DEEP-DECARBONISATION PATHWAYS FOR UK INDUSTRY

A report for the

Climate Change Committee

Element Energy

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1 Executive summary

1.1 Context and scope

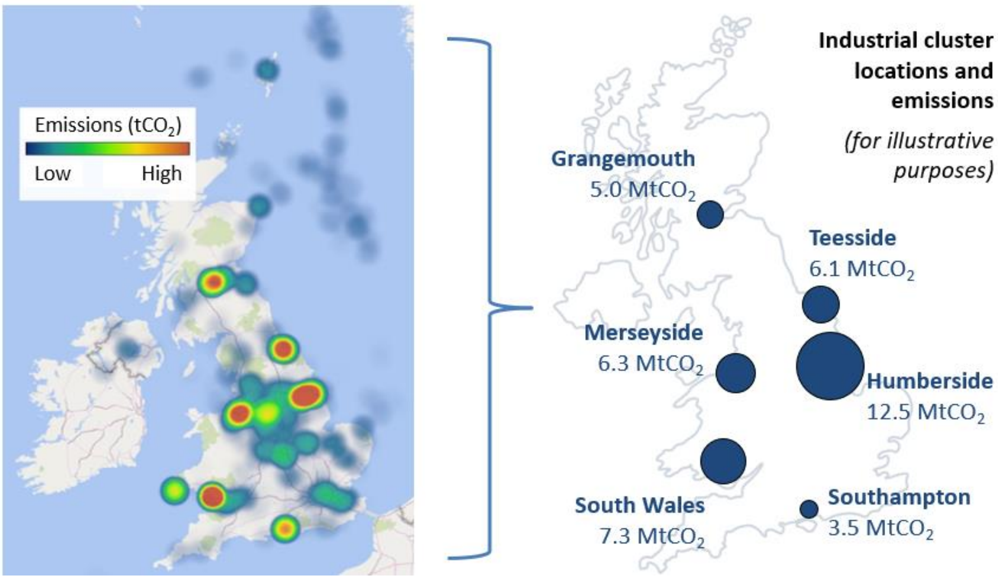
Pathways for deep decarbonisation of UK industry by 2050 and the transition to net zero

In May 2019, the Climate Change Committee (CCC) published 'Net Zero: The UK's contribution to stopping global warming'. The report set out the Committee's advice that the UK should commit to achieving net zero greenhouse gas emissions by 2050. The UK Government and Devolved Administrations subsequently legislated for net zero greenhouse gas targets. In 2020, the CCC began working on their sixth carbon budget advice to Government and sought to develop their understanding of pathways to 2050 for industrial decarbonisation, along with the necessary hydrogen and CO_2 transport and storage infrastructure.

Work previously carried out by Element Energy supported the CCC's analysis on reducing industrial emissions through options including carbon capture and storage (CCS), bioenergy with carbon capture and storage (BECCS), switching to low carbon fuels, and reducing fossil fuel production emissions and fugitive emissions. Although that was a robust analysis, areas were identified to build on, particularly around pathways to reach net zero through deep decarbonisation, the selection of competing decarbonisation technologies, and the potential constraints on the pace of decarbonisation. This study aims to address these points and assess viable pathways for deep emissions reductions in UK industry through the developed Net-Zero Industry Pathways (N-ZIP) model. Along with supporting the CCC's sixth carbon budget advice, this work is a critical input to informing the near-term decisions that are urgently needed from Government on policies for delivery, and on the funding required to support deep decarbonisation of industry.

Industrial emissions were 110.9 $MtCO_2e$ in 2018 and concentrated in clusters

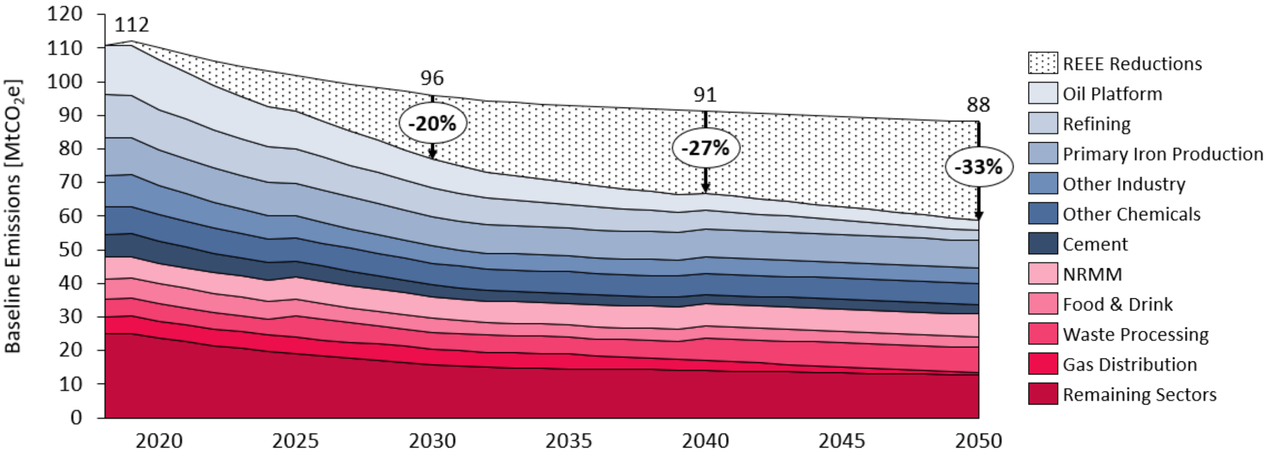
This study focuses on emissions of greenhouse gases (CO_2, CH_4, N_2O) from existing industrial sites that are categorised as '**scope 1**', i.e. occur on-site from the combustion of fossil fuels or directly from industrial processes. Specifically, emissions from industries in scope amounted to 110.9 $MtCO_2e$ in 2018. Large point source sites identified in the study were responsible for 66% of emissions within scope, with the remaining 34% arising from smaller sites. Many of the largest sites are concentrated in industrial clusters (see image below). This bears important implications for the geographical prioritisation of future decarbonisation efforts and for the corresponding infrastructure development plans.



Heat map of 2018 emissions from large sites correlates directly to the corresponding locations of the UK's six major industrial clusters (emission values derived from the NAEI database – 50km radius)

Disaggregation and projections of industrial emissions with key abatement technologies

The industries in scope were categorised into **28 sectors, each with defined process archetypes**. The figure below highlights the total baseline emissions projected to 2050, broken down by the ten highest-emitting sectors (as of 2020) with the remaining sectors aggregated. The dotted portion of the curve reflects reductions in emissions through resource efficiency, energy efficiency and actions in other sectors (REEE)[1], determined by analysis undertaken outside the scope of this study. Before REEE reductions, emissions are projected to decrease, largely as a result of reduced fossil fuel production. With REEE measures implemented and without any deep decarbonisation abatement applied, industrial emissions would remain at 58.8 $MtCO_2e$ in 2050.



Baseline and post-REEE emissions projections to 2050 (Balanced scenario)

The breadth of existing equipment and processes used in industry means that any solution for decarbonising industry requires a similarly broad and bespoke range of technologies. This study has incorporated a range of key technologies, with a summary shown in the table below. Technologies were assessed on their capital and operating costs, along with cost reductions over time due to technology learning, and a number of key constraints impacting their deployment (e.g. technology readiness level, policy support, hydrogen and CO_2 transport and storage availability, supply chain capacity).

Summary of the deep decarbonisation technology options included in this study

Type of Option		Key Technology Types	Key Sectors
	Electrification	Electric Boilers, Kilns, Furnaces, Ovens, Dryers, and Compressors Electric Arc Furnaces (for Iron and Steel)	All Sectors
	Hydrogen (Green and Blue)	Hydrogen Boilers, Combined Heat & Power, Kilns, Ovens, Furnaces, Dryers, and Compressors Hydrogen Direct Reduction (for Iron and Steel)	All Sectors
	CCS	Carbon Capture on: Internal Fuel Combustion, Large Equipment/Sources, Process Emissions	Refining, Chemicals, Cement, Iron and Steel
	BECCS	Carbon Capture on Existing Biogenic Emissions Fuel Switching to Biomass Combined with CCS	Waste Processing, Cement, Lime, Glass, Paper
	Methane Management	Leak Detection and Repair, Continuous Monitoring, Flaring Reduction	Fossil Fuel Production and Fugitive Emissions (FFPFE), Iron and Steel

[1] Approximately 10 $MtCO_2e$ of REEE abatement was a result of reduced economy-wide demand for petroleum products, with approximately 6 $MtCO_2e$ of REEE abatement from reductions in Waste Incineration.

1.2 Deep-decarbonisation scenarios and results

Five scenarios were investigated, all of which result in deep industrial decarbonisation

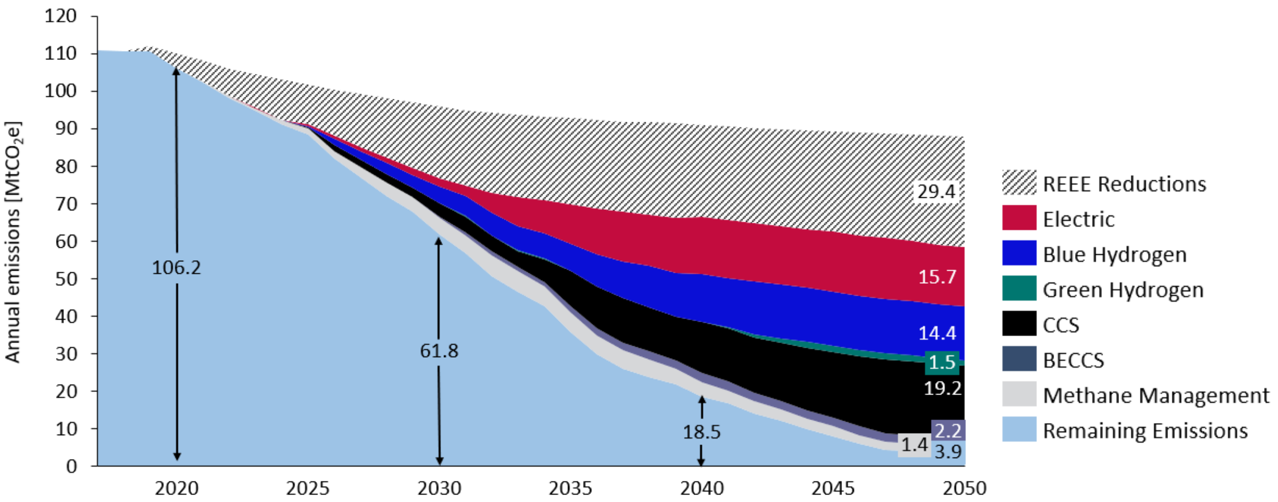
As part of the CCC's economy-wide sixth carbon budget analysis, five scenarios were defined, with each representing a credible future scenario for economy-wide net zero emissions by 2050:

- Widespread **Engagement** (high efficiency and electrification): People are willing to make more changes to their behaviour. This reduces the demand for the most high-carbon activities and increases the uptake of some climate mitigation measures.
- **Headwinds** (high hydrogen): People change their behaviour and new technologies develop, but there are no widespread behavioural shifts or innovations that significantly reduce the cost of green technologies ahead of current projections. This scenario is more reliant on the use of large-scale hydrogen and CCS infrastructure.
- Widespread **Innovation**: This scenario sees high innovation in several carbon mitigation technologies and measures. Costs fall faster than central projections, allowing more widespread electrification and more cost-effective technologies to remove CO_2 from the atmosphere. Resource and energy efficiency measures play a balanced role across the economy.
- **Tailwinds:** A scenario with a combination of accelerated deep decarbonisation drivers from each of the 3 broad scenarios defined above.
- **Balanced** Net Zero Pathway: An 'options-open' pathway that undertakes low-regret measures and develops options sufficiently to progress towards net zero whatever state of the world occurs. The pathway includes a balanced mix of technologies in the long term, which enables decision-making to change track depending on developments in the short-to-medium term.

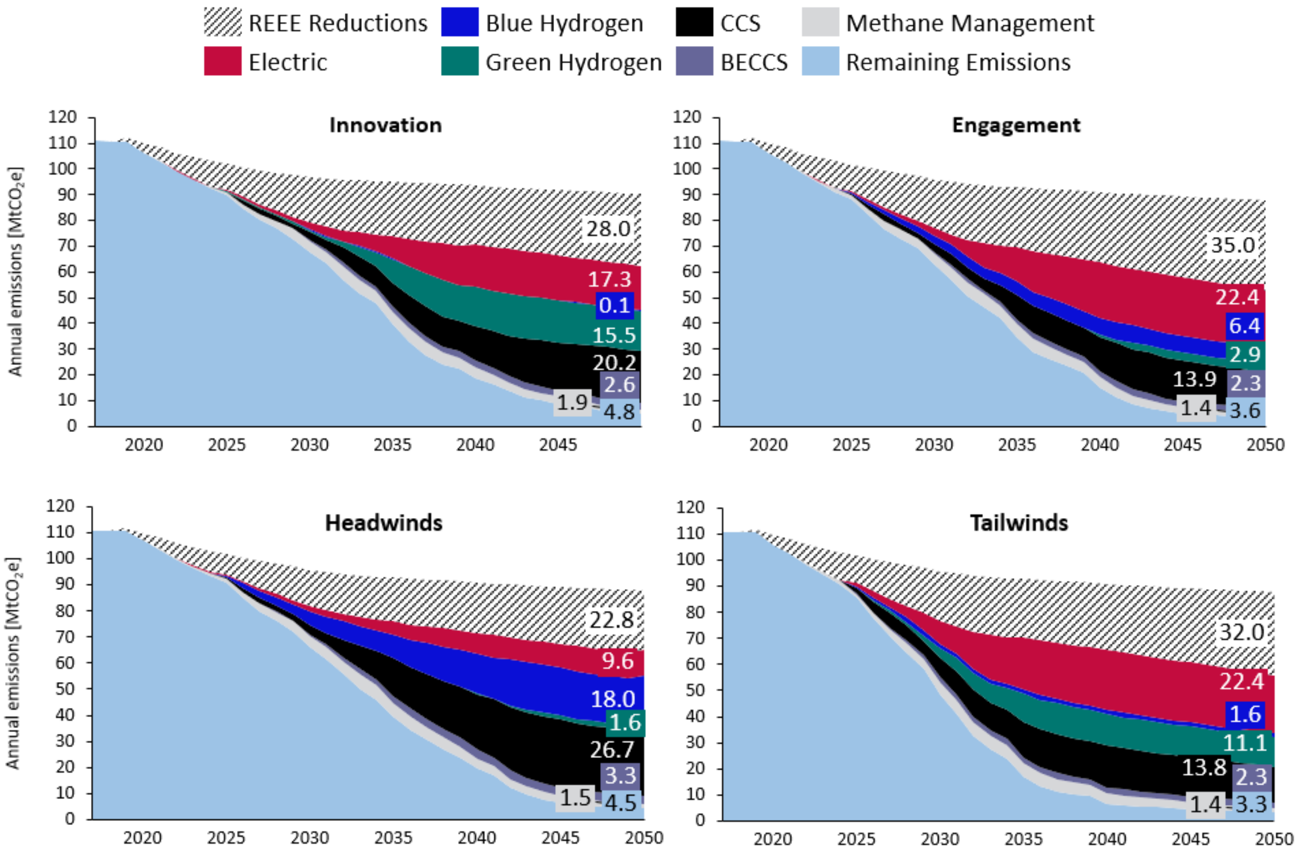
Fuel costs used in all scenarios are based on long run variable costs (LRVCs), rather than the retail price paid by industrial sites. The LRVCs exclude supplier costs, supplier profits and additional costs from lower carbon policies (e.g. carbon price, climate change levy, etc.), and are used to assess the system cost of pathways in a technology-neutral manner. The LRVCs used in this analysis are consistent with the CCC's sixth carbon budget work in other economy sectors.

Emissions can be reduced by over 95% by 2050 with remaining emissions offset by BECCS

Industrial emissions across the UK are reduced to similar levels in all deep decarbonisation scenarios, resulting in remaining emissions between 3.3 $MtCO_2e$ and 4.8 $MtCO_2e$ in 2050. This represents a reduction of 95% or greater from the 106.2 $MtCO_2e$ of industrial emissions in 2020. The similar decarbonisation potential of all scenarios results from a target-driven carbon value trajectory which ensures the majority of decarbonisation options have costs below the carbon value by the late 2040s.



Emissions abatement pathway for the Balanced scenario



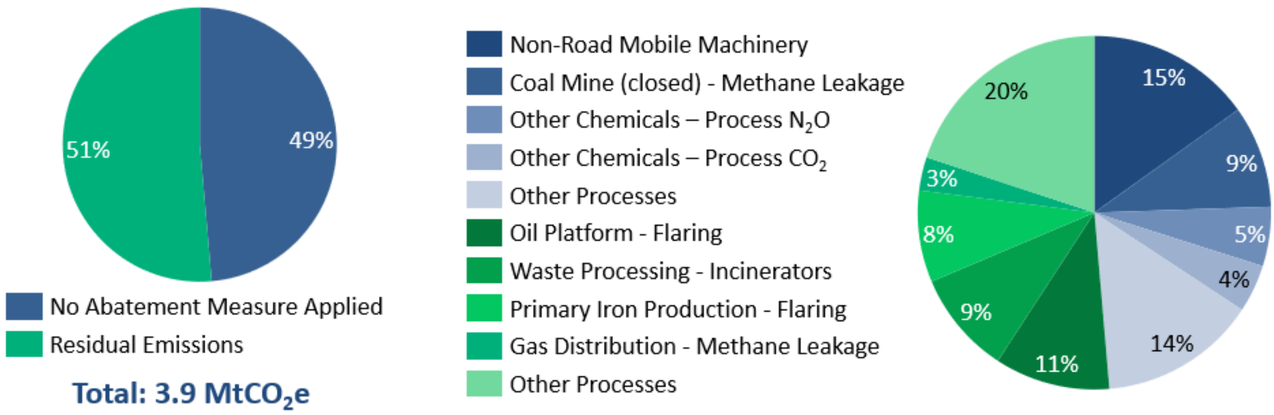
Emissions abatement pathway for the other four CCC scenarios

The different contributions of efficiency, fuel switching and CCS in each scenario's decarbonisation pathway by 2050 are evident from the charts above. A number of attributes apply across all abatement pathways:

- **CCS has a relatively consistent baseline of emissions reductions across the scenarios**, remaining a key technology for industrial decarbonisation; no scenario has less than 13 $MtCO_2e$ of emissions reductions from CCS. This is because CCS technologies are likely the only option for decarbonising process emissions of CO_2, internal fuel use, and waste incineration. Additionally, CCS is key for the production of a large amount of blue hydrogen in many scenarios.
- **BECCS is viewed as favourable for sites due to the potential for negative emissions** by capturing biomass combustion emissions. BECCS is generally chosen as the first choice of technologies where it is deemed a suitable technology and if there is sufficient biomass resource. In addition, where biomass is currently used as a combustion fuel (not included in these emissions plots due to biogenic emissions), CCS is applied to these processes, providing additional negative emissions.
- **There is a role for both electrification and hydrogen in all scenarios, though the relative scale of each varies**. In some processes, one or the other is heavily favoured (approx. 9-10 $MtCO_2e$ of emissions reductions each), while for other processes, electrification and hydrogen are reasonably competitive with each other, with the technologies chosen varying by scenario (another approx. 10-12 $MtCO_2e$). CCS also competes on a minor level for some of these emissions, however its use in this sense is largely limited to the larger sites.
- **Blue and green hydrogen remain closely matched** – there is no clear winner between blue and green hydrogen across the different scenarios, with each dominating the hydrogen demand in two of the five scenarios. When a site decarbonises with hydrogen, it chooses either blue or green hydrogen based on lowest cost, sticking with that hydrogen supply up to 2050. In reality, supply arrangements are likely to be more flexible, with sites likely reticent to remain tied into long term contracts, meaning the blue vs. green hydrogen supply might change more in the later years of these scenarios.

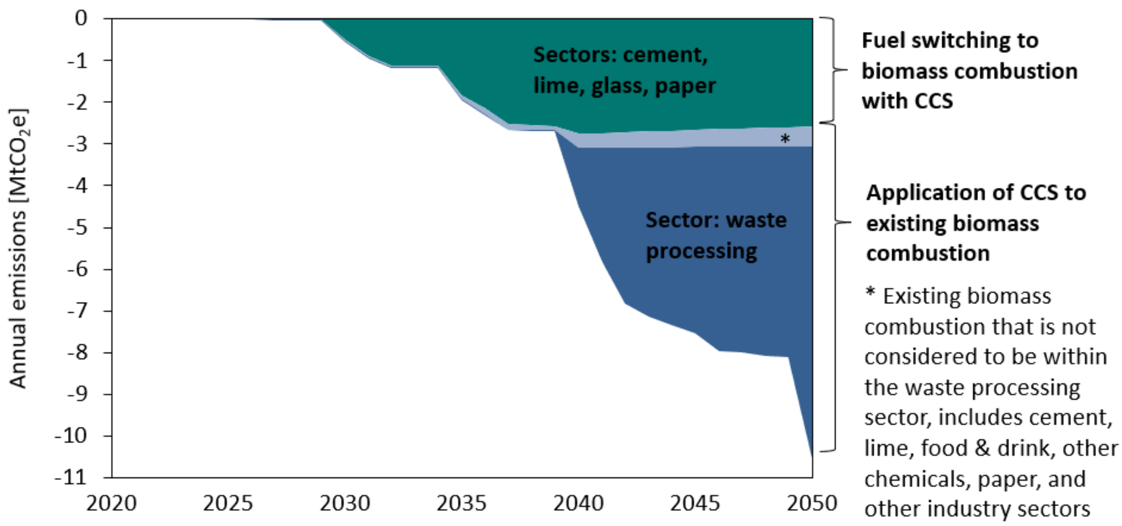
Remaining emissions are balanced out by negative emissions from BECCS

In all scenarios, there are two types of remaining emissions in 2050. The first is attributed to **processes with no abatement applied.** These are processes on sites which have not had any abatement applied to them, either because the abatement is too expensive to achieve a positive net present value (NPV), or because there were no options identified to overcome these. The second are **residual emissions** which remain after abatement technologies without an 100% abatement rate are applied. These are generally emissions remaining from <100% capture rate of CCS technologies, or technologies to abate flaring or other fugitive emissions.



Remaining emission sources in 2050 (Balanced scenario)

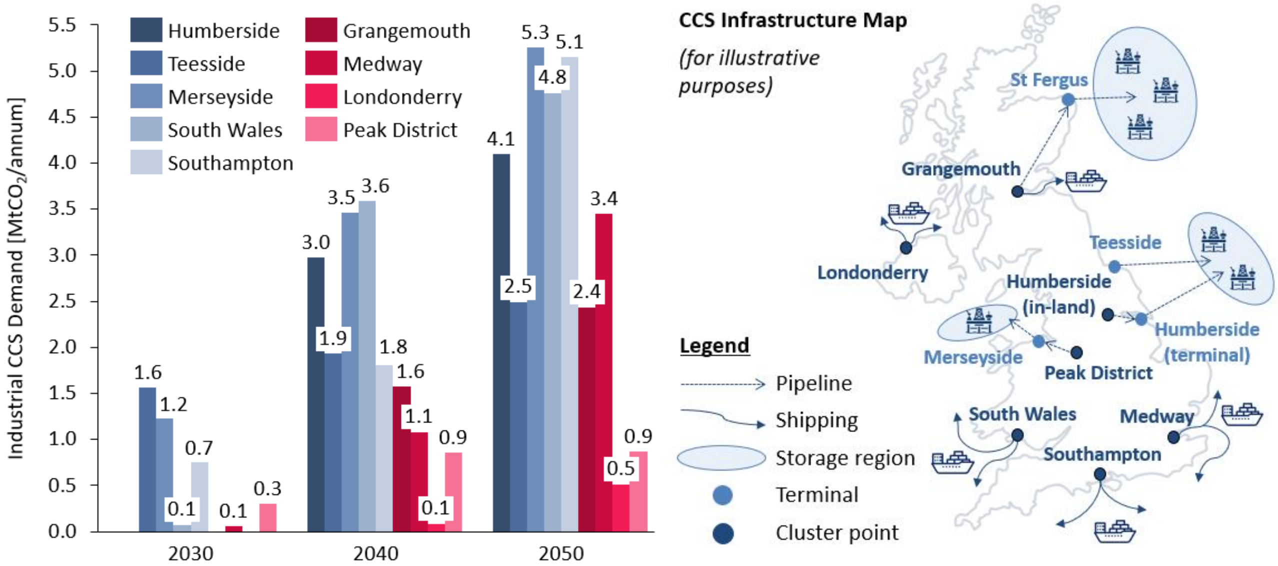
Industry generates approximately −10 $MtCO_2e$/year of negative emissions by 2050. Initially this uptake is mostly composed of the negative emissions from fuel switching to biomass combined with carbon capture, primarily in the cement sector. In the later time periods, CCS is applied to the emissions from existing biogenic combustion, which is dominated by the waste processing sector. This is where emissions from the waste processing sector are captured from the incineration of mixed biogenic and non-biogenic waste, resulting in negative emissions from the capture from the biogenic part of the fuel. These negative emissions provide an opportunity for some of these sectors which have unabated emissions or residual emissions from <100% CCS capture rate to reach net zero and beyond. It is also worth noting that the negative emissions from industry as defined in this study become greater than the remaining emissions by the mid to late 2040s, meaning industry becomes a net negative sector by 2050.



Negative emissions potential from BECCS in industry (Balanced scenario)

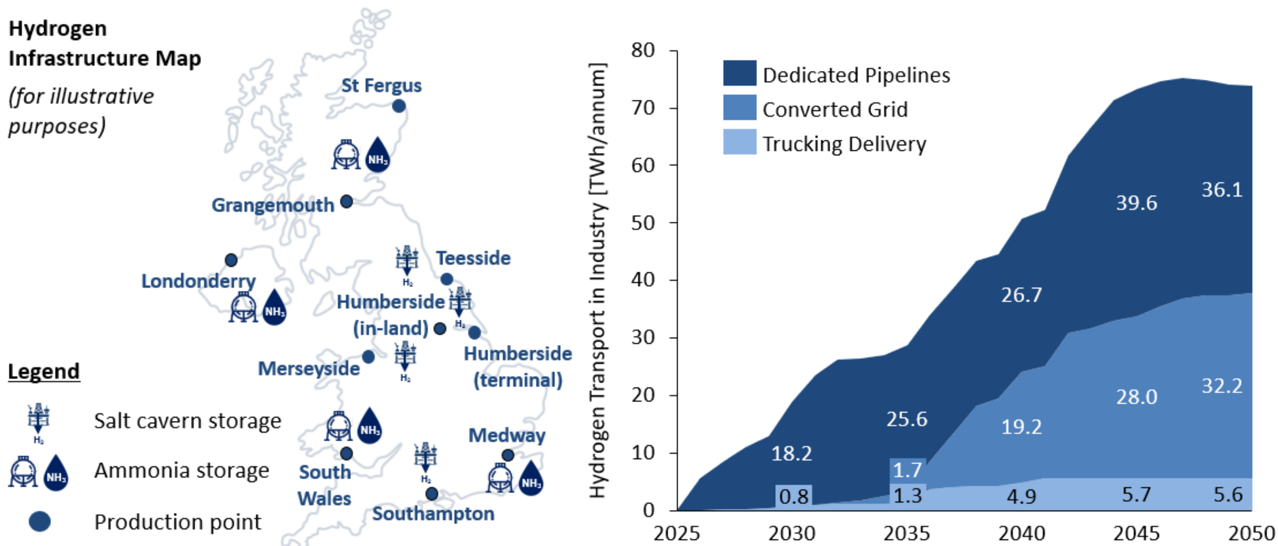
Detailed analyses of H_2 and CO_2 transport and storage infrastructure underpin all scenarios

Costs and geographical constraints play a key role in determining which methods of hydrogen and CO_2 transportation and storage (T&S) are most likely to become widespread across regions and within industrial clusters in the UK. The N-ZIP model work has incorporated costs and constraints for onshore and offshore CO_2 T&S in the North Sea and Irish Sea. The figure below highlights the trajectory in the next three decades for CO_2 T&S demand from industrial carbon capture sources. By 2050, total economy-wide CO_2 T&S demand, including power, greenhouse gas removal and blue hydrogen production, is concentrated across all six major UK clusters and three additional defined T&S points.



CO_2 T&S uptake from industry at defined points (Balanced scenario)

Similarly, the N-ZIP model work assesses the costs and constraints for UK-wide deployment of hydrogen T&S infrastructure. **Development of hydrogen transport infrastructure is of particular importance for industrial sites aiming to secure a reliable method of hydrogen supply**. This study has assessed the potential for three primary modes of transport, with trajectories over time shown in the figure below. Early hydrogen uptake is supplied by dedicated pipelines, suggesting initial hydrogen pipeline build out around clusters to industrial sites is a cost-effective option prior to grid availability**.** Once gas grid conversion can be implemented at a site then this option generally takes over as the cheapest supply route. This grid conversion occurs if and once other sectors such as domestic and power become ready for hydrogen conversion.



Hydrogen supply to industry by transport method (Balanced scenario)

1.3 Conclusions and policy recommendations

The emission trajectories presented above and additional outputs from this study provide a number of key conclusions:

- **Deep decarbonisation by 2050 is possible and economically favoured** – given the assumed carbon value trajectory (£121/tCO_2 in 2030, rising to £346/tCO_2 in 2050), industrial decarbonisation is highly favoured and industry achieves net zero by 2050, with ~3-5 MtCO_2e of residual emissions in 2050 balanced out by the negative emissions from BECCS.
- **All decarbonisation technologies considered are likely to be important** – the most irreplaceable technology is likely to be CCUS, given its crucial role in abating process emissions. The scale of hydrogen fuel switching or electrification varies between the scenarios; each of them has processes and scenarios where they are the most favoured.
- **All scenarios favour a rapid decarbonisation as the ideal pathway**– this involves implementing the large majority of decarbonisation by 2045 and swift action by the early 2030s on all of the major industrial clusters, including the acceleration of infrastructure deployment.
- **Industrial decarbonisation remains relatively low cost** – given the large incentives modelled by the carbon value, industrial decarbonisation remains highly favourable, despite some increases in costs from previous estimates to account for any potential bias towards optimistic low costs.
- **Supply chain and skills availability is a key constraint for decarbonisation** – this, rather than cost, constrains the speed of decarbonisation in some sectors, so swift action over the coming years is needed to ensure this constraint is mitigated to the levels modelled here or further.
- **Infrastructure availability could constrain decarbonisation** – infrastructure and industrial sites were highly interdependent within this project, and this interdependence could be a barrier to project developers. This could be mitigated by clarity on business models across all elements of the value chains.
- **Progress on technology availability would constrain early adopters** – with the modelled carbon value, technology availability does constrain implementation. Hence it is valuable to accelerate technology development and commercialisation.
- **There remains significant uncertainty, both around suitability and costs of technologies** – however much of this should be mitigated over the coming years through early technology demonstrators and detailed subsector assessments of decarbonisation.

Policy intervention is required to stimulate investment in deep decarbonisation

The introduction of new industrial decarbonisation policies is widely expected to have a pivotal role in enabling deep decarbonisation. The interviewed and roundtable stakeholders representing UK industrial sectors and clusters believed **policy support** to be **essential for establishing early business cases for deep decarbonisation investments while simultaneously mitigating the risk of carbon leakage**. To further mitigate against the risks of slower technology development timelines, lack of infrastructure availability and lock-in of existing fossil-fuel appliances, the following policy-driven actions can be taken:

- **Support the development of pilot projects** within each sector (if required) to robustly test the technical and economic potential of abatement technologies, develop assurance in novel technologies for industry investors, and keep options open for different technology options.
- **Detailed follow-on studies at the sector level** to provide a comprehensive set of measures required for the sector to reach net zero. This could focus on deep decarbonisation options for a few representative sites to gain a holistic understanding of the interventions required. Extensive knowledge sharing should be encouraged to enable parameter updates in models such as N-ZIP.
- **International collaboration** should be pursued so that that work is not duplicated and that public sector funds are spent efficiently and with maximum impact.
- **Finance comprehensive feasibility studies** to support early implementation of technologies already available which could start decarbonising immediately (predominately in the context of process

electrification). It is recommended that a specific focus on deep decarbonisation (ideally net zero) be required, as well as extensive knowledge sharing of project findings.

- **Ensure that the required infrastructure is developed well ahead of time**, so that fuel switching and CCUS can be implemented without delay when the business case is established. Government should aim to accelerate their implementation of the regulated asset base business model for a cluster-based CO_2 T&S network. Similarly for hydrogen infrastructure, policy and funding designs should be tailored towards cost-effective infrastructure projects which, where possible, lead to repurposing or re-using parts of the existing natural gas infrastructure, helping to reduce costs and avoid stranded pipeline assets.
- **Introduce a financial support mechanism for a broad range of low carbon technologies**. One option could be to adapt the government's proposed approach for Contract-for-Difference financing for industrial emitters (to be implemented for CCUS projects) to evolve over time for other technology options (fuel switching, process changes, etc.).
- If technology lock-in cannot be mitigated across all industrial sites, **early decommissioning (i.e. scrappage) of fossil-fuelled appliances** may need to be promoted or mandated on processes which are unable to be retrofitted.

Despite the advantages these policy designs offer, the risk of carbon leakage is likely to persist. To mitigate against this risk, Government may need to consider policy designs beyond those that support technology and infrastructure deployment. A prominent policy lever proposed to address the concerns around carbon leakage is a **Border Tariff Adjustment** (BTA), which can be designed to issue import fees on goods produced in countries with lower carbon pricing policies and remit carbon taxes on exports intended for the same countries. It should be recognised that BTAs are a complex policy to design and implement, with further concerns still to be addressed on their effectiveness in mitigating carbon leakage. In particular, BTAs would need to be accordant with World Trade Organisation rules and free trade arrangements between governments.

The focussed technical results from this study should be evaluated alongside broader considerations on the social, economic and environmental impacts of pathways. It is stressed that other factors will need to be considered for a complete evaluation of possible pathways for the deep decarbonisation of UK industries. This study touched on some of these factors but ignored many others, such as wider environmental impacts outside of greenhouse gases, job creation and social equity. Thus, the final recommendation is that the results from this study should be complemented by a broader, more holistic assessment of the possible decarbonisation pathways.

Authors

This report has been prepared by Element Energy.

Element Energy is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. The team of over 70 specialists provides consultancy services across a wide range of sectors, including the built environment, carbon capture and storage, industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon transport. Element Energy provides insights on both technical and strategic issues, believing that the technical and engineering understanding of the real-world challenges support the strategic work.

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Acronyms

ATR	Autothermal Reforming
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy and Industrial Strategy
BTA	Border Tariff Adjustment
Capex	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCC	Climate Change Committee
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Utilisation, and Storage
CfD	Contract-for-Difference
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalents
DRI	Direct Reduction of Iron
DUKES	Digest of UK Energy Statistics
EAF	Electric Arc Furnace
EEP	Energy and Emissions Projections
EPC	Engineering, Procurement and Construction
EU ETS	European Union Emissions Trading System
ETS	Emissions Trading System
FEED	Front-End Engineering Design
FFPFE	Fossil Fuel Production and Fugitive Emissions
FOAK	First of a Kind
GHG	Greenhouse Gas
GOR	Government Office Region
H_2	Hydrogen
LDAR	Leak Detection and Repair
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LRVC	Long Run Variable Cost
MPa	Mega pascals
Mt	Mega tonne
N_2O	Nitrous Oxide
NAEI	National Atmospheric Emissions Inventory
NOAK	N^{th} of a Kind
NPV	Net Present Value
NRMM	Non-Road Mobile Machinery
N-ZIP	Net-Zero Industry Pathways
Opex	Operational Expenditure
ONS	Office for National Statistics
REEE	Resource Efficiency and Energy Efficiency
SIC	Standard Industrial Classification
SMR	Steam Methane Reforming
SOAK	Second of a Kind
SSF	Solid Smokeless Fuel
T&S	Transport and Storage
TRL	Technology Readiness Level
UKPN	UK Power Networks

Note on terminology

Blue hydrogen refers to hydrogen produced from a feedstock of natural gas by steam methane reforming (SMR) or autothermal reforming (ATR) coupled with carbon capture, utilisation and storage (CCUS) of the resulting carbon dioxide emissions. Green hydrogen refers to hydrogen produced through water electrolysis using renewable electricity. Low-carbon hydrogen refers to both blue and green hydrogen.

Whilst Carbon Capture, Utilisation, and Storage (CCUS), Carbon Capture and Storage (CCS), and Carbon Capture and Utilisation (CCU) are often used interchangeably in the literature, for consistency purposes, this report primarily uses CCS, with exceptions for when CCUS or CCU is used directly in the cited sources or tailored to a specific region. In this study's modelling work, all captured CO_2 was assumed to be stored offshore.

Contents

2 Introduction

2.1 Background

In May 2019 the Climate Change Committee (CCC) published 'Net Zero: The UK's contribution to stopping global warming'. The report set out the Committee's advice that the UK should commit to achieving net zero greenhouse gas emissions by 2050. The Government and Devolved Administrations subsequently legislated for net zero greenhouse gas targets. Element Energy supported the CCC's analysis on reducing industrial emissions through a range of options including CCS, BECCS, fuel switching as well as reducing fossil fuel production emissions and fugitive emissions. Although that was a robust analysis using information available at the time, a number of areas were identified to build on, particularly around pathways to net zero, the selection of competing decarbonisation technologies, and the potential constraints on the pace of decarbonisation.

In 2020, the CCC began working on the sixth carbon budget advice to Government and sought to develop their understanding of pathways to 2050 for industrial decarbonisation, along with the necessary hydrogen and CO_2 infrastructure. Moreover, a number of key Government publications are expected this year including the Treasury's review of how the costs of the transition to a net zero society can be funded, and the spending review and fiscal budget. The CCC's advice will be published in December 2020, as required by the Climate Change Act, and preceding the key international climate change conference (COP26) due to take place in Glasgow in 2021.

2.2 Scope

This work is a critical input to informing the near-term decisions that are urgently needed from Government on policies for delivery, and on the funding required to support them. The overarching objective of this project is to inform the CCC's sixth carbon budget advice to Government, relating to industrial decarbonisation and infrastructure for hydrogen transmission and distribution, and for CO_2 transport and storage. This is to be done by (i) identifying a set of plausible pathways for decarbonisation that are credibly deliverable and that prepare sufficiently to complete decarbonisation by 2050, and (ii) creating an 'options-open' pathway that undertakes low-regret measures and develops options sufficiently to progress towards net zero.

The scope of this project, and the Net-Zero Industry Pathways (N-ZIP) model developed, included:

- Developing a bottom-up spatial UK industry database of GHG emissions[2] and fuels use mapped onto the emissions inventory, including baseline projections
- Identifying and quantifying all key constraints for technology and infrastructure deployment
- Developing a technology database and a cost model calculating costs of all relevant decarbonisation technologies considering a wide range of infrastructure options (e.g. hydrogen and CO_2 transport and storage (T&S) networks)
- Incorporating all emissions, constraints, technologies and costs into a framework to simulate the decision-making process for industrial organisations' investment and decarbonisation decisions utilising 'Net Present Value' (NPV) as a metric
- Developing a fully transparent, unlocked, user-friendly model that will be used by the CCC and BEIS for scenario planning
- Assess a wide range of sensitivities and developing key pathways using the N-ZIP model
- Identifying key actions and policy measures for Government informed by the key pathways

The final pathways considered were based on the CCC's definition of 5 scenarios, which are characterised broadly as follows:

[2] The scope of this database covered CO_2, CH_4 and N_2O emissions, but excluded F-gas emissions.

- Widespread **Engagement** (high efficiency and electrification): People are willing to make more changes to their behaviour. This reduces the demand for the most high-carbon activities and increases the uptake of some climate mitigation measures.
- **Headwinds** (high hydrogen): People change their behaviour and new technologies develop, but there are no widespread behavioural shifts or innovations that significantly reduce the cost of green technologies ahead of current projections. This scenario is more reliant on the use of large-scale hydrogen and CCS infrastructure.
- Widespread **Innovation**: This scenario sees high innovation in several carbon mitigation technologies and measures. Costs fall faster than central projections, allowing more widespread electrification and more cost-effective technologies to remove CO_2 from the atmosphere. Resource and energy efficiency measures play a balanced role across the economy.
- **Tailwinds**: A scenario with a combination of accelerated deep decarbonisation drivers from each of the 3 broad scenarios defined above.
- **Balanced** Net Zero Pathway: An 'options-open' pathway that undertakes low-regret measures and develops options sufficiently to progress towards net zero whatever state of the world occurs. The pathway includes a balanced mix of technologies in the long term, which enables decision-making to change track depending on developments in the short-to-medium term.

2.3 Report structure

The remainder of this report is structured into seven additional chapters as follows:

Chapter 3 presents the overarching methodology that was developed for the N-ZIP model, incorporating site decision-making criteria and the NPV calculation.

Chapter 4 presents the methodological approach used to disaggregate the UK's industrial emissions, leading to baseline emissions projections for defined sectors and processes.

Chapter 5 informs the reader on the challenges and opportunities for infrastructure availability (primarily hydrogen and CO_2 transport and storage, but also including electrification) and how these have translated into constraints within the N-ZIP model.

Chapter 6 provides an overview and comparison of the deep decarbonisation technologies considered in this study, along with their timescales for commercialisation and availability, fuel supply constraints (primarily biomass), and supply chain constraints.

Chapter 7 defines the unique differences that exist between the CCC's five scenarios and provides the full set of results from the decarbonisation scenarios and sensitivities on the Balanced scenario.

Chapter 8 provides a closer look at the results by displaying greater detail on emissions projections and technology deployment for key industrial sectors.

Chapter 9 concludes by summarising key findings from the study, including key policy recommendations that have been informed by the results.

3 Modelling Methodology

3.1 Overview

Within the Net Zero Industry Pathways (N-ZIP) model there are 6 main stages, as illustrated in Figure 1 below.

- **Industrial Emissions and Fuel Use Projections** – emissions and fuel use projections are collated for a baseline case and a case including resource and energy efficiency, disaggregated to the level of industrial sites and processes. More information on methodology and results is available in section 4.
- **Infrastructure requirements and cost** – The cost of shared hydrogen and CO_2 infrastructure is calculated, calculating the cost of hydrogen an CO_2 transport and storage experienced by industrial sites in different regions. More information on methodology and assumptions is available in section 5.
- **NPV calculation for decarbonisation options** – for each process at an industrial site, the net present value (NPV) is calculated for each decarbonisation option in each possible year. More information on assumptions behind this are available in section 3.2.
- **Site Decision Making Criteria** – sites decide on their prioritisation of technology and timing for decarbonisation on the basis of NPV combined with constraints, such as technology availability (see section 3.3).
- **Constraints application –** The technology options are selected for decarbonisation through assessing the impact of constraints such as availability of CO_2 transport and storage capacity, UK wide biomass availability, technology readiness and capacity of the supply chain (see sections 3.4 and 5).
- **Infrastructure sizing** – The infrastructure requirements for the calculated pathway are output, and another decarbonisation pathway calculated using this infrastructure sizing as an input. If the infrastructure requirements output are consistent with those used as the input for the pathway calculation, the pathway is used as the final output. The full set of details outlining infrastructure cost calculations can be found in the model's Assumptions Log.

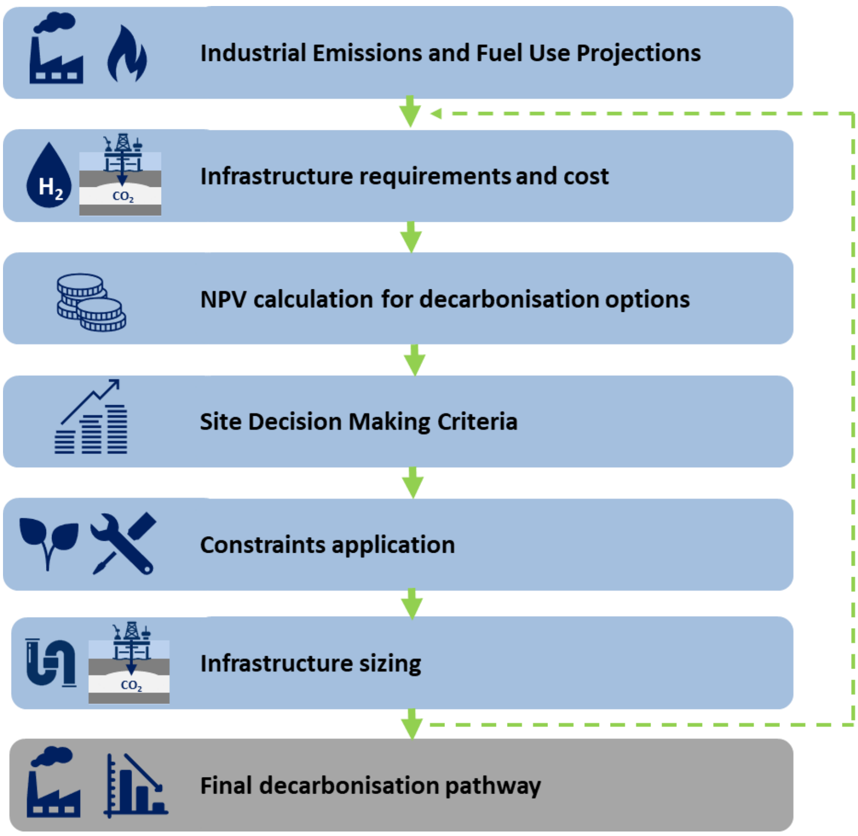


Figure 1 Schematic of N-ZIP model

3.2 NPV Calculation

One key part of the model is the framework to decide which decarbonisation technologies could be appropriate to install in a given year, for a given process at a site. Within this model, the metric used to assess the value of decarbonisation technologies is their Net Present Value (NPV). This refers to difference between the cost of the decarbonisation technology and the cost of the counterfactual, taking into account the discount rate and the value of avoided and abated carbon emissions.

$$Net\ Present\ Value\ (NPV) = \sum \begin{matrix} Value\ of\ Avoided\ / \\ Abated\ Carbon \end{matrix} - \sum \begin{matrix} Cost\ of \\ Decarbonisation\ Option \end{matrix} + \sum \begin{matrix} Cost\ of \\ Counterfactual \end{matrix}$$

The model takes each site and calculates the NPVs of the decarbonisation options (combinations of decarbonisation technologies and years of installation) for each process on a site. This considers:

- **Suitability of technologies** for decarbonising each process (more information in section 6).
- **The value of carbon and other drivers for decarbonisation**, which are represented through the inclusion of a **carbon value projection** to represent the value of abated emissions in each year.
- **Capital costs (Capex)**, including the cost of capital and scrappage costs where relevant.
- **Fuel costs** for the decarbonisation option compared to the counterfactual
- **Other operational costs (Opex)**, for example some components of the CO_2 transportation and storage are represented as a fee here.

Further information on the NPV calculations is available in the technical Assumptions Log.

3.3 Site Decision Making Criteria

Once the NPVs of all decarbonisation options (combinations of decarbonisation technologies and years of installation) have been calculated, the site needs to decide which options are possible, and then which options should be prioritised. Initially some options are eliminated, for example if the decarbonisation technology is not available in that year or if the site might close due to resource efficiency too soon after the decarbonisation option would be implemented.[3]

The remaining decarbonisation options are then ranked to produce a ranked list. This is done on the basis of maximum NPV, with the constraint that the 2nd ranked option cannot have an earlier implementation year than the 1st ranked option, the 3rd ranked option cannot have an earlier implementation year than the 2nd ranked option, etc.. This constraint is put in place for the constraint application, described in the subsequent section. The output of this is a ranked list of decarbonisation options for each process on each site.

3.4 Constraint Application

Using the ranked list of decarbonisation options as the basis, the decarbonisation options are selected for the outputted pathway through application of constraints. Each site initially chooses its top ranked option, which produces a draft pathway. This pathway is assessed against a range of constraints including constraints on supply chains (the percentage of sites in a sector which can decarbonise in a given year), CO_2 T&S infrastructure availability and capacity, H_2 availability and production capacity and UK wide biomass use.

These constraints are assessed year by year from 2020 to 2050. When constraints are exceeded, the pathway is updated by changing the choice of those sites which break the constraints to choose their next ranked technology option. The prioritisation of sites within the limits of constraints is done on the basis of the NPV of the decarbonisation option divided by the amount of the constraint which the decarbonisation option takes up.

This produces the outputted pathway, which is taken into the infrastructure sizing portion of the model (and then the final pathway).

[3] In addition, the model accounts for some degree of non-rational actors. For instance, small sites below a certain size (<1ktCO_2e/annum) are restricted to new installations at the end of life of existing equipment. Further discussion on the model's capacity for accounting for non-rational actors can be found in the Assumptions Log.

4 Disaggregation and Projection of Industrial Emissions

4.1 Overview

The following section covers the approach for disaggregating and projecting the UK's industrial GHG emissions within the N-ZIP model, including an overview of baseline industrial fuel consumption and counterfactual technologies. This resulted in the development of:

- A database of industrial sites including processes, counterfactual technologies, energy use and emissions.
- Geographical outputs from the database, showing a geographical disaggregation of fuel consumption by sectors and sites, focusing on the composition of key industrial clusters.
- A baseline projection for energy use and emissions in the spatial database, applying CCC projections of energy, emissions, and abatement through energy/resource efficiency.

Further information on modelling assumptions is available in the technical Assumptions Log and the N-ZIP model.

4.2 Disaggregation of UK Industry

4.2.1 Data sources and disaggregation approach

This assessment of GHG emissions[4] in the N-ZIP model was based on a mixture of publicly available data, including the National Atmospheric Emissions Inventory (NAEI), Office for National Statistics (ONS)[5] and other data Element Energy has access to from previous work, including detailed emissions and fuel use data from industrial trade associations. The analysis built upon Element Energy's existing bottom-up stock models of industrial processes and gas consuming appliances in the UK.[6] This process also involved mapping site/location-specific emissions data from the NAEI point source emissions database[7] onto the NAEI categories of emissions[8].

Table 1 below summarise the data and process used to define UK industry in this study. For "industrial sites", broadly two different approaches were taken for large emitters, under the EU Emissions Trading System (ETS), and small emitters. As mentioned above, the NAEI point source emissions dataset is already available for large emitters in the UK, which was then combined with Element Energy's detailed data on industrial processes (or appliances). For small emitters or emitters not included in the NAEI point source dataset, location-specific emissions data was not available. Emissions assigned to these sites were split between UK regions (former government office regions or GORs), and then split among a number of sites, with these sites defined to be of a size corresponding to a small site in that sector.

[4] Covering CO_2, CH_4 and N_2O emissions, and excluding F-gas emissions.
[5] ONS Dataset on UK business: activity, size and location. https://www.ons.gov.uk/businessindustryandtrade/business/activitysizeandlocation/datasets/ukbusinessactivitysizeandlocation
[6] Industrial Fuel Switching, CCC Net Zero, CCC Fossil Fuel Production and Fugitive Emissions, and Hy4Heat studies
[7] https://naei.beis.gov.uk/data/map-large-source
[8] UK emissions 1990 to 2018, on a by source basis. https://naei.beis.gov.uk/data/

Table 1 Disaggregation of UK industry data and methodology to define site types

Emitter Size	CO_2 emissions data	Fuel consumption data	Industrial process / equipment archetypes
Large emitters	• Site/location-specific via NAEI point sources (within the EU ETS)	• Sector-level data is available, i.e. Digest of UK Energy Statistics (DUKES) • Some site-specific data is available to Element Energy (e.g. gas consumption from network operators and data Element Energy gathered from Associations)	Element Energy built bottom-up stock models of appliances and industrial processes covering all industrial sectors included in this study (for BEIS industrial fuel switching, BEIS Hy4Heat WP6 industrial appliances, and CCC net zero industry studies)
Small emitters	• Difference between NAEI point source data and NAEI complete industrial emissions inventory		
Methodology to define UK industry based on site types			
Large emitters ("point sources")	Location specific information available (CO_2 emissions from NAEI point sources) was mapped onto Element Energy's existing stock model of industrial processes/appliances (from BEIS Hy4Heat / BEIS Industrial Fuel Switching / CCC net zero industry studies) to develop a bottom-up stock model of industrial sectors and processes for large emitters.		
Small emitters ("non-point sources")	NAEI process-level emissions inventory was mapped to defined industrial sectors (cement, food & drink, etc.). The difference between the inventory emissions and point source emissions data was allocated to small emitters. The non-point source emissions were geographically modelled within each of the UK's regions (former GORs); this assumed a share of sectoral emissions in each region relative to the ONS data on businesses, which was mapped to each sector by Standard Industrial Classification (SIC) code.		
Fossil fuel production, fugitive and other emissions (FFPFE)	Utilising the same data sources described above, FFPFE emissions were categorised into both the small and large emitters based on the existing level of information; no additional "site-specific" or locational data was added.		

4.2.2 Sector and process archetypes

The N-ZIP model and this study grouped the UK's industries into 29 sectoral categories. Additionally, each industrial sector was represented via simplified archetypes which enable a reasonably accurate representation of the energy and fuel use across different industrial processes. For the industrial heating processes, Table 2 Categorisation of industrial heating processes by indirect/direct and high/low temperature provides a high-level categorisation of each by indirect or direct heating and high or low temperature.[9] In Appendix 10.1, an additional table provides an overview of all industrial sectors and process archetypes which were defined for this study, along with the number of point source sites which are contained within each sector. Further details can be found in the Assumptions Log and N-ZIP model.

Table 2 Categorisation of industrial heating processes by indirect/direct and high/low temperature

	Indirect Heating	Direct Heating
High Temperature	Steam Reformers Boilers (some)	Kilns and Furnaces Metal Rolling and Melting Blast Furnaces and Sinter Plants Dryers (some, e.g. rotary)
Low Temperature	Regasification Boilers (most) CHP	Ovens Dryers (most)

[9] Broadly speaking, high temperature refers to processes operating above 240°C and low temperature below that. A deeper analysis of this categorisation can be found in Element Energy and Jacobs' Industrial Fuel Switching Market Engagement Study for BEIS (2018).

4.2.3 Baseline emissions

Carbon emissions from industries in scope amounted to 110.9 $MtCO_2e$ in 2018. Based on the sectoral characterisation, emissions are highly concentrated in the top 5 GHG-intensive sectors (i.e. oil platform, refining, primary iron production, other chemicals, and cement[10]), which taken together amount to approximately 48% of the total emissions, as shown in the breakdown in Figure 2.

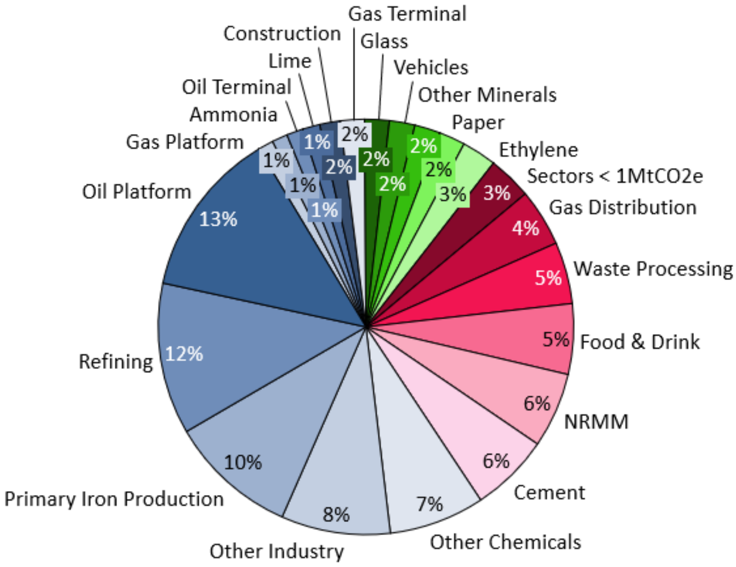


Figure 2 Baseline GHG emissions (2018) breakdown by industrial sector for the UK. [11]

Another key output of the disaggregation was the geographical mapping of industrial point source emissions, highlighting features of the emissions intensity of the different industrial clusters, illustrated in Figure 3.

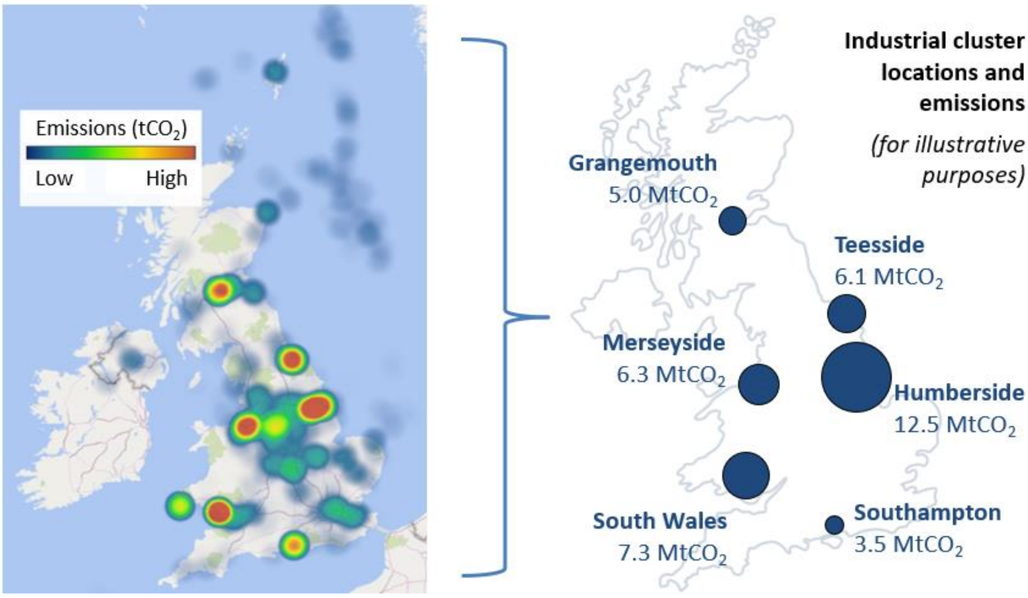


Figure 3 Heat map of 2018 point source emissions (left) correlates directly to the corresponding locations of the UK's six major industrial clusters[12] (right).

[10] "Other Industry" is not included in this list because it is an aggregation of a number of small industrial sectors.
[11] NAEI 2018 Emissions. The grouping "Sector < 1 $MtCO_2e$" category is a sum of all sectors whose individual total emissions are less than 1 $MtCO_2e$. This includes the following sectors: Non-ferrous Metal, Other Iron & Steel, Compressor Station, Coal Mine (closed), Other Fuel Production, LNG Terminal, Coal Mine (open).
[12] Emission values shown on the map for the industrial clusters are 2018 baseline emissions, including both point and non-point source emissions within a 50km radius of each cluster.

The majority of emissions (73.2 $MtCO_2e$, 66% of emissions in scope) are from the large point sources included in the NAEI point source dataset, as previously defined, with the remainder of emissions (37.6 $MtCO_2e$) distributed across the non-point source sites. Figure 4 and Figure 5 show the contribution from point and non-point sources towards the total 2018 baseline emissions in each sector, split by sectors totalling greater and less than 2 $MtCO_2e$.[13] As highlighted in these figures, the split between point and non-point sources is highly variable, with some sectoral emissions even classified solely by point sources or non-point sources.

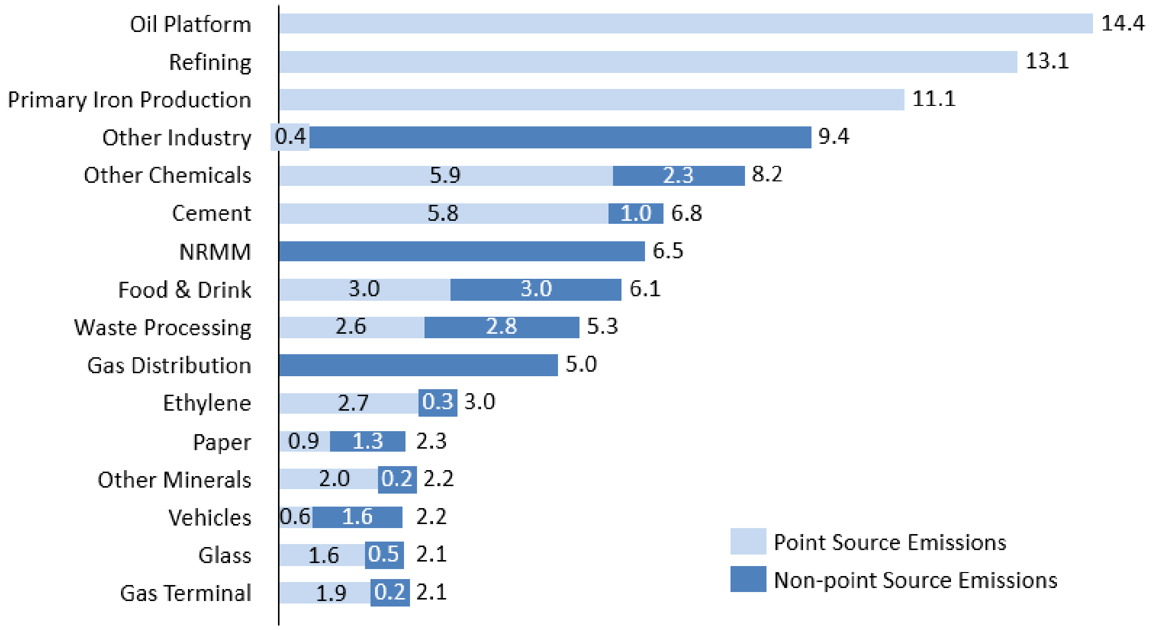


Figure 4 Baseline GHG emissions (2018) for each industrial sector above 2 $MtCO_2e$ split by contributions from point and non-point source emissions.

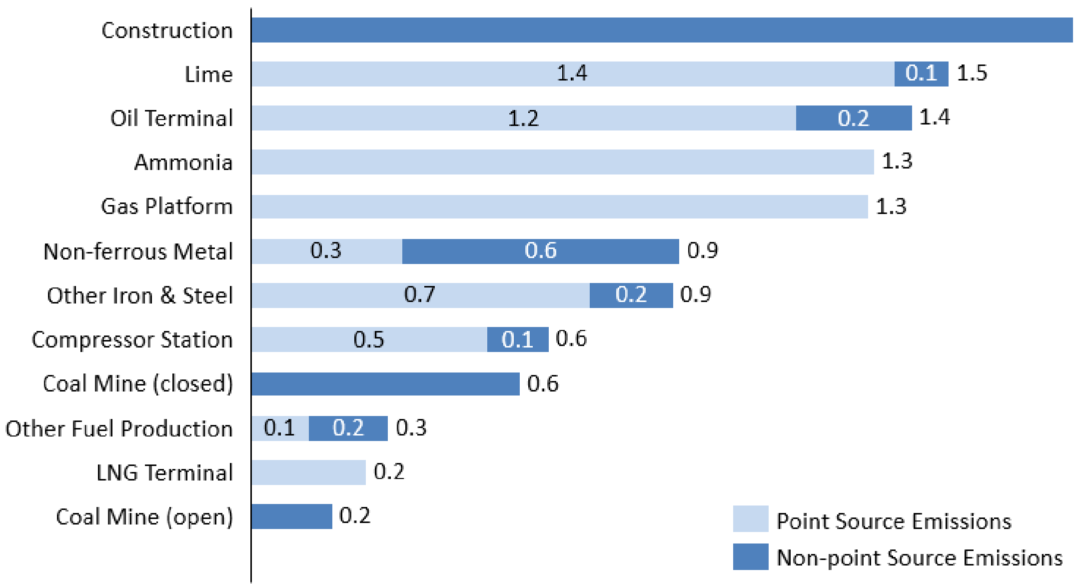


Figure 5 Baseline GHG emissions (2018) for each industrial sector below 2 $MtCO_2e$ split by contributions from point and non-point source emissions.

[13] For this study, baseline emissions from NAEI Point Sources in 2017 were assumed to remain equal in 2018.

4.3 Baseline Projections

After disaggregation of the UK industry was completed, baseline energy and emissions projections were produced using estimates provided by the CCC, which incorporated data from DUKES, NAEI, and BEIS' Energy and Emissions Projections (EEP). Further details on the approach to integrate emissions projections into the N-ZIP model can be found in the project's Assumptions Log.

The final breakdown of baseline emissions projections by each industrial sector, separating out the top ten sectors with greatest 2018 emissions, is shown in Figure 6. In addition, baseline fuel consumptions projections are shown in Figure 7.

Key points to note from the baseline projections include:

- Fossil fuel production sectoral emissions decline in the baseline up to 2050, due to the decline in production from UK assets.
- Gas distribution has decreasing emissions, largely associated with decreased methane leakage from the network, due to the Iron Mains replacement programme reducing leakage, as well as the potential closure of parts of the network and/or switching parts of the network to hydrogen.
- Emissions from the waste processing sector increase up to 2050, largely resulting from the incineration of increased volumes of waste.
- The decrease in fuel consumption in the baseline projection is largely due to decreased natural gas consumption over the 2020-2040 period (following BEIS' EEP).

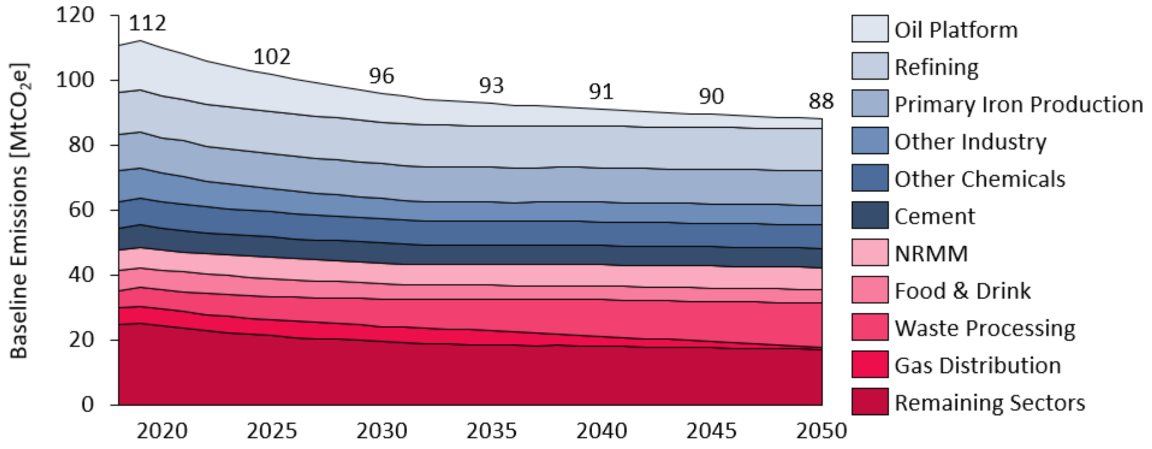


Figure 6 Baseline emissions projections to 2050.

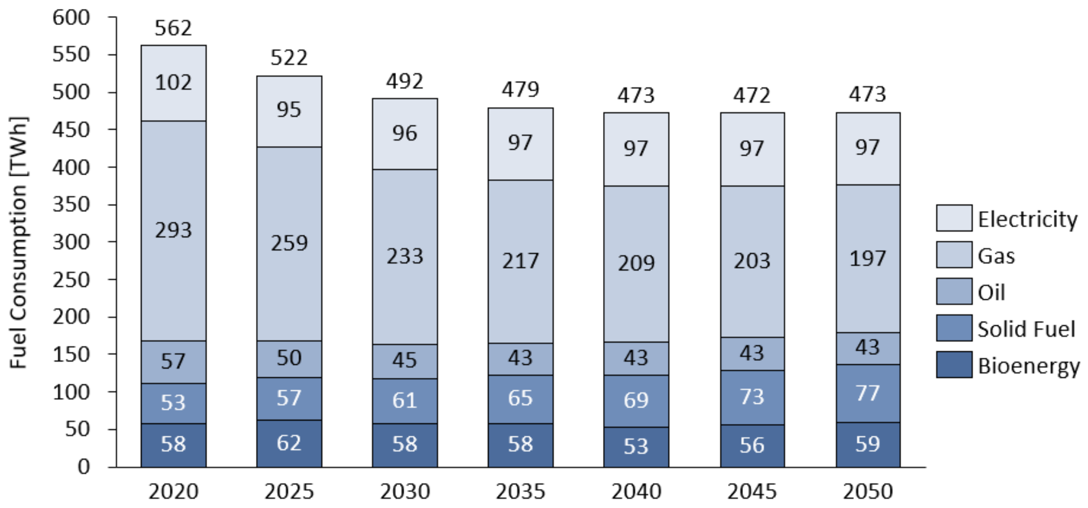


Figure 7 Baseline projections for fuel consumption across all of UK industry.

4.4 Resource Efficiency and Energy Efficiency (REEE) Projections

After baseline energy and emissions projections were produced, assumptions for resource efficiency and energy efficiency (REEE) abatement over time were applied[14]. This included different levels of resource efficiency in each sector, as well as different levels of energy efficiency for each sector and each fuel. The categories included in the assessment of REEE were:

- **Energy Efficiency** – reductions in fuel use and hence emissions for a given level of activity.
- **Resource Use in Production –** reductions in the amount of material used to produce a product (e.g. reduced on site wastage/losses) resulting in reductions in fuel use and emissions for a level of activity.
- **Material Substitution** – change in the materials used in production, and resulting change in emissions and fuel use for a level of activity (e.g. increased use of cullet - recycled glass).
- **Consumption of Resources –** reduction in the demand for the product, and hence reductions in the level of activity in the sector.
- **Effects from economy-wide decarbonisation –** additional changes in the level of activity of the sectors due to wider economy decarbonisation (used in the waste processing and refining sectors).

The level of abatement provided by REEE varied between scenarios, with the Balanced scenario shown in Figure 8 and Figure 9. The key step in this process involved mapping the high-level disaggregation of the projections provided by the CCC / University of Leeds to the disaggregation decided for the project (i.e. industrial sectors and processes, as defined in the previous sections).

Within the REEE analysis, a proportion of the reductions in emissions and fuel use in the two categories resulting in reductions of the sectors' levels of activity (consumption of resources and effects from economy-wide decarbonisation) were modelled as closures of sites, rather than reductions in the sizes of sites.

These post-REEE projections of fuel use and emissions for each process on each site were the key output taken forward into the modelling of deep decarbonisation, with these projections used as the 'counterfactual' for modelling the implementation of deep decarbonisation technologies. Therefore, it should be noted that the level of abatement assigned to REEE is potentially inflated, given its preferential application as an 'initial measure'. It is likely that in reality some of the REEE measures will actually correspond to fuel cost savings put in place after deep decarbonisation takes place, rather than emissions abatement, with corresponding increased emissions abatement 'assigned to' the deep decarbonisation technologies.

Some of the figures are discussed in more detail in section 7.2, however some key points to note include:

- As modelled, REEE results in an approximate emissions decrease of 20-35% from the baseline, depending on scenario. More than half of this decrease comes from the effects of economy-wide decarbonisation (e.g. impacts on refinery product demand and waste management).
- Economy-wide fuel switching away from petroleum products results in a large decrease in emissions from the refining sector (approximately 9 $MtCO_2e$ of abatement), largely as the result of decarbonisation in other sectors of the economy, meaning lower demand for petroleum products.
- The waste processing sector emissions are decreased significantly from resource efficiency due to other sectors producing less waste for incineration and waste fuel usage in other sectors. The Balanced scenario shown in Figure 8 has a significant decrease from the baseline (approximately 6 $MtCO_2e$ of abatement), with the Engagement and Tailwinds scenarios (not shown) including an even more pronounced decrease.

[14] Analysis of REEE measures undertaken independently by the University of Leeds.

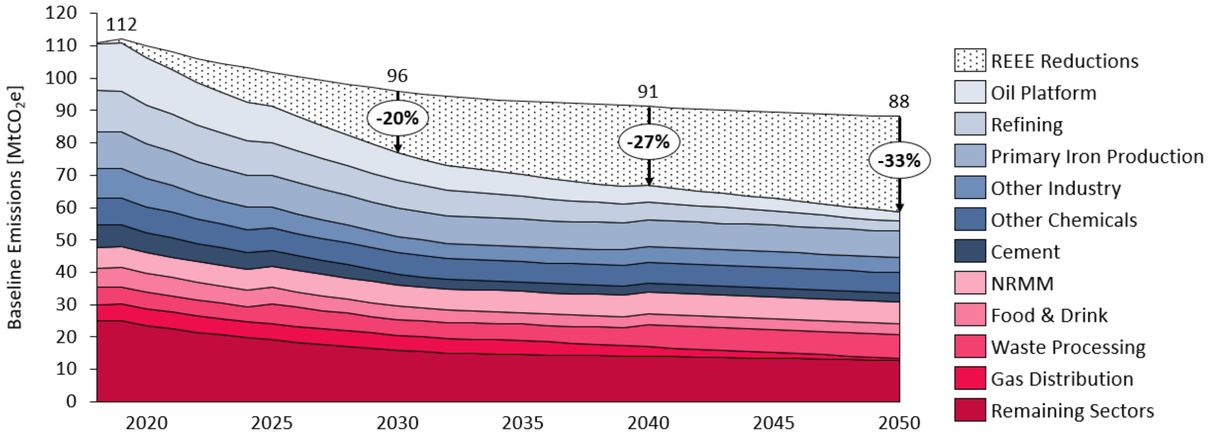


Figure 8 Baseline and post-REEE emissions projections to 2050 (Balanced scenario).

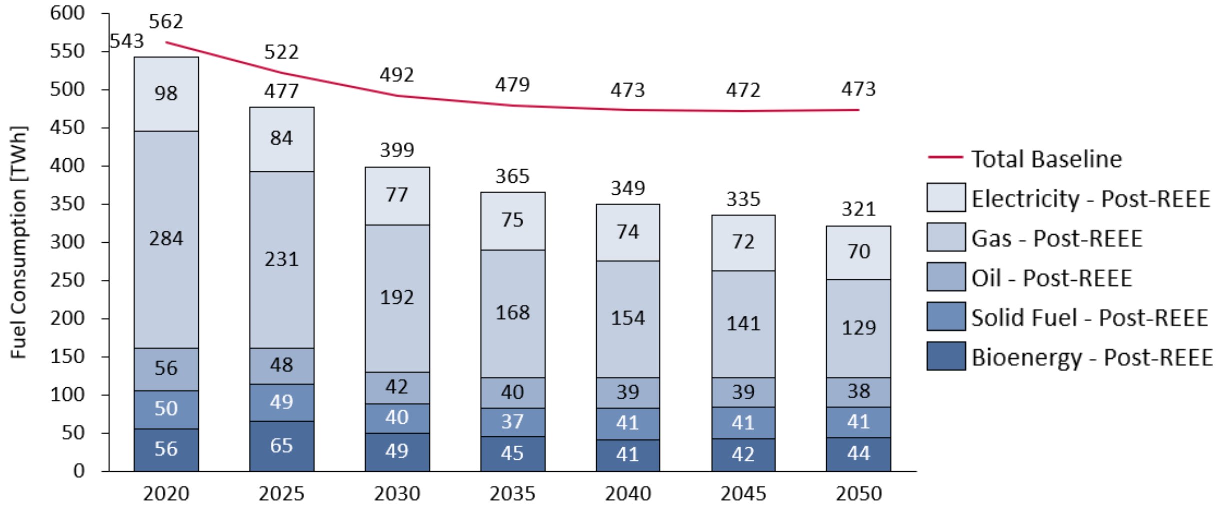


Figure 9 Post-REEE projections for fuel consumption across all of UK industry (Balanced scenario).

5 Infrastructure for Deep Decarbonisation of Industry

This section explores the required infrastructure for deep decarbonisation of industry and explains the assumptions and methodology to quantify constraints on the pace of CO_2 and hydrogen infrastructure within the N-ZIP model. A shorter discussion on the challenges of electrification infrastructure is included; however, it should be noted the model does not directly quantify the potential challenges impacting the pace of electrification (e.g. site connections, expansion of networks, etc.). Discussions with stakeholders in key industrial clusters and potential project developers in the UK were conducted to validate assumptions[15]. Further information can be found in the technical Assumptions Log and the N-ZIP model itself.

Two key constraints for infrastructure deployment will be the availability of commercial business models and enabling policy/regulatory conditions, which the N-ZIP model does not strictly take into account in the lead times for infrastructure. However, stakeholder engagement confirmed that the initial years of availability for infrastructure were determined to allow enough time for an enabling policy/regulatory environment to be developed, given there is sufficient political will. Using a target-driven carbon value analysis, this work aimed first to develop deep decarbonisation scenarios that were based on physical constraints limiting deployment of infrastructure, then to identify appropriate measures and policies based on the outputs.

5.1 Hydrogen Infrastructure

5.1.1 Hydrogen production

In the N-ZIP model, all hydrogen production points (Figure 10) were assumed to have the availability of both blue and green hydrogen, with estimates for initial years of availability shown in Table 3. Future large-scale hydrogen production is likely to be centralised and delivered to multiple sectors (e.g. residential/commercial heating, heavy-duty vehicles, shipping, etc.). Blue hydrogen, coupling reforming of natural gas with CO_2 transport and storage infrastructure, is currently being developed in many of the UK's industrial clusters with the aim to deliver hydrogen to industrial sites as early as 2025 in some clusters[16]. Similarly, green hydrogen, coupling electrolyser technology with renewable electricity generation, is also being trialled with the with the aim to deliver hydrogen to an industrial site as early as 2024-2025[17].

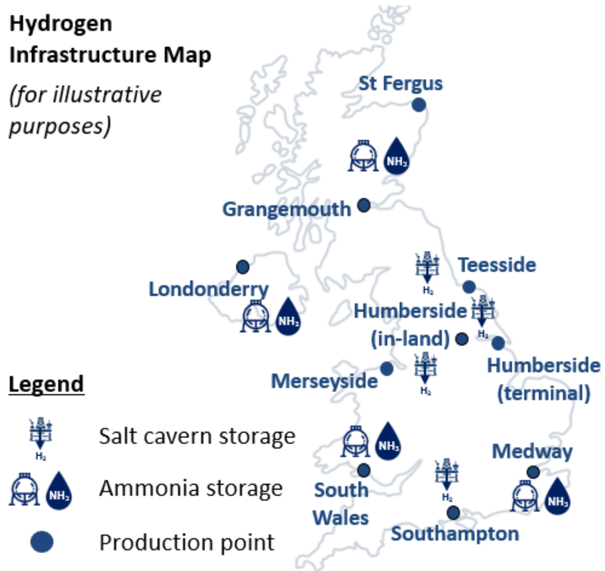


Figure 10 Locations of production points and storage options for hydrogen infrastructure.

[15] In addition, infrastructure assumptions were showcased and validated at two stakeholder roundtables, which included experts from Ofgem, National Grid Ventures, National Infrastructure Commission, DNV GL, and cluster projects.
[16] For example, the HyNet, Acorn, Zero Carbon Humber, and Net Zero Teesside projects.
[17] For example, the Gigastack project in the Humberside region.

It is worth noting the rationale for the selection of hydrogen production points. A majority of the points were selected on the basis of current project plans in industry: Acorn project in Scotland (St Fergus/Grangemouth), Net Zero Teesside project (Teesside), Zero Carbon Humber project (Humberside), HyNet project (Merseyside), Project Cavendish (Medway) and the South Wales Industrial Cluster roadmap (South Wales). Londonderry was selected on its potential for CCS infrastructure in Northern Ireland[18] and proximity to industrial sites in the region that could utilise hydrogen/CCS infrastructure. Southampton was also selected on the basis of its high emissions density and potential demand for hydrogen (e.g. Fawley refinery).

Table 3 Initial year of hydrogen availability for each of the production points.

Production Point	Initial Year of Availability[19]		Production Point	Initial Year of Availability
Merseyside	2025		Humberside (in-land)	2028
St Fergus	2025		Southampton	2030
Grangemouth	2025		South Wales	2030
Teesside	2026		Medway	2030
Humberside (terminal)	2027		Londonderry	2030

5.1.2 Hydrogen transport and storage

After hydrogen is produced, the methods of hydrogen transport and storage shown below (Figure 11) enable the delivery of hydrogen to individual industrial sites. Costs and geographical constraints play a key role in determining which methods are most likely to become widespread across regions and within industrial clusters in the UK.

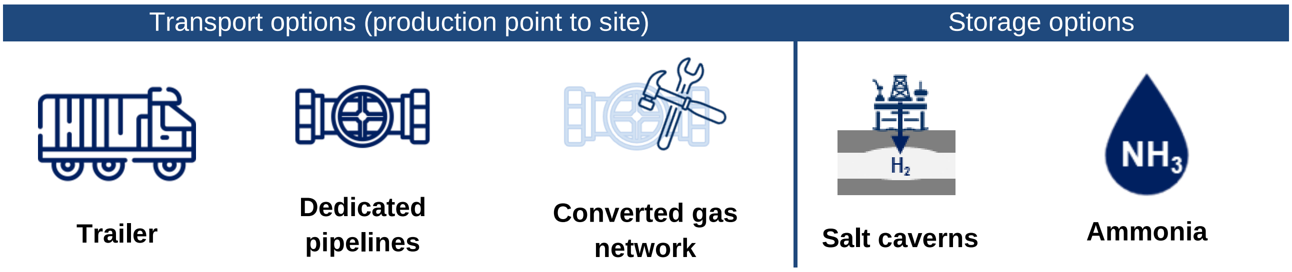


Figure 11 Hydrogen transport and storage options considered in the modelling work.

Hydrogen storage will be a necessary component of infrastructure to buffer base load hydrogen production with intermittent or variable demand or intermittent electrolysis with continuous demand. **This study took the approach of modelling two key hydrogen storage options for the UK:**

- **Salt caverns.** For regions that have access to them, underground salt caverns are likely to be a cost-effective storage option, particularly if re-using existing salt caverns used for gas storage (e.g. Teesside hydrogen storage at the Seal Sands salt field[20] and the Rough hydrocarbon field for natural gas storage[21]).
- **Ammonia-based:** Hydrogen storage is also being explored through the production of ammonia, a high energy density chemical with mild cryogenic and pressurization constraints, that can be more

[18] BEIS, CCS deployment at dispersed industrial sites, 2020. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/929282/BEIS_-_CCUS_at_dispersed_sites_-_Report__1_.pdf
[19] Broadly consistent with the latest cluster project estimates, incorporating internal Element Energy estimates on infrastructure lead times that have been revised based on feedback from stakeholder interviews.
[20] H21 Leeds City Gate Report
[21] Element Energy, Hy-Impact Series (Study 1: Hydrogen for economic growth) (2019)

easily stored at scale in above ground storage tanks or transported via shipping. For areas that lack salt cavern storage, such as Scotland and South Wales, ammonia could be produced in locally-sourced blue hydrogen production facilities (e.g. Port Talbot) or imported for cracking.[21]

Other methods of hydrogen storage exist, including line packing in the transmission system and distribution network, or direct storage in large above ground tanks. Both of these are better suited for locations situated close to high demand variations in localised supply and are unlikely to be used at scale for the centralised storage requirements resulting from large demand variations across regions or seasons.[22]

For hydrogen fuel switching applications, industrial sites will be constrained by the means in which they can receive dedicated supply from the hydrogen production points. Large industrial consumers and/or sites within industrial clusters closely situated to hydrogen production locations are likely to be early adopters of hydrogen fuel switching, as evidenced by current projects and trials underway. **The modelling work conducted explored three key options for hydrogen transport:**

- **Dedicated pipelines:** Dedicated hydrogen pipelines, which may be a mix of new and existing infrastructure, can be developed such that industrial hydrogen consumers can share the costs of hydrogen delivery at scale. Cluster-based hydrogen supply networks will be able to supply numerous energy users through their routing and are likely to be in operation in one or two clusters by the late 2020s.
- **Trailer Delivery:** For industrial users who may be more dispersed or using smaller quantities of hydrogen, hydrogen transportation could be performed using trailers, as delivering hydrogen from centralised hydrogen sources via long-distance, low capacity pipelines could become cost prohibitive.
- **Converted gas grid:** For many industrial sites, particularly those with lower hydrogen consumption and/or dispersed sites outside of clusters and further away from hydrogen production point, the ability to transition to hydrogen-fueled appliances will likely require waiting for the conversion of the local gas grid. First steps towards a 100% hydrogen gas network are now underway across the UK, including projects such as H21 North of England, SGN's H100, and National Grid's HyNTS. These have explored the safety case for hydrogen in transmission and distribution pipelines, along with investigating the new processes and procedures required to provide the necessary balancing and storage services for future intraday and interseasonal hydrogen demands. This will include the development of new industrial metering equipment capable of withstanding high pressure and injection rates, as current natural gas equipment is unable to cope with the accurate metering required for high volume industrial users.[23]

5.1.3 Constraints on pace of deployment and cost considerations

The necessary infrastructure components for an industrial site's hydrogen supply will be limited by both future development timelines and specific geographical constraints. As such, a site's strategy for securing hydrogen supply will be dependent on whether new infrastructure will be deployed for hydrogen transmission/distribution or whether parts of the gas network will be converted to hydrogen at given times. To simulate these factors influencing the supply of hydrogen to industrial consumers, the following constraints and cost impacts in Table 4 were incorporated into the N-ZIP model.

[22] Element Energy, Hydrogen supply chain evidence base (2018)
[23] ENA Delivering the transformation to hydrogen networks, 2019

Table 4 Constraints impacting hydrogen infrastructure deployment and cost

Constraints	Impact on Model
Maximum hydrogen production rates for industry in each year and region (ramping up of production)	Industrial sites are pre-assigned to hydrogen production points, each of which are constrained by the cumulative hydrogen demand in that region. To determine which sites were early hydrogen adopters, prioritisation was done on a first come first served and most cost-effective basis.
Lead time from investment decision to operation of a centralised cluster transmission and distribution pipeline network	An estimate for the earliest availability of hydrogen supply (i.e. earliest year for hydrogen supply for sites, see Table 3). Costs for hydrogen pipelines of the cluster-based networks and dedicated pipelines are incorporated into the capital and operating costs for hydrogen conversion at the site level.
Lead time and regional rates of conversion to convert existing distribution network from gas to hydrogen	An estimate for the availability of hydrogen supply (i.e. earliest year and roll-out rates for hydrogen supply[24] for dispersed or smaller sites requiring grid conversion). Network costs for hydrogen distribution are incorporated into the fuel cost if sites select this option.
Variable options for hydrogen storage within different regions / production points	Green and blue hydrogen fuel costs (specifically the storage cost component) are dependent on cost estimates for salt caverns or ammonia production and cracking within each region.

5.2 CCS Infrastructure

5.2.1 Carbon capture and cluster points

In the N-ZIP model, industrial sites benefit from economies of scale when considering carbon capture for abatement as regional CO_2 transport and storage costs are driven down by increasing capacities. This was an important consideration as for a number of key industrial sectors (cement, lime, iron and steel, etc.), where CCS or BECCS abatement technologies will be pivotal for achieving deep decarbonisation. Projects where the CO_2 transport and storage infrastructure is shared by multiple neighbouring industrial emitters, as clusters, benefit from substantial economies of scale and are expected to represent the predominant format for commercial projects. In the UK, this cluster-based approach for infrastructure development has already been proposed in various regional projects. The assumed locations of cluster points and terminals used in this modelling work are shown in Figure 12.

[24] The possibility for grid conversion and hydrogen supply from the gas network is assumed to begin 5 years after the first year of hydrogen production availability and expands radially over time from hydrogen production points at a rate of 10 km per year.

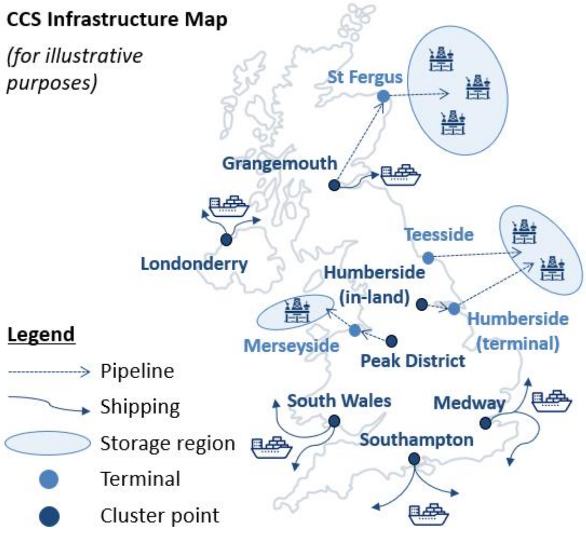


Figure 12 Locations of cluster points and terminals for CO_2 T&S infrastructure.

Most industrials clusters are situated around or near major ports and terminals. The four terminals that have reached the most advanced stages of CCS project planning are at Merseyside, Peterhead, Teesside and Humberside. To achieve economies of scale, the CO_2 transport demand at these terminals will need to be sufficiently high in the offshore pipeline networks to ensure high injection rates (in the order of $MtCO_2$/yr) downstream into the CO_2 storage sites. For the clusters with more easily accessible storage sites in the North Sea (Grangemouth[25], Teesside, Humberside) and the East Irish Sea (Merseyside), large-scale CCS deployment is planned to occur earlier. Due to storage limitations, other clusters (e.g. South Wales and Southampton) may rely on CO_2 transport to other clusters by ship, so CCS operations is planned to begin later. The estimates for initial years of availability used in the modelling are shown in Table 5.

Table 5 Initial year of availability for CO_2 T&S infrastructure for each of the terminals / cluster points.

Terminal / Cluster Point	Initial Year of Availability[26]		Terminal / Cluster Point	Initial Year of Availability
Merseyside	2024		Southampton	2030
St Fergus	2024		South Wales	2030
Grangemouth	2025		Peak District	2030
Teesside	2026		Medway	2030
Humberside (terminal)	2027		Londonderry	2030
Humberside (in-land)	2028			

5.2.2 CO_2 transport and storage

After CO_2 is captured at each industrial site, the methods of CO_2 transport and storage shown below (Figure 13) enable the final sequestration of carbon in offshore storage sites in the East Irish Sea and North Sea. Costs and geographical constraints play a key role in determining which methods are most likely to become widespread across regions and within industrial clusters in the UK.

[25] Via transport to the St Fergus terminal (i.e. Acorn project).
[26] Broadly consistent with the latest cluster project estimates, incorporating internal Element Energy estimates on infrastructure lead times that have been revised based on feedback from stakeholder interviews.

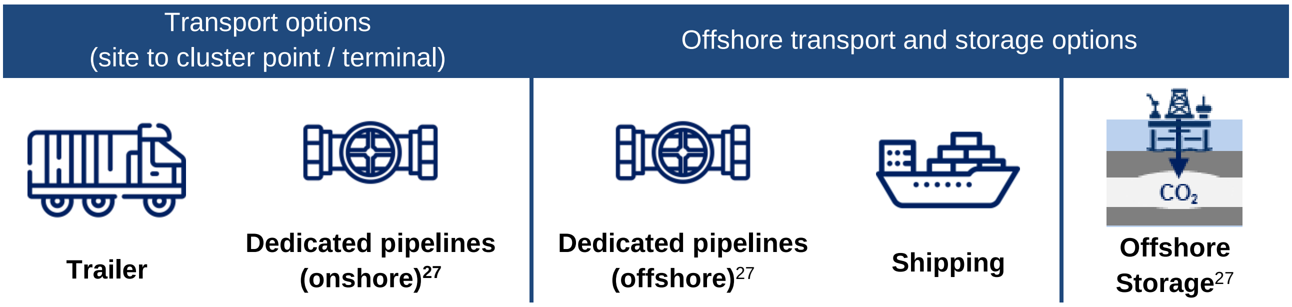


Figure 13 CO_2 transport and storage options considered in the modelling work.

For offshore transport and storage from terminals, an important consideration for project developers will be the re-use of existing assets. This involves re-purposing offshore oil and gas assets (pipelines, depleted reservoirs, platforms, etc.) that have reached the end of their commercial life for producing hydrocarbons to be part of a CO_2 transport and storage network. Current proposals include the Acorn project's re-use of offshore trunk pipelines from St Fergus that connect to the Captain sandstone storage formation and HyNet's re-use of a range of existing infrastructure that connects the Merseyside terminal (at Point of Ayr) to the Liverpool Bay gas fields.[28] Some clusters may also benefit from re-use of existing onshore assets, such as Acorn's proposal to re-purpose the Feeder 10 natural gas pipeline in Northern Scotland to transport CO_2 from Grangemouth to Peterhead.

Industrial clusters may also exist in-land, such as the concentration of cement and lime sites in the Peak District or the various industrial sites situated around the Drax Power Station in Humberside. For such locations, achieving economics of scale for CO_2 transport will require large onshore trunk pipelines from a collection point within the clusters to the nearest port or terminal.

Shoreline-based clusters with easy access to ports and in areas where offshore pipeline construction is unfeasible are likely to develop CO_2 shipping solutions as a lower cost solution to transport CO_2 to operating terminals with offshore T&S infrastructure. Business models for CO_2 shipping are likely to open up opportunities for international collaboration. As a result, the UK could begin to use some of its shipping fleet and/or its terminals for receiving CO_2 shipments from continental Europe (or vice versa for exporting). This could connect UK ports with potential early movers such as Norway and Rotterdam or other key industrial hubs with limited offshore CO_2 storage potential (e.g. France and Germany).[29]

5.2.3 Constraints on pace of deployment and cost considerations

An industrial site's decision to incorporate CO_2 capture technology will be highly dependent on its ability to access low-cost CO_2 T&S infrastructure and the years in which the infrastructure becomes available. Historically, long lead times for CCS projects have been projected (especially CO_2 storage, which may take around 10 years from appraisal to operation). However, with recent appraisal studies having now been conducted for a greater number of CO_2 storage sites, lead times are likely shorter for these sites, if project planning and permitting does not present significant unforeseen delays.

Planning delays could occur in clusters where sites are unable to commit to utilising CO_2 capture for abatement. This CO_2 volume uncertainty presents significant risk for project developers as to whether CO_2 infrastructure can be over-sized (or right-sized) for follow-on projects. Sites may also be hindered from obtaining the required implementation and operating consent, permits and licenses for all aspects of the CCS chain, which may lead to further delays in reaching final investment decisions and construction. Particular concerns surround the geographical constraints of certain industrial sites; for example, dispersed cement and

[27] Includes options to re-purpose existing oil and gas assets.
[28] BEIS Consultation for Re-Use Of Oil and Gas Assets for Carbon Capture Usage and Storage Projects https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819901/reuse-oil-gas-assets-ccus-projects.pdf
[29] Element Energy, Hy-Impact Series (Study 1: Hydrogen for economic growth) (2019)

lime sites in the UK, which may require road/rail transport if onshore pipelines are not feasible, may be sited in national parks and may not be able to receive a permit[30].

To simulate the factors impacting the availability of CO_2 T&S infrastructure for industrial consumers, the constraints in Table 6 were incorporated into the N-ZIP model. The lead time constraints in Table 6 were also used to inform and develop the years of infrastructure availability outlined previously in Table 5.

Table 6 Constraints impacting CCS infrastructure deployment and cost

Constraints	Impact on Model
Lead time from appraisal to operation of CO_2 storage site / facility	An estimate for the availability of an operating CO_2 storage facility will define the start year for T&S infrastructure from the defined shoreline terminals. This estimate is derived from current projects and incorporates constraints on various stages of project development (planning; front-end engineering and design (FEED); engineering, procurement and construction (EPC); etc.).
Maximum capacity of appraised / potential CO_2 storage sites	In each storage region, CO_2 storage limits on an annual injection rate (Mt/y) are set in each year. These limits reflect the total potential demand coming into each region (e.g. Teesside and Humberside terminals limited by sites in Southern North Sea). Sites are prioritised if necessary on a first come first served and most cost effective basis.
Lead time for construction of pipelines or re-use of existing pipelines	Lead times for construction of pipelines were found to be shorter than CO_2 storage lead times, and so are assumed to not constrain availability of T&S infrastructure.
Lead times for shipping and port infrastructure	Additional lead time estimated for clusters requiring shipping (e.g. South Wales and Southampton). Our model assumes these clusters will also require another shoreline terminal being online before they can connect to storage.

5.3 Electrification Infrastructure

An industrial site's peak electricity consumption influences the size of its existing connection to the grid. If a site decides to electrify its existing fossil-fuelled processes, this existing connection/network may have spare capacity to deliver additional electricity supply or, conversely, require localised network reinforcements. In cases where new electricity consumption is significant enough, reinforcements may even require new substation installations with fixed costs (£/kW) that decrease as connection size increases. While there is some evidence available to determine general costs on upgrading overhead lines or underground cables, there are large uncertainties associated with future site-specific network reinforcement costs, given the assumptions that would need to be made on the variables involved (e.g. existing connection, spare network capacity, future network changes).[31] Variations in estimates of reinforcement costs are shown in Figure 14. **For the N-ZIP model, an average fixed cost (£/kW)[32] was assigned to all processes requiring an increased electrification demand of 8 MW or greater and applied to a percentage of sites below this level (assumed to be 90% of the remainder of the sites).[33]**

[30] Element Energy for BEIS, CCS deployment at dispersed industrial sites (2020)
[31] In this project, the CCC engaged with the Energy Networks Association and their Low Carbon Technologies Working Group (made up of the electricity system operator and transmission/distribution network operators) to discuss the various assumptions on network reinforcement costs for industrial sites. A rigorous analysis of costs was deemed not possible due to the lack of detailed data at the site-level.
[32] This ranged between 350 – 450 £/kW depending on the scenario.
[33] Estimate based on internal knowledge from Element Energy's electricity networks experience representing a number of highly geographically variable factors.

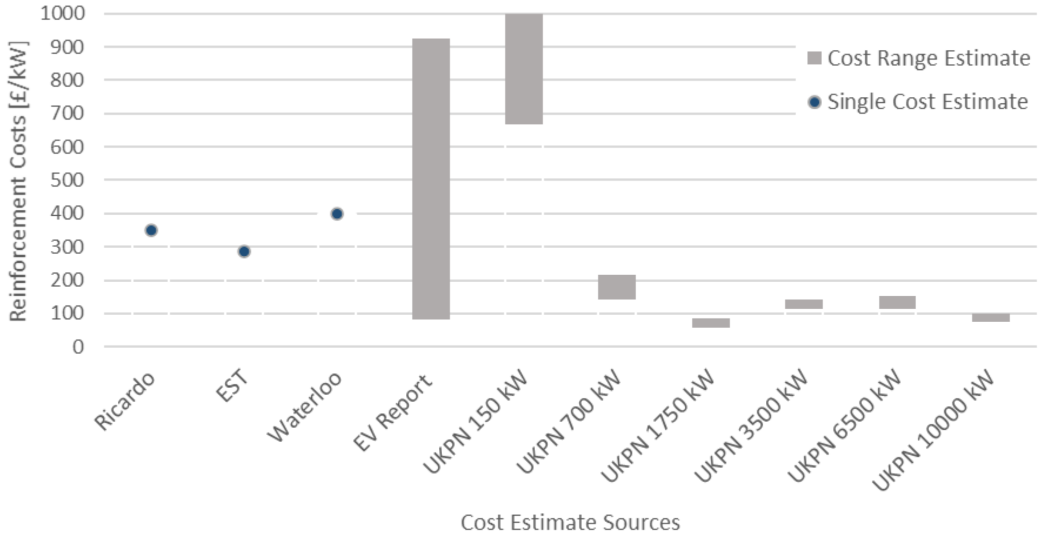


Figure 14 Variability of estimates for network reinforcement costs for industry[34]

Evidently, while specific sites may be constrained by upgrades to local distribution networks before electrifying appliances or processes, it was determined that there need not be a constraint on rollout if there is sufficient notice to the networks from both government and sites themselves. Ideally, sites should coordinate with their local distribution network operators to construct a detailed, coordinated plan for rollout of electric technologies such that the networks can plan their upgrades in advance.[35]

At the national level, widespread electrification of transport and heating has been evaluated to determine its impact on the necessary build-out rates for new electricity generation. Recent studies suggest that build-out rates of new electricity generation between 2020 to 2050 can support nationwide increases in electricity consumption of 6 to 7 TWh per annum,[36] with deployment in accelerated scenarios as high as 16 TWh per annum.[37] **In this study, the additional electricity consumption from industry resulted in a modest average increase in electricity consumption of 1.7 TWh per annum.**[38]

5.4 Impact of Cross-sectoral Demand

In addition to the impact of geographical constraints, the future costs of blue hydrogen and CCS deployment will be highly dependent on the demand for CO_2 transport and storage. This study has incorporated economies of scale into the costs of CO_2 transport and storage, as shown in Figure 15, by developing cost curves for the necessary CCS infrastructure components at each cluster point and terminal. These cost variations are fed into blue hydrogen's CCS cost component, which decreases accordingly as demand increases. **Industrial sites that select blue hydrogen or CCS abatement in early years are therefore subject to more expensive hydrogen fuel costs and CO_2 T&S operational costs in the early years of the model's NPV calculation.**

[34] Courtesy of the CCC. References for graph: "Ricardo" - HGV Infrastructure Requirements; "EST" - Stakeholder engagement with Energy Savings Trust's chargepoint team; "Waterloo" - LowCVP's Low Emission Bus Guide (Waterloo bus depot); "EV Report" – range of costs from Cross River Partnerships' EV Report; "UKPN" – stakeholder engagement with UK Power Network's (UKPN) connections team (range of costs provided for varying new connection sizes).
[35] Element Energy stakeholder engagement with the Energy Networks Association and UKPN.
[36] https://www.theccc.org.uk/wp-content/uploads/2019/05/CCC-Accelerated-Electrification-Vivid-Economics-Imperial.pdf
[37] National Grid Future Energy Scenarios (2019) http://fes.nationalgrid.com/fes-document/
[38] Taken as the average between 2020 and 2050 for the Balanced scenario run.

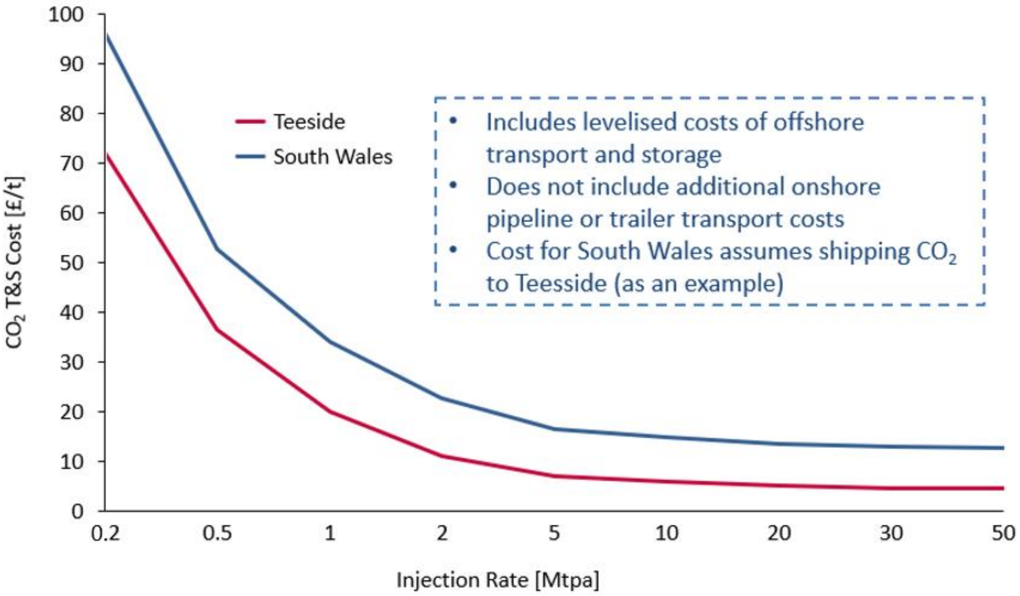


Figure 15 Sample of cluster point and terminal offshore CO_2 T&S levelised costs (note the non-linear scale).

To effectively represent economy-wide infrastructure requirements, the model's costs of blue hydrogen and CCS infrastructure are also impacted by the demand from other sectors of the economy (e.g. increasing uptake of hydrogen consumption for residential heating or the power sector). Estimates from additional CCC modelling work have informed these assumptions and a sample of the final 2050 demands are provided in the results section (Figure 34).

6 Decarbonisation Technologies in Industry

6.1 Overview

The breadth of the equipment and processes used in industry means that any solution for decarbonising industry requires a similarly broad and bespoke range of technologies. The N-ZIP model incorporates a range of key technologies to a certain level of detail, with a summary shown in Table 7, however further work is possible to improve the cost information included as well as the granularity with which technologies are represented. More information is available in the technical Assumptions Log and the N-ZIP model, however this section covers some of the key assumptions around the different technologies modelled for industrial decarbonisation, including:

- Details of technology options and some key modelling assumptions.
- Discussions on two key constraints: when technologies would become available and the pace at which the supply chain can support industrial decarbonisation.

Table 7 Summary of the deep decarbonisation technology options included in the N-ZIP model

Type of Option	First Year of Technology Availability	Key Technology Types[39]	Key Sectors
Electrification	2023 - Electric Boilers Late 2020s – Furnaces, Kilns, etc.	Electric Boilers Electric Kilns, Furnaces, Ovens, Dryers, Compressors, EAF for Iron and Steel	All Sectors
Hydrogen (Green and Blue)	2025 – Hydrogen Boilers Late 2020s to Early 2030s – Furnaces, Kilns, etc.	Hydrogen Boilers/CHP, Hydrogen Kilns, Ovens, Furnaces, Dryers, Compressors, Hydrogen Direct Reduction	All Sectors
CCS	Early to Late 2020s – 1st Gen Techs (Amines/Blends) Ealy 2030s – 2nd Gen Techs (Calcium Looping)	1st/2nd Gen CCS on: Internal Fuel Combustion[40], Large equipment/sources, Process Emissions	Refining, Chemicals, Cement, Iron and Steel
BECCS	Late 2020s – 1st Gen Techs (Amines/Blends) Ealy 2030s – 2nd Gen Techs (Calcium Looping)	CCS on existing biogenic emissions, Fuel switching to Biomass combined with CCS.	Waste Processing, Cement, Lime, Glass, Paper,
Methane Management	Early 2020s	Leak Detection and Repair (LDAR), Continuous Monitoring, Flaring Reduction	Fossil Fuel Production, Fugitive Emissions, Iron and Steel,

[39] Key technology types shown here are a summary of technology types included in the N-ZIP model, many of which are sector specific.
[40] Internal fossil fuels are generated from process feedstock, such as crude oil in refining, and then combusted to drive processes on site.

6.2 Data Sources for Technology Costs

To a large extent, the technology costs, suitability and dates of availability included in the N-ZIP model are derived from previous publicly available work conducted by Element Energy for the CCC and BEIS, bringing together these pieces of work into a coherent modelling framework covering the whole of ‘industry’, including fossil fuel production, fugitive emissions and waste incineration. In places where gaps existed or more up to date information was available, these were filled using publicly available information. These assumptions, particularly around the first years of technology availability, were validated through engagement with industrial stakeholders throughout the project.

When considering these **it is important to acknowledge the significant uncertainty that surrounds the technical and economic characteristics of all fuel-switching technologies**, most which have not yet been demonstrated in their operational environment. It is expected that over the course of the coming years, this uncertainty will be reduced as technology development progresses, and costs within the N-ZIP model can be updated going forward.

Within the N-ZIP model, an **optimism bias** setting was implemented to account for the potential for undershoot in the early estimates of the capital costs for these technologies, taking into account some of the costs which might have been excluded from the scopes of cost estimates or underestimated. For the majority of the CCC scenario analysis this was set to a 66% increase in technology capital costs, with the exception of the Tailwinds scenario, where this was set to 0%[41]. This is a significant inclusion and the 66% likely represents an upper bound, so it is useful to note that despite this the results from the CCC scenarios (section 7) still show a relatively fast decarbonisation of industry.

6.3 Technology options - assumptions

6.3.1 Fuel switching

This project primarily focused on electrification and hydrogen fuel switching as potential substitutes to fossil fuels. Both ‘green’ and ‘blue’ hydrogen[42] are considered to be part of the potential future energy mix, with industrial sites able to select either type of hydrogen supply depending on which is the lowest-cost option (see discussion on fuel costs in section 7.1).

It should also be noted that, when switching to hydrogen, the N-ZIP model currently assumes all fossil-fuelled appliances would be suitable for retrofitting. This eliminates the need to calculate costs associated with both new appliances and retrofits. In contrast, electric appliances were treated as new builds with the added cost of scrappage if applied before the end of the counterfactual lifetime. A discussion of retrofitting industrial natural gas appliances to hydrogen can be found in previous work by Element Energy, Advisian, and Cardiff University.[43]

Switching to bioenergy was primarily assessed for sectors already utilising significant amounts of bioenergy,[44] which contain processes that burn bioenergy feedstocks directly or waste-derived fuels with biomass mixed in (e.g. municipal solid waste at energy from waste facilities)**.** This approach follows the recommendation by the Climate Change Committee,[45] who only consider use of bioenergy in industry as an effective long-term option when in combination with CCUS (i.e. bioenergy CCS, or BECCS) or for sites where bioenergy is already in use.

[41] Derived from HM Treasury, Supplementary Green Book Guidance – Optimism Bias.
[42] See Note on Terminology at start of report for definitions of green and blue hydrogen.
[43] Element Energy, Advisian, & Cardiff University. (2019). Hy4Heat WP6: Conversion of Industrial Heating Equipment to Hydrogen. https://www.hy4heat.info/reports.
[44] Cement, Lime, Paper and Waste Processing sectors.
[45] Committee on Climate Change. (2018). Reducing UK emissions: 2018 Progress Report to Parliament. https://www.theccc.org.uk/wp-content/uploads/2018/06/CCC-2018-Progress-Report-to-Parliament.pdf

6.3.2 CCS and BECCS

A range of technologies exist to capture CO_2 from flue gas streams, differing in technical and commercial maturity, energy requirements, and costs.[46] The most commonly deployed carbon capture technology uses amine scrubbing, in which CO_2-containing gas passes through vessels of amino compounds which are capable of absorbing CO_2. For this project, the following carbon capture technologies were integrated into the analysis:

- Currently available carbon capture technologies - first-generation amines were selected as incumbent carbon capture technology
- Future carbon capture technology options – this was modelled as calcium looping technology considering its potential to be the lowest-cost technology across the majority of sectors[47]

In this study, all CCS technologies were modelled as retrofits, as it's assumed the majority of industrial sites would likely select this implementation option to maintain their upstream operations without the need for substantial production process changes. The complete set of assumptions underpinning the analysis of CCS is reported in the project's Assumptions Log, but some of the key factors with a significant impact on the cost of capture include:

- The **CO_2 concentration** in the gas stream, which is highly dependent on the emission source. Specifically, it is easier and cheaper to capture CO_2 when it is not excessively diluted (the limiting case is that where atmospheric CO_2 is captured).
- The **capture rate**, i.e. the proportion of CO_2 contained in the incoming gas stream which is captured. This also affects the abatement potential; a capture rate of **95%** is assumed for the Balanced, Headwinds and Engagement scenarios, with captures rates up to **99%** available in the Innovation and Tailwinds scenarios.
- The **energy source** used to meet the significant heat demand from the capture process, **assumed to be low-carbon hydrogen**, rather than natural gas, so as to enable the maximum emissions abatement.
- The **absolute emission level**, which determines economies of scale.
- **The pressure to which the captured CO_2 must be compressed** before it is transported. It is assumed the CO_2 is always captured at atmospheric pressure (0.11 MPa) and must be compressed to 10 MPa.

This study has also assessed **the potential for negative emissions which could be unlocked by combining CCS with bioenergy combustion** (known as bioenergy CCS, or BECCS)**.** The processes (and sectors) determined to be suitable for fuel switching to biomass and BECCS included:

- Boilers and CHP (Paper sector)
- Furnaces (Glass sector)
- Kilns (Cement and Lime sectors)
- Other existing biomass-fuelled processes (Cement, Lime, Food & Drink, Other Chemicals, Other Industry, Paper, and Waste Processing sectors)

The CCC recognises that the amount of biomass used by the UK should be constrained by the supply of low-carbon sustainable feedstocks. **For this reason, the model incorporates a constraint on total biomass availability (including wastes) for industry**, taken from the CCC's internal sixth carbon budget biomass supply allocations. These allocations vary by scenario and contain the annual UK-wide limit on industry's biomass supply in TWh/yr.

6.3.3 Iron & steel and fossil fuel production

Given the Iron and Steel sector's significant contribution to the overall emissions of UK industry (10% of total), the sector was analysed in greater detail for its technology adoption. **Globally, primary iron production has**

[46] A thorough review of all capture technologies can be found in Element Energy, Carbon Counts, PSE, Imperial College, & University of Sheffield's [Demonstrating CO_2 capture in the UK cement, chemicals, iron and steel and oil refining sectors by 2025: A Techno-Economic Study (2014)]
[47] Exception: advanced amines or blends was selected for modelling Refinery Process emissions

the potential for a number of innovative technologies to replace incumbent routes. Currently, UK primary iron production is blast furnace based, and substitution of hydrogen would be limited to a very low percentage of demand. However, in the future, alternative processes include:

- Coal-based processes, such as HISarna[48], which could be compatible with a higher share of fuel substitution and combined with CCS/BECCS for greater emissions reductions.
- Direction reduction of iron (DRI) processes, such as HYBRIT[49], which could utilise 100% low-carbon hydrogen as fuel and reductant.
- Replacement of existing plants with secondary production (steel made from a 100% scrap metal feedstock) utilising electric arc furnaces (EAFs).

The five CCC scenarios all differ in their adoption of the three proposed options outlined above, with greater detail provided in the project's Assumptions Log.

In the UK, industrial emissions from fossil fuel production and fugitive emissions (FFPFE) are also of particular importance. Previous work by Element Energy and the Imperial College Consultants / The Sustainable Gas Institute explored the potential for reducing emissions in FFPFE sectors and processes.[50] The outputs of this work included baseline emissions estimates, abatement technology potential, costs and potential technology deployment rates, which were used to inform recommendations in the CCC's Net Zero reports. This project has taken the results of the previous FFPFE work and integrated them into the modelling for the FFPFE sectors defined.

6.4 Constraints on technology availability

In assessing the first year of technology availability, the model considers the commercialisation timescales along with policy and implementation delays set for earlier years. This decision-making process is shown in Figure 16. Policy delay impacts the first year in which a site may install a technology and therefore the first year in which a technology is available to abate emissions. The base settings for all technologies are 2022 (Year of Policy Availability) and 3 years (Time for Implementation), meaning the earliest deep decarbonisation technologies could be applied in 2025[51].

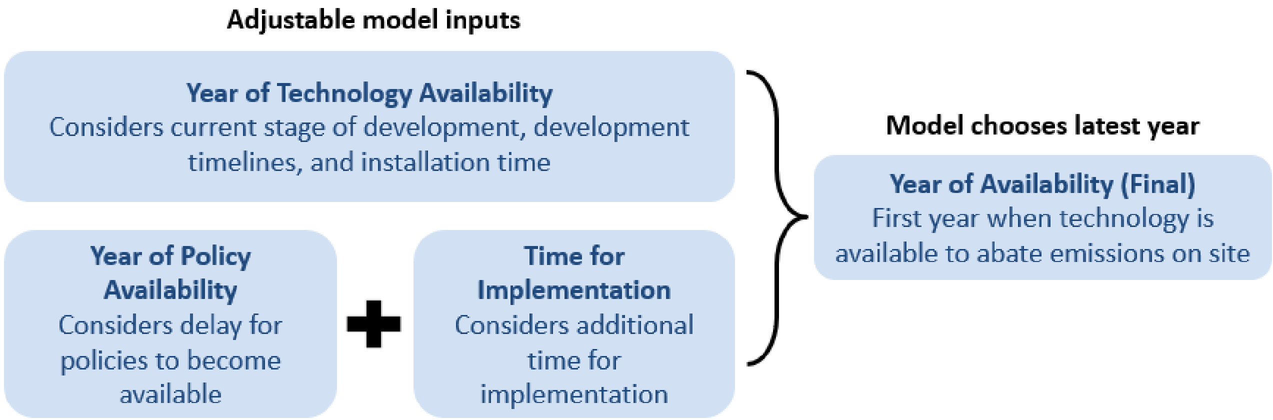


Figure 16 Assumptions informing an abatement technology's first year of availability.

The full set of assumptions surrounding each abatement option's year of technology availability can be found in the project's Assumptions Log. However, it is worth mentioning a few key trends here:

[48] https://www.tatasteeleurope.com/ts/sustainability/carbon-neutral-steel
[49] https://www.hybritdevelopment.com/steel-making-today-and-tomorrow
[50] Assessment of Options to Reduce Emissions from Fossil Fuel Production and Fugitive Emissions (2019): https://www.theccc.org.uk/publication/assessment-of-options-to-reduce-emissions-from-fossil-fuel-production-and-fugitive-emissions/
[51] There is an exception to this for a small subset of technologies which are currently available and potentially commercially viable.

- **The maturity and technology readiness level (TRL) of electrification technologies is generally higher than that of hydrogen technologies for low temperature heat.** Accordingly, the estimated date of first deployment of electrification technologies generally occurs earlier than that of hydrogen technologies.
- **For higher temperature heat applications, electrification and hydrogen generally have similar technology readiness,** with similar years of availability estimated. However due to similarity to the incumbent largely gas fired heating, hydrogen technologies could have fewer barriers in development, for example from the relative ease of piloting or testing hydrogen combustion on existing facilities.
- **Hydrogen technologies are limited in their adoption by access to hydrogen supply infrastructure**, even for the high TRL hydrogen technologies which may become available in the next 10 years. This is location-dependent, see section 5.1.3 for more information.
- Regardless of the exact year in which each technology is first deployed, it is worth noting that **all fuel-switching technologies are expected to become available at the required scale by the early 2030s**. This expectation is conditional on the implementation of suitable policies and economic incentives to support development and commercialisation of the technologies.
- **Carbon capture technologies are at various TRLs across applications, which are dependent on the integration of technologies in specific industrial sectors**. For this project, first-generation CO_2 capture technology's years of technology availability are between 2025 and 2030, whereas second generation technologies are assumed to become available between 2028 and 2035.
- **There is an exception to the policy and implementation base case settings** for gas monitoring, leak detection and repair (LDAR), and continuous monitoring abatement options for methane leakage and flaring in the FFPFE sectors. Given their readiness for deployment, these technologies were set to 2020 (Year of Policy Availability) and 1 year (Time for Implementation).

6.5 Technology Learning and Innovation Seeds

Due to the low technology readiness levels and maturity of many of the technologies involved in industrial decarbonisation, there is potential for cost reductions as time progresses and as the technologies develop. Within the N-ZIP model this is represented by 'learning by doing', where the installation of a technology influences the cost reductions of that same technology in the future. This is done through technologies progressing through a timeline from when the first of a kind (FOAK) installations are installed, through to when second of a kind (SOAK) and Nth of a kind (NOAK) installations are implemented[52].

The cost reductions associated with 'learning by doing' are represented in two ways, through a reduction in the cost of capital[53] and a reduction in the capex and non-fuel opex of decarbonisation technologies. The values of these are given below[54]:

- FOAK: Cost of Capital: 12%, Costs as a % of FOAK: 100%.
- SOAK: Cost of Capital: 11%, Costs as a % of FOAK: 90%.
- NOAK: Cost of Capital: 10%, Costs as a % of FOAK: 80%.

As part of this 'learning by doing' process, '**innovation seed**' sites were included as a way to stimulate and simulate technology learning. These are sites which are forced to decarbonise early with a specified technology, which begins the 'learning by doing' process and cost reduction for that technology. This was done

[52] For most technologies in the model, this timeline is set at 5 years before cost reductions associated with SOAK are achieved and 10 years before cost savings associated with NOAK are achieved. The timeline begins at the earliest year of when a technology was first installed in the UK in the previous iteration of the pathway or five years after the first year of availability (representing the filtering of learnings into the UK through global nature of industry).
[53] Cost of capital represents the hurdle rate for the minimum rate of return on an investment, used in the N-ZIP model to calculate the NPV of abatement technologies' capital expenditure.
[54] The N-ZIP model contains the functionality to adjust the cost as a % of FOAK value for each technology, however the large majority of technologies were left at the default values shown here, with a few adjustments for CCS technologies.

through the mechanism within N-ZIP to force sites to adopt specific technology options at a specific point in time[55]. The set of innovation seed sites and technologies used varied for the different CCC scenarios.

6.6 Supply chain constraints

Preliminary modelling results suggested that supply-chain constraints could be an important factor impacting the speed of industrial decarbonisation. However, the potential capacity of the supply chain for rapid implementation of low carbon technologies and infrastructure was a key area of uncertainty. Supply of equipment, components, skills & labour, and capital would need to ramp up quickly from current levels to meet demand for industrial decarbonisation. To provide a clear quantitative input regarding these constraints and gather further information on justifying or updating the model's supply-chain constraint, three specific areas impacting the supply chain were explored:

- Amount of skilled labour
- Supply of technologies/market growth
- Availability of capital/finance

The pace of supply chain ramp-up was explored via a dedicated consultation with suppliers, engineering firms and financiers. This involved reviewing the initial assumption that overall supply chain capacity would be limited to abatement of around **5% of annual baseline emissions for a given sector, or abatement of the closest number of single sites, increasing to 10% in 2030.**[56] The key responses from the consultation were that:

- 5-10% of abatement per year per sector is reasonable, but pace is uncertain and will rely on business models being available to provide greater certainty to the supply chain to justify ramp up (which could take approximately 5 years from FOAK plants).
- Supply of components will grow in response to increased demand, but there is likely to be competition for local labour, especially for large infrastructure projects.
- A deeper assessment of the availability of specific skills and components is needed.
- Capital is unlikely to be a limiting factor, but different rates will apply for FOAK, SOAK and NOAK projects.

Thus, the initial assumption was refined based on stakeholder feedback and its impact on the different CCC scenarios. The final constraints incorporated into the modelling are shown in Figure 17.

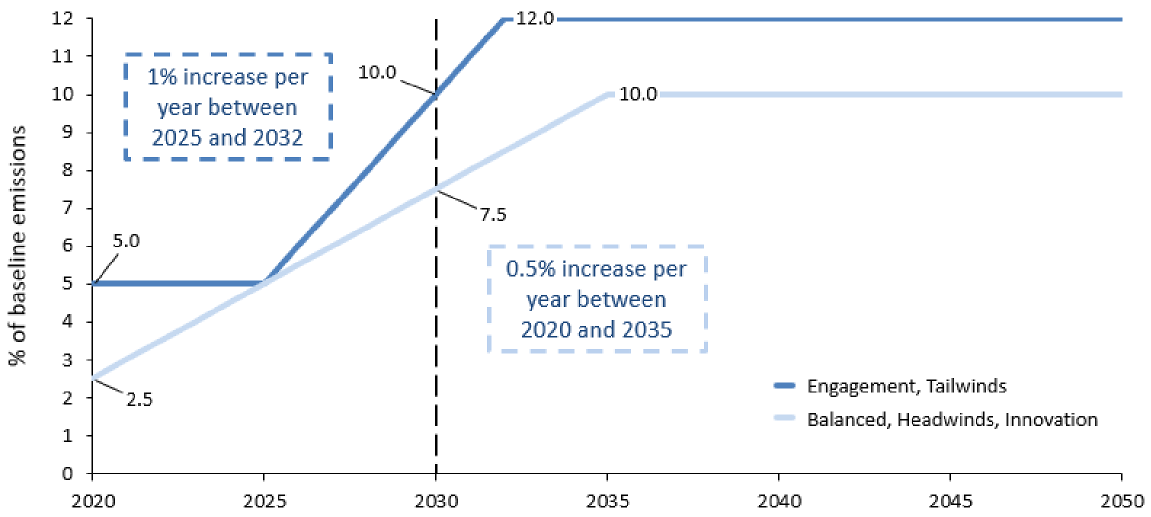


Figure 17 Ramp-up in supply chain capacity between 2020 and 2050 for the CCC scenarios

[55] Provided it is compatible with the other constraints in place in the N-ZIP model.
[56] Using a different line of thought, a 10% per year emissions abatement constraint would allow for an entire industrial sector to decarbonise within 10 years in the absence of any further constraints.

Table 8 highlights some of the detailed responses from the supply chain consultation. These points demonstrate the need for additional work in assessing and resolving some of the key bottlenecks impacting the industrial decarbonisation supply chain in the coming 3 decades.

Table 8 Responses from the consultation on industrial decarbonisation supply chain constraints

 Amount of skilled labour	• Consideration of the shortage of electrical engineers. • High potential for shift from oil and gas industry to other large infrastructure projects. • Local labour may be constrained but capacity could also come from abroad. • Phased approach to deployment would enable skills ramp-up. • Further analysis of skills gaps is needed.
 Supply of technologies / market growth	• Transformers and electrodes are already a bottleneck for electric boilers and furnaces. • Limited number of suppliers and new entrants would have a couple of years delay to market entry. • Further development needed in gas monitoring for hydrogen and CCS.
 Availability of capital / finance	• If the right business models are in place, there ultimately would be no constraint on capital. • High level of "bespokeness" for industry projects so interest rates will differ depending on experience (FOAK, SOAK, NOAK) – this might have the effect of limiting capacity to 1 large project per year in the initial years. • Industry clusters may rely on government-backed capital in the short-to-medium term. • Lengthy project delivery times could be a constraining factor to securing investments.

7 Deep-decarbonisation Pathways and Sensitivities

7.1 Overview of CCC Scenarios

As part of the CCC's economy-wide sixth carbon budget analysis, five scenarios were defined, with each representing a credible future scenario for economy-wide net zero by 2050. The N-ZIP model was set up to assess the decarbonisation pathway within each of these scenarios. Broadly, these scenarios are:

- Widespread **Engagement** (high efficiency and electrification): People are willing to make more changes to their behaviour. This reduces the demand for the most high-carbon activities and increases the uptake of some climate mitigation measures.
- **Headwinds** (high hydrogen): People change their behaviour and new technologies develop, but there are no widespread behavioural shifts or innovations that significantly reduce the cost of green technologies ahead of current projections. This scenario is more reliant on the use of large-scale hydrogen and CCS infrastructure.
- Widespread **Innovation**: This scenario sees high innovation in several carbon mitigation technologies and measures. Costs fall faster than central projections, allowing more widespread electrification and more cost-effective technologies to remove CO_2 from the atmosphere. Resource and energy efficiency measures play a balanced role across the economy.
- **Tailwinds**: A scenario with a combination of accelerated deep decarbonisation drivers from each of the 3 broad scenarios defined above.
- **Balanced** Net Zero Pathway: An 'options-open' pathway that undertakes low-regret measures and develops options sufficiently to progress towards net zero whatever state of the world occurs. The pathway includes a balanced mix of technologies in the long term, which enables decision-making to change track depending on developments in the short-to-medium term.

The model incorporates several changes to its operating parameters depending on the selected scenario, including fuel costs, the potential conversion of the gas grid to hydrogen, and the constraints on biomass use and on the supply chain. The full list of parameter settings varying between scenarios can be found in the project's Assumptions Log.

7.1.1 Fuel Costs

One of the key parameters impacting the site decision-making are the input fuel costs, which significantly impact the NPV calculations between different abatement categories (i.e. electricity versus green hydrogen cost). In previous work by Element Energy informing the CCC's 2019 Net Zero report,[57] fuel costs for hydrogen were set at 4.9 p/kWh (assumed to be almost static to 2050) and for electricity were set at 11 p/kWh in 2019, reducing to 8 p/kWh in 2050. These contrast with the fuel costs used in this study's Balanced scenario, which are shown in Figure 18 (i.e. greater green hydrogen cost throughout all years, greater blue hydrogen cost in earlier years and significantly lower electricity cost throughout all years[58]). These costs play a significant influence on the relative attractiveness between hydrogen and electricity fuel switching.

All fuel costs input to this project's model are based on long run variable costs (LRVCs), rather than the retail price paid by industrial sites. The LRVCs exclude supplier costs, supplier profits and additional costs from lower carbon policies (e.g. carbon price, climate change levy, etc.), and are used to assess the system cost of pathways in a technology-neutral manner. The LRVCs used in this analysis are based on analysis by the CCC and this project's analysis of CO_2 T&S and hydrogen infrastructure, and are consistent with the CCC's sixth carbon budget work in other economy sectors. It is important to note therefore that the costs included in this analysis are not representative of the prices which industrial sites currently expect to pay

[57] Extension to Fuel Switching Engagement Study – Deep decarbonisation of UK industries (2019)
[58] Biomass costs are also significantly lower, at 2.3 p/kWh in this work in contrast to the 5p/kWh assumed in the previous study.

for these fuels in the present or future – with policy change/support likely required to move from today's pricing closer to these costs.

For the fuel costs in Figure 18 (all fuels in the Balanced scenario) and Figure 20 (green hydrogen and electricity in all scenarios), the following points should be noted:

- Costs for combustion fuels (hydrogen, biomass, gas, coal, oil) are on an LHV basis.
- Green and blue hydrogen costs shown are the average across all production points (i.e. cost of centralised hydrogen in clusters), with the additional transport costs to transport hydrogen to the site added separately as capital/operational costs in the model's NPV calculation.
- Electricity costs shown (solid line) are the cost to deliver electricity to industrial customers (LRVC), with additional site-level network reinforcement costs added separately as a capital cost in the model's NPV calculation. An additional electricity cost (dashed line) is provided as reference for electricity costs without the network cost components (i.e. transmission, distribution, balancing) included.

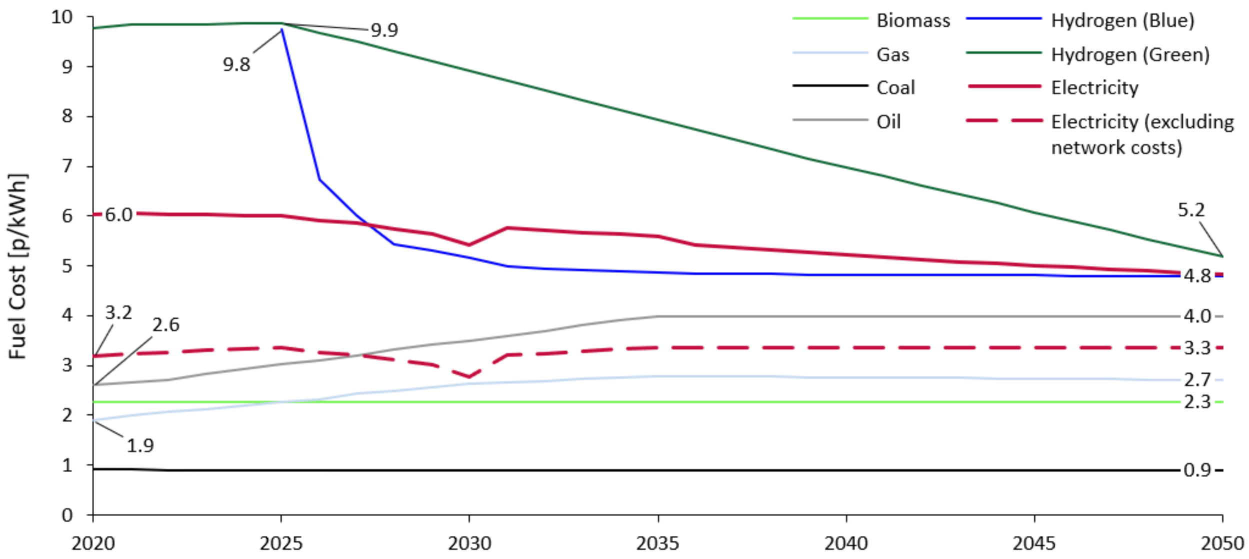


Figure 18 Fuel costs in the Balanced scenario.

A fuel cost component breakdown between green hydrogen and electricity in the Balanced scenario is shown in Figure 19, with the addition of the network cost for a converted gas grid to hydrogen included (~1.0 p/kWh). With the network cost added, the cost of green hydrogen is 34% greater than electricity in 2050. This figure may change when considering sites which have their hydrogen supplied via trucking or dedicated pipelines instead of via a converted gas grid. It is also worth restating that the cost of green hydrogen shown in this figure is on an LHV basis.

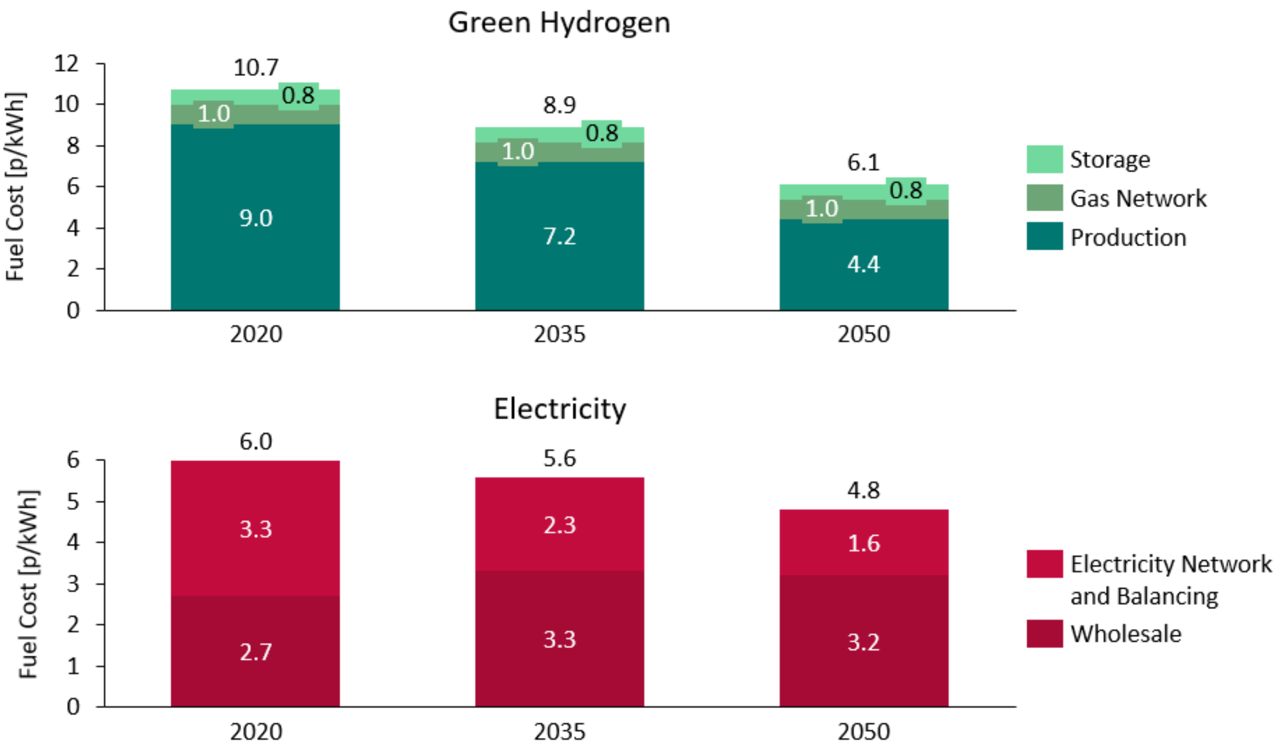


Figure 19 Comparison of green hydrogen and electricity costs in the Balanced scenario

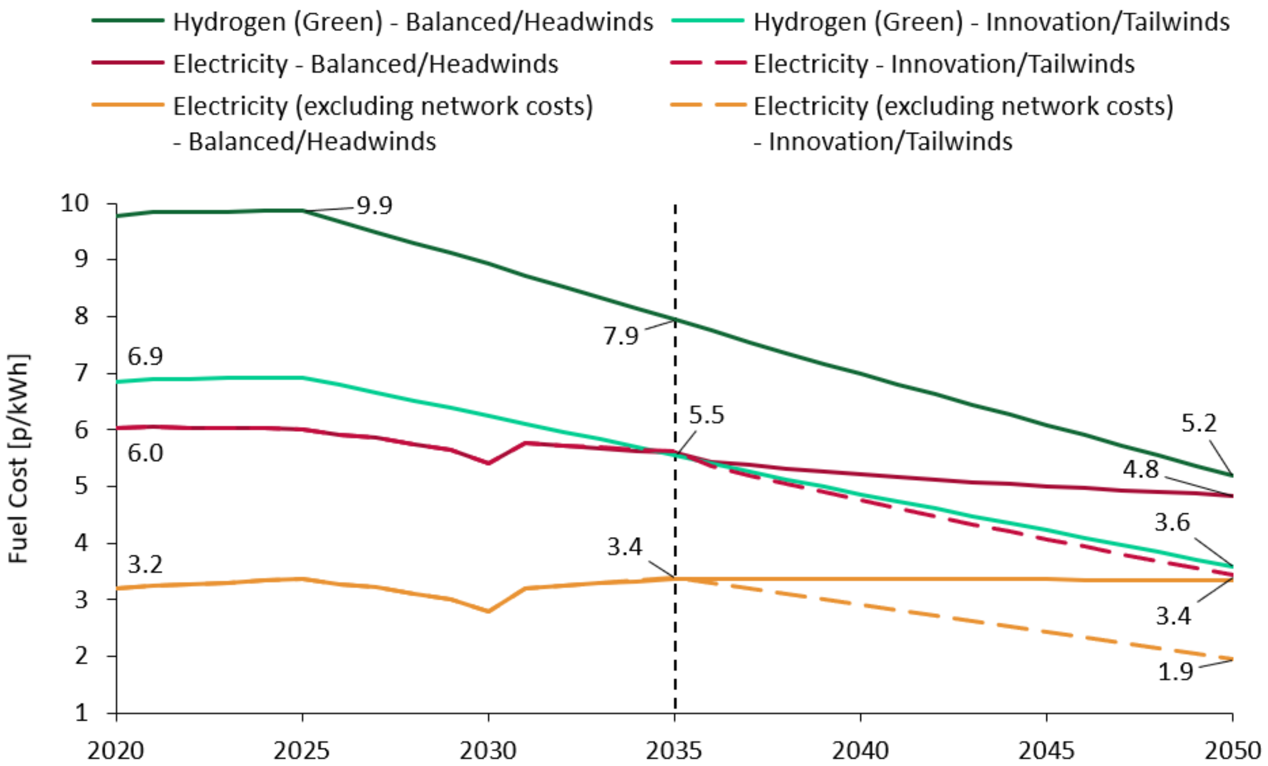


Figure 20 Green hydrogen and electricity fuel costs in the different CCC scenarios.[59]

[59] The Engagement scenario follows closely to the Balanced/Headwinds fuel cost trajectory, with Engagement's electricity costs ranging between 1-6% lower than Balanced between 2037 and 2050.

7.1.2 Scenario Assumptions

It should be noted that **the scope and type of industrial activity (sectors, processes, site locations) is assumed to remain consistent** over the timeline of interest (i.e. to 2050).[60] It is acknowledged that this assumption may not hold in practice, especially in light of the current industrial downturn caused by the COVID-19 pandemic. This **assumption applies across all scenarios** and was made to isolate the impacts of each decarbonisation option while avoiding the inclusion of uncertain assumptions in the analysis (i.e. future evolution of industrial activity in the UK).

Furthermore, this analysis assumes that neither the industrial products nor their manufacturing processes change over the 2020-2050 period (although resource and energy efficiency improvements are assumed, refer back to section 4.4 for further details). For this reason, counterfactual technologies are assumed to remain static, with regular replacement cycles until 2050. Given their highly uncertain nature, breakthrough technologies that may impact existing industrial production processes were left out of scope (e.g. solar-heated reactors for energy intensive industries[61]).

The carbon value used in each scenario is another key driver of the pace and depth of emissions reductions for each scenario. All scenarios except Tailwinds use BEIS' Green Book non-traded (high) carbon values[62], which reach a final value of £346/tCO_2 in 2050. The Tailwinds scenario uses a CCC carbon value path of £450/tCO_2 in 2050, discounted backwards by 3.5%. The evolution of each carbon value over the time period of this study are shown in Figure 21.

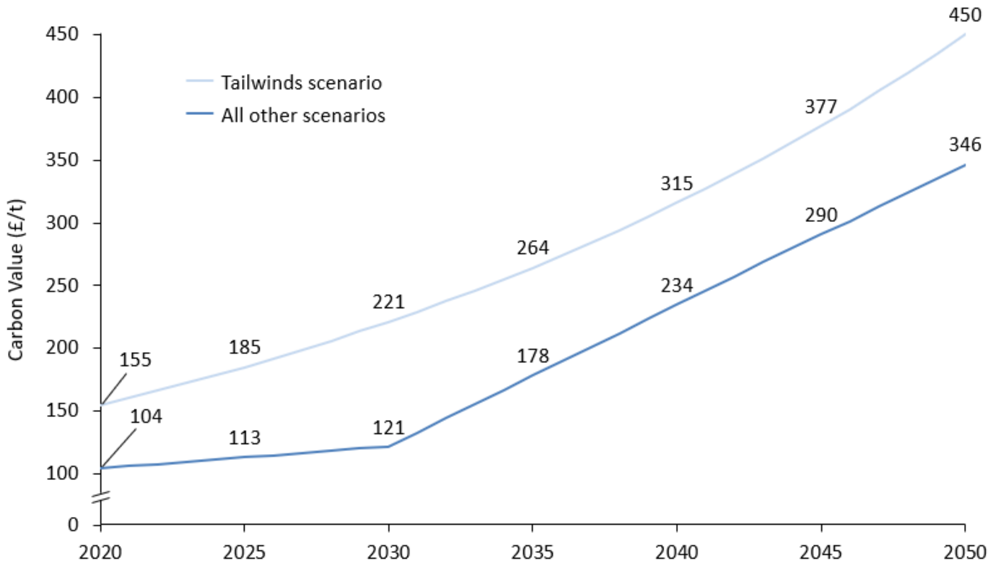


Figure 21 Carbon values used in this study.

7.2 Results

7.2.1 Emissions Reductions to 2050

The first finding of this study is that **remaining emissions from UK industry decrease by over 95% below 2018 levels (110.9 MtCO_2e) by 2050 in all deep decarbonisation scenarios,** reaching 3.9 MtCO_2e in the Balanced scenario and 3.3 to 4.8 MtCO_2e across the other scenarios. The deep decarbonisation potential of all scenarios is first of all explained by the fact that nearly all emissions were assigned at least one suitable

[60] Note this does not imply baseline emissions remain constant. In addition, site closures and REEE measures are taken into consideration in all pathways. Refer to sections 4.3 and 4.4 for more detail.
[61] Trial projects (e.g. SOLPART) and start-ups (e.g. Heliogen) are investigating high temperature (800-1000°C) solar processes suitable for reactive particle thermal treatment in energy intensive industries, such as cement, lime, phosphate, mining, petrochemicals and waste treatment.
[62] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

abatement technology. Second, despite the differences between scenarios, the target-driven carbon value was sufficiently high to make it target-consistent for sites to adopt higher cost abatement options.

The results of each scenario are shown in Figure 22 Emissions abatement pathway for each of the CCC scenarios., breaking down emissions reductions by REEE measures and deep decarbonisation abatement, with the abatement in 2050 assigned to each shown on the right hand side of each plot. It is worth noting cumulative abatement values above the plots do not include REEE reductions, referring to the abatement from deep decarbonisation technologies. Cumulative abatement is affected by the level of abatement in 2050, the speed of abatement and the scale of emissions remaining after REEE measures are applied. For instance, fast abatement is driven by the higher carbon value and the lower level of 'optimism bias' accounts for the higher level of cumulative abatement in Tailwinds. Conversely, greater REEE reductions account for the lower cumulative emissions abatement from 'deep decarbonisation' in the Engagement scenario.

The **speed of the abatement is** also worth noting – many sectors are constrained in their early years not by the economics of the decarbonisation but by the supply chain constraint and how much of the sector is able to decarbonise in a given year. The NPV assessment for many technologies are positive in the early years given a carbon value between £104 - 112/tCO_2e from 2020 to 2030. This means the pace of decarbonisation is controlled by the supply chain constraint, which accounts for the similar shapes of the abatement curves as the supply chain constraint only differs a small amount by scenario (refer back to section 6.6 for more detail).

This speed is worth contrasting to the previous analysis conducted to inform the CCC's 2019 Net Zero report, where the roll out scenarios varied from 20 years in the fast scenario to 38 years in the slow scenario.[63] Despite increased costs of technologies to account for potential optimism bias, the target consistent carbon values included in the modelling here largely drive a roll out consistent or exceeding the previous fast scenario, even accounting for additional costs from the equipment scrappage potentially associated with a faster roll out.

[63] Element Energy, Extension to Fuel Switching Engagement Study – Deep decarbonisation of UK industries (2019)

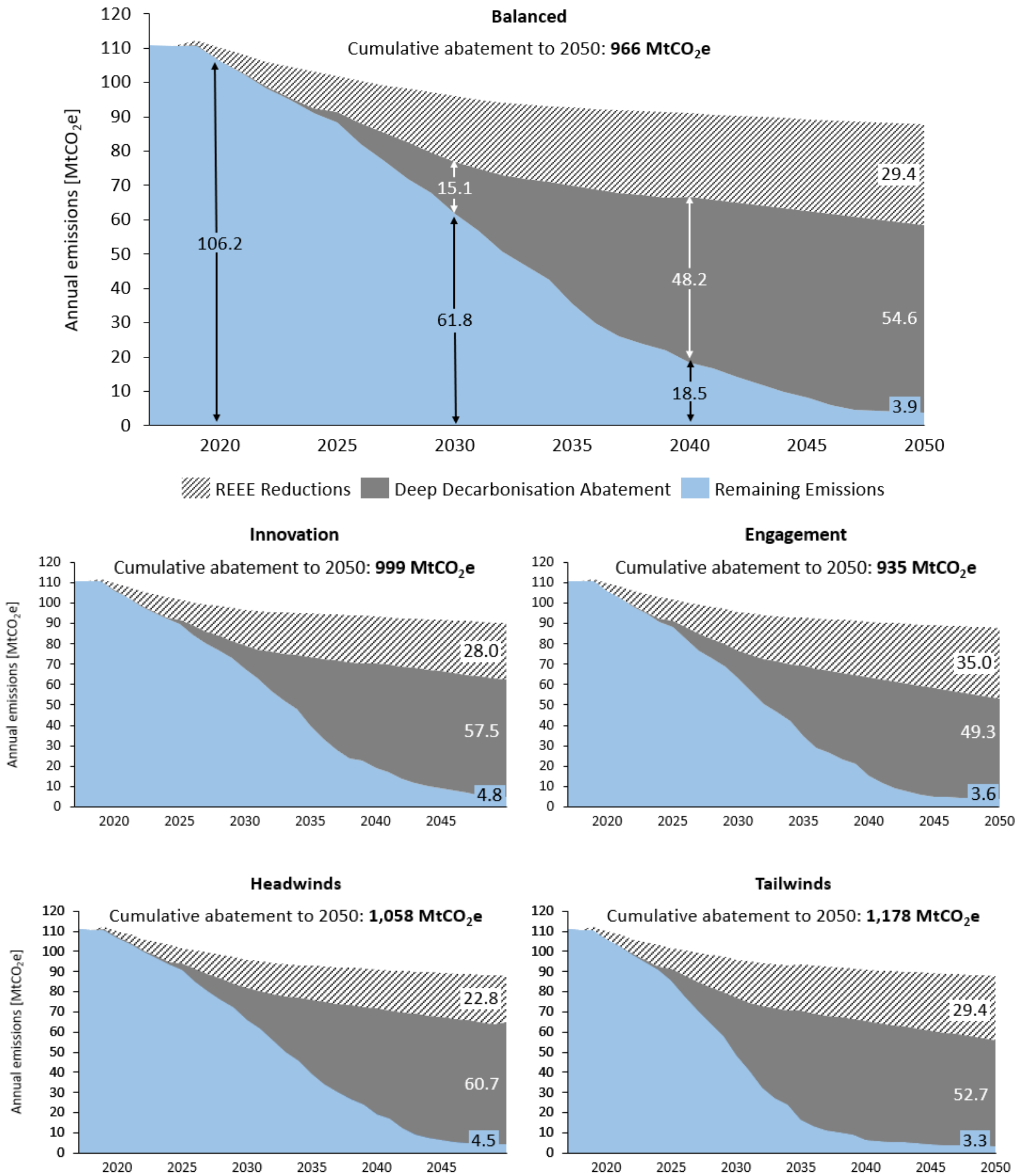


Figure 22 Emissions abatement pathway for each of the CCC scenarios.[64]

[64] Cumulative abatement values above the plots do not include REEE reductions, referring only to the abatement from deep decarbonisation technologies.

7.2.2 Remaining Emissions

In all of the five scenarios, there are emissions which remain in 2050[65]. The level of this ranges from 3.3 $MtCO_2e$ in the Tailwinds scenario to 4.8 $MtCO_2e$ in the Innovation scenario. These represent two types of remaining emissions:

- **Processes with no abatement applied –** these are processes on sites which have not had any abatement applied to them, either because the abatement is too expensive to achieve a positive NPV, or because there were no options identified to overcome these.
- **Residual Emissions –** these represent the emissions which remain after abatement technologies without an 100% abatement rate are applied to a process. These are generally emissions remaining from <100% capture rate of CCS technologies, or technologies to abate flaring or other fugitive emissions.

Figure 23 shows the contribution of these two types of emissions to the remaining emissions in 2050 in the Balanced scenario, broken down into the major contributors.

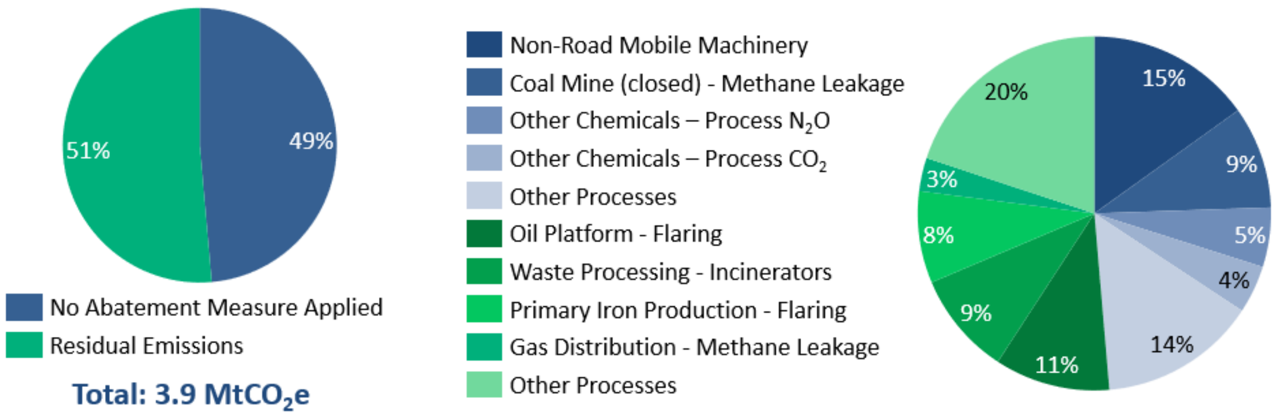


Figure 23 Remaining emission sources in 2050 (Balanced scenario).

The remaining emissions can also be broken down geographically. Figure 24 shows snapshots of the remaining emissions over time for sites within 50km of the UK's six major industrial clusters in the Balanced scenario. Within all clusters, there is significant progress on deep decarbonisation by 2035, with the largest emissions reductions between 2025 and 2035. In this period, 54% of cumulative direct emissions abatement occurs across all cluster points (as defined by the 50km radius), with remaining abatement occurring at dispersed sites. This fast reduction in cluster emissions between 2025 and 2035 contrasts with the wider industry figure shown in Figure 22 Emissions abatement pathway for each of the CCC scenarios., where a larger portion of the decarbonisation is implemented after 2035. This illustrates the relative ease of decarbonising sites within clusters compared to more dispersed sites, and suggests action in 2025-2035 on all industrial clusters might be the NPV optimal approach.

Figure 25 shows the trajectory of remaining emissions split out by the UK's devolved administrations, as well as offshore oil and gas platforms. In all decades, actions are required within each devolved administration to deploy deep decarbonisation technologies and infrastructure in order to meet the required UK-wide abatement levels necessary for net zero industry by 2050. It is also worth mentioning again that a large proportion of the emissions reduction from offshore platforms are allocated to reduced production of and demand for petroleum products[66].

[65] Negative emissions are also present, these are described in section 7.2.5.
[66] If emissions did not decrease due to this reduced demand, it would likely be possible to apply deep decarbonisation technologies on a large proportion of these emissions

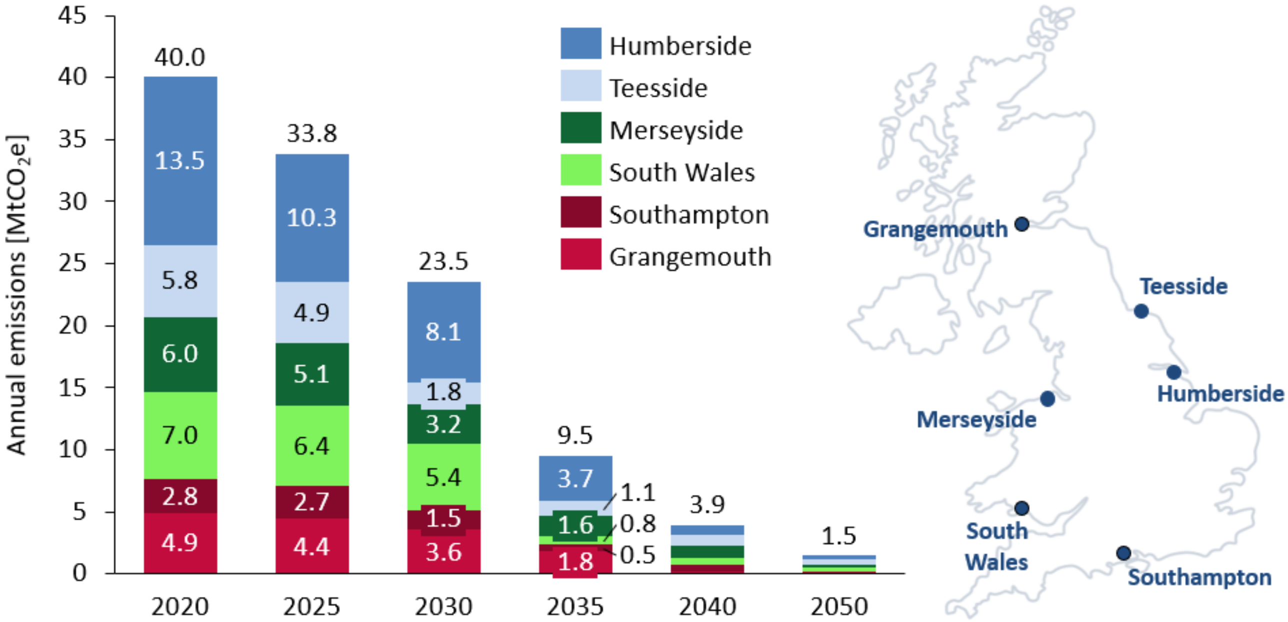


Figure 24 Remaining emissions at sites within a 50km radius of the UK's six major industrial clusters (Balanced scenario).[67]

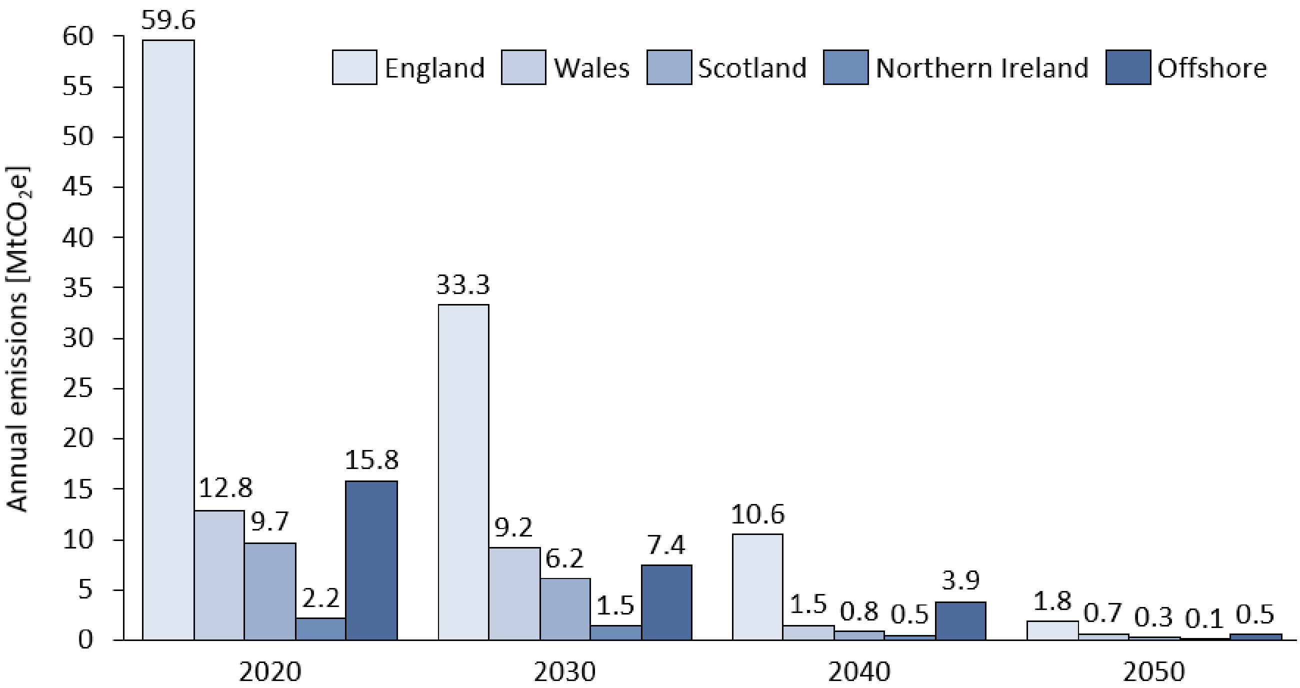


Figure 25 Remaining emissions by devolved administration and offshore sites.[68]

[67] Emissions at the Humberside cluster refer to the sum of emissions from the previously defined Humberside (terminal) and Humberside (in-land) defined points in Figure 12. This also excludes negative emissions present from industry in some clusters.

[68] Excludes emissions from NRMM (emissions were not assigned devolved administrations) and a single waste processing site on the Isle of Man.

7.2.3 Technology Type

The decarbonisation pathways from the scenarios show a number of different attributes when the deep decarbonisation is broken down by technology types, as shown in Figure 26.

- **Resource efficiency and energy efficiency (REEE) levels vary between the scenarios** - the Engagement scenario contains the highest level of emissions abatement from efficiencies, with the Headwinds scenarios containing less.
- **CCS has a relatively consistent baseline of emissions reductions across the scenarios**, remaining a key technology for industrial decarbonisation – no scenario has less than 13 $MtCO_2e$ of emissions reductions from CCS. This is because CCS technologies are likely the only option for decarbonising process emissions of CO_2, internal fuel use, and waste incineration. The Headwinds scenario has a larger proportion of CCS use, both from CCS being advantaged through increased focus on infrastructure, as well as having to decarbonise the larger remaining emissions after REEE reductions are applied. Additionally, CCS is key for the production of a large amount of blue hydrogen in many scenarios.
- **BECCS is viewed as favourable for sites** – due to the potential for negative emissions from capturing biomass combustion emissions, switching fuels to biomass and applying CCS is generally chosen as the first choice of technologies where it is deemed a suitable technology and if there is sufficient biomass resource. In addition, where biomass is currently used as a combustion fuel (not included in these emissions plots due to biogenic emissions), CCS is applied to these processes, providing additional negative emissions.
- **There is a role for both electrification and hydrogen in all scenarios, though the relative scale of each varies**. In some processes, one or the other is heavily favoured (approx. 9-10 $MtCO_2e$ of emissions reductions each), while for other processes, electrification and hydrogen are reasonably competitive with each other, with the technologies chosen varying by scenario (another approx. 10-12 $MtCO_2e$). CCUS also competes on a minor level for some of these emissions, however its use in this sense is limited to the larger sites. It should be noted that within this modelling, the projected cost reductions of fuels (largely electricity and green hydrogen) are clear to sites/decision makers, and are fully included in the NPV calculations.
- **Blue and green hydrogen remain closely matched** – there is no clear winner between blue and green hydrogen across the different scenarios, with each dominating the hydrogen demand in two of the five scenarios. However, as cost reductions over a long time horizon are fully included in the NPV calculations, the fully green hydrogen scenarios are likely to be unrealistic. This is because at the time of decision-making, it is unlikely that industrial sites' decision makers will have certainty and/or confidence in projecting the cost reductions of green hydrogen into the future. Additionally, when a site decarbonises, it chooses either green or blue if choosing a hydrogen option, sticking with that hydrogen supply up to 2050. In reality, supply arrangements are likely to be more flexible, with sites likely reticent to remain tied into long term contracts of decades, meaning the blue vs. green hydrogen supply might change more in the later years of these scenarios.
- **Cost-competitiveness between green hydrogen and electrification are influenced by a number of factors.** Green hydrogen becomes favoured for many large sites near to centralised hydrogen production points which can take advantage of the lower-cost dedicated pipeline networks to industrial users. In later years (i.e. 2035 to 2050), small and medium sized sites may also select green hydrogen, supplied at low cost via a converted gas grid. Electrification offers opportunities for earlier abatement across a range of processes at dispersed industrial sites, which may be able to take advantage of existing electricity network capacities without the need for added network reinforcement costs (refer to section 5.3 for further detail).

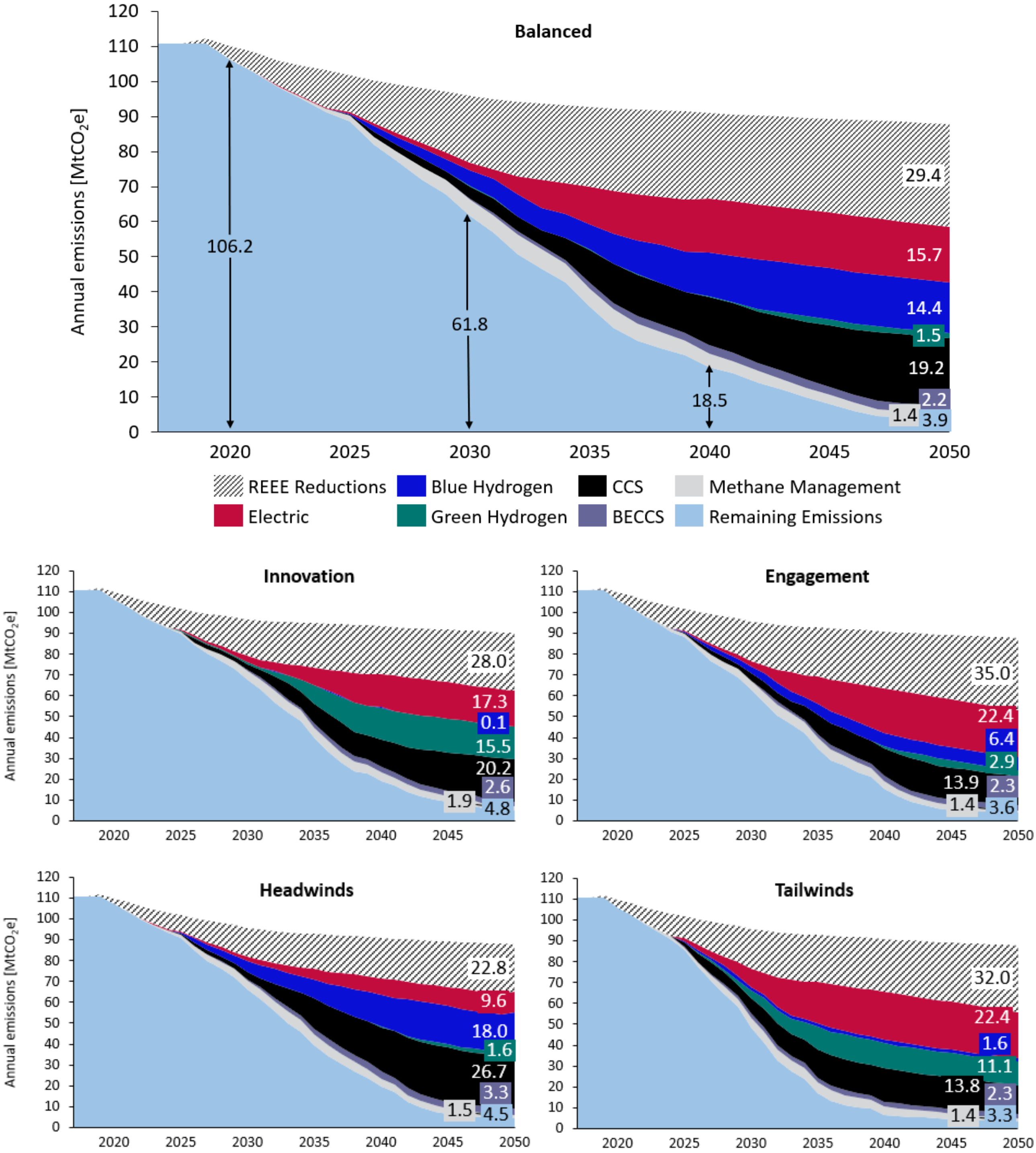


Figure 26 Emissions abatement pathway for each of the five CCC scenarios[69]

These technology categories can be split further by sector and by timing to understand the potential for sequencing interventions and sectoral decarbonisation, shown below for the Balanced scenario in Figure 27. Key points to note here include:

- **Electrification of industry begins quickly with some relatively easy wins progressing to abate 10.5 to 23.1 $MtCO_2e$/year by 2050 across scenarios.** These easy wins (given the carbon value used) come from sectors with significant amount of low temperature heat, such as the food and drink

[69] Cumulative abatement values above the plots do not include REEE reductions. Emissions abatement via BECCS excludes negative emissions. Numbers shown on the right-hand side of each plot refer to 2050 values.

industry, where heat electrification is already proven and relatively widespread globally. In the early 2030s, there is a large demand for electrification in the chemicals sector as well as from uptake of electric arc furnace technologies in the iron and steel sector. The vast majority of the uptake of electrification is completed by 2040, meaning there is potentially room for greater deployment of electrification if technology progresses further or if progress in other technology options is lower than expected. In scenarios with increased electrification demand (i.e. Engagement), uptake is increased in areas away from clusters, as hydrogen fuel switching is less attractive in those areas with a lower focus on infrastructure in the Engagement scenario. In scenarios with lower portions of electrification (i.e. Headwinds), this primarily results from reduced demand in primary iron production, off-road machinery and in indirect heating.

- **Uptake of carbon capture technologies in industry begins fast, growing to abate 13.7 to 26.5 $MtCO_2e$/year by 2050.** Early uptake is focused in industrial clusters around some relatively easy wins in the Refining and Ammonia sector. Between 2030 and 2040 uptake grows from clusters through expansion of demand into other sectors and areas, with notable additions being the addition of CCS technology on primary iron production, as well as expansion of CCS outside of the shoreline clusters to dispersed cement sites. After 2040 much of the uptake comes from the waste processing sector applying CCS on energy from waste incinerators, a rare sector where emissions grow from 2020 to 2050 even when accounting for resource and energy efficiencies. In scenarios where there is lower CCS demand, this is mostly accounted for from lower demand for CCS in waste incinerators, as the other applications of CCS are either highly favoured over other options (large processes in clusters) or likely the only option (process CO_2 emissions). In scenarios with higher CCS demand, this is from increased CCS demand in primary iron and steel, increased activity in waste incineration and increased activity in other sectors from lower REEE abatement.
- **BECCS abates between 2.2 and 3.3 $MtCO_2e$/year by 2050, not accounting for the negative emissions accrued.** This emissions abatement comes from fuel switching industries to biomass, and is concentrated in the Cement, Glass and Paper sectors (see section 6.3.2 for more information on suitability), remaining consistent across many of the scenarios.
- **Hydrogen fuel switching abates between 8.9 and 18.7 $MtCO_2e$/year by 2050**. Before 2025, the hydrogen demand comes solely from the off-road mobile machinery sector, where fuel cell forklifts are well established in the US[70]. Hydrogen is then taken up to provide heat in large industrial sites near to clusters, particularly in relatively simple applications such as large boilers. From 2030 to 2050, hydrogen continues to be deployed in these applications in sites further from the centre of clusters, while also adding increased demand from direct heating in kilns, furnaces and dryers. Additionally, hydrogen is also used to provide heat to sites operating CCS solutions, adding to the overall hydrogen demand beyond this graphic. Within the scenarios with lower hydrogen demand, hydrogen uptake is reduced outside of clusters and in the indirect heating applications, and eliminated in the off-road machinery sector. In scenarios with increased hydrogen demand, this mostly comes from expansion of hydrogen demand at the expense of electrification in similar applications but on less favourable sites (either smaller sites or further from clusters), with increased demand from direct reduction in iron and steel also present in some scenarios.

[70] State of the States: Fuel Cells in America 2017, US DoE 2018

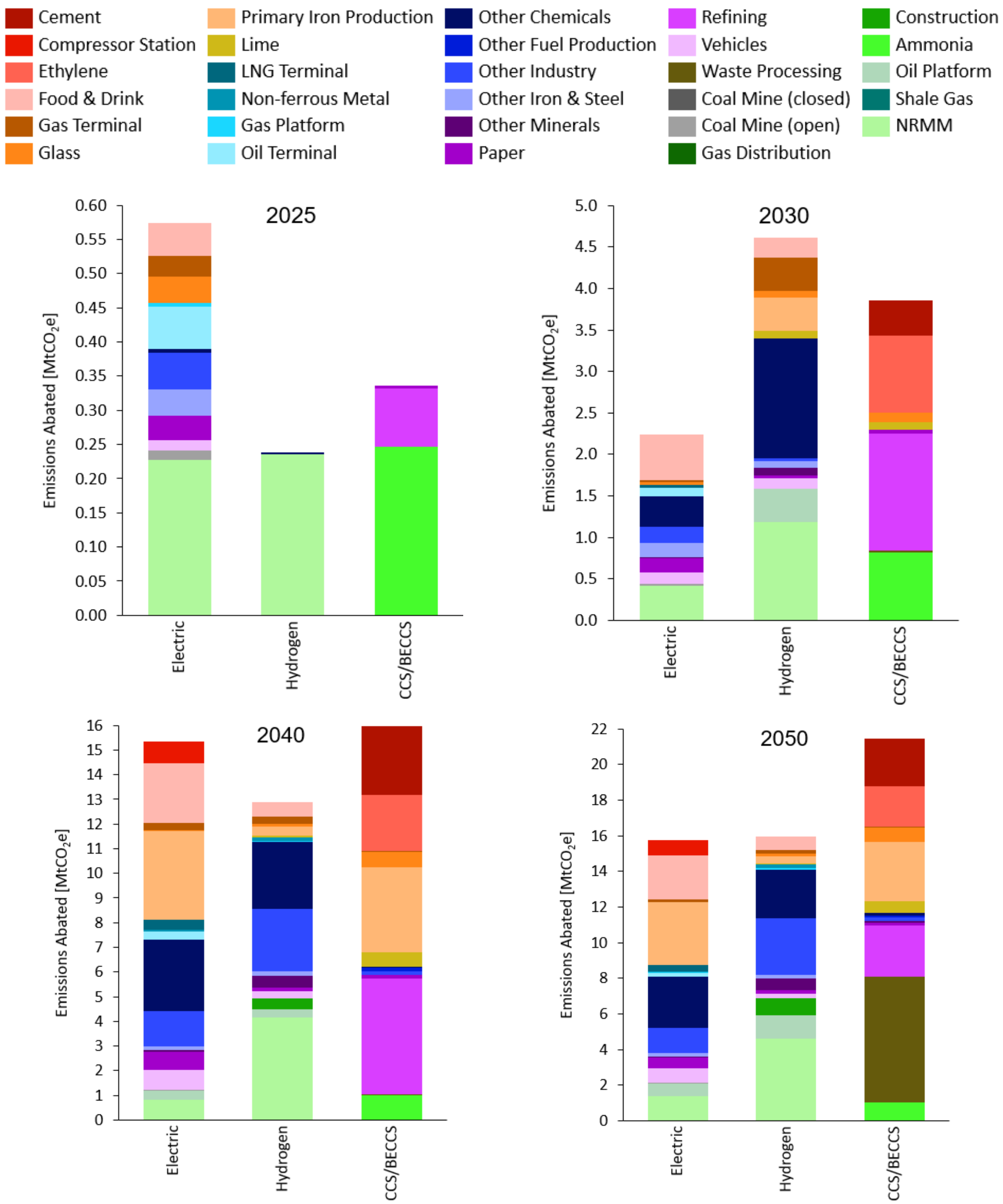


Figure 27 Direct emissions abated by technology type, split by industrial sector (Balanced scenario).[71]

Abatement of indirect and direct heating emissions occurs through a combination of electric and hydrogen technologies. Current assumptions suggest most conventional heat generation technologies can be abated through either hydrogen fuel-switching or electrification abatement technologies. Although

[71] "Methane Management" abatement technologies (e.g. gas recovery/LDAR) are excluded from these figures. Hydrogen includes emissions abated by both blue and green hydrogen.

electrification options may be available earlier, in the long-term there is thought to be no clear technology preference with both options used to abate the same types of processes at different sites within each sector. Different scenarios show a preference for hydrogen or electrification, however this is not as strong a preference as to fully eliminate all use of hydrogen or electrification in scenarios where it is less favoured. Figure 28 illustrates that the size of the application is not a significant factor for determining abatement preference with hydrogen boilers being selected for both small- and large-scale applications.

The selection of hydrogen or electric abatement options is partially dependent upon location, illustrated for boilers in Figure 28. The availability of hydrogen varies by location with constraints associated with hydrogen production and infrastructure deployment meaning availability comes later for dispersed sites. When hydrogen is available (via pipeline or trailer), costs of supply tend to increase with distance from the production site (located at a defined point). Therefore, sites located further from the defined points tend to favour electrification abatement technologies, especially in the earlier years before the modelled conversion of the gas grid to hydrogen becomes available/widespread. Similar results are seen for the decarbonisation of CHP, however these have an additional slant towards re-electrification of heat and power demand. This is due to the increased cost of gas when moving from natural gas to hydrogen (or natural gas with CCS) in comparison to the decreasing cost of electricity from low cost renewables.

BECCS is can be a favourable option where it is allowed for indirect heating, and CCS is applied where required. In addition to electrification and hydrogen options, fuel switching to biomass with CCS is an alternative abatement route for heat generation for indirect heating currently powered by fossil fuels. The use of BECCS is limited by the constraints described in section 6.3.2 but it is seen that when this technology is allowed it generally becomes a favourable option, especially on the larger sites in sectors utilising biomass. On sites that use high proportions of internally generated fuels[72], CCS is also needed.

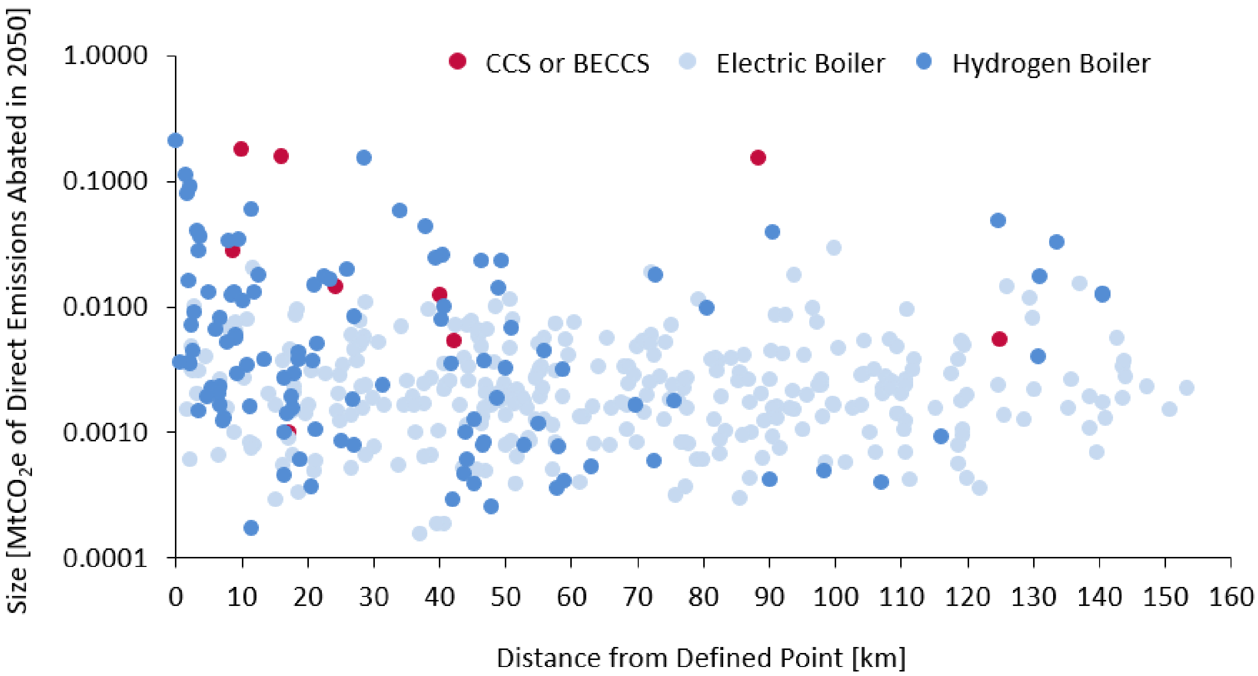


Figure 28 Abatement technology selection for boiler processes (Balanced scenario).[73]

[72] Here post combustion CCS is used in the modelling, however it is recognized that pre-combustion capture through central pre-reforming to hydrogen is likely an alternative option.
[73] Point sources only.

7.2.4 CO_2 T&S and Hydrogen Uptake

CO_2 T&S uptake grows steadily from 2025 with demand split across all available storage sites. Figure 29 shows the uptake of industrial CCS at the defined points, along with the percentage of onshore transport in 2050 which done via pipeline or trucking[74]. The initial uptake occurs at Merseyside with CCS applied to process emissions at a nearby ammonia plant. The next location to receive T&S demand are similar facilities on Teesside. It is worth noting that these uptake rates do not include CO_2 from blue hydrogen production (for industry or other sectors of the economy) or CO_2 demand from other economy sectors (e.g. power) within this figure, which could dominate the T&S demand (see Figure 34).

In the long-term the waste processing sector sees the highest uptake of CCS technology, reflecting the large biogenic and non-biogenic CO_2 emissions from the sector in later years. Figure 30 shows the capture of CO_2 from different sectors over time. From 2035 the growth in CO_2 T&S demand is dominated by increases in CO_2 capture from the waste processing sector, including the negative emissions from BECCS. This CO_2 captured from waste is responsible for the majority of the CCS uptake at Southampton and Medway, and is sometimes from sites near urban areas dispersed from industrial clusters.

The supply of captured CO_2 from individual CCS installations can reduce over time due to the application of REEE measures. In some sectors, application of REEE measures decreases the CO_2 emissions at sites, leading to a decline in the CO_2 T&S demand from existing installations. This effect is typically balanced by an increase in supply resulting from additional installations of CCS technologies at new sites. However, for the refining sector the CO_2 supply to storage peaks in 2035 with subsequent decline aligned with reductions in production associated with the declining oil demand in the rest of the economy. The cement sector also sees a slight decline after 2035.

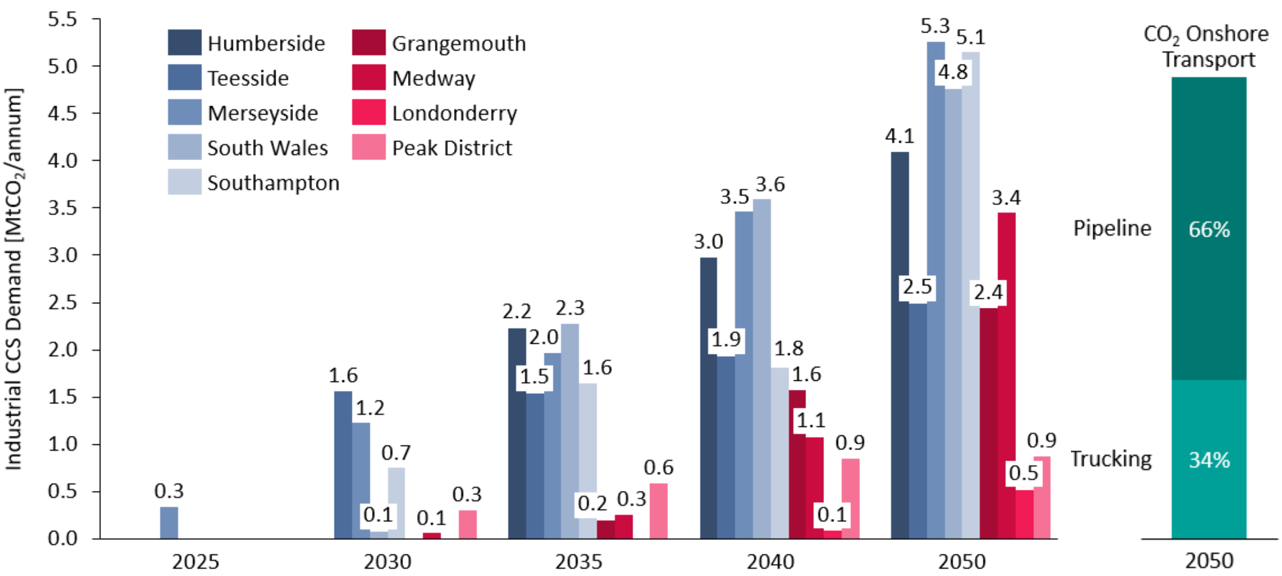


Figure 29 CO_2 T&S uptake from industry at defined points (Balanced scenario), excluding CO_2 T&S demand from hydrogen production for industry.[75]

[74] The % of CO_2 T&S demand supplied by the trucking option might be overestimated here, as the modelling did not consider networking and aggregation of CO_2 T&S demand for point sources close to each other.
[75] Humberside includes CCS uptake at both the terminal and in-land trunk pipeline.

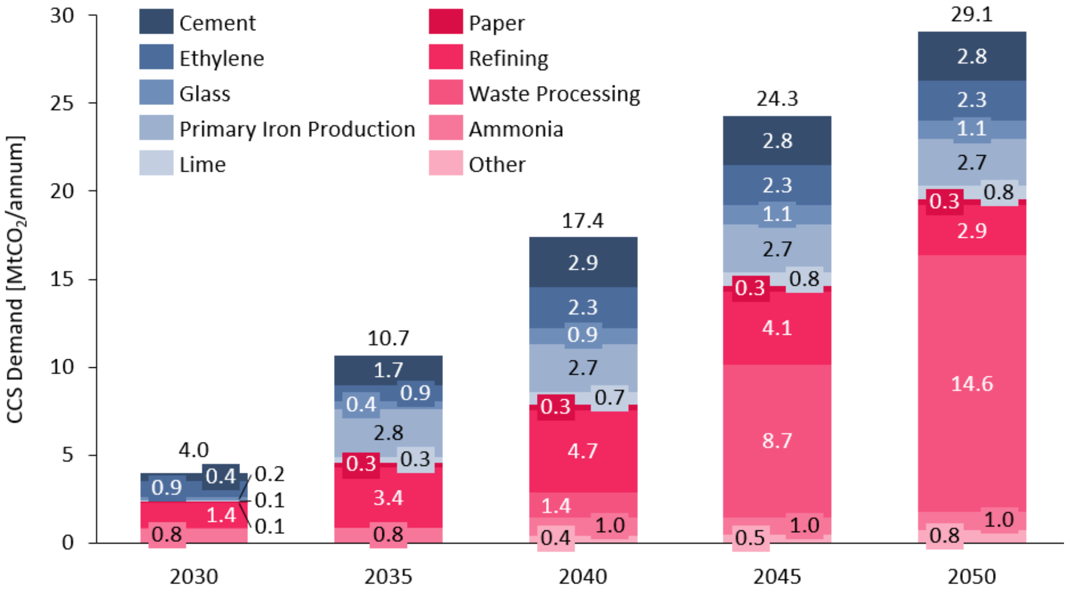


Figure 30 CO_2 T&S uptake by highest demand sectors (Balanced scenario), excluding CO_2 T&S demand from hydrogen production for industry and other sectors.[76]

All industrial clusters have significant hydrogen uptake in the late 2020s and early 2030s. The geographical and temporal variations in hydrogen demand projected for the Balanced scenario are shown in Figure 31. Initial hydrogen uptake is led by Teesside with early hydrogen supply to targeted chemicals sites in the region. However, uncertainties in constraints for initial hydrogen deployment should be considered when interpreting the early-stage hydrogen demand projections at the cluster level. Shortly afterwards, uptake scales up in Peterhead/St. Fergus, Humberside, and Merseyside with long-term demand for hydrogen being greatest in Humberside and Merseyside. However, it should be noted that sequencing of industrial clusters was not a focus in the modelling, indeed the key takeaway was that development of all clusters early is the optimal option in all scenarios.

Early hydrogen uptake is supplied by dedicated pipelines, suggesting initial hydrogen pipeline build out around clusters to industrial point sources. Figure 32 shows the transportation method for supplying hydrogen demand over time. It is seen that when grid conversion is not available, hydrogen is initially supplied by dedicated pipeline to local sites within clusters but is later also supplied by truck to dispersed sites once the carbon value has increased sufficiently enough for this to be economically viable. Once gas grid conversion can be implemented at a site then this option generally takes over as the cheapest supply route.[77] This grid conversion occurs once other sectors such as domestic and power become ready for hydrogen conversion. It is worth highlighting that these options are representative. Some areas may be able to convert their gas networks to hydrogen more quickly, in which case pipelines supply would not necessarily be via dedicated pipelines.

[76] Sectors shown have greater than 0.25 $MtCO_2$/annum captured in 2050. Other sectors with less than this value include: Compressor Station, Food & Drink, Gas Terminal, Oil Terminal, Other Chemicals, Other Fuel Production, Other industry and Other Minerals.
[77] Exception for the Engagement scenario, which does not include gas grid conversion to hydrogen.

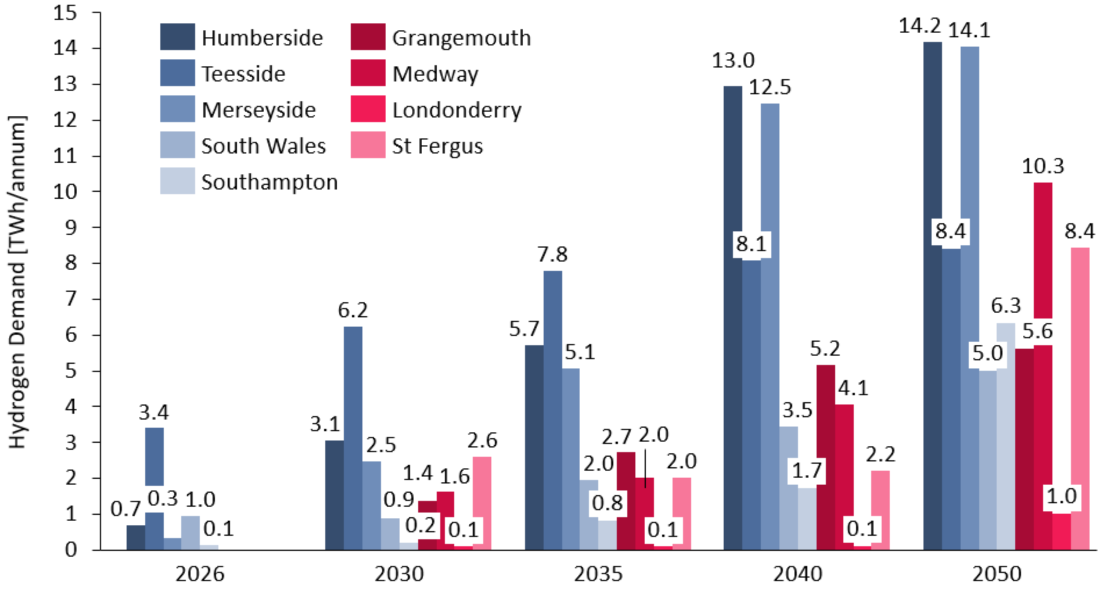


Figure 31 Hydrogen uptake in industry at production points (Balanced scenario).[78]

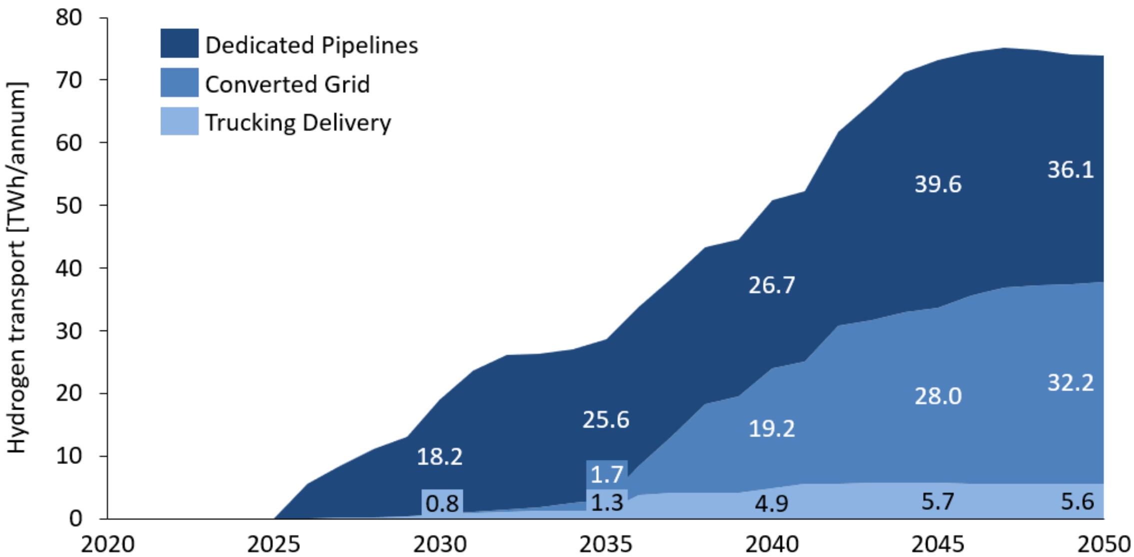


Figure 32 Hydrogen transport method (Balanced scenario).

Electrification uptake leads to significant infrastructure build out and potential need for electricity grid reinforcement and is influenced by availability of hydrogen. As discussed previously, both electricity and hydrogen abatement technologies are used to abate emissions from low temperature heat generation, with each option favoured in different scenarios. Initial infrastructure constraints for hydrogen supply combined with electrification only being constrained by technology availability lead to significant initial uptake of electrification pathways for low temperature heat, especially on smaller sites or those further from industrial clusters.

Initial increases in electricity consumption are driven by low temperature heating in the food & drink, other industry, and other chemicals sectors. Electricity is used for both indirect (steam boilers) and direct (dryers, ovens etc.) applications in these sectors, with some electrification abatement options being introduced in the early 2020s due to existing high levels of technology and commercial readiness. In the Balanced scenario, use of electric arc furnaces in primary iron and steel production results in additional electricity

78 Humberside includes hydrogen uptake at both the terminal and in-land production point.

demand for this sector, however whether this will be the chosen technology option for the large iron and steel producers is relatively uncertain. Electricity demand continues to rise within these sectors up to 2040. Change in electricity demand for the top six sectors is shown in Figure 33; the total change in electricity consumption across industry reaches 59.9 TWh in 2050. Increases in electricity demand also occur in the oil and gas industry, where remote generators are phased out with power instead achieved via grid connection or linking to offshore wind with battery storage.

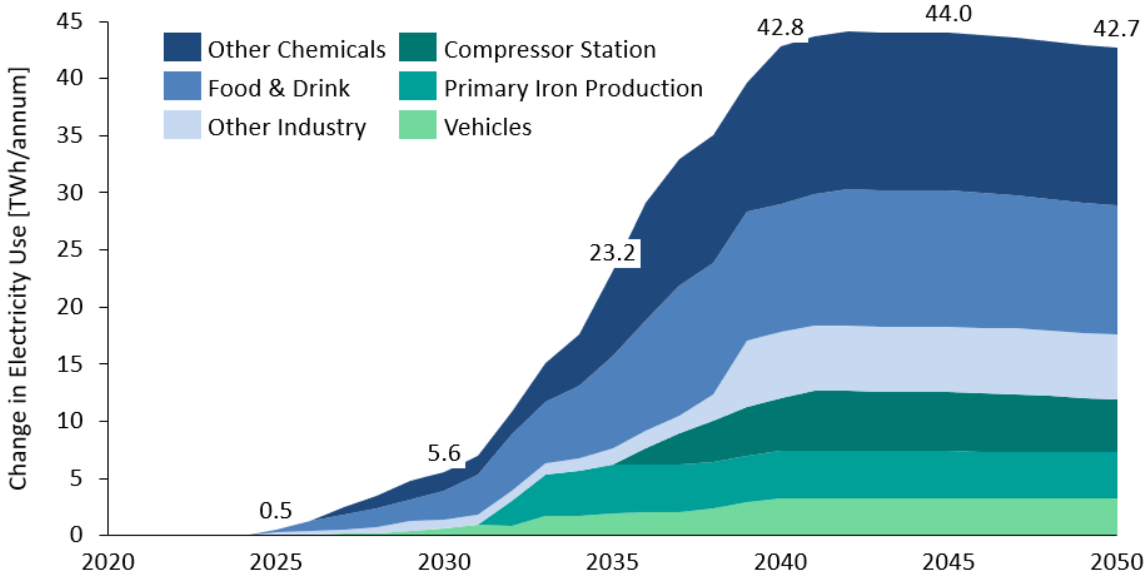


Figure 33 Change in electricity consumption in top six sectors (Balanced scenario).[79]

The estimated annual hydrogen and CO_2 T&S demands from industry and from different sectors of the whole economy CCC analysis are shown for the Balanced scenario in Figure 34. Industry and removals from CCS on biomass combustion in the power sector are each a large proportion of the CO_2 T&S demand shown. Within industry, the modelled proportion of blue hydrogen would add approximately 16 $MtCO_2$ of CO_2 T&S demand, and assessments of the blue hydrogen required for other economy sectors would result in approximately 84 $MtCO_2$ of uptake in the Balanced scenario. This shows the potential dominance of hydrogen production as the largest user of the CO_2 T&S infrastructure in the Balanced scenario, however in other scenarios where green hydrogen is dominant the scale of the required CO_2 T&S infrastructure reduces significantly.

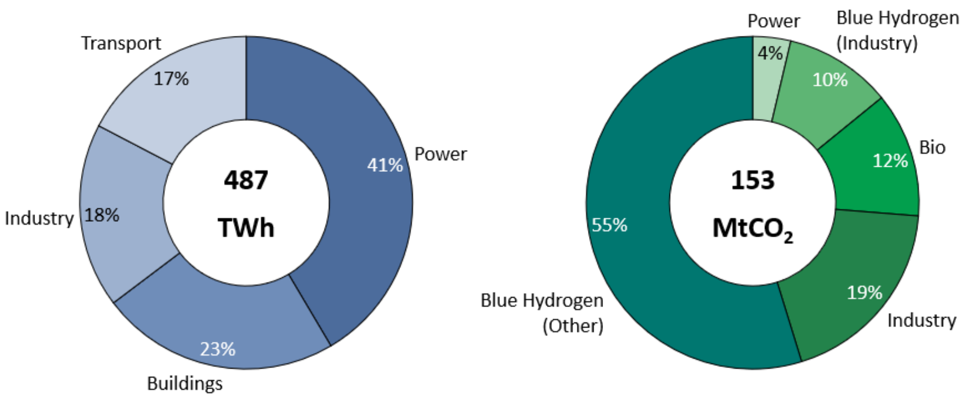


Figure 34 Annual Hydrogen (left) and CO_2 T&S (right) demand in 2050 (Balanced scenario).[80]

[79] Defines change from post-REEE baseline emissions to final consumption after abatement measures applied.
[80] Values for other sectors of the economy besides industry were used as input assumptions and are provisional figures that have been used for the purpose of this analysis. As a result, the CCC's final results will vary from those shown here.

7.2.5 Negative Emissions Potential

Within industry, there is significant potential for negative emissions through the application of CCUS to the combustion of biomass. The application of carbon capture to this biomass combustion results in the capture of biogenic CO_2 emissions, which are then subsequently sequestered underground, generating negative emissions. This can be done both through the application of carbon capture to existing biomass usage, which is projected to drop in the post-REEE projections from 56 TWh/year in 2020 to 44 TWh/year by 2050, as well as integrating some fuel switching to biomass with carbon capture. Fuel switching to biomass (combined with carbon capture) was restricted in the modelling to specific sectors (see 6.3.2), with the change in bioenergy usage due to deep decarbonisation shown in Figure 35.

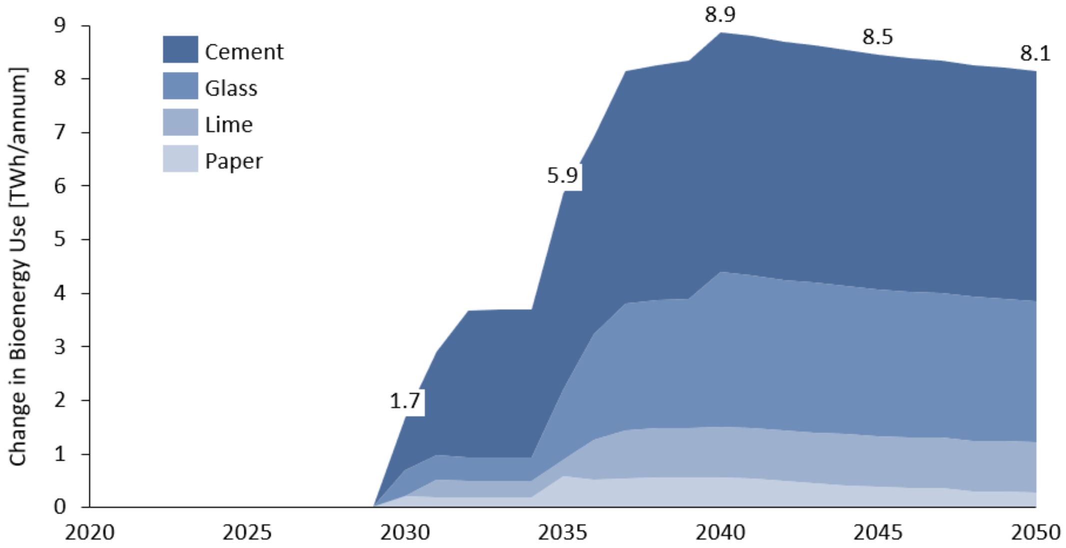


Figure 35 Change in bioenergy consumption from post-REEE baseline in top four sectors (Balanced scenario).[81]

Industry generates approximately −10MtCO$_2$e/year of negative emissions by 2050, with the time profile included below in Figure 36. Initially this uptake is mostly composed of the negative emissions from fuel switching to biomass combined with carbon capture, mostly focused in the cement sector. In the later time periods, CCS is applied to the emissions from existing biogenic combustion, which is dominated by the waste processing sector. This is where emissions from the waste processing sector are captured from the incineration of mixed biogenic and non-biogenic waste, resulting in negative emissions from the capture from the biogenic part of the fuel. This provides an opportunity for some of these sectors which have residual emissions from <100% capture rate through CCS to reach net zero and beyond through these negative emissions. It is also worth noting that the negative emissions from industry as defined in this study become greater than the remaining emissions by the mid to late 2040s, meaning industry becomes a net negative sector by 2050.

[81] Defines change from post-REEE baseline emissions to final consumption after abatement measures applied.

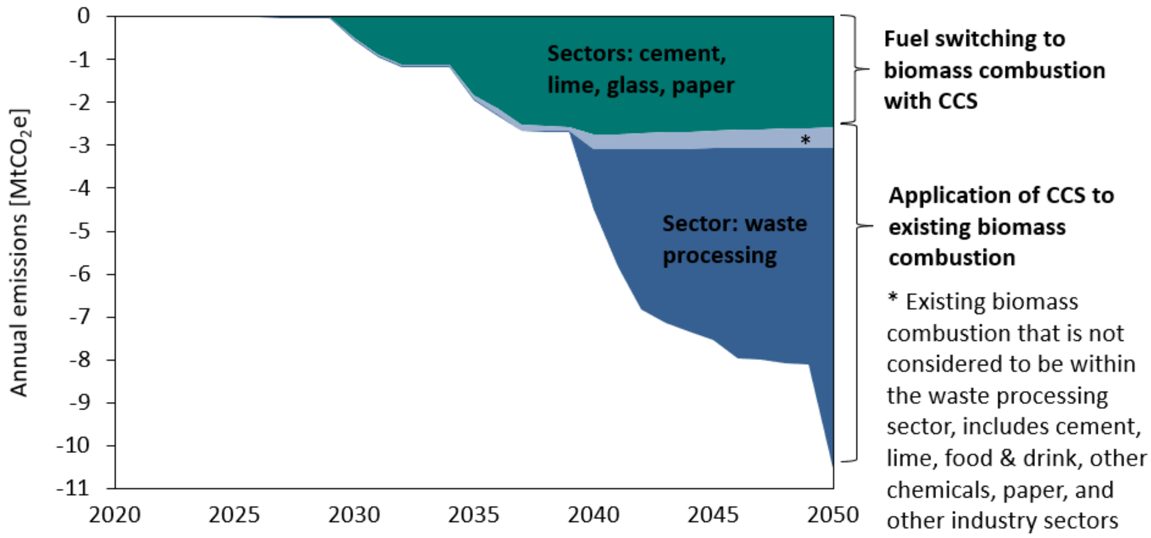


Figure 36 Negative emissions potential from BECCS in industry (Balanced scenario)[82].

7.2.6 Costs of abatement

The annualised cost of abatement technologies are shown in Figure 37 below. **Cost increases begin to ramp up in 2030, with the pace steadily increasing until 2045, after which the pace slows down to reach a final cumulative cost of £120bn up to 2050**. The majority of costs across all years are attributed to fuel costs, with capital costs constituting the second greatest portion of annualised costs. It is also worth noting that operational costs shown here include the CO_2 T&S costs for CCS abatement. Costs in early years (prior to 2025) are primarily attributed to FFPFE abatement options (LDAR/gas recovery), as well as abatement of off-road mobile machinery.

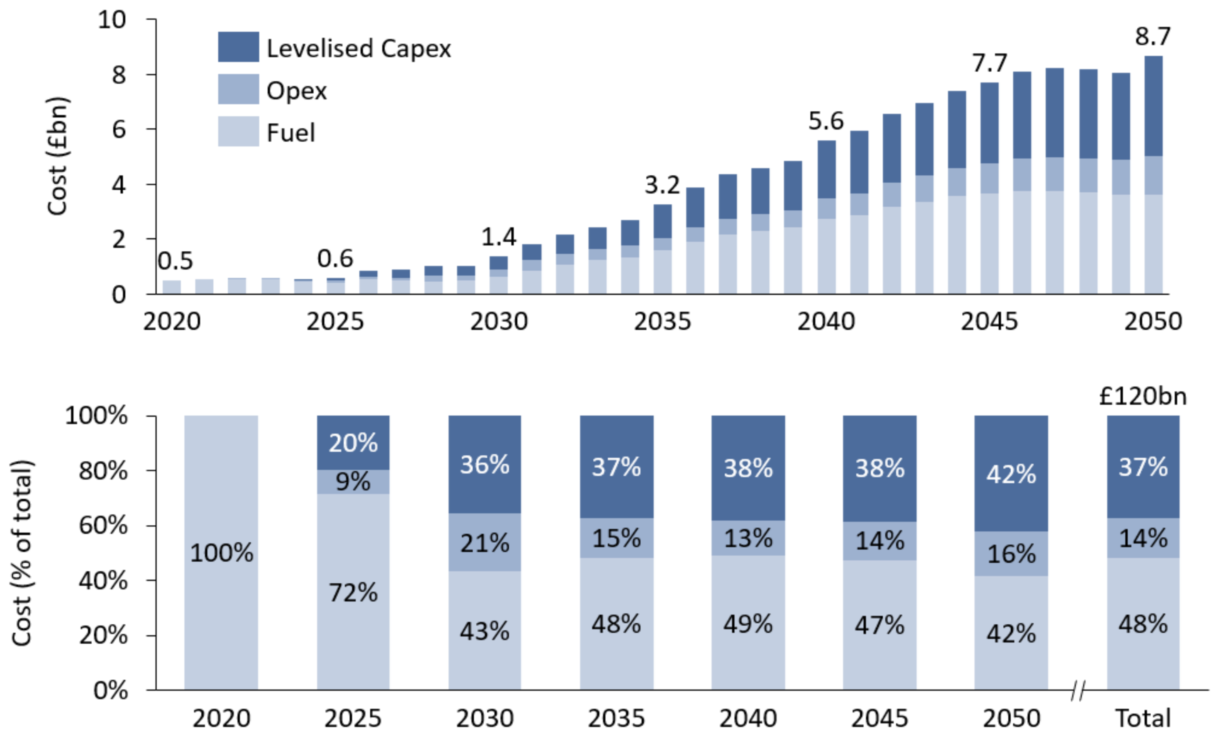


Figure 37 Total annualised costs of abatement technologies (Balanced scenario).

[82] Additional assessments of other options for biomass use or land use are not included here.

7.3 Sensitivities

To explore the potential impact of some of the data uncertainties and assumptions within the N-ZIP model, a number of sensitivities were tested on the Balanced scenario. Figure 38 displays the results of each sensitivity's percentage change in total NPV and cumulative abatement to 2050, relative to the Balanced scenario. The full set of emissions pathways can be found in Appendix 10.3. The definition of each sensitivity and key outcomes are summarised as follows:

- **Optimism Bias at 0%**: Reduced the optimism bias setting from its base value of 66% (refer to section 6.2 for more details) to 0%. This results in a reduction in the overall capital costs of technologies, leading to earlier abatement potential and the greatest cumulative abatement. This also leads to a greater uptake of electrification technologies instead of hydrogen, as electrification becomes a more cost-effective option in early years and hydrogen uptake remains hindered by low-cost delivery via the grid only becoming available in later years.
- **Low Electricity Cost**: Removal of the electricity grid connection cost (refer to section 5.3 for more details) and the transmission cost component of electricity's LRVC. This represents the potential for 'distributed' electricity generation on or near to industrial sites, leading to earlier abatement and greater uptake of electrification technologies (i.e. an increase of 6.3 $MtCO_2e$ abated by electrification in the 2050 end state).
- **Reduced Number of Cluster Points**: Removal of the cluster points for CO_2 T&S and hydrogen production at Londonderry, Medway, and Peak District. Sites previously accessing downstream CO_2 T&S networks or hydrogen supply from these points were reassigned to the next nearest cluster points, thereby increasing the distance, and hence cost, of CO_2/hydrogen transport. Overall, this resulted in a modest decrease in total NPV, slight decrease in speed of decarbonisation and minimal change in abatement technology selection.
- **No H_2/CO_2 Demand from Other Economy Sectors**: The demand for hydrogen production and CO_2 T&S from other sectors of the economy (power, transport, buildings, etc.) was reduced to zero. This resulted in an increase in the overall cost of the CO_2 T&S network due to reduced economies of scale. Given the relatively small contribution of the CO_2 T&S cost to the overall cost of industrial decarbonisation, this did not cause a substantial impact on the relative selection of abatement technologies in later years, although a minor shift from blue to green hydrogen was observed.
- **Higher Cost H_2/CO_2Transport for Dispersed Sites**: This sensitivity reflects a potential reality in which dispersed sites are significantly constrained in their ability to access hydrogen/CO_2 T&S networks. The inputs were adjusted to limit sites beyond a distance of 25km from defined points to utilise trucking transport only, along with doubling trucking costs for these sites. For a majority of dispersed sites, this results in a higher cost of transport than dedicated hydrogen/CO_2 pipelines or conversion of the local gas grid to hydrogen. The result is an overall slow-down in the pace of decarbonisation, larger remaining emissions in 2050, and a greater proportion of dispersed sites selecting electrification as an abatement option.
- **Reduced Supply Chain Constraint**: Decreasing the capacity of the supply chain by reducing the rate of maximum possible decarbonisation to 66% of the original value (refer back to Figure 17). This sensitivity reaches the lowest cumulative abatement, simulating a significant slowdown in the pace of decarbonisation. As a result, both CCS and electrification have lower abatement values in 2050. This result signals that a key success factor for industrial decarbonisation by 2050 will be the growth of skills and capacities in the supply chain.
- **Low Fossil Fuel Prices**: Reduces the price of fossil fuels (gas, coal, oil) to 66% of their original values (refer back to Figure 18). While this sensitivity has a minimal impact on the final remaining emissions in 2050 - a modest increase of 0.1 $MtCO_2e$ - the pace of decarbonisation is substantially slowed down. The decreases in counterfactual fuel costs in this low fossil fuel prices sensitivity also result in this being the sensitivity with the lowest total NPV.

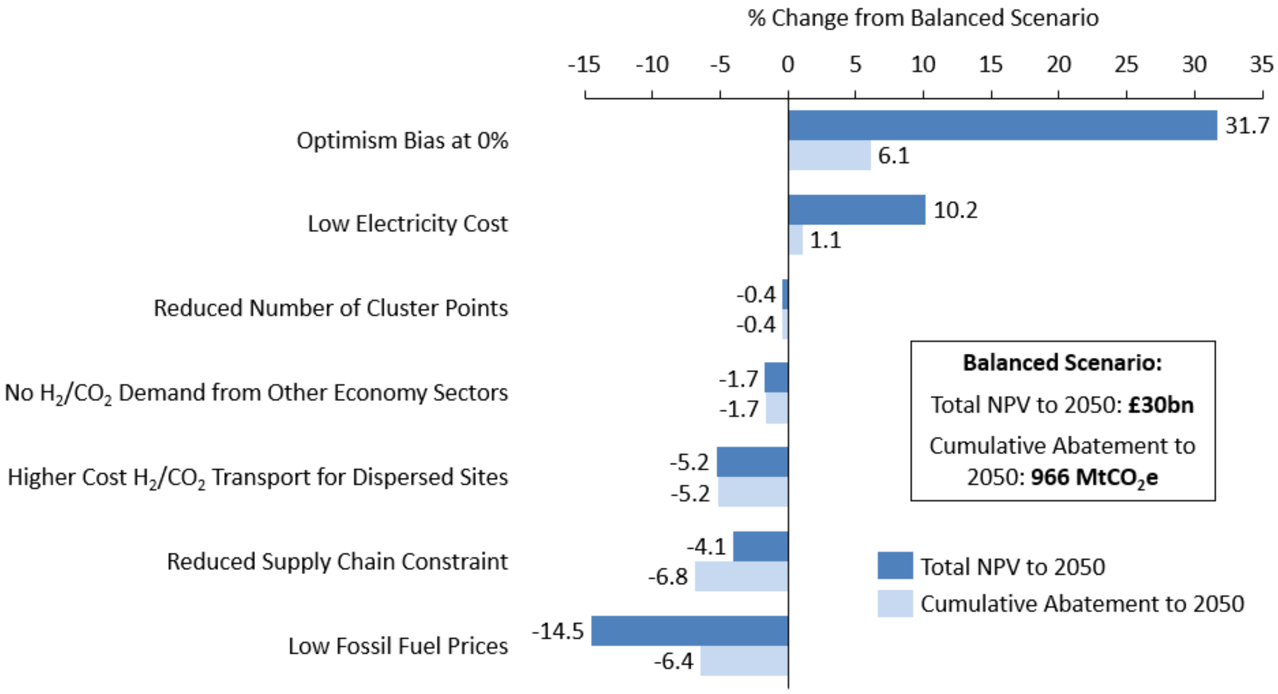


Figure 38 Sensitivity analysis results for the Balanced scenario.

8 Summaries for Industrial Sector Groups

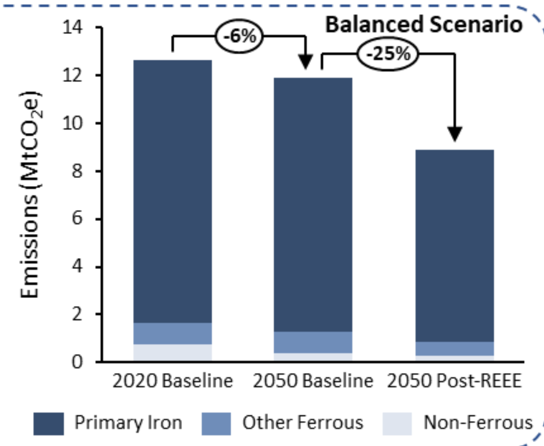
The following pages provide a deep dive into specific industrial sector groups which share similarities in their existing processes, and hence their potential for deep decarbonisation. While it will be important for industrial sectors to identify which abatement options are most suitable for each of their sites, additional consideration should be given to the potential synergies and applicability of cross-sectoral abatement technologies. In each sector group summary, the sectors' baseline emission projections, abatement results and key technologies, levelised cost of abatement and additional noteworthy points are highlighted.

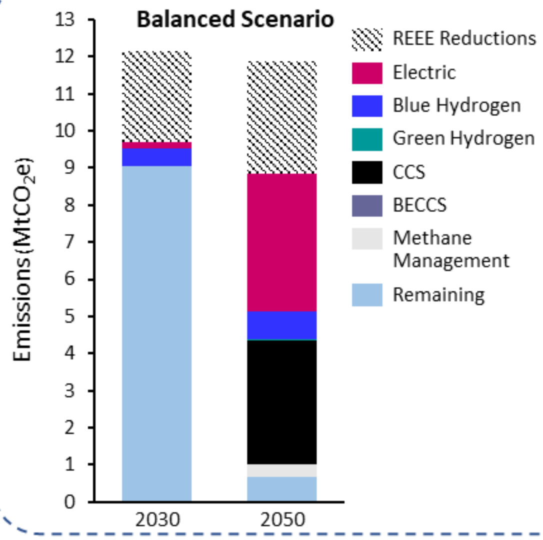
8.1 Primary Iron Production and Other Metals Processing

Sectors: Primary Iron Production, Other Iron and Steel, Non-ferrous Metals

Baseline emissions projections

- Emissions dominated by blast furnace processes from sites at Scunthorpe and Port Talbot. Other emissions are split evenly between direct heating (7%), flaring in primary iron production (7%), and indirect heating (6%).
- Main fuels used are coal and natural gas, with off gases supplying some heating in Port Talbot and Scunthorpe
- Without REEE measures, the baseline emissions are similar between 2020 and 2050, however application of REEE measures leads to a 25% reduction by 2050. However, the non-ferrous metals sector has significant decreases in baseline activity from the projections.



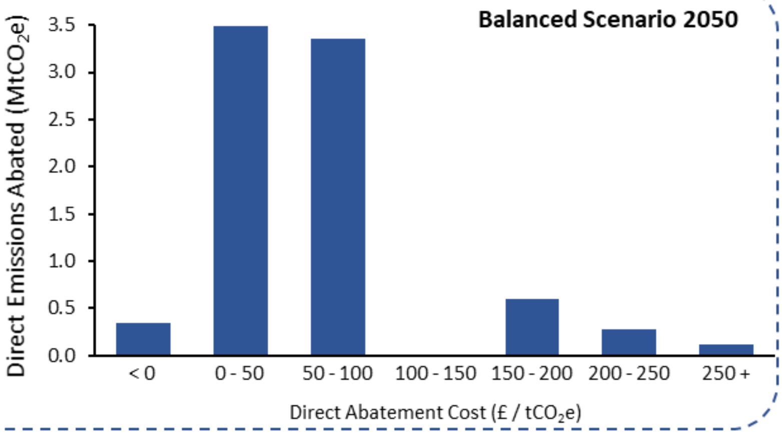


Technologies for abatement

- Initial abatement in the sector before 2030 mainly from decarbonisation of boilers through hydrogen at large sites within clusters and electrification at small sites, as well as some decarbonisation of smaller furnaces mainly through hydrogen. In other scenarios, there is a greater balance between hydrogen and electrification abatement.
- Later abatement in the Balanced scenario focuses on CCS and electric arc furnace (EAF) as the main routes for decarbonising primary iron production, however there is a large uncertainty in this.
- Other scenarios use purely CCS to decarbonise primary iron (Headwinds), solely EAF (Engagement), Direct Reduction of Iron (DRI) and EAF (Tailwinds), or CCS and DRI (Innovation).
- Remaining emissions are residual emissions from CCS as well as some unabated use of carbon in processing.

Cost of abatement

- **Flaring abatement** potentially comes with cost reductions, though with process management challenges.
- **EAF (~£40/tCO2e) and CCS (~£80/tCO2e)**, but EAF could come with a substantial process and product change.
- Hydrogen use and electrification on smaller scale sites correspond to the more expensive options.



Additional key points for the sector

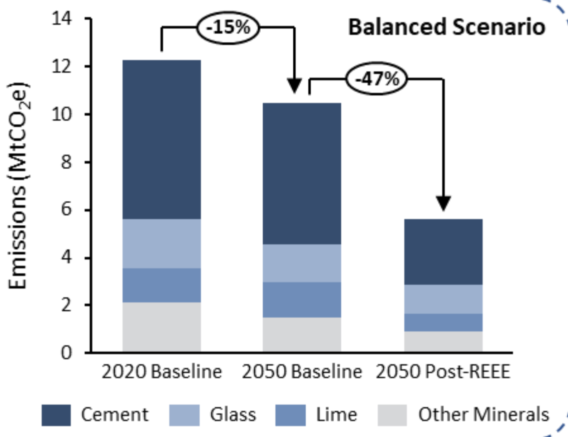
- **Significant changes** - primary iron production has 2 technology options (DRI and CCS) with relatively low TRL, and the other option (EAF) is a large process change and might limit the product quality achievable.
- **Infrastructure** - Port Talbot and Scunthorpe are key components of industrial clusters, however the rest of the sector are smaller sites which are more dispersed, making CO_2 or H_2 infrastructure more difficult to access.

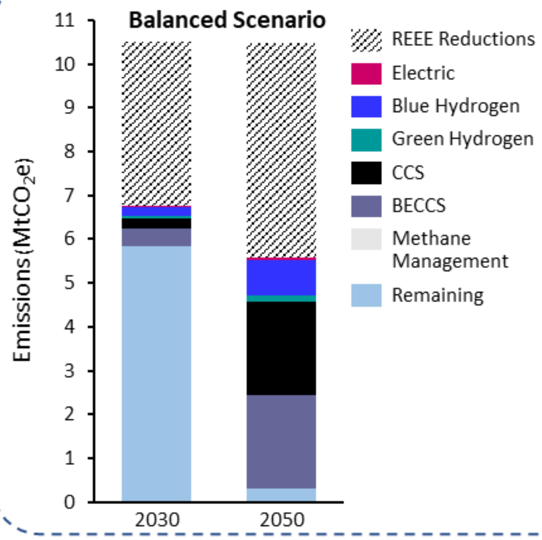
8.2 Non-Metallic Minerals

Sectors : Cement, Lime, Glass, and Other Minerals

Baseline emissions projections

- Emissions result from direct heating processes (57%) and process CO_2 emissions (43%).
- >50% of emissions from process in cement/lime, with lower process emissions in glass and ceramics (0-15%)
- 15% decline in baseline emissions to 2050, with significant opportunities for further reductions (47%) through application of REEE measures including material substitution and reduced consumption/production of resources.
- Large existing use of waste fuel in sector, particularly cement. Cement sector uses high fractions of non-biogenic (~30%) and biogenic (~15%) waste fuel.



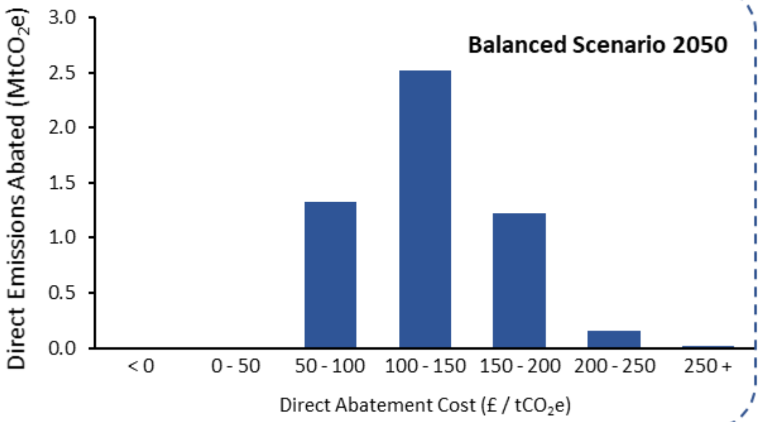


Technologies for abatement

- CCS is the most important technology in these sectors for abating emissions, whether as the only option for process emissions or providing negative emissions when combined with biomass fuel switching.
- Lime sector also uses hydrogen kilns on some sites to switch from natural gas, together with CCS and BECCS.
- Glass sector mostly uses biomass fuel switching and BECCS technologies, to synergise with CCS on its process emissions, however hydrogen fuel switching and electrification are also taken up to some extent.
- Ceramics sector is the exception, mostly relying on fuel switching dryers/kilns to electricity and hydrogen.
- Most abatement technologies are introduced in 2030, with the majority of cement and lime emissions abated by 2040.
- Glass and other minerals sectors see a more gradual introduction of abatement technologies.

Cost of abatement

- CCS and BECCS in cement and lime sector mostly falling around £80-140/tCO_2e, with a small amount of capture in the £250+/tCO_2e bracket.
- The glass sector falls mostly in the £100-150/tCO_2e bracket, independent of electrification, hydrogen or BECCS.
- The other minerals sector has some abatement options spread over the full range of costs, with dryer electrification possibly being relatively low cost.



Additional key points for the sector

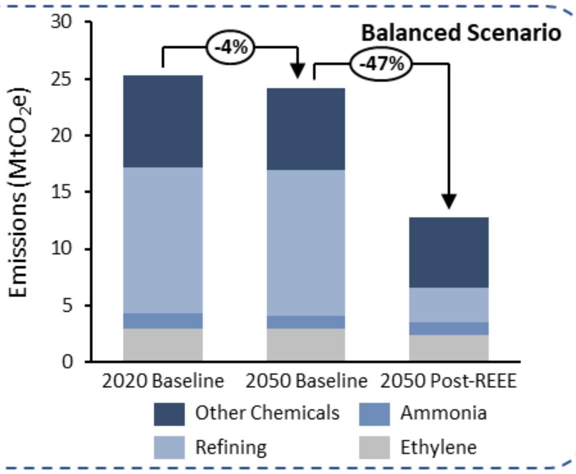
- **Negative emissions potential** – relatively easy use of waste biomass in cement sector and significant process emissions in cement, lime and glass makes these sectors a prime target for BECCS in industry.
- **Infrastructure and dispersed sites** – most sites are dispersed around the country/away from main clusters particularly for cement/lime, which can make accessing needed CCS infrastructure difficult.

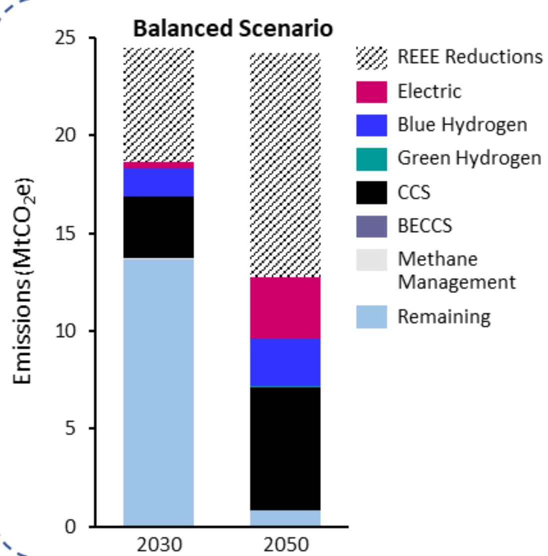
8.3 Refining and Chemicals

Sectors : Refining, Ethylene, Ammonia, Other Chemicals

Baseline emissions projections

- Application of REEE measures result in a 47% decrease in 2050 baseline emissions, dominated by reduced demand for petroleum products impacting the refining sector.
- Post-REEE 2050 emissions mostly consist of process related emissions (40%) and emissions from CHPs (26%), with other emissions from direct and indirect heating.
- High prevalence of internally generated fuels used within the sectors (aside from other chemicals) makes abating many emissions through fuel switching challenging.



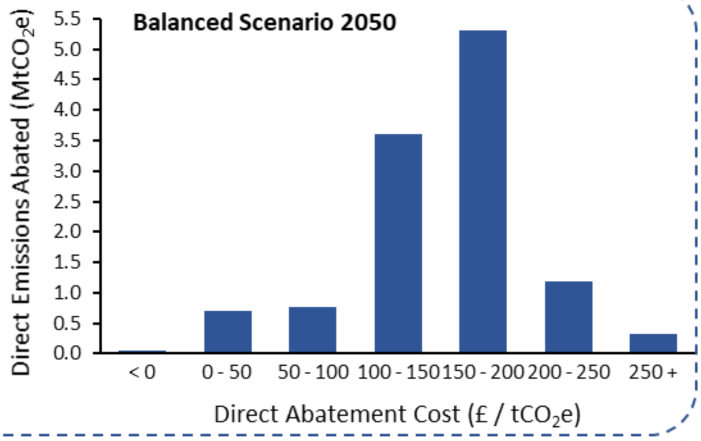


Technologies for abatement

- Emissions in the refining, ammonia and ethylene sectors are abated using CCS technology given the prevalence of process emissions and internal fuels. CCS was modelled as post combustion capture, however in refineries central pre-combustion capture of refinery fuel gas is also an option.
- The majority of ammonia abatement technologies are applied in the late 2020s with a significant amount of ethylene abatement also occurring in the mid 2020s. Refining sees a more gradual introduction of technologies up to 2040, with CCS on SMRs implemented first.
- The other chemicals sector applies a combination of electric and hydrogen technologies to replace CHPs, boilers, and dryers, generally in clusters and large sites initially and then for small sites, mostly completed by 2040.
- Remaining emissions are largely residual emissions from <100% capture rate CCS.

Cost of abatement

- Abating CO_2 from easy to abate sources like high purity process emissions from methane reformers on refinery and ammonia sites make up the <£50/tCO_2e abatement options.
- Less easy to abate options including CCS on combustion emissions mostly falls into the £140-200/tCO_2e range.
- CCS on emissions from the ethylene sector generally costs around £110/tCO_2e.
- Blue hydrogen and electrification generally falls between £100-200/tCO_2e, though there are some expensive options here.



Additional key points for the sector

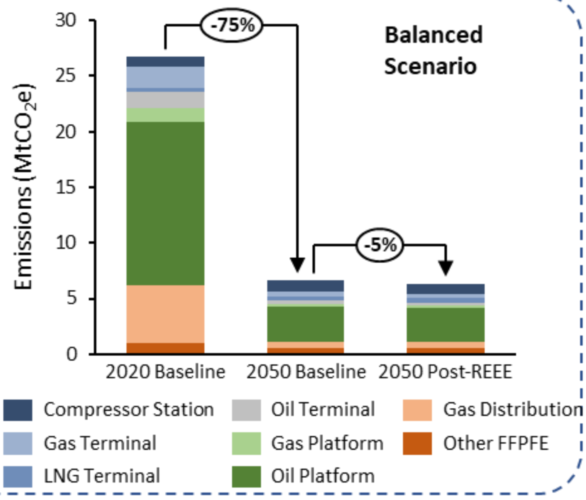
- **Anchor sites** – the low cost CCS abatement options available in these sectors makes them good anchor projects for industrial clusters, with the large emissions from the same sites offering easy expansion routes.
- **Hydrogen production** – these sectors have the most experience of hydrogen production and use, putting them in a prime position for future hydrogen production developments.

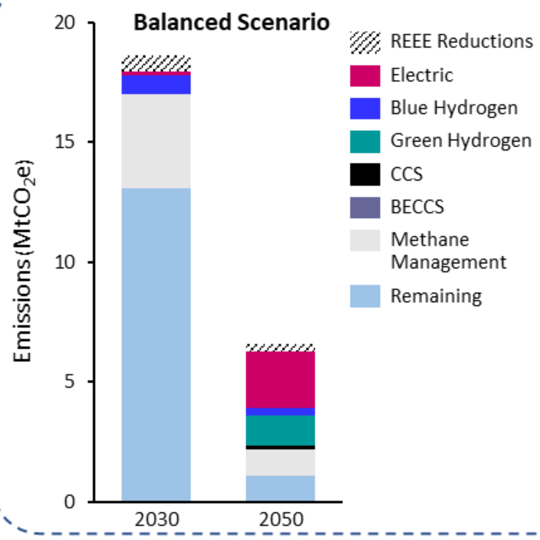
8.4 Fossil Fuel Production and Fugitive Emissions (FFPFE)

Sectors : Offshore Oil & Gas, LNG, Gas Distribution, Coal Mines & Other Fuel Production

Baseline emissions projections

- A significant reduction in baseline emissions is projected for this category, linked to projected decline in offshore oil and gas production rates. Ongoing improvements to the gas distribution network through Iron Mains replacement and the like also contribute.
- Minimal reduction in emissions from REEE abatement, mostly consisting of minor emissions reductions through energy efficiency.
- Post-REEE 2050 emissions mostly consist of remote power generation (47%) and emissions from flaring, venting, and leakage (33%), with the remainder from heat generation.



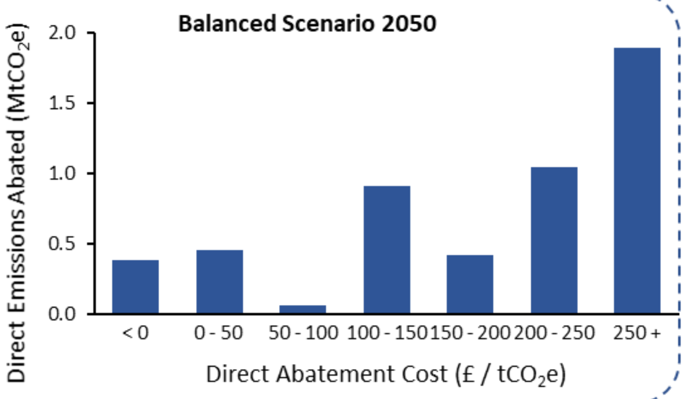


Technologies for abatement

- Emissions for flaring and venting are abated via sector initiatives to change operations to reduce flaring and venting, mostly during the 2020s.
- Leakage of gas is reduced through advanced monitoring of methane leakage, and technologies such as leak detection and repair (LDAR).
- Power generation emissions are abated mostly from 2030 to 2045 - through a combination of electrification (connection to grid or offshore wind) and hydrogen powered generators and compressors.
- Electrification generally occurs in the later time period in the modelling, though is likely to be implemented as new platforms come online.
- Remaining emissions are associated with remaining fugitive emissions from closed coal mines, as well as some residual emissions from gas leakage.

Cost of abatement

- Abatement of leakage and reductions in flaring/venting are generally a low cost option <£50/tCO_2e.
- Deeper decarbonisation is likely to be more expensive, especially around the offshore sector, however these cost estimates might reduce with better cost data which can then reduce optimism bias corrections.
- Remaining emissions in 2050 which were not abated are likely to have abatement costs >£400/tCO_2e (not shown and not abated).



Additional key points for the sector

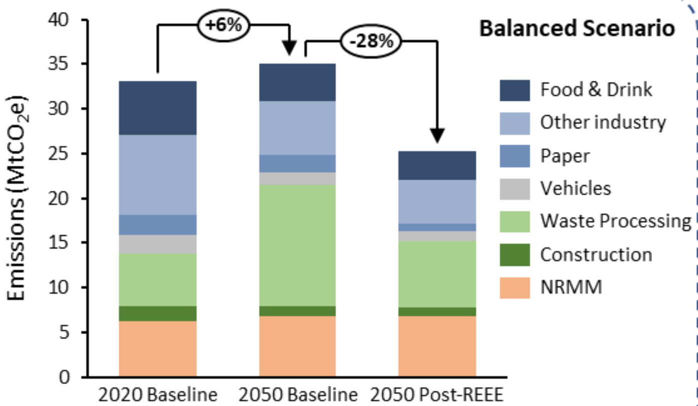
- **Deep decarbonisation of the sector** is possible and reasonable based on the carbon value despite natural declines in emissions, however policy concerns/perception might restrict incentives for decarbonisation.
- **Availability of cheap on site fuels** could result in higher cost decarbonisation in the sector (e.g. own use gas allowances).

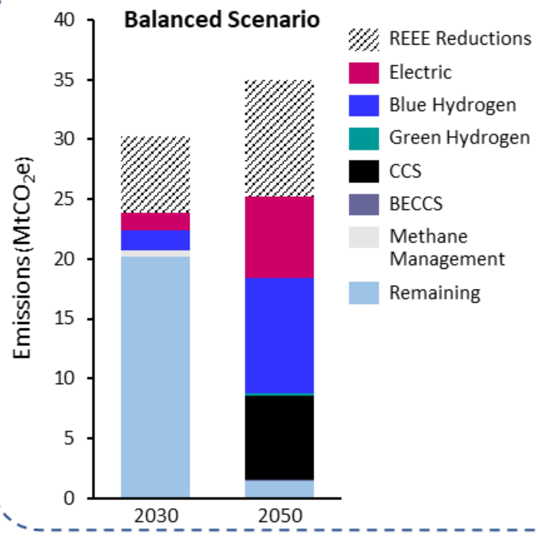
8.5 Other Industrial Sectors

Sectors : Food & Drink, Paper, Vehicles, Construction, Waste Processing, Other Industry, Non-Road Mobile Machinery (NRMM)

Baseline emissions projections

- Baseline emissions in waste processing and NRMM are projected to increase to 2050, whilst food & drink and other industry emissions decrease.
- A 28% decrease in 2050 emissions occurs from REEE, mostly composed of reductions in waste being incinerated.
- Non-NRMM emissions mostly arise from indirect heating (34%) or incinerators (46%), with the remainder mostly from CHP.
- Biomass fuel is used in the paper, food & drink, waste processing, and other industry sectors.



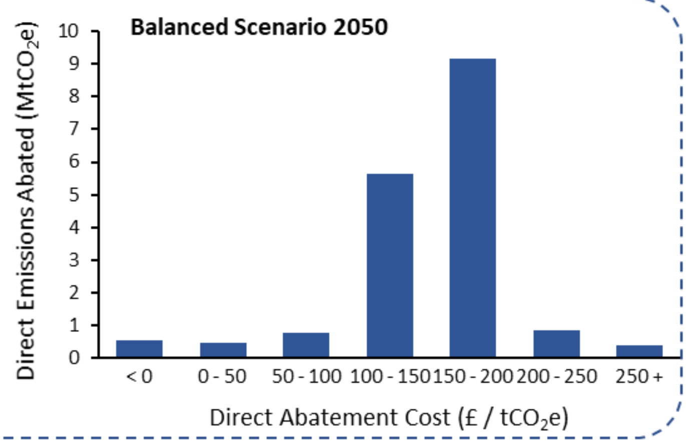


Technologies for abatement

- Lack of low cost gas reduces economic case for CHPs, which are replaced with electric boilers and grid imports.
- Direct and indirect heating is abated with a combination of electrification and fuel-switching to hydrogen; a small amount of fuel switching to biomass with CCS occurs in the paper sector.
- CCS is an important abatement technology for waste processing (incinerators), applied in early 2040s.
- NRMM emissions are abated using hydrogen (fuel cell electric vehicles) and electric vehicles.
- Emissions for food & drink, vehicles and paper are mostly abated by the mid/late 2030s with the gradual introduction of electrification technologies from the mid 2020s.
- BECCS is implemented on the biomass fuel used in the paper, food & drink, waste processing, and other industry sectors, providing negative emissions.

Cost of abatement

- Costs of abatement are mostly focused in the £100-180/tCO_2e region, with the largest single portion from CCS on waste incinerators (~£170/tCO_2e).
- Electrification and hydrogen fuel switching is also mostly concentrated between £100-160/tCO_2e. However this varies substantially by site size and whether sites are dispersed or in a cluster.
- Off road machinery technology costs varies widely depending on machinery size, as well as by the appropriate abatement option.



Additional key points for the sector

- **Dispersed sites** – for these sectors, access to hydrogen and CO_2 T&S infrastructure will be key as energy from waste sites are relatively dispersed, with other sectors sites also not concentrated in clusters.
- **Variety of industry –** other industry and food & drink, while powered mostly by boilers, also contains a variety of bespoke processes which will need careful consideration around implications of fuel switching.

9 Conclusions and Policy Recommendations

The primary objective of this project was to inform the CCC's sixth carbon budget advice to Government, relating to industrial decarbonisation and infrastructure for hydrogen transmission and distribution, and for CO_2 transport and storage. This section summarises the key conclusions of the study, as well as knowledge gaps that were identified. It also includes some recommendations for policy to encourage development and uptake of deep decarbonisation technology and infrastructure.

9.1 Summary of Key Findings

- **Deep decarbonisation by 2050 is possible and economically favoured** – given the assumed carbon value trajectory (£121/tCO_2 in 2030, rising to £346/tCO_2 in 2050), industrial decarbonisation is highly favoured and industry achieves net zero by 2050, with ~3-5 MtCO_2e residual emissions in 2050 balanced out by the negative emissions from BECCS.
- **All decarbonisation technologies considered are likely to be important** – the most irreplaceable technology is likely to be CCUS, given its crucial role in abating process emissions. The scale of hydrogen fuel switching or electrification varies between the scenarios; each of them has processes and scenarios where they are the most favoured.
- **All scenarios favour a rapid decarbonisation pathway as the most optimal option** – this involves implementing the large majority of decarbonisation by 2045 and swift action by the early 2030s on all of the major industrial clusters, including the acceleration of infrastructure deployment .
- **Industrial decarbonisation remains relatively low cost** – given the large incentives modelled by the carbon value, industrial decarbonisation remains highly favourable, despite some increases in costs from previous estimates to account for any potential bias towards optimistic low costs.
- **The supply chain and skills availability is a key constraint for decarbonisation** – this, rather than cost, constrains the speed of decarbonisation in some sectors, so swift action over the coming years is needed to ensure this constraint is mitigated to the levels modelled here or further. The sensitivity results on supply chain constraints further validated this conclusion (section 7.3).
- **Infrastructure availability could constrain decarbonisation** – infrastructure and industrial sites were highly interdependent within this project, and this interdependence could be a barrier to project/cluster developers. This could be mitigated by clarity on business models across all elements of the value chains. Coordination between and within clusters will also be important to ensure all clusters can begin infrastructure planning and development within the next decade.
- **Progress on technology availability would constrain early adopters** – with the modelled carbon value, technology availability/readiness does constrain implementation. Hence it is valuable to push technology development and commercialisation early as far as possible.
- **There remains significant uncertainty, both around suitability and costs of technologies** – however much of this should be mitigated over the course of the coming years through early technology demonstrators and detailed subsector assessments of decarbonisation.
- **Further planning and forecasting should be supported by 'what-if' scenarios** – the sensitivity results (section 7.3) suggest the pathways to decarbonisation may vary wider than the 5 core scenarios explored. Over time and as work on decarbonisation progresses, greater certainty on the likely scenario will enable parameter updates in models such as N-ZIP, and greater clarity on the ideal pathway to net-zero.

9.2 Further Work

To continue progress and improve upon the N-ZIP model and similar modelling in the future, further work is needed to build knowledge through engagement and collaboration and to provide validation of assumptions through feasibility assessments and demonstration projects. Much progress is being made currently in the area through existing UK programmes, such as Industrial Fuel Switching, the Industrial Energy Transformation Fund, the CCUS Innovation Programme and other initiatives, and it is critical that this continues. The findings and detailed parameters from this UK work should be disseminated as far as possible to enhance learnings and to enable parameter updates in models such as N-ZIP. Additionally, given the international nature of many of these industries and companies, learnings from similar work abroad can and should be incorporated into the evidence base, with international collaboration key for this. Our recommendations around knowledge building are shared below.

Recommendations for evidence gathering and validation:

- **Feasibility studies and site assessments are needed to validate the assumptions around cost and suitability** of abatement technologies for specific processes, which are currently at an early-stage. These should include wider assessment of site-level requirements to facilitate integration of process or technology changes. These assessments will also help to build skills, increase industry confidence, and reduce uncertainty in the costs of options by providing a more concrete assessment.
- **Demonstration projects are needed to enhance industry confidence** and enable a better understanding of costs and requirements of different options. BEIS' recent programmes will provide some of this, however it is crucial that these initial projects are supported and built upon and that the results are as open, accessible and disseminated as widely as possible.
- **The cost of electricity grid connections and capacity** were only assessed at a high level within this study, remaining a significant knowledge gap. Further investigation should assess the grid reinforcement and capacity build out required for industry electrification on this scale, together with the likely portion of that cost which would or should fall on industry, to validate some of the cost estimates for industry used within this and other modelling.
- As the field progresses and better cost and suitability estimates become available, it is important to **update the assumptions in existing models** with new learnings to ensure they stay abreast of the latest developments and the pathways and outputs remain relevant. This includes enhancing the general technology assumptions, but also specific site assumptions once feasibility studies have been done and plans are put in place.

Recommendations for engagement and collaboration:

- **International collaboration** should be pursued so that evidence for a transition is built quickly. Additionally, findings should be disseminated as widely as possible internationally, so that work is not duplicated and that public sector funds are spent efficiently and with maximum impact.
- Results from UK projects should be **open and shared as widely as is commercially possible.** Furthermore, it would be beneficial to facilitate collaboration and knowledge sharing between industrial sectors, particularly those that share similar equipment types.
- As a key constraint for the pace of the pathway, **the capacity of skills and supply chain needs to be developed.** While this can be partially done through demonstration projects, additional work on mapping supply chains and future skills gaps is likely to be needed. As part of this, engineering, procurement and construction (EPC) contractors, industrial organisations and training institutions need to be engaged and consulted on new training courses for the required upskilling.
- Work needs to be done alongside the **range of relevant regulatory bodies** to assess the impacts of these decarbonisation options, with particular emphasis on the Environment Agency and Health and Safety Executive for technology development. While consistent guidelines and regulations would likely be preferred, this also needs to be coordinated with devolved administrations where they have responsibility.

9.3 Policy Recommendations

The introduction of new industrial decarbonisation policies is widely expected to have a pivotal role in enabling deep decarbonisation. The interviewed and roundtable stakeholders representing UK industrial sectors and clusters believed **policy support** to be **essential for establishing early business cases for deep decarbonisation investments while simultaneously mitigating the risk of carbon leakage**[83]. Without UK-

[83] Carbon leakage refers to the situation that may occur if, due to costs related to climate policies, businesses were to transfer production to other countries with lower emission constraints, thereby leading to an increase in their emissions.

wide policy intervention, there is a large risk of industrial competition being negatively impacted by an increasing carbon price - which may even result in some industrial site closures. In a worst-case scenario, an industrial site could prefer to relocate to a country with a lower carbon price, thus not achieving any global carbon abatement.

The policy recommendations that follow are focused on mechanisms to support technology and infrastructure deployment, along with a brief discussion on policy options to expand the skillset of the supply chain and reduce the risk of carbon leakage. It should be noted that these are not the only policy levers available to government and that other interventions will be crucial to enable deep decarbonisation efforts (e.g. carbon disclosure/caps, low carbon procurement, product/carbon standards).

9.3.1 Technology financial support mechanisms

The fuel cost projections shown in section 7.1.1 illustrate that although the financial requirements for deep decarbonisation are significant and diverse in nature, the single most important policy focus should be in offsetting the increase in energy costs, largely due to hydrogen and electricity costing more than fossil fuels. It is also worth noting that costs included in this modelling work do not represent the likely price which industrial consumers pay for their fuel, but the cost excluding profit and pre-existing policy cost. Hence additional support for industry might be required to achieve these levels or mitigate higher fuel prices than the costs modelled here. These costs also directly impact the marginal cost of production, hence affecting industrial competitiveness. An option to reduce this risk is to implement a Contract for Difference (CfD) on the energy price, which could reduce the energy price differential and ensure that industries that decarbonise pay no more than competitors who use fossil fuels.

A second goal of policies aimed at supporting deep decarbonisation technologies should be to reduce the upfront capital expenditures, which are the second largest cost factor after fuel costs. Grants and low-interest financing would be obvious ways for policy to provide capital support. Another option is to combine these with CfD financing mechanisms for bespoke industrial abatement projects, by providing a payback on investments relative to the carbon price. The UK government’s current proposal to move forward with the design of a CfD model using this approach is highlighted in Box 1.

Box 1 – UK government proposes business model for industrial CCUS

The UK government has recently proposed a CfD financing mechanism combined with an upfront grant to support CCUS projects, which they are aiming to have implemented in 2022[84]. The upfront government co-funding would help finance the capital costs of constructing the CO_2 capture plant, along with a CfD to provide revenue support over an agreed operational duration of the capture plant. A contractually agreed upon strike price per tonne of CO_2 abated would be defined, however further investigations are ongoing to determine appropriate reference prices and benchmark emissions. The CfD financing would be used to cover the project's operational capture costs (this will include fuel costs), the capex investment for the project, and CO_2 T&S infrastructure costs.

The CfD was selected based on its potential to provide a high degree of revenue certainty for the industrial site, along with value of taxpayer money spent. Another main benefit was its successful past integration in the power sector, where it was utilised in competitive auctions to support the deployment, and cost reduction, of low carbon electricity generation. Similarly, government aims to develop the CfD model for UK industry to prioritise incentives for deploying early projects, acknowledging the need to have a flexible mechanism in place for later deployment projects which may span across a number of different industrial sectors. Government expects the level of support needed to reduce over time, as technology learning leads to CCUS cost reduction (along with increased carbon pricing), enabling a sustainable and cost-effective CfD mechanism in the long-term.

Other financing models considered in the consultation process included a number of suggestions from a recent Element Energy report for BEIS on industrial carbon capture business models[85]:

- **Cost plus**: all properly incurred costs are reimbursed through taxpayer funding.
- **Tradeable tax credits**: a tax credit is awarded for each unit of CO_2 stored (or simply abated, which could make this mechanism relevant to fuel switching as well), and this reduces a firm's tax liability. The credit can also be traded with other firms.
- **Decarbonisation certificates**: certificates representing the amount of CO_2 abated (through CCUS or other technologies) which can be traded, and towards which emitters have an obligation.

To expand financial support for a wider range of industrial abatement technologies, one option for government is to adapt their CfD financing business model for other low carbon technology options (fuel switching, process changes, etc.). For instance, similar to a CfD model, the Netherlands' Sustainable Energy Transition Scheme (SDE++) applies to a wide range of CO_2 reducing categories, including low carbon heat in industry, CCUS and hydrogen electrolysis. The SDE++ provides subsidies to abatement technologies on a defined 'operating shortfall' (i.e. difference between fixed 'base amount' and market-fluctuating 'correction amount').[86] However, this a challenging policy to implement – given the costs of abatement across industry vary widely due to site location and availability of nearby infrastructure, as highlighted in section 5. Costs of CO_2 T&S, hydrogen supply, and other infrastructure (e.g. pipelines, electricity grid connection) may be highly site dependent, which may then require sites to have different financing incentives.

To keep options open for a range of decarbonisation pathways, it is recommended that any financial support offered should be as technology neutral as possible. The results of this study highlighted that even though some deep decarbonisation technologies are going to be critical for the transition to net zero – CCUS and fuel switching in particular – different industries are likely to adopt different technology mixes. Policy interventions could reduce uncertainty by selecting preferred technology options (e.g. supporting the adoption of electrification instead of hydrogen, or vice versa). However, the findings in this study suggest that a number of

[84] UK Department of Business, Energy & Industrial Strategy, Response on potential business models for CCUS.
[85] Element Energy. (2018). Industrial carbon capture business models. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/759286/BEIS_CCS_business_models.pdf.
[86] https://english.rvo.nl/subsidies-programmes/sde

pathways deliver substantial decarbonisation, with the range of decarbonisation options considered being deployed in at least some industrial sectors. Moreover, given the high uncertainty around the future price of hydrogen and electricity, it would be difficult to justify policy measures that could limit other options which may turn out to be more effective for deep decarbonisation.

The pathways studied assume that investments in fuel-switching technologies can take place in any year of the lifetime of fossil-fired appliances, since hydrogen is modelled as a retrofit and electrification modelled as new builds which include the scrappage costs of counterfactual technologies. While within the model scrappage of previous equipment was not a showstopping barrier when using a social discount rate, the shorter timescales and higher discount rates of industry might increase its importance if appropriate policy is unable to compensate for this. Additionally, if the uptake of fuel switching technologies were to be delayed by slower technology development timelines, lack of infrastructure availability, or by the lack of economic incentives, the number of sites finding themselves with additional scrappage costs due to 'locked-in' fossil-fuelled technologies could become significant. This could make it a challenge to meet the economy-wide net zero target by 2050. To mitigate this risk policy should:

- **Support the development of pilot projects** within each sector (if required) to robustly test the technical and economic potential of abatement technologies, develop assurance in novel technologies for industry investors, and keep options open for different technology options.
- **Support detailed follow-on studies at the sector level** to provide a comprehensive set of measures required for the sector to reach net zero. This could focus on deep decarbonisation options for a few representative sites to gain a holistic understanding of the interventions required.
- **Finance comprehensive feasibility studies** to support early implementation of technologies already available which could start decarbonising immediately (predominately in the context of process electrification). It is recommended that a specific focus on deep decarbonisation (ideally net zero) be required, as well as extensive knowledge sharing.
- **Ensure that the required infrastructure is developed well ahead of time**, so that fuel switching and CCUS can be implemented without delay when the business case is established. Policy levers for infrastructure deployment are expanded upon in section 9.3.2.
- If technology lock-in cannot be mitigated across all industrial sites, **early decommissioning (i.e. scrappage) of fossil-fuelled appliances** may need to be promoted or mandated on processes which are unable to be retrofitted.

9.3.2 Infrastructure financial support mechanisms

Announced alongside the CfD financing mechanism for industrial carbon capture, the UK government plans to progress work on its development of a **CO_2 T&S business model**, and is currently minded to operate the infrastructure through an economic form of regulation, drawing on experiences from other regulated network models. The CCUS Cost Challenge Taskforce, the BEIS Select Committee on CCUS and the CCUS Advisory Group all shared the view that due to the characteristics of a CO_2 T&S network, a regulated asset base funding model would be a suitable funding model in the long-term.

Under a regulated asset base model, the T&S company would receive a licence from an economic regulator, which grants it the right to charge a regulated price to users in exchange for delivering and operating the T&S network. To prevent monopolistic disadvantages, the charge is set by an independent regulator who considers allowable expenses, over a set period of time, to ensure costs are necessary and reasonable. Model variants could include the provision of financial support to decrease the upfront capital expenditure or to support early adopters of the network subject to higher initial costs. Early funding support for the T&S network is likely to come from the UK's recently proposed CCS Infrastructure Fund, highlighted in Box 2. Policy should ensure that implementation of this funding is not delayed, considering the key role that CO_2 T&S plays in industrial decarbonisation.

Box 2 – UK announces CCS Infrastructure Fund

In March 2020, a new CCS Infrastructure Fund was announced as part of the UK's Budget. In November 2020, the Government's Ten Point Plan for a Green Industrial Revolution further increased the value of the Fund to £1bn. The focus of the Fund will be to deliver on the promise of deploying CCUS in at least two industrial clusters, with the aim to have one in the mid-2020s and a second by 2030. In addition, the Fund will be used to help finance the infrastructure needed for the construction of a gas power station with CCS by 2030. Supported by the Government's proposed business models for CCUS, the Fund will enable the deployment of deep decarbonisation technologies within industry, further helping to achieve:

- the Industrial Clusters mission of one low-carbon cluster by 2030 and the world's first net zero cluster in the following decade (by 2040), and
- the UK's target of net zero emissions by 2050.

In its current stage of development, the UK government does not plan for any technologies to be ineligible for funding. Moreover, consideration is being given economy-wide to how the Fund can support industry, power, T&S, as well as low carbon hydrogen CCS projects. While designing individual funding mechanisms, the government plans to engage closely with each sector to identify the gaps which funding could fill. For instance, financing that may not be supported by the private sector or not already supported via existing governments funding programmes.

The UK government has already recognised that the development of CO_2 T&S networks in the UK will be complex infrastructure undertakings that are likely to involve a variety of approaches, including the development of new onshore and offshore infrastructure, the potential for re-use of existing oil and gas infrastructure and use of CO_2 shipping to extend a network's reach. This is evident from Government's recently completed consultation on the re-use of oil and gas assets for CCUS projects.[87]

Similarly for hydrogen infrastructure, policy and funding designs should also be tailored towards **cost-effective infrastructure projects** which, where possible, lead to **repurposing or re-using** parts of the existing natural gas infrastructure, helping to reduce costs and avoid stranded pipeline assets. Furthermore, any new policies should be designed with the scope to include all forms of low carbon hydrogen production to ensure that the most cost-effective options are able to be deployed in the near term. It is emphasised that hydrogen generation and distribution should be supported with the appropriate business model to encourage private sector investment, particularly for early projects. Any support mechanism should be compatible with the mechanism chosen for fuel switching to ensure the appropriate level of support is given for development of the full hydrogen supply chain.

Lastly, while this work has modelled infrastructure demand exclusive of import or export opportunities, it is crucial that government acknowledges the broader impacts of the potential avenues for interregional trade and transport of hydrogen and CO_2. An EU-hydrogen economy could very well be supported by UK exports of low-cost hydrogen production, transported via ships docking at adapted LNG terminals. Transport can happen as pure gaseous or liquid hydrogen or bound in bigger molecules that are easier to transport (e.g. ammonia or liquid organic hydrogen carriers). Financial support for investments in port and shipping infrastructure should evaluate the potential for increasing demand that the wider hydrogen economy brings. Conversely, clusters or regions in need of shipping CO_2 may consider lower cost downstream T&S chains that exist in the EU (e.g. as part of Norway's Northern Lights project in the North Sea).[88] Government should engage closely with industrial clusters and with multinational companies to ensure policies

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[87] The response to the consultation on the re-use of oil and gas assets for CCUS projects can be found at: https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-projects-re-use-of-oil-andgas-assets

[88] In partnership with the Netherlands and Norway, the UK proposed a provisional amendment to the London Protocol to allow for cross-border transportation and storage of CO_2 which was successfully passed at the International Maritime Organisation in October 2019, representing a significant milestone for cross-border transport of CO_2.

and financing mechanisms drive support for the development of UK-based T&S networks, or are amended to support the portion of the T&S network that is within the UK's jurisdiction (e.g. trunk pipelines from large emission sources or port infrastructure).

9.3.3 Expanding the capacity and skills of the supply chain

While many new technologies and infrastructure share synergies with existing technologies, there likely needs to be significant support for the transfer of knowledge and upskilling. This could be directly supported through policies which incentivise training or can be indirectly facilitated by policies which create more market certainty and therefore promote private sector investment in supply chains.

To support the long-term transition to deep decarbonisation of industry, the UK will need to build expertise in the new technologies and infrastructure required. These skills are for achieving net zero emissions by 2050, and also represent an opportunity for the UK, with the potential growth of an export market for similar services to other countries looking to decarbonise. Clarity on the UK's decarbonisation agenda would provide industry with some of the certainty required to invest in skills development in the UK.

Appropriate local training near to industrial clusters will be important. Government should continue to encourage connections between industrial clusters and local education institutions that could provide appropriate training for the technologies required in the region. This would ensure the availability of a trained workforce around industrial clusters and would reduce risks of workforce shortages.

9.3.4 Preventing carbon leakage

Carbon-intensive and trade-intensive industrial sectors are particularly impacted by the risk of carbon leakage, since they are subject to greater competition across international markets and are less capable of passing on additional costs (e.g. resulting from an increased carbon price) without losing market share. To mitigate against this risk, Government may need to consider policy designs beyond those that incentivise technology and infrastructure deployment.

To address carbon leakage risk, a policy lever could offer an adjustment on the import and export prices of products exposed to different carbon pricing regimes. The aim is to provide a financial 'correction' to the manufacturing cost so that all manufacturers are competing on an even carbon price basis. The prominent policy option of this type is a **Border Tariff Adjustment** (BTA),[89] which can be designed to issue import fees on goods produced in countries with lower carbon pricing policies and remit carbon taxes on exports intended for the same countries. It should be recognised that BTAs are a complex policy to design and implement, with further concerns still to be addressed on their effectiveness in mitigating carbon leakage. In particular, BTAs would need to be accordant with World Trade Organisation rules and free trade arrangements between governments.

Despite these challenges, the **EU Commission's proposed creation of a BTA**, the Carbon Border Adjustment Mechanism (CBAM)[90], was identified in the European Green Deal as a critical policy lever to achieving a climate-neutral Europe by 2050. The EU Commission has recently launched consultations (July 2020) on the CBAM, with the aim of adopting an act into EU law by the second quarter of 2021. The UK government should look towards investigating key transferable learnings from these early stages of implementation of the CBAM to inform the potential for development of their own national BTA.

[89] Also known as Border Adjustments or Border Tax Assessments.
[90] EU Commission, EU Green Deal (carbon border adjustment mechanism)

10 Appendix

10.1 Sectors and Process Archetypes

Industry sector	Process archetypes[91]	# of point source sites
Ammonia	Combustion CO_2; Process CO_2	2
Cement	Kiln; Process CO_2; Biomass Process	11
Coal Mine (closed)	Methane Leakage	0
Coal Mine (open)	Generators; Lubrication; Methane Leakage	0
Compressor Station	Compressor	23
Construction	Generators; Lubrication	0
Ethylene	Boiler – Steam; Combustion CO_2; Dryer; Process CH_4; Process CO_2	3
Food & Drink	Boiler – Steam; CHP; Dryer; Oven; Biomass Process	162
Gas Distribution	Lubrication; Methane Leakage	0
Gas Platform	Compressor; Flaring; Generators; Venting	35
Gas Terminal	Boiler – Steam; Compressor; Flaring; Generators; Methane Leakage; Process CO_2; Venting	23
Glass	Furnace; Process CO_2; Glass Other	26
Lime	Kiln; Process CO_2; Biomass Process	6
LNG Terminal	Regasification (Vapourisers)	3
Non-ferrous Metal	CHP; Metal Melting; Metal Rolling; Non-ferrous Metal – Process; Process CO_2	14
Non-road Mobile Machinery (NRMM)	N/A[92]	0
Oil Platform	Compressor; Flaring; Generators; Methane Leakage; Venting	81
Oil Terminal	Compressor; Flaring; Generators; Methane Leakage; Process CO_2; Venting	10
Other Chemicals	Boiler – Steam; CHP; Dryer; Methane Leakage; Process CH_4; Process CO_2; Process N_2O; Pumps; Biomass Process	133
Other Fuel Production	Coke production; SSF Production[93]	6
Other Industry	Boiler – Steam; CHP; Generators; Incinerators; Lubrication; Process CO_2; Process N_2O; Biomass Process	57
Other Iron & Steel	Boiler – Steam; Electric Arc Furnace; Metal Melting; Metal Rolling	27
Other Minerals	Dryer; Kiln; Process CH_4; Process CO_2	156
Paper	Boiler – Steam; CHP; Dryer; Biomass Process	46
Primary Iron Production	Boiler – Steam; CHP; Electric Arc Furnace; Flaring; Metal Rolling; Blast Furnace and Sinter Plant	2
Refining	Boiler – Steam; CHP; Furnace; Process CO_2	9
Shale Gas	Compressor; Flaring; Generators; Methane Leakage; Venting; Process CO_2	0
Vehicles	Boiler – Steam; CHP; Dryer; Furnace; Oven	32
Waste Processing	Incinerators; Biomass Process	74
Total		**941**

[91] Emissions from any sectors with a "Biomass Process" are not considered in the baseline.
[92] No defined processes. Analysis for NRMM was undertaken separately by the CCC and incorporated into the results.
[93] Solid smokeless fuel (SSF) production uses anthracite as the base ingredient because of its naturally high carbon content. Ideal for domestic open fires/stoves, SSFs combust with with fewer volatile materials and no acrid smoke.

10.2 Methodology and Assumptions Tables

10.2.1 Hydrogen T&S Infrastructure Components and Lead Times

Infrastructure	Base Length	Constraints on Length	Estimated Minimal Length	Progress / Examples
Salt Caverns (Storage)	7 years[94]	Appraisal of new sites, leaching process	6 years	H21 North of England roll-out plans for new salt caverns commissioned by 2027 (H_2 storage already occurs in Teesside at the Seal Sands salt field for industrial chemical users)
Ammonia (Production, Storage and Cracking)	5 years	Over-sizing/right-sizing (i.e. H_2 demand volume uncertainty leading to low asset utilisation)	3 years	BEIS has awarded funding for industry-led feasibility studies on the use of ammonia in the delivery of low-cost bulk hydrogen[95]
New Transmission Pipeline	8 years[96]	H_2 supply volume uncertainty, planning approvals and land purchases, pipe and equipment manufacture, construction delays	4 years[97]	H21 North of England roll-out plans for a new transmission pipeline (begins operating by 2028 for West Yorkshire, Tyneside, Manchester)
Existing Distribution Pipeline Conversion	8 years96[96]	New / accurate industrial metering needs to be developed for compositions up to 100% H_2, ensuring pipelines are able to provide peak demand network balancing / storage	4 years[97]	Cadent HyNet Phase 2 (2023-26) aims to have high concentrations of hydrogen fuels supplied to industry[98]

[94] The leaching process itself can take up to 7 years depending on geological factors.
[95] https://www.gov.uk/government/publications/hydrogen-supply-competition
[96] For the first large-scale project, anticipated lead time is up to 8 years (based on schedule for proposed H21 North of England project, including FEED and EPC).
[97] Depending on size and scope of H2 transmission pipeline development or distribution pipeline conversion in other regions, future lead times are estimated to range from 4 to 6 years.
[98] https://hynet.co.uk/#timeline

10.2.2 CO_2 T&S Infrastructure Components and Lead Times

CO_2 Storage Development Stage	Base Length	Constraints on Length	Estimated Minimal Length	Progress / Examples
Storage Appraisal (for new sites)	4 years	Well drilling, seismic surveying, modelling	3 years	Currently appraised[99]: Northern North Sea (12 Mt/y), Southern North Sea (30 Mt/y), Irish Sea (5 Mt/y)
Pre-FEED Planning	2 years	Data sourcing/collection, due diligence, labour requirements, storage licensing, additional appraisal modelling	2 years[100]	Projects at this stage: Zero Carbon Humber, HyNet (Merseyside), Net Zero Teesside, Acorn (Grangemouth and Northern Scotland)
FEED	2 years	Permitting, permissions, leasing, consents	1 year[100]	Acorn (2020)[101], HyNet (2020)[102], Zero Carbon Humber (2020-2021)[103], Net Zero Teesside (2022-2024)[103]
Final Investment Decision (FID)	-	-	-	Acorn (2021)[101], HyNet (2022)[102]
EPC	3 years	Availability of experienced geo / petroleum engineers and drilling equipment / rigs, delays in procurement / construction	2.5 years[100]	

[99] ETI Appraisal Project (2016)
[100] Acorn Project feasibility deliverables (2018)
[101] Acorn Project ACT workshop (Nov 2019)
[102] HyNet Project update (Oct 2019)
[103] Estimate

Transport Infrastructure	Base Length	Constraints on Length	Estimated Minimal Length	Progress / Examples
Existing Onshore or Offshore Pipeline	7 years[104]	Regulatory uncertainty (i.e. unable to secure change of use or owner), operator unwilling to dispose of asset, operational challenges (e.g. pipeline corrosion, depressurisation, CO_2 venting)	4 years	Acorn Project includes plans to re-use three offshore pipelines (starting 2024) and National Grid's Feeder 10 onshore gas transmission pipeline to connect Grangemouth to Peterhead (planned for 2027)
New Onshore or Offshore Pipeline	5 years[104]	CO_2 supply volume uncertainty (i.e. over-sizing/right-sizing pipeline assets for future carbon capture projects), permitting, delays in procurement/construction	4 years	HyNet Project planning for new onshore pipeline from ATR plant to existing pipeline at Connah's Quay
Rail[105] / Road	2 years	Delays in building infrastructure (filling stations/temporary storage at industrial sites, ports, etc.) or purchasing trucks or rail wagons	1 years	Certain industrial sites near or within National Parks / Areas of Outstanding Natural Beauty unable to acquire pipeline permits may be constrained to use rail/road CO_2 transport
Shipping	7 years	Inadequate port facilities due to length and draft limits[106], modernisation and upgrade of existing fleet (e.g. improving maximum ship length and storage space)	5 years	Currently, there is limited experience in CO_2 shipping in the UK at the scale needed. A Norwegian CCUS project, Northern Lights, plans to scale up CO_2 shipping in the North Sea and is on track for FID in 2020/2021 (and if successful, operational in 2023).

[104] Includes pre-FEED planning, FEED and EPC work.
[105] Some dispersed industrial sites may not have rail network access or experience capacity constraints on the rail system (e.g. parts of the network with increased passenger traffic) thereby requiring the use of road transport.
[106] For example: Aberdeen and Londonderry/Foyle ports are unable to accommodate the largest 30 kt ships https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/929282/BEIS_-_CCUS_at_dispersed_sites_-_Report__1_.pdf

10.3 Emissions Pathways for Sensitivities