><th>Activity</th><th>Funding</th><th>Maturity</th><th>Scope</th></tr>
<tr><td colspan="2">Industrial Hydrogen Accelerator (IHA)</td><td>Demonstrate end-to-end industrial fuel switching to hydrogen to provide evidence on feasibility, cost and performance</td><td>Feasibility and demonstration</td><td>Innovation funding</td><td>Innovation projects</td><td>End-to-end project</td></tr>
<tr><td colspan="2">Industrial Fuel Switching (IFS)</td><td>Support development of fuel switching and fuel switch enabling technologies, including hydrogen, for UK industry</td><td>Demonstration</td><td>Innovation funding up to £6m per project</td><td>TRL 4-7</td><td rowspan="2">Industry end-use</td></tr>
<tr><td colspan="2">Industrial Energy Transformation Fund (IETF)</td><td>Support the development and deployment of technologies that enable businesses to transition to a low carbon future</td><td>Feasibility, FEED and permanent deployment</td><td>CAPEX grant co-funding, Total grant funding provided is up to:
• Feasibility studies = £7m
• Engineering Studies = £14m
• Deep Decarbonisation Deployment = £30m</td><td rowspan="5">TRL 7+</td></tr>
<tr><td rowspan="4">Net Zero Hydrogen Fund (NZHF) & Hydrogen Business Model</td><td>Strand 1</td><td>Support development of new low carbon hydrogen production to grow the pipeline of projects in the UK</td><td>FEED and post-FEED costs</td><td>DEVEX grant 50% co-funding for FEED and post-FEED studies, Grant awards of £80k–£15m</td><td rowspan="4">Hydrogen production</td></tr>
<tr><td>Strand 2</td><td>Support low carbon hydrogen projects to take FID and begin deployment in the early 2020s</td><td>Permanent deployment</td><td>CAPEX grant 30% co-funding, Grant awards of £200k–£30m</td></tr>
<tr><td>Strand 3</td><td>Support electrolytic hydrogen projects to take FID and deploy at scale</td><td rowspan="2">Permanent deployment and operation</td><td rowspan="2">CAPEX grant co-funding and ongoing revenue support via the hydrogen business model</td></tr>
<tr><td>Strand 4</td><td>Support for CCUS-enabled hydrogen projects</td></tr>
</table>

Policy risks and barriers

The policy risks and barriers associated with hydrogen fuel switching are outlined in Table 13.

[81] BEIS 2022, Hydrogen investor roadmap: leading the way to net zero

Table 13: Policy risks and barriers for hydrogen fuel switching

Risks	Description
Lack of financial risk coverage	Major uncertainties around the future cost of hydrogen for industrial users can limit uptake to reduce risk exposure, unless there is financial risk coverage.
Uncompetitive commodities	Many industrial products from the Humber are commodities. Lack of suitable carbon border adjustment mechanisms can lead to carbon leakage and uneven competition from unabated imported products.
Barrier	**Description**
Perception of carbon credentials	The public perception of the carbon credentials of electrolytic and CCS-enabled hydrogen can act as a barrier to increasing low-carbon hydrogen production and availability.
Compliance with policy	The compliance with a low-carbon hydrogen standard will provide certainty to the carbon credentials of hydrogen, irrespective of their production route. However, compliance with the standard can also limit the scaling up of hydrogen production.

2.2.4 Regulatory study

Health, safety, and environment

Hydrogen fuel switching has additional environmental impacts. As mentioned above, hydrogen combustion can cause an increase in NOx emissions. Also, the electrolysis of water for electrolytic hydrogen production and for consumption in the water gas shift reaction for CCS-enabled hydrogen will increase **water requirements**, which may be problematic in region deemed to be under water stress. The effect of hydrogen fuel switching on water requirements are assessed in the parallel "Water study".

Fuel switching faces additional regulatory barriers linked to the health, safety, and environment (HSE) risks posed by the technologies. Fuel switching to hydrogen could result in additional HSE risks within industrial sites or power plants. The **higher NOx concentration** in the raw flue gas will lead either to emissions re-permitting or to the use of low-NOx burners or alternative mitigation technologies. Emissions monitoring will be required, as well as standardisation and collaboration with the Environment Agency over permitting requirements. Furthermore, **hydrogen has a wider flammability range** than natural gas, and consequently explosive atmosphere regulations (DSEAR) can have cost and space impacts. Affected equipment and workstations might need to be moved or replaced, implementing solutions on a site-by-site basis. Above ground hydrogen storage may be required on site, at least for the early adopters of hydrogen fuel switching. Higher storage pressure than for natural gas will be required, with storage risks relating both required. Storage risks relate both to the high pressure and to the broad flammability risk. The **use of hydrogen on site might push sites over the COMAH aggregation limits**[82], although only a small number of sites may require re-permitting to change their risk category. Solutions (like re-permitting or reduced storage) will need to be assessed on a site-by-site basis.

Planning requirements

Consents required

Currently the infrastructure required to facilitate fuel switching, as indicatively summarised above, is not listed within the criteria or thresholds stated in the Planning Act. Projects of this nature would therefore not be considered Nationally Significant Infrastructure Project (NSIP) and would not be consented through the Development Consent Order (DCO) process.

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[82] The Control of Major Accident Hazards Regulations (COMAH) sets thresholds and aggregation limits to categorise sites into risk categories. Establishments belonging to the top tier are required to comply with more stringent reporting of safety risks.

It is therefore likely that projects relating to fuel switching would require planning consent under the Town and Country Planning Act 1990 (TCPA). This, however, would need to be confirmed once the scope of the project has been defined.

As with other technologies of this nature, if retrofitting to existing industrial facilities and/or if part of a wider project, the whole project would need to be assessed against the Planning Act to determine whether it met any threshold to make it an NSIP and trigger the need for a DCO.

Again, as with other technologies such as CCUS, there may be an opportunity to submit a Section 35 direction to Planning Inspectorate to request that the project is accepted as an NSIP so as to be consented through the DCO process, though whether this is appropriate would depend on the nature and scope of the proposal. Fuel switching infrastructure can vary significantly in terms of scale of infrastructure and complexity of project. For example, and in very general terms, if the project is of a significant scale and is considered of national importance, but not specifically defined as an NSIP, then it would be more likely to be accepted as an NSIP. If it was not of significant scale nor considered of national importance, then it would be less likely to be considered a NSIP.

At the other end of the scale, it may be that some infrastructure associated with fuel switching could be permitted development by virtue of the Town and Country Planning (General Permitted Development) Order 2015 (GPDO), and therefore not require planning permission. This would be limited to more minor types of projects, possibly within existing facilities, and would be assessed on an individual project basis

Key considerations and requirements

Fuel switching technologies are considered emerging technologies in respect of planning and consenting, and as such, they are not explicitly referred to within the Planning Act or the current National Policy Statements (NPS). Fuel switching is referred to within the draft National Policy Statement EN-1 Overall National Policy Statement for Energy, in that it supports methods of decarbonising industry, including fuel-switching. CCUS meanwhile is considered fundamental to decarbonisation and is also referred to in the draft NPS EN-1.

Fuel switching technologies and infrastructure therefore would currently be consented through the TCPA.

The current proposed Regulatory Reform could possibly bring the technologies into the NSIP and DCO regime, though this would need to be reviewed once further details are available.

An Environmental Impact Assessment could be required with any planning application, though this would be assessed on an individual project basis.

Permitting requirements

In addition to hydrogen fuelled appliances, this review also covers fuel switching that leads to operating heating appliances burning biomass/waste-derived fuels. Fuel switching replaces the energy supply from the natural gas grid with alternative low carbon fuels. Industrial processes in the Humber may need to replace or convert industrial appliances such as boilers, furnaces and kilns to be compatible with alternative fuel sources.

Consents required

The switching of fuels does not necessarily entail a change to a permitted activity. Depending on what switch is made will determine what changes are required to an existing permit and can range from a minor to a substantial variation and potential change in primary regulated activity.

Combustion (heat and power sector)

Combustion activities associated with the heat and/or power sector are likely to be operated with gas fired plants. Switching fuels (total or partial) will likely be switching to hydrogen firing from natural gas. Such a change would not change the activity itself but may require a variation to the existing permit depending on the nature of the changes to the plant. The EA would seek reassurance that Emission Limit Values (ELVs) would still be met and/or agree new ELVs as appropriate.

Switching of solid fuels is most likely to be a switch from coal to biomass or waste. The burning of waste biomass or waste-derived fuels may have waste regulatory implications for dealing with waste (storage, handling etc). Where a change in fuel source results in a change of activity (e.g., converting a coal fired power station to a Biomass plant/power station), this would be considered a change in the listed activity (and different BREF implications). New ELVs and BREF requirements may be applicable.

For combustion activities burning a fuel in an appliance with a rated thermal input of 50 megawatts or more, the activities would still need to adhere to the large combustion BREF. This would include emissions meeting the set emission limit values (plus relevant Annex of the IED for emissions not covered by the BREF).

Combustion plants falling below 50MWth input may be subject to the Medium Combustion Plant Directive and/or Specified Generator Regulations. Combustion plants within scope of these regulations will need to comply with the requirements.

Combustion (direct firing e.g., Kilns)

Combustion activities for direct firing (e.g., kilns) will need to consider the same points as discussed for power sector/gas firing. The switching of fuels may require a permit variation and need to ensure ELVs can still be met and/or agree new ELVs as appropriate.

Emission limit values would be determined by the relevant BAT conclusions for the direct firing activity.

Combustion (process furnaces)

Not all combustion process emissions would be suitable for fuel switching due to the nature of the process and/or the nature of the fuel gas currently being used. Where appropriate, process furnaces would also need to consider the same points as discussed for the heat and power sector/gas firing. The switching of fuels may require a permit variation and need to ensure ELVs can still be met and/or agree new ELVs as appropriate.

Emission limit values would be determined by the relevant BAT conclusions for the process furnace activity.

Key considerations and requirements

A large proportion of emissions in the Humber are either process emissions or from combustion of internal fuels which are not applicable/abated by fuel switching due to the nature of the process and/or the nature of the fuel gas currently being used. This includes iron & steel and oil & gas refining, responsible for over two thirds of total emissions, which use a large share of internal fuels[83]. Therefore, not all combustion process emissions would be suitable for fuel switching.

Fuel switching would be most applicable to combustion activities (heat and power sector and direct firing). Sites would need to ensure that the fuel switching option remains compliant with the relevant BREF/BAT requirements (including applicable emissions limits/ BAT-AELs). Although BAT-AELs might not change, it might be more difficult to meet when using a different fuel. A change in fuel may result in different flame and combustion characteristics etc. This should be considered during the design phase along with considering if there will be a total or partial switch of fuels or even a mix of fuels.

Other industrial sectors such as refineries, iron and steel may use alternative fuels in their processes. They would need to comply with their relevant BREF/BAT requirements.

[83] Humber Industrial Decarbonisation Plan (HICP) Lot 2 Market, Policy, and Regulatory Analysis Lot 3 Emissions Offsets and CO_2 Imports Analysis Workshop on Consenting Process and HSE Issues.

The equipment to be used with these alternative fuels will need to be able to still function for its primary purpose. The implications of changing fuels in equipment should be considered and understood.

Regulatory risks and barriers

The regulatory risks and barriers associated with hydrogen fuel switching are outlined in Table 14.

Table 14: Regulatory risks and barriers for hydrogen fuel switching

Risks	Description
-	No regulatory risks related to hydrogen fuel switching identified.
Barrier	**Description**
Inconsistent planning application	The consenting regime (DCO or TCPA) is poorly defined for hydrogen fuel switching technologies. Gaining planning permission will be dependent on the clarity of the application.
Changing output streams	Hydrogen fuel switching from existing processes will have design implications that would need to be considered to ensure that existing or new emission limit values can still be met.

2.2.5 Recommendations and actions

Action 1: Finalise the hydrogen business model

There are currently no commercial scale low-carbon hydrogen projects in the UK and the business model is still under development. This could delay industrials from investing in fuel switching technology until further clarity is provided. BEIS need to release the finalised version of the hydrogen business model to provide clarity over how the support mechanism will operate. This will provide transparency to HIC industrials on the level of support that can be expected throughout the lifetime of operation and enable projects to work towards a FID. BEIS should release the finalised update as soon as possible. Ideally, this will be by early 2023.

Action 2: Subsidise the cost of low-carbon hydrogen for early adopters

Hydrogen fuel switching would cause a substantial increase in the cost of energy, unless covered by policy incentives. Moreover, the price of blue hydrogen will remain tied to that of natural gas, contributing to its volatility. BEIS have currently proposed that hydrogen producers will be responsible for setting the sale price of hydrogen to try to incentivise higher cost sales. Fuel switching to low-carbon hydrogen is likely to result in significantly higher costs for industrials. BEIS should develop policy support and incentives to bridge this cost gap until the cost of low-carbon hydrogen reduces sufficiently. Low-carbon hydrogen is expected to be available in the Humber from 2026-2027 when several CCS-enabled and electrolytic hydrogen production projects are expected to commence operation. Industrials will require increased confidence in the expected support levels in the years leading up to this period (2023-2025) to enable projects to reach FID.

Action 3: Increased financial support for hydrogen fuel switching in industry

Capital costs for hydrogen equipment are high and are scantly covered by available funding. Support for low-carbon hydrogen is primarily focused on hydrogen production via the hydrogen business model and Net Zero Hydrogen Fund. Increased financial or capital support may be required to incentivise industry to convert existing appliances or invest in new hydrogen fired technologies. BEIS should increase support for hydrogen fuel switching in existing industrial processes before low-carbon hydrogen becomes locally available. In the period from 2023 to 2025 industrials will need such support to ensure sufficient time to develop and upgrade the technologies.

Action 4: Identify easy wins for hydrogen fuel switching

Many industrials replace or upgrade components within their facilities at regular intervals or when nearing end of life. Processes that can be switched to hydrogen with minor adaptions may provide the opportunity for significant emissions reduction in the shorter term. Industries in the Humber should identify processes that can be switched to hydrogen with minor adaptions to existing operations. These 'easy wins' should be prioritised emissions reductions that can be implemented without delay. Rolling mill furnaces at the British Steel site in Scunthorpe, already running on internal fuels with a high hydrogen concentration, provide an example of an easy win for hydrogen fuel switching. Easy win fuel switching opportunities should be identified in the years leading up to the period (2023-2025) when low-carbon hydrogen projects are expected to commence operation.

Action 5: Transition away from hydrogen colour terminology

The public perception of the carbon credentials of green and blue hydrogen can act as a barrier to increasing low-carbon hydrogen production and availability within the Humber. Support to hydrogen should be linked to the net greenhouse benefits each production route presents and not to its terminology. A low-carbon hydrogen standard can provide support to both types of hydrogen, provided they meet adequate specifications, and offer certainty amidst the debate between the relative benefits and disbenefits of each. BEIS have released guidance on the UK Low Carbon Hydrogen Standard but will rely on project developers to move away from the hydrogen colour terminology in their marketing. Guidance on the UK Low Carbon Hydrogen Standard has already been released and all projects that are competing for funding support via the hydrogen business model will need to achieve this standard. Projects should therefore move away from the colour terminology immediately.

Action 6: Ensure hydrogen transport and storage infrastructure is scalable

There is a cross chain risk across the low carbon hydrogen value chain that acts as a barrier to hydrogen fuel switching in industry. As a nascent market, the lack of hydrogen dedicated infrastructure is seen as a barrier by industries, whilst the uncertainty around the hydrogen demand is seen as a barrier by the transport, storage and production parties. BEIS need to confirm the hydrogen production projects that are eligible for support from Phase 2 of the cluster sequencing process. This will provide greater certainty to HIC industrials on the quantity of low-carbon hydrogen that is likely to be available and when. Hydrogen infrastructure developers such as National Grid (pipelines) and Centrica (storage) should ensure that capacity is scalable. This will ensure that rising demand can be met by producers such as H2H Saltend and Uniper H_2 hub projects. Hydrogen infrastructure developers need to consider how designs can be scaled to allow for market growth. This should be considered at pre-FEED stage.

Action 7: BEIS should consider the energy security implications of alternative decarbonisation options

The use of CCS-enabled hydrogen inevitably leads to an increased primary demand for natural gas. As a rising share of natural gas is imported there are concerns on the energy security implications that CCS-enabled hydrogen might present. BEIS needs to assess the energy security risks of the different hydrogen production routes and of alternative decarbonisation options. The energy security implications should inform the design of incentives immediately.

Action 9: Water requirements and availability should be considered at the early stages of project development

The Humber is forecast to be a water stressed region in the future, particularly south of the river. Both CCS enabled and electrolytic hydrogen production are water intensive technologies, that could further exacerbate water supplies in the Humber region if deployed at large scale.

Industrials and project developers looking to fuel switch to low-carbon hydrogen will increase the demand for hydrogen production in the Humber region, resulting in an increased demand for water. The additional impact on water demands for the Humber region should be considered for hydrogen fuel switching alongside alternative decarbonisation pathways at the initial stages of project development.

Action 10: Water reuse and recycling should be considered to increase project resilience

In the summer months, where water availability in the Humber is likely to be lower, water may be a constraining factor for project operation. The Environment Agency and public water companies can limit or even completely restrict water supplies in times of drought to protect the environment.

Industrials and project developers looking to fuel switch to low-carbon hydrogen should consider how they can increase their water resilience. Onsite water storage and recycling options should be considered by all projects to minimise the requirement to import water from the environment. For instance, the Gigastack hydrogen project in the Humber aims to deploy the innovative solution of reusing industrial wastewater from the Phillips 66 Humber refinery to ensure no additional water demand is placed on the environment. Further work on the potential to recycle water from the combustion of hydrogen in heating processes is required. Additionally, projects should not be reliant on importing water from a single source. Where possible, a project should be able to access multiple sources to allow operation to continue if access to the primary water resource becomes restricted.

3 Carbon capture, utilisation, and storage

3.1 Carbon capture from local industries

3.1.1 Overview

Carbon capture, utilisation, and storage (CCUS) includes a group of technologies that involve the process of capturing CO_2 before it enters the atmosphere and either utilising it or transporting it and storing it permanently. The primary stages in the CCUS value chain are displayed in Figure 13. In certain cases, captured CO_2 can also be utilised (CCU) as feedstock in the production of minerals, chemicals, or synthetic fuels. CCU applications are currently in the early stages of development and are only available at small scales or high cost. Due to the low volumes of CO_2 that can be treated via CCU and to the varying carbon abatement potential, geological storage of CO_2 is likely to play a much greater role in future decarbonisation of industry[84].

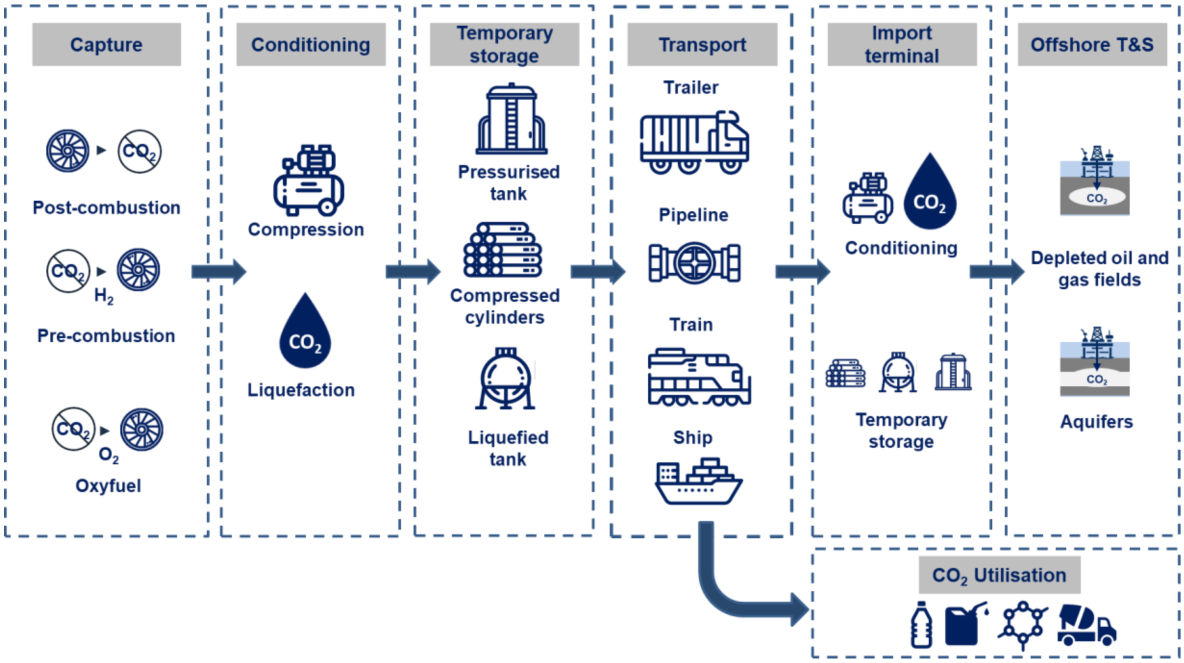

Figure 13: Overview of CCUS value chain

Carbon capture, the first link in the CCUS value chain, includes three distinct approaches: **pre-combustion capture**, **post-combustion capture**, and **oxy-fuel combustion**. Pre-combustion capture refers to cases like CCS-enabled hydrogen production, where CO_2 is removed from a gas mixture (of carbon monoxide and hydrogen, known a syngas), rather than from combustion flue gases (post-combustion). Oxy-fuel capture involves burning a fuel using oxygen separated from the atmosphere rather than air; this gives a relatively pure CO_2 stream for further processing and compression **This chapter focuses on post-combustion capture**, the most widely applicable process for anticipated emissions in the Humber, which is illustrated in the process diagram in Figure 14. Hard-to-abate emissions streams produced as a by-product in industrial processes can be decarbonised via the application of post-combustion carbon capture technology. Today, post-combustion capture is the most mature group and the one concentrating the highest number of developers working on alternative capture technologies.

The most suitable capture technology for a given process depends on process parameters, like the CO_2 content of the flue gas, on site-specific conditions, like energy costs, and on the technical and commercial maturity of options available at the time deployment decisions have to be made. Post-combustion capture technologies are likely to play the greatest role in providing deep decarbonisation of industrial emissions in the foreseeable future.

[84] For these reasons, this study specifically focuses on the CCS value chain, while a brief discussion of CCU is provided in Box 4.

Solvent-based chemical absorption with amine-based solvents is the most mature capture technology for low-pressure gas streams, but other capture technologies exist.

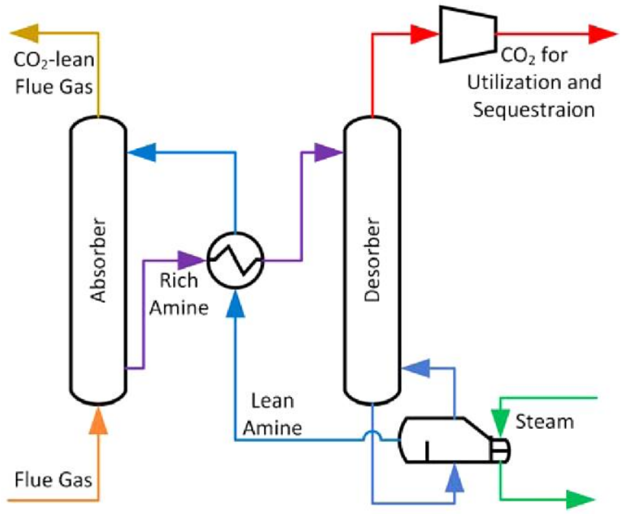

Figure 14: post-combustion solvent-based chemical absorption CO_2 capture process[85]

Decarbonisation potential

CCS deployment can result in deep decarbonisation with modern facilities capable of capturing well over 90% of CO_2 from emissions streams. UK BAT Guidance for post-combustion capture from power plants specifies 95% as a minimum design standard[86] and higher capture levels, up to the entire added CO_2 in the flue gas, appear well within the technical capabilities of amine post-combustion capture[87]. Capture technology enables industrial facilities to continue usual operations whilst enabling the majority of direct CO_2 emissions (scope 1) to be decarbonised from streams that it is applied to. However, CCS might lead to increased indirect emissions from purchased electricity or steam (scope 2) or from other indirect sources (scope 3), such as manufacturing the necessary equipment and infrastructure (scope 3). CCS is the only technology that enables the capture of process emissions[88] and emissions from the combustion of internal fuels, without changing the industrial process. Process emissions are unavoidable in many Humber industrial sectors including lime and titanium dioxide production, and chemical subsectors such as ammonia production. In those sectors, CCS is an essential technology for decarbonisation.

For some industrial sectors, the complete deployment of carbon capture is unfeasible to fully abate emissions due to technological and economic reasons. This could be the case for industrial facilities that have multiple emissions sources with different process characteristics. For example, refineries can have more than 20-30 stacks with varying flow rates, concentrations, and pressures, where it would be unlikely that capture would be applied to all emissions streams[89]. In many cases, a hybrid decarbonisation approach will be required where small point source emissions are electrified or switched to hydrogen, whilst CO_2 capture is deployed at the remaining emitting streams.

Technology status

Post-combustion carbon capture has reached commercial status for some applications, such as coal-fired power generation and EfW plants. Other sectors have a lower maturity. For instance, post-combustion capture from

[85] Dutcher et al 2015, Amine-Based CO_2 Capture Technology Development from the Beginning of 2013 – A Review.
[86] Environment Agency 2021, Post-combustion carbon dioxide capture: best available techniques (BAT).
[87] Michailos & Gibbins 2022, A modelling study of post-combustion capture plant process conditions to facilitate 95–99% CO_2 capture levels from gas turbine flue gases.
[88] Process emissions - from the chemical transformation of raw materials in industrial processes that release CO_2.
[89] Carbon Limits 2020, The Role of Carbon Capture and Storage in a Carbon Neutral Europe.

the glass industry is currently at pilot scale level of development. Lack of certainty around CO_2 transport and storage (T&S) for some applications means that the whole CCUS value chain cannot be considered TRL 9 for all sectors. To date, research and development (R&D) focus has been on large-pilots and improving performance, mainly related to energy requirements. Experience with commercial coal projects has shown that solvent management and replacement costs can be much more significant than previously assessed and this, plus environmental emissions, is now also getting attention.

Cost considerations

The cost range for carbon capture is very wide as, at a general level, it depends on the application and its scale as shown illustratively in Figure 15. Location- and time-dependent factors will have a significant influence on capital and operating costs and generalisations have limited applicability. In general, the plant capacity is the main variable that influences CAPEX costs with a 1 $MtCO_2$/year capacity capture facility typically having a total capital requirement of circa £350m[90]. Carbon capture would typically be applied to large scale facilities as higher captured volumes are favoured by economies of scale – although above a certain scale the need to have multiple capture trains removes scale effects.

The energy requirements to operate the capture facility are conventionally expected to be the main operating expenditure (OPEX) components with both electricity and heat necessary for most processes (discussed next). The CO_2 concentration in flue gas has a secondary impact on the capture energy requirements because higher CO_2 concentrations can result in smaller energy demand, and some process equipment components can be smaller. Today, capture rates of 95% and above are achievable: whilst there are no hard technical limits, specific CO_2 capture costs are thought to increase disproportionately as the capture level approaches 100%. It should be noted that 100% of CO_2 in a flue gas is not required to achieve a carbon neutral process; it would suffice that the CO_2 concentration in the exiting flue gas equals ~400 ppm concentration in the incoming air. For instance, for gas turbine flue gas that corresponds to a capture level of 99%.

Other factors will also affect the cost of capture. In practice, solvent management has been reported to be the major cost component in both of the only two large-scale flue gas PCC applications built to date[91]. The actual retrofit feasibility for the plants, the transport to site for large vessels, load factors, the life expectancy of the asset being retrofitted and access to the CO_2 transport and storage network are all important cost elements.

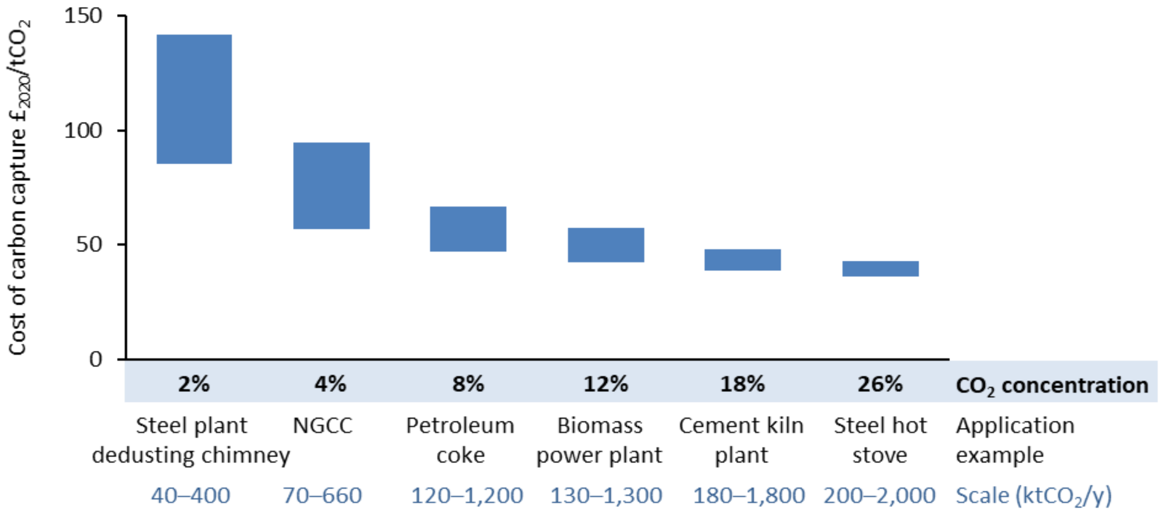

Figure 15: Idealised relative cost range for carbon capture applications at varying scale for a 90% capture rate[92]

[90] Pieri and Angelis-Dimakis 2021, Model Development for Carbon Capture Cost Estimation
[91] Global CCS Institute 2019, Global Status Report 2019, p. 65
[92] Adapted from: Global CCS Institute 2021, Technology Readiness and Costs of CCS

Energy and resource implications

Post-combustion capture technology is an energy intensive process requiring 2-3.5 GJ of heat input per tonne of CO_2 captured[93] plus additional electric power for compressors and other rotating equipment. Because heat is typically required at 125 °C to 140 °C it can be recovered from processes that have already extracted most of the useful exergy and would otherwise need to reject a fraction of the input energy. Some capture technologies rely on the availability of abundant waste heat which presents trade-offs with energy efficiency measures. Alternative capture technologies such as solid adsorption or membrane separation aim to lower the heat requirements or use electricity-driven processes and are often portrayed as using less energy. The use of low-grade heat, however, should not be conflated with the use of higher quality electrical energy. In idealised theory the additional energy requirements for carbon capture will depend on the industrial process and on the flue gas CO_2 concentration, with the lowest typically having the highest energy capture requirements.

Carbon capture is the first stage of the CCS supply chain and is reliant on the development of downstream transport and storage (or utilisation) infrastructure. Energy is required by pumps and compressors to transport the CO_2 in the desired condition to the final geological storage site. The transport and storage networks that are proposed to be used will determine the CO_2 specification that must be adhered to by the capture facilities. The energy requirements will depend on the required transport condition and infrastructure types and are discussed in more detail below.

Infrastructure for CO_2 transport and storage

Shared pipeline infrastructure can connect multiple CO_2 emitting sources in a hub or cluster such as the Humber. A shared pipeline has the benefit of lowering the barrier to entry for individual emitters looking to access CCS infrastructure as they are not required to develop or maintain their own CO_2 transport and storage infrastructure. This can often be a significant barrier to deploying capture technology at dispersed sites. Shared pipeline infrastructure also has the advantage of increasing the volume of CO_2 transported, increasing economies of scale across the CO_2 value chain and reducing the levelised cost of transportation. Emissions sources can develop a short distance CO_2 pipeline that connects to the primary shared infrastructure pipeline, providing reduced cost access to storage. However, the development of new build pipelines can often face challenges acquiring planning consent and from environmental restrictions.

Geological storage involves injecting captured CO_2 into rock formations deep underground, typically at depths greater than 800m to ensure captured CO_2 stays in a dense liquid state. Rock formations with pore space and sufficient permeability for CO_2 injection are required. This enables injected CO_2 to flow through the underground reservoir and fill up the pore space. The storage site is secured by an impermeable rock formation known as the cap rock which prevents the CO_2 from migrating upwards and escaping back into the atmosphere. CO_2 is pressurised to match that of the geological formation before injection into the reservoir to ensure efficient storage and minimise risks related to equipment damage due to sudden changes in pressure. CO_2 is permanently trapped underground through several mechanisms: structural trapping by the cap rock, solubility trapping where the CO_2 dissolves in the brine water, residual trapping where the CO_2 remains trapped in pore spaces between rocks, and mineral trapping where the CO_2 reacts with the reservoir rocks to form carbonate minerals (mineralisation)[94].

Storing CO_2 in geological formations is an advanced technology that has been used safely and effectively for decades, but mainly for enhanced oil recovery (EOR), where CO_2 storage is not prioritised or measured (the Weyburn project is an isolated example of verified storage as part of EOR[95]). The Sleipner project in Norway was the first commercial scale CO_2 storage project, sequestering approximately 1 $MtCO_2$/year since 1996[96]. Over 20 $MtCO_2$ have been stored securely under the seabed by the Sleipner project without incident, however, the In Salah project in Algeria is an example of a project that was suspended due to concerns over the seal

[93] IEAGHG 2019, Further Assessment of Emerging CO_2 Capture Technologies for the Power Sector and their Potential to Reduce Costs, p. 205
[94] IEA 2021, About CCUS.
[95] British Geological Survey 2005, The IEA Weyburn CO_2 Monitoring and Storage Project.
[96] Equinor 2019, Sleipner partnership releases CO_2 storage data.

integrity (although no CO_2 leakage was reported)[97]. As of September 2022, there were 30 operational CCS projects with a total capacity of 42.6 $MtCO_2$/year[98].

In common with any activity that relies on complex geological conditions deep underground that cannot be fully assessed from the surface, aquifer CO_2 storage can be expected to throw up surprises in some cases. These surprises will be managed, in well-conceived projects, by using back-up options (e.g., modifying injection procedures), using alternative injection horizons or developing back-up well sites nearby. Aquifer performance will probably only be known with greater confidence after a year of more of injection at full rate, when the pressure response of the formation and the dispersion pattern of the injected CO_2 will hopefully match predictions.

Saline aquifers and depleted oil and gas fields are both potentially suitable geological formations for CO_2 storage. Formations will need to be appraised and have specific characteristics to make them effective and reliable stores of CO_2. These include sufficient pores within the formation to provide the capacity to store the CO_2, permeability to enable the formation to accept the CO_2 at the rate it is injected, allowing the CO_2 to move and spread out within the formation, and an extensive cap rock or barrier at the top of the formation to contain the CO_2 permanently[99]. Economies of scale of larger storage sites are associated with both saline aquifers and depleted oil and gas fields, particularly offshore where the unit cost of storing CO_2 can decrease significantly when larger volumes are stored in a single storage facility. Carbon capture and utilisation (CCU) is an alternative destination for captured CO_2 emissions, although likely to be applied for smaller scale applications (see Box 4).

In the Humber, the Northern Endurance Partnership aims to store 450 $MtCO_2$ in the Endurance aquifer in the Southern North Sea, with future expansion enabling access to approximately 1,000 $MtCO_2$ capacity[100]. The project is developed by a group of oil and gas companies, including BP, National Grid, Equinor, Total Energies and Shell. A new pipeline will have to be built as there is no existing pipeline that can be repurposed. The Endurance site has considerable buildout potential, with licenses for four separate storage sites and Bunter Closure 36 located in close proximity should the initial capacity be reached. The Viking CCS project aims to repurpose existing oil and gas infrastructure for storage in the depleted Viking gas fields. The Viking fields are a set of fields operated by Harbour Energy (formerly Chrysaor) which are currently being considered for CO_2 storage, due to the existing pipeline connection to the stores via the Theddlethorpe terminal. This would add an additional 300 $MtCO_2$ of storage capacity in the Humber. An existing 120km pipeline would be repurposed with a CO_2 capacity of approximately 11.0 $MtCO_2$ /year. The DelpHYnus project developed by Neptune Energy involves a combined development comprising a CO_2 T&S network serving the South Humber Industrial area, together with production facilities for CCS enabled hydrogen, at the former Theddlethorpe Gas Terminal site[101].

[97] MIT 2016, In Salah Fact Sheet.
[98] Global CCS Institute 2022, Global Status of CCS 2022.
[99] Global CCS Institute 2018, Geological storage of CO_2:Safe, permanent, and abundant.
[100] Equinor 2022, Major step forward for East Coast Cluster as Equinor and bp handed carbon storage licences.
[101] Neptune Energy 2022, DelpHYnus project.

Box 4 - CO_2 utilisation

CO_2 utilisation refers to using CO_2 in the development of products and services containing carbon. Whilst the direct use of CO_2 in certain products is well-established (e.g. carbonated beverages, fire-extinguishers), there is growing interest in the chemical conversion of captured CO_2 to produce products such as fuels, chemicals, proteins, or building materials. This can be driven by goals to increase sustainability and lower emissions in the production of conventional products – for example, in the case of fuels and chemicals these products currently rely on fossil-derived carbon feedstocks. It can also be driven by other factors such as opportunities to improve processes or lower feedstock costs compared to conventional production routes.

Many different techniques for CO_2 utilisation (via conversion) are under development, including chemical (e.g. catalytic or electrochemical), biological (e.g. fermentation) and accelerated mineralisation routes. Some technology developers have completed pilot demonstration and are operating small-scale commercial facilities. For example, in Iceland, Carbon Recycling International has been operating a pilot plant since 2012 producing 4 kt methanol from CO_2 per year sold to European customers[102], whilst in the UK, technology to stabilise alkaline wastes with CO_2 to produce aggregates has been in operation since 2012[103]. Recent CO_2 utilisation demonstration projects announced in the UK include the Lanzatech and Carbon Engineering project AtmosFUEL[104], producing kerosene from atmospheric CO_2, and the Proman and Global Energy Group e-methanol plant at Nigg Oil Terminal[105], producing methanol from industrial CO_2.

Factors that impact the environmental benefits of CO_2 utilisation include: the lifecycle emissions of the production route (including energy sources and additional feedstocks such as hydrogen), the lifecycle emissions of the product being substituted for the CO_2-derived product, the origin of the CO_2 used and the alternative to its use (e.g. sequestration or release). CO_2 utilisation can reduce emissions of a product if it substitutes a more emission intensive production pathway. It should however be noted that in many cases the utilised CO_2 is emitted to the atmosphere in a short period of time (e.g. via fuel combustion) and so not abated. Therefore, in the long-term atmospheric or biogenic CO_2 is preferable to avoid displacing the permanent sequestration of fossil CO_2 emissions in geological storage. It is not yet clear how carbon accounting of utilised CO_2 should work, however a recent proposal for the EU emissions trading scheme (ETS) indicates that emissions liability should remain with the site at which the CO_2 is produced[106].

The future scale of CO_2 utilisation in products is limited by market demand, and in most cases is likely to be small compared to the total CO_2 that needs to be mitigated. Many pathways result in considerable cost-premiums of products compared to conventional production pathways, and there are currently limited market-drivers to counteract this barrier. However, one promising large potential market is the production of CO_2 derived fuels that can either directly substitute conventional fossil fuels (e.g. synthetic kerosene for aviation) or act as a new liquid-fuel alternative (e.g. methanol in shipping). The development of this market is supported by policies such as sub-mandates on the use of renewable fuels of non-biological origin[107].

For the Humber, production of chemicals and fuels from CO_2 utilisation could be a long-term future area of interest due to the availability of low-carbon hydrogen, the existing skills of the region, the potential to re-use assets, and existing supply chains for fuels and chemicals.

[102] Carbon Recycling International 2022, Carbon dioxide to methanol.
[103] OCO Technology 2022.
[104] Carbon Engineering 2021, Carbon Engineering and LanzaTech partner to advance jet fuel made from air.
[105] Offshore Energy 2021, GEG, Proman to build renewable power to methanol plant in Scotland.
[106] European Commission 2021, Directive 2003/87/EC establishing a system for greenhouse gas emission allowance trading within the Union.
[107] For example, the 2021 ReFuelEU aviation policy proposal includes a sub-mandate for synthetic fuels of non-biological origin in aviation that increases to 28% by volume by 2050 – European Commission 2020, ReFuelEU Aviation.

3.1.2 Market study

Opportunities for deployment

Carbon capture from high-pressure gas streams like gas processing and ammonia production[108] is mature and already occurring (though not integrated with CO_2 storage). Carbon capture from low-pressure gas streams is more challenging, but CCUS is applicable to all the main sectors from the Humber cluster. However, there is an uneven level of development, with some sectors exhibiting a higher maturity and others lagging behind due to specific challenges.

The East Coast Cluster, including the Humber industrial cluster was selected as a Track 1 cluster for developing a CO_2 transport and storage network, removing a significant hurdle to the development of carbon capture in the region. The transport and storage network is currently in development and the site for storing captured emissions below the North Sea has already been identified. BEIS announced the eligible projects for Phase 2 of the cluster sequencing process in March 2022[109]. In the Humber, this included a range of projects from power generation, CCS-enabled hydrogen production, refining, waste and chemical production. However, it is not expected that all shortlisted projects will be supported by BEIS via the first round of funding.

Carbon capture also allows for the continued use of the blast furnaces which are at the heart of the integrated iron and steel Scunthorpe site without extensive process modifications. The relatively high CO_2 concentration in the iron and steel production off-gases (25-30%) makes for lower energy penalties than when capturing CO_2 from energy generation. There is a theoretical trade-off with capturing CO_2 from the on-site power plant rather than from the blast furnace gas directly. Post-combustion capture downstream from the on-site power plant would allow to capture a larger share of emissions from a single point and would ease integration (as coke oven gas and basic oxygen furnace gas are also combusted), but nitrogen is incorporated into the flue gas and dilutes the CO_2 concentration. It should be noted, however, that the addition of carbon capture infrastructure locks in the BF-BOF route, as steel industry investment cycles are long and large investments will be required to extend the lifetime of coke ovens and for relining or reconstructing blast furnaces

Market risks and barriers

Although CCS is seen as an essential contributor to the UK's long-term emission reduction, there are several market risks and barriers that need to be resolved to ensure it can be deployed at scale in the Humber, outlined in Table 15.

[108] Although only part of ammonia-related emissions is from high-pressure gas stream. IEA 2021, Ammonia Technology Roadmap.
[109] Power BECCS projects were not included in this announcement.

Table 15: Market risks and barriers for CO_2 capture

Risks	Description
Limited land availability	Capture plants can be as big as the industrial plant, impacting relatively small capacity facilities with a small balance of plant. If not enough land is available on site to install the capture unit, a site extension is needed, impacting on process integration, permitting and the CAPEX. For example, the Phillips 66 Humber refinery has limited free space available that may increase the complexity of plant design and potentially result in delays for capture deployment.
Supply chain constraints	The scale of global CCS deployment needed exceeds the current deployment rate and there are few mature technology developers. The installation of carbon capture units in the Humber could meet supply chain constraints and a skilled labour shortage as other regions/countries also decide to install capture plants. Several industrial users have expressed concern on the supply of CO_2 compressors. Furthermore, the largest absorption columns required for capture deployment at sites such as the Phillips 66 Humber refinery, cannot be produced by UK manufacturers and would face significant transportation challenges if manufactured offsite[110].
Water availability limitations	Carbon capture deployment may require an increase in water demand in the Humber region due to requirements for cooling. Water abstraction constraints placed on industry and public water companies may hinder the deployment of water-cooled carbon capture in the Humber. Air-cooled systems would not be affected in the same way. VPI Immingham are considering a hybrid cooling system for their carbon capture project that will be primarily air cooled due to expected constraints on water supply in the region.
Uncertainty on most cost-effective pathway	It is not yet fully clear which approach (electrification, hydrogen fuel switching, or CCS) will be most cost-effective for each sector. The evaluation is susceptible to future factors such as changes in energy and carbon prices. Opting for an approach today can result in a suboptimal choice.
Barriers	**Description**
Lack of existing commercial scale projects	For less mature CO2 capture applications in industries that have seen limited or no commercial deployment to date, first- and second-of-a-kind projects will face higher costs and risks. Except for early movers eager to take more risk, other sites may prefer to delay deployment and wait for greater commercial demonstration.
Immature business model	There are currently no commercial scale CCS projects in the UK and the industrial carbon capture business model is still under development. This could delay industrials from investing in capture technology until further clarity is provided.
Retrofitting plants	Retrofitting carbon capture to existing plants is likely to cause disruption to plant activities and logistics. Process integration with operating plants will imply a planned stop, which could lead to costly down-time and missed revenues. Flue gases with high concentrations of impurities (e.g., energy-from-waste plants) would therefore need additional treatment prior to CO2 capture, which would increase the cost of capture.
Flue gas pre-treatment requirements	Flue gases with high concentrations of impurities may need additional treatment, depending on solvent choice. The need to treat flue gases to a higher degree than the required to comply with emissions limits increases the cost of capture.

3.1.3 Policy study

Policy status and future enablers

A clearly defined business model and a stable and predictable price signal and investment framework are key enablers for commercial CCS projects. BEIS published their most recent update to the carbon capture business model in April 2022 (see below) however remaining uncertainties can result in less predictable cost recovery and a higher cost of capital. The immaturity of the capture market, complexity of the technologies, high investment and operational costs make financial support crucial for the deployment of early commercial CCS projects. The confirmation of the East Coast Cluster as Track-1 cluster provides access to the CCS Infrastructure Fund.

Low-carbon products are usually more expensive than high-emissions ones, in part because the true economic and environmental costs of existing carbon intensive processes are not factored into the market price. A green

[110] Nuclear AMRC 2022, CCUS supply chain intervention strategy

premium is the additional price that customers would need to pay when choosing an alternative low-carbon product over an existing high-carbon option. **Certain customers have already indicated their willingness to pay a green premium**, potentially as high as 30% for green steel.[111] However, the depth of the market for such green products is not yet fully clear and may restricted in sectors with high-cost sensitivity. Growing demand for low-carbon industrial products charged at a market premium can act as an alternative enabler to unlocking the carbon capture business model, as industries will be incentivised to invest in carbon capture technologies to ensure they can meet consumer demand. Today, green premiums are high due to the high cost of low carbon technologies and processes, and policy is therefore required to make carbon intensive products more expensive, or low-carbon options cheaper, or a combination of both[112].

BEIS business model for industrial carbon capture

The UK government have proposed a CfD financing mechanism combined with an upfront grant to support CCS projects[113]. The upfront government co-funding would help finance the capital costs of constructing the CO_2 capture plant, along with the CfD to provide revenue support over an agreed operational duration of the capture plant. The proposed revenue flows for the industrial carbon capture (ICC) business model are shown in Figure 16.

Contracts for Difference (CfDs) have been used successfully in the UK to provide price support to emerging low-carbon technologies such as offshore wind for renewable electricity generation. A CfD involves the government agreeing to pay the difference between the actual value of a commodity (the market price) and a value agreed on when the contract was entered into known as the strike price. CfDs are commonly used as a means of providing price support to emerging low-carbon technologies and to encourage private investment from industry. By providing predictability of future revenue streams, they encourage investment in new technologies which might otherwise not occur at all if solely reliant on market prices.

The initial government position is that T&S fees will be funded via the ICC business model for the duration of the ICC Contract. The contract will be comprised of a 10-year contractual payment term with the option for a 5-year extension, for which the emitter will be eligible if predefined conditions, and access to suitable T&S for the duration of the extension, are met. The emitter would have to achieve certain performance conditions during the initial 10-year period based on average capture rate (>85%) and average volumes of CO_2 captured (>90% of contract estimate).

Figure 16: Revenue flows between various parties involved in the ICC business model[114]

Capital grants will be available to co-fund capital investment for initial ICC projects that apply through Phase-2 of the Cluster Sequencing. Capital will be provided on a “last spend” basis, where industry is incentivised to fully exploit other sources of capital first. Industry is set the challenge of raising as much private sector capital as

[111] Washington Post, 2021. How Steel Could Become Green, and What It Would Take..
[112] Breakthrough Energy 2022. The Green Premium.
[113] The Dispatchable Power Agreement (DPA) is not considered in this study. Updates on the DPA can be found on the BEIS website at BEIS, 2022. Carbon capture, usage and storage (CCUS): business models.
[114] BEIS, 2021. CCUS: An update on the business model for Industrial Carbon Capture.

possible, and then indicating what remaining funding gap would need to be filled for the project to be fully financed.

The government sees grants as a transitional form of support where funding is likely to be provided to initial capture projects only. For initial ICC projects, a contractually agreed upon strike price per tonne of CO_2 abated will be negotiated bilaterally based on the expected costs of carbon capture for the project. The CAPEX component will apply from the start of operations to the point at which capex has been repaid, where the payment is a fixed £ amount per tonne of CO_2 captured.

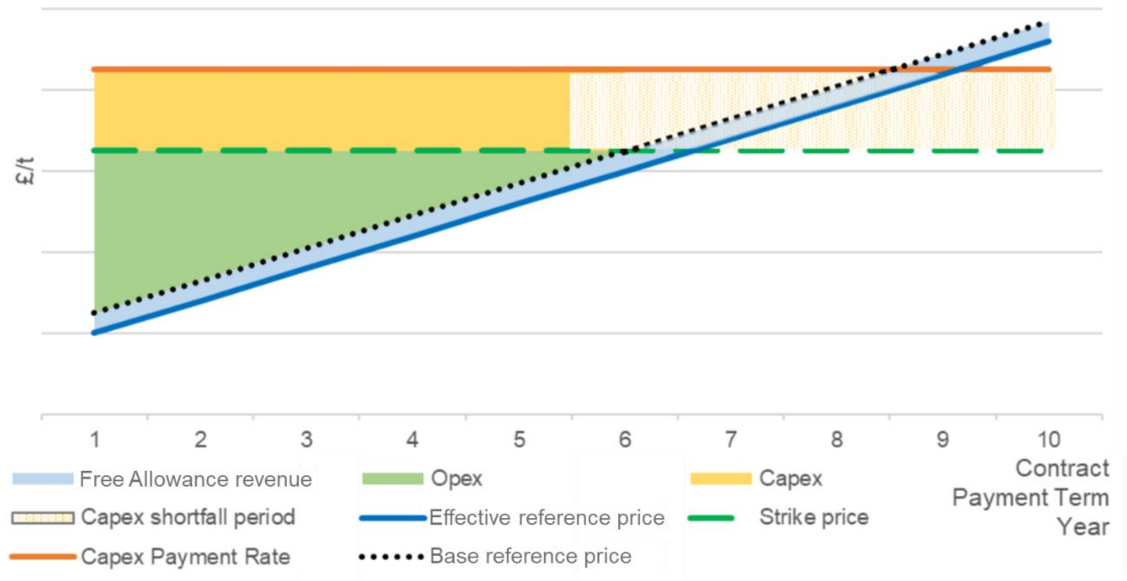

Figure 17: ICC contract payment components[115]

The OPEX component will apply for the duration of the contract and will be indexed to the Consumer Price Index. For the first 10 years the base reference price will follow a fixed trajectory that will be set out to emitters prior to initial contract negotiations. The fixed trajectory reference price is not linked to the prevailing market carbon price Unlike traditional 'two-way' CfD mechanisms, an asymmetric (one way) design feature will be applied for initial projects where payments will be made to the emitter from the ICC Contract Counterparty if the strike price is above the reference price, however if the reference price is above the strike price, no reverse payments will be made by the emitter[115]. This payment is expected to reduce over time as shown in Figure 17 as carbon prices increase and the relative cost of CO_2 abatement reduces. Beyond the first 10 years of operation, the fixed reference price trajectory will transition to the UK ETS carbon price and symmetrical (two-way) payments will apply under the contract.

Funding mechanisms

The UK Government has announced capital grant funding for the CCS sector via the confirmation of the £1bn CCUS Infrastructure Fund (CIF). This aims to support the development of the CO_2 transport and storage infrastructure (that is essential for carbon capture deployment) in the four industrial clusters by 2030. CAPEX and OPEX funding for the industrial carbon capture business model will be provided via the Industrial Decarbonisation and Hydrogen Revenue Support scheme. A summary of the UK government funding for CCUS development is shown in Figure 18.

[115] BEIS, 2022. CCUS: An update on the business model for Industrial Carbon Capture.

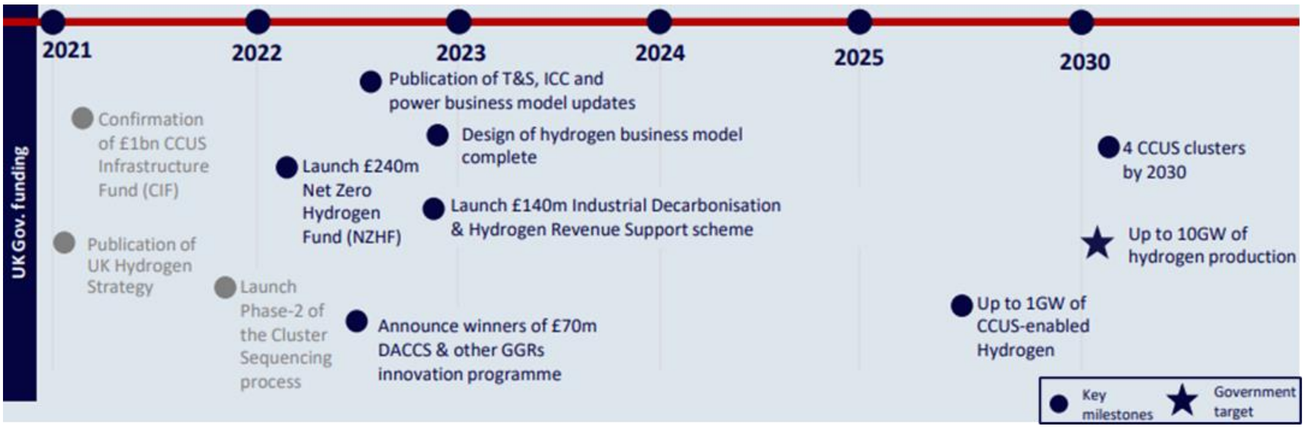

Figure 18: UK government funding for CCUS[116]

To date many of the BEIS funds have been split into at two least phases, consisting of phase 1 feasibility studies and phase 2 demonstration projects. Conducting a BEIS funded feasibility study is often a requirement to access future funds and so this can slow down the deployment of publicly funded demonstration projects. BEIS aim to support CCUS technology development via the CCUS Innovation 2 competition. This will provide £19.5m in grant funding via the Net Zero innovation Portfolio (NZIP) for projects developing novel capture processes that reduce the cost of deployment. Projects will be split into two lots, with Lot 1 focusing on mid-stage CCUS innovation (TRL 3-5) and grants up to £1m per project, while Lot 2 will focus on later-stage CCUS innovation (TRL 6-8) at larger scales with grants of up to £5m per project.

Policy risks and barriers

The policy risks and barriers associated with carbon capture are outlined in Table 16.

Table 16: Policy risks and barriers for CO_2 capture

Risks	Description
Loss of competitiveness and carbon leakage	Carbon leakage refers to policies where emissions are relocated to countries with less ambitious greenhouse gas emissions reduction policies. As the price of products and services increases to include the capture cost, they will face uneven competition from unabated imported products, reducing competitiveness and increasing the risk of industry relocating outside of the UK.
Barrier	**Description**
BEIS business model not yet finalised	The immaturity of the market, complexity of the technologies, high CAPEX and high OPEX make financial support crucial for the deployment of early commercial CCS projects. It is expected that the BEIS business model should address these issues once finalised.
Public acceptance	The lack of awareness around carbon capture technology might lead to public resistance that can block or delay the permitting process.

3.1.4 Regulatory study

Health, safety, and environment

Depending on the cooling system deployed, **carbon capture could substantially increase water requirements and wastewater flows** at sites deploying it. Water is required at different stages of the capture

116 . BEIS, 2022. CCUS Investor Roadmap.

process, and consumption for some applications has been estimated to range up to 1.71 m^3/tCO_2 captured for coal-fired power generation to 2.59 m^3/tCO_2 for natural gas-fired power generation[117]. However, depending on the cooling methods used, post-combustion carbon capture can collect water in the process of cooling the flue gas which results in the condensation of water[118]. Moreover, carbon capture technologies may increase certain air pollutant emissions and reduce others. SOx and particulate matter emissions are expected to drop as the capture unit pre-treatment requirements are more stringent than environmental regulations. On the other hand, the NOx concentration in the flue gas could increase. The use of amine-based solvents can also entail fugitive emissions of ammonia and new pollutants: amines and nitrosamines, potential carcinogens[119]. The appropriate choice of solvent, solvent management, and the use a final acid wash can reduce such emissions to very low levels and comply with strict emission limits[120].

The consenting of carbon capture plants needs to deal with the health, safety and environment (HSE) risks entailed by the process. Carbon capture plants will need to be on-site or within the immediate vicinity of the industrial plant. Changes in the permitting process could lead to complications, particularly if the plant is near population centres creating concerns around emissions, in particular amine emissions and on-site CO_2 storage risks. There is concern around the public health risk arising from post-combustion carbon capture plants emissions. Amines can be corrosive or irritating, and amine degradation products such as nitrosamines are potent carcinogens[121]. Storing and transporting CO_2 requires high operating pressures. CO_2 is denser than air, so a potential rupture of or intense leakage from storage tanks or pipelines could cause CO_2 to accumulate in low-lying areas and eventually lead to asphyxia.

Planning requirements

This study considers the construction of a full CCS project, including the infrastructure required to connect it to the necessary industrial processes.

CCS is the capture (from a large point source such as a power station or other industrial installation), transport (by pipeline or ship) and storage (within underground geological formations) of CO_2, to prevent it from entering and polluting the atmosphere.

Consents required

Carbon Capture and Storage Infrastructure

Currently, CCS infrastructure does not fall within the criteria of the Planning Act and is therefore not considered a Nationally Significant Infrastructure Project (NSIP). This means that any applications for 'standalone' CCS projects and possibly projects retrofitting CCS to existing facilities (subject to confirming the scope of whole project) can be consented through the Town and Country Planning Act 1990 (TCPA).

However, whilst not specifically included within the Planning Act, clear reference is made to CCS within the National Policy Statements and a direction under Section 35 of the Planning Act can be sought from the Planning Inspectorate requesting that the project is accepted as an NSIP and consented through the Development Consent Order (DCO) process. It is considered likely that this would be accepted by the Inspectorate given the references supporting CCS within NPS and the proposed emerging changes within the draft NPS and the proposed Planning Reform.

There are several possible benefits to CCS projects being consented through the DCO process, including the national presumption in favour of CCS as part of the UK's decarbonisation strategy, clarity of timescales, benefiting from national decision making and inclusion of other consents within any DCO, such as land powers.

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[117] Rosa et al, 2021, The water footprint of carbon capture and storage technologies.
[118] Global CCS Institute 2016, Water use in thermal power plants equipped with CO_2 capture systems.
[119] The Royal Society, 2021, Effects of net-zero policies and climate change on air quality.
[120] Gibbins & Lucquiaud 2021, BAT Review for new-build and retrofit post-combustion carbon dioxide capture using amine-based technologies for power and CHP plants fuelled by gas and biomass as an emerging technology under the IED for the UK.
[121] Låg et al, 2011, Health effects of amines and derivatives associated with CO_2 capture.

The decision on whether to seek a Section 35 direction would be on the case-by-case basis for each project, weighing the merits of the DCO consenting regime against that of the TCPA.

Importantly, NPS EN-1 acknowledges that where CCS infrastructure is not covered by the NSIP definitions and thresholds in the Planning Act, and is the subject of a Section 35 direction, the Secretary of State should give substantial weight to the need for CCS established in EN-1, when considering whether to grant a DCO.

Carbon Capture as part of a Generating Station

When CCS is associated with or delivered as part of a wider project it is necessary to consider whether the project as a whole requires planning consent, and under which regime. In respect of generating stations, one of the likely facilities to introduce CCS, Section 14(1) of the Planning Act includes the construction or extension of a generating station and development relating to underground gas storage facilities.

As defined within Section 15 of Part 3 of the Planning Act, a generating station will be a NSIP if:

- its generating capacity is more than 50 MW, is not offshore and does not generate electricity from wind
- its generating capacity is more than 100 MW and is offshore[122]

Therefore, if CCS forms part of a generating station project that is considered an NSIP, the whole project including the CCS need to be consented through the DCO consenting process.

Pipelines

CCS requires pipelines to connect to the source and end point of the technology. If the project includes new pipelines these will need to be considered as to whether planning permission is required, and under which regime.

The construction of a pipeline, either as a standalone project or associated with a wider project may require consent. The construction of a pipeline by a gas transporter wholly or partly in England falls under the Planning Act as a nationally significant infrastructure project if any of the following criteria are met. Gas Transporter Pipelines which are:

- expected to be more than 800mm in diameter and more than 40 kilometres in length. or
- likely to have a significant effect on the environment. The design operating pressure must be expected to be more than 7 bar gauge. The pipeline must be expected to convey natural gas for supply to at least 50,000 potential customers. These pipelines are referred to in this NPS as Gas Transporter Pipelines.
- Pipelines over 16.093km (10 miles) long which would otherwise require consent under s.1 of the Pipe-lines Act 1962 together with diversions to such pipelines regardless of length. These pipelines are referred to as cross-country pipelines.

Pipelines which meet the Planning Act threshold could be carrying different types of gas, fuel or chemicals. The Planning Act currently only covers those nationally significant infrastructure pipelines which transport natural gas or oil.

Some pipelines which are not nationally significant infrastructure projects, may nevertheless be granted development consent as associated development by virtue of their connection with another nationally significant infrastructure project such as a power station.

[122] Offshore means in waters in or adjacent to England or Wales up to the seaward limits of the territorial sea, or in a Renewable Energy Zone, except any part of a Renewable Energy Zone in relation to which the Scottish Ministers have functions.

The draft NPS EN-4, which specifies the government's proposed updated approach to gas supply infrastructure and gas and oil pipelines, confirms the legal position that new carbon dioxide pipelines over 10 miles long will be considered nationally significant infrastructure requiring a DCO under the Planning Act.

Key considerations and requirements

In terms of the consenting of CCS infrastructure, as most elements of CCS on their own are not expressly included within the definition of NSIP projects within the Planning Act, they will often fall outside the DCO regime. Therefore, CCS infrastructure can often be consented through the TCPA route, should it be a project in its own right rather than part of a wider project which may require a DCO. The exception to this is pipelines, which could fall with the definition of an NSIP subject to certain thresholds.

If the CCS project falls outside of the DCO regime, it is possible to request that the project be considered as an NSIP. To take advantage of the Planning Act consenting process, a Section 35 direction will be needed from the Secretary of State which puts the particular project into the NSIP regime.

The Planning Inspectorate would decide whether to accept the project as an NSIP, which would be based generally on whether the project is considered of national significance.

The need for new CCS infrastructure has been acknowledged by the UK government and support illustrated for its development in proposed changes to planning policy.

CCS is one of the emerging technologies[123] (emerging in planning consenting terms, not the technology itself) that the UK government has identified as central to its plans to reduce emissions associated with electricity generation and from energy intensive industries, and to provide negative emissions to offset sectors that are difficult to decarbonise.

The support for CCS stems from the government's recognition that 'net zero' targets cannot be met by reducing carbon emissions alone. In the case of energy, both renewable "clean energy" is needed, along with the means by which to capture, transport and store carbon emissions.

Detail of the government's approach to supporting CCS infrastructure in the years ahead are contained in the draft national policy statements for energy infrastructure[124] – documents which, when finalised, will guide decision-makers when determining applications for development consent for nationally significant energy infrastructure under the Planning Act regime.

Of importance to this consideration is the inclusion of CCS in NPS and reference to the need for, and importance of, CCS is specifically mentioned in the draft NPS EN-1. Therefore, there is clear recognition of the national importance of CCS technology and projects, and the contribution that it can make to national decarbonisation.

EN-1 also requires that applications for development consent for power CCS projects include details of how the carbon dioxide will be transported and stored, assess environmental impacts cumulatively, and set out what other consents are required for the full chain. This is an important requirement for any such DCO application.

In respect of pipelines, there may be useful precedent from existing pipelines or through repurposing pipelines that could make the consenting process easier, insofar as the existing pipeline would have the necessary consents and land agreements. This provides useful precedent and demonstrates that it is achievable for that particular location.

[123] Pinsent Masons 2021, The role for emerging tech in UK energy infrastructure planning policy
[124] BEIS 2021, Planning for new energy infrastructure: review of energy National Policy Statements

Environmental Impact Assessment

If the project is taken through the DCO process projects of this nature would fall under Schedule 1, paragraph 23 of the Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 and the Town and Country Planning (Environmental Impact Assessment) Regulations 2017 ("EIA Regulations) as 'Installations for the capture of carbon dioxide streams for the purposes of geological storage pursuant to Directive 2009/31/EC from installations referred to in this Schedule, or where the total yearly capture of carbon dioxide is 1.5Mt or more'.

Any project that captures over this amount of carbon dioxide per annum is therefore classified as 'EIA development' and as such the DCO Application or TCPA planning application would need to be supported by an EIA. It may also be that projects that don't meet this threshold are also considered as EIA development depending on the scale and impacts of the proposals.

Permitting

The scope of this review includes the operation of a post-combustion carbon capture (PCC) plant at the main emitters in the Humber[125]. PCC plants can be fitted to new or existing power plants to capture the CO_2 in the flue gas.

Consents required

The operation of a PCC plant itself would fall under a Section 6.10 listed activity under the EPR and would require a Part A (1) environmental permit from the EA in order to operate. A new bespoke permit would be required if the carbon capture plant facility is standalone or a permit variation to add the plant to an existing installation permit would be required. The carbon capture activity would be a listed activity for the permit, whether a new permit or a variation.

There is no single BAT Reference document that covers carbon capture. The EA has recently published their own BAT guidance for that covers Best Available Techniques for PCC[126]. See below for further details.

Unless the PCC plant is a standalone facility, it is likely that the permit would include the activity the carbon is being captured from on the same installation[127]. Therefore, the relevant BREFs for those activities will be applicable (i.e. the Large Combustion Plant BREF, Refineries BREF etc).

Further engagement with/pre-application advice from the EA would be recommended to help better understand the permitting implications.

Key considerations and requirements

New Standalone Facility

If the carbon capture plant is to be its own standalone facility, a new bespoke Part A (1) permit will be required from the EA in order to operate.

Existing Facility – addition of carbon capture plant

For existing industrial sites, these sites are likely to already hold an environmental permit. Therefore, the capture plant would be added to an existing permit as an additional listed activity via a permit variation.

[125] The main emitters considered for this review are those from the following activities: refining, iron and steel, power generation/combustion, chemicals and cement and lime. Other industrial activities/emitters may also be present within the Humber industrial cluster. These have not been reviewed further in this section.
[126] Post-combustion carbon dioxide capture: best available techniques (BAT) - GOV.UK (www.gov.uk)
[127] see examples of relevant activities in footnote 125.

The permitting variation process is similar to applying for a new permit (Section 7.2.50). The inclusion of retrofitted plant to an existing permitted installation site will also need to ensure consistency with its already primary activity and ensure compliance with the associated BREF(s) (e.g., Large Combustion Plant BREF).

Emissions to air, wastewater, and solid waste streams

The purpose of a carbon capture plant is to remove CO_2 emissions from an existing source gas. Carbon capture plant may involve the use of amine solvents. Emissions of amine solvents would need to be assessed through detail air quality modelling to demonstrate compliance with the recently adopted Environmental Assessment Levels (EALs). Emissions of other parameters such as Nitrogen Oxides (NO_x), Sulphur Oxides (SO_x), Carbon Monoxide (CO), particulates and aerosols would also need to be assessed.

The carbon capture plant design would also need to take into account whether amine solvents/degradation products would be discharged in a wastewater effluent stream and if treatment processes would be required. If discharge to sewer is likely, then in addition to the Environmental Permit, the appropriate authorisation and consent will be required from the applicable sewer company.

Solid wastes and the removal of hazardous wastes will also need to be considered.

Regulatory risks and barriers

The regulatory risks and barriers related to CO_2 capture are associated with the specific rules, requirements and certification methodologies which must be complied with to develop and operate a CO_2 capture facility are outlined in

Table 17.

Table 17: Regulatory risks and barriers for CO_2 capture

Risks	Description
IP disclosure risk	Process licensors will need to disclose solvent composition to comply with Environmental Permitting Regulations[128,129]. Whilst this can help build public acceptance of CCS, some process licensors are concerned with the possibility of solvent composition becoming public under a public information request, which would conflict with their requirements for maintaining the commercial confidentiality of their solvent formulation.
Safety and siting concerns	Concerns around amine emissions and on-site CO_2 could arise, resulting in complications in the permitting process, particularly if the plant is near population centres.
Barrier	**Description**
Long-term liability risks	There is a lack of clarity around the liability for long-term CO_2 storage. The unclear risk allocation between the different actors across the value chain can be a source of industry reluctance for investment.
Unclear regulatory regime	The current regulations do not set out clear CO_2 specifications for injection to the T&S network. These specifications will impact the CAPEX and OPEX tied to post-treatment of the CO_2-rich stream. There is also uncertainty on the network charges from the TRI model.
Inconsistent planning application process	Some CCS projects may be consented through the DCO process, whereas others could be through the TCPA. This therefore may result in inconsistencies of approach and assessment.
Limited BAT guidance for capture technologies	Not all carbon capture technologies have associated BAT guidance. The EAs BAT guidance for PCC only covers the capture of CO_2 from selected activities, however, there is a wider scope of emitters within the Humber.

[128] The Environmental Permitting (England and Wales) Regulations 2016, SI 2016/1154, art 51(3)
[129] Environment Agency, 2021, AQMAU recommendations for the assessment and regulation of impacts to air quality from amine-based post-combustion carbon capture plants.

3.1.5 Recommendations and actions

The risks and barriers outlined above cover the market, policy and regulatory dynamics of CCS. In considering actions to mitigate those risks and barriers, there is merit to considering actions in the context of all three of these dimensions, due to the overlapping benefits which arise.

Drawing on the stakeholder discussions held, reviews of the literature, and Element Energy's own market insights, the following set of action categories are recommended to help actors within the Humber cluster navigate what is a complex and nascent market. These actions would either be considered the responsibility of industries operating within the Humber cluster, policy makers, and regulators.

Action 1: Finalise the carbon capture business model

There are currently no commercial scale CCS projects in the UK and the carbon capture business models are still under development. This could delay industrials in the Humber from investing in carbon capture technology until further clarity is provided.

BEIS need to release the finalised version of the industrial carbon capture business model to provide clarity over how the support mechanism will operate. This will provide transparency to HIC industrials on the level of support that can be expected throughout the lifetime of operation and enable projects to work towards a final investment decision. BEIS should release the finalised update as soon as possible; ideally this will be by early 2023.

Action 2: Increase focus on capture development for retrofit applications

Many industrial emitters will operate for many years before reaching end of life and will therefore require retrofitting of equipment to decarbonise. There are logistic impacts and disruption to plant activities tied to retrofitting plants and process integration, that can currently act as a barrier to carbon capture deployment.

Research institutions and technology developers should focus significant effort on developing capture technology that is designed for retrofit application. This includes innovation focusing on reducing space requirements, energy demands and the release of environmental pollutants that will streamline the permitting process for capture plants. Reducing the cost of capture retrofit has the potential to significantly increase uptake and maximise decarbonisation of existing facilities. Funding provided by BEIS will help accelerate this process however, research institutions and technology developers should focus efforts on developing retrofit capture immediately to enable time for trials and testing prior to scale up. This will provide industrials with greater confidence in the technologies capability prior to investment decisions being made.

Action 3: Address supply chain constraints on key components

Many of the components required to develop a carbon capture facility are already developed within the UK. However, several industrial users have expressed concerns relating to supply chain risks for key components such as compressors and absorption columns.

Government and industry should develop an inventory and schedule of key components for capture projects and prepare a supply chain analysis programme for carbon capture. The development of a supply chain analysis programmer will require significant input and collaboration from both sets of stakeholders. The CO_2 transport and storage network in the Humber is expected to be operational by 2026-2027. Analysis should therefore be conducted from 2023 to enable time for local supply chains within the Humber as well as the wider UK to be upgraded, to ensure capture plants can be developed in parallel to the transport and storage network.

Action 4: Minimise delays to capture development caused by planning

The risk of emissions released to the air, water requirements for carbon capture, or space availability constraints could impact on the planning process and delay or block the development of capture facilities in the Humber. Innovative solutions will be required by some industrials to deploy capture at their sites.

Early engagement with local planning authorities and regulatory bodies to identify constraints for developing capture plants will allow industry time to develop solutions that are less likely to be halted by planning authorities. Local planning authorities in the Humber region and existing industrials should be aware of the requirements for capture plants, with the planning application process streamlined where possible to minimise delays to development and industrials ready to work on innovative designs. Technology developers should focus on innovations that reduce the space requirements for capture plants. Existing industrials and local authorities should conduct feasibility studies that identify potential sites for capture development. Early identification of land-based or other constraints will ensure more time to develop solutions that are compatible with existing Humber operations.

Action 5: Communicate the essential role of carbon capture to the public

Carbon capture technology is currently poorly understood by the general public. The negative socio-environmental impacts of carbon capture (and of the whole CCS value chain), and the lack of awareness around the technology, might lead to public resistance. The public resistance can block the permitting process.

Carbon capture will be essential for many industrials to decarbonise, whilst also providing the lowest cost of abatement for others. Increased effort needs to go into communicating the important role the technology can play within the Humber and why it is required to achieve net-zero. The Humber Energy Board are well placed to communicate this information to the public, with the ability to incorporate the views of all stakeholders. The Humber Energy Board should continue to emphasise the importance of carbon capture deployment within the Humber through all public communication streams.

Action 6: Ensure CO_2 transport and storage infrastructure is scalable

There is a cross-chain risk across the CCS value chain that acts as a barrier to capture deployment in industry. As a nascent market, the lack of dedicated CO_2 T&S infrastructure is seen as a barrier by industries, whilst the uncertainty around demand for capture is seen as a barrier by the T&SCo network developers.

BEIS need to confirm the capture projects that are eligible for support from Phase 2 of the cluster sequencing process. This will provide greater certainty to the T&SCos on the level of demand that can be expected in the future. CO_2 T&S infrastructure developers in the Humber such as the Northern Endurance Partnership and Viking CCS should ensure that network capacity is scalable. This will ensure that rising demand for capture can be met by future phases of development. BEIS need to confirm the capture projects selected for support by 2022, while T&SCo network developers need to consider how designs can be scaled to allow for market growth. This should be considered at the pre-FEED stage of project development.

Action 7: Water requirements and availability should be assessed – and issues mitigated – at the early stages of project development

The Humber is forecast to be a water stressed region in the future, particularly south of the river. Carbon capture can be a water intensive technology, depending on the cooling configuration deployed that could further exacerbate water supplies in the Humber region if deployed at large scale.

Industrials and project developers looking to deploy carbon capture to reduce onsite emissions need to consider the water requirements of the proposed capture technology, and how water will be sourced sustainably at the initial project stages. Early engagement with the Environmental Agency and public water companies such as Yorkshire Water and Anglian Water is recommended for all new projects looking to deploy carbon capture. These organisations will be able to advise on the availability of water supply in the Humber region. This stage should be incorporated as part of the project pre-application advice to improve understanding of the permitting requirements.

Action 8: Alternative water sourcing options should be considered to increase project resilience

In the summer months, where water availability in the Humber is likely to be lower, water may be a constraining factor for project operation. The Environment Agency and public water companies can limit or even completely restrict water supplies in times of drought to protect the environment.

Industrials and project developers looking to deploy carbon capture should consider how they can increase their water resilience. Onsite water storage and recycling options should be considered by all projects to minimise the requirement to import water from the environment. Additionally, projects should not be reliant on importing water from a single source. Where possible, a project should be able to access multiple sources to allow operation to continue if access to the primary water resource becomes restricted. Hybrid carbon capture systems that can operate without water at times of low water availability could be a key means of protecting water resources in the Humber region during dry periods.

3.2 Imports of CO_2 from outside the Humber

3.2.1 Overview

The Humber has the potential to enable emitters beyond the core cluster to decarbonise by importing captured emissions for permanent geological storage. By developing capabilities to receive CO_2 imports, the Humber has the potential to provide storage as a service to emitters that will rely on carbon capture but are unable to connect to another transport and storage network. Approximately 80% of the UK's currently licensed CO_2 storage capacity is accessible from the Humber, with potential for further expansion[130]. Given the Humber's broad access to ports and considering that many large UK and European emitters are also situated near ports – albeit without access to CO_2 storage – shipping is likely to emerge as the dominant transport method for importing CO_2 to the Humber over the coming decades. Accordingly, multiple emitters in the UK and across Europe are expected to have to rely on CO_2 ships to transport captured emissions as a precondition to implementing CCS. Notwithstanding, other options exist to import CO_2 to the Humber via land, as discussed below. As of today, there is no operational market for CO_2 imports. Given the prospects for its rapid development over the next two decades, early movers are however likely to gain a competitive advantage as the market evolves.

CO_2 transport can be performed at various CO_2 conditions of temperature and pressure. At lower temperatures and pressures, CO_2 density increases allowing greater quantities of CO_2 to be transported for a given volume which is important in batch like processes such as shipping. Stakeholders involved in the development of the CO_2 shipping sector are considering two primary cryogenic conditions, medium-pressure (approximately -30°C and 15 bar_g) and low-pressure (approximately -50°C and 7 bar_g). Cryogenic CO_2 transport conditions focus primarily on the shipping element of the supply chain, whereas several studies argue that lower cost transport and storage can be achieved at ambient (high pressure, 5-10°C and 40-44 bar_g) conditions when the full CCS supply chain is considered[131]. Today, there is a lack of established standards and practices for CO_2 transportation which is leading to a range of differing transport conditions being proposed.

The definition of CO_2 imports is based on the following:

- **Final destination of the CO_2:** The CO_2 must be permanently stored in a storage site operated by a transport and storage company (T&SCo) with onshore CO_2 handling facilities in the core Humber cluster[132].
- **Geographical:** To be considered imports, the original CO_2 emitter (the 'customers') must be located outside the Humber region defined by the four local authorities of East Riding, North Lincolnshire, North East Lincolnshire and Hull[133].

Energy and resource implications

CO_2 can be transported in many conditions and different forms of transport. This may require transport via several intermediary steps on the way to the storage site including ports, terminals, and processing facilities. Various CO_2 transport options exist, although scale and transportation distance influence overall economics. A summary of the available transport conditions is shown in

[130] Humber Energy Board 2022, Humber 2030 Vision.
[131] Zero Emissions Platform 2022, Guidance for CO_2 transport by ship.
[132] The Northern Endurance Partnership and Viking CCS projects are the two storage sites currently in development in the Humber.
[133] As noted in the scope, an exception is made for the Drax power station, considered part of the Humber cluster though located outside the boundaries of the Humber local authorities.

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Table 18: Comparison of CO_2 transport types

Method	CO_2 transport volume	Advantages	Disadvantages
Pipeline	<30MtCO_2/year	• Only option transporting CO_2 at significant scale • Excellent safety record • Potential to repurpose gas pipelines, leading to cost savings • Subject to large economies of scale	• May be difficult to plan new builds due to safety, planning and consenting • Lack of widespread quantitative risk assessments industry-wide acceptance of HSE systems
Shipping	<60ktCO_2	• Technical feasibility and the cost of CO_2 shipping are well understood • Ships and port infrastructure are similar to those for LNG and LPG	• Large scale transport for CCS has not yet been achieved • Use is largely conditioned by port infrastructure limitations • Required additional storage capacity may affect feasibility at space constrained sites
Rail	<60tCO_2	• Can carry larger CO_2 volumes than road alternatives • Cost savings possible if rail infrastructure is already in place	• Large scale transport for CCS has not yet been achieved • Limited to deliveries where rail infrastructure exists • Required additional storage capacity may affect feasibility at space constrained sites
Road / truck	<30tCO_2	• Best suited for small quantities and for short distances, where demand is geographically dispersed • Large flexibility when it comes to final CO_2 destination	• Route choice constraints because CO_2 is considered to be a dangerous substance • Most carbon intensive form of transport • Required additional storage capacity may affect feasibility at space constrained sites • Impact of additional traffic on road system and local public

Trucking or rail transport may be considered for smaller emitters located in remote areas. Road transport of CO_2 provides the greatest level of flexibility when transporting CO_2 to storage sites and is currently operational commercially. Rail infrastructure can carry larger volumes of CO_2 and can provide cost savings where existing rail infrastructure can be utilised. Large scale transport of CO_2 via rail is yet to be operational and is unlikely to be a viable option unless infrastructure connecting emissions sources to planned transport and storage networks already exists.

CO_2 transport via pipelines and ships are regarded as the most suitable technologies for transporting large quantities of CO_2 over large distances (often required for CCS). Considering that gaseous CO_2 has a low density, it is often more cost-effective to transport it in a dense phase. Typically, CO_2 is transported via pipeline at high pressure (>100 bar) to minimise frictional losses via a number of compression stations. Liquefaction can also increase the density of CO_2 for ship transport via a series of refrigeration and compression steps. However, this is a very energy intensive process, hence the benefits of higher density that enable greater quantities of CO_2 to be transported in a given volume must be balanced against the increased energy-related costs required for liquefaction which is required to change the phase of the CO_2. Consideration should also be given to the purity of the transported CO_2 as impurities can affect the density, pressure and temperature of the CO_2 which is often required to operate within specific tolerance limits[134].

Pipelines are currently the most common method of transporting very large quantities of CO_2 and are operating commercially today. They are a well understood transportation technology for a wide range of fluids, particularly in the oil and gas sector. legacy oil and gas pipeline infrastructure is available, it is also possible that this can be reconverted to be utilised for CO_2 transportation with multiple benefits. Pipeline conversion can significantly reduce the cost of pipeline transport, dominated by investment costs, and also reduce the cost of decommissioning legacy assets. Furthermore, it may make it easier to obtain development consent and hence reduce the development timeline. The potential for legacy pipeline conversion should however be carefully assessed on a case-by-case basis to identify potential technical limitations and risks to health, safety, and the environment.

Shipping CO_2 has been operational at small scale for the past 30 years with demand primarily coming from the food and beverage industry. Current CO_2 ships have capacities of less than 2,000 tCO_2. Significantly larger ships are required for commercial CCS applications. For example, a ship with a capacity of 10,000 tCO_2 is required for a project with a moderate flow rate of 1 $MtCO_2$/year[135]. Shipping could be more economical than offshore pipelines over longer distances and for smaller CO_2 volumes. Over very long distances the cost of offshore pipeline development can become unviable, particularly where small volumes of CO_2 transport are considered.

[134] Guidance on transporting CO_2 in pipelines is provided by the Health and Safety Executive – HSE: Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects
[135] Element Energy for BEIS 2018, Shipping CO_2 – UK Cost Estimation Study.

Infrastructure: CO_2 imports

The import of CO_2 into the Humber would require the development of terminals and conditioning infrastructure that enables connection to the transport and storage network. This can often require a transformation of CO_2 condition via gasification or compression facilities to ensure a consistent CO_2 standard across the network. The onshore infrastructure requirements in the CO_2 import value chain are shown in Figure 19. These consist of the following stages:

- **Unloading** of the CO_2 off the ship via conventional articulated loading arms or flexible cryogenic hoses. Energy is required to drive pumps and operate the automated loading arms.
- **Temporary/buffer storage** is required to bridge the gap between (semi-)continuous CO_2 capture and batch transportation by ship.
- **CO_2 conditioning** to optimise CO_2 temperature and pressure for pipeline transport. Energy is required to drive pumps, compressors and heat the CO_2 to increase efficiency of pipeline transport.
- **Pipeline transport** of the captured CO_2 to the storage site requires energy for pumps and compressors to maintain the CO_2 at the required transport condition.

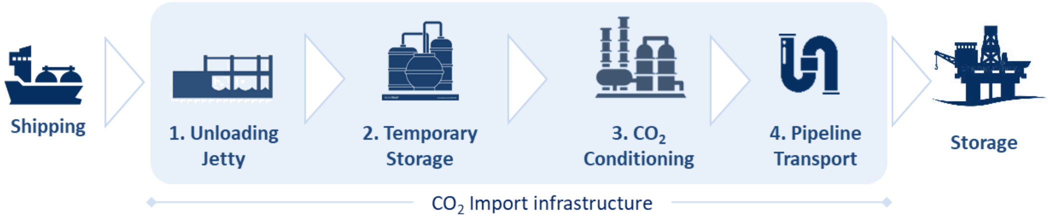

Figure 19: Onshore infrastructure requirements for CO_2 imports via ship

Depending on the CO_2 import condition, these process steps can often be energy intensive.

The infrastructure for CO_2 transport and storage can consist of several onshore components including an unloading jetty, temporary storage, conditioning facilities and pipelines. The infrastructure is typically optimised for a single CO_2 condition with low, medium and high-pressure conditions all possible transportation options. CO_2 is pressurised to match that of the geological formation before injection into the reservoir to ensure efficient storage and minimise risks related to equipment damage due to sudden changes in pressure. Shipping, road and rail are all batch processes that can result in peaks and troughs in volumes of CO_2 imported into the network. Buffer storage facilities can smooth the rate of injection into the network however they can be very big with land requirements of up to 7,000m^2 for a single (190,000m^3) tank commonly seen in the LNG industry which shares similar characteristics to the CO_2 shipping value chain[136]. Additionally, CO_2 shipping will likely require dedicates jetties and offloading infrastructure. This could be developed at existing ports however it is possible that this could interfere with existing shipping activities in some capacity, depending on the demand for imports, frequency of unloading and ships size.

3.2.2 Market study

Opportunities for deployment

Depending on the level of demand for CO_2 imports to the Humber, multiple shipping terminals could be developed both onshore at existing or new-build ports, or offshore, for direct injection at the storage site. Potential locations include the Immingham port, which currently operates a diverse trade base including liquid bulks, dry bulks, roll-on/roll-off and containers. Early studies identify significant potential to develop a CO_2 import terminal at the existing port located in close proximity to the planned Viking CCS CO_2 transport and storage

[136] 7,000m^2 based on a 190,000m^3 LNG storage tank at the Isle of Grain.

infrastructure[137]. The port has deep water capabilities enabling it to accommodate large CO_2 carriers (up to 50,000m^3) that are likely to be associated with low-pressure CO_2 shipping. This has led to Harbour Energy and Associated British Ports announcing an exclusive commercial relationship to develop a CO_2 import terminal at the Port of Immingham, that will connect to Viking CCS. Associated British Ports plan to invest in new infrastructure at the port, including a jetty to service the import and export handling of liquid bulk products. Construction of the jetty is expected to begin in late 2024 with the aim to be operational and ready to receive first CO_2 imports from 2027[138].

This study aims to quantify the market size for CO_2 imports to the Humber from both onshore and shipping transport modalities. Large scale industrial emitters surrounding the Humber region could rely on carbon capture to decarbonise with over 12 $MtCO_2$/year of emissions located within a 100km range of the core Humber cluster. Over greater distances, CO_2 shipping is likely to be the most economical method of transportation and essential for clusters without access to geological storage such as Southampton. Market sizes for CO_2 shipping are based on project announcements, with many clusters actively looking to export CO_2 from both existing industrial emitters as well as future sources of CO_2 such a CCS-enabled hydrogen production. This analysis presents a low-uptake and high-uptake scenario for CO_2 imports to the Humber over a time period from 2030-2040.

This study breaks down the potential for CO_2 imports into three separate categories. These include UK imports via land, UK imports via ship and European imports via ship. Details of this approach and the primary sources of captured emissions are provided in the following sections. The combined emissions total that could be imported from outside the Humber region are shown in Figure 20 for both the Low Uptake and High Uptake scenarios. This analysis suggests that there is likely to be significant demand for CO_2 storage solutions, both in the UK and Europe. This could justify further analysis into the investments that would be required for infrastructure development required to enable CO_2 imports. The complete methodology for assessing CO_2 shipping is shown in the appendix.

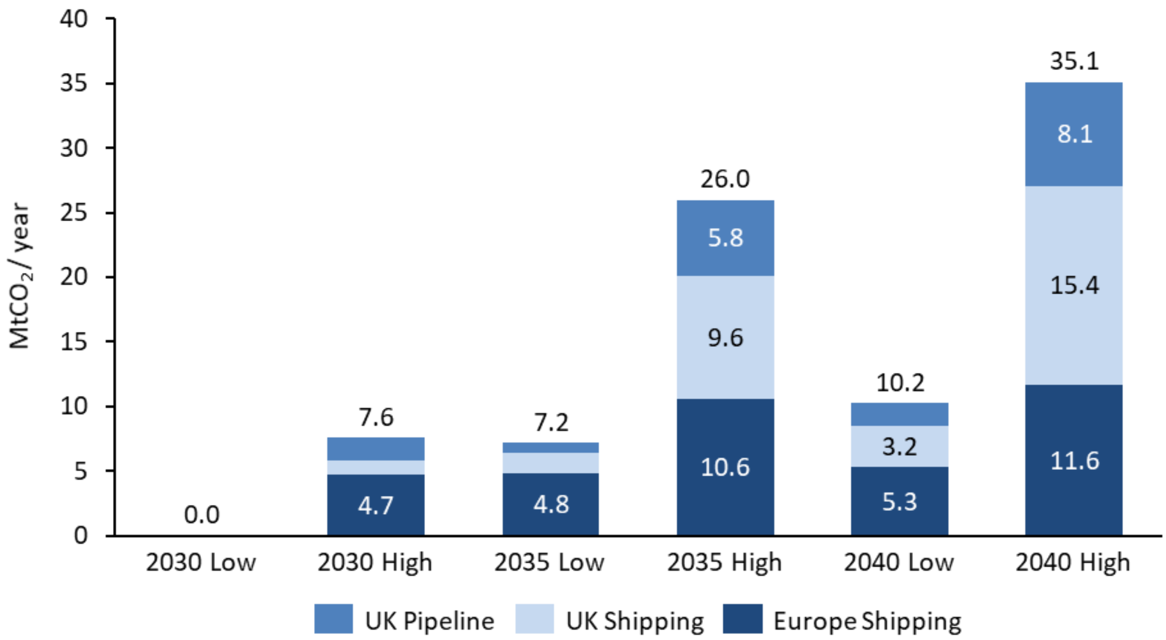

Figure 20: Potential CO_2 imports to the Humber from pipeline and shipping

There is unlikely to be significant volumes of CO_2 imported to the Humber by 2030. This is primarily due to initial CCS projects focusing on pipeline transportation methods resulting in a lack of capacity for CO_2 shipping. The Humber is unlikely to have developed the operational CO_2 import capabilities by 2030. The first large scale CO_2 shipping projects are likely to be operational by 2035, with initial routes likely to come from industrial clusters

137 V Net Zero 2021, Landmark study to explore potential of Humber to emerge as carbon shipping hub.
138 Viking CCS 2022, Viking CCS and Associated British Ports embark on major step towards a future CO_2 shipping industry in the UK.

within the UK. Both Southampton and South Wales industrial clusters could be transporting large volumes of CO_2 to UK storage sites, including the Humber. The volumes of CO_2 transported are likely to be dependent on the uptake of CCS-enabled hydrogen in these regions. European clusters such as Dunkirk, Antwerp and Rotterdam could all ship a portion of emissions to the Humber by this time period.

The CO_2 shipping market is likely to be more established by 2040, transitioning towards a market-based model. The Humber cluster is likely to be one of the primary North Sea storage sites, benefitting from access to the Endurance and Viking CCS storage capacities. Early development of CO_2 import terminals is likely to provide a competitive advantage compared to newly developed storage projects. The volume of CO_2 transported to the Humber is likely to be dependent on the price relative to alternative storage sites within the region.

Imports from UK sites via land

The expansion of the Humber CO_2 pipeline network could enable multiple sites from the surrounding areas to decarbonise via carbon capture deployment. There are a range of large-scale power, cement and lime emitters that could be suitable for CCS deployment within 100km of the cluster as shown in Figure 21. New CCS-enabled hydrogen production facilities could also enable the expansion of the pipeline network beyond the core Humber cluster. However, HyNet, the CO_2 transport and storage network located in the North West of England selected for track 1 sequencing alongside the East Coast Cluster could also extend their pipeline network, resulting in significant competition for emitters in the North of England. The requirements for new transport and storage infrastructure to enable CO_2 imports in the Humber region is detailed in section 3.1.1.

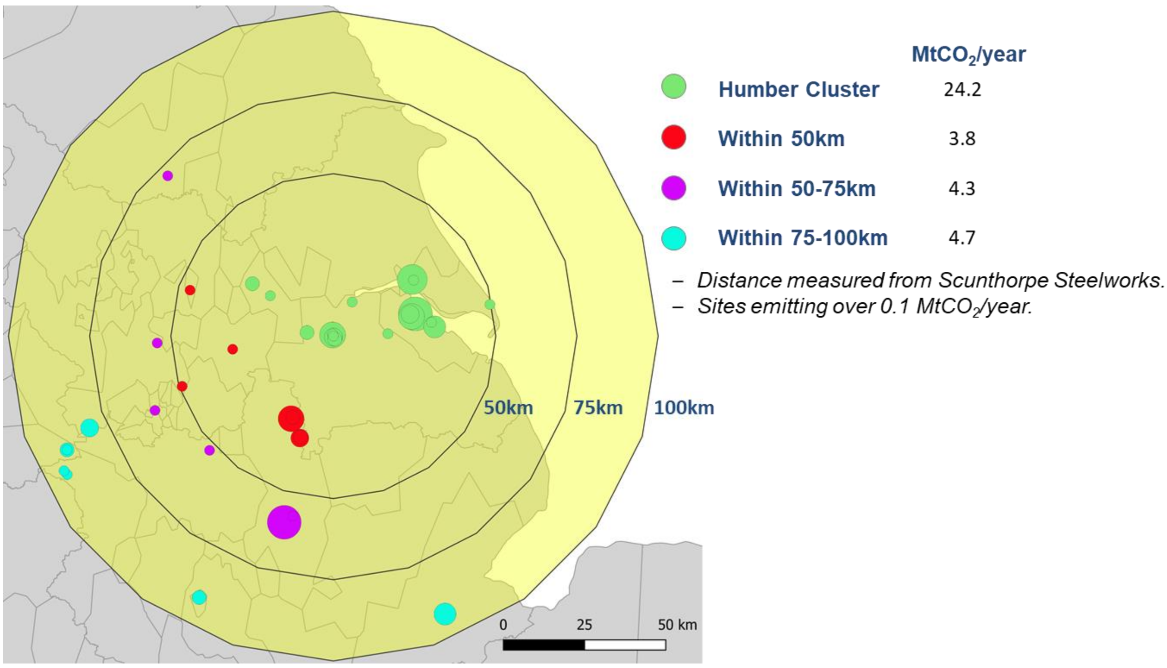

Figure 21: Potential CO_2 imports to the Humber[139,140]

The Humber has the potential to import CO_2 from a range of onshore emitters in the surrounding region as shown in Figure 22. This study assumes that there are no onshore imports in the Low Uptake scenario as it is likely that the required import terminal or pipeline extension infrastructure will not have been developed by this time period. However, by 2040, it is likely that there will be some level of onshore imports, particularly from the cement sector where carbon capture deployment will be essential for decarbonisation.

[139] Data source: National Atmospheric Emissions Laboratory (NAEI) 2019 Dataset.
[140] It is not feasible to develop pipelines through areas of natural and environmental significance. Some emitters would require very long indirect routes to connect to the Humber cluster.

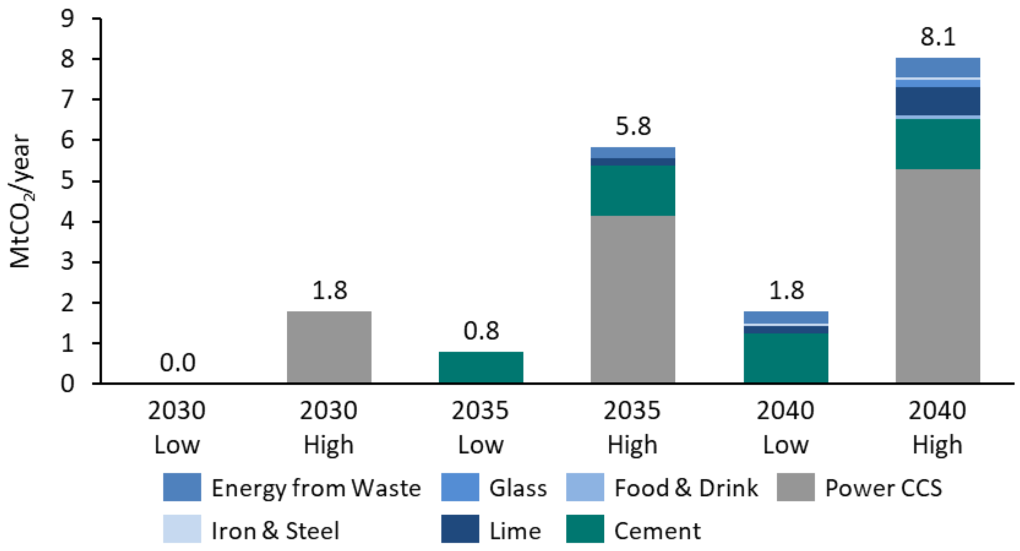

Figure 22: Potential demand for UK imports via land

In the High Uptake scenario, it is assumed that 50% of existing fossil fuelled power capacity will be retrofitted with carbon capture technology or replaced with new-build power generation facilities with carbon capture technology. This assumes that facilities closest to the Humber will connect to the transport and storage network first. Although many existing power plants will be replaced by renewable generation such as offshore wind, 24-hour dispatchable power demand is likely to still be required locally by some industrial facilities. This could result in an additional 1.8 $MtCO_2$/year of imports in 2030, growing to 5.3 $MtCO_2$/year in 2040. The High Uptake scenario also assumes that carbon capture is applied to a portion of all industry by 2040, as by this period barriers to capture deployment are likely to be significantly reduced. Capture from industrial emitters could result in an additional 1.7 $MtCO_2$/year in 2035, growing to 2.8 $MtCO_2$/year in 2040.

Imports from UK sites via ship

Industrial sites without access to nearby geological storage are likely to rely on CO_2 shipping to achieve their decarbonisation goals. This is due to the high investment costs associated with developing pipelines over long distances that can result in CO_2 transport via ship being lower cost. In the UK, the southern North Sea and northern Irish Sea provide nearby access to depleted gas fields and saline aquifers suitable for geological CO_2 storage. However, no suitable storage sites have been identified in the south of the UK. For this reason, CO_2 shipping is being considered as the primary transport modality for large scale decarbonisation at the South Wales Industrial Cluster (SWIC) and Southampton cluster.

The development of new infrastructure will be required to enable the imports of CO_2 via ship to the Humber. Today, there are no projects developing the infrastructure required to receive imports of CO_2 via ship and funding is not available in the first round of BEIS support for the Track 1 clusters to develop CO_2 shipping.

This analysis considers emitters in the UK that are most likely to ship CO_2 to the Humber cluster. This accounts for current public announcements that aim to support CO_2 shipping, vicinity to alternative CO_2 storage sites, and the potential volumes of CO_2 captured. Today, the sites considered most likely to ship CO_2 to the Humber include the South Wales Industrial Cluster, Southampton Cluster and Cory Riverside Resource Recovery as shown in Figure 23.

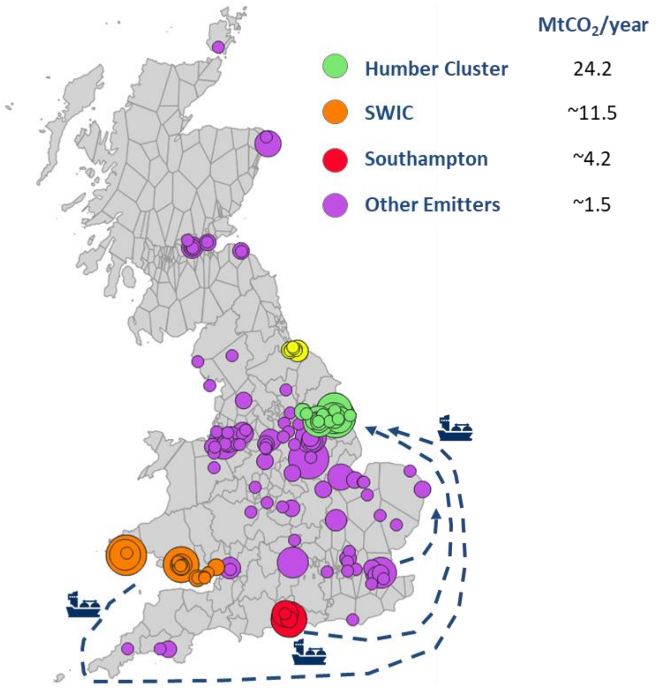

Figure 23: Potential UK CO_2 shipping imports to the Humber

The potential volumes of CO_2 shipping imports to the Humber from the UK are shown in Figure 24. In the short-term, volumes of CO_2 shipped are expected to be low, with large-scale CO_2 shipping unlikely to be operational prior to 2030. To enable both the South Wales Industrial Cluster and Southampton cluster to decarbonise by 2050, uptake of CO_2 shipping is likely to increase rapidly during the 2030's. Large industrial emitters such as the Fawley refinery, Milford-Haven refinery and Port Talbot steelworks are currently some of the largest point source emitters in the UK and likely to be some of the early sites selected for CCS deployment. New projects, including a CCS-enabled hydrogen production facility in Southampton could also require large volumes of CO_2 to be transported via ship in the future. The High Uptake scenario also considers the growth of inland shipping of CO_2 to enable sites to decarbonise with the recently announced project at Cory Riverside Resource Recovery[141] (an energy from waste facility in London) potentially a significant source of imported CO_2 emissions to the Humber. By 2040, between 3.2 $MtCO_2$/year to 15 $MtCO_2$/year could be imported to the Humber cluster in the Low Uptake and High Uptake scenarios respectively.

[141] Cory 2021, Cory announces plans for world's biggest energy from waste decarbonisation project.

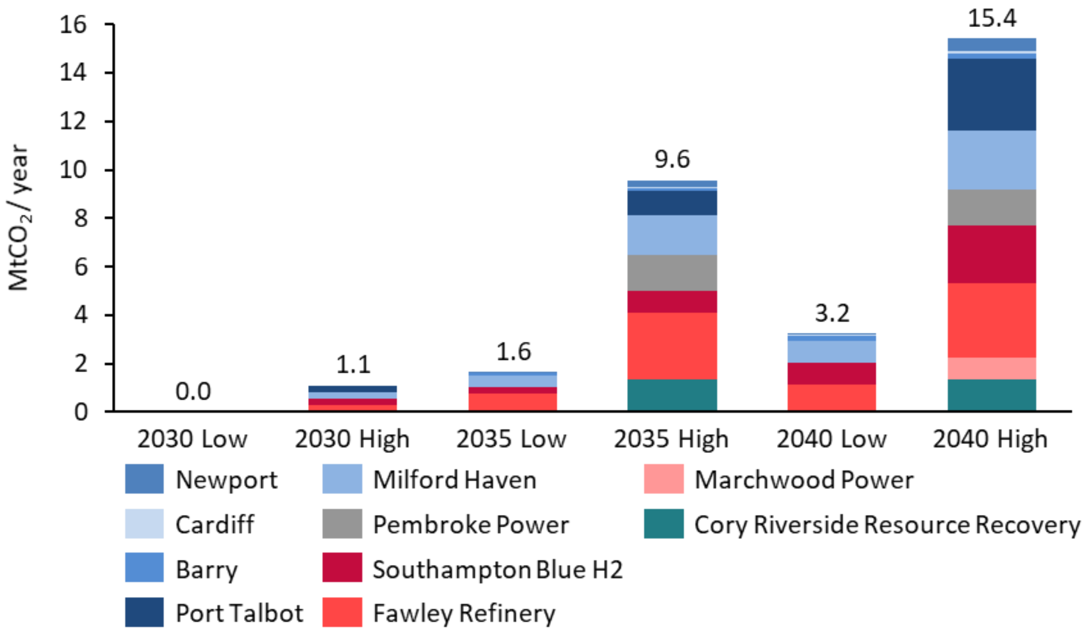

Figure 24: Potential CO_2 imports to the Humber – UK shipping

Imports from European sites via ship

Many regions in Europe do not have access to nearby geological storage and will rely on CO_2 shipping to decarbonise. The development of terminals that enable CO_2 imports via ship could unlock access to over 100+ $MtCO_2$/year from existing industry and power facilities in Europe. Large industrial clusters are located within 500km from the Humber in regions including the Netherlands, Belgium and France.

There are several CCS projects currently in development across Europe, the majority of which will look to utilise storage in the North Sea. Norway is in the process of developing the world's first large-scale commercial CO_2 shipping infrastructure through the Northern Lights project that aims to be operational by 2024. This could enable investment in carbon capture facilities and the infrastructure required for exporting CO_2 by many coastal industrial emitters. In the long term, CO_2 transport and storage in Europe is likely to transition to a more competitive market structure with multiple shipping operators connecting emitters with many storage sites. If the Humber can offer CO_2 storage at lower cost than European competitors, it has the potential to import large volumes of CO_2 from European emitters in the future.

This analysis considers CO_2 shipping imports from three of Europe's largest industrial clusters as shown in Figure 25. These were shortlisted due to their public announcements for developing CO_2 shipping exports in the future alongside the relatively short shipping distances to the Humber cluster. European CO_2 shipping exports to the Humber are considered from:

- **Dunkirk** – the Humber is likely to be the 2nd closest CO_2 storage option for the Dunkirk cluster and could play a significant role in decarbonising the highest emitting region in France. The ArcelorMittal iron and steel production facility is the largest emitter in the region and is likely to require CCS in some capacity to decarbonise in the future. The region also includes aluminium production and chemical facilities that would be suitable for carbon capture deployment. Initial studies suggest that over 10 $MtCO_2$/year could be captured from the Dunkirk cluster for storage by 2035[142].
- **Antwerp** – the Port of Antwerp is home to the largest integrated energy and chemical cluster in Europe and has plans to develop multimodal CO_2 transport and storage solutions utilising both pipelines and

[142] 3D CCS 2021, DMX Demonstration Dunkirk.

shipping. The port aims to reduce 50% of current emissions by 2030, equivalent to over 18 $MtCO_2$/year. The Humber could provide a competitive solution for large portions of emissions from Antwerp.

- **Rotterdam** – Rotterdam plan to develop a CO_2 hub terminal that will enable both CO_2 import and export capabilities. Porthos and Aramis are the two major CCS projects in the region where pipeline solutions are likely to be primary storage location for the majority of captured emissions. In the future, significant emissions could also be shipped to Rotterdam via river barge shipping from the North Rhine-Westphalia region, the industrial heartland of Germany. CO_2 shipping exports to stores such as the Humber could be required at times of limited network capacity.

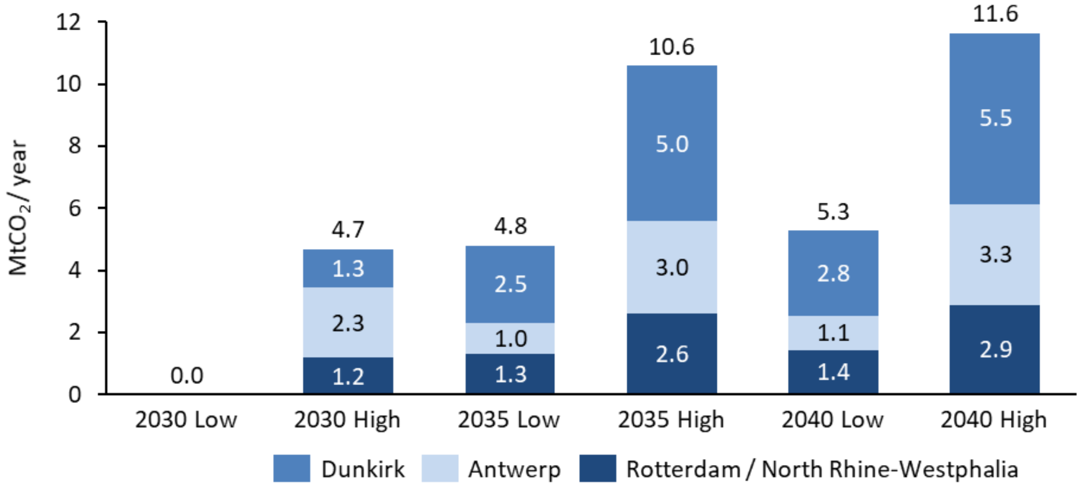

Figure 25: Potential demand for European imports via ship[143]

In the short-term, the Low Uptake scenario assumes that volumes of CO_2 shipped are expected to be low, with large-scale CO_2 shipping from Europe unlikely to be operational prior to 2030. However, the market for CO_2 shipping is likely to increase rapidly during the 2030's with many clusters and emitters across North West Europe aiming to secure storage contracts at competitive prices. This could result in emissions of over 5 $MtCO_2$/year imported to the Humber by 2040, equivalent to more than that of the entire Southampton cluster today. This study assumes that in the High Uptake scenario, the development of the CO_2 shipping sector evolves at an advanced rate as barriers to deployment are removed. This enables many CO_2 shipping operators to be operational by 2030 with large volumes of CO_2 captured from Europe's largest clusters. Due to the proximity of the Humber to the Dunkirk cluster, large volumes of emissions are imported from the iron and steel production facility and surrounding industries with up to 5 $MtCO_2$/year imported by 2035. By 2040, up to 11.6 $MtCO_2$/year could require storage in the Humber region, equivalent to the South Wales industrial cluster today.

Additional CO_2 shipping projects are likely to be developed in the future that could transport emissions to the Humber for storage. Due to the high levels of uncertainty associated with forecasting the market for CO_2 shipping future projects were considered out of scope for this analysis.

Market risks and barriers

The market specific risks and barriers associated with developing a CO_2 import market reflect the high level of uncertainty caused by the low technology maturity and the fact that no projects are yet importing CO_2 on a commercial scale. The primary risks and barriers for importing CO_2 to the Humber are outlined in Table 19.

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[143] This analysis only considers announced projects likely to develop CO_2 shipping – additional shipping projects are likely to be developed in the future.

Table 19: Market risks and barriers for CO_2 imports

Risks	Description
Import infrastructure asset constraints	Possible constraints on elements needed to import CO_2 such as land availability, dimensions of existing port jetties and water depths or pipeline routing, which can limit or completely hinder the scale of imported volumes. A lack of terminals may limit the maximum capacity of CO_2 shipping imports that can be processed, whilst existing shipping activity may also restrict potential import capacity. In the Humber region, the Port of Immingham is the UK's largest port by tonnage, whilst the Humber is the biggest trading estuary in the UK. However, North Lincolnshire is blessed with the largest undeveloped site fronting a deep-water port in the UK[144].
High cost of CO_2 import infrastructure	Additional cost of the full CCS chain when CO_2 imports are needed challenges competitiveness of CCS projects that rely on imports when compared to localised CCS projects. Emissions capture from new CCS-enabled hydrogen, power CCS and engineered carbon removal projects could be located near emerging CO_2 storage infrastructure in the first place if it is found that the cost of CO_2 transport would constitute a significant cost factor.
Competition with other T&SCo operators	Competition puts additional pressure to reduce costs and accelerate plans to develop CO_2 import capabilities. There is a significant risk that part of the import market in the North of England could be captured by the HyNet cluster as well as other storage projects in the North Sea such as the Northern Lights in Norway and Aramis in the Netherlands.
Competition with neighbour clusters for CO_2 imports	There is a risk that HyNet captures part of the future market for CO_2 in the North of England reducing potential for CO_2 imports to the Humber. Today, there is no funding within the scope of the current Humber pipeline project to enable imports from any onshore transportation method.
Competition with hydrogen exports	CO_2 import and hydrogen export value chains are likely to be technically and commercially similar. This can lead to competition between the two (e.g., for repurposing of compatible pipelines, for land to deploy liquefaction assets, limitation of port activity due to simultaneous imports and exports).
Optimal balance between design, underutilisation and additionality	The level of confidence and credibility of potential dispersed emitters is smaller than cluster emitters. Initial designs by T&SCo project developers could ignore potential additionality of more distant emitters, limiting future import potential unless initial assets are designed to allow for phased growth.
Barrier	**Description**
Inconsistent CO_2 specification requirements	If specification requirements for Humber networks are relatively stricter than those of competitors, this can limit the potential and flexibility for CO_2 imports.
Projects not taking a coordinated approach	Fragmented approach to developing commercial opportunities for CO_2 imports could result in projects with shareable infrastructure or consenting plans to develop physical assets separately missing the opportunity for economies of scale or higher competitiveness.

3.2.3 Policy study

Policy status and future enablers

CO_2 transport and storage business model

For CCS to be a key technology in supporting the government to achieve its net zero targets, there is a need to raise around £15 billion in private investment to construct and deliver the early phases of the CCS T&S assets. This CO_2 T&S business model is crucial to delivering the government's Net Zero targets and will be a primary driver of private investment into the CCS T&S infrastructure.

Today, the focus for BEIS is on developing a wider regulatory system & contractual framework. A private sector delivery model is the preferred approach for the delivery of the T&S network (initially supported by targeted forms of government support). BEIS recognise potential need for public sector support in capital funding, which can be offered via CCS Infrastructure Fund (CIF) both as debt and equity.

[144] Marketing Humber 2022, Invest in North Lincolnshire

The current BEIS preference is for the T&SCo owning both the onshore and offshore networks/systems (especially in early phases) since BEIS think the T&SCo is best placed to negotiate and develop solutions for resolving interface risks between the different T&S elements of the infrastructure. Ofgem have been selected for the role of Regulator of T&S networks in the UK due to their experience regulating the energy markets. Ofgem have the aim of protecting consumers' interests and will set the allowed revenues that the T&SCo can charge to emitters to ensure value for money to taxpayers.

The T&SCo will be responsible for setting T&S fees to collect the allowed revenue set by the Regulator. T&S fees will be set annually, four months in advance of the charging year, based on users forecast volumes of CO_2 to be injected into the network and users booked capacity.

Transport and storage fee invoices will be sent directly to users' each month, based on their utilisation of the network in the previous month. Interest will be applied to late payments to incentivise users to pay in a timely manner. T&SCo's revenue stream will be made up of payments from those who use the T&S network to have their captured CO_2 transported and stored, known as the 'User Pays' model as shown in Figure 26. The model can be extended to accommodate the import of CO_2 from sources external to the T&S network (i.e., directly injecting CO_2 at the storage site) or enable the reuse of CO_2 in the future, (i.e., users who connect to the T&S network to offtake CO_2 will make payments to T&SCo too).

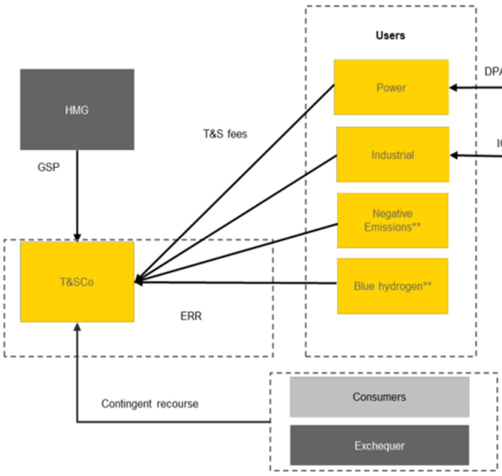

Figure 26: Illustration of the User Pays revenue model[145]

Different types of pipelines could attract different types of connection charges. Users could connect to trunk or feeder pipelines, or transport CO_2 via non-piped transport methods e.g. shipping. No connection charge should be levied on users in the early operational phase of the T&S network. T&SCo will incur system costs driven by the length and the capacity of the onshore and offshore pipelines, the volume and distance of the CO_2 transported, and the volume of CO_2 stored. Use of system charges will be levied on users to reflect the costs their use of the network imposes on the T&SCo. BEIS propose two use of system charges for onshore / offshore pipelines and storage. Both will have the structure shown in Figure 27. Onshore pipeline charges should not vary by the distance over which the CO_2 is transported in the early operational phase.

[145] BEIS 2022, CCUS: An update on business models for Carbon Capture, Usage and Storage.

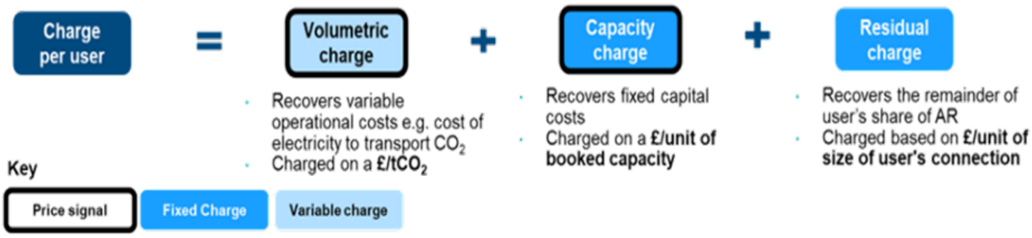

Figure 27: System charges for pipeline transport[146]

Funding mechanisms

Funding for CO_2 imports is likely to come via the CO_2 transport and storage business model in the future. BEIS consider the capacity for transport and storage networks to be able to accept CO_2 from dispersed sites and international sources, transported by non-pipeline transport modalities vital to achieving the UK's long-term decarbonisation goals. Today, BEIS are in the process of developing the licence conditions and business model arrangements so that non-piped sources of CO_2 can be accommodated by the CO_2 transport and storage business model. The development of a dedicated CO_2 shipping model could also be a key incentive for the growth of CO_2 imports in the future with investment and revenue support likely to accelerate uptake.

Policy risks and barriers

Today, policy development associated with the transport of CO_2 has primarily focused on pipeline solutions. A future CO_2 import market could play an important role in enabling UK decarbonisation and policy development at BEIS is considering how imports could be integrated into existing CO_2 transport policy. The policy-related risks and barriers associated with CO_2 imports are outlined in Table 20.

[146] BEIS 2022, CCUS: An update on the business model for Transport and Storage.

Table 20: Policy risks and barriers for CO_2 imports

Risks	Description
BEIS settles for a T&SCo owning all infrastructure ownership model	BEIS' minded to ownership position for T&SCo to be owned by one operator only can limit import opportunities via pipelines, ignoring transport models which would enable independent onshore pipeline operators to connect to enter CO_2 transport value chains. In the future, CO_2 shipping has the potential to transition from a T&SCo-owned-and-operated model, to a market-based model. This could consist of shipping operators servicing multiple emitters and storage sites as the market matures with individual contracts for transport and storage components.
Barrier	**Description**
Non-piped CO_2 transport inclusion in the TRI	BEIS will not include non-piped CO_2 transport modes in the initial design of the TRI Model and has not specified a time when change will be introduced. Within 100km of the Humber, there are a range of industrial emitters including cement, glass and waste facilities representing almost 3.5 $MtCO_2$/year. Many of these sites may rely on carbon capture in the future but will require a means of connection to a transport and storage network, potentially via NPT solutions. Today, their lack of inclusion for support limits the early development of CO2 imports as NPT projects cannot be subsidised.
Oversubscribed Humber pipeline network	Once local carbon capture projects are developed, it is highly possible that the local Humber pipeline network will be utilised at its full capacity, which will constrain access to the network for CO_2 imports. Today, there is no funding available to extend the transport and storage network beyond the core Humber cluster, however, there could be substantial demand in the future if this were to be made available. Viking CCS is a Track 2 transport and storage company (T&SCo) that could increase the T&S capacity available in the Humber. If selected by BEIS for Track 2 funding, the Viking CCS project could commence operation by 2027 to inject CO2 into the Viking storage site, a depleted natural gas field.

3.2.4 Regulatory study

The Humber will look to have a CO_2 import/operating terminal to handle, process and store CO_2. CO_2 imports planned for the Humber would include CO_2 emission sources from beyond the Core Humber cluster. This study focuses on the regulatory requirements for importing CO_2 via ship, as this is predicted to be the largest source of CO_2 emissions imported to the Humber.

The CO_2 terminal will need to include a Jetty, CO_2 pipelines, temporary storage of CO_2 and Conditioning plant (compression/liquefaction).

Planning requirements

Consents required

Projects including the construction of a shipping terminal with CO_2 imports facilities can potentially be consented through different regimes depending on the scope of the project and the extent of the proposed development and its operation. For this reason, it is necessary to consider the following legislation:

- Planning Act 2008
- Town and Country Planning Act 1990
- Harbours Act 1964
- Marine and Coastal Access Act 2009

Planning Act 2008

The Planning Act sets out in Section 24 the thresholds for Nationally Significant Infrastructure Projects (NSIPs). For the ports sector, applications for development consent will be considered NSIPs and therefore referred to Planning Inspectorate if the estimated annual capacity exceeds:

- 0.5 million Twenty Foot Equivalent Units (TEU) for a container terminal.
- 250,000 movements for roll-on roll off (ro-ro).
- million tonnes for other (bulk and general) traffic. Or
- a weighted sum equivalent to these figures taken together.

If a project's throughput exceeds the threshold stated within the Planning Act the proposed port terminal would therefore constitute an NSIP, requiring consent from the Secretary of State via a DCO.

The DCO consent includes the planning consent as well as other necessary consents for the project such as a Marine Licence under part 4 of the Marine and Coastal Access Act 2009.

Harbours Act 1964

The Harbours Act 1964 ("the 1964 Act") remains the relevant consenting process for any port and harbour developments that do not meet one of the thresholds within the Planning Act.

New port/harbour developments concern both the terrestrial and marine planning regimes. Local authorities only have jurisdiction to determine planning applications over land down to the low water mark. Any new port or harbour project will require consent not only for the development above the low water mark, but also covering those elements of the development below the low water mark, and, importantly, control over an area of sea adequate to enable the operation and maintenance of the port/harbour and its facilities.

The promoter of a port/harbour development will require statutory authority in order to override rights of public navigation and the harbour order confers authority over an area of sea within prescribed (and therefore enforceable) limits as well as all necessary powers to construct, operate and maintain the port/harbour structures and to control the activities of vessels within those seaward limits, including land powers.

Powers are likely to include "works powers" such as, for example, powers to construct physical works, to dredge channels for vessels to follow etc. This may require the creation of a new statutory harbour authority to carry out those functions.

It may also be necessary to include powers of compulsory acquisition over third party land and property. For all this, any project will need the express consent of the Secretary of State for Transport.

The procedure for obtaining a Harbour Order is set out in Schedule 3 to the 1964 Act. The schedule has changed over time to take account of European legislation concerning environmental impact assessment including, most recently, the EIA Directive 2014.

No application can be made until the promoter of the scheme has formally notified the Marine Management Organisation (MMO) of the intention to make the application, and the MMO has responded.

Town and Country Planning Act

Where port projects do not fall within the thresholds identified within the Planning Act and it is not considered appropriate to seek a Harbour Order due to the scope and scale of the project, the planning consent for the proposal could be sought through the Town and Country Planning Act 1990 (TCPA).

This would be a 'standard' planning application where consent would be sought from the Local Planning Authority. Only planning consent is obtained through this process. All other necessary consents would need to be obtained separately.

Marine and Coastal Access Act 2009

Some marine developments require marine licences under the Marine & Coastal Access Act 2009 and/or planning permission under the Town & Country Planning Act 1990. In 2010, following the coming into force of the Marine and Coastal Access Act 2009, the functions of the Secretary of State under the 1964 Act were delegated to the newly established Marine Management Organisation ("MMO").

- The types of activities taking place below mean high water that might require a marine licence include:
- Construction, alteration or improvement of works
- Dredging
- Deposit, incineration or removal of any substance or object
- Scuttling of any vessel

A port or harbour authority is exempt from the need to obtain a marine licence for dredging and disposal of dredged material where such activities are specifically authorised by the harbour authority's own harbour legislation.

Activity taking place in the inter-tidal area could fall under both the marine licensing and terrestrial planning regimes. However, some activities undertaken by a port or harbour authority are permitted development that does not require planning permission, including:

- Transport related development for the purposes of shipping, or in connection with the embarking, loading etc of passengers or goods at a dock, pier or harbour
- Development specifically authorised by a harbour order.

Environmental Impact Assessment

Irrespective of the consenting regime and method, given the nature of the project it is extremely likely that that an EIA will be required. If so, the notice of the proposed application must include certain environmental information to enable the MMO to determine, having consulted with relevant bodies with environmental responsibilities, whether an EIA is required and, if so, what it should cover. It is incumbent on a prospective applicant to canvas the views of all such bodies, and other relevant interested parties such as local wildlife trusts, before giving the MMO formal notice, and to take their feedback into account when explaining the proposal to the MMO.

Key considerations and requirements

The National Policy Statement for Ports was designated on 26th January 2012. The policy states that ports have a vital role in the import and export of energy supplies, including oil, liquefied natural gas and biomass, in the construction and servicing of offshore energy installations and in supporting terminals for oil and gas pipelines. It acknowledges that port handling needs for energy can be expected to change as the mix of our energy supplies changes and particularly as renewables play an increasingly important part as an energy source. Thereby recognising the importance of ports in meeting the national energy targets.

Ports are considered to need to be responsive to changes in different types of energy supplies needed, as well as to possible changes in the geographical pattern of demand for fuel, including the development of power stations fuelled by biomass within port perimeters.

The National Policy Statements is one the key considerations that the planning decision-maker should take account of the when making decisions on new port applications under the Planning Act.

Local planning policy may specifically designate areas suitable for jetty/harbour/port developments, which would provide a useful policy presumption in favour of the principle of the development. In the absence of specific policy relating to the principle of development, the project would need to provide specific justification to support the proposed location as well as the proposed development.

Permitting requirements

The scope of this permitting review includes the operating terminal which consists of:

- Jetty
- CO_2 pipelines
- Temporary storage of CO_2
- Conditioning (liquefaction and compression)

Consents required

The Jetty and CO_2 pipelines are not listed activities under the permitting regulations. The permitting regulatory review has also not identified the need for an environmental permit for conditioning activity or temporary storage of CO_2 for reasons as follows.

It is understood that the liquefaction and compression would be part of the conditioning process within the CO_2 operating terminal. The general principle of liquefaction is a combination of process stages of cooling and compression of the CO_2. Specific details on the operation of such conditioning equipment are not known at this stage.

As per the EAs Regulatory Guidance Note (RGN) 2, gasification and liquefaction of "other fuels" must involve changes to the chemical composition of the material in order to be considered a Section 1.2 Energy Activity.[147] It is assumed that conditioning activities proposed at the CO_2 terminal would not involve the chemical change of the CO_2 and therefore the energy listed activities are not applicable. It is also assumed that no combustion activities would be required.

Key considerations and requirements

The permitting regulatory review has not identified the conditioning activity or temporary storage of CO_2 to be their own listed activities under the EP Regulations.

Consideration should be given to the details of the activities and any changes to the process to ensure they do not fall into permitting scope. It is not known at this stage if combustion units will be part of any conditioning process. A further review would be required if combustion forms part of the process.

The temporary storage of CO_2 is also not a listed activity itself under the EP Regulations. However, there is an emission from storage BREF[148] that may be of relevance in determining good environmental practice for such an activity.

Regulatory risks and barriers

The CO_2 import supply chain involves the repurposing of many existing assets that in some cases already have well defined regulations. There is uncertainty surrounding specific regulations in the import supply chain today, however, once defined these barriers are likely to be overcome in the short to mid-term. The regulatory risks and barriers associated with CO_2 imports are outlined in Table 21.

[147] Regulatory Guidance Note No. 2 Understanding the meaning of regulated facility - Appendices 1 and 2 (publishing.service.gov.uk).
[148] esb_bref_0706.pdf (europa.eu).

Table 21: Regulatory risks and barriers for CO_2 imports

Risks	Description
Existing land allocations can restrict development	Projects may need to rely on existing land allocations in Local Plans to gain planning permission for port-related development, storage and related activities. 'Greenfield' or constrained sites such as those with environmental protection designations, would present significantly more challenges.
Barrier	**Description**
Lack of governing network codes	BEIS has not yet developed the governing codes for CO_2 networks. This limits the potential to technically determine the design specification for the capture of CO_2, directly influencing the specification requirements for the import of CO_2 via any means and thus hindering immediate progress.
Exposure to different regulatory frameworks	International shipping of CO_2 would be exposed to and would have to comply with, different international regulatory frameworks including EU-ETSD, EU CCS Directive, UNCLOS, the International Convention for the Safety of Life at Sea and the IGC Code, on top of any additional regulation internally developed by the UK.
Variable consenting regimes for planning	If a project is to be consented through the DCO process the general principle of the project would be supported by national policy and is generally in accordance with emerging national energy strategy. If the project is consented through the TCPA and determined by the local authority, local policy and considerations would have greater weight than through the DCO process.

3.2.5 Recommendations and actions

The risks and barriers outlined above cover the market, policy and regulatory dynamics of a future CO_2 import market in the Humber. In considering actions to mitigate those risks and barriers, there is merit to considering actions in the context of all three of these dimensions, due to the overlapping benefits which arise.

Drawing on the stakeholder discussions held, reviews of the literature, and Element Energy's own market insights, the following set of action categories are recommended to help actors within the Humber cluster navigate what is a complex and nascent market. These actions would either be considered the responsibility of industries operating within the Humber cluster, government policy developers, and CCS regulators.

Action 1: Increased funding for non-piped transport (NPT) solutions

NPT methods via ship, road and rail are not included in the initial design of the CO_2 transport and storage regulatory investment (TRI) business model. Today, their lack of inclusion for support limits the early development of CO_2 imports to the Humber region as NPT projects cannot be subsidised.

NPT transport modalities should be included in the CO_2 TRI business model to enable dispersed sites or those without access to geological storage to decarbonise. BEIS should include support for NPT methods in future editions of the CO_2 TRI business model to provide project developers with confidence in the support levels provided and ensure decarbonisation of dispersed sites is not delayed. A policy stance should aim to be published by 2023 to enable NPT projects to reach FID by 2026.

Action 2: Establish transport specification for CO_2 imports

There is a need for some degree of standardisation across the sector to minimise compatibility constraints between projects in the future. Stakeholders involved in the development of CO_2 import infrastructure should either agree on a CO_2 standard expected to be optimal at system level, or they should ensure that CO_2 infrastructure can accommodate the different shipping solutions under development to enable future expansion.

The Northern Endurance Partnership and Viking CCS projects are the organisation responsible for developing the onshore and offshore CO_2 T&S infrastructure in the Humber and are therefore very likely to be heavily involved in the development of any import infrastructure and CO_2 specification requirements. There is still significant uncertainty across the shipping sector on the optimal condition for CO_2 transportation and it is likely that up to 3 standards could be adopted across Europe. The Humber is unlikely to have capacity to receive large-scale imports prior to 2030 and further clarity on which standards are likely to be widely adopted will be established over the next few years providing further clarity for investors. A clear decision should be made by 2025, before entering pre-FEED stage for any import project.

Action 3: Identify land for CO_2 terminal infrastructure

CO_2 terminals are required to process imports from non-piped transport methods. Early identification of land availability / constraints for developing import infrastructure will ensure projects can develop without delay. Port operators such as Associated British Ports in Immingham should identify potential to develop new CO_2 import infrastructure within the existing port. Local planning authorities in the Humber region should also be aware of the requirements for CO_2 terminals, with the planning application process streamlined where possible to minimise delays to development.

Port operators should conduct feasibility studies that identify potential sites for import infrastructure development. Early identification of land-based constraints will ensure more time to develop solutions that are compatible with existing Humber operations.

Action 4: Ensure CO_2 transport and storage infrastructure is scalable

The level of confidence and credibility of potential dispersed emitters is smaller than cluster emitters. Initial designs by T&SCo project developers could ignore potential additionality of more distant emitters, limiting future import potential unless initial assets are designed to allow for phased growth.

CO_2 T&S infrastructure developers in the Humber such as the Northern Endurance Partnership and Viking CCS should ensure that network capacity is scalable to allow non-piped transport (NPT) emitters to connect to the network in the future. This is likely to require the development of terminals that connect to the pipeline network. T&SCo network developers need to consider how designs can be scaled to allow for market growth. This should be considered at pre-FEED stage.

Action 5: Provide funding support for CO_2 import / export infrastructure

Additional cost of the full CCS chain when CO_2 imports are needed challenges competitiveness of CCS projects that rely on imports when compared to localised CCS projects. Emitters with direct access to CO_2 storage via a pipeline are likely to always have an economic advantage. High costs of CO_2 import infrastructure are a barrier to projects that will rely on NPT solutions.

BEIS should provide support for CO_2 import / export infrastructure development to help connect emitters without a storage solution to CO_2 T&S networks. NPT solutions should be included in updated editions of the CO_2 TRI model to provide project developers with confidence in the support levels provided and ensure decarbonisation of dispersed sites is not delayed. A policy stance should aim to be published by 2023 to enable NPT projects to reach FID by 2026.

Action 6: Identify synergies between H_2 and CO_2 infrastructure development

CO_2 import and hydrogen export value chains are likely to be technically and commercially similar. This can lead to competition between the two (e.g., for repurposing of compatible pipelines, for land to deploy liquefaction assets, limitation of port activity due to simultaneous imports and exports).

National Grid are the organisation developing both the Humber hydrogen and CO_2 pipeline infrastructure (onshore), whereas Associated British Ports are likely to have significant involvement in the development of shipping infrastructure for both hydrogen and CO_2. Synergies between infrastructure development should be leveraged where possible (e.g. shared pipeline corridors and multipurpose CO_2/H_2 jetties). Opportunities for synergies between hydrogen and CO_2 import infrastructure development should be identified at the project feasibility stage.

4 Options to remove atmospheric CO_2

According to the latest International Panel on Climate Change (IPCC) report[149] methods for **removing CO_2 from the atmosphere are "unavoidable" if the world is to reach net-zero**. Carbon dioxide removals – referred to below as carbon removals, CO_2 removals, or simply 'removals' – are a sub-set of greenhouse gas removal technologies specifically targeting CO_2[150]. Carbon removals include engineered technologies and natural pathways that *actively remove carbon from the atmosphere*, the term does not include pathways that avoid or reduce future emissions. Removals will likely make a crucial contribution to reaching net-zero in 2050 by compensating unavoidable, residual emissions from hard-to-abate sectors that cannot be technologically and economically decarbonised. After 2050, carbon removals may be used to reverse any overshoot of atmospheric CO_2 and reduce concentrations back towards pre-industrial levels. Across scenarios in the IPCC report for limiting warming to 2°C, 2100 cumulative CO_2 removal reaches an average of 328 Gt for BECCS, 252 Gt for land-based measures, and 29 Gt for DACCS[151].

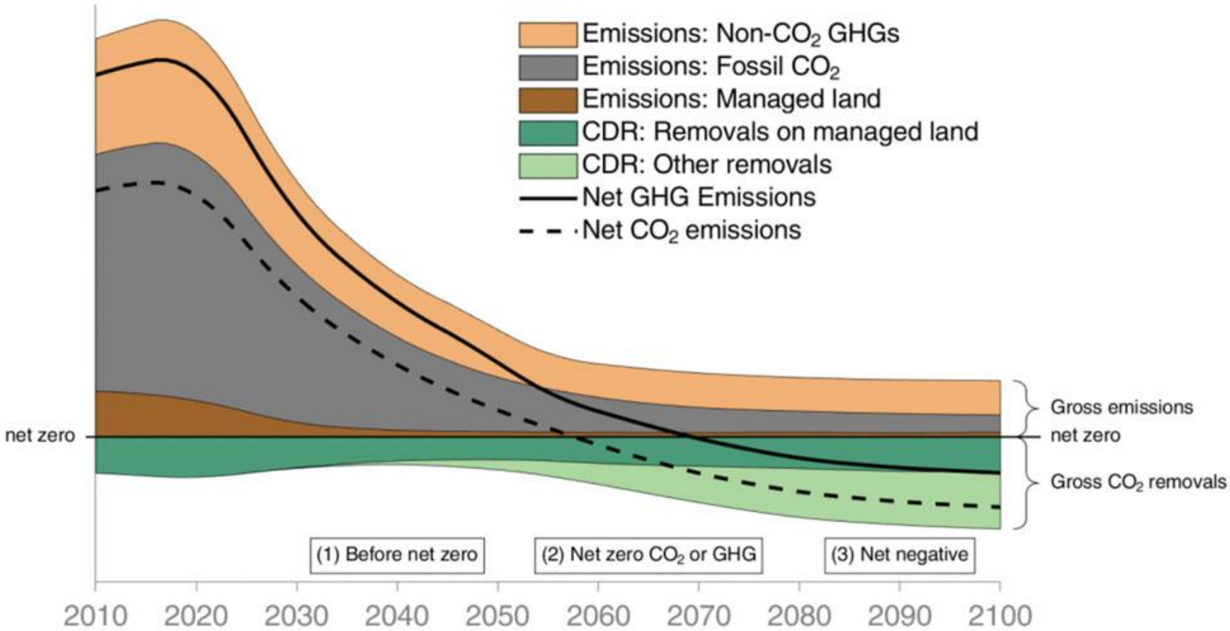

Figure 28: The role of carbon removals ("CDR") in a stylised pathway of ambitious climate action[152].

The removal landscape is complex, with a range of removal pathways being proposed. Removal methods range widely in their level of technology readiness, from conceptual ideas to techniques close to commercialisation, right through to established pathways deployed around the globe. **Carbon removals are then commonly split into engineering (or technological) solutions and Natural Climate Solutions (NCS).** The main two engineered pathways are Bioenergy with Carbon Capture and Storage (BECCS) and Direct Air Carbon Capture and Storage (DACCS), often simply referred to as DAC, these technologies provide reliable and measurable carbon removal and geological storage. These pathways are not yet fully commercialised with the few initial operational DACCS plants prohibitively expensive and early commercial BECCS projects currently being planned. NCS comprise of actions that enhance natural processes to capture and store carbon through ecosystem conservation, restoration, and improved land management. NCS can be preferred due to their significantly lower cost and ability to provide environmental and social co-benefits to local communities and

[149] IPCC, 2022: Summary for Policymakers. Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the IPCC.
[150] While carbon removals are the focus of this study, it should be noted that removal projects targeting other greenhouse gases like methane and nitrous oxides also exist.
[151] See footnote 149.
[152] See footnote 149.

environments. However, the carbon benefits of NCS are harder to measure, monitor, verify, and often include less resilient biological and terrestrial storage mechanisms that are more prone to reversals.

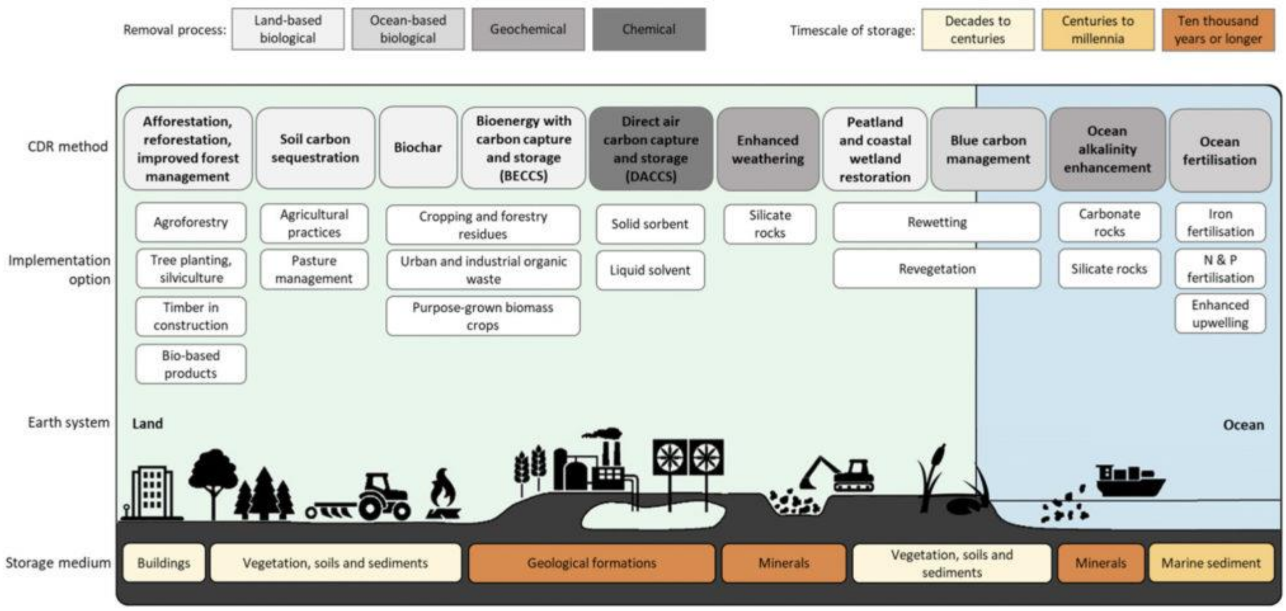

Figure 29: Removal landscape categorising pathways by earth system and storage mechanism[153]

Carbon removals can also be categorised depending on the method of capture and storage:

- **Engineered Capture** – Removals require capture of atmospheric CO_2 and there exists a suite of emerging technological solutions that can achieve this. A number of these solutions capture CO_2 directly from the atmosphere, Direct Air Capture (DAC). There are currently two main types of DAC technology ready for deployment, solid and liquid sorbent pathways, that rely on very different technologies and have different energy requirements.
- **Biological Capture** – A key capture method for many removal pathways, particularly BECCS and the broad suite of NCS. Growth of biomass involves capture of CO_2 from the atmosphere and conversion of this CO_2 into biogenic carbon during the process of photosynthesis in plants. Biological capture naturally offsets a large fraction of anthropogenic emissions, but removal pathways can further enhance this sink.
- **Inorganic Capture** – The final atmospheric capture category relies on chemical reactions between minerals (on land, in the ocean, or in clouds) and atmospheric CO_2. These reactions produce chemical compounds that include carbon atoms and therefore reduces the amount of carbon in the atmosphere.
- **Geological Storage** – Geological sequestration refers to the trapping of CO_2 in porous rock formations, typically via injection into depleted oil and gas reservoirs or saline aquifers. Geological sequestration is most resilient storage mechanism currently available and is used in both DACCS and BECCS. Injection of CO_2 initially results in physical trapping below an impermeable cap-rock. Subsequently the CO_2 moves into less connected pores (residual trapping), dissolves into lingering water (solubility trapping), and then reacts with minerals to form carbonates (geochemical trapping). This final formation is a very stable chemical state and therefore once reached it is highly unlikely that CO_2 would leak.
- **Biological Storage** – Trees and other plants store organic carbon in their biomass which can be protected from reversals through land management activities to provide stable storage in ecosystems such as forests and wetlands. Biological storage is susceptible to storage reversals due to human influence (land clearance) or natural disasters (wildfires), so must be adequately protected and insured.
- **Terrestrial Storage** – A major natural carbon pool is the storage of carbon in soils. This carbon pool can be enhanced to provide additional storage. Carbon removal pathways can specifically enhance soil carbon

[153] IPCC, 2022: Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change

sequestration or add carbon rich additives to the soil for storage. Several inorganic capture methodologies pair with this storage mechanism as they can be readily deployed on large areas of agricultural land, often with some co-benefits for agricultural productivity due to improve soil health.

- **Built Environment / Materials Storage** – A variety of pathways are emerging that can result in storage of carbon in the materials used in construction and the built environment. Carbon rich materials, such as bioplastics, can also offer storage potential if captured CO_2 can be incorporated into their production.
- **Oceanic Storage** – The ocean naturally absorbs and stores a significant proportion of anthropogenic carbon emissions however several removal pathways depend on enhancing the storage of the oceans to lock CO_2 away from the atmosphere. Storage of carbon in the ocean does however increase the issue of ocean acidification as it dissolves and forms carbonic acid.

4.1 Bioenergy with carbon capture and storage

4.1.1 Overview

Bioenergy with carbon capture and storage (BECCS) combines the combustion or gasification of biomass to produce energy with carbon capture and storage (CCS) to remove the CO_2 from the atmosphere. Emissions are counted in the land use sector at the point of harvest and biomass is only considered carbon neutral when sourcing meets strict sustainability and regulatory requirements, which must be verified using stringent MRV practices across the integrated and often global biomass supply. Biomass supply may even be considered carbon negative if it involves a significant increase in soil carbon. There are multiple pathways to deliver negative emissions with BECCS:

- **BECCS Power** – This pathway uses biomass to produce power in the form of electricity or heat, and captures the carbon released during the process of power generation.
- **BECCS Industry** – Several industry processes, such as cement production, can use biomass directly as a feedstock or energy source and produce CO_2 as a by-product to be captured.
- **BECCS Hydrogen** – The hydrogen pathway addresses the possibility to produce hydrogen from biomass and then capture the subsequent CO_2 process emissions.
- **BECCS Energy from Waste (EfW)** – The BECCS EfW pathway is distinguished from BECCS Power by using commercial or industrial wastes rather than purely organic biomass as the fuel to produce power. This could result in a fraction of the captured CO_2 (i.e., the biogenic fraction) representing a carbon removal.
- **BECCS Biofuels** – Biomass can be converted into a range of biofuels with the resultant process emissions of CO_2 captured.
- **BECCS Anaerobic Digestion and Biogas** – Production of biogas through anaerobic digestion of biomass material, often sludges and wastes, can be fitted with CCS to produce negative emissions.

Each of these pathways requires different processes, faces different costs, and holds varying potential to upscale in the Humber. This report focusses mainly on BECCS Power as it is most relevant to the short-term plans of the Humber cluster, however it should be noted that other BECCS pathways may be more relevant in different geographies or clusters and in the long-term as power demand reduces in a flexible and renewable-dominated energy network. **The BECCS Power (from herein referred to just as BECCS) application delivers energy or fuel with both negative and avoided emissions; this production of reliable or flexible, net-negative energy is a unique characteristic of BECCS.**

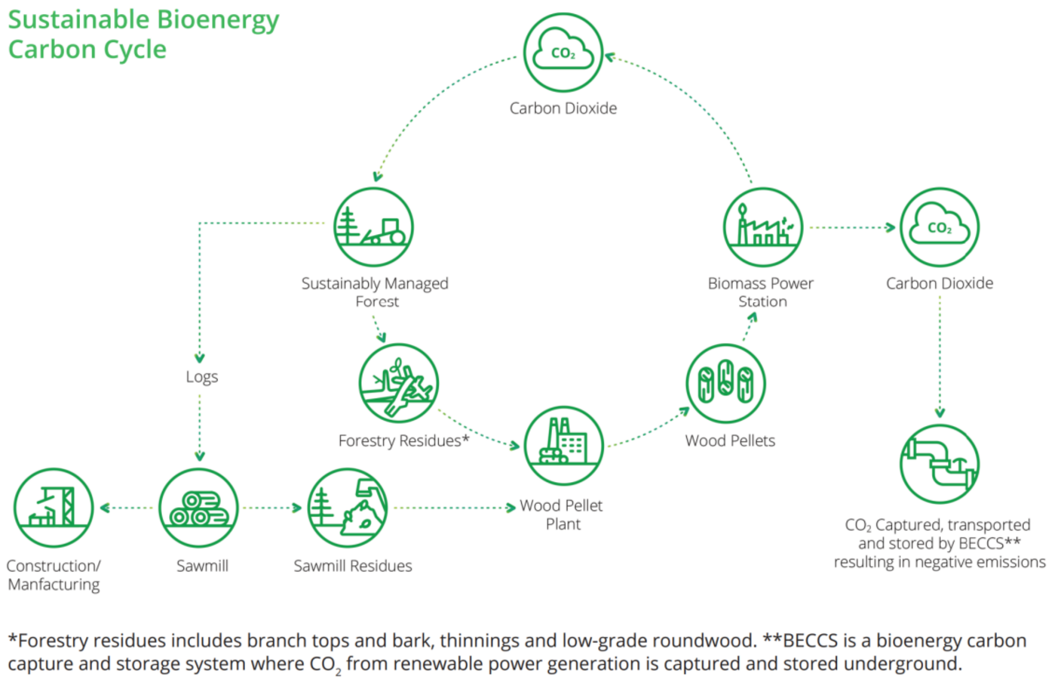

Figure 30: BECCS value chain showing key mass and energy flows (excluding transportation logistics)[154]

Decarbonisation potential

Biomass is already employed globally as an energy source and is considered carbon neutral for Scope 1 and 2 accounting purposes, when sustainably sourced. However, incomplete capture and supply chain emissions mean bioenergy use does usually entail non-zero lifecycle emissions. Therefore, the **capture of the CO_2 from biomass combustion only constitutes a net removal to the extent that emissions captured are greater than supply-chain related emissions** (including biomass growing, harvesting, processing, transport, and storage). It should also be noted that net negative emissions from BECCS may be associated with a temporal "carbon debt" associated with the different timescales of absorption of atmospheric CO_2 through biomass growth, which generally happens over multiple decades after harvesting, and of biomass combustion and associated CO_2 release occurring in a much shorter timeframe[155]. It should however be noted that such carbon debt is highly variable and depends on numerous ecological, economic, and methodological factors[156]. It also depends on the counterfactual uses for the biomass: for instance, the issue of carbon debt is less applicable to cases where waste biomass is used, compared to biomass from large-scale forest clearance.

Nonetheless, BECCS is considered a credible and scalable technology. CCC and National Grid's 2020 Future Energy scenarios indicate that it is not possible to achieve net zero without BECCS. Several estimates of BECCS potential have been made reaching globally up to 10 $GtCO_2$/year[157] and with UK potential of up to 90 $MtCO_2$/year[158]. However, although access to global sustainable biomass sources is likely to increase in the near term, it may then decrease to 2050 as international decarbonisation efforts accelerate and countries define

[154] The High Level Panel on BECCS Done Well 2022, BECCS Done Well: Conditions for Success for Bioenergy with Carbon Capture and Storage.
[155] Chatham House 2021, BECCS deployment: The risks of policies forging ahead of the evidence.
[156] Cowie et al. 2021 - Applying a science-based systems perspective to dispel misconceptions about climate effects of forest bioenergy
[157] Royal Society 2018 – Greenhouse Gas Removal.
[158] Element Energy 2021 – GGR methods and their potential UK deployment.

priority uses for their scarce, sustainable biomass resources[159]. It will therefore be important to balance demand for sustainable biomass across a range of sources in agriculture and forestry as well as across geographies.

Box 5 – Sustainable biomass is a finite, highly valuable resource

Biomass resource can contribute in many ways to reaching net zero cost-effectively as a raw material, an absorber and store of carbon, and as an energy source. The UK and EU ETS's currently promotes bioenergy use by "zero-rating" its emissions, provided it adheres with sustainability criteria[160]. In the near-term, the primary benefits from biomass combustion derive from its ability to substitute for fossil fuels - not necessarily requiring capture and net-negative emissions[161]. The growth of biomass is not necessarily a removal unless the carbon removed is additional and remains stored over a long period.

There is ongoing criticism of using primary biomass for BECCS with a range of concerns often levelled at BECCS, such as, additional process emissions (cultivation, transport etc.), competition for fertile land, felling of primary forest ecosystems, and foregone sequestration (the loss of subsequent plant growth). The scale of possible biomass capture on land is constrained by land and water availability and must be managed appropriately as to not negatively influence these ecosystem services, biodiversity, or water/food security. **Sustainable biomass should be scaled appropriately as to not displace other land uses**. Supply chains should limit life-cycle emissions from land use change, harvesting, processing, and transport whilst maximising capture efficiencies after combustion. Developers should address potential social concerns such as misalignment with the SDGs and mitigating unbalanced impacts on vulnerable communities, such as to air pollution or water security. Nevertheless, these concerns can all be comprehensively mitigated with adequate sustainability controls and practices, and in fact biomass growth can deliver ecosystems benefits alongside carbon sequestration by supporting healthy soil, water retention, flood management, and biodiversity.

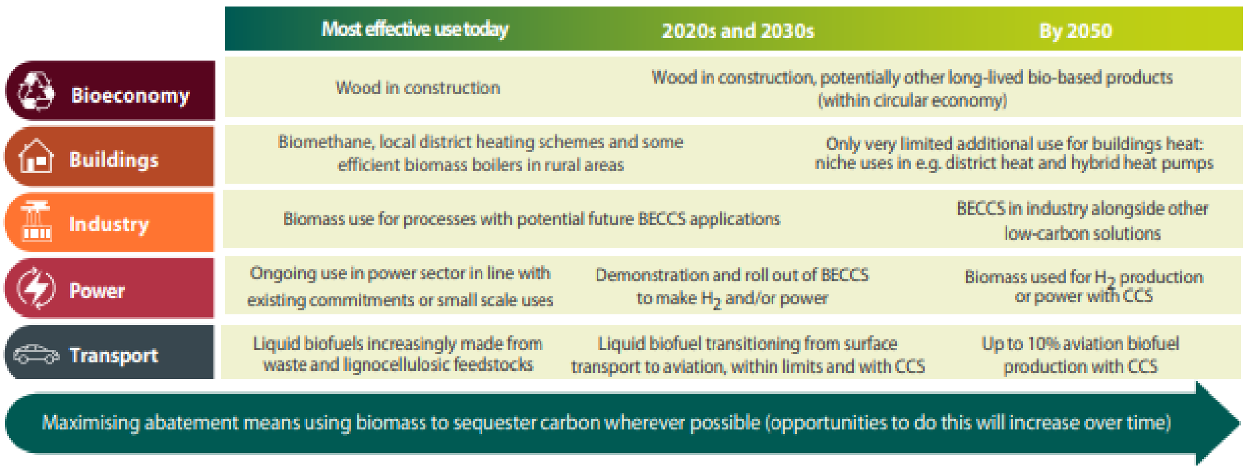

Figure 31: Evolution of the hierarchy of best use for sustainable biomass resource across relevant sectors[162]

As a result of these concerns and limitations, sustainable biomass is a finite resource with uncertainty about its future availability. In the UK, around a third of existing biomass is imported with the majority of domestic biomass coming from wastes and residues. There is scope to expand the supply of both domestic and imported sustainable biomass. However, potential demand is likely to exceed sustainable supply, implying action is needed to ensure biomass is used effectively. Most current uses of biomass do not sequester

[159] Ricardo 2018 - Analysing the potential of BECCS in the UK to 2050.
[160] BEIS – Biomass Policy Statement.
[161] See footnote 154.
[162] CCC 2018 - Biomass in a low-carbon economy.

Box 5 – Sustainable biomass is a finite, highly valuable resource

carbon and are in sectors with increasingly viable low-carbon alternatives, so current biomass use needs to change[163]. There are several practices the Humber could employ to improve the sustainability of biomass production and utilisation[164]:

- Prioritise local waste/residue feedstock for new biomass consumption pathways following the waste hierarchy (minimise waste, maximise value, and minimise environmental impact). Ensure biomass supply avoid the exploitation of primary forest in all cases.
- Use landscape-based approaches to exploit synergies with other sectors and natural climate solutions (NCS) or nature-based solutions (NbS) in forest and agriculture landscapes to enhance negative emissions and provide co-benefits.
- Wherever possible biomass growth should attempt to restore or improve environmental qualities, such as on marginal, degraded land.
- Follow stringent sustainability regulations for domestic and imported biomass with a renewed focus on encouraging a race to the top by limiting fertiliser use, water consumption, and power usage.
- Avoid "lock-in" of sub-optimal biomass use, this means limiting long-term use of biomass for power or fuel without co-deploying CCS.
- Deploy CCS with biomass wherever possible, and as feasible in retrofits of industrial processes.
- Exploit competitive advantage from surrounding CO_2 T&S infrastructure that will reduce cost and emissions associated with applying CCS to biomass uses.
- Direct biomass to high value and employment markets, such as speciality chemicals or hydrogen, and those applications where biomass substitution provides the greatest carbon benefit, often is sectors with limited renewable alternatives.
- Proactively address growing public concern on the potential for BECCS to support and drive rapid, deep decarbonisation.

Technology status

Biomass power stations are a mature technology while CCS is yet to be deployed at a commercial scale, with BECCS projects at similar stages, or even ahead, of development to Drax also in North America and Japan. Therefore, **the integration of the CCS component into the bioenergy system, to form a BECCS plant, limits the TRL to between 5-7 depending on the capture[165, 166,167,168].** Other forms of BECCS have already been deployed at scale, such as on ethanol plants, and BECCS EfW is likely to develop rapidly. The main technical developments expected to increase the cost-effectiveness of BECCS relate to boosting generation efficiency and handling variability in feedstocks to allow the use of mixed biomass and biogenic wastes. Near-term development of bioenergy and carbon capture processes may rely on smaller scale, CO_2 utilisation pathways some of which are more economically viable in the current market.

Cost considerations

The origin of biomass supply can have significant impacts on the cost and environmental impact of BECCS. For example, using local and/or waste products as the feedstock can significantly reduce the price compared to imported and/or dedicated energy crops. Emission and sustainability concerns can be mitigated by using biogenic waste products (agricultural, commercial, or industrial). These wastes are often treated by policy as being zero emissions as without utilisation they would decay to release the same amount of CO_2 to the atmosphere, and they have not demanded any significant process emissions in their production. These waste biomasses may be more applicable for direct heating applications rather than for BECCS Power. **Cost estimates are highly sensitive to assumptions on electricity price, plant lifetime, and efficiency.** Various

[163] See footnote 162.
[164] For a comprehensive review of the conditions that must be met to ensure sustainable use of biomass in BECCS, see: The High Level Panel on BECCS Done Well 2022, BECCS Done Well: Conditions for Success for Bioenergy with Carbon Capture and Storage.
[165] See footnote 157.
[166] See footnote 158.
[167] EE & E4Tech 2021 - Review of International Delivery of NETs.
[168] BEIS 2021– Biomass Policy Statement.

reports estimate the cost of removed and stored carbon at £100-200/tCO_2[169], £110-200/tCO_2[170], and £125-300/tCO_2[171]. Research suggests a price range in 2050 of £30-170/tCO_2 in the UK[158] whilst the IPCC suggests global prices will fall in the range of £40-190/tCO_2.

BECCS costs can be reduced through proximity – and hence reduced cost of access – to CO_2 T&S infrastructure. BECCS could be made cost competitive by the 2030s but requires UK Government support to deploy FOAK projects and develop business models that value negative emissions. Studies show that BECCS has the potential to reduce the cost of meeting the UK's 2050 GHG emissions target by up to 1% of GDP[172] if supported sufficiently.

Another factor that can significantly affect the cost of CO_2 removal with BECCS is the value of the electricity generated. Power generation could either be the primary or secondary output of a BECCS facility, depending on the relative price of negative emissions compared to that of electricity sold. Depending on the capture technology a NOAK BECCS plant could generate electricity at a LCOE of between £150-200/MWh[158,173,174]. While this is higher than comparable benchmarks of £43-53 for offshore wind and £81-94 for early gas plants fitted with CCS[175], BECSS can deliver additional value through the negative emissions it provides.

Energy and resource implications

BECCS is a net energy generator, producing 1-10 GJ/tCO_2 removed if using energy crops[176], which partially offsets the extensive land and resource requirements described below by replacing resource intensive fossil fuel power generation and reducing the need for other renewable energy deployment. Access to CO_2 infrastructure and plant build rates restrict the potential deployment rates until the early 2030s and suggest a competitive advantage for retrofits and CCS industrial clusters, such as Drax and the Humber.

Land use can be substantial if using virgin biomass feedstocks instead of residues from existing forestry and agriculture or other biomass waste products. Land use requirements for dedicated energy crops should be carefully balanced against food or feed production and may conflict with certain Sustainable Development Goals[172]. Biomass will have to be sustainably sourced without negatively influencing agricultural production or environmental quality. It is estimated that **50 MtCO_2/year BECCS removals in the UK** (greater than the CCC 2050 balanced pathway's demand) **could be supplied through moderate imports and planting 30,000 ha/year**[172] **of dedicated crops** on marginal land, appropriate grasslands, and available agricultural land. Forestry and agricultural wastes could support up to 10 MtCO_2/year[177], however, these products are often bulky and expensive to transport, unless pelleted, so would preferably be locally sourced.

Energy crops have the potential to produce significant higher yields if fertilized; however, this invokes additional nutrient and energy requirements and may encounter associated environmental issues such that it is generally not preferred. Water use can reach 60m^3/tCO_2[178] with further consumption possible in the CCS process. Widespread implementation of BECCS could have a negative impact on soil health, water availability, and biodiversity but could equally, if proactively managed, have positive impacts on biodiversity, soil health, and reducing eutrophication.

169 Royal Society 2018 – Greenhouse Gas Removal.
170 See footnotes 158,159.
171 See footnote 175.
172 ETI 2016 - Evidence for Deploying BECCS in the UK.
173 See footnote 158.
174 Excluding any carbon price which will be crucial to the commercial viability and positive impact of BECCS deployment
175 REA 2019 – Going Negative: Policy Proposals for UK BECCS.
176 See footnote 158.
177 See footnote 175.
178 See footnote 169.

4.1.2 Market Study

Opportunities for deployment

The UK is well-placed to host significant deployment of BECCS as it has vast CO_2 storage opportunities offshore, and strong academic and industrial experience in both bioenergy and CCS. **Drax is planning to retrofit two 645 MW biomass units with CCS by 2027 and 2030, respectively,** and is considering retrofitting the other two units on the site by 2035. Once retrofitted with CCS the four units combined have **potential to achieve 16-18 $MtCO_2$/year capture**[179], equivalent to the lower bound of the 2050 CCC BECCS target[158,180]. Early deployment of BECCS at the Drax facility will develop the CO_2 T&S infrastructure in the Humber required by carbon capture solutions and other engineered removals once they are developed. Drax currently underpins the scale and commerciality of the Humber CO_2 pipeline and by means of its Western location ensures the pipeline passes all major industrial sites in the cluster. Furthermore, as the Humber develops into a CCS cluster it will be able to offer low cost, pre-existing CO_2 infrastructure for other BECCS deployments providing a significant siting advantage in reducing the capital expenditure necessary to connect to a CO_2 pipeline.

There is scope for deployment of other BECCS pathways within the industrial cluster. Possible synergies exist with the lime sector, but only if biomass is pre-converted into biogas as existing lime kilns are not compatible with solid fuels without significant modifications. Coupling CCS with EfW plants in the Humber can also lead to negative emissions, by capturing and storing emissions from the biogenic portion of waste[181]. There is also significant potential to couple BECCS with biofuels production given the Humber's expertise and infrastructure in the chemicals sector, although this will produce a reduced amount of negative emissions for a given volume of biomass. Hydrogen production and use is expected to grow significantly across the cluster which may prompt interest in the BECCS hydrogen pathway as an alternative to conventional CCS enabled/electrolytic hydrogen, with the added co-benefit of negative emissions. The deployment of BECCS hydrogen is dependent on technological advancements in the gasification stage and the availability of sufficient scale and quality of biomass. These alternative pathways may be able to utilise other lower-grade feedstocks that can reduce the impact of biomass supply chains.

Market risks and barriers

The market risks and barriers associated with BECCS are outlined in Table 22.

[179] Baringa, Drax 2021 – Value of BECCS in Power.
[180] Element Energy 2021 – GGR methods and their potential UK deployment.
[181] A reader interested in bioenergy use in the lime sector and energy from waste plants can find a more detailed discussion in Chapter 0.

Table 22: Market risks and barriers for BECCS

Risks	Description
Uncertain energy prices	BECCS projects will rely on the energy they produce, as well as the carbon removals, so are vulnerable to fluctuating energy prices without policy support.
Biomass cost and supply uncertainty	As the global biomass market grows, uncertainty exists around the supply, price, and sustainability of BECCS feedstocks. As a relatively young sector supply chains are yet to fully develop and could restrict deployment in early years.
Fertile land restriction	Producing sufficient biomass from dedicated energy crops or forestry to fulfil UK targets for BECCS will require a large area of suitable, fertile land that may compete with agriculture and other land uses.
Barrier	**Description**
Project capital cost variability	Significant cost differential and uncertainty exists between new build and retrofit BECCS plants. Drax being the most mature BECCS developer in the UK creates cost and risk implications during contract negotiations.
Supporting both low carbon energy and carbon capture value	BECCS produces two valuable products which must both be valued in order to encourage deployment however the balance of support must be correct to prioritize sustainable deployment. As the business model for BECCS is not yet available and given uncertainty in energy prices and limited markets for the carbon removals produced by BECCS, projects are unlikely to be investable at this time without additional support.

4.1.3 Policy study

Policy status and future enablers

BEIS business models

BEIS consulted on business models for engineered removals in 2022[182]. This consultation aims to set out details of the preferred mechanisms to incentivise early investment and enable commercial demonstration of a range of removal technologies from the mid-to-late 2020s. The consultation will consider how incentives for removals interact with policies and business models currently under development for CCS, hydrogen production, sustainable aviation fuels and other relevant sectors, along with wider carbon pricing policy. It will also consider how near-term policy incentives can most effectively leverage private investment and enable a transition towards a market-led framework as the sector matures.

Funding mechanisms

One of the key risks identified for BECCS development and deployment is the lack of a business model, as they are not yet included in the UK ETS or valued through another market- or government policy-based mechanism, to make projects commercially viable and investable. Government is currently consulting on a new GGR business model (see DACCS chapter for more details), however BECCS Power will require a unique combination of funding to support both carbon removal and power generation. BEIS ran a separate consultation in 2022 for a preferred business model to support power BECCS within the UK[183]. To make BECCS feasible, within the business model provided by the government there should be support available for the combination of the low carbon energy produced and the carbon captured, with a balance struck to support sustainable deployment. The business model should also successfully counteract the high uncertainty and variability in both electricity and carbon prices. The significant capital cost of developing BECCS projects is another barrier that must be overcome through the financial case produced by the business model being sufficient to encourage private investment. BEIS is considering a range of options to support the creation of a business model for BECCS Power[184]. These include:

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182 BEIS 2022, Business Models for Engineered Greenhouse Gas Removals (GGRs).
183 BEIS 2022, Business model for power bioenergy with carbon capture and storage (Power BECCS).
184 Frontier Economics 2021, Supporting the deployment of BECCS in the UK: Business Model Options.

- **Power Contract for Difference (CfD)** where the strike price of the CfD would be set to include remuneration for negative emissions, low carbon power, and for learnings and spill over benefits.
- **Carbon payment** where a contractual carbon payment would provide a fixed payment per tonne of negative emissions. The payment level would be set to include remuneration for negative emissions, low carbon power and for learnings and spill overs.
- **Carbon payment and power CfD** combines the two options above. The carbon payment would provide remuneration for negative emissions and learnings and spill overs while the power CfD would support power market revenues for the plant's renewable power output.

A combined model is predicted to be preferred by BEIS as it would offer a clear path to a technology neutral and subsidy free world, delivering learnings relevant for other removals in the process. Further clarity on where the negative emissions carbon payment is accounted for is required in biomass-based business models**.** The government will publish its **consultation on the Power BECCS business model in 2023.** The recent Phase-2 shortlist identified the power CCUS, CCUS-enabled hydrogen, and industrial carbon capture (ICC) projects that will proceed to the next stage of due diligence. BEIS invited power BECCS plants to complete the project submission to join the Track-1 shortlist for consideration for power BECCS business model support from August 2022[185]. Power BECCS projects that can deploy on Track-1 timescales are eligible for application.

Other BECCS pathways are receiving various levels of government support from several different policies. BECCS industry will receive its support from the Industrial Carbon Capture (ICC) business model with will cover biogenic CO_2 capture in the same was as for fossil-based CO_2 with additional funding for fuel switching to biomass available through the Industrial Energy Transformation Fund until 2025. The ICC business models will also support early deployment of BECCS EfW as part of the Phase 2 of the CCS cluster sequencing process. BECCS Hydrogen is expected to be supported not by GGR policy but by the new hydrogen business model, however BEIS is open to consultation on the requirements for further support as BECCS Hydrogen may be uncompetitive with electrolytic/CCS-enabled hydrogen in this scenario. For other pathways support and plans are limited but other support is available, such as the Renewable Transport Fuel Obligation (RTFO) and Sustainable Aviation Fuels mandate for biofuels produced using BECCS, or the Green Gas Support Scheme for BECCS biomethane and anaerobic digestions.

BECCS projects could also reach economic viability through the voluntary carbon market where CO_2 removals credits can be sold to emitters such that they can offset their emissions. The voluntary carbon markets remain nascent and will require significant further development before being able to support BECCS projects. Further discussion around the potential to sell such credits in the voluntary carbon market is provided in Section 4.4.

Greater support for developers is required in funding for innovation, research & development, and pilot projects that will be crucial in further reducing the cost of BECCS and developing the surrounding ecosystem of accounting frameworks, market mechanisms, and environmental safeguards required to deploy BECCS at scale.

Policy risks and barriers

The policy risks and barriers associated with BECCS are outlined in Table 23.

[185] BEIS 2022, Cluster sequencing for carbon capture, usage and storage (CCUS) deployment: power bioenergy with CCS (BECCS).

Table 23: Policy risks and barriers for BECCS

Risks	Description
Uncertain carbon prices	If BECCS is included in market mechanisms then the economic viability of projects is dependent on the price of carbon, which is currently highly variable.
International policy alignment and cooperation	No international policy mechanism currently holistically supports the implementation of BECCS, which is problematic given the supply chain is geographically dispersed and spans multiple sectors. Sufficient links are necessary between geographies and sectors to avoid negative implications on land use, forest landscapes and agriculture related to biomass import, CCS infrastructure, and offshore CO_2 storage.
Barrier	**Description**
Lack of incentive for negative emissions	BECCS does not currently have a price incentive for negative emissions produced. Further development of market or policy mechanisms to reward net negative emissions is necessary.
Underdeveloped CO_2 T&S infrastructure	CO_2 T&S infrastructure in the UK is currently at initial stages of development and although BECCS developers do not bear the cost or complexity of deploying T&S they are therefore dependent on the CCS cluster sequencing process to deliver T&S solutions. Although the Humber has plans in place through the Zero Carbon Humber consortium, the reliability of this pipeline network will be uncertain given it is to be one of the first in the UK. Nevertheless, compared to many other locations for the Humber the availability of a pipeline is a less pressing issue given the clusters relative progress in this space, the locality of storage sites, and the expected demand from within the cluster.
Conflicting policy in other sectors	Large-scale deployment may force significant changes in the agricultural sector and require wider integration to ensure balance and exploit synergies. Furthermore, currently DEFRA oversees land use and BEIS manages Power and CCS creating an interfacial risk.
Lacking government action and strategy	Creates uncertainty for developers in when government will develop and implement sufficient, supportive policy mechanisms for BECCS.
Lack of support for innovation and pilot projects	Current support, beyond developing BEIS' BECCS power business model, is limited for pilots and demonstration projects which will both be crucial to drive BECCS technologies forward and inform the development of accounting frameworks, market mechanisms, and environmental safeguards.
Project developers may need to overcome public opposition	Given the view expressed by some that carbon removals are "false solutions" to addressing climate change that could diminish society's urgency for direct emissions reductions. Specific opposition to BECCS has developed as it attracted significant press attention from accusations of using timber-grade wood suitable for more sustainable applications (e.g., in construction) and over-estimated claims of net negative emissions, given the life-cycle emissions and potential for foregone sequestration.

4.1.4 Regulatory study

CCS technologies either require pre-treating flue gas to reduce SO_x and NO_x concentrations or will remove SO_x and some NO_x in the amine solvent, so will indirectly mitigate air-quality issues from increased biomass combustion. Amine-based CCS will need additional regulatory controls to limit the environmental impact of on hazardous degradation products[186].

Planning requirements

Consents required

Bioenergy with carbon capture and storage

Currently BECCS does not fall within the criteria of the Planning Act and is therefore not currently considered a Nationally Significant Infrastructure Projects (NSIP). This means that any applications for 'standalone' BECCS projects and some retrofitting of BECCS to existing facilities (subject to confirming the scope of work, and subject

[186] UK Parliament 2020 - POST Note on BECCS.

to certain thresholds) could be consented through a planning application under the Town and Country Planning Act 1990 (TCPA).

However, whilst not specifically included within the Planning Act, clear reference is made to BECCS within the National Policy Statements (NPS) and a Section 35 direction can be sought from Planning Inspectorate requesting that the project is accepted as an NSIP and consented through the Development Consent Order (DCO) process. There are several possible benefits to this, including the possible national presumption in favour of BECCS and its contribution to decarbonisation.

Importantly, NPS EN-1 acknowledges that where new infrastructure is not covered by the NSIP definitions and thresholds in the Planning Act, and is the subject of a Section 35 direction, the Secretary of State should give substantial weight to the need for CCS established in EN-1, when considering whether to grant a DCO.

BECCS as part of a Generating Station

As with CCS, when BECCS is associated with a wider project it is necessary to consider whether the project as a whole requires consent, and under which regime. In respect of generating stations, Section 14(1)(a) and 15(2) of the Planning Act includes the construction or extension of a generating station.

A generating station will be a NSIP if:

- its generating capacity is more than 50 MW, is not offshore and does not generate electricity from wind
- its generating capacity is more than 100 MW and is offshore[187]

Therefore, if BECCS forms part of a generating station project that is considered an NSIP, the whole project including any associated CCS would go through the DCO consenting process.

Environmental Impact Assessment

As with CCS, if the project is taken through the DCO process projects of this nature would fall under Schedule 1, paragraph 23 of the Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 ("EIA Regulations) as 'Installations for the capture of carbon dioxide streams for the purposes of geological storage pursuant to Directive 2009/31/EC from installations referred to in this Schedule, or where the total yearly capture of carbon dioxide is 1.5 Mt or more.'.

Any project that captures over this amount of carbon dioxide per annum per biomass unit and is therefore classified as 'EIA development' and as such the DCO Application would need to be supported by an Environmental Impact Assessment (EIA).

In respect of planning applications under the TCPA, the same threshold and definition exists within The Town and Country (Environmental Impact Assessment) Regulations 2017.

Key considerations and requirements

In respect of planning and consenting, BECCS is not explicitly included in the definitions on NSIP projects within the Planning Act. Therefore, where the projects are either standalone or not considered NSIP by virtue of being part of a generating station that meets the thresholds in the Act, consent would be required through the TCPA. It is possible however to seek a Section 35 direction from the Planning Inspectorate requesting that the project is accepted as an NSIP and consented through the DCO process. There is a planning policy presumption in favour of BECCS within the NPS, acknowledging the contribution these projects can make to the national energy strategy.

[187] Offshore means in waters in or adjacent to England or Wales up to the seaward limits of the territorial sea, or in a Renewable Energy Zone, except any part of a Renewable Energy Zone in relation to which the Scottish Ministers have functions.

While EN-1 focusses on gas generation with CCS, it recognises that BECCS may have a role, providing either baseload or dispatchable low carbon generation, whilst delivering negative emissions to offset residual emissions. However, it is noted that use of BECCS may be constrained by the availability of a sustainable biomass fuel source.

Permitting requirements

The scope of this review includes carbon removal activities. This includes operating a bioenergy/biomass power station with a CCS plant and operating a DACCS plant.

Consents required

The operation of a Biomass plant involves the combustion of biomass as a feedstock with the purpose of the plant to produce energy in the form of electricity or heat (steam or hot water). It has not been identified at this stage if the biomass feedstock would be dedicated energy stock or waste products.

Depending on the thermal input capacity, the combustion or gasification of a non-waste feedstock may fall under a Section 1.1 combustion activity. Where the total capacity at a site exceeds 50MWth, then a Part A (1) permit. In addition, where individual emitters, or combustion plant emitting through a common stack exceed 50MWth then the emissions would be subject to the requirements of the Large Combustion Plant Best Available Techniques Reference document (LCP BREF) and Chapter III of the Industrial Emissions Directive (IED). Therefore, the activity would need to comply with BAT of the LCP BREF including associated emission limits (BAT-AELs). Smaller emitters may be considered Medium Combustion Plant and be regulated according to the requirements and emission limit values of the Medium Combustion Plant Directive (MCPD).

If the feedstock consists of waste biomass, this will result in the activity being categorised as a Section 5.1 waste incineration activity rather than a combustion activity. Therefore, operation of a Biomass plant would then fall under Waste Incineration activities and would need to comply with BAT for Waste Incineration BREF including associated emission limits. This assumes that the plant capacity is above the waste incineration thresholds i.e., above 10 t/day for the incineration of hazardous waste and above 3 t/hour for non-hazardous waste.

The operation of a carbon capture plant associated with a Biomass plant would require inclusion of a Section 6.10 listed activity in the permit. For further details of the permitting requirements for carbon capture, see Section 3.1.4.

Key considerations and requirements

If the operation of a Biomass plant is to include waste feedstock (waste biomass), other waste implications including the Waste Framework Directive (WFD) 2008/98/EC needs to be considered as well as BAT requirements of the Waste Incineration BREF. Waste storage, handling, transportation etc are further elements that will need consideration.

Permitted facilities are required to be energy efficient. Plants with a thermal input greater than 50MW or expansion of plant to more than 50MWth capacity will trigger the requirements for a heat user study to be included with the permit application.

BECCS considers the use of a Biomass plant with carbon capture. As discussed in Section 3.1.4**,** it is understood that carbon capture plant may involve the use of solvents. If amine solvents are utilised, emissions of would need to be assessed through detail air quality modelling to demonstrate compliance with the recently adopted Environmental Assessment Levels (EALs).

Emissions of other parameters would also need to be assessed as these may alter due to the addition of a carbon capture plant along with the emissions associated with the Biomass plant itself. It would be expected that a detailed air quality modelling assessment would be undertaken to support a permit application for the installation of a Biomass plant.

Additional requirements concerning the carbon capture plant are discussed in Section 3.1.4.

Regulatory risks and barriers

The regulatory risks and barriers associated with BECCS are outlined in Table 24.

Table 24: Regulatory risks and barriers for BECCS

Risks	Description
Biomass sustainability	UK regulatory requirements for primary biomass sustainability will need to be continuously reviewed as production and demand increases. Current regulations are well developed and need to be stringently enforced to ensure the sustainability of biomass supply such that BECCS operations will provide positive climate and environmental benefits.
Scope 2 emissions	Poor upstream agricultural practices could increase Scope 2 emissions from BECCS reducing, or possibly even eliminating, positive environmental impacts
Barrier	**Description**
Monitoring and verification of CO_2 storage	Current monitoring methodologies and verification regulations are underdeveloped and will be required to accurately credit and value carbon removals.
Air quality impacts and waste products	Research is required to understand and address the air quality and wider environmental impacts from BECCS combustion, carbon capture solvents, and CCS waste products. Regulations specific to the capture plant and potential air quality impacts and waste products are also in need of further development.
Negative public perception of BECCS	The operation of a biomass plant may fall under waste incineration (depending on feedstock) which can be negatively received by the public. The EA are required to consider all public responses to a permit application advertisement. The operation of such plant could potentially attract high public interest and therefore may cause delays to the permit determination.
Clarification of biomass feedstock	The biomass feedstock needs to be clarified in order to establish the permitting requirements. There is ongoing criticism of using primary biomass for BECCS with issues including additional process emissions and foregone sequestration (the loss of subsequent plant growth) which can delay the permitting process.
Permitting complexity	BECCS involves two key technologies, the operation of a Biomass plant and carbon capture. Both have permitting regulatory requirements that will need to be considered which could make the permit determination more complex and take longer to determine. BAT guidance is available for post-combustion carbon capture plants although careful consideration will be required to determine if this guidance can be applied to other carbon capture technologies, including the combination of biomass and CCS.

4.1.5 Recommendations and actions

The risks and barriers outlined above cover the market, policy, and regulatory dynamics of BECCS separately. In considering actions to mitigate those risks and barriers, there is merit to considering actions in the context of all three of these dimensions, due to the overlapping benefits which arise.

Drawing on the stakeholder discussions held, reviews of the literature, and Element Energy's own market insights, the following set of action categories are recommended to help actors within the Humber cluster navigate what is a complex and rapidly developing market. These actions would either be considered the responsibility of BECCS developers within the Humber cluster, government policymakers, and/or BECCS market regulators.

Action category 1: Ensure BECCS carbon removals can be certified as tradable units

The Humber has the potential to help sites beyond its borders decarbonise via the import of CO_2 and the sale of negative emissions credits from BECCS deployment. BECCS the potential to provide high integrity carbon credits to the market however these compliance and voluntary carbon markets are currently immature.

Therefore, BECCS credit producers (Drax), NGO registries (Verra, Gold Standard), and UK government will need to work individually and collaboratively to ensure CO_2 removals can be certified as tradable units through an appropriate standard/carbon code. The development of these standards and methodologies can be driven initially by the voluntary market registries or by government compliance markets like the Woodland Carbon Code, with the support of key early BECCS deployment such as Drax crucially important. This work should also extend to developing accounting, sustainability, and MRV frameworks will likely prove crucial in developing the confidence and markets necessary to encourage private investment into BECCS, and other GGRs. The current voluntary markets available for trading BECCS credits are immature and most compliance markets do not have standards developed for removals. However, clear regulations should be in place in the next few years, prior to the first engineered removals projects coming online, with increasing interest in carbon removals and new organisations (IC-VCM, VCMI) tackling key issues in the voluntary market.

Action category 2: Develop an efficient and comprehensive business model for BECCS

In the UK, the current policy and market structures are insufficient to encourage private investment in scaling BECCS deployment. The business model consultation for BECCS power ran from August to October 2022 with no business model currently operational. The price and markets for negative emissions in the voluntary markets are not sufficient to provide an acceptable return on investment to encourage investment. without inclusion in the UK ETS or reliable voluntary markets.

BEIS needs to provide a viable business model for BECCS that values both negative emissions and other co-products, such as energy or fuels. BECCS could also be incentivised through inclusion in the UK ETS or developing a new market for GGRs. BEIS should continue consultation on business models for BECCS and act quickly to establish the mechanisms necessary to support deployment. These business models must also complement and synergise with support for developing BECCS pathways that receive support through other mechanisms such as the Hydrogen Business Model or the RTFO. BEIS should also continue to investigate the potential to build a market-based mechanism for all GGRs that may be able to take over from the business models in due course. BEIS aims to deploy 5 $MtCO_2e$ and over 20 $MtCO_2e$ of GGRs by 2030 and 2035 respectively with BECCS expected to be a significant contributor to both these targets. Therefore, a viable business models needs to provide the potential for early deployments with the next few years, hopefully by the end of 2023.

Action category 3: Increase funding availability for promising BECCS technologies

Innovation projects are a key stage in advancing a technology to enable large scale BECCS across different deployment pathways such as BECCS Hydrogen or biofuels. Increased funding should be allocated to develop BECCS pathways that show potential for large scale emissions removal as well as other economic benefits and efficient use of biomass resources to maximise carbon benefits. Funding is likely to come from government (BEIS) grant schemes, but technology developers could also be supported by local private investors who could benefit from the negative emissions produced and the rapid advancement of widely deployable technologies. BEIS aim to achieve near commercial scale demonstration for GGR technologies by the mid 2020's. The Humber CO_2 transport and storage network is expected to be operational by the late 2020's with additional capacity expected to be developed as demand increases. The deployment of large scale BEECS projects could therefore be shortly afterwards with operation feasible by around 2030.

Action category 4: Clarify interaction between policy and regulation across geographies and sectors

BECCS supply chains will likely be geographically diverse and influence policy in several sectors across all these geographies. Regulatory and monitoring frameworks to ensure sustainability of biomass must all be enhanced to effectively address complex international supply chains. Furthermore, the markets that BECCS credits are sold into could be local, international, or corporate. This means BECCS is currently influenced by different policymakers and subject to international collaboration and policy. This may lead to missed opportunities for the market as hesitance prevent investment to drive greater scale, integrity, collaboration, and sustainability. Regional and national policymakers should therefore work together to align and produce effective policy that can support deployment of BECCS that will produce high quality negative emissions whilst also benefitting wider economic targets and support natural ecosystems. This work should be immediate and ongoing to support BECCS projects already in development and those looking to identify opportunities and investment.

4.2 Direct air carbon capture and storage

4.2.1 Overview

To constitute a carbon removal, direct air carbon capture and storage (DACCS) requires two main stages: the capture of atmospheric CO_2 via direct air capture (DAC) technologies and its resilient storage in ways that prevent the release of carbon back into the atmosphere, for instance in geological reservoirs. To ensure carbon removal the source of power used for heating and power in the DACCS process should be low carbon, this could include renewable sources or abated fossil fuel energy (with CCS). **Current DAC technologies are generally divided into two categories, solid and liquid sorbent.** Solid sorbent technologies occur in modular systems operating a single cyclical process of chemical adsorption onto the solid filter and desorption at low temperatures (80-120°C) in vacuum conditions. For liquid sorbent technologies the process of regeneration at high temperatures (900°C) occurs in a separate cycle to capture.

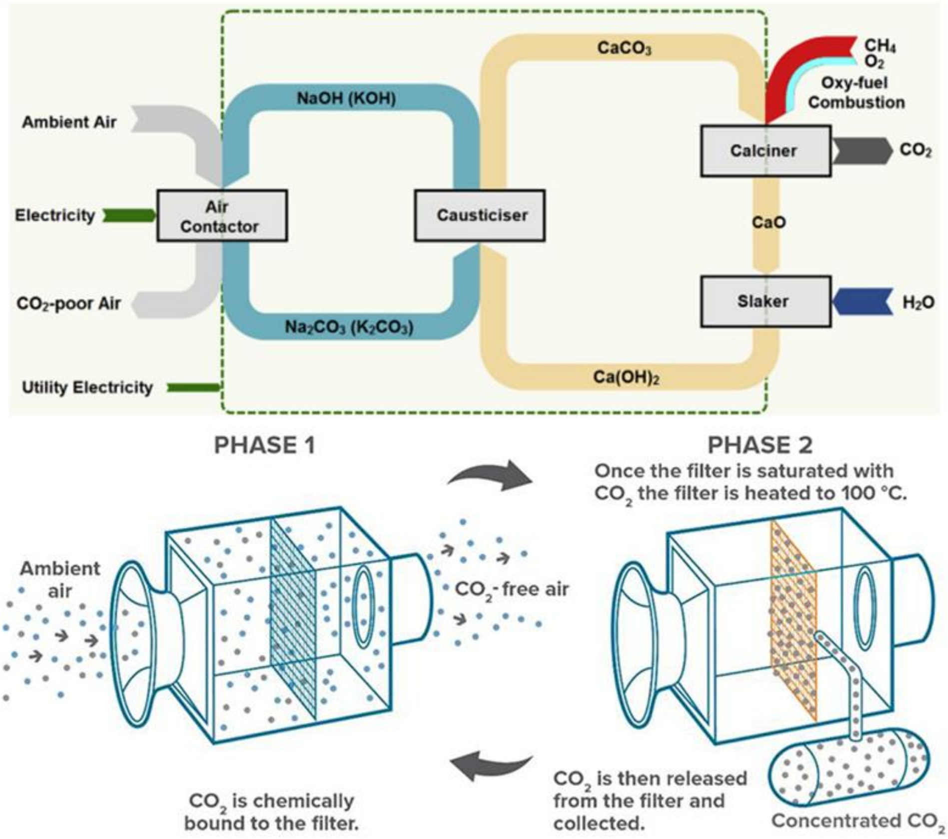

Figure 32: Schematic Illustration of the high-temperature liquid sorbent DAC process (top)[188] and of Climeworks DAC air contactor units using solid adsorbents and a temperature-vacuum-swing process (bottom)[189]

Decarbonisation potential

DACCS provides negative emissions by capturing and storing atmospheric CO_2 (Scope 1). However, several sources of emissions exist in the DACCS value chain that offset some of these negative emissions. The

[188] Fasihi et al. 2019.
[189] Beuttler et al. 2019.

provision of heat may include emission from natural gas combustion (Scope 1), electricity demand may have associated emissions (Scope 2), and manufacturing, construction, and CO_2 transport and storage all produce emissions to varying degrees (Scope 3). Therefore, to maximise the decarbonisation potential of DACCS projects it is particularly beneficial to utilise low emission electricity and heat, potentially from integration with sources such as curtailed renewables and industrial waste heat.

Literature suggests that global deployment of DACCS may have a removal potential of 0.5-5 $GtCO_2$/year by 2050[190]. Recent analysis shows UK DACCS potential is around 50 $MtCO_2$/year in 2050 however decarbonisation scenarios commonly utilise a maximum of 30 $MtCO_2$/year[191] given the high expected cost associated with DACCS. Current deployment is limited by the readiness of capture technologies and the small scale of demonstration projects although current plans within the sector could rapidly change this outlook in the coming years. Key future constraints are likely to be the availability of low carbon (renewable) energy, development of CO_2 T&S, and construction rates.

Technology status

Current DACCS demonstrations are limited to a technology readiness level of 4-7. Solid sorbent DAC research includes energy reduction for regeneration, improving cost and durability of adsorbents, and reducing capital costs through air contactor design[192]. Liquid-sorbent technology based on the potassium carbonate/lime cycle uses more mature chemical processes that already have some parallels in industry. This could enable faster scale-up so current research is focused on optimising plant-design[192]. Innovative technologies and novel approaches are emerging; these include Moisture Swing Absorption which uses moisture rather than heat to trigger CO_2 release in a similar configuration to solid-sorbent DACCS[193,194]. For liquid-sorbent DACCS there is emerging research into opportunities to use electrochemical or crystallisation techniques to allow for electrically driven or lower temperature regeneration[193]. These novel approaches have seen commercial focus on small-scale systems for niche applications and most of the approaches are only at laboratory testing or proof-of-concept prototyping stages.

Cost considerations

The cost of electricity and heat have considerable impact on the cost of DAC, contributing up to 20% for solid-sorbent systems. For solid sorbent DAC the current dominant cost factor is frequently replenishing the expensive adsorbent chemicals. The costs of solid sorbent removals in literature vary wildly with assumptions, and future reductions are dependent on innovation progress[192,195]. Nevertheless, increased deployment will allow for economies of scale in production of the modular units. In 2018, Carbon Engineering published a cost breakdown of their liquid sorbent process including estimates of 163-232 $/$tCO_2$ for first-of-a-kind plants[196]. Their analysis indicated a 30% reduction for a future, mature plant. Recent analysis found energy and operational costs can also be significant for liquid-DAC[197]. Reduced energy costs or further optimization of plant design are a key feature of cost reductions. Ambitious scenarios with very low energy costs and waste heat availability, result in prices around 100 $/$tCO_2$. Initial cost estimates for innovative DACCS techniques are found in literature based on theoretical or lab-scale performances[193]. The current CAPEX cost of Moisture Swing Absorption has been estimated at 200-475 $/$tCO_2$ but development of the sorbent could increase capture, and reduce price, 10-fold[198].

Table 25: Reported costs for different DAC technologies. Additional cost (15-50 $/$tCO_2$) is likely for CO_2 transport & storage.

[190] Fuss et al. 2018.
[191] Element Energy 2021 – GGR methods and their potential UK deployment.
[192] NAS 2019 - Negative Emissions Technologies and Reliable Sequestration.
[193] Fasihi et al. 2019.
[194] ICEF 2018 – DACCS Roadmap.
[195] Clean Energy Ministerial Webinar 2020.
[196] Keith et al. 2018.
[197] Element Energy 2022 - Global Assessment of DACCS Costs, Scale and Potential.
[198] See footnote 193188188.

Capture Technology	Current Cost Range ($/tCO_2$)	NOAK Cost Range ($/tCO_2$)
Solid Sorbent	600-800	88-228
Liquid Sorbent	160-390	80-280
Moisture Swing Absorption	200-475	25-50

Energy and resource implications

Significant requirements for heat and electrical power exist to drive DACCS, both of which will need to come from low-carbon sources to maximise the climate benefits. For solid sorbent DAC, energy requirements are 4-6 GJ thermal and 150-300 kWh electricity per tCO_2 captured[199192]. For liquid sorbents, energy requirements are ~5 GJ of high-temperature thermal energy and 366 kWh electricity per tCO_2 captured[200195]. Novel techniques aim for low energy consumption and Moisture Swing Absorption is expected to require only 316-621 kWh electricity per tCO_2 captured as well as 5-15 tons of water per tCO_2[201193]. These high energy requirements mean there is a near-term opportunity cost associated with directing scarce renewable generation to DACCS. The alternative of utilizing natural gas and capturing the additional CO_2, has upstream environmental impacts and social effects from continued fossil-fuel reliance.

DAC has low direct land requirements for the capture plant itself, but potentially high indirect requirements for renewable energy generation. Access to CO_2 infrastructure may restrict the potential deployment rates until the early 2030s and suggest a competitive advantage for siting within CCS industrial clusters, such as the Humber.

Additional resources needed for solid-sorbent DAC are the adsorbent chemicals whereas liquid-sorbent methods need other chemical feedstocks, such as calcium carbonate and potassium hydroxide for Carbon Engineering's technology. Lifecycle emissions occur during production of capture chemicals, CO_2 transport and storage and electricity generation, which if from high carbon source could significantly reduce or even overturn carbon removal potential. Verification of permanent sequestration in geological storage can be difficult, particularly for novel storage approaches or long-term utilisation approaches. There is limited research on the potential wider environmental impacts for DACCS. Impacts on the local environment will be project specific with further research required into the potential degradation products of capture sorbents[202]. Some smaller DAC companies are developing systems designed for indoors building and claim cleaner, healthier air as a co-benefit.

4.2.2 Market study

Opportunities for deployment

The Humber may be an appropriate location for DACCS for three main reasons. Firstly, the **availability of low-carbon, low-cost energy** from the growing supply of local offshore wind could be used to satisfy the high energy requirement of DACCS and reduce the significant cost component derived from energy supply.

Secondly, there is greater **chance of coupling the heat requirement of DACCS processes,** especially the low temperature heat requirements of solid sorbent DACCS, **to waste heat** produced within the industrial cluster, providing a cost advantage and energy/emission saving.

Finally, the vast **CO_2 storage opportunities offshore provide local, geological storage options** that mean that as the Humber develops into a CCS cluster it will be able to offer low cost, pre-existing CO_2 T&S for DACCS. This will provide a significant siting advantage in reducing the CAPEX requirement to connect to a CO_2 T&S

[199] NAS 2019 - Negative Emissions Technologies and Reliable Sequestration..
[200] Keith et al. 2018.
[201] Fasihi et al. 2019.
[202] See footnote 199.

pipeline or the running costs of CO_2 transport to storage sites, for example by ship, from DACCS facilities outside established hubs.

Market risks and barriers

The market risks and barriers associated with DACCS are outlined in Table 26.

Table 26: Market risks and barriers for DACCS

Risks	Description
Uncertain energy prices and carbon intensity	DACCS requires large amounts of low-carbon, inexpensive energy and therefore needs a sustainable, reliable supply of electricity and/or heat to encourage investment and scale. The Humber could prove an attractive location for DACCS plants given the availability of low cost, renewable power from offshore wind near the cluster is a significant attraction for potential DACCS developers. The availability of waste heat from sites within the cluster could also be effectively coupled with DACCS deployment.
Availability of key resources	Large scale DACCS deployment will require a significant volume of several different resources to produce both the chemicals used in the capture process and the surrounding infrastructure.
Barrier	**Description**
Project capital cost variability	Significant cost differences may exist between different DACCS technologies and uncertainty is present in the price of scaling these different technologies
Development of voluntary carbon markets	DACCS has the potential to provide high integrity reliable carbon credits to the market however these markets are currently immature, and many registries do not yet accept DACCS projects.
Investment size and risk	Deploying DACCS technologies at a significant scale will require large upfront investment which remains unattractive investors currently due to the immaturity and associated risks of the technologies.

4.2.3 Policy study

Policy status and future enablers

BEIS business models

BEIS is currently consulting on business models for engineered removals[203]. This aims to set out details of the preferred mechanisms to incentivise early investment and enable commercial demonstration of a range of removal technologies, although biochar and enhanced weathering are excluded from the consultation document, from the mid-to-late 2020s. The design and implementation of business model is expected in 2023. The government is considering three options:

- Negative Emissions Contract for Difference (CfD): the difference between the strike price and a reference price is paid by the counterparty to the developer.
- Negative Emissions Payment: government pays for negative emissions and then either sells the credits in a market or ask developers to sell the credits and share the revenue with the government.
- Negative Emissions Guarantee: developers bid for the option to sell credits to the government at a guaranteed price in regular intervals. The project then tries to sell credits in the market with the agreement it can sell any unsold credits to the government.
- The consultation also suggests that government will seek a market-based solution in the long term where engineered GGRs are funded by the remaining emitters in hard to abate sectors. This will require the development of a suitable market, which could be provided by integration into the UK ETS, development

[203] BEIS 2022, Business models for engineered greenhouse gas removals: accelerating investment in engineered carbon removals

of a new GGR obligation scheme, or through the voluntary carbon market, either in existing market bodies or through a government designed market similar to that accompanying the Woodland Carbon Code.

DAC can be deployed in multiple configurations, including DAC with CO_2 utilisation. CCU is not expected to be supported by the GGR business model. Nevertheless, the utilisation configuration allows for a revenue for the sale of CO_2 generated through DAC, and potentially allows for a voluntary green premium for low carbon products. DAC with CO_2 utilisation may therefore present a simpler business model than DACCS. A business model for DAC needs to consider this possible alternative use for DAC plants, as it is a variable influencing the UK's targets for carbon removal technology deployment. If UK DAC facilities are primarily operated to produce synthetic fuels, this could result in a greater reliance on BECCS technology to produce negative emissions. **Full business models for DAC with CO_2 utilisation products may need to consider charges for end-of-life release of CO_2** (e.g., for release of emissions from burning synthetic fuels) as this fundamentally influences the climate benefit that results from these activities.

Funding mechanisms

To overcome the aforementioned commercial risks will require a resilient and well-constructed DACCS business model. There is a strong preference for investable business models and support mechanisms which provide direct financial remuneration for negative emissions. Contract mechanisms could be suitable for supporting large-scale engineered removals as they are well understood by investors. DACCS projects are also likely to encounter similar risks such as high capital costs and uncertain longer-term revenues. Contracts can guarantee that a specific volume of removal will be delivered over a given timescale, providing certainty for the government's net zero plans. A contract scheme for DACCS could be based on business models currently being developed for CCS and hydrogen production to ensure consistency of approach. Developers are likely to seek long-term contracts, however government could prefer shorter contracts, potentially at a higher initial price, on the basis that more auction rounds will enable price discovery. A contract that pays on delivery will reduce the risk to government, as no payment needs to be made if the contractor fails to deliver. Technologies could be separated into auctions or tenders based on maturity or cost, in a similar manner to the separate contract for difference auctions for different types of renewable technology.

Most carbon removal technologies are at a pre-commercial stage and require innovation and demonstration support prior to commercial deployment. Carbon removal technologies are included as one of ten innovation priority areas announced in the *Ten Point Plan* and BEIS and UK Research and Innovation (UKRI) are investing £100m in the research, development, and demonstration of removals across multiple programmes. **This includes a direct air capture and other carbon removal innovation competition which will support the construction of pilot plants for a range of promising technologies to help them achieve commercial realisation.** The programme's pilot projects could remove up to 1 $MtCO_2$/year in 2025 with the potential to scale up to millions of tonnes by the 2030s[204].

Another potential source of funding for DACCS is the voluntary carbon market where carbon removal credits can be sold to emitters such that they can offset their emissions. **The high quality and resilience of DACCS credits may allow them to charge a premium price in the voluntary carbon market** as has been seen for the initial small volumes of credits from early projects such as Climeworks' "Orca" facility. For further discussion of the potential to sell removal credits in the voluntary carbon market (see Section 4.4).

Policy risks and barriers

The policy-related risks and barriers for DACCS are presented in Table 27:

[204] BEIS 2021, Net Zero Strategy: Build Back Greener.

Table 27: Policy risks and barriers for DACCS

Risks	Description
Uncertain carbon prices	If DACCS is included in market mechanisms then the economic viability of projects is dependent on the price of carbon, which is currently highly variable.
Barrier	**Description**
Lack of incentive for negative emissions produced	DACCS is not currently supported by a government business model, carbon price, or viable international voluntary carbon markets and therefore does not currently have a reliable price incentive for negative emissions produced. Development of market mechanisms to reward negative emissions would be necessary to encourage long-term storage instead of utilisation.
Underdeveloped CO_2 T&S infrastructure	CO_2 T&S infrastructure in the UK is currently at initial stages of development and the capital cost and complexity of setting up the infrastructure is restrictive. Although somewhat mitigated in the Humber by pre-existing plans and funding through the Zero Carbon Humber consortium, there is a risk due to the necessary development of T&S infrastructure which is required for DACCS to reach a reasonable price for removals.
Lack of support for R&D and pilot projects	Current support is limited for pilots and demonstration projects, except the DAC technologies competition[205], which will both be crucial to drive DACCS technologies forward given the vital roles these projects have in reducing the cost and increasing the viability of scaled DACCS deployment and, in a similar way to BECCS, informing and creating the supporting systems and regulations to ensure best practices are maintained
Inclusion in international carbon accounting frameworks	DACCS is among several new carbon removal approaches where international carbon accounting rules have not yet been fully accepted and developed.
Lacking government action and strategy	Creates uncertainty for developers in when government will develop and implement sufficient, supportive policy mechanisms for DACCS. This could continue to contribute towards developer and investor hesitance to establish themselves in the UK and could result in projects choosing international markets where clearer policy frameworks are established.

4.2.4 Regulatory study

Planning requirements

Consents required

Direct air carbon capture and storage

As with other forms of carbon capture and storage, DACCS does not fall within the criteria of the Planning Act and is therefore not considered an NSIP. This means that any applications for DAC projects could be consented through a planning application under the TCPA.

Again, as with CCS and BECCS, and depending on the scale and scope of the DACCS project, it is possible to seek a Section 35 direction from the Planning Inspectorate requesting that the project is accepted as an NSIP and consented through the DCO process. There are several possible benefits to this, including the national presumption in favour of DACCS. Whether this would be accepted would be dependent on the nature and scale of the project.

Environmental Impact Assessment

As with CCS, if the project is taken through the DCO process projects of this nature would fall under Schedule 1, paragraph 23 of the Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 (“EIA Regulations) as ‘Installations for the capture of carbon dioxide streams for the purposes of geological storage

[205] Direct Air Capture and other Greenhouse Gas Removal technologies competition.

pursuant to Directive 2009/31/EC from installations referred to in this Schedule, or where the total yearly capture of carbon dioxide is 1.5 Mt or more.'.

Any project that captures over this amount of carbon dioxide per annum is therefore classified as 'EIA development' and as such the DCO Application would need to be supported by an Environmental Impact Assessment (EIA).

In respect of planning applications under the TCPA, the same threshold and definition exists within The Town and Country (Environmental Impact Assessment) Regulations 2017.

Key considerations and requirements

In respect of planning and consenting, DACCS is considered a new and emerging technology, and for that reason it is not explicitly included in the definitions on NSIP projects within the Planning Act. Therefore, where the projects are either standalone or not associated with a wider NSIP project, consent would be required through the TCPA. It is possible however to seek a Section 35 direction from the Planning Inspectorate requesting that the project is accepted as an NSIP and consented through the DCO process.

There is a planning policy presumption in favour of DACCS within the NPS, acknowledging the contribution these projects can make to the national energy strategy.

Permitting requirements

DACCS refers to the chemical scrubbing of CO_2 directly from the ambient air before storing it. The Environmental Permit Regulations state that carbon capture is associated with the capture of CO_2 from an installation, not from ambient air. Therefore, at present, it is understood that the operation of DACCS technologies would not be covered under the permitting regulations or associated BAT/BREFs. This interpretation should be confirmed with the Environment Agency (EA). No precedent has yet been set as there are no DAC/DACCS plants operating in the UK.

Regulatory risks and barriers

The regulatory risks and barriers related to DACCS are presented in Table 28.

Table 28: Regulatory risks and barriers for DACCS

Risks and Barriers	Description
Lack of standards for utilisation pathways	CO_2 utilisation may be crucial in developing early DAC whilst geological storage is not widely available or until the price of carbon removal credits is sufficient to support DAC. Nevertheless, these novel applications are only just emerging from R&D stages and will require the adoption or modification of regulations to permit their use in different industries. Many utilisation products, such as concrete or aggregates, do not have established standards allowing them to be used in industry
Monitoring of CO_2 storage	current monitoring methodologies and verification regulations for CO_2 transport and geological storage are not yet defined in national or international regulations.
Waste product safety	Regulations surrounding potential emissions and waste products related to the chemicals used in capture are still to be exhaustively specified. Research is required to understand and address the environmental effects from potentially hazardous DACCS chemicals and waste products
Lack of coverage by permitting regulation	The operation of DACCS technologies is not specifically covered in permitting regulations or associated BAT/BREFs. Engagement with EA will be important to help clarify regulatory requirements. Where guidance is lacking, this could cause delays in the EA coming to a determination on a permit application for novel DACCS technologies. To date and to ERMs understanding, no DACCS plant has been permitted in the UK.

4.2.5 Recommendations and actions

The risks and barriers outlined for DACCS above cover market, policy, and regulatory aspects separately. In considering actions to mitigate those risks and barriers, there is merit to considering actions in the context of all three dimensions, due to the mutual benefits which often arise from solutions.

Drawing on the stakeholder discussions held, reviews of the literature, and Element Energy's own insights, the following set of action categories are recommended to help actors within the Humber cluster navigate what is a complex and rapidly developing market. These actions would either be considered the responsibility of technology developers and investors within the Humber cluster, government policymakers, and/or DACCS market regulators.

Action category 1: Aggregate demand for high quality DACCS negative emissions to encourage scale

The Humber has the potential to catalyse the UK market for DACCS due to the scale of emissions, and likely residual emissions, that will need to be offset with high quality credits. Currently, project developers struggle to create a financial case due to demand and price uncertainty in the future but aggregated demand from a consortium within the cluster would be able to provide greater certainty for DACCS developers to allow investment into the region and encourage scale. Recently Frontier, funded by a collective of global corporates, came together to form a $925m advanced market commitment to buy permanent carbon removals. Large emitters, including industry and local authorities, in the Humber could collaborate together in a similar fashion to support the development of GGR projects in the local area, UK, or abroad through the voluntary market. Carbon removal credits are already being bought in advance of project deployment and verification in the voluntary market, so pathways do exist to provide upfront funding. However, it is likely that more established mechanisms will emerge in coming years.

Action category 2: Ensure DACCS negative emissions can be certified as tradable units

The Humber could prove an attractive location for DACCS plants given the availability of low cost, renewable power from offshore wind near the cluster is a significant attraction for potential DACCS developers. The availability of waste heat from sites within the cluster could also be effectively coupled with DACCS deployment. This could allow the cluster to not only offset its own residual emissions but also those of other national, and international, corporations. DACCS can provide high integrity negative emissions credits although current markets have limited certification standards and methodologies for certification of DACCS projects. There are gaps in monitoring, sustainability, and carbon accounting frameworks that will require development before the large-scale trading of DACCS credits on voluntary or compliance markets.

To create a stable and investable market for DACCS will require either the development of voluntary or compliance markets by NGO registries or governmental organisations (national or international) respectively. With the growing interest in negative emissions credits, especially the high integrity credits from DACCS projects, clear regulation is becoming increasingly necessary to manage the market effectively. As the first large scale projects are deployed by the end of the decade these market regulations will need to be developed.

Action category 3: Develop an investable DACCS business model

Private investment in scaling the UK DACCS market is currently held back by insufficient policy and market structures. The business model consultation for BECCS power ran from August to October 2022 with no business model currently operational. The price and markets for negative emissions in the voluntary markets are not sufficient to provide an acceptable return on investment to encourage investment.

The business model for engineered GGRs, which will include DACCS, is currently under consultation with implemented expected from 2023 onwards. This shows a relatively mature level of development from BEIS in their support for DACCS, but the business model mechanism is still to be confirmed so uncertainty prevails. Consultation also suggests that government will seek a market-based solution in the long term which will require the development of a market. This could be provided by integration into the UK ETS, development of a new GGR obligation scheme, or through the voluntary carbon market. BEIS should work vigorously towards the 2023 deadline for the deployment of the business model, and then focus on creating the necessary market conditions for a market-based solution to be able to replace the business model.

Action category 4: Increase funding availability for promising DACCS technologies

Innovation projects are a key stage in advancing a technology to enable large scale deployment. BEIS and UK Research and Innovation (UKRI) are investing ~£110m in the research, development, and demonstration of removals across multiple programmes. This includes a direct air capture and other carbon removal innovation competition; however, further funding is likely to be essential to develop DACCS technologies at the speed and scale required to achieve net-zero. Increased funding should be allocated to develop DACCS technologies that show potential for large scale emissions removal at a price that could be competitive in future carbon markets. BEIS should allocate funding to support the deployment of the most promising engineered removal technologies from the Direct Air Capture and Greenhouse Gas Removal Programme. BEIS aim to achieve near commercial scale demonstration for GGR technologies by the mid 2020's. The Humber CO_2 transport and storage network is expected to be operational by the late 2020's with additional capacity expected to be developed as demand increases.

4.3 Natural climate solutions

4.3.1 Overview

Natural Climate Solutions (NCS) rely on enhancing and protecting natural ecosystems to remove or avoid GHG emissions. In the context of decarbonisation, the NCS pathways discussed are limited to the subset that remove CO_2 from the atmosphere, therefore excluding those techniques that are credited for reducing future emissions (e.g., avoided deforestation) or target other GHGs. For this review we do not discuss the generally immature ocean storage and inorganic capture techniques, except for enhanced weathering due to its potential and synergies with other carbon removal methods. It is important to differentiate NCS, from Nature-based Solutions (NbS), as only those activities that deliver carbon removals, not activities that focus on other environmental benefits. To align with a 1.5°C trajectory, global carbon emission must halve by 2030 and according to available estimates, NCS could contribute up to a third of the net emissions reductions required[206].

[206] World Economic Forum 2021.

Beyond storing carbon, NCS can deliver co-benefits for biodiversity and local communities, contributing to several SDGs. Despite the potential scale, relatively low cost of removal, high public approval, and wider environmental co-benefits, NCS receives only 2.5% of global climate mitigation finance**[207]**.

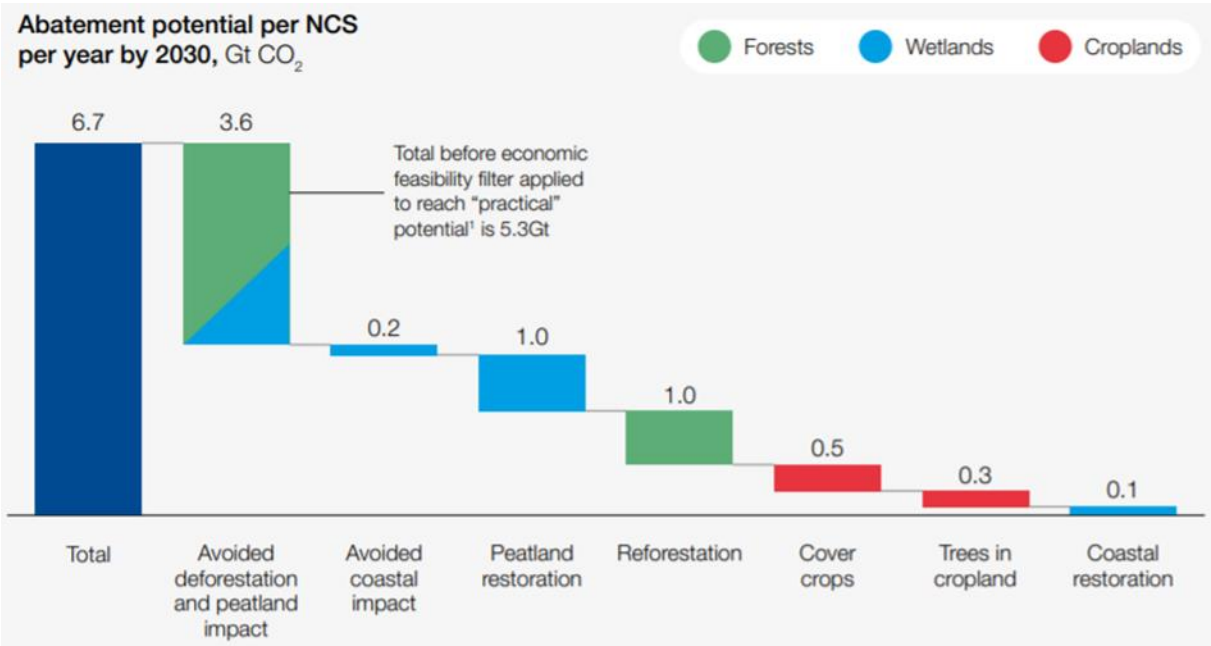

Figure 33: Maximum cumulative potential of major NCS pathways for carbon abatement by 2030[206]

The UK is expected to need around 130 $MtCO_2$/year of offsets in 2050[208] and **mature NCS pathways could provide early deployment options until the mid-2030s** when engineered solutions are expected to expand in scale as prices fall. NCS in the UK will occur through reforestation (15 $MtCO_2$/year), wetland, saltmarsh, and peatland restoration (5 $MtCO_2$/year) and via pathways on agricultural land such as soil carbon sequestration (10 $MtCO_2$/year), enhanced weathering (15 $MtCO_2$/year) and biochar (5 $MtCO_2$/year)[209].

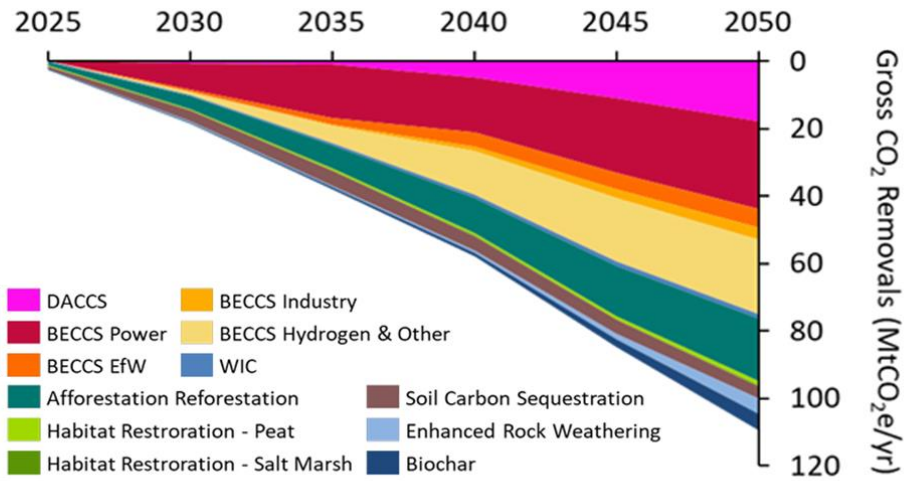

Figure 34: Carbon removals in the CCC's Balanced Deployment Scenario[210]

[207] Griscom et al., 2018.
[208] Element Energy 2021 – GGR methods and their potential UK deployment.
[209] Ibid
[210] Ibid.

NCS face several common challenges focused on their permanence, leakage, additionality, monitoring, and potential for negative socio-ecological impacts if not managed correctly. For example, sustainable projects must prevent activity leakage where biomass growth projects simply displace carbon intensive activities (such as unsustainable logging) and therefore carbon removals are cancelled out. The permanence of carbon storage is a key issue faced by many NCS given that many pathways are likely to only store carbon on relatively short timescales. For example, using wood products in construction only retains the carbon locked in the wood as long as the building is protected for as soon as the building is demolished, and the wood thrown away it will decompose and release the stored carbon to the atmosphere. As for all other removals, NCS should only be used as offsets in accordance with the mitigation hierarchy (avoid, reduce, offset) and must not replace emission reductions[211].

Main pathways

Afforestation and reforestation are expected to be key in addressing climate change. Forests sequester carbon by capturing CO_2 from the atmosphere and transforming it into biomass as they grow. Negative emissions are established through reforestation (planting trees on previously forested land) and afforestation (planting trees where none existed prior). Reforestation is often perceived to be environmentally superior as it ensures the forest is being planted on suitable land whilst restoring degraded habitats. Afforestation and reforestation provide important co-benefits through ecosystem services, valuable wood products, potential waste biomass for BECCS, preserving biodiversity, avoiding soil degradation, and protecting natural resources. Afforestation and reforestation are relatively cheap, well-developed, and has very large potential compared to other removal pathways. Afforestation and reforestation require large land areas to sequester significant amounts of carbon and other major resource demands include water and nutrients (fertiliser). Accurately quantifying CO_2 removals associated with these techniques and ensuring their permanence is challenging. Considering that the Humber region is one of the least forested in the UK, this shows a potential opportunity for reforestation in the area, although a lack of appropriate land may prevent widespread afforestation, with low-lying flood prone land unsuitable for afforestation.

Agroforestry is the process of integrating trees onto agricultural or pastoral land that leads to increased sequestration in biomass and soil reservoirs. Agroforestry actively rehabilitates degraded agricultural land or can be employed on land already worked to provide additional co-benefits. Agroforestry can provide economic security for local landowners through having multiple income streams. Agroforestry promotes biodiversity, soil health, and water quality by creating a more diverse ecosystem. Low density carbon storage means large land areas would need converting to create significant carbon drawdown with storage dependant on continued management, yet agroforestry could be widely employed on the farmland surrounding the Humber and in combination with other NCS or BECCS.

Building with biomass involves using biological materials in construction, for example hemp can be used as insulation. The practice of using biomass for building is well developed globally and new innovations, such as cross-laminated timber, are creating construction opportunities beyond the capabilities of ‘normal’ wood. Building with biomass can involve harvesting timber from mature forests which allows space for new planting and continued removal, however this must be done sustainably and not reduce standing carbon stocks. Exploiting biomass in building not only stores carbon but also avoid emissions from alternative construction materials. Permanence of storage is anthropogenically dependant and both processing and transport emissions may reduce carbon removal potential. Widespread and large-scale deployment needs adjustment to building regulations and both safety and quality assurances to encourage industry uptake and confidence.

Wetland habitat restoration (often termed “blue carbon”) refers to techniques that utilize saltmarshes, tidal marshes, seagrass meadows, peatlands, and mangroves to increase biomass and soil carbon stores. Management of these habitats has occurred for centuries, so practices and understanding are well developed. Restoring coastal or wetland habitats can store a high density of carbon per unit area and provides numerous ecosystem services, flood risk management, and economic opportunities. Monitoring and verifying carbon removal in these “blue carbon” pathways is difficult and costly. CO_2 removals may be offset by the production

[211] Oxford Offsetting Principles for Net Zero Aligned Carbon Offsetting, 2020.

of biogenic GHGs, especially in peatlands, and these delicate ecosystems are vulnerable to climate change and modified ecosystem drivers, such as sea level rise.

Biochar is created by a process called pyrolysis. Biochar is then spread on agricultural land and as it will not readily decompose, it stores extra carbon in the soil. Biochar is a commercial product that can be used to improve soil and crop yields by storing nutrients, water and air, all of which can be beneficial to soil health, alongside providing other environmental benefits including stabilising heavy metals and reducing soil NO_2 emissions. Biochar production is also a net energy generator. The permanence of carbon storage needs further investigation however uncertainties in resilience will require detailed monitoring. Furthermore, in using biomass as a feedstock biochar production is susceptible to many of the potential risks discussed around the sustainability of biomass supply.

Soil carbon sequestration involves changing land management practices to increase the carbon content of soil. There are many practices that can promote sequestration, such as no-till agriculture, planting cover crops, nutrient management, and fire management. Soil carbon sequestration practices increase or maintain soil health including through broadening nutrient profiles, preventing erosion, and developing overall fertility. While some carbon can be stored for centuries, much of the organic matter in soils is relatively prone to transformation, therefore this pathway requires long-term monitoring to ensure permanence. Sequestration will also reach saturation in as little as a couple of decades. Monitoring, reporting and verification can be difficult because the changes are small relative to the large background level.

Enhanced weathering is based on the natural process by which silicate rocks naturally break down, in a reaction which absorbs CO_2 and releases (bi)carbonate ions to the ocean or to be precipitated as carbonates. Enhanced weathering involves milling the silicate rocks to increase their surface area and spreading the dust over managed cropland where roots, microorganisms, and acidity further hastens the reaction. Enhanced weathering reduces soil acidification and increases carbon stocks which may increase productivity, rejuvenate marginal agricultural land, and result in decreased fertiliser or pesticide use. Application may have negative impacts on water quality and emissions occur as a result of mining, refinement, and transportation of the minerals. **Biochar, soil carbon sequestration and enhanced weathering could all be co-deployed on surrounding agricultural land.** However, reducing agricultural land use in future may reduce this opportunity.

Long-lived bio-products refers to the conversion of biomass into bioplastics and other long-lived bio-based products, using chemical or biological pathways. Bioplastic products can reduce demand for conventional fossil fuel derived plastics and therefore avoid further emissions alongside the carbon directly stored in the product. Bio-products produced using microalgae may be able to consume a wide range of biowastes limiting the need for and cost of virgin biomass and provide other co-benefits, such as wastewater purification. There are possible opportunities with pre-existing refining technology and expertise in the cluster however this is not part of any pre-existing plans.

4.3.2 Opportunities for deployment

Current projects implementing Nature-based Solutions in the Humber do not specifically focus on carbon, and therefore climate, related benefits. They were developed with the aim of improving ecosystem services, such as mitigating flood risk or restoring habitats for threatened species. **However, some of these projects may also provide carbon removal as a co-benefit so could have been deployed as NCS** given a renewed focus on carbon removal. The abundant supplementary motivations for potential NCS projects may be problematic as unless the project can show it has stored additional carbon because of investment tied to the carbon benefit it would be unable to claim removal credits. This is because similar NbS schemes are being funded anyway, without the need for carbon removal finance, a problem known as "additionality risk".

Several projects are already underway which show the potential for and interest in NCS within the Humber region and should contribute to creating greater opportunities for local NCS projects. One such project is being run after the UK Centre for Ecology & Hydrology received £100,000 funding from the Natural Environment Investment Readiness Fund (NEIRF[212]) to develop a UK Saltmarsh Carbon Code[213]. The year-

[212] Natural Environment Investment Readiness Fund
[213] National Saltmarsh Restoration Project

long project which started in October 2021 is kick-starting the process of developing and piloting the Code. The aims of the Code are to unlock £1bn investment and improve 22,000 ha of saltmarsh over a 25-year period. The project will ensure verification of carbon removal through the Code, connect with existing projects to allow carbon crediting, and create incentives for new schemes, for example the project involves four test sites including Skeffling on the Northern side of the Humber estuary. The project will also develop scientific and business models to help UK projects attract private investment at scale. There is potential to build an umbrella Blue Carbon Code applicable in other marine habitats although this does not fall under the current remit of the funding received and will develop gradually as sufficient data becomes available. Not only will the Code encourage projects that remove carbon from the atmosphere but also those that prevent further ecosystem degradation, habitat loss, and provide flood risk management benefits. It is thought the Code could be completed within a 5-year period however this is dependent on renewed funding and ongoing resources being made available.

NEIRF also provided equal funding to another local project run by the Lincolnshire Wildlife Trust which is aiming to establish local market mechanisms to trade biodiversity, carbon, and water credits generated through improvements to agricultural landscapes[214]. The “Green Investment in Greater Lincolnshire” project will work with landowners to identify potential for projects, establishing a registry pipeline of shovel ready projects.

Another project in the local area is Humberhead Levels which is creating an internationally renowned, unique network of wetlands and peatlands in a predominantly agricultural landscape. The project covers 2,000 km^2 with 1190 ha of habitat improved having received £2.6m in Defra funding from 2012. Continued support until 2018 was provided by a £248,000 grant from WREN’s Biodiversity Action Fund, and finally Defra awarded a £500,000 Nature for Climate Peatland Grant this year. Although the project is not claiming carbon benefits and is therefore currently an NbS project focused on improving ecosystem services, such as flood risk management and biodiversity, it demonstrates the local potential for peatland restoration which, with appropriate funding structures, could produce removal credits. There are also reforestation projects in the local area such as Humber Forest[215], part of the Governments Northern Forest[216] programme, which is fostering community forestry by offering landowners access to funding and practical help to plant trees efficiently and effectively.

These projects show there are opportunities in the Humber region for NCS, especially wetland or saltmarsh habitat restoration, that could be funded, developed, and then claimed against emissions by companies in the cluster assuming they are additional and used in addition to aggressive decarbonisation. These projects will have significant co-benefits for the region and may be able to claim other types of credits (biodiversity etc.) to increase financial viability. The range of existing projects means there is substantial expertise in local partners and the Humber Nature Partnership which could help develop NCS projects. There are also opportunities for NCS in soil management, seagrass planting, and the use of hemp as insulation in buildings which may be beneficial in building a diverse portfolio of offsets.

4.3.3 Risks and barriers

Whilst the UK government has expressed the importance of NCS, so far it has not provided sufficient policy and financial support to accelerate their deployment. This is most clear in the lack of any incentive for the negative emissions produced by NCS projects. This leaves no stable market for selling the negative emissions with the international voluntary markets still volatile, disaggregated, and immature. Currently the Woodland and Peatland Carbon Codes verify and credit most UK NCS projects however as the market grows inclusion in the UK ETS may become beneficial in standardising approaches and best practice. Integrating NCS into the UK ETS, or a linked market, is a common request and is under consideration.

Wider policy concerns arise from the restricted clear government strategy which creates uncertainty for how projects may interact with other sectors, international policies, and the potential for double counting/claiming within the various accounting frameworks employed at corporate, local, and national levels. Policy is also unclear on the interaction of NCS with other land uses and how possible competition for land use, with agriculture or renewable energy for example, will be prioritised. Barriers also exist due to the disaggregated and

[214] Green Investment in Greater Lincolnshire
[215] Humber Forest
[216] Northern Forests

scattered nature of policy and funding between the different sectors that NCS interacts with, which may lead to missed opportunities and increased effort in efficiently developing projects.

Table 29: Summary of risks and barriers faced by the deployment of NCS

Risk/Challenge	Description
Financial additionality	Many habitat restoration projects currently occur in the region as NbS without carbon credit revenue which may undermine new projects claiming credits
Immature markets	NCS credits are not currently included in the UK ETS leaving no stable market for negative emissions with the international voluntary markets still immature
Competition with other land uses	NCS projects will often be using land that could also be employed for other activities, such as agriculture or renewable energy
Lack of policy support	Limited clear government strategy creates uncertainty for how projects may interact with other sectors and international policies
Measurement, monitoring, and crediting	Quantifying the carbon removed/avoided is complicated and requires detailed standards and methodologies to provide adequate verification
Regulatory additionality	Changing environmental regulations, as the UK develops its NDCs, may change the additionality requirements for NCS projects
Double counting	Projects, corporations, local, national and international governments all account for carbon credits which can result in offsets being used multiple times

There are numerous regulatory barriers corresponding to possible flaws and changes to carbon accounting methodologies. One pertinent risk to developing NCS projects in the UK especially is that of ensuring financial additionality given the dispersed funding opportunities and significant co-benefits that are produced by NCS projects. Projects would not be able to claim carbon credits if the sequestration is not additional to what would have occurred in the alternative “baseline” business as usual scenario (e.g., where a NbS project occurs instead to reduce flood risk and improve biodiversity). There are also additionality concerns regarding the regulatory conditions in the UK as changing environmental regulations, especially as the UK implements and updates its NDCs, may change the regulatory additionality requirements for NCS projects. Finally, the **measurement, monitoring, and crediting of the carbon removed by NCS projects is complicated and requires detailed standards and methodologies to provide adequate verification.** These standards do not currently exist for NCS pathways in the UK, expect for the Woodland and Peatland Carbon Codes, and although available they are routinely criticized in the international voluntary space.

4.3.4 Policy status and future enablers

UK NCS policy is still under development, but the Net Zero Strategy[217] acknowledges the potential of NCS in achieving both our short-term climate targets and net zero by 2050. The strategy includes plans to treble woodland creation rates by the end of this Parliament, restore 35,0000 ha of peatland by 2030 and 280,000 ha by 2050, engage 75% of farmers in low carbon practices by 2030, including promoting agroforestry, and investigate and close evidence gaps on other NCS pathways such as “blue carbon” habitats and soil management practices. The Green Finance Strategy[218] sets a target to raise at least £500 million in private finance annually to support nature’s recovery by 2027, rising to more than £1 billion by 2030.

[217] Net Zero Strategy: Build Back Greener, 2021.
[218] Green Finance Strategy.

Several policies improve the viability of NCS projects in the UK and the Net Zero Strategy introduces further land management schemes:

- The England Peat Action Plan[219]
- The Agriculture Transition Plan[220]
- The England Trees Action Plan[221]
- The National Food Strategy[222]
- The Sustainable Farming Incentive Scheme[223]
- The Local Nature Recovery Scheme[224]
- The Landscape Recovery Scheme[225]

Funding mechanisms

There are several government funding schemes available that may be applicable to NCS projects with the largest potential source being the £750 million Nature for Climate Fund (NCF[226]) which is to be assigned by 2025. In addition, the £80 million Green Recovery Challenge Fund (GRCF[227]) is set to plant almost one million trees and the £10 million Natural Environment Investment Readiness Fund (NEIRF[212]) intends to develop projects/schemes until they can provide a return on investment to attract private finance. The Farming Innovation Programme[228], part of Defra's innovation and R&D investment, allocated £17.5 million in the first of three funding rounds and could provide opportunities for NCS on agricultural land such as biochar, agroforestry, or enhanced weathering.

These funding streams have already supported research and a variety of projects:

- £16 million of NCF funding has been distributed to the Nature for Climate Peatland Grant Scheme by Natural England, to award Restoration Grants to five successful applicants over the next four years[229], which has included extending support for the Humberhead Levels project[230].
- The NCF has also funded a £15 million boost for the "Northern Forests" project[216] aiming to plant 50 million trees.
- UK Research and Innovation invested £30 million in five carbon removal technology demonstrator projects investigating a range of NCS pathways[231].
- 90 project grants were awarded funding under round two of the GRCF.
- The NEIRF has made 27 grants of £100,000 to a diverse range of projects, including two projects local to the Humber region that may grow substantial opportunities for further offset projects in the region: the Lincolnshire Wildlife Trust's 'Green Investment in Greater Lincolnshire' project214 and to the UK Centre for Ecology & Hydrology to develop a UK Saltmarsh Carbon Code[213].
- The Woodland Carbon Guarantee is a £50 million scheme that aims to help accelerate woodland planting rates and develop the domestic market for woodland carbon by providing the option to sell captured verified Woodland Carbon Units, to the government for a guaranteed price every 5/10 years up to 2055/56[232].

[219] England Peat Action Plan.
[220] Agriculture Transition Plan.
[221] England Trees Action Plan.
[222] National Food Strategy.
[223] Sustainable Farming Incentive Scheme.
[224] Local Nature Recovery Scheme.
[225] Landscape Recovery Scheme.
[226] Nature for Climate Fund.
[227] Green Recovery Challenge Fund.
[228] Farming Innovation Programme.
[229] Nature For Climate Peatland Grant Scheme by Natural England.
[230] Humberhead Levels.
[231] UK invests over £30m in large-scale greenhouse gas removal.
[232] Woodland Carbon Guarantee.

4.4 Exporting CO_2 removal credits

4.4.1 Overview

Whilst ambitions for reducing CO_2 emissions are high, the challenging practicalities facing sectors and companies as they endeavour to decarbonise operations swiftly are becoming increasingly evident, and many sectors are therefore engaging with the carbon offsetting market to lessen the pressure on directly reducing carbon emissions. Carbon offsetting markets allow CO_2 emitters to compensate for or 'balance' their emissions by purchasing credits, leading to the ability to claim the status of 'net zero' emissions for parties that own the credits. Credits are tradeable certificates that each represent a tonne of CO_2 removed from the atmosphere or delivering CO_2 emission reductions (this distinction is discussed below).

As discussed previously in this chapter, the Humber cluster has multiple opportunities to develop and operate CO_2 removal projects. The question arises of how CO_2 removal players in the Humber cluster could engage with the carbon offsetting market to sell the **CO_2 removal credits** they could generate.

Carbon offsetting markets are rapidly growing and evolving, with demand for credits soaring, alongside ongoing development of broader policy initiatives to tackle climate change. This market growth may present an opportunity for the Humber cluster to sell CO_2 removal credits, but also brings risks associated with engaging in an emerging market. This section therefore aims to provide interest parties in the Humber with insight into how it might engage with this market and mitigate the risks involved through addressing the following questions:

- Who may purchase credits delivered through CO_2 removal projects, and what is the approximate market size?
- What risks and barriers are there to realizing the opportunity of CO_2 removal credits?
- What mitigating actions are required of various stakeholders (i.e., policy makers, investors, businesses) to overcome these risks and barriers?

Before addressing these questions, the next section provides some background context around carbon markets, and definitions for terms used throughout the analysis. This is important information given the various possible interpretations of terms like 'offsetting', 'carbon market' and 'carbon credit'.

Context and definitions

Despite being widely recognised as an essential component of tackling climate change, the principle of paying for CO_2 emission removals or reductions suffers from poorly defined terminology, particularly around the practice of 'carbon offsetting'. This section tackles the key relevant concepts and definitions.

Defining 'carbon offsetting'

There is no clear definition of the term 'carbon offsetting'. It is generally understood that carbon offsetting is an activity intended to compensate for an entity's own emissions - measured in carbon dioxide equivalents (CO_2e) - by funding activities which reduce or remove CO_2 emissions elsewhere. Eunomia developed the following definition in work for the Environment Agency:

> *"The practice of reducing or removing greenhouse gas emissions to balance ongoing greenhouse gas emissions, in order to achieve claims such as climate neutrality or net zero".*[233]

[233] Environment Agency, 2021, A review of the evidence behind potential carbon offsetting approaches.

There are three main components of this definition:

- To balance ongoing CO_2 emissions that have not yet been eliminated;
- This enables the purchaser to claim a status such as climate neutrality or 'net zero' (see below for further discussion); and
- The mechanism used to offset carbon can include reducing the rate of CO_2 emissions into the atmosphere or removing CO_2 emissions from the atmosphere

Carbon offsetting can be considered a verb, i.e., an action which can be undertaken by an entity (e.g. a business or government). This activity involves purchasing a climate outcome (a CO_2 emission reduction or removal) that is in some way certified, usually termed a 'certificate' or 'credit' with 1 certificate or credit representing 1 tCO_2e (see below for further discussion regarding certification). These outcomes are often referred to as 'carbon certificates' or 'carbon credits' (and sometimes simply 'offsets', where the term 'offset' becomes a noun, rather than a verb). These outcomes are delivered by projects which cause changes in CO_2 emission or removal rates. There are two main types of carbon offsetting projects from which carbon credits can be purchased:

- **Carbon reduction projects**: also referred to as carbon compensation or avoidance projects. Purchasing credits from these projects helps other parties to reduce their CO_2 emissions, thereby reducing the overall CO_2 emissions released into the atmosphere (e.g. installing solar panels, funding distribution of cleaner cooking methods). As this does not remove CO_2, the CO_2 emissions in the atmosphere continue to build up, albeit at a slower rate; and
- **Carbon removal projects**: also referred to as carbon neutralisation or sequestration projects, these projects involve solutions that remove and store CO_2 from the atmosphere, such as forest restoration or engineered carbon capture and storage.

In the context of the Humber cluster, the focus is on the latter of these project types – carbon removal projects. This section considers whether, through delivering removals, and having these certified to produce CO_2 removal credits, the Humber cluster may be able to access an additional source of finance from the sale of the CO_2 removal credits. Selling these CO_2 removal credits would allow other parties (e.g., businesses or governments) to carbon offset, and make a claim such as 'net zero'.

Making claims – 'carbon neutral' and 'net zero'

Carbon offsetting is typically undertaken as part of an entity's ambition to achieve a target or make a claim regarding how effectively they are combatting climate change. Two claims are common – to be 'carbon neutral', and/or to be 'net zero'. Each have a history that can be plotted against the international climate agreements of Kyoto[234] (1997) and Paris (2015).

The Kyoto Protocol (1997) first formalised the need for industrialised nations to collectively lead on actions to address climate change. From this, the principle of carbon neutrality was formed (used interchangeably with the term climate neutrality), which involves offsetting CO_2 emissions caused in one place by reducing or removing CO_2 emissions in another. Notably during the Kyoto Protocol era, the emphasis of carbon offsetting projects was heavily skewed towards *carbon reduction.* This enabled countries to provide funding for other countries to reduce their CO_2 emissions, as a means of counter-balancing emissions from within their territorial boundaries. The terms carbon neutral and climate neutral are typically associated with the use of purchasing carbon credits from carbon reduction projects.

When the Paris Climate Agreement came into force in 2015, the term 'net zero' made a more prominent appearance in general parlance. When discussing the status of 'net zero', there is much greater emphasis on a *balance* between CO_2 emissions, and carbon removals, than is the case for carbon neutral/climate neutral. This stems from the understanding that limiting climate change to 1.5°C requires global CO_2 emissions and removals to be balanced (i.e. 'net zero') by 2050, with CO_2 removal outweighing CO_2 emissions thereafter. Applying these concepts at the scale of a business means that in order to claim to be 'net zero', companies must balance their own CO_2 emissions by removing an equivalent (or higher) quantity of CO_2 emissions from

[234] United Nations Climate Change, 2016, The Kyoto Protocol.

the atmosphere. As a prerequisite, a company will implement its own emission reduction initiatives first and only use offsetting options where CO_2 emissions are unavoidable. It is this motivation – the status of 'net zero' – that is most likely to drive organisations and/or governments to purchase CO_2 removal credits.

It is important to note that offsetting emissions should only be used as a 'last resort' to balance residual emissions that remain after all feasible mitigation measures have been implemented. There are concerns that offsetting could act as a mitigation deterrent and be used to avoid the longer-term investment required to tackle emissions at source. To counter this, the **Science-Based Targets Initiative** (SBTi) has proposed setting a 5-10% cap[235] on the proportion of an entity's baseline emissions that can be offset to reach their 'net zero' goal, which is an important development as it moves the market away from offsetting as a 'silver bullet' by which to reduce emissions. It is likely this cap will vary between governments and organisations, and that harder to abate sectors, such as heavy industry, will be allowed a higher cap. Carbon removal credits can, and should, be bought in addition to rapid internal decarbonisation however SBTi considers this a separate, voluntary activity and does not allow these credits to offset emissions until the limit of residual emissions is met.

To claim 'net zero' an entity needs to offset its CO_2 emissions at the same rate they are produced. As the reduction of carbon to anything above zero still results in an overall build-up of CO_2 emissions in the atmosphere, projects that remove carbon from the atmosphere are being prioritised within current carbon markets. This does not automatically mean that carbon reduction projects cannot be utilised – these projects have an immediate beneficial impact so they can lower (or slow down the rate of) CO_2 emissions in a short period of time. In addition, carbon removal projects are still relatively new to the market and require more time to be implemented at scale. This means, therefore, that carbon reduction projects should no longer be completely eliminated as means of carbon offsetting – only that their use isn't compatible within mainstream definitions of 'net zero' emissions.

Interactions with policy and the law – national, international, statutory and voluntary

Questions are often asked about how carbon offsetting fits into policy/legal landscapes, and the answer is that this is complex and varies based on several factors. As a framework for addressing this question, three 'axes' of factors are particularly important to discuss:

- **National vs international:** Choices or requirements to carbon offset vary based on national and international settings. Within individual nations there are different requirements/frameworks for offsetting, and there is also overarching governance which can be considered international, which can be separated into guidance from the United Nations (UN), and guidance emanating from a range of non-governmental organisations (NGOs) operating within carbon markets.
- **Voluntary vs statutory:** The undertaking of carbon offsetting can be stimulated by a voluntary commitment or a statutory requirement. This distinction in carbon offsetting motivation, alongside variation in the rules governing acceptable carbon offsetting practices in these two contexts has led to two carbon offsetting markets often being described:

    - **The voluntary carbon market (VCM):** Encapsulating organisations purchasing carbon offset certificates for voluntary reasons, and market governance largely led by international NGOs; and
    - **The compliance market (CM):** Encapsulating organisations (often regulated, heavy emitters) or countries, purchasing carbon offset certificates due to a statutory obligation, and market governance being largely led by the UN.

- In practice there are many areas of grey between these extremes (e.g., a voluntary buyer who purchases credits certified for a compliance market), though the broad distinction remains useful to understand.
- **Public sector vs private sector:** The purchasers of carbon offset certificates may be public sector or private sector entities, or indeed the charity/NGO sector. The public sector includes both national governments acting at the international level, as well as government departments or sub-national government entities operating independently of government as buyers within carbon markets.

[235] Science Based Targets, 2021, Net Zero Targets: 'Less Net More Zero '.

Given these dynamics it is very difficult to typify the interaction between policy, the law, and carbon markets. However, considering the context of the Humber cluster, several specific points are of relevance:

- **The purchase of carbon offsetting certificates generated in the UK, by businesses based in the UK, is voluntary.** There are two certification schemes that operate in the UK, one for woodland (Woodland Carbon Code) and one for Peatland (Peatland Code). International businesses are only able to purchase these certificates for CO_2 emissions associated with their UK activities.
- **The UK's carbon offsetting market is relatively undeveloped:** This is like much of Europe, and is the result of the Kyoto Protocol, which required carbon offsetting projects to be undertaken in countries which were not given CO_2 reduction targets within the Protocol. This has led to extensive carbon offsetting projects across South America, Africa, and Asia (where fewer countries were given CO_2 reduction targets within the Kyoto Protocol), and a relatively paucity of projects in Europe.
- **Future UK policy/law concerning carbon offsetting is unclear**: the current voluntary market is being allowed to continue operating, though there has been limited communication from government around the future role of carbon offsetting in supporting the delivery of national climate change commitments. At present the UK Emissions Trading Scheme (ETS) purely operates on an allowance system, rather than permitting the use of certificates from carbon offsetting projects. The UK government has, however, indicated that CO_2 removal credits could become part of the UK ETS in future.[236]
- Paris Agreement carbon market governance is rapidly developing, alongside guidance from NGOs governing the VCM. Specific details include:

    - The creation of the Taskforce on Scaling Voluntary Carbon Markets (TSVCM). This private sector-led initiative was established in 2020 with the purpose of working to scale an effective and efficient VCM. In 2021, the private-sector-led Integrity Council for the Voluntary Carbon Market was established to advance the work of the TSVCM. These have proposed a new, independent governance body to promote high integrity offset projects and are in the process of finalising and implementing their Core Carbon Principles to set a benchmark of carbon credit quality.
    - The announcement of the Science-Based Targets Initiative that companies in future may have defined limits on how much offsetting is permitted. A 5-10% ceiling on the proportion of an entity's emissions that can be offset has been proposed.
    - The Voluntary Carbon Market Integrity Initiative (which is more NGO-focused than the TSVCM) was established in 2021 with the aim of addressing greenwashing in the offsetting sector and ensuring supply-side integrity and transparency of offsetting projects.
    - The inclusion of a mechanism to reduce the risk of double-counting of carbon reductions and removals in **Article 6** of the Paris Agreement.

        - Article 6 was first developed in Paris in 2015 and consists of principles for how countries can pursue voluntary cooperation to reach their targets. However, the pathways to doing so proved contentious.
        - At the UN Climate Change Conference of the Parties in Glasgow ('COP26') in 2021, countries agreed on the rules to govern international carbon trading.
        - **Article 6.2** provides an accounting framework for international cooperation, allowing carbon credits to be transferred between countries and specifying that a "corresponding adjustment" must be made when this occurs, to avoid double-counting of emissions reductions.
        - **Article 6.4** contains a mechanism to create a global carbon market that has a UN-regulated "supervisory body". Credits generated via specific projects can be approved and traded between countries under a central accounting framework. Though the 'rulebook' for this to occur is still being developed, it signifies a step towards a more transparent credit market.

- The release in 2020 of the ***Oxford Principles for Net Zero Aligned Carbon Offsetting***[237] which has contributed throughs regarding best practice of offsetting, with a particular focus on promoting permanent carbon removal technologies (on the basis that biogenic carbon sequestration such as tree planting is inherently impermanent).

[236] Financial Times, 2021, UK Emissions Trading Scheme plans to adopt credits for Direct Air Capture.
[237] Smith School Oxford University, 2020, Oxford Offsetting Principles.

The key takeaways for the Humber cluster are that the links between carbon offsetting, policy making, and the law present a grey area to navigate where there is a lot of movement and new bodies and policies emerging. The reader may wish to refer back to this context throughout this section as much of the discussion involves reflecting on carbon offsetting markets in their **present form**. In particular, the risks, barriers and mitigating actions described in Section 4.4.3 build on this context.

Certification of climate outcomes

The sale of carbon as a unitised 'commodity' naturally attracts concern from many stakeholders, resulting in an overriding push towards ensuring high levels of integrity of CO_2 removals and reductions purchased. Therefore, standard-setting organisations have been established to provide quality assurance for carbon offset certificates. These organisations range from international regulatory bodies (the UN Framework Convention on Climate Change[238]) to independent programmes led by NGOs (Verra or Gold Standard). Historically the former has certified credits for regulatory purposes on the compliance market and the latter have served voluntary buyers, but this distinction has blurred, and most certifications now serve both markets.

Standard-setting organisations perform three primary functions:

- Develop and approve criteria for the quality of carbon offset credits.
- Review projects against these standards.
- Manage the issuance of credits to registry systems.

As the types of carbon offset projects available on the market have evolved, so have the certification programmes available to oversee and verify the projects and their issuing of credits. Well-established offset types have equally well-established certifications (such as the Woodland Carbon Code).

However, engineered CO_2 removal projects are based on novel technologies and therefore lack a track record for offset certifications. The CCS+ Initiative is currently developing a framework for verification of CCS[239], which will be accepted and managed by Verra, a global agency for certifying reductions.[240]

Moreover, the European Commission (EC) is currently consulting on a government-operated mechanism[241] for certification of carbon removal technologies and projects.[242] The EC is aiming for integration of CO_2 removal into a wide range of policies, and the establishment of a common baseline of approving CO_2 removal credits. It is likely that this certification will take several years to begin operating, but nevertheless this announcement is noteworthy as it marks the first time that an influential and well-regarded legislator is entering into and defining the CO_2 removal market.

Other standalone projects have developed their own CO_2 removal methodologies and achieved independent third-party validation. For example, the Climeworks "Orca" DACCS facility in Iceland has been validated by DNV (independent expert in quality and risk assurance) according to all requirements listed in ISO 14064-2 and Climeworks' own methodology.[243] This represented the first third-party validation of a DACCS project with permanent CO_2 removal and highlights the lack of standards specifically targeting the CO_2 removal market. Similarly, nature-based carbon reduction projects other than woodland and peatland – such as saltmarsh restoration and regenerative agriculture – likewise lack dedicated certification standards within the UK, but progress is underway to develop guidance and standards for new and emerging project types, and there is considerable international precedent to build on.

In the context of the Humber cluster, the key takeaways regarding certification are:

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[238] United Nations Climate Change, 2021 The UN Carbon Offset Platform.
[239] CCS+ Initiative, 2022, Carbon capture and storage in its various forms.
[240] Verra, 2021, New Initiative to Boost Carbon Capture and Storage Solutions Will Develop a Methodology Under the Verified Carbon Standard.
[241] European Commission, 2022, Certification of carbon removals - EU rules.
[242] European Commission, 2021, European Green Deal: Commission proposals to remove, recycle and sustainably store carbon.
[243] Climeworks, 2021, Climeworks' direct air capture plant Orca has achieved validation by DNV.

- Certification of CO_2 removals will be a pre-requisite to selling climate outcomes to almost any buyer.
- Certification systems for BECCs and DECCs are less well established in the present market, so there may be some risks/limitations associated with proceeding with present methodologies.
- Certification systems for woodland and peatland projects are well developed in the UK, with other habitat types still lacking market-ready certification systems.

The following section explores the value chain for carbon offset certificates in more detail, with the goal of making the processes and stakeholders clear to the Humber cluster.

The value chain for CO_2 removal credits

This section identifies, maps out and discusses the value chain for CO_2 removal credits, from their production through to their purchase and end use. It also considers how this value chain interacts with external interfaces.

Figure 35 schematically demonstrates the value chain of CO_2 removal (or reduction) credits, from their generation to their delivery and retirement.

The narrative of this cycle is as follows:

- **Project implementation**: This includes project design, feasibility studies, selecting a certification methodology, and beginning delivery. If there is not an approved carbon offset certification methodology for the project type, a new methodology would need to be created before credits could be produced. It should be noted that project implementation overlaps with some areas of the certification process (this is illustrated in the figure) – it is unlikely that a project which was started prior to seeking carbon credit certification would be permitted to generate carbon credits.
- **Certification** is essential for ensuring that the project genuinely delivers its objectives. The certification process varies according to the project type and whether it is used for the compliance or voluntary market, but a high-level overview is as follows:
- The process begins with the development of the **Project Design Document** (PDD), which states the aims of the project, an estimate of the volume of emissions reductions/removals, a justification of how the project contributes to sustainable development, a justification of additionality, evidence of stakeholder engagement, and how the project will follow the rules of the certification standard.
- The **validation** phase is when a 3rd party assessor evaluates the PDD to ascertain whether the proposed delivery has followed all the established criteria and rules (e.g. stakeholder interviews, resolution of any issues raised in the PDD).
- Based on the review of the above by the certification standard (e.g. Gold Standard), the project is **registered** and **implemented**, and delivery begins. **Monitoring** of the project's impacts also commences.
- **Verification** of credits involves a 3rd party audit to ascertain whether the project has achieved the aims stated in the PDD, based on the project monitoring (a different assessor is required to undertake the validation and verification phases). The involvement of the 3rd party assessors is to ensure robust, authentic removals.
- The end of the certification phase is the **issuance of credits**. Following satisfactory verification by a certification standard, the credits are transferred to a registry and can be sold.
- The **sale of credits** is when the credits are sold by the project developer to a buyer (either a company, government, broker or trading company). The sale of credits can be to one or several purchasers, and can be at a local, national or international level.
- **Retirement** involves credits being fixed to the final buyer on the market / credit registry such that they cannot be sold and transferred again. Credits can be traded until they are retired – sometimes this is managed in-house by a credit purchasing organisation but is often outsourced to credit brokers.
- The **marketing** of credits can happen before delivery (ex-ante credits) and a contract to sell the credits can be signed at any stage during this cycle.

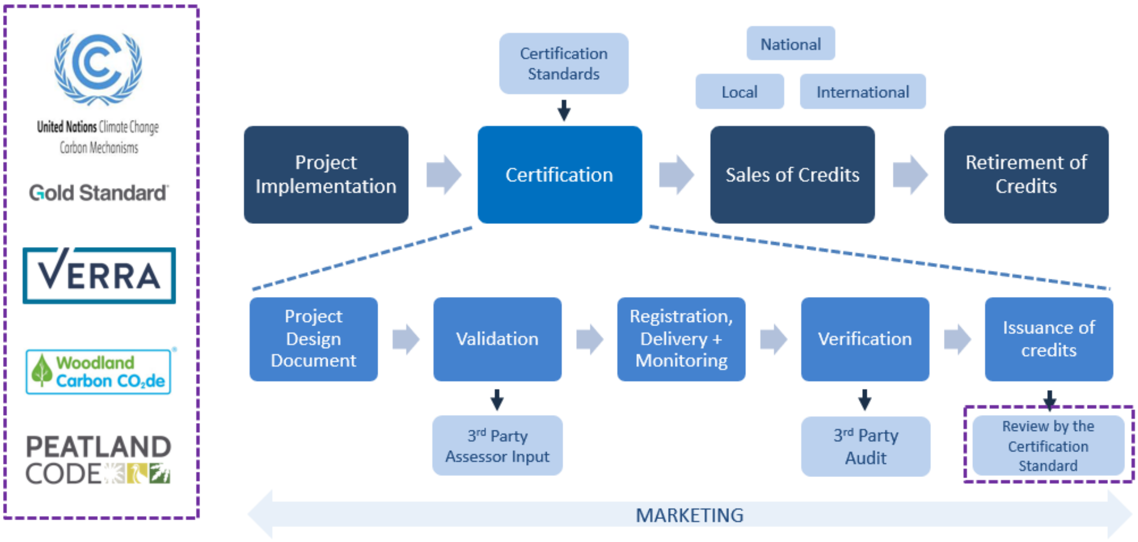

Figure 35: Representation of the value chain for CO_2 removal credits[244]

The process is reasonably lengthy – it will take between a few months to a year to go through the PDD and the validation process, then project delivery can take many years to fulfil its emissions reduction or removal requirement. The subsequent stages of verification and formal issuance of credits usually take in the order of several months.

4.4.2 Market demand for CO_2 removal credits

For potential creators of CO_2 removal credits such as the Humber cluster it is important to understand the possible size of the market, to ascertain whether there is sufficient demand for credits. This section therefore provides an overview of patterns of demand for CO_2 removal credits, both across different spatial scales, industries and how this will change through time.

There are many different methods and angles by which to understand and quantify demand for CO_2 removal credits. For this section three different perspectives – sectoral, global, and national – are considered and discussed in below. All these groups are (or are set to be) significant purchasers of CO_2 removal credits.

The following section explains each of these perspectives and what the approximate demand might be, with quantitative demand estimates presented in Figure 36. It also includes discussion of the reasons why these numbers should be treated with caution. Key messages for the Humber cluster when establishing demand for its CO_2 removal credits are summarised in the Discussion below.

Demand from key industries

Though decarbonisation is required in every aspect of the economy, there are specific high-emitting sectors where offsetting, and in particular removals, is likely to be most utilised, due to the difficulty and scope of eliminating emissions. Demand is likely to come from the following industries:

- Sectors in which it is inherently difficult to reduce emissions, such as **aviation** and **shipping**, are likely to have high demand for CO_2 removal credits.
- Some industries (e.g., **cement**, **aluminium**, **chemicals** and **steel**) are anticipating using carbon removal in their own decarbonisation pathways, though the feasibility of applying carbon capture technologies at the scale outlined in sectoral 'net zero' transition plans is questionable, and therefore credits may still be required in these sectors.

[244] Adapted from Carbon Offset Guide, 2022, Offset Project Implementation.

- Industries such as **professional services** have shown strong early demand for CO_2 removal credits. Examples include:
  - Frontier (a partnership of 5 of the largest tech and consulting firms: Stripe, Alphabet, Meta, Shopify and McKinsey) has pledged US$925m to buy credits from promising carbon removal start-ups.245
  - Swiss company South Pole and Japan's Mitsubishi are developing a carbon removal facility aiming to generate approximately $500 million of CO2 removal credits for sale by 2030.246
  - Microsoft (professional services and manufacturing) have announced a massive investment in developing their own carbon removal technology portfolio;247 the firm has committed to removing 2.5 MtCO2 in FY2021-22.

The demand from other sectors will vary depending on action taken in the near future – for example, the **agricultural sector** has the potential to require offsetting if near-term action to change high-emitting practices does not occur. Other high-emitting sectors such as **electricity** and **transport** are unlikely to be purchasers as they are already moving towards their own reduction of emissions (such as widespread deployment of renewable energy, and the move towards hydrogen and electric transport).

Whilst most industries will require large-scale carbon removal in order to hit 'net zero' targets, it is difficult to quantify demand for CO_2 removal credits from different sectors. There is significant uncertainty surrounding the trajectories of sector growth (and emissions) and technological availability. Each sector faces unique challenges and pathways to decarbonisation and therefore will have varying levels of demand, but this high-level analysis provides an indicator of where demand might be concentrated. Hence, within this report, it has not been possible to deliver a quantitative estimate of demand through the lens of each of these sectors.

Global demand

Calculating potential global demand for CO_2 removal credits is likewise associated with high uncertainty, but it is possible to gauge a broad estimate for the scale of carbon removal required for global warming to be limited to 1.5°C.

Removals are essential for meeting the pathways modelled by the Intergovernmental Panel on Climate Change (IPCC) where global warming remains within this limit. The best estimate of global demand is based off the IPCC Special Report,[248] in which numerous scientific models are reviewed to reach a consensus that **annual CO_2 removal** must reach **15 $GtCO_2$ in 2050**.

Individual countries will account for territorial removals under their Nationally Determined Contributions (NDCs). Article 6 of the Paris agreement (discussed in 0) allows for trading of CO_2 removal credits if mutually agreed between countries, and 'corresponding adjustments' are made to national GHG accounting, and therefore CO_2 removal credits generated in one nation can be claimed by another. The requirements and commitments of individual nations to using CO_2 removal are challenging to understand due to the 'high-level' nature of NDC commitments.

The stakeholder engagement undertaken for this research indicated that it is unlikely that global players will purchase UK credits, as they are likely to be more expensive than those available from other nations. Moreover, it is likely that the UK will need to use all removal credits generated within the UK for its own accounting.

Demand within the UK

The UK will require removals within its territory to 'balance' territorial residual CO_2. Our analysis of demand for CO_2 removal credits within the UK is based on estimations in the UK Government's Net Zero Strategy,[249] which

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[245] Birch, in Business Chief, 2022, Stripe, Alphabet, Meta, McKinsey debut carbon removal fund.
[246] Reuters, 2021, South Pole, Mitsubishi eye up to $800 million of CO2 removal credits by 2030.
[247] Joppa et al., in Nature, 2021, Microsoft's million-tonne CO2-removal purchase — lessons for net zero.
[248] IPCC, 2018, IPCC Special Report Global Warming of 1.5°C.
[249] HM Government, 2021, Net Zero Strategy: Build Back Greener.

outlines the UK government's commitment to CO_2 removal projects. This strategy – which focuses on reducing emissions across the economy – uses an evidence-based projection to predict that by 2050, deployment of engineered CO_2 removals of between **75 and 81 MtCO₂/year** will be required to compensate residual emissions across all sectors.

Within the national commitment to 'net zero' and the associated demand for CO_2 removal, there is also a range of sub-national commitments, including those from local governments, public bodies, industries, landowners and private companies. The demand for CO_2 removal from these is less well-evidenced and moreover is (by virtue of these actors being within the UK territory) approximately captured in the UK's holistic economy-wide projections.

It is also important to note that there will be significant demand for CO_2 removal credits solely from within the Humber cluster, which is the highest-emitting cluster in the UK.[250] The UK territorial area of emissions is likely to need all possible removals produced in the Humber (which poses a potential barrier to selling CO_2 removal credits to international buyers). At present there is uncertainty over the ownership of CO_2 removal credits and how they will be claimed amongst the variety of interested stakeholders, which is discussed further in Section 4.4.3

Key considerations

A representation and comparison of the perspectives on global and UK demand in Mt CO_2 removal per annum in 2050 for CO_2 removal credits is schematically demonstrated in Figure 36. It is evident that CO_2 removal demand (global or UK) is extensive and well beyond the scale of delivery estimated for the Humber cluster.

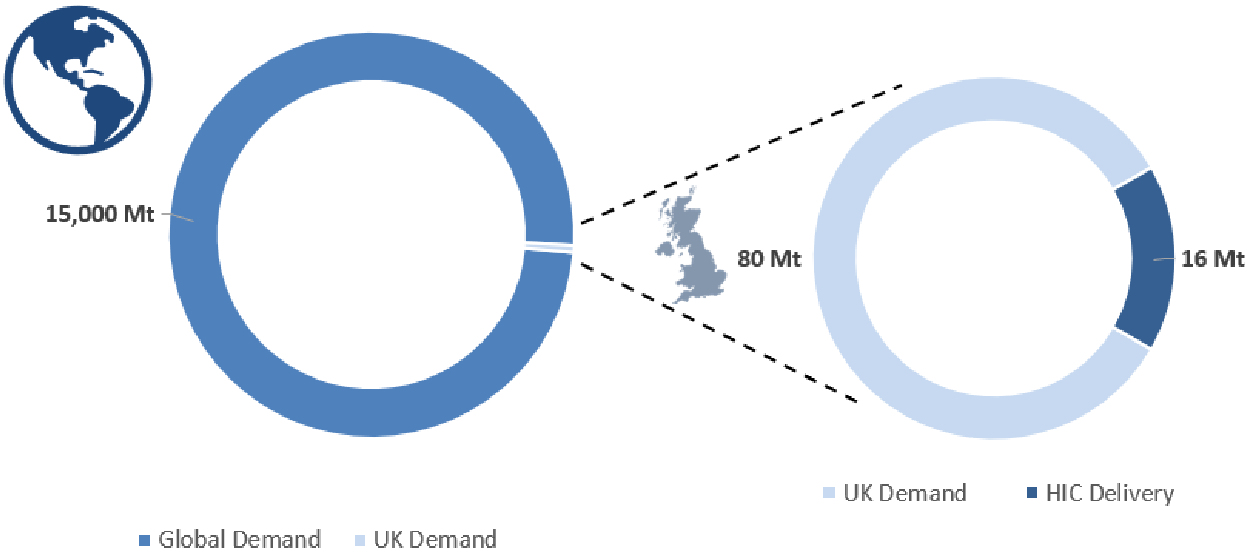

Figure 36: Mapping global and national demand for CO_2 removal credits

This indication of demand for CO_2 removal credits generated in the Humber cluster is a holistic perspective on the potential demand from different stakeholders and at different scales. It is evident that large-scale CO_2 removal is required globally. These figures relate to the volume of CO_2 removal necessary to limit warming to 1.5°C and have been modelled based on a 'climate change lens' to ascertain the maximum possible demand.

[250] HM Government, 2019, Clean Growth Grand Challenge: Industrial Clusters Mission.

However, the CO_2 removal credits market is very much in flux, so the size of traded markets is yet to reach this scale. The *need* for this scale of CO_2 removal is evident but there are various reasons as to why market demand may not reach this volume:

- Significant change and developments in carbon markets are expected in the coming years. Therefore, quantifications of demand are subject to much uncertainty – instead, a more cautious view of demand would be on a project-by-project basis (i.e. can a buyer be found for a particular project?), including consideration of the important regional context.
- It should be considered that the VCM – probably the main market in which the Humber cluster would be engaging – is a mechanism by which corporates meet their targets as opposed to nations reaching international or regional targets. The IPCC framework for GHG accounting for nations – which includes targets and compliance – has notable differences to the corporate market. Countries may choose to deliver CO_2 removals without the incentive of voluntary carbon markets.
- It is important to note the distinction between what is necessary, what is feasible, and what the market allows. These demand estimates are based on the quantity of CO_2 removal that is required to limit global warming to 1.5°C; the feasibility of delivering that volume of CO_2 removal is subject to rapid future technological development and deployment. That is further distinct from the demand for credits from the market, which is uncertain.

Overall, this uncertainty presents the potential for very high demand for CO_2 removal credits, but perhaps not the clear signal for market engagement that may appear on first review.

4.4.3 Risks and barriers

The carbon removal market is a developing area, with new policies and stakeholders emerging, and consequently there are risks and barriers associated with entering the maturing market. This section discusses these risks and barriers – categorised into those pertaining to markets, policy and regulation – which the Humber cluster will likely need to navigate to enter this market.

This assessment of risks and barriers was developed from reviewing literature, news and announcements, and policies relating to the carbon removal market and the offsetting sector. It is also informed by previous work within carbon markets of our consultancy team. Stakeholder engagement was then undertaken with experts from different stages of the carbon credit value chain, including the Woodland Carbon Code, Gold Standard, Drax, and a senior member of a carbon offsetting project development and brokerage organisation. These semi-structured interviews enabled the identification and discussion of mitigating actions for the Humber cluster to consider if they were to sell CO_2 removal credits.

Market risks and barriers

The market-specific risks associated with engaging with the CO_2 credit markets are outlined in Table 30. These are primarily focused on international carbon pricing, financing projects, and supply and demand dynamics.

Table 30: Market risks and barriers

Risks	Description
Fragmented VCM	The VCM is a fragmented market with significant geographical variations in the validity of carbon credits – certain project types and/or certification standards may be unacceptable to international buyers.
Global variation in carbon price	There is large variation in carbon prices across major economies; UK credits may be seen as a more expensive option than others on the market, which could mean that some buyers prefer to purchase credits from other countries (where prices are cheaper), and at the extreme could mean very limited international demand for UK-produced carbon credits. Carbon credit prices vary due to market dynamics. Whilst there are many reasons to expect prices to keep rising over the coming years,[251] there is always a risk that there could be a dip in prices due to a range of factors. If credit sales are not agreed in advance, this creates uncertainty regarding future revenues from the sale of carbon credits.
Low carbon credit price	Current credit prices may not be sufficient to warrant project investment. The role of selling carbon credits is to make viable projects which would not otherwise have occurred. Depending on the financing structure of the project in question, current carbon credits prices may not be sufficient to tip the balance of project viability.
Lack of income guarantee from sale of carbon credits	Income streams from the sale of carbon credits may not be guaranteed if the Humber cluster sells credits in individual chunks (rather than all credits in one transaction), with the associated risk that the Humber cluster is left with unsold credits and lower than anticipated revenue.
Temporal variability of carbon price	Carbon prices could unexpectedly fall below the assumed/desired price, lessening the anticipated revenue stream from selling carbon credits. This could occur as a result of: Market supply of carbon credits catching up with demand (market demand is currently greater than supply); and/or Competition from different/new technologies that are cheaper to implement, and therefore require a lower carbon price; and/or Confidence in the market declining and demand reducing as a result.
Barriers	**Description**
Insufficient carbon credit price for business case development	Current carbon credit market prices may be too low to develop a business case for project implementation – the price of carbon is likely to increase in the future but there is widespread uncertainty around this.
Preference for *ex-post* credits	Buyers prefer to purchase credits from projects where the removal has already been achieved (e.g., the forest has already grown), which leaves a financing gap for project initiation.
Limited pricing data	Limited available pricing data makes it challenging to understand future revenues and therefore to plan projects with confidence.
Limited market knowledge	There are generally limited levels of knowledge around how the market functions, which restricts demand and creates uncertainty.

Policy risks and barriers

The carbon credit market (especially the CO_2 removal credit market) is currently lacking in policy direction. The market has grown significantly with soaring international demand, which has led to rapidly rising prices,[252] but policy development, which will ensure the markets meet high quality criteria and minimise uncertainty for buyers and investors, is struggling to keep pace. The policy-related risks identified are presented in Table 31.

[251] Bloomberg, 2022, Carbon offsets price may rise 3,000% by 2029 under tighter rules.
[252] Ecosystem Marketplace Insights Team, 2021, Voluntary Carbon Markets Rocket in 2021, On Track to Break $1B for First Time.

Table 31: Policy risks and barriers

Risks	Description
Interaction with future policy instruments is uncertain	There is uncertainty regarding how carbon markets interact with other policy instruments (such as carbon taxes, or ecosystem service markets like biodiversity credits). This introduces the risk that revenue streams from carbon credits sales are undermined by these other policy structures, on the basis the other policy structures provide alternative financing or mandates for projects which could otherwise have been funded through sales of carbon credits.
Uncertainty in carbon credit trading rules	While agreements have been made to proceed with trading mechanisms under Article 6.2 and 6.4 of the Paris agreement, their operational structures and rules are yet to become clear. This introduces uncertainty into whether and how it will be possible to trade carbon credits across national borders in the future.
Future limits on international credit trading	Paris Article 6 arrangements may limit the motivation for international trading of carbon credits. The UK government could discourage the sales of UK-generated credits abroad, as once claimed by another nation/organisation in another nation, they would not be counted within the national GHG inventory and could not therefore contribute to national net zero goals. This would limit any sellers of carbon credits in the Humber cluster to domestic buyers.
Offsetting rejected in favour of CO_2 reductions	Carbon offsetting through CO_2 removals could become a limited tool for tackling climate change due to emphasis being firmly placed on CO_2 reductions. For example, the SBTi has indicated that CO_2 removals should be limited to 5-10% of an organisation's baseline footprint, with the remainder of CO_2 emissions needing to be tackled through CO_2 reductions. This could have the effect of limiting CO_2 removal offsetting demand.
Potential subsidy support leakage	Subsidy support leakage could occur where credits generated within in the UK (e.g., credits produced by a UK-based CCS project which has received government funding) are sold abroad. The international buyer would then receive the benefit of the subsidy provided by the UK government in the price of the carbon credits purchased, as well as the CO_2 removal outcomes.
Barriers	**Description**
Uncertain future of VCMs in the UK	There is general ambiguity around how the government intends for voluntary carbon markets to operate in the UK, for example, how sales of credits on carbon markets may interact with other policies designed to encourage low carbon practices, and how intra-UK and extra-UK trading of carbon credits on voluntary markets should work. There is a need for absolute transparency as to where the emissions reductions are claimed.
Evolving definitions of 'best practice'	The 'goal-posts' of NGO-driven definitions of 'best practice' for offsetting are currently emerging, hence there is uncertainty regarding which projects will be viewed as robust and therefore attract buyers. In particular, engineered CO_2 removal projects are new to the market and are unfamiliar to buyers and regulators.
Local consent required	Local consent for CO_2 removal projects may not be given (e.g., due to local planning disputes).

Regulatory risks and barriers

The regulatory element of risks related to engaging with CO_2 removal markets are presented in Table 32. Here, 'regulatory' considerations are viewed as those associated with the specific rules, requirements and certification methodologies which must be complied with to participate in CO_2 removal markets.

Table 32: Regulatory risks and barriers

Risks	Description
Current regulation lacks focus on quality	The regulatory focus for many project deliverers and bodies is on risk and disclosure, not ambition and high performance. This may limit the extent to which existing certification methodologies require higher quality standards for carbon credits, such as more stringent additionality criteria. This may contribute to confidence in carbon markets being undermined.
Future of UK regulation is uncertain	There is uncertainty in the UK regarding whether a national regulator will become involved with verifying project outcomes. This may bring the benefit of added integrity to the market but could introduce additional resource requirements for getting carbon credits certified, especially if changes or additions were made retrospectively applicable).
Barriers	**Description**
Lack of removal-specific certification	Most CO_2 removal project types lack carbon offset certification schemes in the UK (certification schemes are only available for woodland and peatland projects). Market players are therefore likely to need to develop (or adapt from international markets) specific certification standards for removal technologies/approaches of interest.
Verification market lags behind demand	The slow emergence of the UK credit verification market may mean certification resources (i.e. the availability of skilled teams to review projects and conduct certification) are restricted in short term.
Contested 'ownership' of removals	There is poor clarity over the 'ownership' of CO_2 removals from certification standards in the present move to a Paris Article 6 overseen market, which may inhibit moving confidently forward with project investment.
Certification is time-intensive	Complying with existing certification methodologies is reasonably time intensive and requires specialist expertise, which must be borne in mind by any project developer when planning for implementation.

4.4.4 Recommendations and actions

The risks and barriers outlined above cover the market, policy and regulatory dynamics of CO_2 import markets separately. When considering actions to mitigate those risks and barriers, there is merit to considering actions in the context of all three of these dimensions, due to the overlapping benefits which arise.

Drawing on the stakeholder discussions held, reviews of the literature, and Eunomia's own market insights, the following set of action categories are recommended to help actors within the Humber cluster navigate what is a complex and nascent market. These actions would either be considered the responsibility of organisations and developers within the Humber cluster with specific technology/carbon market engagement interests, and/or a Humber cluster body coordinating the carbon market engagement. Each action category refers to a broader set of actions taken to support the overall ambition of each category – further details are described in the text relating to each category.

Action 1: ensure CO_2 removals can be certified as tradable units

Certification is one of the most important aspects of entering the credit market – it will ensure that the project outcomes are viewed as robust, that the generation of credits is transparent, climate outcomes can be bought and sold, and that buyers have confidence in the Humber cluster's CO_2 removal credits.

CO_2 removal certification standards of most interest to the Humber cluster are not currently available in the UK but are currently being developed by various organisations. Carbon removal project developers and stakeholders within the Humber cluster should proactively support the adaptation of existing standards / creation of new ones to match CO_2 removal approaches relevant to the Humber cluster, test these standards with stakeholders (e.g. NGOs and government representatives) and potential purchasers (e.g. corporates and local authorities). There will likely be a need to ensure that there is sufficient dedicated resource within the Humber cluster to oversee the (possibly lengthy) certification process.

Action 2: support further clarity regarding ownership of CO_2 removals

This action category relates to the widespread uncertainty of how international and intra-UK trading of carbon credits will occur in future and how claiming of credits interacts with more general accounting of removals at regional or national scales.

Articles 6.2 and 6.4 of the Paris Agreement were clarified at COP26, though substantial policy infrastructure is required to see these articles implemented which is still in development. The Humber cluster should track the UK government's approach to, and interaction with these emerging governance structures, as this concerns the interaction of CO_2 removal certificates with NDC accounting.

In addition, the Humber cluster can also advocate for greater clarity regarding sub-national ownership claims of removals within the UK – between landowners, businesses, project deliverers and local government.

In the absence of further clarity at the policy level on these subjects, there may be a case for pressing forward and using sensible principles to guide claims of CO_2 removal ownership. Establishing such principles may be a useful action if this route ahead is preferred.

Action 3: support further clarity regarding interaction of market-based payments for CO_2 removal credits and other policy / subsidy mechanisms

Some of the most pressing policy-related risks relate to uncertainty as to how voluntary carbon markets will interact in the future with other policies (mandatory actions, subsidies or taxes) designed to stimulate low carbon technologies. Actions to address this uncertainty could include:

- Regularly reviewing project financial plans to understand the optimal financing structures and considering what would be the preferred mix of subsidy / market-based payment options to de-risk future financing. This will enable any Humber cluster project developers to be aware of the risks to any of these financial streams changing or becoming unavailable;
- Engaging in debates around possible regulatory frameworks for carbon markets in the UK, and calling for greater clarity regarding additionality criteria; and
- Developing a preferred policy position which could be put forward into these debates.

Action 4: De-risk revenues through forward contracting market sales of CO_2 removal credits

Many of the market risks noted above related to planned revenues from the sale of CO_2 removal units being undermined by selling credits iteratively, leaving unsold credits vulnerable to changing market prices, and limiting the scale of finance which could be attracted early in the project development phase.

A potential solution for mitigating this risk is to forward-contract credit sales as early in the project development process as possible. By forward contracting, the project developer (in this hypothetical instance, a Humber cluster member) can be confident of a future payment for credit sales, potentially even receiving some payment upfront.

Taking this solution forward would involve pre-market testing with a range of potential buyers to understand their needs and possible sale prices. Alongside project development, legal arrangements could be developed with the preferred buyer. When the project developer was confident that the forecast CO_2 removals were accurate and would be realised, forward contracts could then be signed. This of course comes with the risk of defaulting on the forward contract or locking in at prices lower than the future spot prices, and therefore due care and consideration of liabilities is essential.

Action 5: General market engagement

The discussion in this section has clearly indicated the considerable uncertainty present in CO_2 removal markets. An important action for mitigating risks is therefore proactive engagement with the offsetting market in general. This would likely take the form of participating in government consultations, reviewing reports from relevant stakeholders (e.g., research organisations, NGOs), attending industry events, and holding meetings and discussions with stakeholders including project implementers, project certifiers, supporting consultancies, and CO_2 removal credit buyers. This will enable the Humber cluster to track factors such as how offsetting and CO_2 removals are perceived, any new certification methodologies which may be relevant to the cluster, trends in demand and sales prices, and how offsetting is likely to fit within UK emissions reductions targets.

5 Other possibilities to reduce industrial emissions

5.1 Other site-level options: energy efficiency and process changes

Other possibilities to reduce industrial emissions other than fuel switching and CCS could play a significant role in system wide decarbonisation. Site-level measures such as **energy efficiency** improvements and the optimisation of existing processes – or their replacement with intrinsically less carbon-intensive ones – can result in significant emissions reduction. This includes a range of options, with some of the available process changes summarised in Table 33. A further option to partially reduce emissions would be to switch to lower-carbon fuels, as would be the case with transitioning primary iron and steel production to natural-gas based direct reduced iron, potentially with a view of later replacing natural gas with low-carbon hydrogen.

Table 33: Illustrative options for energy efficiency and process changes

Sector	Onsite Measures	
	Energy Efficiency	Process Changes
Refining	Waste heat utilisation (combined with heat pumps).	• Utilisation of waste / low-grade feedstock streams e.g. for onsite CCS-enabled hydrogen production via partial oxidation.
Iron & Steel		• Electric arc furnaces (EAF) for scrap metal recycling. • Sustainable charcoal used for heat input.
Chemicals	Waste heat for district heating.	• Bio-feedstocks replacing ethane/naphtha. • Development of electrochemical processes (long term).
Cement & Lime	Other improvements from energy use optimisation, energy efficient lighting, insulation and pumps.	• Alternative low-carbon chemistries. • Low-emissions pre-calciner.
Gas Terminals		• Replacing hydrocarbon-based purge gas with carbon-free gases.

5.2 Circular economy

It is also possible that other **economy-wide trends will lead to changes in the demand for carbon-intensive products**, also supported by policies that incentivise a transition to low-carbon alternatives. A key part of this transition could be played by the growing application of circular principles across the different areas of the economy. In some cases, the implementation of such practices could unlock synergies, for instance between neighbouring sites – a concept known as 'industrial symbiosis' – and hence reduce the cost of on-site decarbonisation due to synergies between pathways. Furthermore, this can not only reduce emissions but also allows for more efficient resource use and reduction in waste streams. In many cases, these alternative pathways for decarbonisation of industrial supply chains will be deployed alongside the deep decarbonisation options for individual sites reviewed in this study.

Circular economy principles applied to large industrial sectors are expected to result in significant emissions reduction, particularly in the metals and plastics industries[253] as shown in Figure 37.

[253] Energy Transitions Commission 2018, Mission Possible.

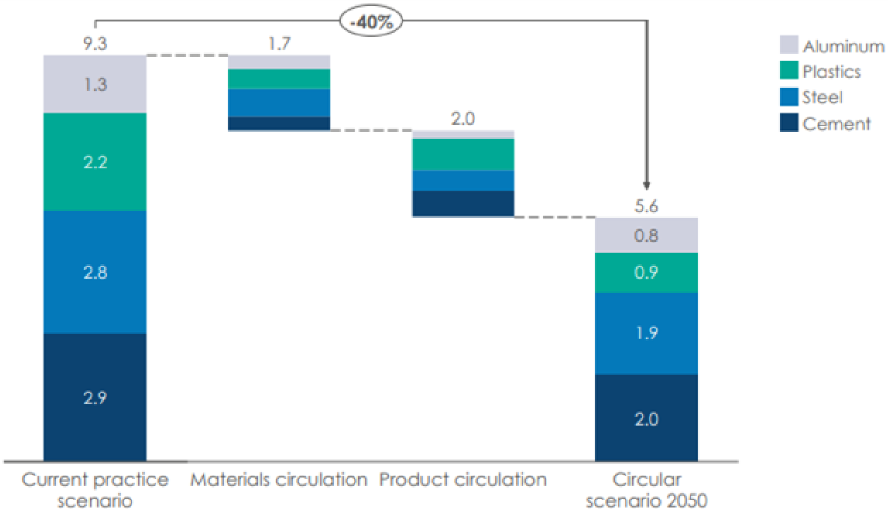

Figure 37: Global emissions reductions potential from a more circular economy ($GtCO_2$/year)[254]

Industry has traditionally operated in a linear model of production and consumption that is highly wasteful and emissions intensive. Making better use of existing resources through recycling and repurposing of materials, whilst also reducing the demand for these resources can result in significant emissions reductions when implemented across many sectors. Circularity reduces lifecycle emissions by reducing need for new products, virgin materials, and associated processing. Circular economy principles in industry could reduce CO_2 emissions by more than 55% in developed economies by 2050[254]. However, capturing these opportunities will require major changes to industrial processes, product design and to relationships between companies operating at different points across the value chain.

Policy development is required to create incentives for industry to make these changes, alongside regulations that enforce increasingly stringent standards for waste streams. The adoption of circular economic models and design principles alongside the deployment of low-carbon technologies will be essential for total energy system decarbonisation. However, implementing circular principles and processes in practice is a challenge that requires careful consideration at all levels of the industrial value chain. The core circular design principles that can be applied across industrial sectors are shown below:

Circular design

- Reduces over-specification of materials.
- Extends the lifetime of a product through increased durability and ability to repair.
- End of life dismantling, sorting and recycling of materials to more easily enable reuse.

Circular business models

- **Circular supply** – supply of renewable, biodegradable or fully recyclable resources into circular production.
- **Resource recovery** – eliminate material leakage and downgrading whilst maximising value of product return flows.
- **Product life extension** – repairing, upgrading and reselling of products.
- **Sharing platforms** – collaboration among product producers, users and end use processors.
- **Products as a service** – products used in a lease or pay-per-use arrangement where the producer is accountable for the repurposing the product at end of life.

A summary of circular economy principles applied to industrial processes are shown in Table 34. Circular economy principles may not be applicable to all industrial products and these approaches are often difficult for

[254] Energy Transitions Commission 2018, Mission Possible.

individual companies or facilities to implement alone. In many cases they involve multiple stakeholders at different points of the value chain, and often across industrial sectors, that traditionally have limited interaction. Industry collaborations are therefore key to implementing and scaling up circular solutions, where industrial producers will have to work alongside large industrial consumers in the future. New collaborations could lead to previously undiscovered synergies between sectors being unlocked as greater industrial symbiosis is achieved. In addition, technological innovations and a favourable policy environment are essential to enable the transition to a more circular future.Specific carbon reduction benefits achieved via the application of circular principles for an industrial product would require individual lifecycle assessments (LCA).

Table 34: Circular economy principles in industry[255]

Circular economy levers in heavy industries	Description	Industry Practice
Increase product utilization	Maximising the use cycles and intensity of use of products, reducing the need for new products.	• Extend product lifecycle • Recover and reuse product components • Design for end of use
Replace material / product with circular alternative	Utilise circular material alternatives, either creating the same product or a substitute.	• Substitute products with improved circularity • Circular (or renewable) feedstocks
Reduce material per product	Reduce material required per product and prevent over supply.	• Optimise product design • Efficient / lean product production
Recycle material for new products	Replace virgin material with recycled material where possible.	• Use recycled material • Maximise reuse value of products

Circular decarbonisation measures are summarised for industrial sectors operational in the Humber in Table 35.

Table 35: Circular economy principles influencing industrial demand

Sector	Circular economy principles
Refining	• Utilisation of waste feedstock streams. Velocys - Altalto facility in Immingham expected to be Europe's first commercial scale waste-to-jet-fuel facility. • Phillips 66 Humber refinery utilising sustainable waste feedstocks to produce sustainable aviation fuel for British Airways.
Iron & Steel	• Circular design principles in construction and infrastructure. • Deployment of an electric arc furnace (EAF) at British Steel to enable scrap metal utilisation in the production of iron and steel products.
Chemicals	• Utilisation of waste plastic streams.
Cement & Lime	• Increased use of demolition materials. • Circular design principles.
All	• Service focused business models.

[255] World Economic Forum 2018, Circular Economy for Net-Zero Industry Transition.

5.3 Shifts in demand for industrial products

The economy-wide transition to net zero is likely to result in a gradual shift in the demand for industrial products. As noted just above, the application of circular economy principles may increase demand for recycled materials (e.g., secondary steel) at the expenses of virgin ones (e.g., primary iron), resulting in corresponding adaptations in industrial activity levels. Also, decarbonisation pathways for other sectors of the economy could boost demand from supply chains of emerging low-carbon solutions (e.g., batteries for electric vehicles) while reducing demand for industrial outputs associated with a carbon-intensive economy (e.g., refined fuels).

Industrial emissions from the different sectors may decrease because of this shift, as illustrated in Table 36, provided those industrial products that will experience growth are produced in low-carbon supply chains. While this may represent a challenge for the continued operation of certain industrial assets, **the emergence of a net zero economy will provide significant opportunities for green growth in regions with the right infrastructure**. First, sites that produce equivalent products with a lower carbon content are likely to gain competitiveness and market share as carbon pricing increases over time. This could result in enhanced profitability for sites in low-carbon clusters even in cases where the sector is experiencing contraction. Second, new industrial products will be necessary to support the net zero economy. Regions that can offer connection to low-carbon infrastructure may be able to attract investors looking to develop new – low-carbon – manufacturing sites.

Table 36: Potential drivers of shifting demand for industrial products

Sector	Demand side measures and low-carbon alternatives
Refining	• Growth of electric vehicle and fuel cell electric vehicle ownership could result in a significant decline in demand for refined products. • Refineries are likely to increase production of low-carbon fuels such as biofuels and synthetic (e-fuels). • The Phillips 66 Humber refinery increasing production of graphite coke, an essential component for battery production[256].
Iron & Steel	• Building and infrastructure design with reduced steel alongside increased use of recycled steel could result in a decline in virgin steel. • Timber in construction.
Chemicals	• Increased plastic recycling could result in reduced demand for some chemical feedstocks. • Syngas could be made from captured CO_2 (CCU) or biomass at Saltend. Syngas is utilised in a variety of industrial processes including the production of acetic acid.
Cement & Lime	• Increased use of demolition material and low-carbon building alternatives could result in reduced demand.
Gas Terminals	• Electrification of heat and industrial processes (e.g., heat pumps).
Policy and standards	• For industrial products and services within the UK.

Policy and standards driving alternative decarbonisation pathways

A more circular economy could create more resilient and localised supply chains, that are less prone to disruption in the event of resource shortages or breakdowns in the supply of key materials. Supporting the development of policies that will enable this transition will be required across the industrial value chain. This will require government to co-operate with industry to embed circular economy principles in their future policymaking

[256] HICP 2022, The Refinery of the Future

to ensure regulations, fiscal incentives and market mechanisms are aligned to support resource efficiency and capturing the maximum value of materials in use[257].

The implementation of circular principles will require updates to be made across the entire economic value chain. In industry, this could include lifecycle carbon prices applied to products, achieved via increased digital traceability. This could also enable the adoption of mandatory product standards and low/zero carbon labelling scheme. A summary of the policy and standards that are currently driving the uptake of alternative decarbonisation pathways is shown in Table 37.

Table 37: Policy and standards driving alternative decarbonisation pathways

Sector	Policy and Standards
Refining and gas terminals	• Green fuel mandates. • Removal of fossil fuel subsidies. • Banning of domestic flights. • Banning the sale of fossil fuel vehicles and their operation in cities.
Iron & Steel	• Green steel mandates. • Carbon border adjustment mechanisms - carbon price levied on "dirty" imported steel at the border to match domestic carbon price in the UK Emissions Trading Scheme.
Chemicals	• Legally binding recycling targets for plastics. • Material efficiency standards for durability – "sell less use, use more". • Carbon taxation on incineration of plastics. • Lifecycle emissions regulations on packaging. • Right to Repair acts – UK likely to adopt similar standards to the EU requiring products to be designed for repairability.
Cement & Lime	• Reduction targets for embodied carbon in construction materials. • BREEAM – new construction standards for the built environment. • LEED – building design and construction standards.

The Humber has an opportunity to implement circular principles across a broad range of sectors, spanning the entire value chain for many industrial products. Due to the nature and scale of industrials operating in the Humber, there is significant potential for synergies to develop between organisations, where low-value or waste streams can be utilised as feedstocks in separate processes. To ensure maximum emissions reductions can be realised, communication between industrials will need to commence imminently to enable plans for circular interactions between organisations to develop. 'Quick win' circular solutions should be prioritised for further study, focusing on the necessary requirements and process changes for deployment. **Today, the adoption of circular principles in industry is an under explored area with importance that cannot be understated.** In many cases, major emissions reductions may be achievable at low levelised cost when compared to decarbonisation pathways such as electrification, hydrogen fuel switching and carbon capture. **Circularity should therefore be considered at all sector levels, regardless of future decarbonisation plans.**

[257] Aldersgate Group 2021, Closing the Loop – Time to Crack on with Resource Efficiency.

6 Overarching recommendations

6.1 Recommendation to overcome key risks and barriers

The following section details a list of the key recommendations and actions that will support the deployment of vital low-carbon technologies in the Humber considering market, policy, and regulatory dimensions. A more detailed review of each low-carbon technology and the associated recommendations and actions are provided in the relevant chapter for each technology. Participation and coordination of relevant stakeholders is needed to enable ambitious decarbonisation plans to succeed. This study integrates perspectives from over 20 stakeholders from industry, academia, and policy. Actionable recommendations are proposed for a range of groups as shown in Table 38, with the most impactful actions for decarbonisation highlighted based on the categories shown in Figure 38.

Figure 38: Primary action categories

Table 38: Key recommendations and actions to enable industrial decarbonisation in the Humber

	Action category	Key recommendations and actions
Technology availability and reliability		Technology developers should develop pilots to demonstrate a broad range of technologies in each sector.
		Universities and research institutions should focus R&D on reducing energy consumption of low-carbon technologies.
		Industrial production facilities should drive down capex via mass-manufacturing (only for technologies that demonstrate scalability and positive impact).
		Policy makers should provide clear indication that support will be higher for early risk-takers.
		To protect taxpayers, policy developers should balance rewarding excessive scale-up of inefficient solutions and stimulating innovation.
Energy and carbon prices		Electricity prices can be stabilised through long term power purchase agreements (PPAs) between industrials and energy suppliers.
		Ofgem should reform the industrial electricity market to decouple the cost of electricity from fossil generation and the market price of natural gas.
		Project developers should aim to strategically position CO_2 capture plants near waste heat sources and/or excess renewables.
		The UK ETS Authority requires much higher carbon prices to incentivise fuel switching.
		Policy makers should develop (relative) price stabilisation mechanisms to incentivise investment in fuel switching.
Feedstock and resource constraints		Future demands for critical resources should be carefully mapped out under a range of scenarios by industry alongside support from government.
		Policy makers should incentivise circularity in materials use and waste reduction. This should also become a priority focus of R&D.
		Local leadership should explore opportunities for circularity starting with industrial symbiosis for using waste heat and other physical streams to air, water, or land.
		Project developers should focus on supply chain innovations that utilise abundant materials. Scarce resources should be prioritised for use where they are essential or most beneficial.
		Technology developers must secure long term supply contracts for critical resources.
Supply chains and skills		Government and industry should develop a comprehensive assessment of skill & supply chain requirements for the different decarbonisation pathways vs available today.
		Colleges and training institutions should collaborate with industry and government to develop programmes to support workers shifting to low carbon sectors.
		Industry should leverage existing skills and assets from carbon intensive sectors where relevant to accelerate the transition to a future low carbon economy.
		Project developers should phase deployment of major projects to minimise the impact of supply chain bottle necks.
		Policy makers should develop a social safety net to encourage workers to take up less secure jobs in emerging sectors/companies.
Infrastructure availability		Project developers and government should accelerate the build out of renewables, essential to all pathways.
		Policy makers must mitigate key counter party risks through business model development.
		Network operators should ensure redundancy in infrastructure to ensure continued operation during times of network maintenance or repair.
		Policy makers should require infrastructure fit for later expansion and open access, preventing monopolistic behaviours that restrict access.
		Project developers should aggregate demand for CO_2 T&S (including imports) to leverage opportunities for economies of scale.

	Action category	Key recommendations and actions
Customers and markets		Policy makers and investors should carefully consider long term alignment of decarbonisation projects with Net Zero.
		Industry should seek market niches with customers prepared to pay a green premium.
		Policy makers need to provide a clear indication of timeline for extending support to CO_2 imports needed.
		Policy makers should support and develop markets for CO_2 removal credits through voluntary or compliance markets.
		Project developers should aggregate long-term demand for removal credits at scale to de-risk investment.
Regulatory compliance		Universities and technology developers should focus R&D on reducing water consumption as well as minimising impacts on air quality and the environment.
		Technology developers should consider broader HSE implications early on.
		Project developers of water intensive technologies should consider alternative water sourcing strategies early on.
		Project developers should consider alternative decarbonisation pathways in water constrained regions.
		Permitting regulators should define technology specific consenting regimes and publish guidelines for compliance.
Policy support		The UK ETS Authority and government should adopt policy measures that drive carbon prices to the level required to incentivise deep decarbonisation.
		The UK Environmental Audit Committee and government should adopt supportive regulations like CBAMs to preserve industrial competitiveness and prevent carbon leakage.
		BEIS need to rapidly finalise business models to provide clarity around financial support, mechanisms for (relative) price stability, and mitigation against the key counter party risks.
		BEIS and government should increase policy support for measures that boost demand for green products across all sectors.
		BEIS and government should ensure value for money for the taxpayer and sustainability of financed projects through careful due diligence processes.

6.2 Opportunities for the Humber

Deep industrial decarbonisation may deliver multiple co-benefits to the Humber and beyond as shown by Table 39. Potential benefits will be dependent on scenario and type of technology deployed in the Humber region. A holistic view of how decarbonising industry in the Humber can benefit the environment and wider society should be considered in future decision-making processes. However, further investigation is needed to understand the key opportunities for leveraging benefits between sectors, as well as potential trade-offs.

Table 39: Co-benefits of industrial decarbonisation for the Humber

	Co-benefit	Sector	Description
	Environment & health		Reduced water needs when replacing water-intensive processes.
			Reduced release of pollutant linked with fuel combustion.
			Reduced resource consumption.
			Ecosystem protection through sustainable habitat management.
	Industrial competitiveness & economic development		Waste heat used in carbon capture/DAC/H_2 production.
		ALL	Early mover advantage enabling long-term competitiveness.
		ALL	Inwards investment for accessing low-carbon infrastructure.
			Reduced primary energy need through heat pump utilisation and potential for lower costs if electricity prices are decoupled from gas.
		ALL	Green price premiums could reduce policy support needs. important to evaluate the impact on final product prices to identify market niches.
		H_2	Becoming an export hub for H_2 and H_2 derivatives.
	Synergies for UK-wide decarbonisation	H_2	Synergies between energy efficiency and fuel switching.
		CO_2	Enabling other geographies and sectors to decarbonise.
		CO_2	Export of CO_2 removal credits.
		H_2	Potential provision of grid services.

6.3 Conclusions for policy and private sector stakeholders

The Humber has the opportunity to achieve net-zero by 2040 and become the world's first net-zero industrial cluster. Emissions can be reduced through the deployment of carbon capture, hydrogen fuel switching and electrification technologies, alongside the potential to deliver negative emissions via engineered removals. There are currently a range or market, policy and regulatory barriers that could restrict the Humber from reaching net-zero, that will require co-ordinated action from a range of stakeholders. The priority recommendations and actions for each stakeholder group are shown in Table 40 – these have been identified as crucial for ensuring the Humber reaches net-zero by 2040.

Table 40: Summary of priority actions by stakeholder group

Stakeholders		Recommendation / Action			
Policy makers (UK Govt departments like BEIS, Treasury; UK Parliament)		Provide support for NPT solutions in CO_2 T&S business model to unlock CCS for sites far from CO_2 storage		✓	
		Finalise business models for H_2 fuel switching and GGRs - specifically providing clarity on the level of financial support that will be made available	✓		
		Develop business model for electrification to ensure level playing field between alternative options	✓		
		Implement CBAMs or equivalent measures to enable carbon pricing to drive decarbonisation, not carbon leakage	✓		
		Increase innovation and deployment funding via dedicated innovation funds for new techs that reduce the cost of decarbonisation	✓		
Regulators	**Ofgem**	Electricity market reform to decouple cost of electricity from fossil generation	✓		
	Ofwat	Ofwat to reduce allowable water leakage for public water companies		✓	
	EA	EA to further investigate future water availability to provide industrials and project developers with region specific information relating to water constraints in the Humber region		✓	
Industry	**Industrials in the Humber**	Identify easy wins for H_2 fuel switching through early site decarbonisation studies			✓
		Stimulate demand for green products through the development of increased scope 1-3 emissions traceability across the full product supply chain		✓	
	Project developers	Adopt CO_2 standard compatible with European shipping and outline requirements for CO_2 imports to the Humber region		✓	
		Aggregate demand from GGR projects by identifying opportunities for joint project development in the Humber region			✓
		Identify constraints in supply chains via detailed supply chain studies (with support from the government)		✓	
	Technology developers	Increase focus on retrofit technology development		✓	
Local authorities (especially Planning & Permitting offices)		Work alongside the government to update how planning consent is awarded for projects of national significance		✓	
Local leadership (Humber Energy Board / Opportunity Humber)		Identify potential synergies between processes and promote circularity between industrials through information and communications support		✓	
Research and training institutions	**Universities**	Focus R&D on reducing the cost of CO_2 capture, hydrogen production and electrification, alongside further analysis of promising alternative pathways	✓		
		Focus R&D on minimising water consumption		✓	
	Colleges and training bodies	Increased support for re-training courses that upskill experienced professionals alongside early career development for energy transition roles		✓	
Utilities and infrastructure operators	**Energy networks / utilities**	Identify constraints in electricity grid and opportunities for electrification	✓		
	Water utilities	Communicate potential water constraints to industrials and project developers		✓	
	Port operators	Integration planning for CO_2 shipping via early feasibility studies		✓	

Overarching policy recommendations to prevent loss of industrial competitiveness

Carbon leakage refers to policies where emissions are relocated to countries with less ambitious greenhouse gas emissions reduction policies. In the context of industrial decarbonisation in the Humber, there are two primary concerns. Domestic producers losing market share to higher carbon imports as a result of higher carbon costs in the UK than those faced by international competitors, and diversion of investment from countries with more ambitious carbon constraints to those with less ambitious ones. The ideal option would be to ensure that no regulatory asymmetries existed in the first place. If all industries across the world faced the same carbon price, there would be no incentive to relocate. However, political challenges in reaching such an agreement and the expected difficulties in its enforcement make its implementation unlikely, at least in the short term.

To mitigate the risk of carbon leakage while preserving incentives for industrial decarbonisation, the implementation of carbon border adjustment mechanisms and policies that stimulate demand for green industrial products could be implemented. Policy support will be critical for at least one of these to minimise carbon leakage in the Humber, however, it is also possible for both to be deployed in parallel. Price increases would negatively affect market demand for high carbon industrial products and would simultaneously incentivise innovation in green industrial and disruptive low-carbon alternative products.

Consider the adoption of a carbon border adjustment mechanism

Carbon Border Adjustment Mechanisms (CBAMs) adjust the import and export price of industrial products based on the applied carbon price. The EU have recently introduced CBAMs on a range of industrial commodities with plans to expand coverage to a greater number of products over time. The UK Environmental Audit Committee is currently conducting an inquiry into the role CBAMs could play in addressing carbon leakage and addressing the UK's environmental objectives.

The UK government should consider policy measures to level the playing field with international competitors, including the adoption of a UK CBAM. The UK should learn from the EU CBAM to avoid likely challenges & prevent subtler forms of carbon leakage. The UK government should consider how a CBAM could work alongside the UK ETS by 2024.

Stimulate demand for green industrial products

Green industrial products are likely to be priced at a premium until carbon prices rise sufficiently. Today, further work is required to close the gap between green products and existing high carbon alternatives. Solutions are required that increase visibility/transparency of Scope 3 emissions. This will stimulate demand for green industrial products and drive innovation. This could also reduce policy costs as the market would be bearing a higher share of the cost of decarbonisation.

Technology developers will be key to driving down the cost of green products whilst also providing solutions that enable greater tracking of embedded emissions along the supply chain. BEIS could also play a role in the design of policies that reward industrials for decarbonisation with consideration for Scope 1-3 emissions. Significant innovation will be required before green products are likely to establish a majority market share. Technology developers should work alongside BEIS in the development of a policy, which is likely to stimulate further innovation. BEIS should aim to clarify how incentive mechanisms could be developed within the UK ETS by 2024.

6.4 Further work

The Humber Industrial Cluster Plan aims to set out the optimal route to fully decarbonise the Humber cluster by 2040. This study investigates the market, policy and regulatory barriers faced by industrials and project developers within the Humber considering the deployment of deep decarbonisation technologies such as carbon capture, hydrogen fuel switching, and greenhouse gas removals. This study provides an overview of the key barriers faced by the Humber cluster, however, due to the constantly evolving policy landscape and advancement of technology development, further analysis will be required to provide a more detailed picture of the hurdles that must be overcome to ensure net-zero by 2040 is achieved.

Policy is a key area of uncertainty for all technology pathways, with government strategy and business models still in development. The lack of clarity on the support that will be provided to industry was highlighted as a key barrier to investment by many stakeholders and an urgent area for action. Confirmation of hydrogen and CCS business models is likely to enable projects to reach FID and encourage greater investment into decarbonisation projects. Two of the least developed areas of policy highlighted in this report relate to support for non-piped CO_2 transport and the development of negative emissions credits from engineered removal technologies. Further work should continue to update the barriers faced by industry within the Humber and provide recommendations to policy makers on the support that is required to incentivise investment in decarbonisation.

Innovation projects are a key stage in advancing a technology to enable large scale deployment. A favourable policy environment should also increase opportunities for innovation and technology development. Increasing innovation and deployment funding via dedicated innovation funds and competitions will be crucial for reducing cost and ensuring resource efficiency. Driving innovation in the short-term is likely to reduce the overall economic cost of decarbonisation and ensuring a just transition to net zero is achieved. Further work should consider how technology advancement as a result of continued innovation will impact the costs and potential barriers to decarbonisation.

This study also provides an overview of the environmental impacts of low-carbon technology deployments and the benefits that circular economy principles can deliver to industries within the Humber. Negative environmental impacts produced as a result of the deployment of these technologies and constraints on resources was considered, with future water supply highlighted as a key area of concern in the Humber. Quick win' circular solutions between existing industries within the Humber should be prioritised for further study, focusing on the requirements and process changes for deployment. Potential synergies between industrials could enable greater resource efficiency and utilisation of waste streams whilst minimising the reliance on environmental resources, providing the same service using less raw inputs. However, further investigation is needed to understand the key opportunities for leveraging benefits between sectors, as well as potential trade-offs.

7 Appendix

7.1 CO_2 import methodology

The methodology for assessing CO_2 imports to the Humber (discussed in section 3.2) is outlined below. This details the approach used and assumptions made to calculate the volumes of CO_2 that could be shipped to the Humber in the future.

7.1.1 Approach

The three-stage approach shown below in Table 41 was utilised to quantify the volumes of CO_2 imports from both pipeline and shipping transport modalities. Geographical mapping software was used to identify existing emitters based on the National Atmospheric Emissions Inventory (NAEI)[258] database for large point sources for the UK.

Table 41: Overview of CO_2 import market sizing strategy for the Humber

		Stage	Requirements / Criteria
1	 	Identify emitters without a CO_2 T&S Solution Focus on sectors likely to require CCS for decarbonisation	• No nearby geological storage • Dispersed sites • Decarbonisation timeline – based on public announcements and maturity of decarbonisation plans. • Large scale emitters • UK – pipeline and shipping • Western Europe – shipping
2		Probability ranking of shipping CO_2 to Humber	• Distance to Humber • Distance to alternative storage sites • Competition from alternative transport (shipping / pipeline) • CO2 capture sectors in development (ICC / Blue H_2 / Power CCS / GGRs) – identifying seasonal fluctuations in CO2 • Project maturity
3		Quantify flow rates at specific time periods	• Quantify potential flow rates from identified emitters in 2030, 2035 and 2040 • Identify constraints / enablers for CO2 imports to the Humber

7.1.2 Onshore imports Assumptions

- In the 2040 High Scenario, limitations to importing CO_2 to the Humber are assumed to be significantly reduced for all industries and distances.
- Existing emitters up to 100km from the core Humber cluster and greater than 0.1 $MtCO_2$/year are considered for import.
- Minimum of 90% capture rate applied to emitter streams.
- 50% of existing power capacity will be replaced by new build / retrofit power ccs.

[258] NAEI 2021, Emissions from NAEI large point sources (2019 data).

Table 42: Onshore CO_2 imports to the Humber

			2030		2035		2040	
Iron & Steel	Liberty Speciality Steels - Rotherham	$MtCO_2$/year	-	-	-	-	0.06	0.06
Glass	Wheatley	$MtCO_2$/year	-	-	-	-	-	0.08
	Barnsley	$MtCO_2$/year	-	-	-	-	-	0.11
Energy from Waste	Ferrybridge MF1	$MtCO_2$/year	-	-	-	0.28	0.28	0.28
	Allerton Waste Recovery Park	$MtCO_2$/year	-	-	-	-	-	0.11
	Sheffield	$MtCO_2$/year	-	-	-	-	-	0.10
Food & Drink	Newark	$MtCO_2$/year	-	-	-	-	-	0.08
Cement	Hope Cement Works	$MtCO_2$/year	-	-	0.78	0.78	0.78	0.78
	Tunstead Cement	$MtCO_2$/year	-	-	-	0.46	0.46	0.46
Lime	Tunstead Lime	$MtCO_2$/year	-	-	-	0.19	0.19	0.19
	Hindlow Quarry	$MtCO_2$/year	-	-	-	-	-	0.12
	Buxton	$MtCO_2$/year	-	-	-	-	-	0.11
	Whitwell	$MtCO_2$/year	-	-	-	-	-	0.28
Power CCS	Power CCS Total	$MtCO_2$/year	-	1.78	-	4.13	-	5.29
Total		**$MtCO_2$/year**	**-**	**1.78**	**0.78**	**5.84**	**1.77**	**8.05**

7.1.3 UK Shipping assumptions

This analysis considers emitters in the UK that are most likely to ship CO_2 to the Humber cluster. This accounts for public announcements in support of CO_2 shipping, vicinity to alternative CO_2 storage sites, and the potential volumes of CO_2 captured. Today, the sites considered most likely to ship CO_2 to the Humber include the South Wales Industrial Cluster, Southampton Cluster and Cory Riverside Resource Recovery Volumes of CO_2 shipped are based on a percentage of the total forecast capture volumes.

- South Wales Industrial Cluster Scenarios
  - Low = DNV GL Minimum CCS Scenario[259]
  - High = DNV GL Maximum CCS Scenario[259] + 50% Power CCS capacity at Pembroke Power[260]
- Southampton Scenarios
  - Blue hydrogen demand = 37TWh in 2050[261]. (S-Curve uptake applied between 2030 and 2050)
  - Fawley refinery - 50% CCS / 50% blue hydrogen.
  - 50% Power CCS capacity replaced at Marchwood Power.
- Competing storage sites
  - The percentage of total captured emissions transported to the Humber was estimated based on shipping distances and storage cost forecasts.

[259] DNV GL 2021, A CCUS Network for Wales.
[260] RWE, Pembroke Net Zero Centre.
[261] Hydrogen East 2021, Southampton Hydrogen Hub.

- The alternative storage sites considered included: HyNet, Porthos and Aramis (the Netherlands), Northern Lights (Norway).

Table 43: Total UK captured emissions transported to storage via ship

		2030		2035		2040		% of captured emissions shipped to the Humber
South Wales Industrial Cluster	$MtCO_2$/year	-	1.1	1.2	9.1	2.3	15.4	50%
Southampton	$MtCO_2$/y	-	0.7	1.4	4.9	2.7	8.5	75%
Other UK	$MtCO_2$/y	-	-	-	1.5	-	1.5	90%

Table 44: UK shipping CO_2 imports to the Humber

			2030		2035		2040	
South Wales Industrial Cluster	Newport	$MtCO_2$/year	-	-	0.0	0.3	0.0	0.5
	Cardiff	$MtCO_2$/year	-	-	0.0	0.1	0.0	0.1
	Barry	$MtCO_2$/year	-	-	0.1	0.1	0.2	0.2
	Port Talbot	$MtCO_2$/year	-	0.3	-	1.0	-	2.9
	Milford Haven	$MtCO_2$/year	-	0.3	0.5	1.7	0.9	2.5
	Pembroke Power	$MtCO_2$/year	-	-	-	1.5	-	1.5
Southampton	Southampton Blue H_2	$MtCO_2$/year	-	0.3	0.3	0.9	0.9	2.4
	Fawley Refinery	$MtCO_2$/year	-	0.3	0.7	2.7	1.1	3.1
	Marchwood Power	$MtCO_2$/year	-	-	-	-	-	0.9
London	Cory Riverside Resource Recovery	$MtCO_2$/year	-	-	-	1.4	-	1.4
Total		**$MtCO_2$/year**	**-**	**1.1**	**1.6**	**9.6**	**3.2**	**15.4**

7.1.4 Europe Shipping assumptions

This analysis considers CO_2 shipping imports from three of Europe's largest industrial clusters that were shortlisted due to their public announcements for developing CO_2 shipping exports in the future alongside the relatively short shipping distances to the Humber cluster. Volumes of CO_2 shipped are based on a percentage of the total forecast capture volumes.

- **Dunkirk**[262] – the Humber is likely to be the 2nd closest CO2 storage option for Dunkirk and could play a significant role in decarbonising the highest emitting region in France. Dunkirk aim to capture 10 $MtCO_2$/year by 2035.
- **Antwerp**[263] – the Port of Antwerp plans to develop multimodal CO2 T&S solutions utilising both pipelines and shipping. The Humber could provide a competitive solution for large portions of emissions from Antwerp. The Port of Antwerp aim to capture 9 $MtCO_2$/year by 2030.
- **Rotterdam**[264] – Rotterdam plan to develop a CO_2 hub terminal that will enable both CO_2 import and export capabilities. Porthos and Aramis pipeline solutions are likely to be primary storage location. Significant imports are likely to come from industrial sectors in Germany, primarily from the North Rhine-Westphalia region[265]. However, CO_2 shipping exports to stores could be required at times of limited network capacity. The North Rhine-Westphalia region accounts for ~59$MtCO_2$/year, of which significant volumes could be decarbonised via CCS.

[262] 3DX 2022, Dunkirk.
[263] Port of Antwerp 2022, Climate and Transition.
[264] Aramis 2022, The Aramis Project.
[265] H2morrow 2022, The Potential of Hydrogen for Decarbonization of German Industry.

Table 45: Percentage of captured emissions shipped to the Humber

	2030		2035		2040	
Dunkirk[1]	0%	25%	25%	50%	25%	50%
Antwerp[2]	0%	25%	10%	30%	10%	30%
Rotterdam[3] / North Rhine-Westphalia[4]	0%	10%	10%	20%	10%	20%

Table 46: Europe shipping CO_2 imports to the Humber

	2030		2035		2040	
Dunkirk	-	1.3	2.5	5.0	2.8	5.5
Antwerp	-	2.3	1.0	3.0	1.1	3.3
North Rhine-Westphalia	-	1.2	1.3	2.6	1.4	2.9
Total	-	4.7	4.8	10.6	5.3	11.6

7.1.5 Total Humber imports

Table 47: Potential CO_2 imports to the Humber (total)

	2030		2035		2040	
UK Pipeline	-	1.8	0.8	5.8	1.8	8.1
UK Shipping	-	1.1	1.6	9.6	3.2	15.4
Europe Shipping	-	4.7	4.8	10.6	5.3	11.6
Total	-	7.6	7.2	26.0	10.2	35.1

7.2 Detailed overview of the consenting process

7.2.1 Scope of the review

This chapter establishes the regulatory implications of identified decarbonisation technologies and CO_2 import terminal, focusing on the planning and environmental permitting elements for the UK. The review includes:

- A review and assessment of legislative and policy context for planning and permitting;
- An overview of the planning and permitting steps/process;
- Analysis of each of the decarbonisation technologies and CO2 import terminal, identifying the regulatory implications for planning and permitting i.e., what consents are required. The review of each technology will include:
- Identification of key considerations and requirements; and
- Key barriers and risks.

Decarbonisation options for the Humber included within scope for this review are identified in Table 48.

Further consents may be required under other environmental or safety legislation, but that they are out of scope of this review. This includes the storage of Hydrogen which is regulated by The Planning (Hazardous

Substances) Regulations 2015 and/or the Control of Major Accident Hazards Regulations 2015 ("COMAH"), depending on the quantities involved.

7.2.2 Planning and Permitting

Within the UK, planning and permitting are two separate consenting regimes with their own regulatory bodies. The planning process/planning consents will cover the development and construction of such infrastructure associated with decarbonisation in the Humber. Environmental permits will cover the operational aspects of the proposed decarbonisation options.

For the decarbonisation options for the Humber in scope of this review, consents will likely be required for both the planning and permitting. **Sections 7.2.3 and 7.2.5** provide more detail about each regime. The applicability to the various decarbonisation options identified within the scope is instead included in the corresponding sections within Chapters 0-4.

Interaction between the regimes

Traditionally permitting applications have been considered after planning consent have been obtained. Not least as permitting tends to have a higher level of design certainty than may be necessary for a planning consent.

More recently however, there has been considerable appetite from regulators to discuss permitting matters during the development of the planning application and Environmental Impact Assessments (EIA), or even to prepare and submit the two in parallel ("twin-track" or "parallel track"). Twin-tracking has several benefits:

- A common set of design parameters and shared impact assessments;
- All stakeholders can be consulted in parallel on the same set of information;
- The applications are likely to be highly self-consistent;
- All regulators are reassured that design iteration between planning and permitting is not intended;
- The planning authority has confidence that they are consenting the 'final' design and are less likely to have variation submissions after the planning permission is granted; and
- From a timescale point of view, the longer running permit determination can start sooner.

However, twin-tracking is not always possible, not least as there may not be Project authorisation to proceed with operational consenting until construction consent is obtained.

The EIA/planning and the permitting assessments can be scoped to contain the necessary information for both consenting processes. There will be information such as Environmental Impact Assessments that can feed into the planning stage as well as the permitting stage. This sharing of information will be useful to ensure consistency between planning and permitting.

Table 48: Project scope and limitations

Topic	Description	Planning scope	Permitting Scope	Limitations
Carbon Capture and Storage	Technologies that involve the process of capturing carbon dioxide before it enters the atmosphere and either utilising it or transport it and store it permanently. Three main capture technologies: pre-combustion capture, post-combustion capture, and oxy-fuel combustion.	Permission to construct and operate carbon capture plant & connecting it to industrial process.	Operating carbon capture plant.	Review not including CO_2 pipelines, storage, or CO_2 utilisation.
Fuel Switching	Fuel switching replaces the energy supply from the natural gas grid with alternative low carbon fuels. Three main classes of low-carbon energy sources are considered for fuel switching: • Electricity; • Hydrogen; • Biomass & and waste-derived fuels.	Permission to provide and operate alternative heating appliances.	Operating alternative heating appliances. Focus on combustion activities.	Appliances to consider are typically in the MW thermal scale, e.g., 1-50 MWth. H_2 infrastructure, electricity grid upgrades to enable electrification etc are not covered in this review.
Carbon Removals	Carbon removal technologies include: • Bioenergy with carbon capture and storage (BECCS); and • Direct Air Capture (DAC/DACCS) – capture of ambient air	BECCS: Biomass combustion and carbon capture plant. DACCS: Installing Direct Air Capture (DAC) plant.	Operating biomass power station +and carbon capture plant. Operating DAC plant.	Up-stream and downstream aspects such as supply, or CO_2 infrastructure are not covered in this review.
CO_2 Imports	The Humber will look to have a CO_2 import/operating terminal to handle, process and store CO_2 (including sources beyond the Core Humber cluster). Terminal includes: • Jetty; • CO_2 pipelines; • Temporary storage of CO_2 and Conditioning plant (Liquefaction/compressions).	Permission to construct and operate shipping terminal with CO_2 imports facilities (jetty, storage etc).	Operating terminal.	-

7.2.3 Planning

Legislative review

Planning legislation supports UK planning practice and policy and takes the form of Acts of Parliament and Statutory Instruments (SIs).

Acts of Parliament create a new law or change existing law. Acts are required to be approved by both Houses of Parliament and are then given Royal Assent.

SIs, also known as delegated, secondary or subordinate legislation, allow the UK government to alter or bring the provisions of the Act into force without needing Parliament to pass a new Act.

For the purposes of this report only relevant 'high-level' legislation will be summarised to provide the legislative framework relating to the principle consenting of the technologies considered by this project.

In this respect, the two main primary planning legislations that provide the consenting frameworks are the Planning Act 2008 and the Town and Country Planning Act 1990. Each are described below along with an explanation of each of the associated consenting processes.

The Planning Act 2008

In 2008 the primary legislation of the Planning Act 2008 (Planning Act) was introduced. This established the legal framework for applying for, examining and determining applications for Nationally Significant Infrastructure Projects (NSIP).

The Planning Act created a new development consent regime for major infrastructure projects in the fields of energy, transport, water, wastewater, and waster. The Act sets out the thresholds above which certain types of infrastructure development are considered nationally significant and require development consent.

Town and Country Planning Act 1990

The Town and Country Planning Act 1990 (as amended) (TCPA) is an Act of UK Parliament that regulates the development of land in England and Wales.

The TCPA covers the main provisions in relation to town and country planning. It contains provisions in respect to many aspects of planning, including the role of planning authorities, the control of development and many other matters relating to planning.

For development that require planning permission, permission is required by virtue of the TCPA.

Types of consents

Development Consent Orders

The Planning Act introduced the Development Consent Order (DCO) process as a way of simplifying and speeding up the process of obtaining planning permission for certain types of projects, designated as NSIP. This includes energy, transport, water and waste projects, and more recently other commercial developments

The DCO process can include several other consents in addition to planning permission, such as listed building consent and compulsory purchase orders.

DCO Process and Timescales

As detailed by the Planning Inspectorate there are six stages to the DCO process, illustrated in Figure 39.

Figure 39: Development Consent Order (DCO) process

National Infrastructure Planning Reform Programme

The Government is currently undertaking a process of National Infrastructure Planning Reform to refresh how the NSIP regime operates, with the aim of making it more effective and deliver more certainty in the process and better and faster outcomes.

Through a letter issued by the Rt. Hon Christopher Pincher MP on 21st June 2021 the Government set out its roadmap to reform, providing details of key activities and milestones. Consultation on the NSIP reform is expected in early 2022, with implementation expected in Autumn 2023.

This is likely to have implications for the technologies considered in this report. The implications of the reform would need to be considered once further information is published.

TCPA Planning Application process and timescales

When planning permission is required it is necessary to secure planning consent through the submission and approval of a planning application to the Local Planning Authority (LPA).

The planning application process can be divided into six stages as illustrated in Figure 40. The process is largely governed by legislation and is designed to allow the input of expert and interested parties into the preparation of the proposals and in the decision-making process.

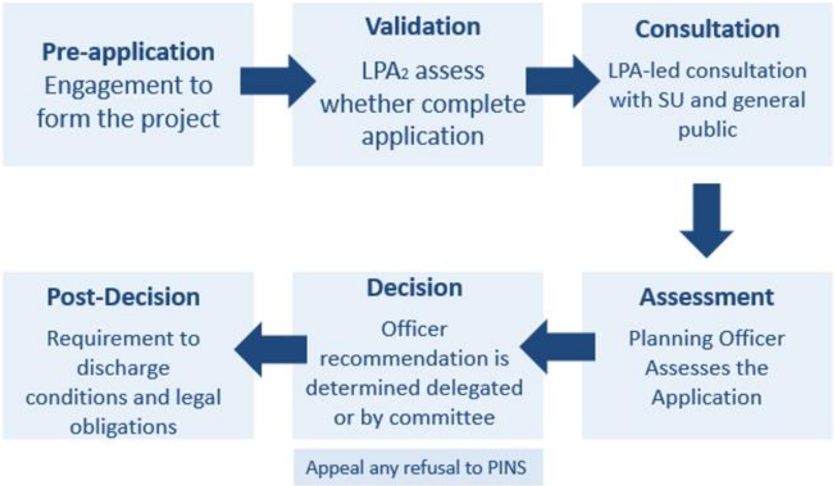

Figure 40: Planning application process

Differences between DCO and Planning Applications

There are some key differences between the DCO and Planning Application processes as detailed in the summaries within this report.

As the processes are distinctly different, it would not be appropriate to compare as such, though for general information and guidance only the following can be summarised:

PLANNING APPLICATIONS

Advantages

- Shorter timescale for determination. Approx. 8 weeks to 6 months (though can be longer)
- Less preparation and detail/information required
- Cheaper to prepare and cheaper process
- Local 'ownership' of determination
- Relatively flexible both during and post-decision

Disadvantages

- Local politics and issues could impact success
- Greater risk to success as less prescribed process
- Does not provide any other necessary consents
- Timescales whilst often shorter, are not definitive. Possibility of being called in by SoS
- Assessed against local policy that may not support

DEVELOPMENT CONSENT ORDERS

Advantages

- More certainty on timescales
- Assessed against national policy, may be more supportive
- Positive outcome arguably more likely
- Provides other necessary consents other than planning e.g. Compulsory Purchase Order and Marine Licences

Disadvantages

- Newer 'decarbonisation' technologies, such as CCUS are not covered in the Planning Act
- Lengthier – approximately 2-year+ process
- Expensive – significantly more work required
- Less flexible to changes during process and post-decision

Permitted development

Given the nature and extent of the technologies considered, elements of the infrastructure may be permitted development by virtue of the Town and Country Planning (General Permitted Development) Order 2015 (as amended) (GPDO), and therefore not need planning permission.

As a general guideline development that is permitted under the GPDO will be of smaller size and scale, and likely to be associated with an existing facility or undertaken by Statutory Authorities.

An assessment would need to be undertaken on each project to see whether some or all of the project would be permitted development by virtue of the GPDO.

Planning policy

Planning policy is the development framework against which applications are assessed. Planning policy considerations are different for DCO applications and planning applications.

DCOs are considered against National Policy Statements (NPS). NPS are set by government and comprise the government's objectives for the development of nationally significant infrastructure in a particular sector and state.

For planning applications under the TCPA, planning policy is set at the national and local level (with some 'regional' policy in certain locations e.g., where combine Local Authorities), with national policy providing the strategic framework that local policy must be consistent with.

DCO and National Policy Statements

NPSs that are designated under section 5 of the Planning Act set out the national policy in relation to each infrastructure field set out in section 14(6) of the Act. The relevant Secretary of State must decide any Development Consent Order application in accordance with any relevant National Policy Statement unless one or more of the certain exceptions specified under section 104(4) to (8) apply. It is therefore important that there is regular consideration of whether and when to review National Policy Statements to ensure effective decision making in line with the latest government policy and relevant information. Ensuring that policy responds to emerging technologies is a key aspect of this.

Details of the National Policy Statements are contained in Appendix.

Revised Energy National Policy Statements

The National Policy Statements for energy are currently being revised and updated by the Government to reflect the policies and broader strategic approach as set out in the *Energy White Paper: powering our net zero future Dec 2020*.

The white paper addresses the transformation of the energy system, promoting high-skilled jobs and clean, resilient economic growth as the UK transitions to net-zero emissions by 2050.

NPS EN1-5 will be reviewed, whereas NPS EN-6 Nuclear is not being reviewed. Consultation was undertaken at the end of 2021.

Relevant to the review of the technologies in this project, the overarching NPS for Energy (EN-1) may have effect on its own as the primary policy for decision making where there is no technology-specific NPS, such as CCS, hydrogen and other forms of low carbon generation and emerging technologies. The draft EN-1 also makes it clear that it will be, in conjunction with any relevant technology specific NPS, the primary policy for the Secretary of State's NSIP decision making on energy infrastructure.

TCPA – National Planning Policy Framework

The National Planning Policy Framework (NPPF), last revised in July 2021, sets out the government's planning policies for England and how they are expected to be applied.

The NPPF[266] sets out the Government's economic, environmental and social planning policies for England. The policies set out in this framework apply to the preparation of local and neighbourhood plans and to decisions on planning applications. The NPPF covers a wide range of topics including housing, business, economic development, transport and the natural environment.

The NPPF introduced the presumption in favour of sustainable development which means that development which is sustainable should be approved without delay. There are three pillars of sustainability (social, economic and environmental) and the Framework contains several sections which, taken as a whole, constitute the Government's view of what sustainable development means in practice.

The National Planning Practice Guidance (NPPG) adds further context to the NPPF, and it is intended that the two documents should be read together. The NPPG is web based with separate sections and is regularly updated when guidance is updated or amended. It includes several key topics such as what should be included in Local Plans, design, neighbourhood planning and the Duty to Cooperate.

The NPPF and NPPG together with other statements of policy constitute Government Policy and guidance.

Humber local planning policy

The project covers an area which contains four Local Planning Authorities within the Humber Region: Kingston upon Hull City Council, East Riding of Yorkshire, North Lincolnshire Council and North East Lincolnshire Council. Therefore, the Local Development Framework documents prepared by each Local Planning Authority would be relevant to the assessment of any planning applications within the respective Authority boundaries either in full or in part.

The policy documents at national, regional and local level that would be relevant to the assessment of a planning application within the relevant Local Authorities are summarised in Appendix.

7.2.4 Environmental impact assessment

The technologies considered as part of this report are likely to trigger the need for an Environmental Impact Assessment (EIA), subject to an assessment of the project against the relevant legislation.

The aim of EIA is to protect the environment by ensuring that a LPA, when deciding whether to grant planning permission for a project, which is likely to have significant effects on the environment, does so in the full knowledge of the likely significant effects, and takes this into account in the decision-making process. The EIA Regulations sets out a procedure for identifying those projects which should be subject to an EIA.

NSIP projects that are consented through the DCO process will need to be assessed against the following regulations in respect of EIA. The Regulations set out the procedures for determining whether a proposed development requires the applicant to undertake an EIA, and the EIA process that must be followed if it does.

- The Infrastructure Planning (Environmental Impact Assessment) Regulations 2017

Planning applications are assessed against the following regulations to determine whether an EIA is required:

- The Town and Country Planning (Environmental Impact Assessment) Regulations 2017 (as amended)

Key aspects of the preparation of an Environmental Statement, which is the document required to be submitted with an application, is the time and cost that it takes to prepare. This is an important factor in the programme, design and consenting process.

[266] DLUHC 2012, National Planning Policy Framework

The general process for determining whether an EIA is required, and the process of the preparation of an Environmental Statement is detailed in Appendix**.**

7.2.5 Permitting

Legislative review

ERM has undertaken a review of the applicable environmental permitting legislation for the decarbonisation options being considered for the Humber Industrial Cluster. The review includes:

- Directive 2010/75/EU of the European Parliament and the Council on Industrial Emissions (the Industrial Emissions Directive or IED).
- The Environmental Permitting Regulations (England and Wales) 2016 (as amended) (the EPR Regulations);

European Directives

IED

Directive 2010/75/EU of the European Parliament and the Council on industrial emissions (the Industrial Emissions Directive or IED) is the main European Union (EU) instrument regulating pollutant emissions from industrial installations and was adopted on 24th November 2010. The IED came into force on 6th January 2011 and had to be transposed by Member States by 7th January 2013 to national law.

The IED aims to achieve a high level of protection of human health and the environment by reducing harmful industrial emissions across the EU, through better application of Best Available Techniques (BAT)[267].

The IED requires operators to obtain a permit to carry out an activity listed under Annex I of the IED[268]. Regulators are required to check compliance against these permits and can impose penalties where issues of non-compliance are present. The Environment Agency (EA) performs the regulatory role in England for permitting.

The Environmental Permitting Regulations (England and Wales) 2016 (as amended) transpose the IED into English Law.

BAT (BREFs)

Article 13 of the IED requires the European Commission to organise 'an exchange of information between Member States, the industries concerned and environmental non-governmental organisations on best available techniques, associated monitoring and developments' and to publish the results as legally binding Best Available Technique Conclusions (BATc). In addition, Best Available Technique (BAT) Reference Documents known as BREFs are published alongside the BATc which describe applied techniques, present emissions and consumption levels, techniques considered for the determination of best available techniques as well as BAT conclusions and any emerging techniques.

BATc determine the reference points employed to set permit conditions for installations covered by the IED. Where BAT conclusions are available for any new installations, those installations must achieve the required standard before the start of operations.

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[267] https://ec.europa.eu/environment/industry/stationary/ied/legislation.htm#:~:text=The%20IED%20aims%20to%20achieve,Best%20Available%20Techniques%20(BAT).

[268] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) (europa.eu)

For existing installations, permit conditions for the installation are reconsidered (and, where necessary, updated) in line with the relevant BATc within four years of its publication.

In the absence of any applicable BATc, installations should continue to ensure that they meet the highest standards of environmental control, based on BATs and associated BREFs[269].

BATc's and the associated BREFs form the basis for regulating IED Annex I activities (activities identified as falling within the scope of IED). A list of potentially applicable BREFs has been identified for each technology in Chapters 2-4.

The UK is no longer a member of the European Union, but currently still refers to EU Best Available Technique Reference Notes (BREF Notes), and therefore has extensive synergies with the EU. BAT conclusions and BREFs adopted before Brexit are retained as legally binding in English law.

Environmental Permitting (England and Wales) Regulations 2016 (as amended)

The Environmental Permitting (England and Wales) Regulations 2016 (as amended) (EP Regulations) transpose the requirements of the Industrial Emissions Directive (2010/75/EU) into English law and provide a framework for the consenting of activities that have the potential to affect the environment or human health as a result of their operation.

The EP Regulations list a series of activities which are required to be regulated in Schedule 1, broadly a transposition of IED Annex I, though also covers additional activities. The Environment Agency (EA) is the regulator for what are known as Part A(1) activities (IED level regulation). Other activities, known as Part A2 or Part B listed activities are typically regulated by the Local Authority in which the facility is located.

Overview on environmental permitting

An environmental permit is required for activities that could pollute the air, water or land as well as increase flood risk or adversely affect land drainage along with the proposed activities falling in scope of the Environmental Permitting (England and Wales) Regulations 2016 as amended.

The EA is England's principal environmental regulator, who issue a range of consents (permits) designed to control activities that could lead to pollution or environmental damage. Operators of installations activities that fall under the EP Regulations must have a permit to operate.

Further details on the permitting process (including types of permits, timeframes, costs, and stakeholder engagement) can be found in Appendix.

As an example, a typical application timeline is shown in Figure 41. Pre-application guidance from the regulator is not compulsory but in this case is strongly advised to engage with the EA, pre-notify them of the Project's intentions and to gain their thoughts on the content of the proposed application.

[269] https://www.sepa.org.uk/regulations/pollution-prevention-and-control/best-available-techniques-bat-reference-documents-brefs/

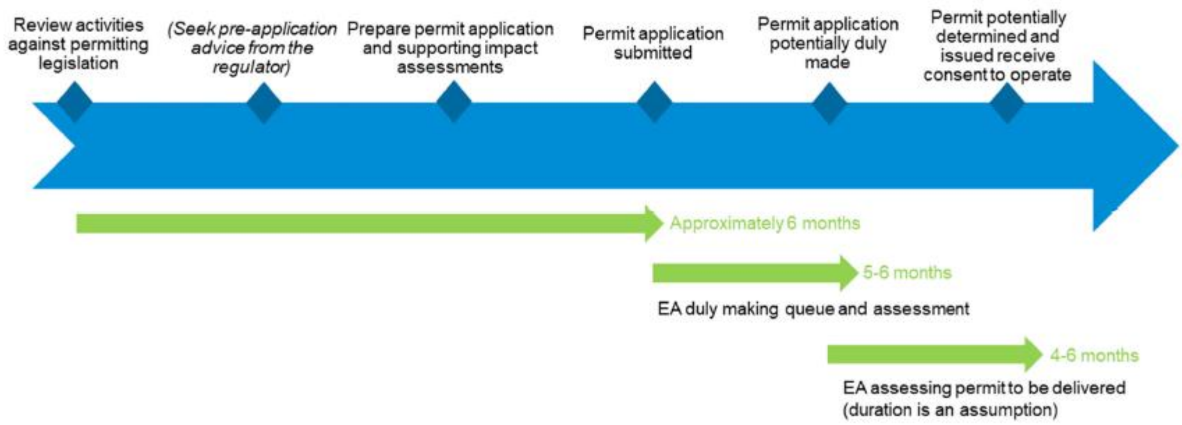

Figure 41: A typical permit application process for future planned activities

7.3 UK Policy context

7.3.1 Climate change agreements and levies

Climate Change Agreements (CCAs) are voluntary agreements made between UK industry and the Environment Agency to reduce energy use and CO_2 emissions. CCAs have the dual aim of supporting industrial businesses to achieve energy and carbon savings through energy efficiency improvements, while helping to reduce energy use in energy-intensive sectors by providing a significant discount on the Climate Change Levy (CCL) payments. Operators who achieve the required improvements in energy efficiency and reduced carbon emissions are certified to continue to receive the CCL payments discount.

The CCA scheme was introduced in 2013 and will run until March 2025. An operator that has a CCA must measure and report its energy use and CO_2 emissions against agreed targets over 2-year target periods. If the operator's target unit meets its targets at the end of each reporting period, the facilities continue to be eligible for the discount on the CCL. CCAs are available for a wide range of industrial sectors and are not limited to the largest emitting sectors. BEIS will continue to review CCAs to ensure they are fit for purpose as a mechanism for reducing emissions whilst also delivering value for taxpayers' money.

The climate change levy scheme acts as an environmental tax on commercial energy use (electricity and natural gas) applicable to organisations operating in various sectors and aims to promote energy efficiency across industry. Organisations are eligible to receive a reduction in fees related to the main rates of the CCL, if they are an energy-intensive business that has entered into a Climate Change Agreement (CCA) with the Environment Agency.

CCLs were introduced in 2001 in an effort to encourage the highest emitting sectors to increase operational efficiency and reduce carbon emissions, The CCL is charged on taxable commodities for heating, power and lighting purposes such as natural gas, electricity, petroleum and coal. All industrial operators will be charged at the CCL 'main rate' other than power generation or combined heat and power stations that pay at the ''carbon price support rate'. In 2021, the CCL was increased for natural gas whilst being reduced for electricity as this is seen as a greener use of energy.

7.3.2 BEIS business model for hydrogen production

The UK government's hydrogen business model consultation[270] proposes a technology-neutral subsidy based on a Contracts for Difference (CfD) model, whereby Government will agree to pay the difference between the

[270] BEIS 2021, Low Carbon Hydrogen Business Model (Consultation).

market value of hydrogen, and a pre-negotiated strike price. Revenue support is likely to be funded by passing on costs indirectly to consumers.

The UK government aims to manage some of the initial risks faced by first of a kind (FOAK) low-carbon hydrogen project, primarily:

- **Market price risk –** this is the risk that the price the producer is able to achieve for selling hydrogen does not cover the cost of producing it, as it is unable to compete against counterfactual fuels, such as natural gas or diesel.
- **Volume risk –** this is the risk that a hydrogen production facility is unable to sell enough volumes of hydrogen to cover costs with reasonable confidence.

Market price support

A **variable premium model** is proposed by BEIS where a premium is paid as the difference between a 'strike price' and 'reference price' for each unit of hydrogen sold. BEIS proposes the reference price to be the higher of natural gas price and the achieved sales price as shown in Figure 11. At any one point, only one reference price would apply with the size of the subsidy expected to decrease over time as the market for low-carbon hydrogen evolves. Producers would not receive additional subsidy for sales below the natural gas price, to deliver value for money for government and to avoid distorting energy markets.

BEIS proposes the strike price to be indexed and it is likely to reflect the input costs of the producer (e.g. electricity and natural gas costs). BEIS are conducting further analysis of indexation of the strike price for different production technologies. The indicative Heads of Terms agreement suggests that for CCS enabled hydrogen production, the strike price will be indexed in certain proportions to the market price of natural gas and the consumer price index (CPI). For electrolytic hydrogen production, the full strike price is likely to be indexed to the CPI.

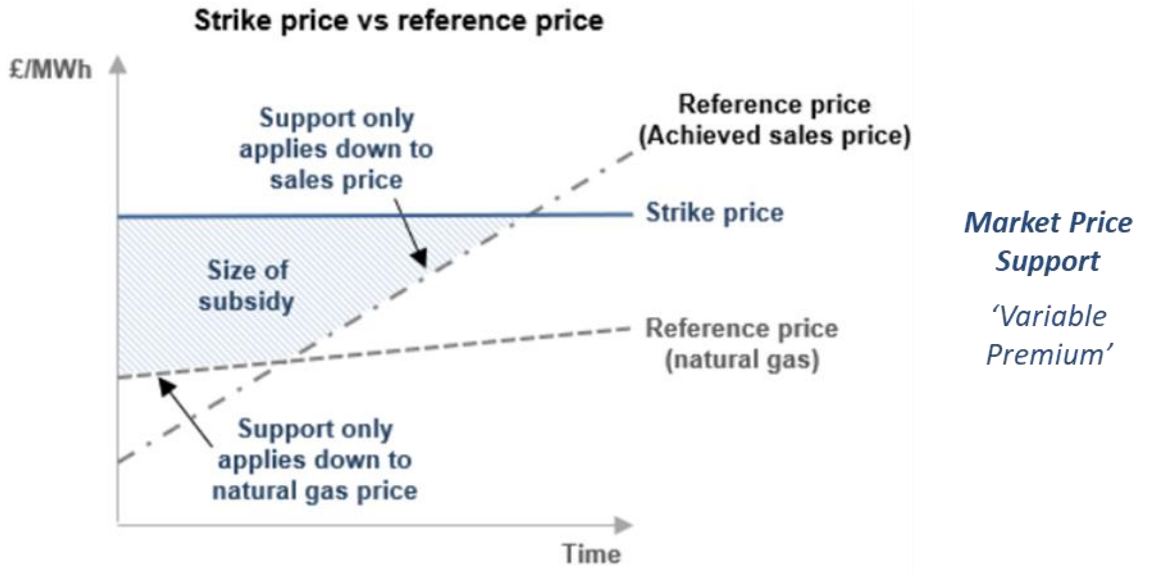

Figure 42: Variable premium model - low-carbon hydrogen market price support[77]

BEIS are considering the risk of overcompensation where hydrogen is used as a feedstock and the potential need to limit price support for feedstock applications. Existing users of carbon intensive hydrogen feedstock (e.g., ammonia production) already place a relatively high value on hydrogen and pay a higher price associated with using carbon intensive hydrogen. Hydrogen subsidised at the price of natural gas could allow an ammonia producer to cut the price of its products without diminishing its margins and gain a competitive advantage compared to other ammonia producers using unsubsidised hydrogen. BEIS intend to allow hydrogen producers to receive subsidy for sales to hydrogen feedstock users, however, propose further work on the potential measures to address the overcompensation of hydrogen feedstock. This is likely to be via an alternative reference price or the price discovery mechanism to incentivise sales at a higher price for feedstock users.

In the response to the Low-Carbon Hydrogen Business Model, BEIS also identify the potential for hydrogen utilisation in power generation[271]. BEIS need to be mindful that support for hydrogen in dispatchable power operation could result in perversely incentivising a higher cost solution when compared to natural gas fired power with post-combustion capture. BEIS have not yet stated how they plan to consider mitigating this risk, however, further consideration would be expected for proposed projects at the pre-FEED stage. Value for money to the taxpayer will be a primary consideration before any financial support is approved by the Treasury.

Volume support

All volume support options assessed by BEIS assume a variable premium being provided as the price support mechanism. Many volume support mechanisms are currently not considered by the low-carbon hydrogen business model. Measures that could reduce volume risk for hydrogen producers include the availability of hydrogen storage infrastructure, the ability to blend hydrogen into the existing gas grid, and a wide pool of end users ready and able to use hydrogen. These measures are unlikely to be available when investment decisions are made, however could be available once projects become operational.

A **Sliding scale** is proposed by BEIS for integration with the variable premium as the price support. This allows for higher level of price support on initial production volumes whilst the level of price support would taper off as production volumes increase as shown in Figure 43. The government does not purchase any hydrogen under this option and therefore does not guarantee volumes or a minimum economic return to the hydrogen producer. The producer earns higher unit prices where offtake volumes are low to help recover fixed and marginal costs, whilst support declines as the offtake volumes the producer secures increase. In the event offtake volumes fall to zero after the contract is in place, no support is provided to the producer. Offtake risk is therefore managed by the producer, not the government.

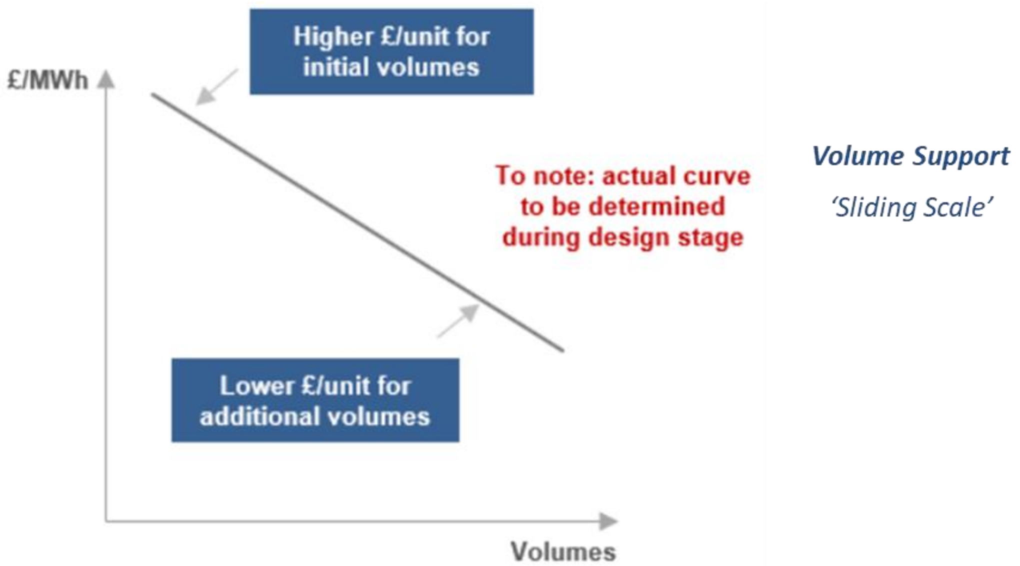

Figure 43: Sliding scale - low-carbon hydrogen volume support[77]

Hydrogen business model limitations

There are a number of policy gaps in the current business model that need to be addressed. Today, there is a lack of capital support for hydrogen fuel switching and funding for feasibility studies. **The business model currently supports the production of low-carbon hydrogen without considering the equipment upgrades**

[271] BEIS 2022, Government response to the consultation on a Low Carbon Hydrogen Business Model.

that will be required to utilise it in industry. The current model will only provide support for small scale hydrogen transport and storage as part of a projects overall production costs when bidding for a business model contract. Uptake of low-carbon hydrogen will require the development of transport infrastructure (such as pipelines) to connect low-carbon hydrogen producers with end users. Hydrogen storage may also be required to ensure supply matches demand requirements. Larger-scale hydrogen transport and storage infrastructure is highlighted by many stakeholders as essential for the growth of the hydrogen economy. In the recent Energy Security Strategy[272], the government has committed to designing a new business model to support the development of hydrogen transport and storage infrastructure by 2025. These barriers need to be addressed if industrial facilities are to consider switching to low-carbon hydrogen in the future.

7.3.3 Local policy

Local infrastructure development

There are some grant and funding schemes available to the industries and research and development, however it has been targeted to small and medium enterprises or restricted to specific geographical areas within the Humber.

Local authorities and LEPs are also active in:

- Local planning authorities are responsible for deciding whether project developments go ahead and delivering on local priorities.
- Investing in skills development and employment programmes, an example action being CATCH and the Humber Energy Skills Hub.
- Provision of loans to the private sector, such as for the Humber Freeport.
- Promoting and encouraging private sector investment, an example being the Green Port Growth Programme.
- Offering advisory services to regional businesses, such as via the HEY Growth Hub.

Local authorities, as the Local Planning Authorities, play a key role to support development of technologies such as hydrogen, CCS and their supporting infrastructure. Whilst no active regional policy examples were found, local authorities could in the future use green procurement policies to incentivise regional industries to produce low-carbon industrial products, or secure clean power purchase agreements from abated power sources via CCS. Local authorities are responsible for waste management, which can support the sourcing of biogenic waste material to be used in future industries or power plants in combination with CCS.

[272] BEIS 2022, British Energy Security Strategy.