The **Making Mission Possible** Series

Carbon Capture, Utilisation & Storage in the Energy Transition: **Vital but Limited**

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Energy Transitions Commission

Carbon Capture, Utilisation & Storage in the Energy Transition: Vital but Limited

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C.

Our Commissioners come from a range of organisations – energy producers, energy-intensive industries, technology providers, finance players and environmental NGOs – which operate across developed and developing countries and play different roles in the energy transition. This diversity of viewpoints informs our work: our analyses are developed with a systems perspective through extensive exchanges with experts and practitioners. The ETC is chaired by Lord Adair Turner who works with the ETC team, led by Ita Kettleborough (Director) and Faustine Delasalle (Vice-Chair). Our Commissioners are listed on the next page.

Carbon Capture, Utilisation & Storage in the Energy Transition: Vital but Limited was developed by the Commissioners with the support of the ETC Secretariat, provided by SYSTEMIQ. It brings together and builds on past ETC publications, developed in close consultation with hundreds of experts from companies, industry initiatives, international organisations, non-governmental organisations and academia.

The report draws upon analyses carried out by ETC knowledge partners SYSTEMIQ and BloombergNEF, alongside analyses developed by the International Energy Agency, Intergovernmental Panel on Climate Change, Global CCS Institute, Rocky Mountain Institute and the Mission Possible Partnership. We warmly thank our knowledge partners and contributors for their inputs.

This report constitutes a collective view of the Energy Transitions Commission. Members of the ETC endorse the general thrust of the arguments made in this report but should not be taken as agreeing with every finding or recommendation. The institutions with which the Commissioners are affiliated have not been asked to formally endorse the report.

The ETC Commissioners not only agree on the importance of reaching net-zero carbon emissions from the energy and industrial systems by mid-century but also share a broad vision of how the transition can be achieved. The fact that this agreement is possible between leaders from companies and organisations with different perspectives on and interests in the energy system should give decision-makers across the world confidence that it is possible simultaneously to grow the global economy and to limit global warming to well below 2°C, and that many of the key actions to achieve these goals are clear and can be pursued without delay.

Learn more at:
www.energy-transitions.org
www.linkedin.com/company/energy-transitions-commission/
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Glossary

Abatement cost: The cost of reducing CO_2 emissions, usually expressed in US$ per tonne of CO_2.

Afforestation and reforestation: The planting of new forests on land not currently under forest cover. The forests remove carbon from the atmosphere as they grow.[1]

Absorption: The process by which one substance, such as a solid or liquid, takes up another substance, such as a liquid or gas, through minute pores or spaces between its molecules.

Adsorption (in CCS): The process by which a material attracts CO_2 molecules to its surface so it can be captured and/or stored.

Ammonia (NH_3): Is a compound of nitrogen and hydrogen. It can be used directly as a fuel in direct combustion process, and in fuel cells or as a hydrogen carrier. To be a low-carbon fuel, ammonia must be produced from low-carbon hydrogen and electricity needs are met by low-carbon electricity.

Aquifer: The technical term for a geological structure whose rock is permeable, or porous enough to allow containment or significant through-flow of fluids.

BECCS: Bioenergy with carbon capture and storage entails power generation using biomass as a fuel (normally wood pellets) with CCS technology used to capture and store CO_2. CO_2 can also be utilised in which case technology is referred to as BECCU. Note that BECCS is distinct from BiCRS (biomass carbon removal and storage) which describes a range of processes that use plants and algae to remove carbon dioxide from the atmosphere and store that CO_2 underground or in long-lived products.

Biochar: The thermal decomposition of biomass in the absence of oxygen forms a charcoal known as biochar. This can be added to soils to improve soil fertility and to act as a stable long-term store of carbon.[2]

Blue Hydrogen: H_2 produced from splitting natural gas (or methane (CH_4) into H_2 and CO_2 and capturing the CO_2.

Carbon price: A government-imposed pricing mechanism, the two main types being either a tax on products and services based on their carbon intensity, or a quota system setting a cap on permissible emissions in the country or region and allowing companies to trade the right to emit carbon (i.e., as allowances). This should be distinguished from some companies' use of what are sometimes called 'internal' or 'shadow' carbon prices, which are not prices or levies, but individual project screening values.

Carbon dioxide removals (CDR): refers to deliberate actions which result in a net removal of CO_2 from the atmosphere. This can include engineered solutions such as BECCS or DACCS or natural climate solutions (NCS) such as afforestation.

Circular economy models: Economic models that ensure the recirculation of resources and materials in the economy, by recycling a larger share of materials, reducing waste in production, light-weighting products and structures, extending the lifetimes of products, and deploying new business models based around sharing of cars, buildings, and more

Direct Air Carbon Capture (DACC): the collective term for various technologies which use chemical processes to separate carbon dioxide from the atmosphere. This term does not carry any implications regarding the subsequent treatment of the CO_2 – it may be utilised or stored. Direct Air Carbon Capture & Storage (DACCS) specifically refers to post-capture subsurface sequestration as the explicit end of life destination. Direct Air Carbon Capture & Utilisation (DACCU) refers to utilisation of captured CO_2 after capture.

Direct reduced iron (DRI): Iron (so called "sponge iron") produced from iron ore utilising either natural gas or hydrogen. This DRI is then converted to steel in a second step called electric arc furnace (EAF). The DRI-EAF is an alternative primary steel production process enabling decarbonisation of the traditional coke-fired blast furnace/basic oxygen furnace (BF-BOF) and an alternative to CCS in iron & steel production.

Electrolysis: A technique that uses electric current to drive an otherwise nonspontaneous chemical reaction. One form of electrolysis is the process that decomposes water into hydrogen and oxygen, taking place in an electrolyser and producing "green hydrogen" when performed using renewable energy.

Energy productivity: Energy use per unit of GDP.

Fischer-Tropsch process: Catalytic production process for the production of synthetic fuels. Natural gas, coal and biomass feedstocks can be used.

Fugitive emissions: Any unintended release of gas or vapour from anthropogenic activities such as the processing or transportation of gas or petroleum.

Greenhouse gases (GHGs): Gases that trap heat in the atmosphere. Global GHG emission contributions by gas – CO_2 (76%), methane (16%), nitrous oxide (6%) and fluorinated gases (2%).

Green hydrogen: H_2 produced from splitting water (H_2O) via renewably powered electrolysis

1 UK Committee on Climate Change (2018) *Biomass in a low-carbon economy.*
2 Ibid.

Levelised cost of X (LCOX): A measure of the average net present cost of a given good such as carbon capture or electricity generation for a plant over its lifetime. For example the Levelised cost of electricity (LCOE) is calculated as the ratio between all the discounted costs over the lifetime of an electricity-generating plant divided by a discounted sum of the actual energy amounts delivered.

Natural Climate Solutions (NCS): conservation, restoration, and/or improved land management actions to increase carbon storage and/or avoid greenhouse gas emissions across global forests, wetlands, grasslands, agricultural lands, and oceans.

Negative emissions: a net reduction in atmospheric CO_2 concentration arising from CO_2 being removed via either NCS or engineered solutions such as DACCS or BECCS.

Point Source carbon capture: CCUS attached to a single, identifiable entity from which CO_2 originates. This is in contrast to Direct Air Capture which isolates CO_2 from the atmosphere.

Process Emissions: CO_2 and other greenhouse gases emissions generated as consequence of a chemical reaction other than combustion occurring during an industrial process.

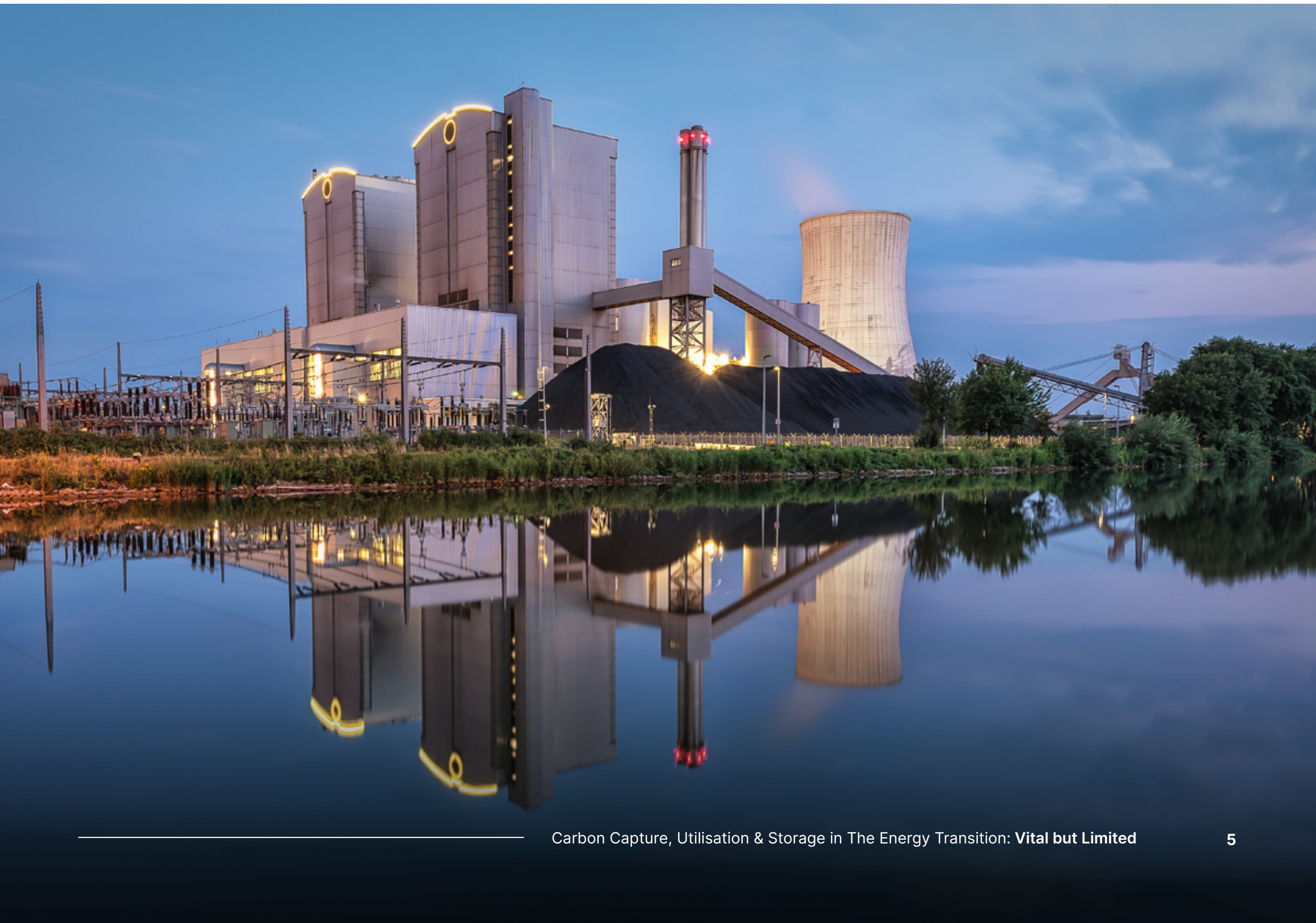
Sequestration: removal or separation of CO_2 such that it is no longer freely moving in the atmosphere.

Steam methane reforming (SMR): A process in which methane is heated and reacts with steam to produce synthesis gas (syngas) - a mixture of hydrogen and carbon monoxide. This process is often coupled with a Water Gas Shift process in which carbon monoxide is heated and reacts with steam to further increase hydrogen yield.

Synfuels: Hydrocarbon liquid fuels produced from hydrogen, carbon dioxide and electricity. They can be zero-carbon if the electricity input is zero-carbon and the CO_2 is from direct air capture. Also known as “synthetic fuels”, “power-to-fuels” or “electro-fuels”.

Technology Readiness Level (TRL): Describes the level of matureness a certain technology has reached from initial idea to large-scale, stable commercial operation. The IEA reference scale is used.

Zero-carbon energy sources: Term used to refer to renewables (including solar, wind, hydro, geothermal energy), sustainable low-carbon biomass, and nuclear.



Major ETC reports and working papers

Global Reports

Mission Possible (2018) outlines pathways to reach net-zero emissions from the harder-to-abate sectors in heavy industry (cement, steel, plastics) and heavy-duty transport (trucking, shipping, aviation).

Making Mission Possible (2020) shows that a net-zero global economy is technically and economically possible by mid-century and will require a profound transformation of the global energy system.

The Making Mission Possible Series (2021) outlines how to scale up clean energy provision to achieve a net-zero emissions economy by mid-century.

Keeping 1.5°C Alive (2021) a COP26 special report outlining actions and agreements required in the 2020s to keep 1.5°C within reach.

Mind the Gap (2022) highlights how carbon dioxide removals must complement deep decarbonisation through clean electrification to keep 1.5°C alive.

Sectoral and cross-sectoral focuses

Sectoral focuses provided detailed decarbonisation analyses on six of the harder-to-abate sectors after the publication of the Mission Possible report (2019).

As a core partner of the MPP, the ETC also completes analysis to support a range of sectorial decarbonisation initiatives:

Aviation:
(2021) Corporate members of the Clean Skies for Tomorrow initiative developed a Sustainable Aviation Fuel Policy Toolkit and Ten Critical Insights on the Path To A Net-Zero Aviation Sector focusing on the need for ramp-up of sustainable aviation fuels to reach net-zero emissions by 2050.

Shipping:
(2021) The Next Wave: Green Corridors raises ambitions to look at how specific trade routes between major port hubs where zero-emission solutions are demonstrated and supported can accelerate the speed of shipping's transition.

Steel:
(2021) The Net Zero Steel Sector Transition Strategy lays out what it will take for the steel sector to reach net-zero by 2050, rooted in technical and economic reality.

Geographical focuses

China 2050: A Fully Developed Rich Zero-Carbon Economy (2019) describes the possible evolution of China's energy demand sector by sector, analysing energy sources, technologies and policy interventions required to reach net-zero carbon emissions by 2050.

Canada's Electrification Advantage in the Race to Net-Zero (2022) identifies 5 catalysts that can serve as a starting point for a national electrification strategy led by Canada's premiers at the province level.

Indian power system and outlining decarbonisation roadmaps for Indian industry (2019-2020) describe how India could rapidly expand electricity supply without building more coal-fired power stations, and how India can industrialise whilst decarbonising heavy industry sectors.

Phase 1 and 2 of Setting up industrial regions for net zero (2021 & 2022) explore the state of play in Australia and opportunities for transition to net-zero emissions in five hard-to-abate supply chains – steel, aluminium, liquified natural gas, other metals and chemicals.

Contents

Introduction

The Paris climate accord committed the world to keeping global warming to well below 2°C above preindustrial levels, aiming ideally for a 1.5°C limit. To have a 90% chance of staying below 2°C and a 50% chance of limiting warming to 1.5°C, the world must reduce CO_2 and other greenhouse gases (notably methane) to around zero by mid-century, with a reduction of CO_2 emissions of around 40% achieved by 2030.[3]

The ETC supports these objectives and believes that all developed countries should reach net zero by 2050 at the latest and all developing countries by 2060.

The vast majority of required emissions reductions can and must be achieved through a combination of the technologies covered in three reports which the ETC has published over the last year (Exhibit 1):

- **The most important priority is clean electrification.** Total electricity use across the world will need to rise to rise from around 20% of final energy demand today to over 65% by 2050, with total direct global electricity use rising 3-5 times.[3] All of this electricity must be and can be produced in a zero-carbon fashion. This principally refers to wind and solar but also includes hydro, nuclear and geothermal.

- **Hydrogen must also play a major role** in many sectors and as a storage mechanism within the power system. Total hydrogen use could rise from today's 100 million tonnes per annum to around 500-800 million tonnes, with the vast majority produced through electrolysis of water ("green hydrogen").

- **In addition, the use of bio resources will play an important role** but must be kept within sustainable limits, avoiding competition with biodiversity and food production.[4]

Together these three technologies could account for over 90% of the mid-century energy mix.[5] Moreover, analysis shows that the transition to this radically changed energy system can be achieved at an affordable cost and that the natural resources required are available[6]. But the costs will be still lower, and resource demands more manageable, if the world also seizes the abundant opportunities to improve energy productivity and efficiency. During 2022 the ETC will therefore produce a report on the scale of those opportunities and how to grasp them.

Improved energy efficiency, electrification and hydrogen, complemented by a focussed role for bioenergy will therefore form the core of the pathway to net zero. Together they could reduce CO_2 emissions from the energy, building, industry and transport sectors from around 35 $GtCO_2$ today to below 5 $GtCO_2$ by 2050. But however aggressively pursued they cannot achieve either an absolutely zero carbon economy by mid-century, nor a 40% reduction in emissions by 2030. Alongside these technologies carbon capture, use or storage (CCUS) must play three vital but limited roles:

- To decarbonise those sectors where alternatives are technically limited (i.e. industrial processes which by their nature produce CO_2 such as cement).

3 ETC (2021) *Making the Hydrogen Economy Possible – Accelerating Clean Hydrogen in an Electrified Economy.*
4 ETC (2021) *Bioresources within a Net-Zero Emissions Economy: Marking a Sustainable Approach Possible.*
5 ETC (2021) *Making Clean Electrification Possible – 30 Years to Electrify the Global Economy.*
6 ETC (2020) *Making Mission Possible: Delivering a Net Zero Economy.*

- To deliver some of the carbon removals that are required in addition to rapid decarbonisation if global climate objectives are to be achieved;

- And to provide a low-cost decarbonisation solution in some sectors and geographies where CCUS is economically advantaged relative to other decarbonization vectors locally.

The ETC's recent paper on Carbon Dioxide Removals (CDR) estimated that 70–225 Gt of carbon dioxide removals will be required between now and 2050, with an ongoing rate of 3–5 $GtCO_2$ per annum thereafter.[7] Many of these removals can be achieved via "natural climate solutions" such as reforestation, but removals which involve "engineered" approaches to capture and/or to storage will also be required.[8] Note that for the purposes of this report, we treat Direct Air Carbon Capture and Storage (DACCS) and Bioenergy with carbon capture and storage (BECCS) as subcategories of carbon capture and storage technology).[9]

This report therefore assesses the roles which CCUS should play on the path to net zero and what must happen to ensure it can do so. The key conclusions are that:

- By 2050, the world will likely need to capture and either store, or in some cases use, 7–10 $GtCO_2$/year through engineered carbon capture solutions.
  - Of this 3–5 $GtCO_2$/year will be needed to achieve net zero emissions in applications where the use of electricity, hydrogen, or bio energy cannot provide a complete solution to decarbonisation.
    - This use of CCUS will make it possible to continue to consume 9 million barrels per day (Mb/d) of oil (or 90% lower than today), and 2,700 billion cubic meters (BCM) of gas per year – (over 30% lower than today) while still achieving a zero emission economy.
    - Around 15% (0.5–0.8 $GtCO_2$/year) will be needed to capture industrial processes such as cement production which by their nature produce CO_2 and 85% from capture from the continued use of fossil fuels where alternatives are less available or prohibitively expensive.
  - Another 4–5 $GtCO_2$/year will be needed to achieve engineered carbon removals.

- Provided strong regulations are in place, CCUS can be technically safe and can be achieved at costs which enable it to play an economically valuable role on the path to net zero.

- The current pace of development of CCUS is far short of what is required. This reflects past confusions about where CCUS is most needed, inadequate investment, and controversies which have generated public opposition.

- A combination of private investment and supporting public policy is required to ensure that CCUS can play its vital but limited role.

In the past, CCUS has been held back by controversy surrounding safety, permanence and appropriate role. Many environmental groups fear that acceptance of a role for CCUS will divert attention from other, more important decarbonisation levers; some fear that CCUS used in applications such as "enhanced oil recovery" could undermine the transition to a zero-carbon economy or prolong fossil fuel reliance; some express fears that CO_2 storage will not be safe or permanent.

It is therefore useful to recognise the key controversies up front and state the ETC's stance: this is set out in Box 1.

This report seeks to define a strategy for CCS which both recognises its essential role and ensures that it does not undermine other aspects of the decarbonisation strategy. It covers, in turn;

1. The role of CCUS in the energy transition – vital but limited.

2. The technology, economics and safety of capture, transportation and storage.

3. Scaling up CCUS in the 2020s and beyond: a plausible pathway.

4. Required action by industry and policy makers.

7 ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive*.

8 Carbon dioxide removals may also be necessary to generate sufficient net negative emissions in the second half of the 21st century to reverse climate-warming effects of an overshoot in the cumulative budget. See chapter 2 of ETC (2022) *Mind the Gap*.

9 CCUS is sometimes associated only with the capture of emissions from fossil fuel or industrial 'point sources'. However for the purposes of this report, we include all technologies that capture and store carbon. This includes Direct Air Carbon Capture (DACC) and Bioenergy with carbon capture (BECC) which are forms of carbon dioxide removal using technological solutions to capture carbon dioxide and to store / utilize for long duration. We therefore treat these as sub-categories of the broader category of CCUS.

The ETC's report on CCUS complements previous analyses of decarbonisation and negative emissions technologies

ETC reports on electrification, hydrogen, bioresources and CDR

Exhibit 1

Where does the ETC stand on key controversies surrounding CCUS?

There are widely differing views on the appropriate role of CCUS in meeting decarbonisation objectives. At one end of the spectrum some groups suggest that heavy emitting industries use the promise of future carbon capture technologies as a means to legitimise continued reliance on fossil fuels today (or even indefinitely). Conversely, industry groups complain that a viable and important technology is unfairly demonized due to its association with the fossil sector. This box sets out the main controversies surrounding CCUS technology, the ETC's stance on each topic and where to find analysis on the subject within this report.

Moral Hazard: does CCUS risk legitimising business-as-usual?
Some published scenarios have in the past proposed a far larger role for CCUS than appropriate or required and have therefore seemed to justify a far greater than optimal future role for fossil fuels and delaying action today. While rejecting that approach, the ETC believes that CCUS will need to play a vital but limited role in transition to a net zero economy. Other means of decarbonisation such as electrification, hydrogen, sustainable bioenergy and energy productivity improvement can deliver the bulk of emissions abatement, but CCUS will be necessary in some specific sectors and applications. There is now room for greater confidence that CCUS deployment can be targeted to ensure its optimal use to deliver decarbonisation and avoid 'locking in' unnecessary, on-going oil and gas use. According to the IPCC: All analysed pathways limiting warming to 1.5°C with no or limited overshoot use CDR to some extent to neutralise emissions from sources for which no mitigation measures have been identified and, in most cases, also to achieve net negative emissions to return global warming to 1.5°C following a peak.[10]
Further detail: Section 1.2 (p.18) and Box 3: Comparing carbon capture scenarios (p.38)

Technology: does CCUS actually work?
CO_2 capture has been demonstrated at scale in many locations. Capture rates over 90% are technically feasible and have been achieved at scale, although early projects often fell well short of this threshold. It is therefore essential to ensure that future projects achieve high capture rates while recognising that even above 90% these make CCUS a very low but not quite zero carbon technology. Storage in geological formations can be permanent and safe if well-managed, as demonstrated by existing CCUS projects and natural CO_2 stores, but strong regulation will be essential to ensure that this is achieved.
Further detail: Section 2.4 (p.60) and Box 4: Carbon capture rates: separating fact from fiction (p.54)

Unrealistic expectations: are the costs and energy requirements for Direct Air Carbon Capture (DACC) implausible?
DACC will always require large energy inputs due to the low concentration of CO_2 in the air. But plausible assumptions on technological progress, renewable energy cost declines, learning by doing and economies of scale, suggests that DACC costs could fall from today's very high levels to below \$100/tCO_2 by 2050. Sufficient land, solar and wind resources are available to support at least 3.5 GtCO_2 per annum of DACC capacity by 2050.
Further detail: Section 2.2.3 (p.48)

Enhanced Oil Recovery: does EOR legitimise oil consumption and lower prices?
In the short term EOR may provide a commercially viable model to fund growth in capture/storage technologies. But use of CCUS for EOR has also played a major role in undermining public confidence in CCUS technologies, CCUS's role in the transition and the 'moral hazard' concerns around legitimising 'BAU' activities raised above.

Public support for CCUS technologies should always strongly favour other critical applications of CCUS (e.g., cement) and on shared transport and storage infrastructure which can underpin multiple applications of CCUS.

But if policy support (such as financial incentives for CO_2 stored) is directed towards EOR this should be strictly limited to situations where i) the combination of CO_2 source and carbon intensity of injection delivers zero or negative net emissions; ii) captured CO_2 is used, with EOR using mined CO_2 never supported (and ideally discouraged); iii) overall oil demand is constrained by ambitious decarbonisation policies applied to end use sectors.[11]

In total EOR should play only a very limited role compatible with future global oil consumption around 7Mb/d. Furthermore, claims of 'carbon neutral' or 'zero-carbon' oil should be regulated and only be made if the net emissions effect of CCUS combined with EOR is truly zero or negative.
Further detail: Section 2.6 (p.80)

Box 1

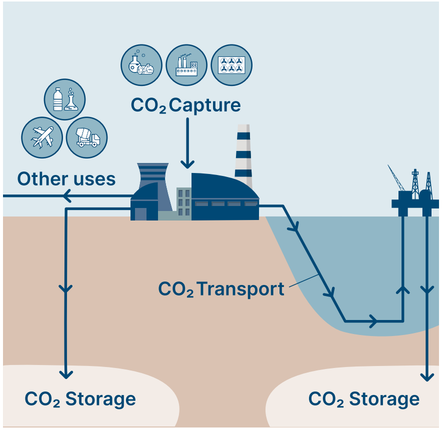
10 IPCC (2022) *6th Assessment Report Working Group 3.*

11 Even in a Net Zero scenario, oil demand does not fall to zero. The ETC estimates 2050 liquids demand at approximately 9Mbd. ETC (2020) *Making Mission Possible: Delivering a Net-Zero Economy)*; the IEA estimates 2050 liquids demand at 24Mbd. IEA (2021) *Net Zero by 2050: A Roadmap for the Global Energy Sector.*

Energy Transitions Commission

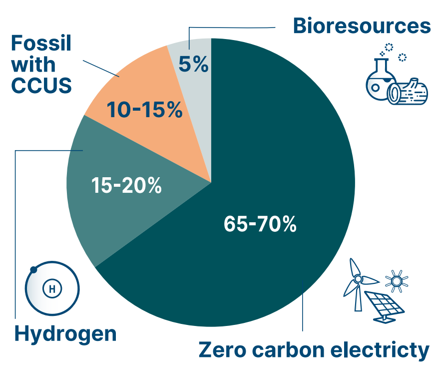
CARBON CAPTURE, STORAGE AND UTILISATION: VITAL BUT LIMITED

CCUS IS CAPTURING CO_2 FOR STORAGE OR USE



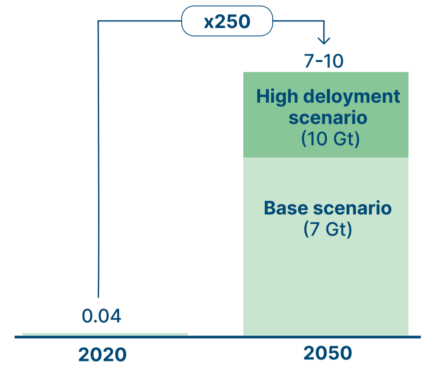
CCUS HAS A VITAL BUT LIMITED ROLE

Final energy mix in a zero-carbon economy by 2050



A SIGNIFICANT SCALE UP IS REQUIRED

Carbon dioxide capture, $GtCO_2$/year



CCUS WILL BE NEEDED IN THREE CONTEXTS

ESSENTIAL ROLE – limited technical alternatives

In industrial processes which produce CO_2 and cannot be decarbonised via other zero-carbon solutions

To provide crucial engineered CO_2 removals from the atmosphere

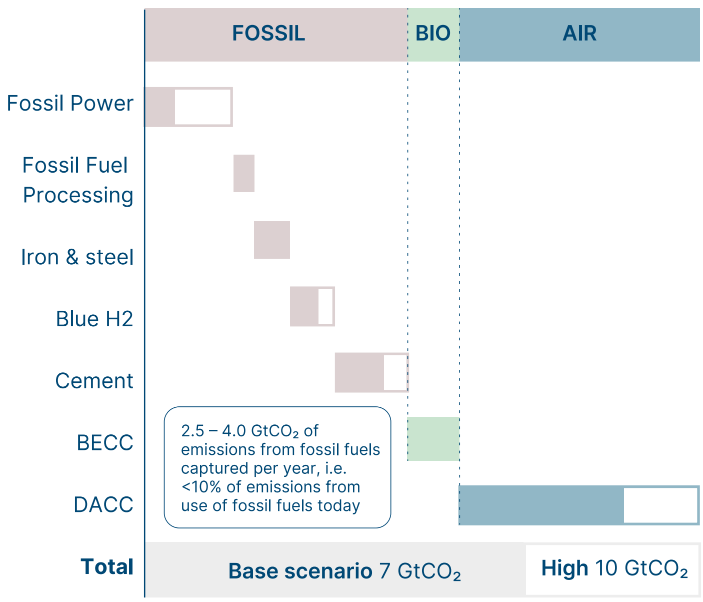
ECONOMIC ROLE

Where it is the lowest-cost decarbonisation solution given local resources and costs

What will it take?

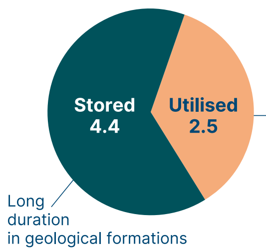
CAPTURING 7-10 $GTCO_2$ PER YEAR

Captured CO_2 by sector, $GtCO_2$/year



MOST CO_2 STORED; SOME UTILISED

CO_2 end of life in 2050, $GtCO_2$/year



HOW IS CO_2 UTILISED?

35% Synthetic Aviation Fuel

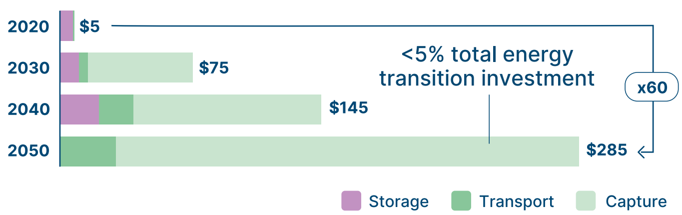
25% High value chemicals & plastics

20% Enhanced oil recovery, under specific and limited conditions

20% Stored in building materials (i.e. cement & concrete)

INVESTMENT MUST REACH $285bn PER YEAR BY 2050

Annual CAPEX by CCS Segment



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RAPID SCALE UP OF CCUS CAPACITY IN THE 2020S

BY 2030 THE WORLD NEEDS

CO_2 CAPTURE

Annual CO_2 capture up x20, from 40 Mt today to 800 $MtCO_2$

>300 CCUS facilities in commercial operation, from 30 today

Capture in the 2020s will be mainly in Power, Blue Hydrogen & Fossil Fuel Processing

TRANSPORT & STORAGE

1 $GtCO_2$/year storage in operation; another 5Gt under development

~100 CCUS industrial hubs operating around the world

Early storage development is a necessary precondition for CO_2 capture investment

INVESTMENT AND R&D

$70bn/year, up from $3bn/year today

Support innovation via R&D and industrial scale demonstrations

Strong carbon price and de-risking mechanisms are key to unlocking finance

6 KEY ACTIONS BY GOVERNMENTS, INDUSTRY & FINANCE

6 KEY ACTIONS	EXAMPLES	GOVERNMENT	REGULATORS	INDUSTRY	OIL AND GAS FIRMS	FINANCE PLAYERS
Overcoming 'green premium' to make CCUS deployment economic	• Carbon pricing • Mandates for low-carbon end products (e.g. cement) • Public procurement • De-risking mechanisms such as Contracts-for-Difference	✓		✓	✓	✓
Developing key infrastructure	• Shared transport pipelines and storage hubs • Publicly available geological data • Reuse of existing O&G infrastructure • Public funding to bring forward 'injection-ready' storage	✓		✓	✓	✓
Fostering business model and technology innovation	• Targeted R&D support for new capture technologies • New business models such as Carbon Capture as a Service to scale up mature technologies	✓		✓		✓
Regulating and managing risks	• Clear delineation of responsibility for CO_2 at each stage of the value chain • Counterparty risk mitigation through public guarantees, state backed insurance and coordinated hub development	✓	✓	✓		✓
Ensuring high capture rates and storage performance	• Real time monitoring of capture rates • Monitoring Transport and Storage for leakage • Meaningful penalties for non-compliance	✓	✓			
Building public support for an appropriate role for CCUS	• Articulating clear strategic, but limited role • Ensuring transparency on capture and storage performance	✓	✓	✓	✓	

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The role of CCUS in the energy transition: vital but limited

- **CCUS must play three vital but limited roles in reaching net-zero:**
  - To decarbonise those sectors where alternatives are technically limited (i.e. industrial processes which by their nature produce CO_2 such as cement).
  - To deliver some of the carbon removals that are required in addition to rapid decarbonisation if global climate objectives are to be achieved.
  - And to provide a low-cost decarbonisation solution in some sectors and geographies where CCUS is economically advantaged relative to other decarbonisation vectors locally.
- **Between 7–10 $GtCO_2$/year of capture capacity will be required by 2050** of which around 65% relates to carbon dioxide from non-fossil fuel sources then stored or used (e.g. cement process emissions, bioenergy for BECCS and Direct Air Capture).
- The other 35% - around 2.5–4.0 $GtCO_2$/year - would allow **a significant but dramatically reduced scale of fossil fuel use** (e.g. around 10 Mb/d oil and 2,700 BCM gas, 90% and 30% below today's levels) to be compatible with achieving a zero-carbon economy.

The Paris climate agreement (2015) set the target of limiting global warming to well below 2°C and ideally to 1.5°C and the Glasgow Climate Pact (2021) reiterated that target. The ETC's recent report on carbon removals set out the CO_2 concentrations and emission pathways compatible with those targets. To have a 50% chance of limiting global warming to 1.5°C and a 90% chance of keeping below 2°C, the world must reduce today's 50 Gt of total annual CO_2-equivalent emissions to around net-zero by mid-century, with reductions of around 40% achieved by 2030.[12]

The vast majority of this reduction can be achieved by clean electrification, the use of hydrogen, and a limited use of sustainable low-carbon bioresources; three recent ETC reports have described in detail the role and potential for each technology. In addition it is vital to drive energy productivity and efficiency improvements to reduce resource needs and costs involved in clean energy supply. The ETC will publish a report on these opportunities at the end of 2022.

But while these levers can and must deliver dramatic emission reductions, they cannot achieve complete net-zero, and thus ensure that climate objectives are met. Carbon capture, combined with either storage or use, will be required in addition, to:

- Decarbonise sectors where alternatives are technically limited (e.g. cement).
- Deliver significant carbon removals, over the next 30 years, and on an ongoing basis thereafter.
- Provide a low-cost decarbonisation solution in some sectors and geographies, where CCUS is economically advantaged relative to other decarbonisation vectors locally.

This chapter therefore sets out:

1. The primary levers of decarbonisation.
2. CCUS's vital but limited role.
3. Implications for sustainable fossil fuel use.

12 CO_2 equivalence depends on the relative Global Warming Potential (GWP) of the greenhouse gas, and under what time frame this is considered. One unit of methane, for example, is equivalent to around 30 units of CO_2 over a 100 year timeframe, but around 80 over a 20 year timeframe.

1.1 The primary levers of decarbonisation

The vast majority of required emission reductions can be achieved through levers other than CCUS. As described in three recent ETC reports, the 3 vital supply side technologies are;

Clean electrification, which must play a dominant role.[13]

- Direct use of electricity could grow from today's 20% to over 65% of final energy demand by 2050, as electricity is applied to an ever wider share of economic activity. This would result in total global direct electricity demand growing from 27,000 TWh per annum today to between 70,000–90,000 TWh.

- All of this electricity must and can be produced in a zero-carbon fashion, with dramatic increases in renewable power supply from wind and solar, supplemented by hydro, nuclear and other zero-carbon power sources.[14] Dramatic falls in the cost of renewables over the last ten years have made this achievable at lower cost than previously believed and therefore imply a lesser role for CCUS in the power sector.

Hydrogen, which will play a major role as a vector of decarbonization in sectors such as steel, shipping (in the form of ammonia or methanol) and chemicals, as well as an energy storage mechanism within power systems. Total hydrogen use could grow from 100 million tons per annum (Mtpa) today to somewhere between 500–800 Mtpa by 2050, with the vast majority (85% or more) produced in a green fashion from electrolysis of water.[15] This could create another 20,000 to 30,000 TWh of electricity demand by 2050.

Sustainable, low-carbon biomass can play a limited but important role, in particular in sectors such as chemicals (as a substitute for fossil feedstocks) and in aviation biofuels. It is essential however that all of the biomass used (either as a feedstock or as an energy source) is produced in a sustainable fashion. In our Bioresources report, we estimated that total sustainable biomass resources may be limited to 40 to 60 EJ (11,000–17,000 TWh) per annum by 2050.[16]

Applying these three supply side levers could result in fossil fuels demand falling from about 70% of final energy supply in 2022 to about 10 to 15% by mid-century (Exhibit 2).

13 ETC (2021) *Making Clean Electrification Possible*.
14 Principally, geothermal and advanced storage technologies.
15 ETC (2021) *Making the Hydrogen Economy Possible*.
16 ETC (2021) *Bioresources within a Net-Zero Emissions Economy*.

Final energy mix in a zero-carbon economy: electricity will become the dominant energy vector, complemented by hydrogen and fuels derived from it

Final energy mix in a zero-carbon economy – illustrative scenario

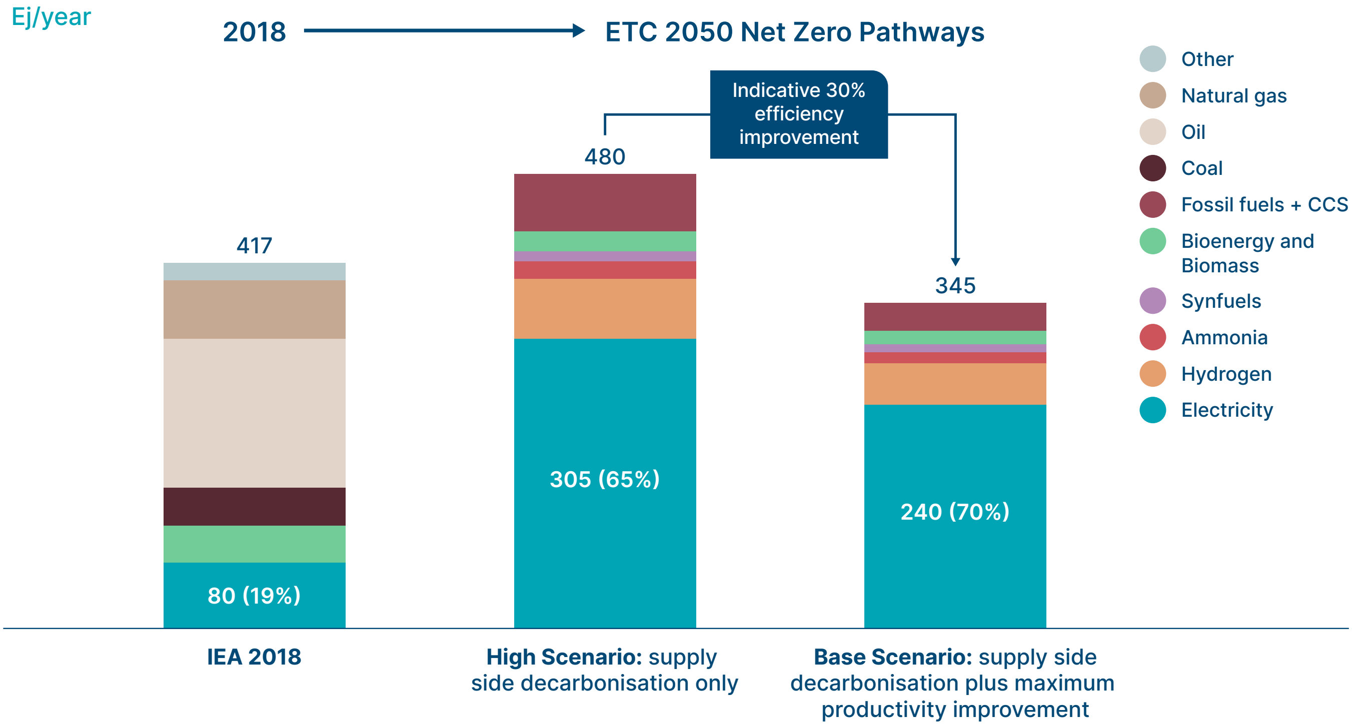


Exhibit 2

SOURCE: SYSTEMIQ analysis for the ETC (2020); IEA (2019) *World Energy Outlook*

The range reflects varying assumptions both regarding how far direct electrification can be pushed, and on the extent to which the world achieves technically available improvements in energy productivity and efficiency. The ETC will produce a report on this topic later in 2022, but analysis by the IEA and others shows that total energy demand could be reduced significantly if available opportunities were seized; Exhibit 2 shows an indicative 30% improvement.[17]

Even with maximum possible energy efficiency improvements, and maximum possible and sustainable use of electricity, hydrogen and bioenergy however, there will be a necessary role for process emissions and an economic rationale for CCUS and fossil fuels in some cases. In addition CCUS will be required to capture some industrial process emissions, and to achieve permanent carbon removals.

1.2 The role of CCUS – vital but limited

Carbon capture combined with either storage or use will play a vital role in achieving a net-zero-carbon economy in four contexts;

- **Carbon removals.** In the ETC's report on Carbon Dioxide Removals we estimate that the world will need to achieve 70–225 Gt of carbon dioxide removals over the next 30 years, with an ongoing requirement for 3–5 $GtCO_2$ per annum thereafter.[18] Many of these removals will initially be achieved via natural climate solutions,[19] but DACCS and BECCS can and should also play a significant role.

- **Process emissions.** Several industrial processes involve chemical reactions which produce CO_2 regardless of energy source. Some of these emissions (e.g. the use of coking coal to reduce iron ore to iron) can be eliminated with the development of alternative, non-CO_2 emitting processes. But in cement and some chemical sector processes, CCUS is very likely to be required.

- **Constraints on alternative energy supply.** In some sectors, sustainable energy demand may exceed sustainable energy supply. In long-distance aviation, for instance, biofuels may play a key role, but limits to sustainable bioresource supply will likely also require the development of synthetic jet fuel, using a captured CO_2 input.

- **Economic advantage.** Even when it is not technically essential, CCUS may be the lowest-cost solution in some applications or regions (at least during transition) and in some cases over the long-term.

For the first of these rationales – carbon removals – the need to capture and then store CO_2 is inherent. But both the capture and storage of the carbon could be achieved in part through nature-based solutions rather than via the engineered capture and storage techniques described in this report. As such, a portfolio of solutions is likely to be required. Natural climate solutions are currently much lower cost than engineered solutions, but tend to face higher risks to permanence (i.e. there is a potential for CO_2 being rereleased). Developing and investing in a portfolio of different removal types can reduce the overall risk for the planet's CO_2 trajectory. Over time, the balance of costs and risks, which initially favours NCS, will shift to allow a greater role for engineered solutions. For further discussion of the roles of nature based and engineered solutions see the ETC's recent report on carbon dioxide removals.[20]

For the other three rationales, alternative technology options might become possible or become more economic over time. The required and optimal role for CCUS will therefore depend on the evolution of both CCUS and other technologies and costs over time. This report therefore sets out two scenarios for the role of CCUS in 2050: a High Deployment Scenario and Base Scenario, with total capture ranging from 7–10 $GtCO_2$/year, shown in Exhibit 3.

17 ETC (2020) *Making Mission Possible: Delivering a Net Zero Economy*; IEA (2019) *World Energy Outlook*.
18 Page 8 of ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*
19 Such as the restoration of rainforests or improved land management
20 Natural climate solutions currently entail lower estimated costs of abatement than the engineered and often provide improved outcomes for biodiversity, water supply, food security. However, NCS assets have inherent risks with respect to accurate estimates of sequestration volumes; permanence of sequestration; of sequestration being reversed e.g., through forest fires. Engineered solutions have much higher costs and fewer co-benefits than NCS. However, the amount of CO_2 sequestered via storage can be defined; Permanence in geological storage is inherently more straight-forward to ensure, provided robust project design, monitoring and verification systems are in place. For further discussion see Chapter 4 of ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*

The ETC Base scenario sees just under 7 $GtCO_2$ captured per annum by 2050; High deployment sees just over 10 $GtCO_2$

Scenarios for CCUS volumes in 2050 - by source of capture

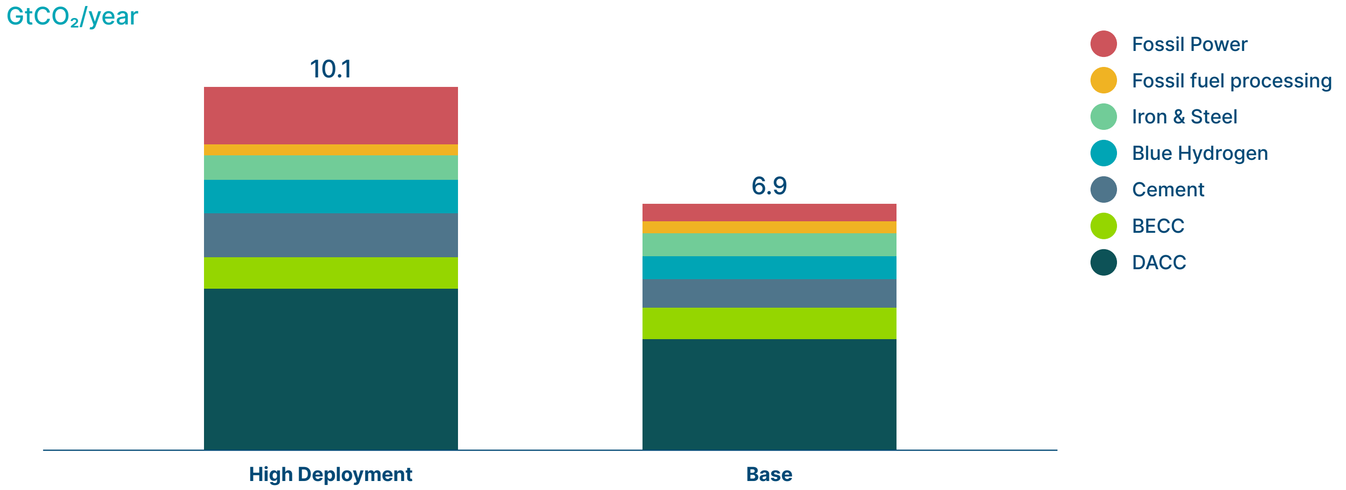


Exhibit 3

NOTES: Fossil Fuel Processing refers to natural gas processing, refinery operations and high value chemicals production. Blue Hydrogen includes ammonia production. BECC = Bioenergy with Carbon Capture. DACC = Direct Air Carbon Capture.

SOURCE: SYSTEMIQ for the ETC (2022)

Exhibit 4 illustrates the different applications to which capture is applied, where carbon dioxide could end up at end-of-life and the impact of CO_2 source and end of life on emissions and atmospheric concentrations for the Base case.

- **CO_2 capture:** About 3.1 GtCO per annum is captured via direct air capture and about 0.9 $GtCO_2$ is first captured via photosynthesis to produce bioenergy and then captured again at the end of a BECCS process.[21] The other 2.9 $GtCO_2$ derives from a range of sectors, with cement, power and iron and steel the most important.
- **End of life:** 4.4 $GtCO_2$ ends up being stored in geological formations, while about 2.5 $GtCO_2$ is used in a variety of applications, of which aviation fuels is the most important. Enhanced oil recovery accounts for a small 0.5 $GtCO_2$. The role of carbon utilisation in different sectors, including EOR is discussed in Chapter 2 Sections 2.5 and 2.6.
- **Source:** Of the 6.9 $GtCO_2$ captured, 2.9 $GtCO_2$ comes from fossil combustion or industrial processes, 3.1 $GtCO_2$ direct from the air and 0.9 $GtCO_2$ from biomass.
- **Impact on emissions:** DACC and BECC when combined with permanent storage result in permanent removals (or so called 'negative emissions').
  - Where capture occurs following a fossil fuel combustion process or chemical reaction and the CO_2 is permanently stored, the result is net zero emissions for the industrial. These together amount to 3.1 $GtCO_2$ per annum in 2050.
  - Where capture occurs at the end of a fossil fuel combustion process or chemical reaction and is combined with utilisation, this results in an increase in carbon efficiency ("using the same molecule twice") but does not achieve zero emissions. This amounts to 1.2 $GtCO_2$ per annum in 2050. The details of these different effects are discussed in Section 2.1.

21 Note that BECC refers to any form of bioresource (e.g. forest residues and dedicated energy crops) combustion or processing for energy purposes when used in concert with carbon capture technology (e.g. power generation or production of biofuels). This is one form of Biomass with Carbon Removal and Storage (BiCRS) which is an umbrella term for hybrid CDR solutions utilising photosynthesis to lower atmospheric CO_2 concentrations levels and includes other technologies, such as biochar. For further details, ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*

Varying combinations of CO_2 capture and end of life imply different impacts on CO_2 emissions

CCUS volumes in 2050 under Base scenario

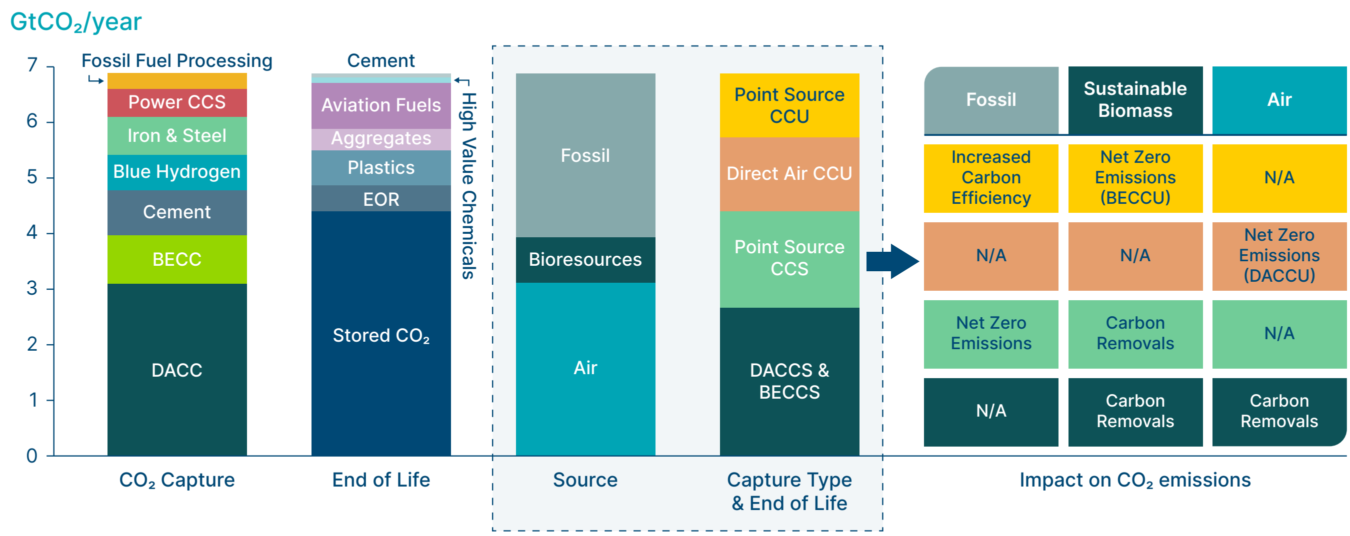


Exhibit 4

NOTES: Volume shown refer to Base Scenario in which demand side measures are fully implemented. Fossil Fuel Processing includes natural gas processing, oil products refining and production of high value petrochemicals (methanol, ethylene, propylene, butadiene, benzene, toluene, xylene). EOR = enhanced oil recovery. CCU = carbon capture and utilization. CCS = carbon capture and storage. DACCS = direct air carbon capture and storage. DACCU = direct air carbon capture and utilization. BECCS = bioenergy with carbon capture and storage. Note that the majority of point source CCS emissions will come from fossil processes and combustion.

SOURCE: SYSTEMIQ for the ETC (2022)

In aggregate, our scenarios suggest a broadly similar 2050 picture to the IEA's Net Zero scenario. In total the IEA suggests that around 7.5 $GtCO_2$ annual volume of CCUS will be required in 2050 (Exhibit 5) but with:

- A smaller role for DACC. This reflects the fact that the IEA's Net Zero scenario is deliberately designed to illustrate how to achieve net-zero without relying heavily on carbon removals, and without any removals via nature based solutions in the land use sector.
- A slightly larger role for blue hydrogen versus green.
- Similar scale of CCS for industrial processes in total.
- And a slightly larger role in the power sector.

For detailed comparison with other scenarios, please see Box 3: Comparing carbon capture scenarios.

The subsections below describe the different roles of CCUS by sector and the factors which will determine the scale of CCUS required.

Global CO_2 capture in the IEA's Net Zero scenario is broadly similar to the ETC's Base Scenario but with a smaller role for DACC

Global CO_2 capture by source in IEA's Net Zero scenario

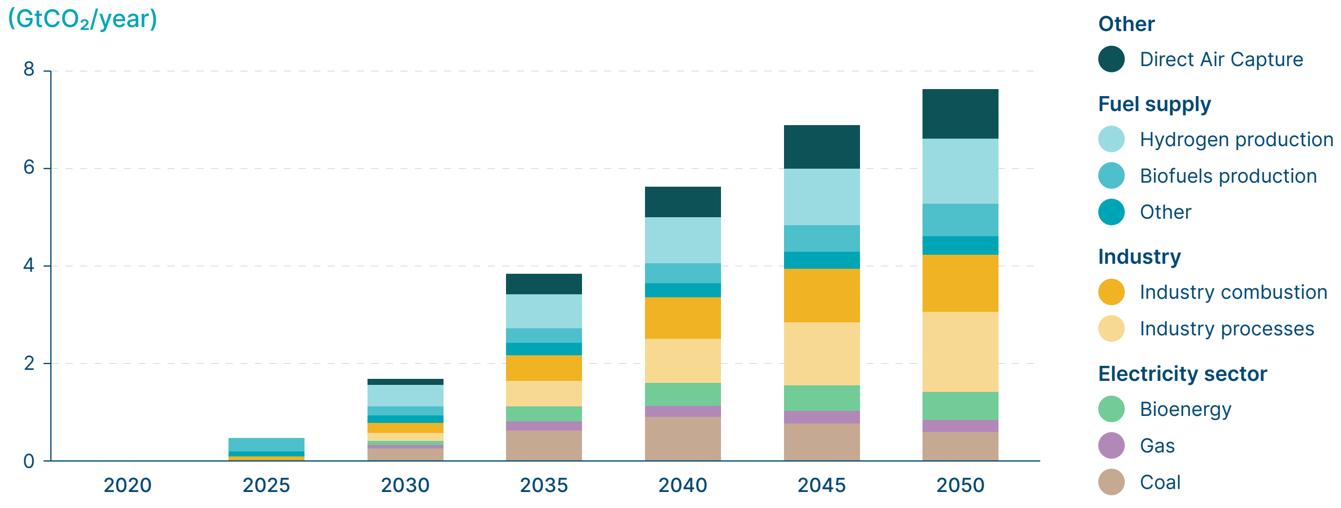


Exhibit 5

SOURCE: IEA (2021) *Net Zero by 2050, A Roadmap for the global energy sector*

1.2.1 Carbon Dioxide Removal

All IPCC pathways that limit global warming to 1.5°C with limited or no temperature overshoot envision a need for carbon dioxide removal (CDR), with a wide estimated range of 20–660 $GtCO_2$ of cumulative removals required over the 21st century.[22] In the ETC's report on Carbon Dioxide Removals we estimate that 70–225 $GtCO_2$ of cumulative removals would be needed over the next 30 years with an annual rate of 3.5 $GtCO_2$ per annum continuing after 2050. This must be in addition to the dramatic reduction in gross emissions which Exhibit 6 shows.[23] This need for these CO_2 removals arises from three factors:

- Net emissions from the energy, building, industry and transport sectors and from agriculture, food and land use (AFOLU) cannot be completely eliminated, leaving a residual of 1–3 $GtCO_2$ of emissions per year and which must be offset by carbon removals.

- Although it is possible for the whole world to reach net-zero GHG emissions by 2050, China and several developing countries are committed to net zero by 2060, with India committed to 2070. Some allowance must be therefore be made for removals to offset their additional residual CO_2 emissions for a period after 2050.

- It is unlikely that N_2O and CH_4 emissions can be reduced to absolute zero by 2050 or indeed ever. Our base case assumption is that N_2O emissions are cut from today's 3.3 $GtCO_2e$ to around 1.5 $GtCO_2e$ by 2050, continuing at around that level thereafter.[24]

22 IPCC (2022) *Working Group 3 Sixth Assessment Report*, C.3.5. Note that this figure represents the necessary negative emissions after both residual CO_2 and non-CO_2 greenhouse gas emissions are accounted for. See ETC (2022) *Keeping 1.5°C Alive – Closing the Gap in the 2020s* (Box A) and ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive* (Section 1.2)

23 ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*

24 Methane emissions in the ETC's scenarios reduce by around 55% to 2050. Given the short half-life of methane emissions in the atmosphere, as long as methane emissions decrease in concurrence with the IPCC illustrative pathway range, and do not increase after 2050, then the overall effect of methane on global temperatures will be neutral or cooling. Therefore no ongoing removals will be required to offset methane emissions.

Carbon removals will play a significant role in meeting net-zero targets

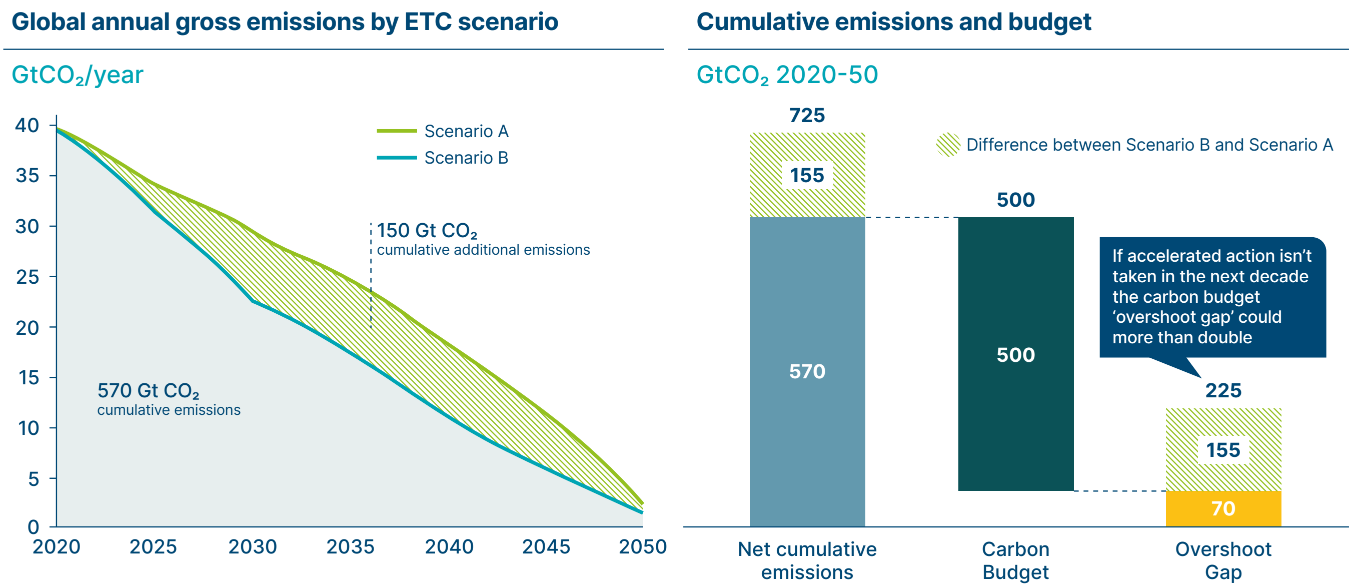


Exhibit 6

NOTES: Point-source CCS are included as part of within-sector decarbonization of gross emissions. Both scenarios envisage rapid and deep cuts to bring global emissions to net-zero by mid-century. In Scenario B, emissions reductions are accelerated in the 2020s by ending deforestation and closure of 50% of the world's coal-fired power generation facilities.

SOURCES: SYSTEMIQ analysis for the ETC based on: IEA (2017), *Energy Technology Perspectives*; IEA (2020), *Energy Technology Perspectives*; IPCC (2021) *Climate Change 2021: The Physical Science Basis*

Carbon removals can in part be achieved through natural climate solutions (NCS) such as reforestation, wetlands protection and changes in land use. The ETC's Carbon Removals report envisages that these will play the major role in the 2020s (Exhibit 7). However, there are potential limits to the scale of feasible NCS sequestration which will become more important over time and NCS solutions face higher risks to permanence than engineered solutions (i.e. there is a risk that the CO_2 could be re-released).

Natural climate solutions can store carbon over periods of decades to centuries (e.g., in standing forest) through to millennia (via peatland), but manmade (e.g., deforestation) and natural disturbances (e.g., wildfire) risk reversing carbon sequestration in some instances. During their lifetime both existing and newly restored natural climate solutions, which aim to sequester carbon over long periods of time, face a range of threats that can destroy or damage an NCS project or affect its growth, and as such a suite of technological, governance and project design tools must be used to mitigate these risks. By contrast, regulated and monitored underground storage of CO_2 is highly likely to be permanent (see Section 2.4.2).[25]

Bioenergy plus carbon capture and storage (BECCS) can also deliver carbon removal while simultaneously producing electricity, heat, hydrogen, or transportation fuels, but its maximum potential is also constrained by availability of sustainable bioresources (as described in the ETC's report on Bioresources).[26] Direct air capture (DACC) is at a lower TRL than BECCS and currently much more expensive. However DACC costs are likely to decline faster than BECC (see Section 2.2.3). Equally, while DACC is constrained by availability of renewable energy supply, ramping up of that renewable energy supply, it does not face the same challenges as increasing the supply of bioresource for BECC sustainably, implying DACC could be deployed much larger scale in the longer term (see Section 1.2.7).

In our scenarios for 2050 we estimate 4–5 Gt of carbon dioxide removals are achieved across DACCS and BECCS (Exhibit 7).

25 For further discussion of the risks to NCS permanence see sections 4.1 and 4.2 of ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*

26 ETC (2021) *Bioresources within a Net-Zero Emissions Economy – Making a Sustainable Approach Possible.*

An ambitious trajectory for CDR scale up to 2050 can deliver cumulative sequestration of ~165 $GtCO_2$ by 2050

Breakdown of annual CO_2 removals by CDR type | **Breakdown of cumulative CO_2 removals by CDR type**

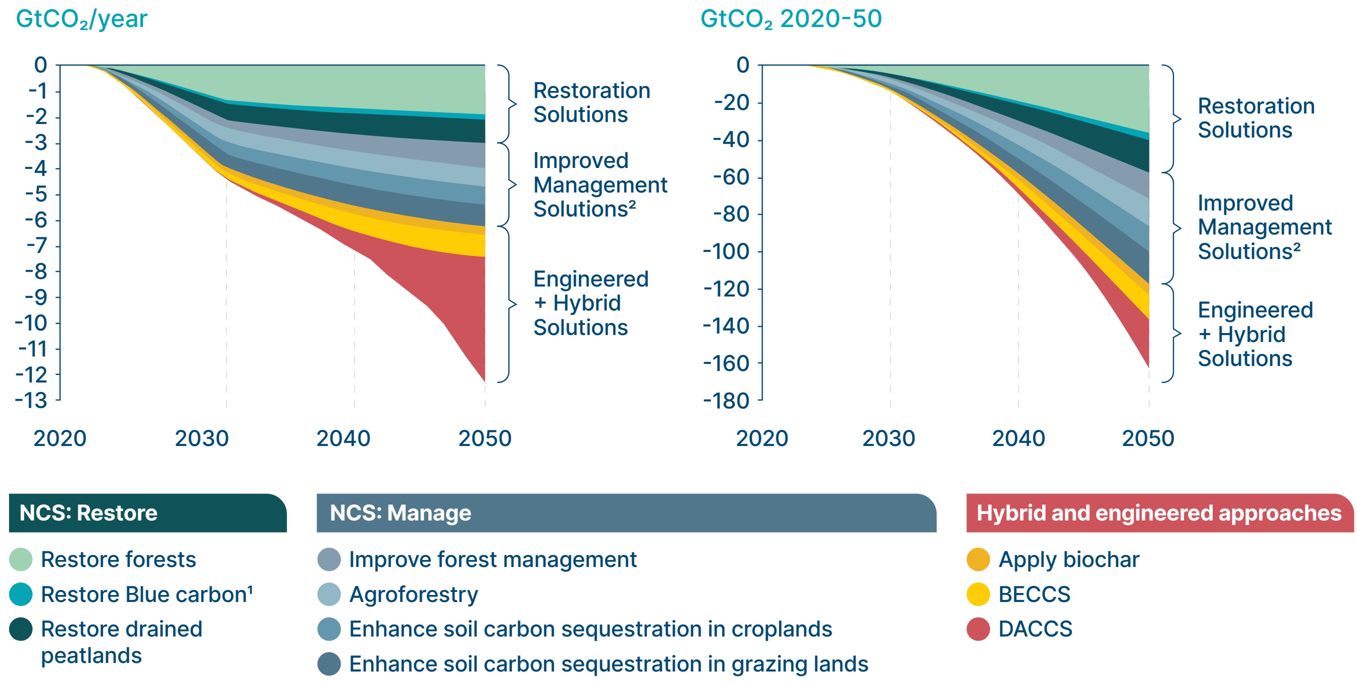


Exhibit 7

NOTES: The analysis was designed to avoid potential double-counting of emissions reductions, and is adjusted from annualised average potential estimates for 2020-2050 period. The models reflect land use & management changes, yet in some instances can also reflect demand-side effects from carbon prices, so may not be defined exclusively as 'supply-side'.
¹ 'Blue Carbon' is defined as ocean-based biomass sequestration including mangroves, seagrasses, and tidal marshes.
² Improved management solutions have been adjusted for feasibility on a country-by-country basis. Overall average reduction is ~50%.

SOURCE: SYSTEMIQ analysis for the ETC (2021), based on Roe et al. (2021), Hannah et al. (2021), Griscom (2017), ETC (2021) *Bioresources for a Sustainable Net-Zero Economy*, High Level Panel for Oceans (2020)

1.2.2 Cement

Global cement demand could increase from 4.3 Gt of cement per year in 2020 to 4.7 Gt per year by 2050, underpinned by increased population and prosperity in emerging markets.[27] On a business-as-usual basis this would imply growth in emissions from 2.3 $GtCO_2$/year today to 2.9 $GtCO_2$/year over the period. Improved building design and other circular economy measures could reduce total demand and emissions by around a third.[28] Reductions in the global average clinker-to-cement ratio could also reduce emissions,[29] and modest savings are also possible through substitution of concrete with other building materials such as wood (although this option is constrained by natural resource availability, climactic restrictions and planetary boundaries).[30, 31]

Around 60% of the emissions from cement production are process emissions arising from the calcination process, in which limestone ($CaCO_3$) is heated in a cement kiln to produce lime (CaO) and carbon dioxide (CO_2).[32] The remaining 40% of cement emissions come from burning fossil fuels to heat kilns to the high temperatures necessary for the calcination process.

27 Material Economics analysis for the ETC (2018) *Mission Possible: Reaching net zero in hard to abate sectors by mid-century*.
28 Ibid.
29 From 2015 to 2020, the global clinker-to-cement ratio is estimated to have increased at an average of 1.6% per year, reaching an estimated 0.72 in 2020. Conversely, the ratio falls 0.8% per year to a global average of 0.65 by 2030 in the IEA's Net Zero Emissions by 2050 Scenario, owing to greater use of blended cements and clinker substitutes, including industrial by-products such as blast furnace slag and fly ash; see IEA (2021) *Cement*.
30 Rockström J, et al. (2009) Planetary boundaries: exploring the safe operating space for humanity.
31 There is considerable uncertainty over the extent which these measures will decouple cement demand from GDP. For instance, the IEA estimates demand could be 4.7Gt per annum in 2050 but alternative assumptions with less ambitious reduction measure yield estimates as high as 6.3Gt per annum; see ETC (2018) *Mission Possible: Reaching Net Zero carbon emissions from hard to abate sectors by mid-century*; IEA (2021) *Cement*; IEA-CSI (2018) *Technology Roadmap – Low-carbon transition in the cement industry*.
32 Carbon Brief (2018) *Why cement emissions matter for climate change*.

The energy input for heat generation could be electrified, or switched from coal to biomass, biogas or hydrogen. However process emissions arising from calcination would remain. The use of alternative cement chemistries that reduce clinker input, as well as process efficiency improvements can lower emissions by approximately 30%, but carbon capture technology is required to address the remaining carbon dioxide produced by the process.[33]

Our scenarios estimate between 0.8–1.2 $GtCO_2$ per annum will need to be captured from cement production in 2050 and thereafter, around half of which is capture of non-fossil emissions in the production process. This assumes that by 2050 around 85% of cement produced globally will come from facilities fitted with carbon capture technology.[34]

1.2.3 Blue hydrogen

Hydrogen is certain to play a major role in a net-zero economy, whether used directly or in the form of derived fuels such as ammonia and synthetic fuels (synfuels). In steel and long-distance shipping, for instance, hydrogen's vital new role is increasingly certain; in fertiliser production, it will continue to be essential; it can replace coal and the reducing agent in steel production and will also almost certainly play a major energy storage role in future electricity systems, helping to balance supply and demand in systems where most electricity is supplied from variable renewable sources. Hydrogen will also likely play a role in industrial heat provision and possibly heavy duty transportation.

Total global hydrogen is therefore expected to grow 5–8 fold from today's 100 Mtpa to reach 500–800 Mtpa by mid-century, with hydrogen (and its derivatives) accounting for 15–20% of final energy demand.[35]

In the medium to long-term green hydrogen made via electrolysis is likely to be the lowest cost option in most locations, and the ETC's base case therefore assumes that green hydrogen will account for a growing percentage of hydrogen production during the 2030s, reaching 85% of the market by 2050 (Exhibit 8).[36]

But blue hydrogen produced by adding carbon capture to methane reforming (Steam Methane Reforming (SMR), or Autothermal Reforming) was cheaper in many locations before the 2021/22 gas crisis and will continue to be in regions which can produce gas at very low cost. It will also often be cost advantaged when SMR plants already exist producing "grey" hydrogen (i.e. unabated) and CCS can be retrofitted. In other regions, the long-term viability of blue or grey hydrogen depends on the extent to which today's high gas prices subside, and the impact of the recent gas price volatility on investment.

Our scenarios assume that 0.6–0.9 $GtCO_2$/year will be captured from gas reforming plants producing blue hydrogen in 2050.

33 Fennell et al. (2021) Decarbonising cement production; Global Cement and Concrete Association (2021) Concrete Future: Roadmap for Net Zero Concrete.
34 Reflecting the IEA's Net Zero scenario, IEA (2021) *Cement*.
35 ETC (2021) *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy*.
36 Ibid. Pages 62 – 65 of ETC for discussion of the interplay between green and blue hydrogen.

Renewably powered electrolysis is set to dominate hydrogen production in the long run

Hydrogen production by technology

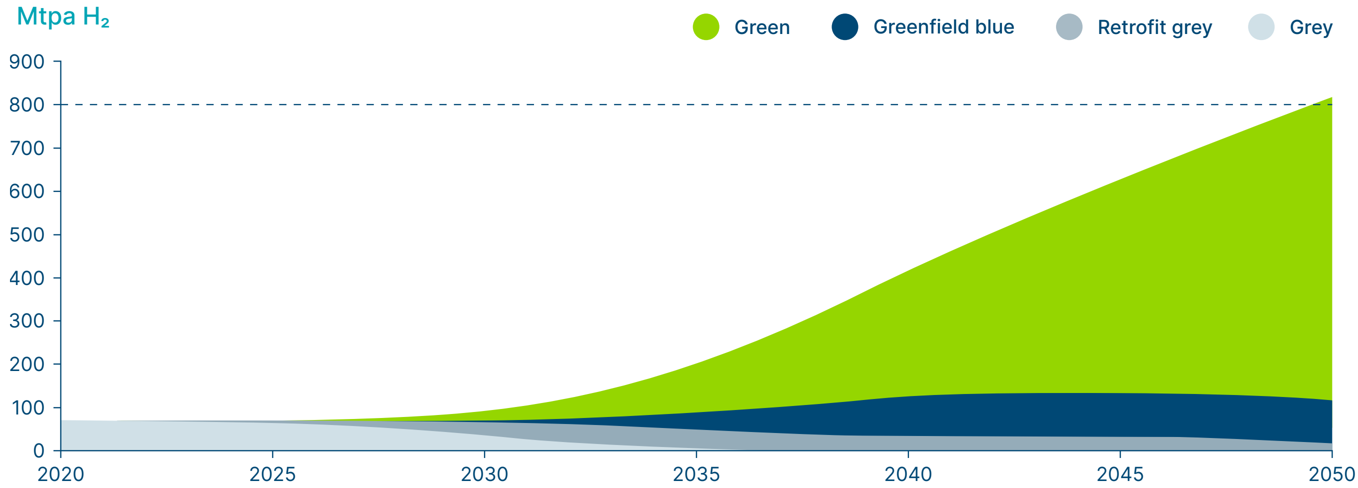


Exhibit 8

NOTES: Based on the "Medium Role for Blue Hydrogen" scenario in the ETC's Making Mission Possible report "*Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy*" (2021). Details on the models methodology describing these scenarios can be found in the Annex of the report. Historical build rates for green and blue projects were based on public databases.

SOURCES: SYSTEMIQ analysis for the Energy Transitions Commission (2021); IEA (2020), *Hydrogen Projects Database*; IEA (2020), *World large-scale CCUS facilities operating and in development, 2010-2020*

1.2.4 Iron and steel

Production of both primary and secondary steel emitted approximately 2.6 $GtCO_2$ in 2020, equivalent to approximately 7% of global emissions.[37] Steel production could increase by around 25% by 2050, from ~2,000 Mt today, driven by growing urbanisation in developing countries in particular.[38] However, circular economy measures which see more reuse of existing steel could reduce global steel demand by up to 40% in 2050, avoiding 18 Gt of steel production over the next three decades. Similarly scrap steel's share of total steel demand in 2050 could increase up to 70% (from 30% today) in a high circularity scenario as lower steel demand and greater scrap recirculation combine to reduce iron ore consumption by 75%.[39] However, taken together this would still leave gigatons of emissions even under the most favourable scenarios.

As detailed in the recent report of the MPP Net Zero Steel Initiative (NZSI) there are a variety of different options to decarbonise primary steel production. These include hydrogen-based Direct Reduced Iron (DRI) and smelting reduction as well as applying CCS to existing coking coal blast furnaces.[40]

A portfolio of solutions is needed to decarbonise steelmaking, as different technologies will be cost-competitive in different locations. Most of today's primary steelmaking is located in places that have historically offered access to coal mines, iron ore deposits, and water or rail transport infrastructure. The transition to net-zero will add new location contexts. Access to low-cost zero-carbon electricity, access to carbon capture and storage (CCS) infrastructure and sequestration sites, access to competitively priced natural gas, and proximity to an industrial cluster will shape the technology transition. The exact mix of steelmaking technologies in 2050 will depend on the price dynamics of key commodities, maturity timelines of different technologies, and the evolution of government policy, among other factors.

37 Mission Possible Partnership (2021) *Net zero steel sector transition strategy.*
38 Ibid. Page 15
39 Ibid. Page 14
40 Ibid. Part 2

Exhibit 9 shows the NZSI's Tech Moratorium scenario for decarbonisation, which assumes that each plant adopts the optimal decarbonisation option at the point at which major new investments will in any case be required. This shows a very major role for technologies (such as H_2 DRI combined with Electric Arc Furnaces (EAF)) which do not require CCS, and a dramatic reduction in the role of blast furnaces, but also a significant role for carbon capture applied to a number of different technologies.[41]

Our scenarios assume that 0.7 $GtCO_2$ will need to be captured from steel production processes in 2050.

Carbon capture technology does not begin to emerge as a decarbonisation vector in the steel industry until the 2030s

Steel production by technology type

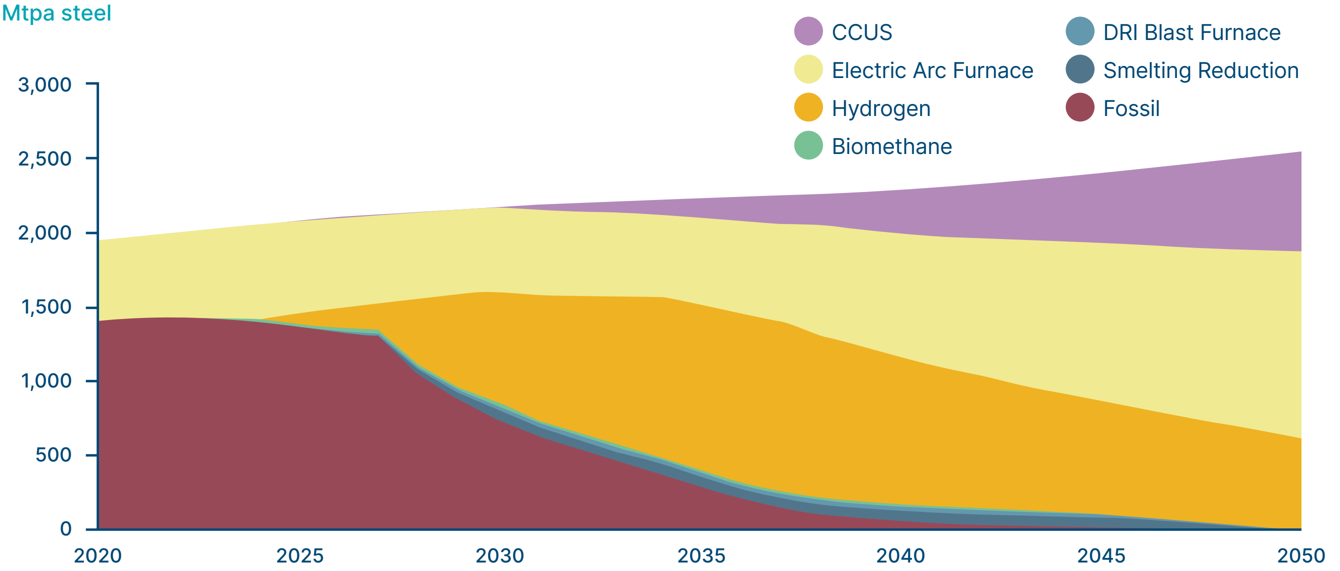


Exhibit 9

NOTES: Based on MPP's "Tech Moratorium" scenario. An Electric Arc Furnace uses electricity to melt scrap steel and produce new virgin materials. DRI blast furnace refers to the Direct Reduced Iron steel-making process which is the process of reducing iron ore without melting it, using a reducing gas (typically a blend of hydrogen and carbon monoxide derived from natural gas).

SOURCE: MPP (2021) *Net Zero steel Transition Strategy*

1.2.5 Petrochemicals

High Value Chemicals (HVC) produced from oil derivatives constitute a critical set of inputs in the global industrial and manufacturing supply chain.[42] Applications range from packaging and textiles to construction and electronics – much of which takes the form of plastics, and include chemicals such as methanol, ethylene, propylene, butadiene, benzene, toluene and xylene.

Process and energy related emissions from petrochemicals production amounted to approximately 1.6 $GtCO_2$ in 2020.[43] Without policy intervention, these emissions could grow to approximately 2.2 $GtCO_2$ by 2050.[44] Emissions arising from the energy used in petrochemical production (including emissions associated with oil and gas extraction) accounted for 85% of the total, with the remainder derived from production process.[45] Energy emissions can be abated via clean electrification. Process emissions can be abated either through the continued use of fossil feedstocks but with CCS in addition; or through the recycling of existing plastics into new feedstocks (via mechanical or chemical means, potentially also relying on CCU); or through use of bioresources as feedstocks.

41 The NZSI's alternative "Carbon Cost" scenario assumes that, at each major investment decision, the steel asset switches to whichever technology offers the lowest total cost of ownership (TCO). A carbon cost is applied to each tonne of CO_2 emitted, rising linearly from $9 in 2023 to $250 in 2050. The same cost is applied to all scope 1, 2, and 3 emissions and all geographies. This results in slightly higher CCS deployment by 2030 but less over the long run.

42 HVC refers to Methanol, Ethylene, Propylene, Butadiene and Aromatics.

43 Petrochemical feedstock accounts for approximately 12% of global oil demand today, but this share is set to rise as petrochemical products consumption grows whilst oil demand in other sectors abates. Saygin D. & Gielen D. (2021) *Zero-Emission Pathway for the Global Chemical and Petrochemical Sector*.

44 Material Economics analysis for the ETC (2018). In a business as usual scenario, plastic consumption roughly doubles by 2040.

45 IEA (2018) *The Future of Petrochemicals*. This excludes Scope 3 emissions which can also be significant for certain petrochemical products (notably plastics) depending on end-of-life outcomes.

CCUS thus has two potential functions in decarbonising these process emissions:

- First, CCUS can be used directly to capture and thus decarbonise production process emissions. This is particularly the case for methanol in regions with abundant, cheap coal reserves and limited biomass availability – notably China.[46, 47]

- Second, CCUS offers a means to reduce emissions from some forms of recycling (e.g. pyrolysis) to near zero. In theory this combination of technologies has the potential to eliminate emissions from low life time plastics entirely – i.e. if 100% of all such plastics were collected, heated to high temperatures with CCU, demand for virgin material could be entirely displaced and total emissions brought to zero. However;

  - Whilst technically possible, achieving 100% circularity is extremely challenging and would entail additional infrastructure investments beyond the CCU technology (collection and processing of waste plastics).
  - In addition, even with a collection rate of 100% by 2050 across major commodity plastics, chemical recycling can only meet around 50% of total plastics demand. This is due to conversion losses which lead to declining overall feedstock levels,[48] and to potential for growth in demand for plastics.
  - Lastly, the utilisation of carbon capture technology alongside plastics incineration still entails some carbon emissions (since capture rates are never 100%) and feedstock losses thus cannot be used to generate a 100% closed loop system.

Our scenarios assume limited uptake of circularity levers, a ban on new conventional production methods after 2025 and an industry-wide net-zero mandate by 2050. Around 300 MtCO_2/year will be captured from petrochemical processes in 2050, whilst ~600 MtCO_2/year will be utilized in petrochemicals production.[49]

1.2.6 Fossil fuel processing

Although natural gas demand is set to decline, it is still expected to be c. 70% of today's consumption levels by 2050.[50] Meeting this demand in a zero-carbon fashion will require the application of CCS not only where natural gas is used, but in its processing.[51]

When natural gas is recovered from underground reservoirs, it typically contains at least some CO_2: concentration levels vary from less than 1% to as much as 70%.[52] At higher concentration levels, CO_2 removal is an essential step in processing natural gas to produce a gas stream of sufficient quality for commercial applications and minimise operational problems such as pipeline corrosion.[53]

Reflecting this, much of the existing carbon capture technology in commercial operation today is used in upstream natural gas processing operations, often utilising the captured CO_2 for use in enhanced oil recovery (EOR). Early examples of CCUS in fossil fuel processing include ExxonMobil's Shute Creek gas processing facility in the USA (1986) and Equinor's Sleipner project in Norway (1996).[54] ETC scenarios suggest natural gas production between approximately 55–80 EJ by 2050, in turn implying approximately 15–20 MtCO_2 capture from processing.[55]

46 The competitiveness of the CCS based methanol production route derives from two aspects. First, the CO_2 concentration in coal-to-chemicals production is very high (see Exhibit 22 and Exhibit 24) so carbon capture could have clear cost advantages. Second, methanol production in China is highly dependent on coal, and the application of CCS enables the best use of existing production capacity and assets, avoiding uncertainties caused by large-scale transformation. However, with the rapid decline in green hydrogen production costs (see Section 1.2.3) methanol production routes using hydrogen will become the cheapest option in the long run. By 2050, coal to methanol with CCS in China is expected to capture less than 30MtCO_2/year. See RMI (2022) *Transforming China's Chemicals Industry: Pathways and Outlook under the Carbon Neutrality Goal.*

47 Autothermal reforming with CCS is potentially the lowest cost option for decarbonizing process emissions in ethane cracking whilst post-combustion CCS is more competitive for naphtha and propane. Bloomberg NEF (2022) *Decarbonizing Petrochemicals: Technologies and Costs*.

48 Bloomberg NEF (2022) *Decarbonizing Petrochemicals: Technologies and Costs*.

49 SYSTEMIQ analysis (2022).

50 Copenhagen Economics (2017) *The Future of Fossil Fuels: how to steer fossil fuel use in the transition to a low-carbon energy system.*

51 Note that emissions arising from natural gas consumption relate not only to combustion but also to methane (CH_4) leakage from production sites and pipelines. This is beyond the scope of this paper but is discussed in ETC (2022) *Making the Hydrogen Economy Possible – Accelerating Clean Hydrogen in an Electrified Economy*.

52 Enbridge (2021) Chemical composition of Natural Gas; Bowerbank G. (2015) Smart design for high CO_2 removal for natural gas production.

53 Tan L.S. (2012) Removal of high concentration CO_2 from natural gas at elevated pressure via absorption process in packed column.

54 Parker et al. (2011) CO_2 management at ExxonMobil's LaBarge field, Wyoming, USA; Equinor (2019) Sleipner partnership releases CO_2 storage data.

55 This assumes that average CO_2 concentration levels in natural gas do not change from current levels.

In addition to processing, liquifying methane for transport as LNG results in significant GHG emissions, with the main source of emissions varying between regions (see Exhibit 10).[56] Of the CO_2 emissions arising from liquefaction, the majority derive from own use energy requirements and can be eliminated via substitution with energy from renewable sources. A small volume of CO_2 may be vented during liquefaction as a result of the process itself but these volumes are negligible and do not merit carbon capture technology. Therefore CCUS is not considered essential to the LNG chain.[57]

As with natural gas, some oil product demand persists even in a net zero scenario, hence there is a role for CCUS in refineries' CO_2-emitting units. These include steam methane reformers that produce hydrogen, catalytic crackers and Combined Heat and Power (CHP) units.[58] Around 10% of all refineries could plausibly be expected to utilise CCS technology by 2030. By 2050, oil products demand is expected to have fallen to just 10 Mb/d owing to electrification of transport and other decarbonisation measures. There will therefore be far fewer refineries in operation but all of them will be utilising CCUS technology for process emissions.[59]

Our 2050 scenarios assume that around 20 $MtCO_2$ will need to be captured from natural gas processing and another 150 $MtCO_2$ in refining, implying a total of approximately 170 $MtCO_2$/year for fossil fuel processing.

56 Blanton E. & Mosis S. (2021) *The Carbon-Neutral LNG Market: Creating a Framework for Real Emissions Reductions.*

57 Emissions arising from liquefying methane for transport as LNG mainly derive from post-combustion emissions. These arise from own-use energy requirement in liquefaction and shipping, such as fuel use in engines or turbines that provide power to compress gases, pump liquids, or generate electricity; and for firing heaters and boilers. Note that LNG liquefaction and transport also result in CH_4 emissions through leakage and boil-off during voyage but these are not considered here. See American Petroleum Institute (2015) *LNG Operations: Consistent methodology for estimating GHG.*

58 Turan G. (2020) *CCS: Applications and Opportunities for the Oil and Gas Industry.*

59 The majority of these will need to be located in emerging markets where demand for refined oil products will persist longer compared to mature markets in which EV uptake will displace oil demand sooner.

The sources of CO_2 emissions in LNG supply vary between regions

Liquified natural gas production & processing emissions by region

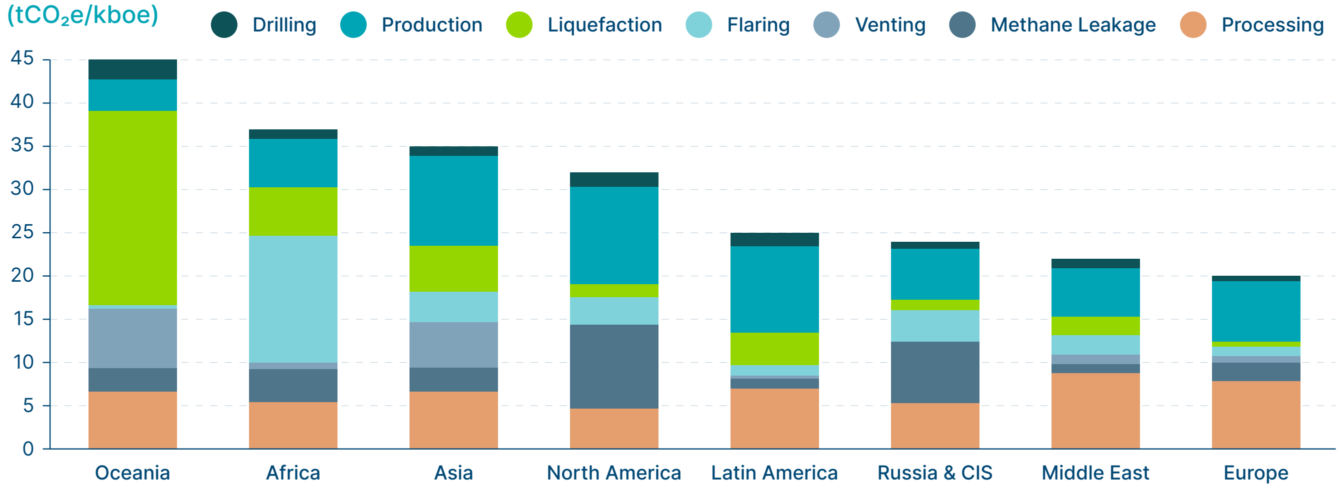


Exhibit 10

NOTE: kboe = kilo barrel of oil equivalent.

1.2.7 Power generation

Variable renewable energy (VRE) such as wind and solar power generation is already cheaper than CCS-fossil generation in most locations. Over time, the cost of VRE generation will also fall below the marginal cost of many existing gas and coal plants, particularly old and inefficient units (Exhibit 11). The role of fossil in baseload generation will decline, as capacity utilisation decreases. Carbon capture in the power sector will therefore mainly be applied to flexible gas plants, with gas + CCS competing with hydrogen and other forms of zero-carbon storage and generation as a means to provide seasonal and daily flexibility.[60, 61] There are two nuances to this long term trend:

- In some regions VRE buildout may be constrained on account of poor wind and solar resources (such as Malaysia) or limited land availability (for example Bangladesh). In such cases, baseload power with CCS may be appropriate, especially in regions with very cheap natural gas.[62]

- During transitions, in some regions VRE build out may be slowed by localised supply chain constraints slowing progress. Baseload gas + CCS may be viable here, either as retrofit or on new plant if the same supply-chain constraints do not apply.

60 It is possible that CCS technologies may impose constraints on the flexible operation of gas power plants. This may potentially limit CCS's role in abating highly flexible open cycle gas turbines (OCGT) which meet peak load needs and Combined Cycle Gas Turbine (CCGT) plant typically used to generate base and intermediate load. This could imply hydrogen is preferable as a means to decarbonise provision of peak power, although it does appear there are ways of overcoming these limitations (see IEA GHG (2012) *Operating flexibility of power plants with CCS.*).

61 Other forms of zero-carbon energy include hydro, nuclear and bioenergy. Energy storage options include pumped hydro, lithium ion and flow batteries and compressed air energy storage (CAES). Demand side measures such as V2G smart charging industrial load shifting. System level balancing options also include long distance interconnection to regions with different renewable resource (e.g., hydro) or with complementary weather patterns. For full discussion of storage options, please see pages 39 – 49 of the ETC's Making Mission Possible report (2021) *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy.*

62 Much as blue hydrogen may remain competitive against green hydrogen in such locations.

BECCS power plants can be run as baseload or flexible capacity but are constrained by competition for sustainable bioresource supply.[63]

Application to coal plants will likely be limited,[64] though there are two caveats to this narrative:

- First, existing coal plants (and certain cases gas) sometimes enjoy long-term fixed price supply contracts in some cases lasting even decades into the future, which in many countries face limited possibilities to alter without penalties and/or legal costs. As a result, uneconomic assets may not exit the system even when VRE costs fall below the marginal cost of operation.

- Second, running down coal generation will have consequences for employment in coal mining, potentially prompting governments to seek to extend these assets beyond rationally economic lifespans.

Where these local factors slow or limit the phaseout of fossil power generation, CCS may be the most pragmatic solution. A plausible net zero scenario could see fossil fired generation with carbon capture technology fitted to supply between 2,000–4,500 TWh per annum by 2050 (between 2–5% of total generation).[65] This implies captured emissions from fossil generation of between 1–2 $GtCO_2$/year in 2050.

Wind and solar are cheaper today than and fossil-fueled power with CCS and remain so in the long run

Global Average LCOE Outlooks

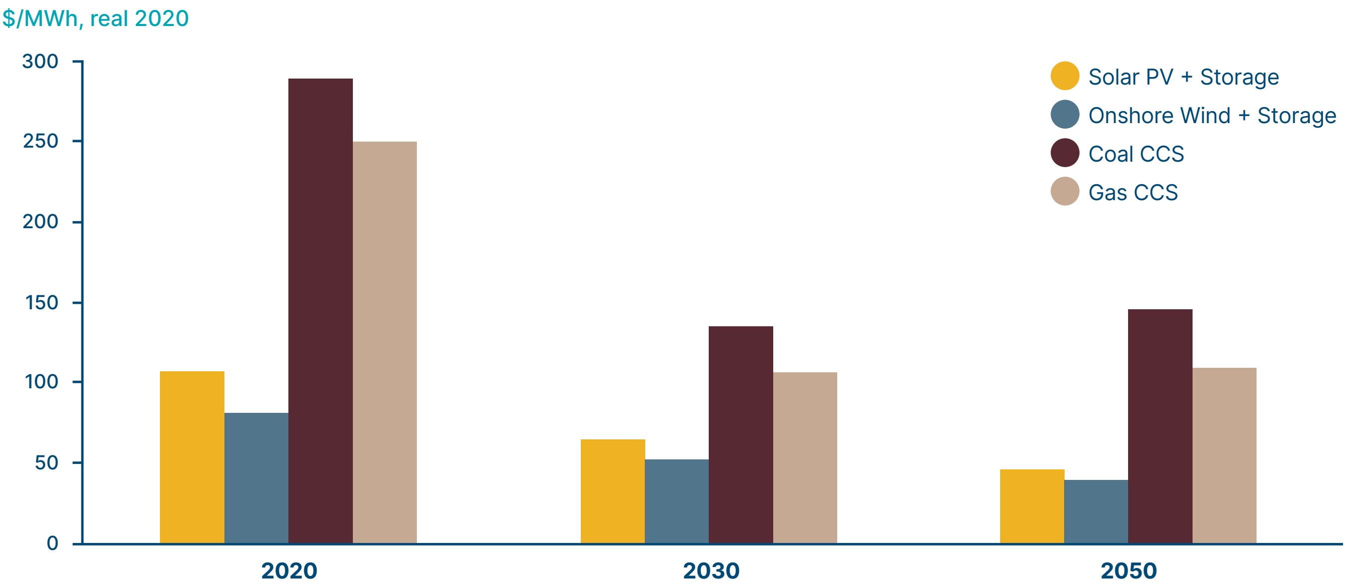


Exhibit 11

NOTES: Based on average Levelised Cost of Electricity for China, Europe, India, Japan and the US. Solar PV refers to fixed axis. Storage assumes a four-hour duration Li-ion battery system with 50% capacity ratio. Capacity factors for wind are 50%. All LCOE calculations are unsubsidized.

SOURCE: BNEF (2021) *Levelised Cost of Electricity Highlights*

63 Converting coal to biomass plants is relatively straightforward, presenting a potential advantage for BECCS in power. See ETC (2021) *Bioresources within a Net-Zero Emissions Economy – Making a Sustainable Approach Possible.*

64 For further discussion of fossil power phaseout and the role CCS in the power sector in a net zero scenario, please see pages 58 – 64 of the ETC (2021) *Making Clean Electrification Possible – 30 Years to Electrify the Global Economy.*

65 Ibid.

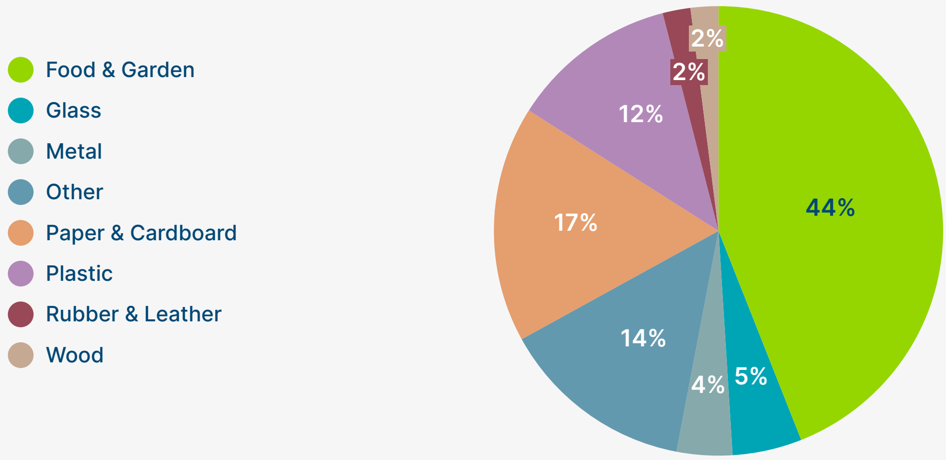
Waste to energy plants with CCS

Municipal solid waste[66] (MSW) is defined as waste collected and treated by or for municipalities. It covers waste from households, commerce and trade, office buildings, institutions and small businesses, as well as yard and garden waste, street sweepings and the contents of litter containers. Food and garden waste typically account for approximately 45% of MSW by mass (Exhibit 12).

Municipal solid waste is principally composed of food and garden waste

Typical MSW composition by mass

%



SOURCE: Kaza et al. (2018) *MSW global average composition by mass*

Exhibit 12

At least a third of all MSW produced globally is not managed and ends up remaining in the open environment, harming health and causing pollution.[67] Of the MSW which is collected, approximately 70% ends up in landfill, leading to substantial CO_2 and methane emissions. The remainder is either reused, recycled (19%) or incinerated (11%).[68]

Waste-to-energy (WTE, sometimes referred to as energy from waste – EfW) entails the controlled (i.e. not open air) conversion of MSW to produce electricity and/or heat. This conversion typically entails combustion but also includes pyrolysis, gasification and anaerobic digestion to produce biogas. WTE offers the advantage of significantly reducing volumes going into landfill, as well as reducing uncontrolled burning or MSW remaining in the open environment.

The majority of WTE capacity today is located in the US, Europe and Japan but growth is strongest in emerging Asian markets, led by China.[69] The global market for WTE is small but growing: around 2,500 WTE plants are active worldwide, with a disposal capacity of around 420 Mtpa. By 2030 under a business as usual scenario, around 3,000 WTE plants may be expected to be in operation, with a processing capacity of over 650 Mtpa,[70] which would correspond to roughly 1,500 –2,000 TWh of energy[71] or approximately 450 $MtCO_2$ emissions (arising from both biogenic and non-biogenic waste).

Adding carbon capture and storage to WTE:

- reduces the CO_2 emissions released following incineration.
- enables the re-use of carbon atoms in new products, theoretically allowing a closed loop waste collection system – although some carbon would still be lost due to imperfect capture rates (see Section 1.2.5).
- offers a potential route to negative emissions in cases where sufficient proportion of the waste is biogenic (i.e. plant-derived).[72]

Box 2

66 IEA (2019) *Will energy from waste become the key form of bioenergy in Asia?*
67 The World Bank (2018) *What a Waste 2.0: A Global Snapshot of Solid Waste Management to 2050.*
68 Ibid.
69 Rogof J. (2019) *The Current Worldwide WTE Trend.*
70 Ecoprog (2021) *Waste to Energy 2021/2022.*
71 Assuming a heating value of 10 MJ/kg, from Wienchol et al. (2020) Waste-to-energy technology integrated with carbon capture – Challenges and opportunities.
72 If a WTE plant were able to capture more carbon dioxide overall than the amount that comes from incinerating the non-biogenic proportion of waste alone, then the operation would become net-negative in terms of carbon dioxide emissions (as the emissions from the biogenic proportion are net-neutral).

Given that flue gas from WTE tends to have a similar mixture of gas species to flue gas from pulverised coal,[73] in theory the application of CCS to municipal waste incineration should be similarly straightforward.

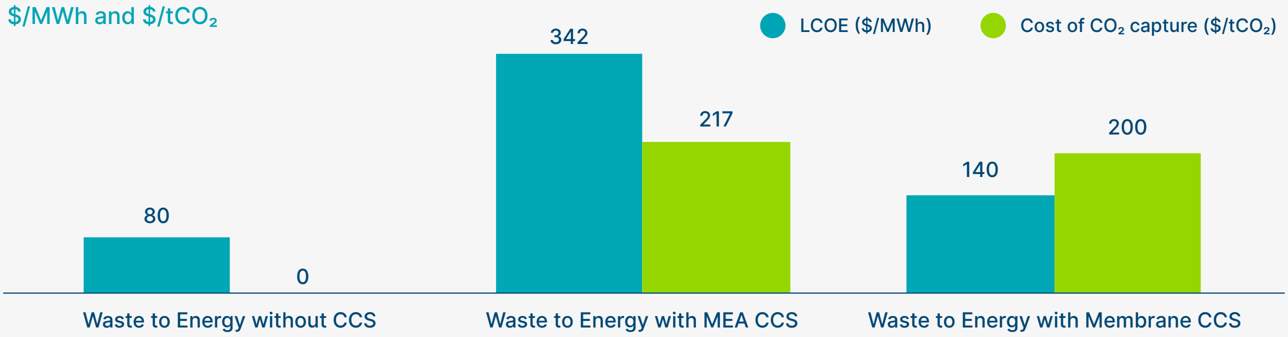
However, there are challenges to adding CCS to WTE:

- Monoethanol amine (MEA) based capture technologies are mature and most widely applied to WTE plants but are relatively expensive (Exhibit 13). Membrane technologies have been mooted as a potentially lower cost alternative in the future but are still at a low TRL in this context.
- New approaches, such as oxy-fuel combustion (where the waste is burned in a mix of oxygen and flue gas, rather than in air), could reduce the energy penalty from CCS thereby lowering costs, but the application of oxy-fuel combustion to WTE is at an even earlier readiness level than conventional combustion with membrane CCS.[74]
- Furthermore, while CCUS addresses CO_2 emissions, other air pollutants such as sulphur dioxide, nitrous oxide or particulates may not necessarily be addressed by these technologies.

Adding to the cost challenge, WTE plants are typically quite small (no projects today are larger than 0.1 Mt per annum) meaning economies of scale less likely to apply than for fossil fuel power generation. Transporting captured CO_2 via trucks could be an option for WTE plants: a 10 MW/1 Mt p.a. plant would require around 10 truckloads of CO_2 to be removed each day. On the other hand, policy measures which impose costs on landfill could make WTE more competitive.

Energy from Waste with CCS is an expensive means to produce power or capture CO_2

Waste to Energy levelised cost of electricity and cost of CO_2 avoided



NOTE: MEA = Monoethanolamine.

SOURCE: Roussanaly et al. (2020) *Impact of Uncertainties on the Design and Cost of CCS From a Waste-to-Energy Plant*

Exhibit 13

In the long run, the impact of WTE & CCUS on CO_2 emissions is likely to be relatively limited:

- The technology can process a high share of municipal waste but supplies a relatively small volume of energy and results in fairly low volumes of CO_2.[75]
- Circularity solutions which maximise the reuse and recycling potential of materials prior to energy recovery are more carbon and energy efficient, meaning WTE is lower down the MSW management hierarchy.[76]
- The scope for utilising WTE with CCS as a source of negative emissions depends upon a high biogenic content (arising from food and green waste, wood, and paper and cardboard) but the figure is falling. Today, approximately half of municipal solid waste has biogenic origins[77] but the proportion of biogenic waste is in decline due to increase recycling of paper and cardboard, and increased volumes of plastic in municipal solid waste.[78]

Box 2

73 Global CCS Institute (2019) *Waste-to-Energy with CCS: A pathway to carbon-negative power generation.*
74 Wienchol et al. (2020) *Waste-to-energy technology integrated with carbon capture – Challenges and opportunities.*
75 IEA (2019) *Will energy from waste become the key form of bioenergy in Asia?*
76 Ibid.
77 ETC (2021) *Bioresources within a Net-Zero Emissions Economy – Making a Sustainable Approach Possible.*
78 The World Bank (2018) *What a Waste 2.0: A Global Snapshot of Solid Waste Management to 2050.*

1.2.8 Synthetic jet fuel

Aviation emissions currently amount to around 1.1 $GtCO_2$ per annum and could grow further with increased aviation demand.[79] For short haul flights, battery electric, hydrogen and hybrid planes have the potential to replace jet fuel over short distances but this will only eliminate about 25% of total aviation emissions by 2050 (Exhibit 14).[80]

For longer distances, limits to the potential gravimetric energy density of batteries and the low volumetric density of hydrogen, will almost certainly make it essential to continue using a liquid hydrocarbon fuel, necessitating clean "drop-in" equivalents to conventional jet fuel:[81]

- Bio jet fuel can play a significant role, but its potential is limited by the constrained supply of truly sustainable biomass (see ETC's Bioresources report).[82] The potential supply of fuels derived from used cooking oil (known as hydro-processed esters and fatty acids) are also limited by feedstock constraints.
- Synthetic jet fuel, produced from the synthesis of hydrogen and captured CO_2, may well therefore eventually account for the majority of aviation fuel use. Such synthetic jet fuel (also known as "e-kerosene") is currently at least 3 times more expensive than conventional jet fuels,[83] and while these costs will decline over time, its use is likely to continue to impose a significant "green cost premium". But in the absence of viable and sustainable alternatives it is a feasible route to the decarbonisation.

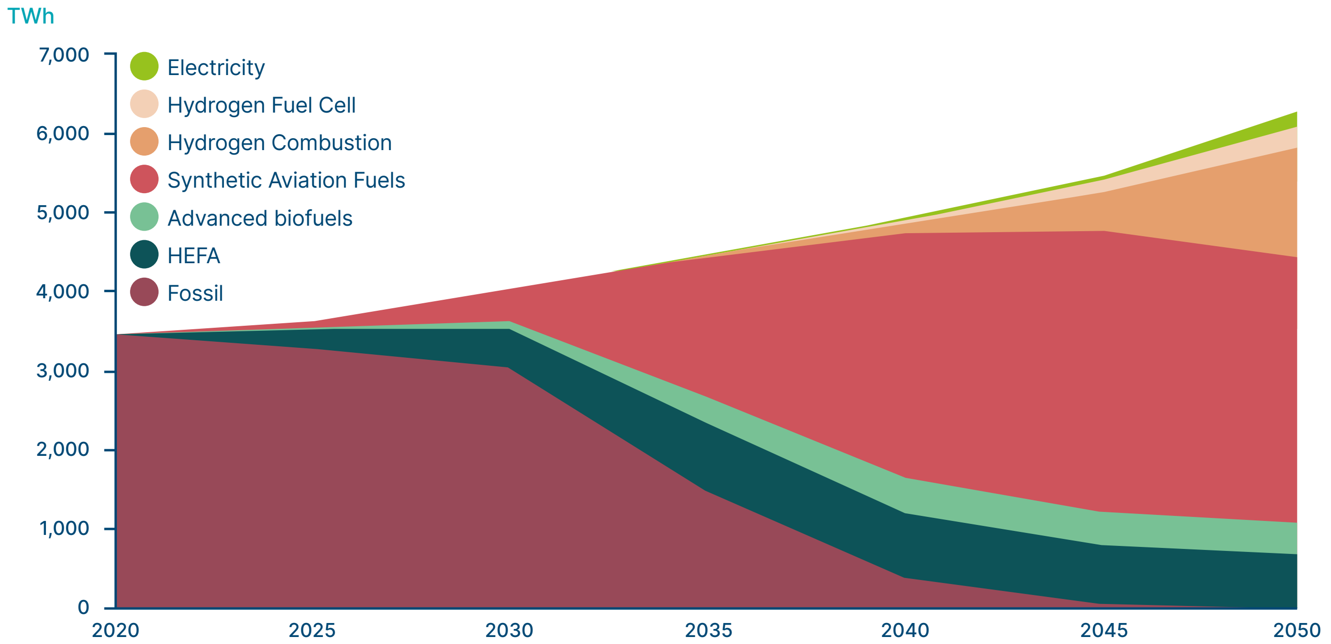
One proposed alternative is to continue using conventional jet fuels while offsetting the emissions via DACCS. But analysis suggests that this is likely to be a less viable decarbonisation option once the climate impact of non-CO_2 forcing factors is taken into account (see Box 6: Synthetic aviation fuel: utilising CO_2 to decarbonise air travel).[84]

Our scenarios for 2050 estimate that around 0.8 $GtCO_2$ will need to be used to produce synthetic jet fuel in that year.[85]

Exhibit 14

Synthetically produced aviation fuels play a key role in decarbonising air travel

Aviation energy demand by fuel type



NOTES: HEFA = hydroprocessed esters and fatty acids (a form of biofuel). Refers to Base Scenario.

SOURCE: Mission Possible Partnership (2021) *Clean Skies for Tomorrow: Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation.* Refers to "Optimistic renewable energy" Scenario

79 Mission Possible Partnership (2021) *Clean Skies for Tomorrow: Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation.*
80 Ibid.
81 Ibid.
82 This could change with advances in ammonia fuel cells or other innovations but progress towards such technologies is still relatively nascent at present. See Mission Possible Partnership (2021) *Ten Critical Insights on the Path to a Net-Zero Aviation Sector.*
83 Mission Possible Partnership (2021) *Clean Skies for Tomorrow: Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation.*
84 Non-CO_2 emissions such as nitrous oxide and soot constitute a non-negligible source of radiative effects. E-Kerosene produced via DACCU emits substantially less NOx and particulates when combusted and constitutes net zero emissions. This means that synthetic jet fuel produced via DACCU is less carbon intensive that conventional kerose offset with DACCS. For full discussion see Cames et al. (2021) *E-fuels versus DACCS: Total costs of electro-fuels and direct air capture and carbon storage.*
85 Mission Possible Partnership (2021) *Clean Skies for Tomorrow: Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation.*

1.3 Energy mix and levers of decarbonisation – implications for fossil fuels

Exhibit 15 sets out the ETC's scenarios for the final energy mix by sector in 2050; if combined with the CCUS volumes by sector described above and summarised in Exhibits 3 and 4, this energy mix would produce a zero-carbon economy. The bars show the potential mix by sector in the "supply-side only" scenario, with fossil fuels in total amounting for around 10% of total final energy demand. The bottom bar shows how the overall mix would adjust in the maximum energy efficiency (Low Deployment) scenario, with direct electricity use becoming still more important and fossil fuels use declining to just 7%.

This fossil fuel use will be compatible with a zero-carbon economy if combined with 2–3.5 $GtCO_2$ of carbon capture applied to fossil fuel combustion applications (with carbon capture in addition used to offset processing emissions and to achieve carbon removals via DACCS and BECCS). Exhibit 16 shows the implications by fossil fuel, with coal use almost eliminated, oil demand falling as much as 90%, and natural gas use down over 30%.

Different decarbonisation strategies across sectors lead to varied final energy mix

Overview of 2050 final energy demand by sector

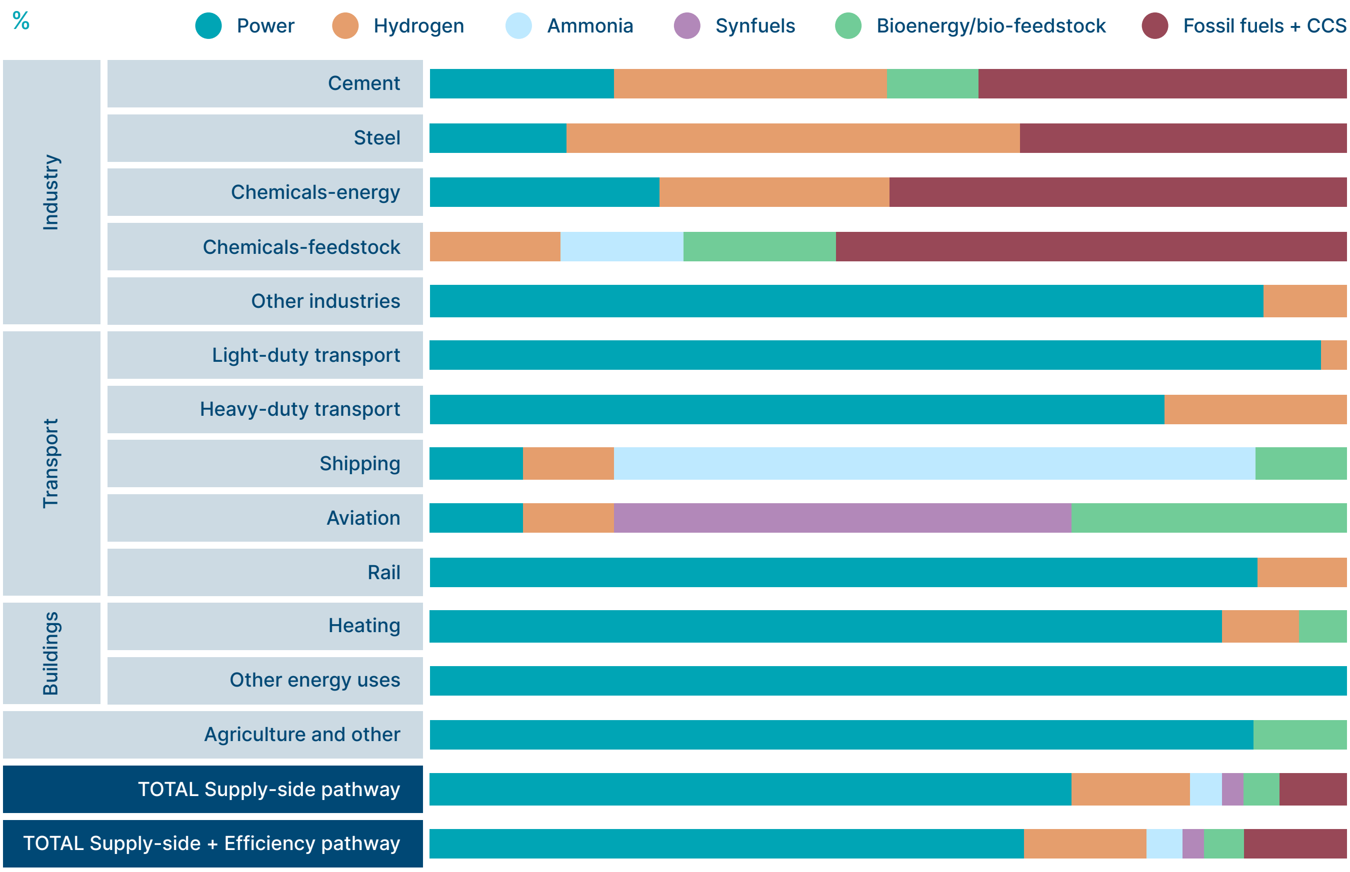


Exhibit 15

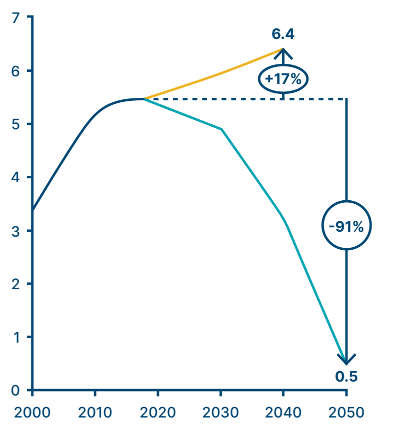
NOTES: refers to Base Scenario.
SOURCE: SYSTEMIQ analysis for the ETC (2021)

Some residual fossil fuel consumption is enabled by carbon capture technology

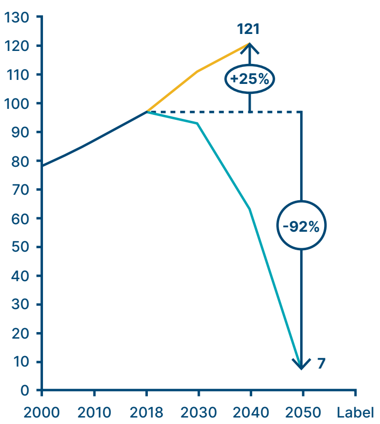
Residual fossil fuel demand under a Net Zero scenario

— ETC Scenario – supply side decarbonisation only — IEA Current Policy Scenario

Coal consumption
Billion tonnes per year



Oil consumption
Million barrels per day



Natural gas consumption
000 bcm per year

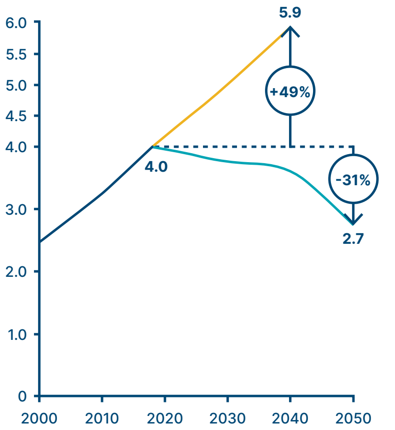


Exhibit 16

NOTES: ETC scenarios for 2030 and 2040 based on the Central Scenario from the Copenhagen Economics paper cited below. The ETC is currently revising these scenarios as part of its work on the future of fossil fuels

SOURCE: SYSTEMIQ analysis for the ETC (2020); IEA (2019) *World Energy Outlook*; Copenhagen Economics (2017) *The Future of Fossil Fuels: how to steer fossil fuel use in the transition to a low-carbon energy system*

Comparing carbon capture scenarios

The ETC has developed two scenarios for modelling the uptake of carbon capture capacity, "High Deployment" and "Base". High Deployment is based on the ETC's illustrative "supply side decarbonisation only" pathway where it is primarily supply side measures that drive the transition to net-zero. The Base Scenario additionally assumes significant energy efficiency and materials circularity improvements (see Section 1.1, Exhibit 2). Both are intended to outline bold yet credible pathways for the technology deployment.

In sectors other than DACC, both scenarios are modelled such that capacity additions represent capture technology requirements *after* other decarbonisation options are exhausted. For DACC, capacity additions are modelled on the basis of carbon removal requirements alongside supply input constraints. The slower pace of renewables growth and efficiency measures in the High Scenario boosts reliance on point source capture (especially for power) and DACC, with total carbon capture in 2050 reaching 10 $GtCO_2$/year ("High Deployment") and 7 $GtCO_2$/year ("Base"), respectively.

Exhibit 15 shows how this estimate compares with other key published studies which present pathways to net-zero by 2050. The chart on the left shows cumulative CO_2 capture capacity for both ETC scenarios alongside the equivalent in the IEA's 2021 *Net Zero by 2050 Roadmap* and BloombergNEF's Grey scenario published in the *New Energy Outlook* 2021.

Overall both the ETC scenarios have a slower rate of capacity additions that the IEA NZE until the 2040s, at which point High Deployment growth accelerates, underpinned by more rapid DACC uptake. Base see consistently less capacity than the NZE throughout the outlook. This is driven by:

- Greater reliance in the NZE on CCS in power generation (in turn reflecting the ETC's more bullish view on wind and solar deployment potential).[86]
- Greater reliance in the NZE on Blue Hydrogen over Green[87] (again reflecting assumptions about renewables buildout and competitiveness).
- Less carbon captured in cement under the Base scenario (0.8 $GtCO_2$) than the NZE (1.4 $GtCO_2$) owing to lower overall production volumes.[88] The High Scenario (1.2 $GtCO_2$) which sees more demand for cement is closer to the NZE's estimate for cement CCS capacity.

Under BNEF's Grey scenario, CCS sees widespread deployment, coal and gas continue to be used, and fossil fuels decline only 2% a year, to 52% of primary energy supply by mid-century, with wind and PV expanding to only 26%. Total CO_2 capture capacity in 2050 is almost double the ETC's Base scenario, driven by:

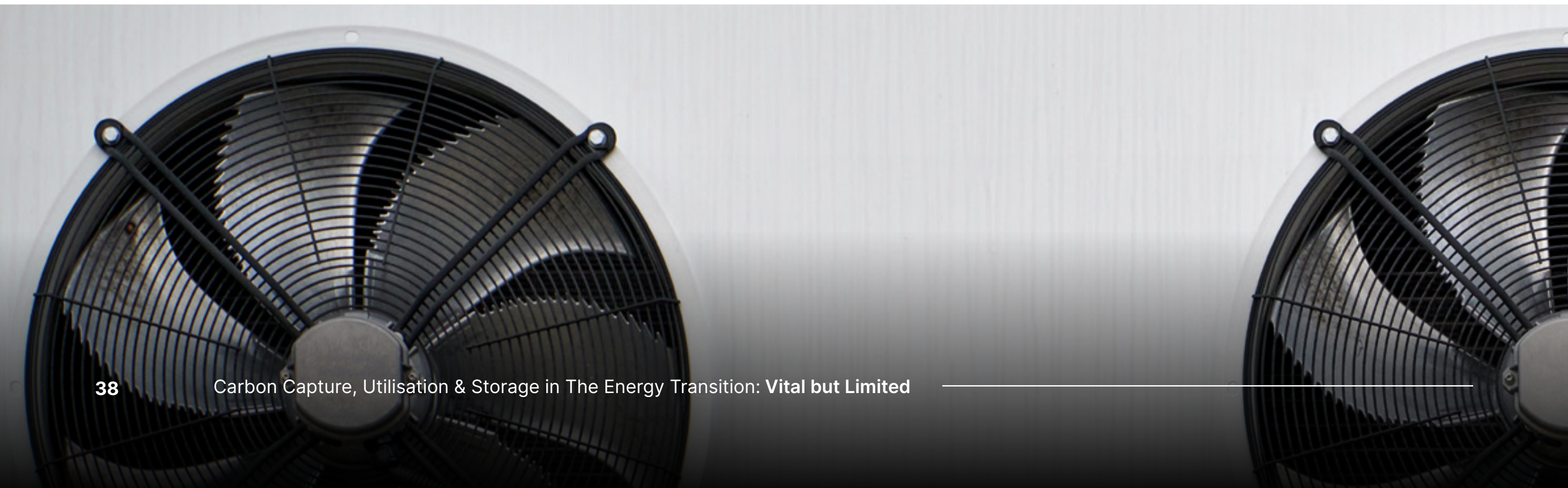
- The slow pace of fossil phaseout and modest growth in renewables drives a very high reliance on CCS in power, with capacity reaching 7.4 $GtCO_2$ in 2050, compared to 0.5–1.6 $GtCO_2$ in the ETC scenarios.
- Very high reliance on blue hydrogen (reflecting slow renewables buildout).
- Persistent reliance on fossil energy in industries, giving rise to greater CCS volumes here too.

Box 3

86 The NZE sees 198EJ combined wind and solar by 2050 (IEA (2021) *Net Zero by 2050*). In ETC (2021) *Making Clean Electrification Possible – 30 Years to Electrify the Global Economy* the ETC sees at least 243EJ wind and solar by 2050.

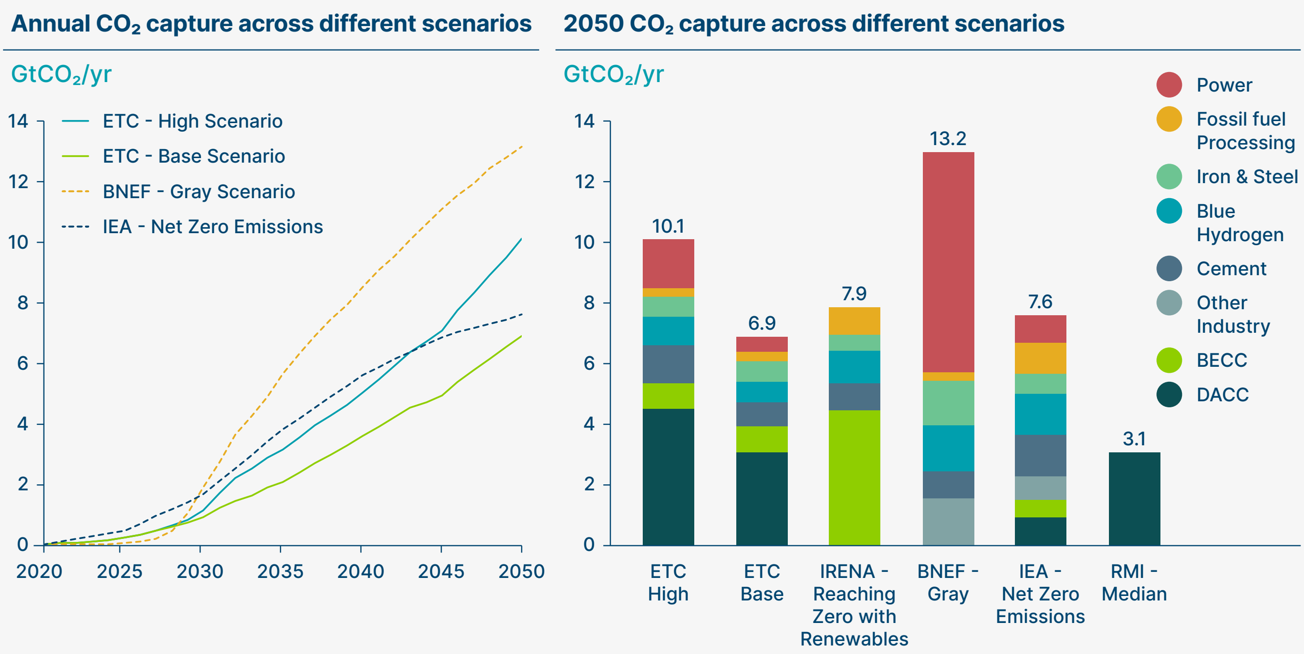
87 The NZE sees 528Mt hydrogen produced in 2050, of which 200Mt is blue and 328Mt green (IEA (2021) *Net Zero by 2050)*. In ETC (2022) *Making the Hydrogen Economy Possible – Accelerating Clean Hydrogen in an Electrified Economy* Medium Scenario (which is used in this report to inform hydrogen assumptions) the ETC estimates between 500 – 800 Mt hydrogen is produced in 2050, of which 15% is blue and 85% green, implying a maximum of 120Mt blue hydrogen.

88 The NZE sees 4,258 Mt cement produced in 2050. This compares with 4,164 Mt in the ETC High Scenario and 2,748 Mt in the Base Scenario.



The chart on the right of Exhibit 17 compares the final installed CO_2 capture capacity by sector for the scenarios described above plus two others. The IRENA Reaching Zero With Renewables scenario has high volumes of BECC, reflecting less stringent assumed constraints on sustainable bioresource availability. Although RMI does not publish a full scenario for all forms of carbon capture, they have modelled DACC capacity in detail: their Median Scenario (which RMI consider to be "ambitious but plausible") reaches 3.1 $GtCO_2$ per year DACC in 2050 – almost exactly the same as the ETC's Base Scenario (3.0 $GtCO_2$).[89] (For further discussion of assumptions underpinning the ETC's DACC volumes, please see Sections 3.1.2 and 3.2.)

ETC projections for CO_2 capture are broadly in line with other scenarios

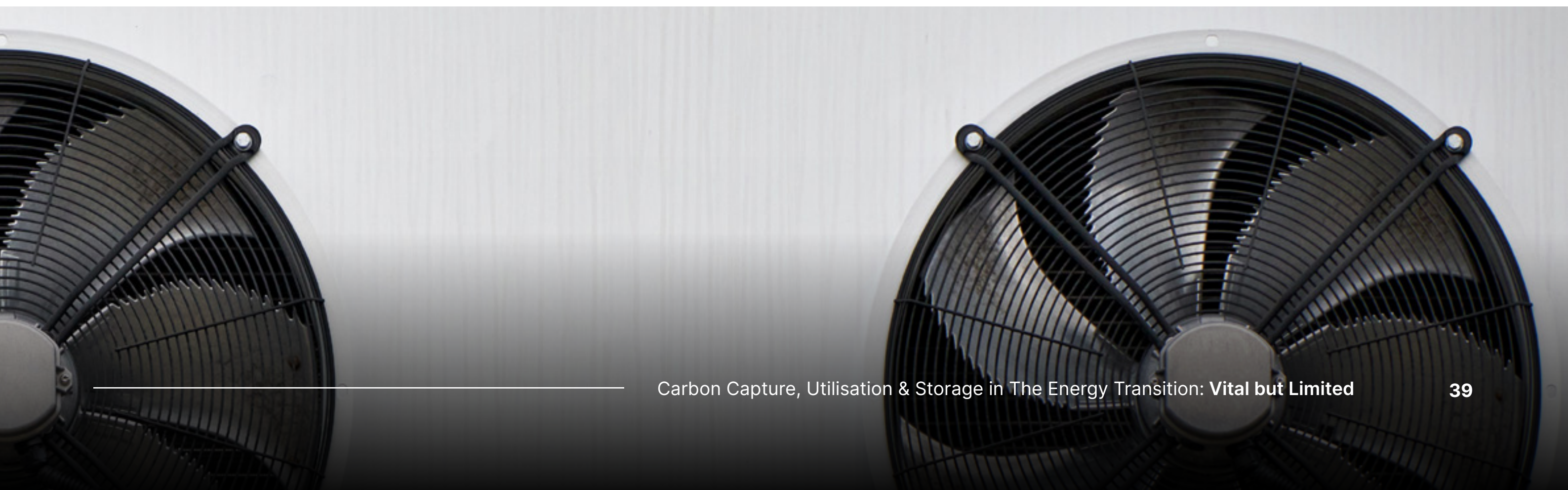


SOURCES: SYSTEMIQ analysis for the ETC; IEA (2021) *Net Zero by 2050*; BNEF (2021) *New Energy Outlook*; IRENA (2021) *Reaching Zero with Renewables: Capturing Carbon*; Rocky Mountain Institute (2022) *Direct Air Capture and the Energy Transition*

Box 3

Exhibit 17

89 In the IPCC's latest pathways which give a 50% chance of limiting global temperature increases to 1.5°C, global cumulative CDR during 2020–2100 from BECCS and DACCS is 30–780 $GtCO_2$ and 0–310 $GtCO_2$, respectively. These figures indicate the ETC's estimates are at the conservative end of the spectrum, although this does not account for the potential buildout after 2050.



The CCUS value chain: capture, transport, storage and/or use

- The impact of CCUS on emissions depends on the combination of the source of CO_2 and the end-of-life outcome.
- The majority of CCUS costs are in CO_2 capture and typically reflect CO_2 concentration. Cost reductions are likely to be gradual where CO_2 is captured from industrial point sources but more dramatic for DACC.
- Resource requirements for 3–5 $GtCO_2$ per annum of DACC will be large but manageable.
- CO_2 can be transported safely and at low-cost via pipeline, truck or ship.
- Large-scale geological CO_2 storage can be safe and permanent, provided it is well managed and strongly regulated.
- CO_2 utilisation plays a secondary role – where available, storage is typically cheaper.
- Enhanced oil recovery should only play a minor role and must only be supported under specific conditions.

The CCUS value chain can be considered in four stages - Source, Capture, Transport, and End-of-life, which in turn can entail either Storage or Utilisation (Exhibit 18). The majority of the costs lie in the energy intensive capture stage, but transport and storage require careful management and strong regulation to ensure safety and permanence. Meanwhile different combinations of Source of CO_2 and End-of-life outcomes have important implications for the total impact on atmospheric CO_2 concentrations and thus on the climate. This chapter therefore covers in turn:

- Sources and End-of-life combinations: the need for clear carbon accounting.
- Capture costs by application and potential future trends.
- Transport: mature technologies and low costs.
- Storage: potentially safe and permanent if well-managed and strongly regulated tight regulation on operations.
- Utilisation: secondary to storage but important in specific applications.
- Enhanced oil recovery: only valuable in specific circumstances with tight regulation on operations.
- A scenario for the balance of storage and utilisation in 2050.

The CCUS value chain can be split into four distinct stages

The CCUS value chain

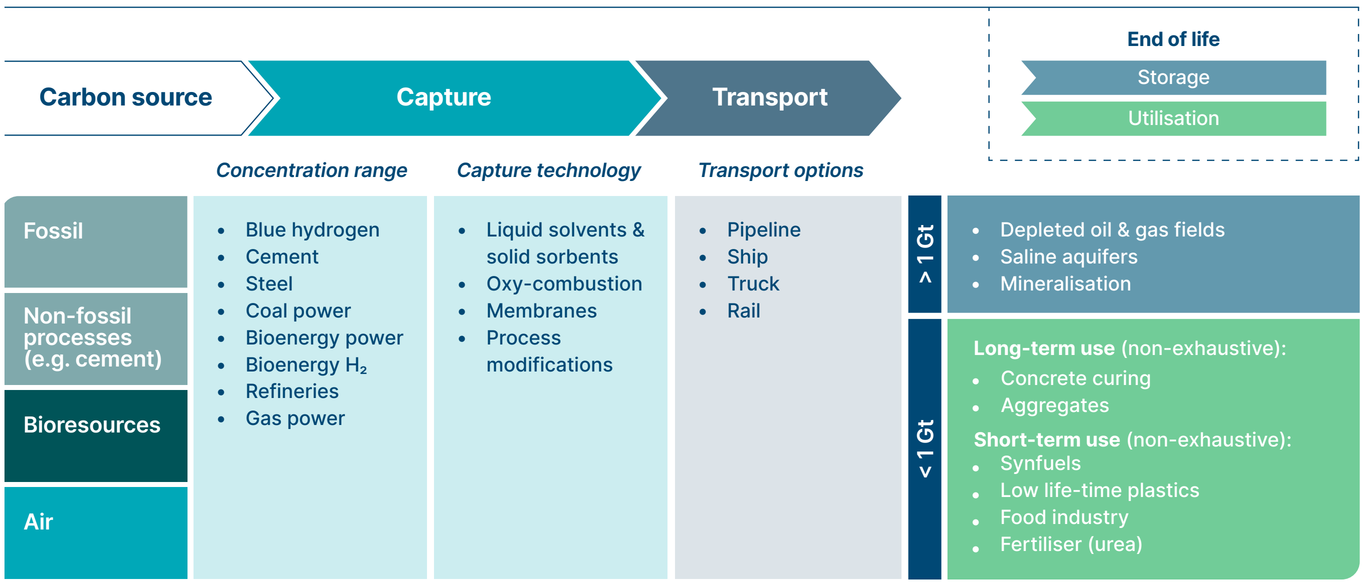


Exhibit 18

SOURCE: SYSTEMIQ for the ETC (2022)

2.1 Source and End-of-life combinations

The impact of CCUS on atmospheric CO_2 concentrations and thus on the climate depends on the source from which the CO_2 is captured and the end-of-life outcome.[90]

- The source can either be from fossil fuels, from biomaterials which originally capture CO_2 via photosynthesis, from industry processes which generate CO_2 as a result of chemical reactions, or directly from the air.

- The end-of-life outcome can be either storage, long-term utilisation or short-term utilisation.

Exhibit 19a and Exhibit 19b show how different combinations of source and end-of-life outcome result in either net carbon removal, decarbonisation of a sector/application to produce net-zero emissions, or "improved carbon efficiency" in which the same carbon molecule can be used in two or more economic activities but is ultimately released.

Thus for instance, the capture of CO_2 from fossil fuel combustion or industrial processes can result in:

- Sector decarbonisation if the CO_2 is stored or is used in long-term applications (such as construction aggregates) or;

- Increased carbon efficiency if CO_2 is used for short-term applications where the CO_2 is released relatively quickly back into the atmosphere (e.g. to produce a synthetic fuel product).

- However, the capture of CO_2 from fossil fuel combustion or industrial processes will never result in a net carbon removal.[91]

In addition, sector decarbonisation can be achieved if CO_2 is used for short-term materials applications (e.g. low-lifetime plastics) and combined with very high materials circularity.[92] Theoretically, the same CO_2 molecule can be used repeatedly via recycling combined with CCUS, 'storing' it within a closed loop material chain and implying atmospheric concentration levels never increase. In practice this outcome is extremely challenging (see Section 1.2.5).[93]

In contrast, if CO_2 is captured via photosynthesis or via direct air capture, and either stored or permanently used, it can generate net carbon removal (Exhibit 19b).

Any public policies which support CCUS, and all carbon accounting for CCUS, must therefore be based on rigorous assessment of the carbon effect, combining both sources and end-of-life outcomes. In particular, linear combinations which result in improved carbon efficiency (e.g. via use to produce transport fuels) are not compatible with achieving a net-zero economy if the input source is fossil fuel combustion or a chemical reaction within an industrial process.

90 Energy emissions should also be included, but that the majority cases these can be decarbonised, primarily via electrification or the use of clean hydrogen.
91 There is a modest improvement in carbon efficiency (since the CO_2 is "recycled" once) but atmospheric concentration still rises.
92 This requires that the carbon molecules re recovered and reused. This can be achieved up to a point through mechanical recycling although this often limits future application options. Alternatively, chemical recycling or pyrolysis in conjunction with CCU can theoretically provide virgin quality feedstock with low emissions. However, these processes are highly energy intensive and can result in declines in feedstock volumes. See SYSTEMIQ (2020) *Breaking the Plastic Wave*.
93 All plastics would need to be collected and then recycled (either through pyrolysis or via incineration) alongside CCS. Even then, some leakage would occur since CO_2 capture rates are not 100%. In the scenarios modelled in this report, we assume around half of the CO_2 utilised in plastic production is recycled in this way (see Section 3.1.2).

Emissions captured from fossil combustion and industrial processes can deliver carbon neutrality or improved carbon efficiency

Ultimate emissions of CO_2 from fossil combustion & industrial process

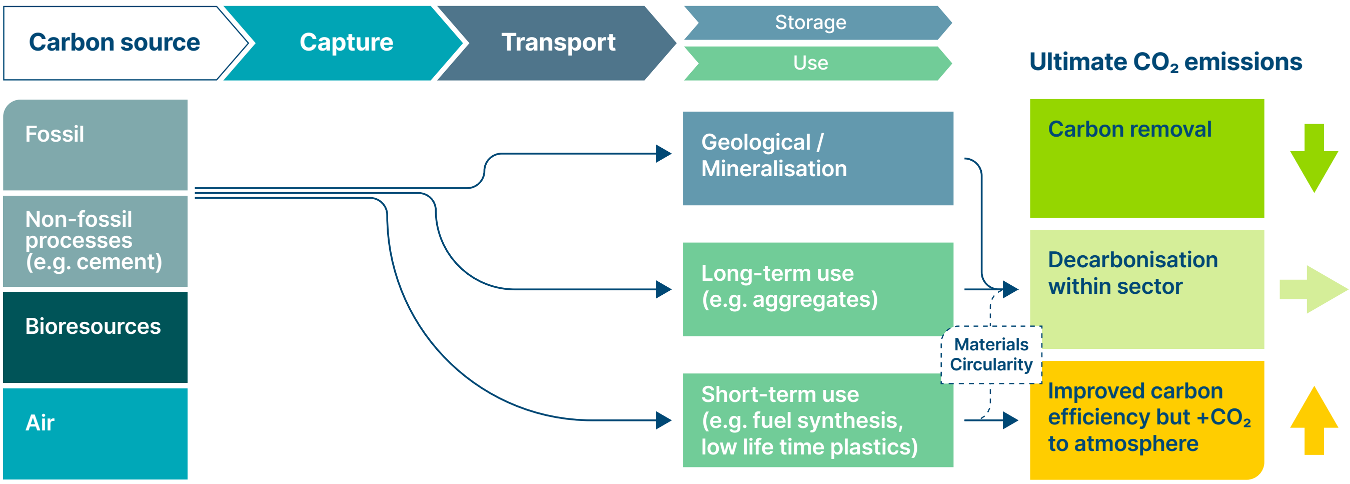


Exhibit 19a

SOURCE: SYSTEMIQ for the ETC (2022)

Emissions captured via DACC & BECC can yield negative emissions

Ultimate emissions of CO_2 from bioresources and DACC

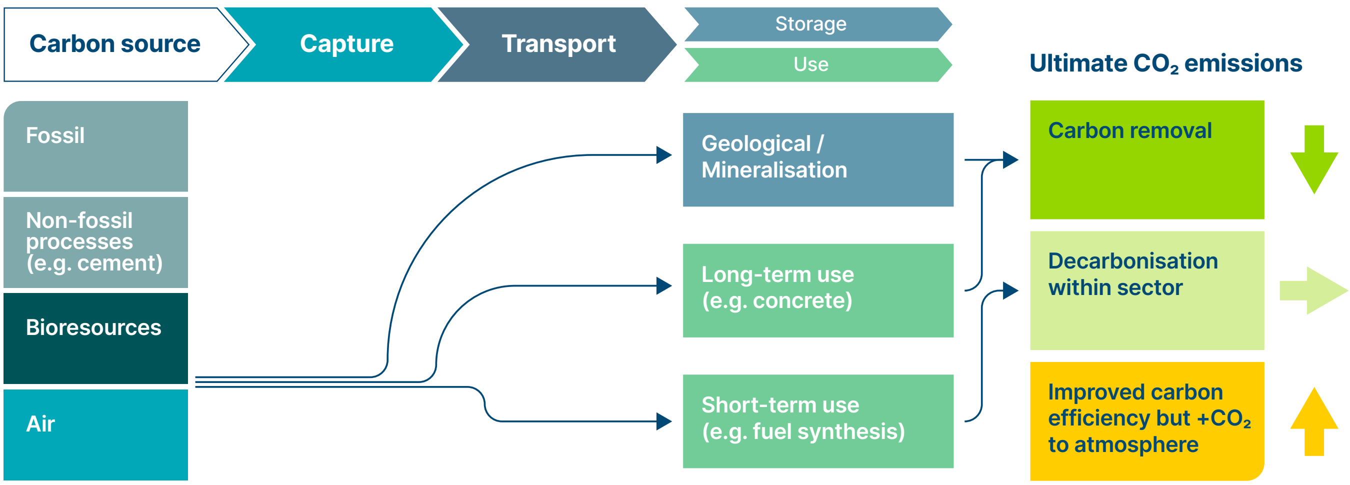


Exhibit 19b

SOURCE: SYSTEMIQ for the ETC (2022)

2.2 Capture costs by application and possible future trends

There are a wide variety of technically feasible means to capture CO_2 with different specific cost implications: capture costs also vary in line with the inherent characteristics of different sector applications, in particular the concentration of CO_2 in streams of gases from industrial sources or other environments. But, in almost all sectors/applications capture costs are much higher than transport or storage costs (Exhibit 20). This section covers in turn:

- The different technologies and the sectors to which they apply.
- Key cost drivers and implications for cost by application.
- Cost versus capture rates - a crucial trade-off.
- Opportunities for future cost reduction.
- Direct Air Carbon Capture (DACC) – costs and resource requirements.

Cost of capture typically drives the total cost of CCS

Levelised cost of capture, transport and storage by application

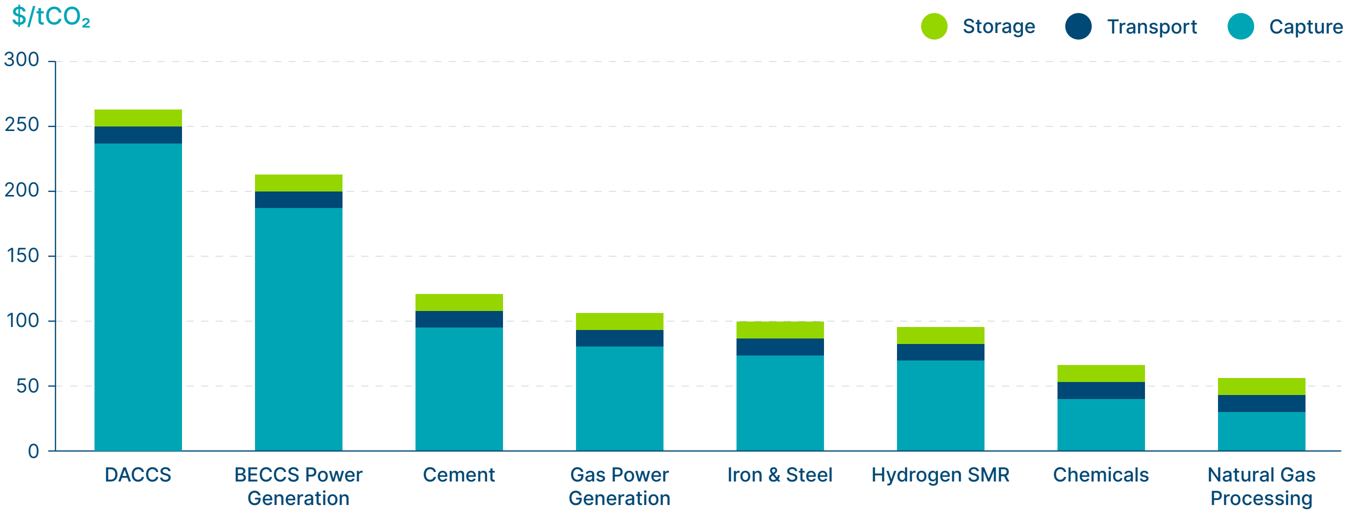


Exhibit 20

NOTES: CO_2 capture costs for hydrogen refers to production via Steam Methane Reformation (SMR) of natural gas. Cost estimates are based on the United States. All capture costs include cost of compression. Chemicals refers to ethylene oxide. Where a range of capture costs are applicable, the midpoint is shown here.

SOURCE: IEA (2019), *Energy Technology Perspectives – CCUS in clean energy transitions*, GCCSI (2017), *Global costs of carbon capture and storage, 2017 update*, IEAGHG (2014), *CO_2 capture at coal based power and hydrogen plants*, Keith et al. (2018), *A Process for Capturing CO_2 from the Atmosphere*, NETL (2014), *Cost of capturing CO_2 from Industrial sources*, Rubin, E. S., Davison, J. E. and Herzog, H. J (2015), *The cost of CO_2 capture and storage; Fuss et al. (2018) Negative emissions—Part 2: Costs, potentials and side effects*

2.2.1 Carbon capture technologies

Multiple technologies can be used to capture CO_2. For combustion and industrial processes, most fall into one of two major categories:

- "**Post-combustion**", where CO_2 is captured from flue gas streams after the combustion of fossil fuel or bio resources (e.g. within a power plant) or after a chemical reaction has occurred (e.g. calcination in cement manufacture).

- "**Pre-combustion**" where CO_2 is captured from a hydrocarbon molecule leaving behind hydrogen which is either combusted or used in a chemical process (e.g. to produce ammonia). These "pre-combustion" processes are often linked with the gasification of coal or partial oxidization of natural gas to first produce a syngas combination of carbon monoxide (CO) and hydrogen.[94]

Two techniques can also be used to increase the purity of the CO_2 stream, reducing the need for energy intensive CO_2 capture. These are;

- **Oxy-combustion**, which entails combusting fossil fuels or biomaterials in pure oxygen rather than air.

- **Process redesigns** to separate chemical reactions from heat generating combustion (e.g. within cement production), so that at least the higher concentration chemical reaction product is isolated close to pure CO_2.

In addition to these technologies for capturing CO_2 from flue gas streams produced by combustion or industrial processes, CO_2 can also be captured directly from the air using liquid solvent or solid sorbent technologies. These are shown in Exhibit 21.

Carbon capture technologies can be categorised according to capture type, system, technology and separation technique

Carbon capture technologies

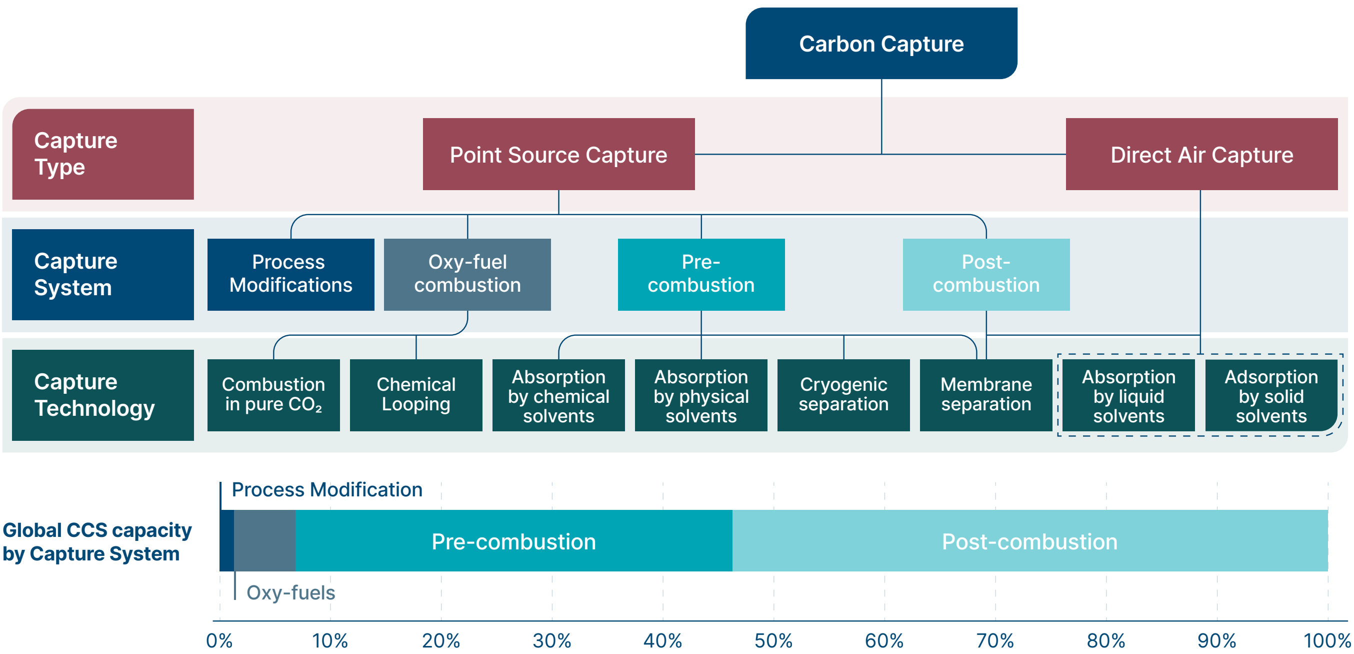


Exhibit 21

SOURCE: SYSTEMIQ for the ETC (2022); Cancawe (2018) *Technology scouting—carbon capture*

94 Precombustion power CCS plants are also in effect blue hydrogen production facilities. Early capacity additions may theoretically hold some extrinsic value as backup capacity (even in regions where green hydrogen outcompetes blue).

2.2.2 Key drivers of capture costs – concentration, technology choice, scale and maturity

The energy required to capture CO_2 from a body of air or gas streams increases as the concentration of CO_2 declines.[95] Different sector applications present different concentration levels, varying from over 95% for coal-to-chemical processes to 0.04% for DACC (reflecting the concentration of CO_2 in the atmosphere). Typical concentration levels for different applications are shown in Exhibit 22.

Energy needs are the primary driver underpinning capture costs and will also vary according to the specific technology chosen (Exhibit 23 and Exhibit 24). In some sectors capital costs will reduce with economy of scale effects as plant size increases (Exhibit 25).

Lowest-cost technology choice for any application or specific plant will therefore reflect a complex combination of factors. As a result, capture costs vary significantly by application, with current estimated costs as low as $30 per ton for hydrogen production via SMR to around $350 per ton for DACC (Exhibit 23) with wide ranges within some sectors, but with the ranking by application strongly driven by CO_2 concentration.

Energy required for CO_2 capture declines with increasing CO_2 concentration

Minimum work required for CO_2 capture

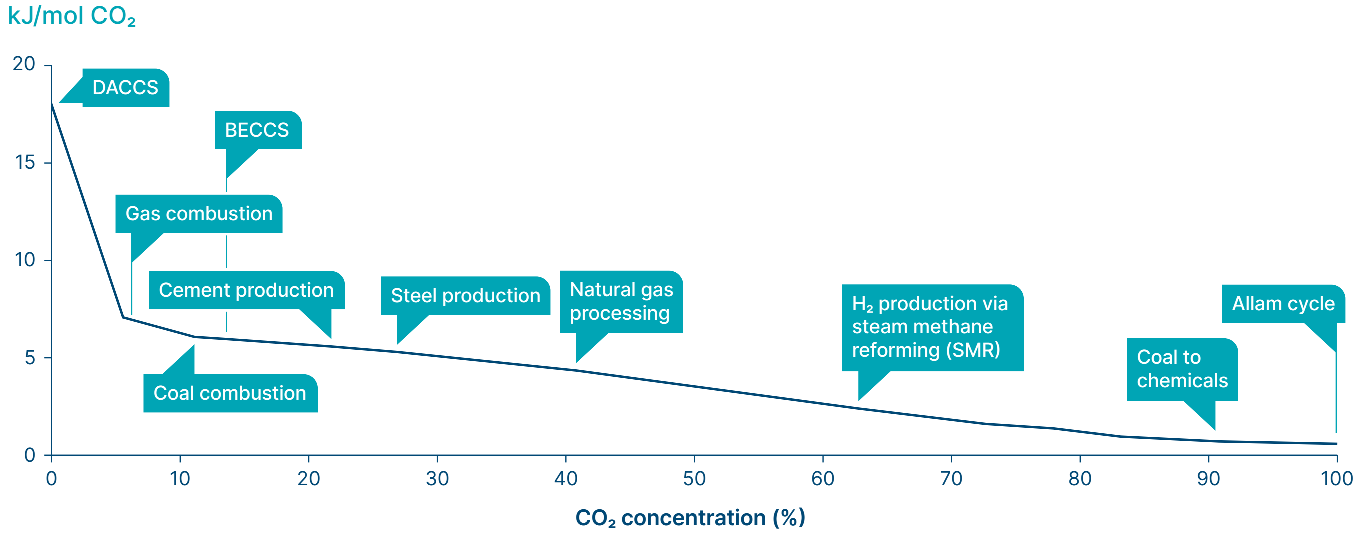


Exhibit 22

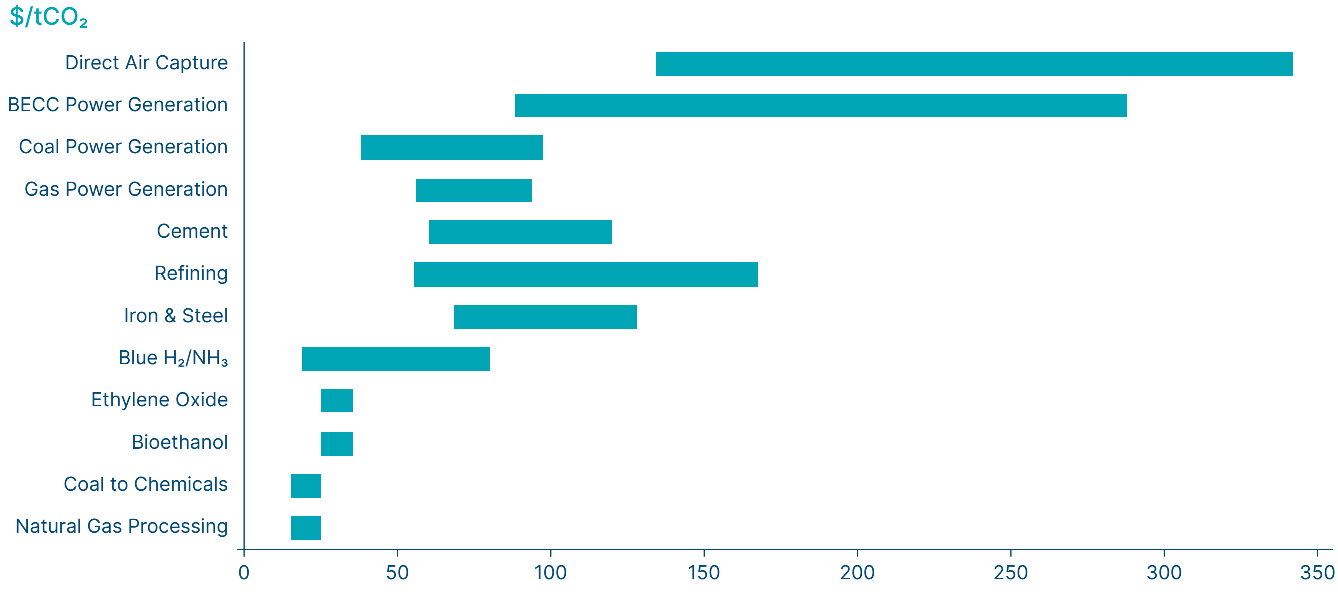
NOTES: SMR = Steam Methane Reforming. The Allam Cycle (see Allam et al. (2017) *Demonstration of the Allam Cycle: An Update on the Development Status of a High Efficiency Supercritical Carbon Dioxide Power Process Employing Full Carbon Capture).*

SOURCE: Bui et al. (2018) *Carbon capture and storage: the way forward*

95 Unless energy is derived from waste heat, this additional energy penalty implies higher cost of capture.

Estimates of sectoral levelised cost of capture today vary widely

Range of levelised cost of capture estimates by sector today

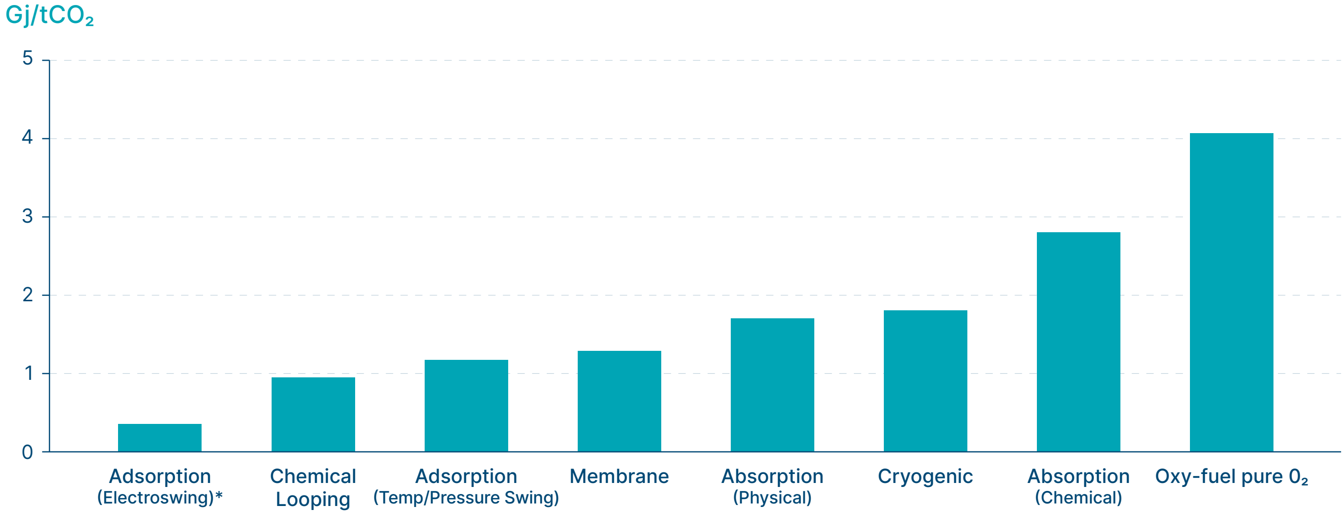


NOTES: Coal to chemicals refers to methanol and ammonia.

SOURCES: IEA (2017) *CCUS in Clean Energy Transitions* (2021), GCCSI (2017), Global costs of carbon capture and storage, IEAGHG (2014), *CO_2 capture at coal-based power and hydrogen plants*, Keith et al. (2018), *A Process for Capturing CO_2 from the Atmosphere*, NETL (2014), *Cost of capturing CO_2 from Industrial sources*, Rubin et al (2015), *The cost of CO_2 capture and storage*; Bloomberg NEF *CCUS Costs and Opportunities for Long Term CO_2 Disposal* (2021); Fuss et al (2018) *Negative emissions—Part 2: Costs, potentials and side effects;* IEA (2021) *Is carbon capture too expensive?*

Energy requirements can vary significantly between capture technologies

Energy required for CO_2 capture using different technologies



NOTES: *Electro Swing Adsorption costs reflect industry estimates and have yet not been achieved at commercial scale.

SOURCE: Hong W.Y., (2022) *A techno-economic review on carbon capture, utilisation and storage systems for achieving a net-zero CO+ emissions future,* Carbon Capture Science & Technology

CO_2 capture costs decline with scale up to a capacity of c. 0.6 $MtCO_2$/year

CO_2 capture cost including cost of compression in power plants

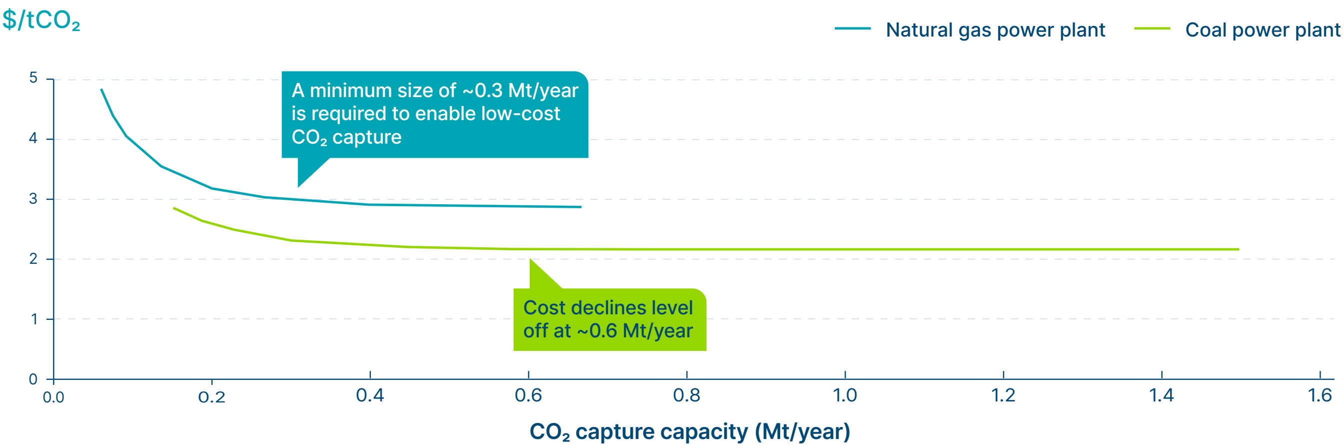


Exhibit 25

NOTES: The coal and natural gas reference prices (United States) applied are $2.11 per GJ and $4.19 per GJ (HHV) respectively. A construction lead time of 3 years for all cases is assumed. Technologies illustrated: Natural gas combined cycle (NGCC) and Supercritical Pulverised Coal (SCPC).

SOURCE: Global CCS Institute (2021) *Technology readiness and costs for CCS*

2.2.3 Direct air carbon capture – costs and resource requirements

The ETC's recent report on carbon removals concluded that the world will need at least 70–225 $GtCO_2$ of removals between now and 2050 alongside rapid and deep global decarbonisation.[96] Further, our scenarios outlined in Chapter 1 assumed that by 2050 DACC could account for 3 to 4.5 $GtCO_2$ of removals per annum.

However, DACC today is a very costly option. Exhibit 23 hows the IEA's estimated levelised cost of capture for DACC ranging up to $350/$tCO_2$, yet other estimates suggest it could be as high as $600/$tCO_2$.[97] These high costs reflect the low concentration of CO_2 in the air (0.04%) and the high energy inputs required for solvent/sorbent regeneration. Today's very high per-tonne energy requirements also imply that developing DACC on a large-scale would require significant electricity (or potentially heat) infrastructure development.

DACC costs are however likely to decline significantly over time, and resource requirements should become more manageable.

Capture costs. Reasonable assumptions imply that the cost of DACC could fall below $100/t CO_2 in favourable regions by 2050 (Exhibit 26) and possibly as soon as 2030, according to interviews conducted with some industry players. Such a decline in costs would be underpinned by three factors:

- **Increased energy efficiency**. Today's technologies require about 2-3 MWh/tCO_2 (7-11 Gj/tCO_2) captured, but this could fall to as low as 0.5 MWh/tCO_2 (2 Gj/tCO_2) by 2050 or sooner. This would depend on progress in breakthrough technologies such as electro-swing adsorption and zeolites, as well as incremental improvements.

- **CAPEX cost decline**s due to learning-by-doing and economy-of-scale effects. DACC is likely to be more amenable to economies of scale-based cost reduction (where multiple plants of the same modular design will be the norm) than in the case of power and industrial plant applications of CCS (where bespoke designs and retrofits will often be required).

- **Falling energy input costs**, as the cost of renewable electricity continues to fall, particularly in climatically favourable locations.

The IEA estimates that the combination of R&D, learning by doing (LBD) and economies of scale (EOS) could reduce the levelized cost of capture via DACC from a range of $140–300 per tonne in "first of a kind" plants to $50–150 per tonne in "Nth of kind" plants.[98]

96 ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*
97 Socolow et al. (2011) *Direct Air Capture of CO_2 with Chemicals*; Ishimoto (2017) *Putting Costs of Direct Air Capture in Context.*
98 IEA (2022) *Direct Air Capture.*

Declines in the cost of energy as well as improved efficiency and reduced CAPEX requirements drive DACC cost savings

Estimated levelised cost of direct air capture by cost driver and energy costs (RHA) for advantaged regions

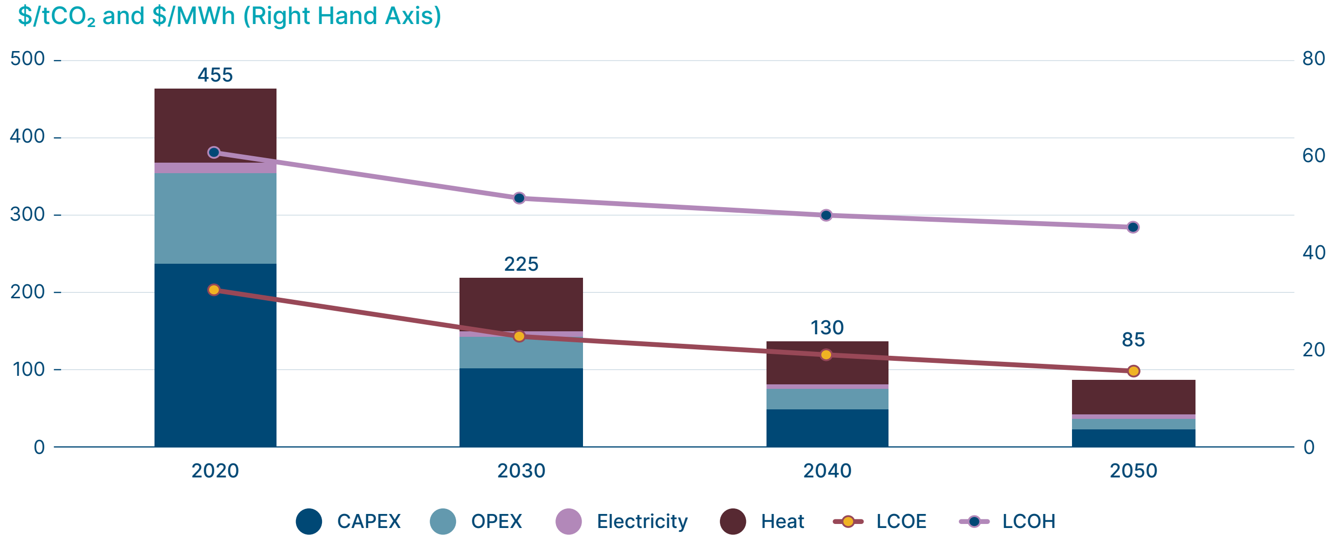


Exhibit 26

NOTES: LCOH/E = levelised cost of heat/electricity; Levelised Cost of CO_2 Direct Air Capture breakdown refers to a fully electrified high temperature DACC system for 5,000 Full Load Hours per annum. Assumes overnight cost of capital for 1MtCO_2 plant in 2020 of $1,470m, weighted average cost of capital of 7% and plant lifetime of 20 years, growing to 30 years by 2050. Capital, heat and electricity costs refer to an advantaged region with abundant wind and solar resources.

SOURCES: SYSTEMIQ for the ETC (2022) based on models developed by Fasihi et al. (2019) *Techno-economic assessment of CO_2 direct air capture plants*; Keith et al. (2018) *A Process for Capturing CO_2 from the Atmosphere*

CAPEX sensitivities. Estimates of DACC's future CAPEX cost trajectory are highly uncertain. Given the rapid cost declines expected, small alterations to assumptions lead to significantly different estimates in overall investment requirements by 2050. Multiple factors are inherently uncertain:

- **Capital costs** for a plant built today are not directly observable outside of the very few companies producing DACC systems,[99] with a wide range across available reported and academic estimates.[100]
- **Learning rates** (the pace at which costs decline with every doubling of capacity installed) for bespoke energy technologies such as centralised power generation typically range up to ~10%.[101] However for modular technologies such as solar PV, lithium ion batteries or electrolysers, the learning rate is often higher, between 15%–20%.[102]
- **Estimates for the installed capacity** by mid-century are inherently uncertain and depend on the scale of role assumed for CCUS in transition and an end-state net-zero economy.[103]

The impact of changes in these assumptions is illustrated in Exhibit 27. A reasonable estimate of today's DACC CAPEX costs, taking into account recently reported projects and academic meta studies is c. $1500/t CO_2.[104] Combined with more and less aggressive learning rates (15% and 10% respectively[105]) and an installed capacity by 2050 of 3.0 GtCO_2, these assumptions together suggest 2050 CAPEX costs in the range of c. $100-200/t$CO_2$.[106]

99 Prices quoted for offsetting other firms' emissions may serve as a proxy for costs, but actual capital requirements are not generally reported in a transparent fashion by DACC companies; McQueen et al. (2021) *A review of direct air capture (DAC): scaling up commercial technologies and innovating for the Future.*

100 Ishimoto (2017) *Putting Costs of Direct Air Capture in Context.*

101 Rubin et al. (2015) *Use of experience curves to estimate the future cost of power plants with CO_2 capture.*

102 Ibid.; Nemet & Brandt (2012) Willingness to pay for a climate backstop; liquid fuel producers and direct CO_2 air capture; Caldera & Breyer (2017) Learning curve for seawater reverse osmosis desalination plants: capital cost trend of the past, present and future; Kittner (2017) *Energy storage deployment and innovation for the clean energy transition.*

103 Per unit CAPEX costs decline by the assumed learning rate with each doubling of capacity – therefore the final capacity will also impact CAPEX costs.

104 This is based on an average of Fasihi et al. (2019), Keith et al. (2018) and the midpoint of Climeworks' ORCA project in Iceland, quoted in McQueen et al. (2022).

105 Fasihi et al. (2019) presents a "conservative" learning rate for S-DACC of 10% and 15% for a scenario which is compliant with effective execution of the Paris Climate agreement, without delay. Rubin et al. (2015) *A review of learning rates for electricity supply technologies* document a similar range for related energy technologies

106 In the investment requirement analysis presented in Section 3.2, we assume a starting point of $1,470/t CO_2 and a learning rate of 12% throughout, implying a CAPEX cost of ~$145/t CO_2 by 2050.

This estimate is towards the optimistic end of other available estimates:

- RMI estimates of removal costs reach \$115–335/tCO_2 in 2050. This range is slightly higher owing to a higher assumption of today's costs[107] and slower learning rates ranging from 8%–12%. Total removals in 2050 reach 3.0 GtCO_2 p.a., the same as the ETC Base Scenario.[108]

- The IEA's estimate from its Net Zero Scenario reaches \$130–365/tCO_2 in 2050.[109] This higher cost reflects a lower estimate for removals of just 1.0 GtCO_2 p.a. in 2050.

- A survey of experts conducted by Shaygeh et al. (2021), suggested a higher cost limit of \$120/tCO_2 and a low limit of \$80/tCO_2 by 2050.[110]

DACC CAPEX cost evolution under different starting points and learning rates

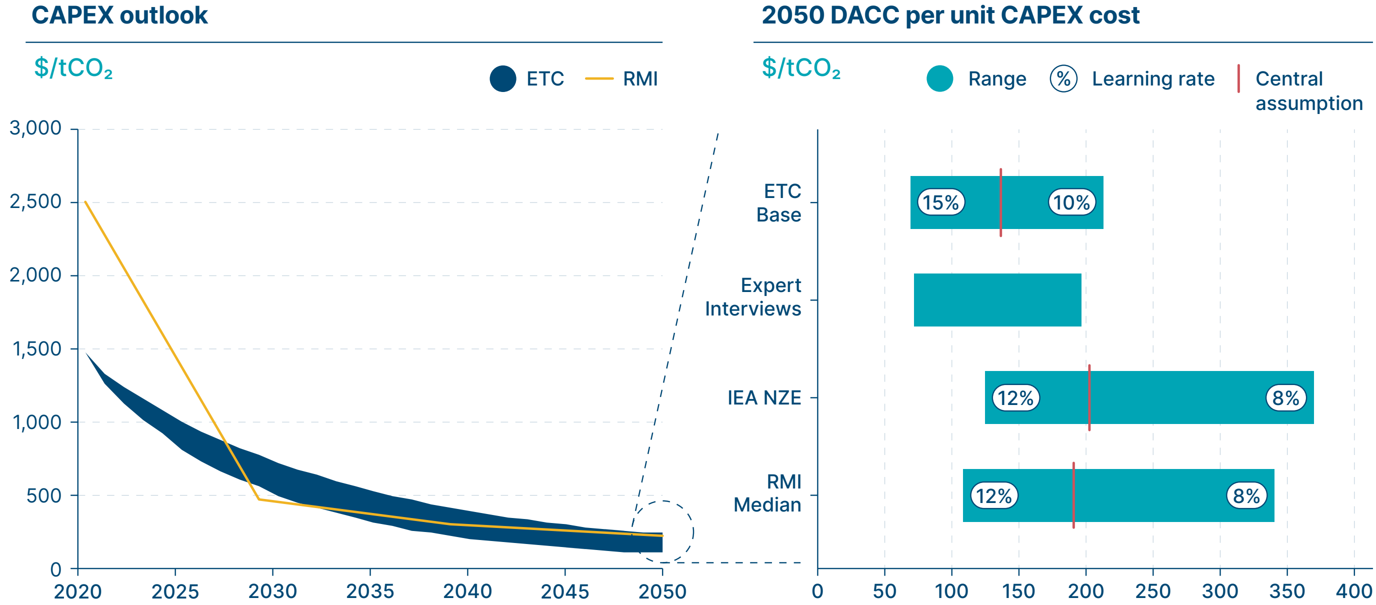


Exhibit 27

NOTES: Range for ETC illustrates impact of different learning rates (Low: 10%; High:15%). Range for right hand side chart expert interviews reflects estimates from industry experts in Shaygeh et al (2021) in which final 2050 capacity not specified. ETC Base scenario and RMI Median capacity both ~3.0GtCO_2/y. IEA Net Zero Emissions sees 1.0GtCO_2/y.

SOURCE: SYSTEMIQ analysis for the ETC (2022); Rocky Mountain Institute (2022) *Direct Air Capture and the Energy Transition: Putting Potential Opportunity Costs in Perspective*. For detailed breakdown of methodology, please see technical annex. Right hand side: SYSTEMIQ analysis for the ETC (2022); Rocky Mountain Institute (2022) *Direct Air Capture and the Energy Transition: Putting Potential Opportunity Costs in Perspective*; Shaygeh et al. (2021) *Future Prospects of DAC Technologies: Insights From an Expert Survey*

107 RMI assumes a midpoint in the range quoted by McQueen et al. (2022) for the ORCA project CAPEX.
108 RMI (2022) *Direct Air Capture and the Energy Transition.*
109 IEA (2021) *Net Zero by 2050.*
110 Learning rates, starting costs and final capacities are not detailed. Shaygeh et al. (2021) F*uture Prospects of DAC Technologies: Insights From an Expert Survey.*

Resource requirements for DACC

Resource needs for DACC include materials such as steel and cement used in construction, and estimates suggest that the volumes involved are not material compared with major uses of steel and cement today.[111] The ETC will publish a report on all the resource needs to drive clean electrification and other key decarbonization technologies, including DACC, later this year.

Instead, the most important resource implications for DACC arise from the large inputs of zero-carbon electricity which will be required:[112]

- If 3–5 GtCO_2 p.a. were captured at today's energy efficiency of ~3 MWh/tCO_2 (~11 Gj/tCO_2)[113], this would imply an additional 9,000–15,000 TWh electricity demand, compared to total global electricity production of 27,000 TWh today. This would add significantly to the ETC's estimate of 70,000–90,000 TWh of direct electricity demand in 2050. In addition, green hydrogen (which would be necessary for high temperature liquid solvent DACC) will also require significant electricity inputs.
- If an efficiency improvement to 1 MWh/tCO_2 could be achieved – which some estimates suggest is possible – then 3,000–5,000 TWh of electricity would be required: a still very significant but more manageable figure.

Even electricity requirements at the top end of this range would be manageable in the long term, given the massive scale of global solar and wind resources and the ability to locate DACC plants where renewable electricity is most abundant and land has limited alternative use value.

For example, 5 GtCO_2/year capacity requiring 3 MWh/tCO_2 yields a power input requirement of 15,000 TWh of electricity from solar photovoltaics. This would imply devoting about 22.5 Mha to DACC-linked solar farms (assuming 1.5 ha/GWh). By comparison the ETC estimates that achieving the equivalent sequestration via natural climate solutions would require land use or land management changes applied to around 1000 Mha of land – around 7% of global land (see the ETC's Carbon Removals report for further discussion of this issue).[114]

We therefore believe that 3–5 GtCO_2 p.a. of DACC removals in 2050 is a manageable objective. But it is vital to understand that large-scale deployment, along with large-scale green hydrogen development and greatly expanded direct electricity use, will depend on a pace of zero carbon electricity deployment far greater than currently being achieved. Without this, the carbon removals derived from DACC are compromised.

The ETC will publish a report later this year on *Barriers to Clean Electrification* which will set out the public policy and private investment actions required to deliver greatly accelerated progress.

2.2.4 Costs and capture rates – a crucial trade-off

The impact of CCUS on carbon emissions, concentrations and temperature depends on the percentage of CO_2 which is captured. But, capture costs per tonne increase as the share of CO_2 captured rises, creating an incentive to choose lower capture rates at the expense of complete decarbonisation.

Post combustion capture rates of around 90% are often treated as a reasonable benchmark of acceptable performance.[115] In practice actual capture rates have frequently fallen short of this threshold, reflecting either cost minimizing decisions, engineering failures or an early stage of technological deployment development. In some cases however, capture rates have actually exceeded their target, see Box 4: Carbon capture rates: separating fact from fiction).

Capture rates above 90% are possible, but with progressively higher costs as rates approach 100%.[116] For open cycle gas-fired power plants for instance, increasing the capture rate from 90% to 96% will incur a modest additional cost penalty of about 12%, taking total cost from around \$80 to \$90/tCO_2. But increasing it to 99% could increase costs to \$160/tCO_2 (Exhibit 28).

111 RMI (2022) *Direct Air Capture and the Energy Transition: Putting Potential Opportunity Costs in Perspective.*

112 This assumes that the majority of the heat energy will be derived from electricity via heat pumps. Heat may alternatively be derived from industrial waste heat streams or from geothermal resources.

113 The range of estimates for energy demand for DACC today is very wide owing to the limited number of projects in operation. For illustrative purposes we have presented an estimate here based on IEA (2022) *Direct Air Capture: a key technology for net zero* which estimates solid DACCS energy requirement at 10 Gj/tCO_2 = 2.8 MWh/tCO_2. In modelling DACC energy requirements and associated CAPEX (Section 3.2) we assume DACC energy requirement today is 9 Gj/tCO_2, declining to 1.5 Gj/tCO_2 by 2050.

114 ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to keep 1.5°C Alive.*

115 IEAGHG (2019) *Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass.*

116 Brandl et al. (2021) *Beyond 90% capture: Possible, but at what cost?* Note that some pre-combustion techniques such as the Allam Cycle process capture is inherently 100% and costs do not increase. See Allam et al (2017) *Demonstration of the Allam Cycle: An Update on the Development Status of a High Efficiency Supercritical Carbon Dioxide Power Process Employing Full Carbon Capture.*

It will therefore often be uneconomic to drive capture rates significantly above 95%. This has three implications:

- CCUS will only be compatible with achieving a zero-carbon economy if residual emissions are clearly recognised and offset by carbon removals.
- Comparisons of the relative cost of different decarbonisation groups (e.g., green versus blue hydrogen) must take into account any residual offset costs.
- It is essential that any public support for CCS is contingent on project developers achieving high capture rates (i.e. at or above ~90%) with support only disbursed when capture has been achieved, accurately measured and verified.

Costs begin to increase sharply as capture rates approach 100%

Carbon capture rates and costs in a gas fired power plant

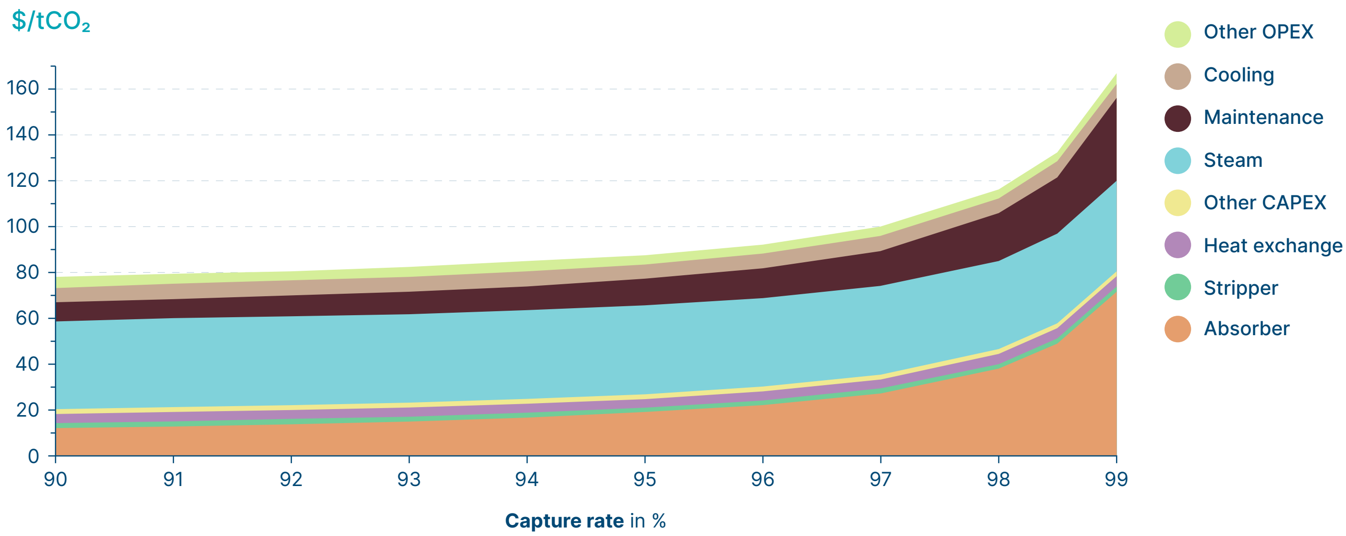


Exhibit 28

SOURCE: Brandl et al, (2021) *Beyond 90% capture: Possible, but at what cost?* International Journal of Greenhouse Gas Control

Carbon capture rates: separating fact from fiction

As discussed in Section 2.2.4, although CO_2 capture rates approaching 99% are technically feasible, real-world capture rates have frequently fallen well short of this. Three high-profile projects help illustrate the challenges of implementing carbon capture at scale (details of each facility outlined in Exhibit 29).

Boundary Dam, Saskatchewan, Canada: The CCS demonstration project at the Boundary Dam coal power plant in Saskatchewan, Canada, illustrates some of the difficulties involved in moving from pilot to commercial scale operations. The plant began operating in 2014 with a nameplate capacity of 1 $MtCO_2$/year and a target capture rate of 90%.[117] However, since the start of operations only ~65% of total emissions have been captured, with just 1,240 tonnes/day captured in the first 12 months of operation.[118] Part of the reason for this was the difficulty the operator, SaskPower encountered when trying to scale up components such as compressors and heat exchangers. Higher than expected degradation of the amines further reduced capture rates.[119]

Gorgon, Australia: In the case of Chevron's Gorgon LNG plant in Australia, the sheer complexity of the project ended up curtailing carbon capture rates. The plant separates CO_2 from natural gas recovered from offshore gas fields, which is then reinjected and stored under a sandstone formation, 2km underground.[120] In the year to July 2021, the capture and injection rate was reportedly just 45%[121] - well below the target 80%.[122] This is partly related to technical challenges (sand clogging the injection pipes)[123] but also reflects the complexity and high number of processes involved: Gorgon has been operating its carbon capture facility for more than four years, but for at least three of those years not a single day had passed when all elements of Gorgon's CO_2 injection system have worked at the same time.[124] This illustrates how even if the capture technology is functioning properly, failures in other systems (in this case injection) can still compromise the plant's overall capture rate. Additional subsurface pressure issues have also arisen at Gorgon. Injecting CO_2 into underground storage increases the pressure in the stores. Evidence from Gorgon CCUS (and a previous CCUS project In Salah in Algeria) highlights the risk of CO_2 leakage if active pressure management systems (e.g., extracting water) are not in place.

Petra Nova, Texas, USA: These cases contrast with the Petra Nova three-year demonstration project in Texas, USA. The plant captured CO_2 from a coal fired power plant for use in EOR. Over 92% of CO_2 in the flue gases of the plant were captured across the whole three-year demonstration period.[125] Although the facility was shut down in spring 2020 due to very low oil prices and remains mothballed, the project actually exceeded technical targets and is widely viewed as a successful example of scaled up carbon capture technology.[126]

Box 4

117 UNFCC Activity Database: Boundary Dam Carbon Capture and Storage Project - Canada.
118 SP Global (2022) *Only still-operating carbon capture project battled technical issues in 2021.*
119 IEAGHG (2021) *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability.*
120 Chevron (2021) *Fact sheet: gorgon carbon capture and storage.*
121 Chevron annual report to Australian Government (2021) *Gorgon Project Carbon Dioxide Injection Project.*
122 Financial Times (2021) *Monster problem: Gorgon project is a test case for carbon capture.*
123 Injecting CO_2 into underground storage increases the pressure in the stores. Evidence from the In Salah and Gorgon CCUS projects highlights the risk of CO_2 leakage associated with active pressure management systems (e.g. extracting water).
124 Energy Voice (2021) *Chevron fails to hit targets with giant CCS scheme at Gorgon LNG.*
125 Kennedy G. (2020) *Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Final Technical Report).*
126 Reuters (2020) *Problems plagued U.S. CO_2 capture project before shutdown: document.*

Performance projects has varied substantially between various CCS

Characteristics of three recent CCUS projects

	Boundary Dam	Gorgon	Petra Nova
Sector & Application	• Power & EOR • CO_2 captured from flue gases at a coal-fired power plant. • CO_2 is then reinjected for enhanced oil recovery.	• Natural gas processing • CO_2 removed from raw natural gas, then re-injected underground for geological storage.	• Power & EOR • CO_2 captured from flue gases at a coal-fired power plant. • CO_2 is then used for EOR.
Companies Involoved	SaskPower	Chevron Australia, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA	NRG Energy, JX Nippon Oil
Plant Operation	2014 - present	2019 - present	2017 - 2020
Plant Size ($MtCO_2$ captured p.a.)	1 $MtCO_2$	4 $MtCO_2$	Not specified, but targeted ~2.9 $MtCO_2$ captured across 2 years.
Target Capture Rate (%)	90%	80%	90%
Achieved Capture Rate (%)	65% between 2014 – 2021 (highest achieved rate of 94.6% throughout 2018)	45% (for 12 months running to July 2021)	92.4% across three years
Main Challenges Faced	Scale-up challenges with flue gas flow, amine flow and heat transfer	Sand blocking successful injection of CO_2 into geological storage site.	Outages leading to down time, of both the carbon capture and other facilities.

SOURCES: SYSTEMIQ analysis for ETC (2022)

Box 4

Exhibit 29

2.2.4 Future cost trends

Section 2.2.2 set out reasonable estimates of the costs of CCUS projects implemented today. The crucial question is how far and fast these costs could fall in future.

Over the last 10 to 15 years carbon capture costs have only declined a little, unlike in solar PV panels, wind turbines, batteries and (more recently) electrolysers, where dramatic cost reductions have been achieved. As a result, the cost competitiveness of other decarbonisation vectors has significantly improved relative to CCUS.

This disappointing progress of CCUS costs in part reflects low build rates over the last decade, the causes of which are analysed in detail in Chapter 3 Looking forward, two drivers of cost reduction could play a role;

- **Learning curve and economy of scale** effects are highly likely to deliver gradual reductions, so long as capacity additions gain pace. The inherent nature of CCS projects, which often involve bespoke plant design or retrofit of existing industrial plants, make it unlikely that CCUS will benefit from the dramatic cost reductions seen in renewable energy, batteries and green hydrogen. But analysis by the IEA suggest that multiple incremental improvements alone could deliver cost reductions ~30% by 2050 (Exhibit 30).

- **Breakthrough technological innovations** which might significantly reduce required energy inputs. If achieved, these might make possible costs significantly below the current and likely future estimated range, illustrated in Exhibit 23.

The Technical Annex describes some of these potential breakthrough technologies, which include Zeolites, carbon nanotubes, porous organic polymers, and carbon molecular sieves. All of them are currently at low technological readiness levels, and decarbonization strategies should not therefore be based on the assumption that they will certainly deliver the promised cost reductions. However, public policy should support early stage research and development: if some do develop as anticipated, they could deliver significant reductions in decarbonisation cost.

There is potential for CO_2 capture costs to decline, but at a slower rate than expected for renewables

CO_2 capture and renewable power cost outlooks

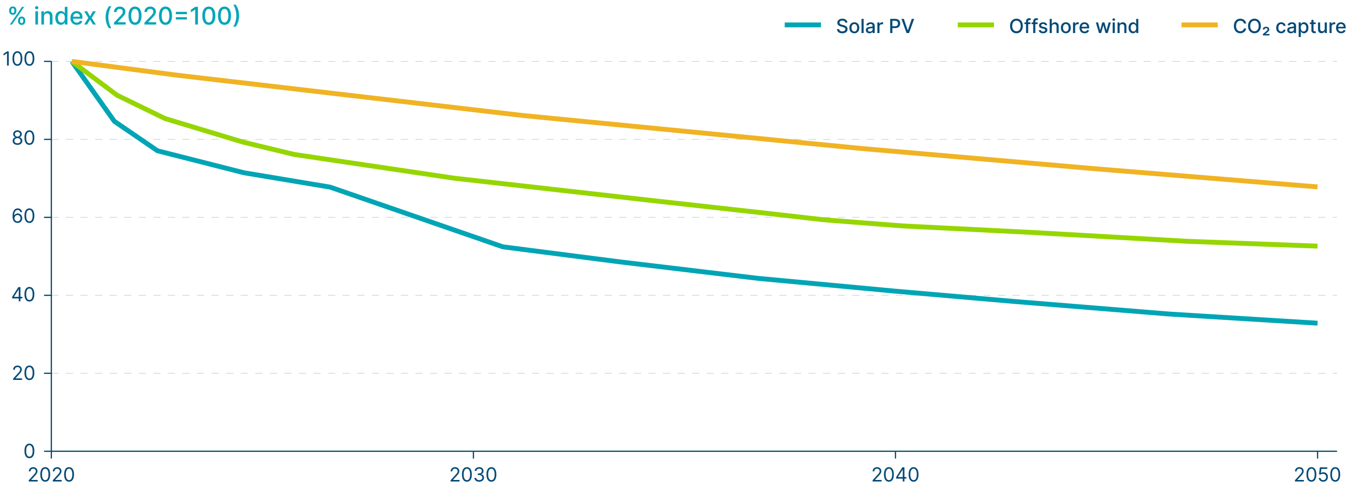


Exhibit 30

NOTES: IEA data refers to learning rates including spill over effects for chemical absorption in coal-fired power generation in the Sustainable Development Scenario. Wind and solar data refers to levelized cost of electricity.

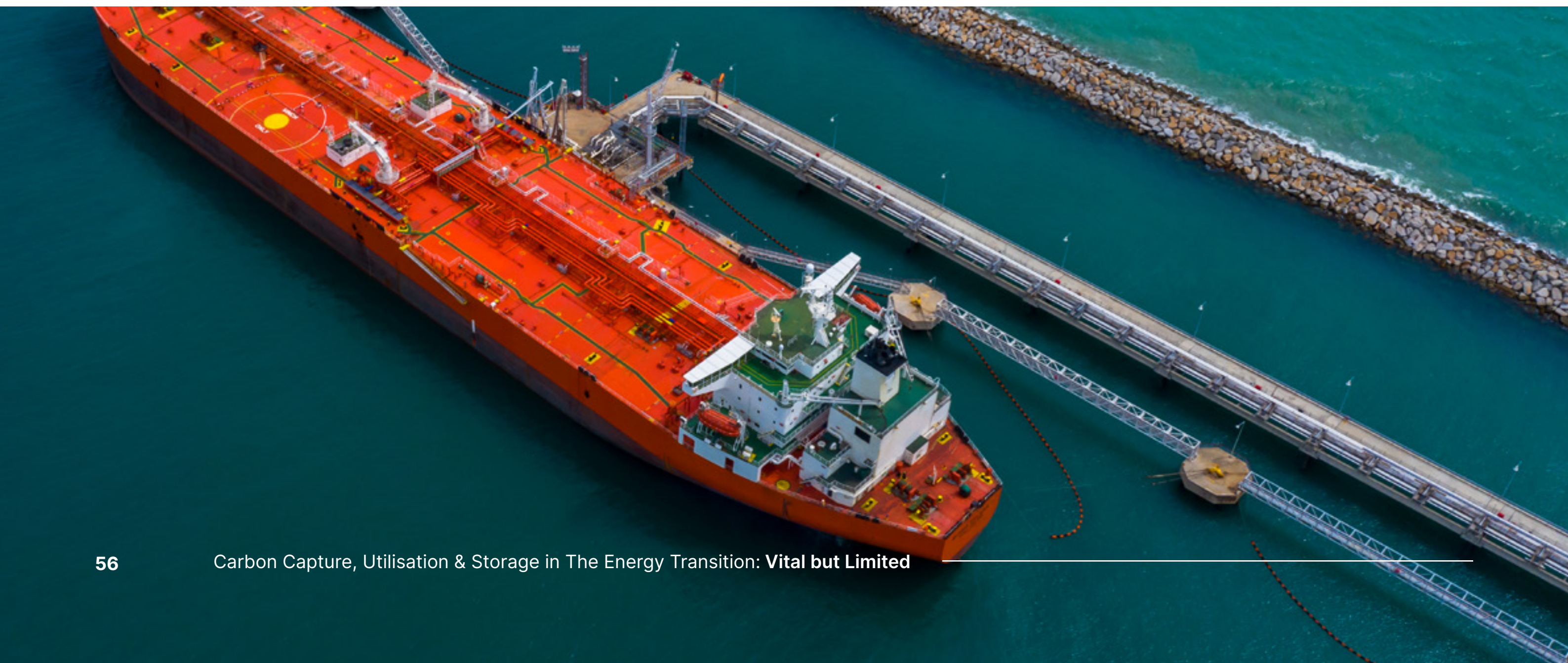
SOURCE: BNEF (2021) *Levelised Cost of Electricity Data Viewer*; IEA (2020) *Energy Technology Perspectives*

2.3 Transport: mature technologies and low costs

Unless CO_2 is captured at, or immediately next to a storage or utilisation site, some form of transportation will be required. There are three principal options for transporting CO_2: pipelines, ships and trucks, of which pipelines are the only mode of transport widely in use for large volumes of CO_2 today. Exhibit 31 details these modes plus rail, which is not widely used today.

Pipeline costs are usually lowest, totalling roughly $6-10 per tonne/km, while trucking is the most expensive option. However, the optimal transport mode varies by distance and volume. This section sets out:

- Key features of the different options.
- Relative costs.
- Risks of leakage.



Pipelines are typically the cheapest means of CO_2 transportation, but other forms of transportation are also low cost

CO_2 transportation options, present day utilisation and optimal scale for 180km and over distance

Transport mode	Today's use	Size	Cost (per tonne/km)
Transmission Pipeline[1]	>8,000 km in operation today, mostly in US	Generally > 1 Mt/year (7 inch or larger)	$6 (Onshore) $10 (Offshore)
Ships	Mostly used in food industry	smaller scale (ca. 1,000 tonnes), future scaling up to 50,000 tonnes	$15
Trucks	Distributed merchant uses (chemical & food industry)	2-30 tonnes/truck	$22
Rail	-/minimal	~30 – 1000 tonnes	$13

Exhibit 31

NOTES: Transport costs are an estimate and indicative as they are likely to vary depending on region, scale, local geology and geographies, labour, monitoring and regulation, and purity prior to transport. [1] Pipeline costs shown refer to trunkline, not distribution.

SOURCE: SYSTEMIQ analysis for ETC (2022); Zero Emissions Platform (2011) *The Costs of CO_2 Transport*; Stolaroff et al. (2021) *Transport cost for carbon removal projects with biomass and CO_2 storage*

2.3.1 Key Features of transport options

The key features which determine ease of application relative to each transport option are listed below for pipelines, shipping and trucking:[127]

Pipelines are a mature technology: an extensive CO_2 pipeline network already exists in North America and the equivalent technology is in use across the world. In the US around 70 $MtCO_2$ are transported via pipeline each year, mainly for the purposes of enhanced oil recovery. International standards concerning materials, safety and leakage rates have been developed, and are in place in some areas today.[128] Transmission pipelines typically require volumes of at least ~2 Mtpa.[129] This tends to imply investment into a pipeline will require either very large producers (e.g. iron and steel or retrofitted large power plants) to justify build, or multiple capture installations feeding into the same pipeline (see Section 3.4.3 for discussion of shared infrastructure and industrial hubs). Distribution pipelines connecting smaller emitters to trunklines (transmission) will be viable at lower volumes.

Retrofitting existing oil and gas pipelines to carry CO_2 is possible and presents an opportunity for reducing transport costs and leveraging what may otherwise become an obsolete asset. However, to date repurposing hydrocarbon pipelines for CO_2 transmission remains relatively uncommon, reflecting the complexities involved in switching to CO_2.[130]

Shipping: transporting CO_2 via ships entails converting the CO_2 into a cryogenic liquid. A CO_2 ship transport system requires a CO_2 liquefaction plant as well as intermediate storage, ship loading and unloading facilities.

Today, most CO_2 transported by ship is used in the food and beverage industries. Shipping capacities typically range between 800 m^3 and 1000 m^3 but are scaling up as focus shifts from utilisation in the food sector to industrial storage quantities: several firms are in the process of developing CO_2 shipping capacity at the time of writing, underpinned by new storage projects which will depend on CO_2 being shipped in from overseas destinations.[131] For example, once in operation, the Northern Lights storage facility in Norway will receive ships loaded with liquefied CO_2, principally from European

127 Additional detail relevant to the options is included in the Technical Annex.
128 International Standards Organisation (2016) *ISO 27913:2016 Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems.*
129 Peletiri et al. (2018) CO_2 Pipeline Design: A Review; BNEF (2020) *CCS Costs and Opportunities for long term CO_2 disposal.*
130 Converting a hydrocarbon pipeline into a CO_2 pipeline requires the addition of a dehydration system to minimise water content, since wet CO_2 increases the risk of corrosion. High-pressure CO_2 pipelines also require crack arrestors as well as modifications to the gaskets and non-ferrous materials of the original pipeline to prevent corrosion. Kenton C. & Stilton B. (2021) *Repurposing Natural Gas Lines: The CO_2 Opportunity.*
131 Danish shipping company, Dan-Utility was placing an order for a 22,000 cubic metre vessel from the American Bureau of Shipping (ABS).

emitters but potentially from across the world.[132] Larger ships benefit from economies of scale as capacity increases from 10,000 tonnes to up to 50,000 tonnes in the future.[133]

Trucks can provide a convenient means for shipping CO_2 over short distances or in situations where the production of CO_2 is intermittent, rendering pipelines unviable. Trucks can also be appropriate in situations where the CO_2 production source is relatively small and remote, making it hard to justify upfront capital requirements for pipelines: trucking is generally cheaper for volumes of less than 1.7 Mtpa.[134] Alternatively, in such a scenario, on-site utilisation options might also be cost competitive.

2.3.2 Costs

The most cost-efficient mode of transport will depend upon distances involved and quantities of CO_2 being transported. In general, pipelines tend to be the cheapest option if transporting large volumes over short distances whereas ships are more competitive over long distances and with smaller volumes. Exhibit 32 shows that when volumes exceed approximately 2 Mtpa, pipelines are the lowest cost mode. This is true of both offshore (where pipelines compete with ships) and onshore (where pipelines compete with trucks).

Over long distances ships regain competitiveness as the upfront capital requirement for pipelines becomes too great. The IEA estimates shipping becomes competitive with pipelines when distances exceed ~800 km (Exhibit 33), roughly equivalent to the distance between the UK and Norway. However abundant geological storage in most regions of the world (see next section) suggests that in most cases CO_2 will need to be transported less than 400 km between most capture and storage sites, suggesting pipelines will be the most common mode of transport.

Ships may also be least cost where supply of CO_2 is intermittent, since pipelines require a continuous flow of compressed gas.[135] Equally, ships can play a central role in the development of import hubs, lowering overall costs (see section 3.4.3).

Pipelines become more competitive when transporting large volumes of CO_2

Offshore CO_2 shipping & pipeline costs by volume

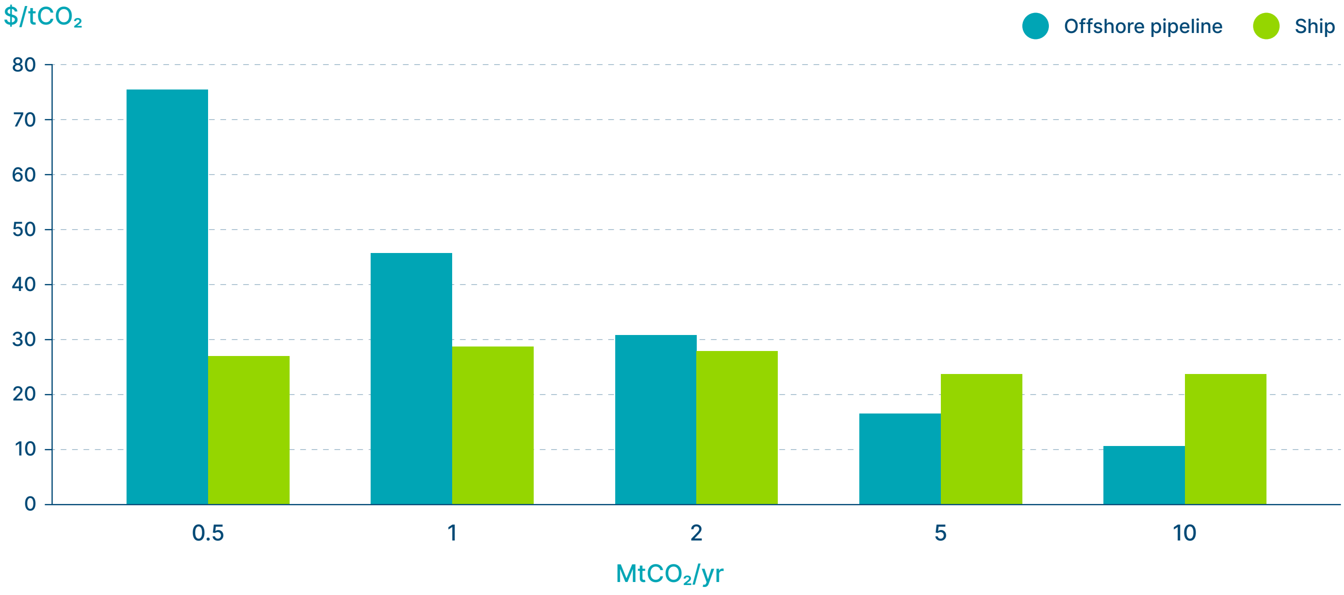


Exhibit 32

NOTE: Assumes distance of 1000km.

SOURCE: IEA (2020) *CCUS in clean energy transitions*

132 Schuler (2021) *Dedicated CO_2 Carriers Ordered for Norway's Northern Lights Carbon Capture and Storage Project.*
133 IEAGHG (2004) *Ship Transport of CO_2.*
134 BNEF (2021) *CCUS Costs and Opportunities for Long Term CO_2 Disposal.*
135 Al Baroudi et al. (2021) A review of large-scale CO_2 shipping and marine emissions management for carbon capture, utilisation and storage.

Shipping is cheaper than pipelines over long distances

Cost of CO_2 shipping vs. offshore pipeline

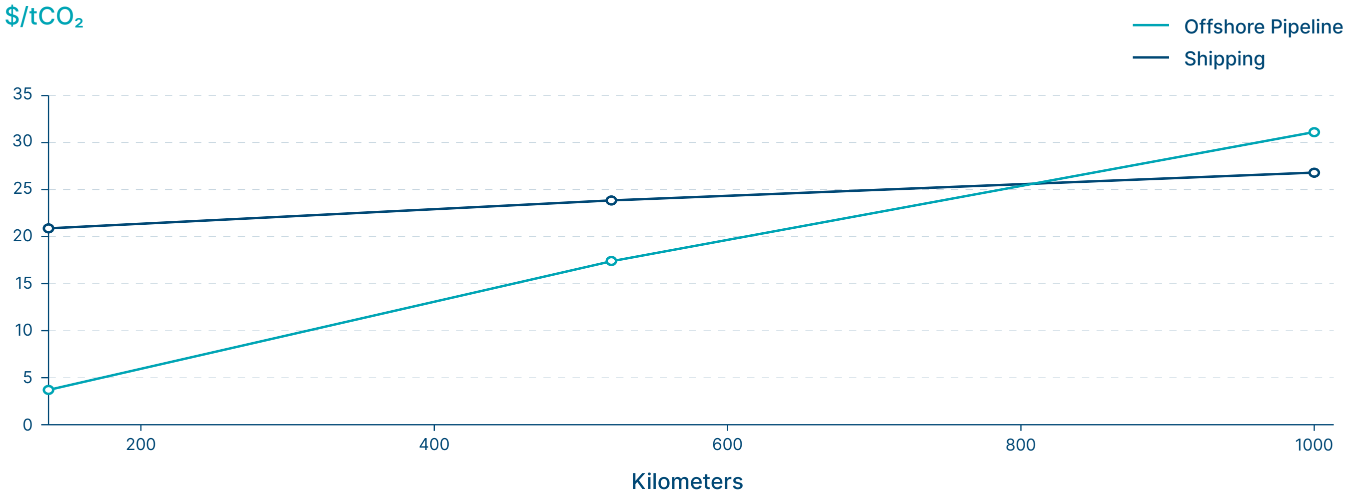


Exhibit 33

NOTES: Assumes a capacity of 2 $MtCO_2$/year.

SOURCE: IEAGHG (2020) *The Status and challenges of CO_2 Shipping Infrastructure*

Specific geographical constraints will also play a key role in determining which mode of transport is appropriate:

- Pipelines located in remote and sparsely populated regions cost about 50-80% less than in highly populated areas; offshore pipelines can be 40-70% more expensive than onshore pipelines.[136]
- Economies of scale in pipelines and shipping present opportunities to develop shared infrastructure and business models linked to hubs or clusters of CO_2 sources in particular regions (see Section 3.4).

2.3.3 Losses and risks of leakage

When CO_2 is carried by pipeline, losses are expected to be minimal due to monitoring systems that measure pressure losses.[137] Shipping and trucks can present more systemic leakage risks owing to the greater number of steps in the transportation chain, although effective design can mitigate this risk to some extent.[138]

As for accidental leaks, each of the possible modes entails its own specific risks: pipelines can leak or be deliberately damaged, ships can collide with other ships or port facilities, and trucks can be involved in road accidents. Given that CO_2 is not flammable, the risk of serious local damage is small, but leakage in confined environments could create health risks in some specific circumstances.[139] However, the risk of accidental leaks on a scale material to climate change is trivial.

Historically shipping has incurred direct CO_2 emissions through boil off (unintentional evaporation) from ships and onshore storage, and indirectly via CO_2 liquefaction (electricity) and ship engines (fuel oil). Whilst indirect emissions can be addressed via clean electrification and alternative shipping fuels such as ammonia or e-methanol, boil off presents an intrinsic challenge.[140] A ship travelling 12,000 km in the past could be expected to lose ~6% of its total CO_2 cargo through boil off (although this figure falls to less than 0.5% for distances below 750 km, which applies to most journeys in the

136 Onyebuchi, V. E. et al. (2018) *A systematic review of key challenges of CO_2 transport via pipelines.*
137 GCCSI (2014) *What Happens When CO_2 is Stored Underground?*
138 Brevik Engineering (2020) *CO_2 Logistic of Shipping; Wong S. (2005) Building Capacity for CO_2 Capture and Storage in the APEC Region.*
139 In February 2020 a pipeline carrying super-critical CO_2 in Mississippi, USA ruptured following localised flooding. The vapor cloud that escaped prompted the evacuation of 200 people; 45 people were taken to hospital. See US Department of Transportation (2022) *Failure Investigation Report – Denbury Gulf Coast Pipelines LLC Pipeline Rupture/Natural Force Damage.*
140 During loading, transport and unloading of CO_2 vapour is released in variable amounts. In particular during loading and unloading gas generation is enhanced. Also the sloshing of liquid CO_2 in the vessels and the penetration of ambient heat may lead to an increase in gas generation: Reyes-Lua et al. (2021) *CO_2 ship transport: Benefits for early movers and aspects to consider.*

North Sea).[141] Boil off rates today tend to be lower among modern ships and performance in this regard is likely to improve with the commissioning of new vessels expressly designed to transport CO_2. Measures to prevent boil off include robust insulation systems and ventilation arrangements which trap boil-off gases inside the containment system. These measures can potentially limit boil off to zero for short journeys (excluding safety critical situations which necessitate venting). For longer voyages re-liquefaction using zero-carbon fuels has been mooted as a means to limit boil off, although this will incur additional costs.[142]

2.4 Storage: Widely available and low risk when properly regulated

Under the right conditions and if well-regulated, CO_2 can be safely stored in geological formations with minimal risks of significant accidental CO_2 release. Geological assessments indicate that there is plentiful storage capacity to absorb the quantities of CO_2 capture envisioned in our scenarios. Storage costs, at around $10–20 per tonne, are usually significantly lower than capture costs.

This section sets out the details supporting these conclusions covering in turn the technologies involved, our assessment of leakage risk, capacities available and costs.

2.4.1 Injection and storage technologies

CO_2 can be stored underground in depleted oil/gas fields, saline aquifers, basalt formations or organic shale formations. Although depleted fossil fields tend to be preferred for projects today since their formations are already well understood, saline aquifers are expected to account for the majority of future storage capacity owing to wider geographical distribution and larger theoretical storage resources.[143]

The process of pumping CO_2 underground for permanent storage requires several steps, as shown in Exhibit 34.

- **Compression.** Before it can be injected underground, CO_2 is first compressed under high pressure (meaning more CO_2 can be contained in a smaller space).

- **Injection.** Once compressed, the CO_2 is injected underground to a minimum depth of ~800m into porous geological formations, where the pressure is even higher.[144] Density continues to increase until a depth of around 1,500m at which point CO_2 occupies around 3% of its volume above ground. Beyond this depth, density does not increase much more, hence most storage will be between 800–1500m deep.[145]

- **Containment.** At depths of over 800m, geological layers will act as natural barriers to the re-release of CO_2 from storage sites.

- **Trapping.** Over time, the injected CO_2 will dissipate into the storage formation, being dissolved in brine or physically adsorbed into rock pores and potentially mineralised (see further information below).

- **Plugging.** Once CO_2 has been pumped underground and the well has reached its limit, a cement plug is used to seal the injection well permanently.

141 IEAGHG (2004) *Ship Transport of CO_2*.
142 Lee et al. (2017) Design of boil-off CO_2 re-liquefaction processes for a large-scale liquid CO_2 transport ship.
143 Global CCS Institute (2018) *Geological storage of CO_2*.
144 At ~800m the pressure is sufficient that CO_2 takes on a "super-critical fluid" state in which it is dense like a liquid but has viscosity similar to gas.
145 In addition to depth, one or more quality seals (barriers to vertical migration), the absence of transmissive faults, and an understanding of existing well penetrations also determine the risk of loss of containment.

The process of storing CO_2 is broken into injection, containment, trapping and plugging

The process of storing CO_2 in onshore and offshore aquifers

1. **Injecting**
Compressed CO_2 pumped underground via well

2. **Containment**
CO_2 impermeable cap rock layer on top of the resevoir or aquifier prevents diffusion to the ground

3. **Trapping**
CO_2 moves within store and becomes trapped by dissolving in brine or being physically absorbed in small rock pores

4. **Plugging**
At the end of operation, a cement plug is used to seal the injection well permanently

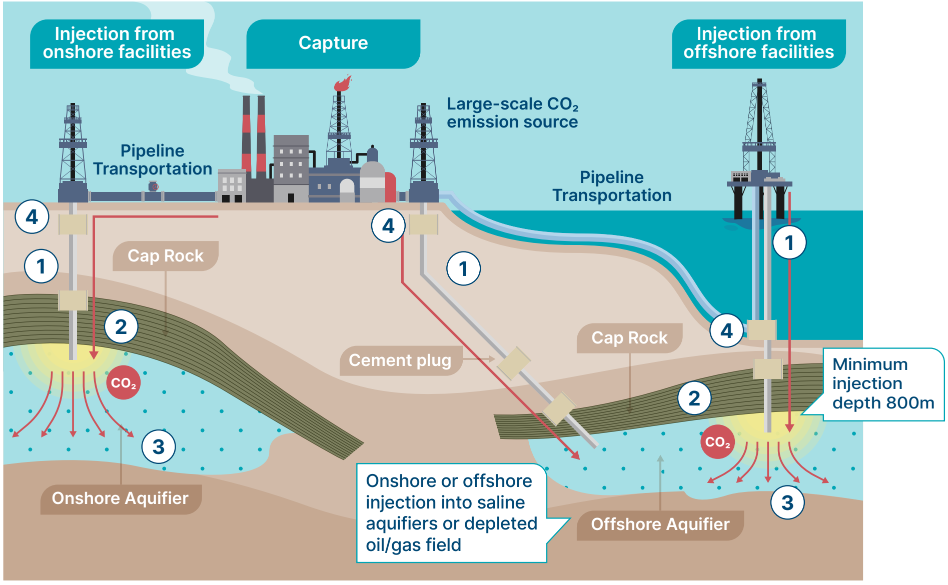


Exhibit 34

SOURCE: : Figure adapted from Think Geoenergy (2010) *Overview of the Geological Sequestration System*

Once injected the CO_2 can remain trapped underground by virtue of a number of naturally occurring mechanisms:

- **Structural Trapping (also known as 'secondary trapping'):** CO_2 is contained through a cap rock which is non-permeable to CO_2 and sits above the saline aquifer. Injected CO_2 is marginally more buoyant than the saline already in the rock formation, so some of the CO_2 will migrate to the top of the formation and become structurally trapped beneath the cap rock, which acts as a seal.[146]

- **Residual Trapping:** CO_2 becomes trapped in the pores as isolated bubbles of CO_2 and remain in-situ as a super-critical fluid.

- **Dissolution Trapping:** CO_2 dissolves into the saline solution in which it is held (in saline formations).

- **Mineral Trapping:** CO_2 reacts with the reservoir rocks to form a new mineral – a process referred to as "mineral trapping" which effectively locks the CO_2 in-situ permanently, as a solid mineral.

These trapping mechanisms act on different timescales as shown in Exhibit 35. The structural trapping will be active at the early stages for around a hundred years while the mineral and dissolution trappings will take place very slowly, over several thousand years.[147]

146 IPCC (2018) *Special Report on Carbon Dioxide Capture and Storage.*
147 Igualer S. (2018) *Optimum storage depths for structural CO_2 trapping.*

Over time, the physical process of residual trapping and geochemical processes of solubility and mineral trapping increase storage security

Storage security over time

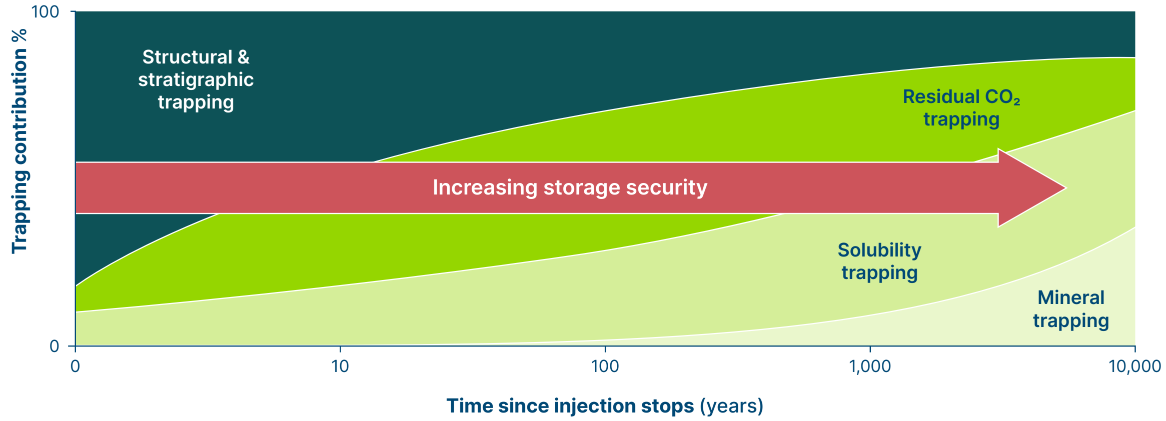


Exhibit 35

SOURCE: IPCC (2005) *Special Report on Carbon Capture and Storage*

2.4.2 Risk of Leakage

Theoretically there is a risk that CO_2 injected underground may leak out of the reservoir through naturally occurring pathways (such as faults) or via manmade pathways (such as faulty wells). Such leakage could interfere with other subsurface activity (e.g., natural gas storage, deep-well injection of wastes) or cause groundwater contamination; or it could reach the land surface and escape into the atmosphere.

In practice however evidence from existing natural and man-made storage sites, along with academic research and technical feasibility studies suggests these risks are already low and can be reduced to an acceptable level via careful management and strong regulation:

- **Natural pathways:** Whilst it is technically possible for CO_2 to escape into the atmosphere via natural pathways evidence from a variety of sources suggests this is unlikely:
  - Numerous studies have shown that the volumes likely to reach the surface are negligible.[148] This reflects the effects of intervening sedimentary layers: CO_2 is intercepted by overlying geologic strata, as detailed above. Thus, any CO_2 which escapes the reservoir still typically remains underground.[149]
  - Natural subterranean stores of CO_2 have remained trapped for thousands of years demonstrating that very long-term storage exists.[150] Where leakage from these stores has occurred it has been at exceptionally low levels (less than 0.01% per year).[151]
  - Evidence that hydrocarbons and other gases and fluids including CO_2 have remained trapped underground for millions of years, with minimal leakage to surface level, implies that CO_2 can also remain in-situ when injected into similar geological formations.[152]
- **Faulty Wells.** The risk of CO_2 escaping via faulty well design is more acute but can be mitigated via strong regulation.
  - Exhibit 36 shows the modelled cumulative leakage of CO_2 as a percentage of the total volume injected for an offshore

148 Celia MA. et al. (2015) *Status of CO_2 storage in deep saline aquifers with emphasis on modelling approaches and practical simulations*; Bielicki et al. (2015) *An examination of geologic carbon sequestration policies in the context of leakage potential.*
149 Bielicki et al. (2016) *The leakage risk monetization model for geologic CO_2 storage.*
150 N. Kampman et al. (2016) *Observational evidence confirms modelling of the long-term integrity of CO_2 reservoir caprocks.*
151 Miocic et al. (2019) 420,000 year assessment of fault leakage rates shows geological carbon storage is secure.
152 Bradshaw et al. (2005) *Storage retention time of CO_2 in sedimentary basins: Examples from petroleum systems*; Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (2004); Magoon, L.B. and Dow, W.G. (1994) *The Petroleum System.*

Effective regulation is crucial to ensuring low CO_2 leakage rates

Potential CO_2 leakage by form and quality of storage

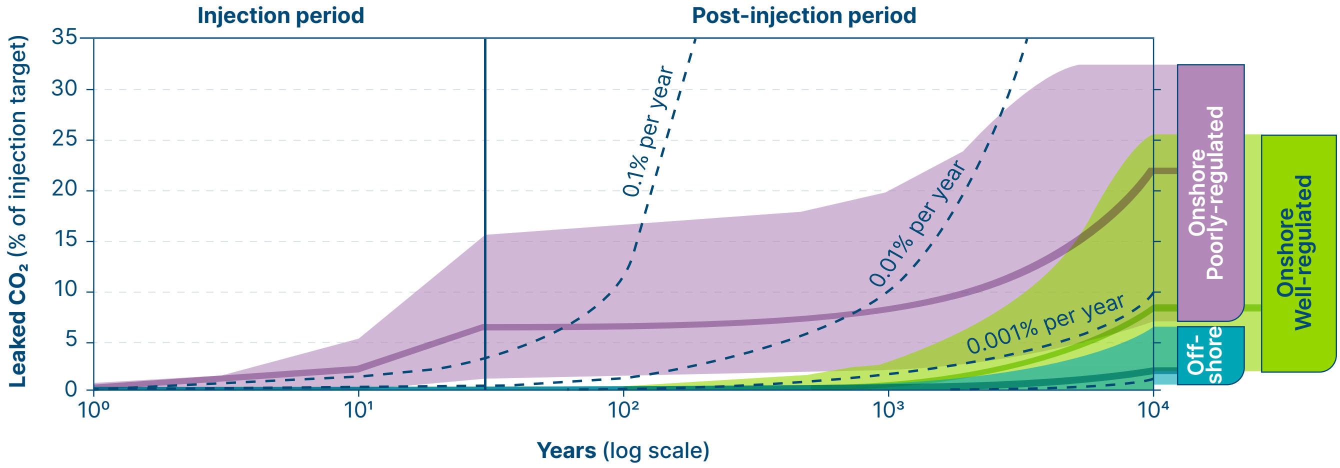


Exhibit 36

SOURCE: Alcalde et al., (2018) *Estimating geological CO_2 storage security to deliver on climate mitigation*

well and an onshore well. The onshore well's performance is also modelled under good and bad regulation.[153] The analysis suggests the risks of CO_2 leakage are minimal, and if best practice regulations are in place around 98% of the injected CO_2 is likely to remain trapped over 10,000 years.[154] It also suggests that offshore storage may be more reliable, owing to the low number of wells for CO_2 to escape through.

- One pathway which has been identified as a potential risk is degradation of cement plugs. There is some evidence to suggest that cement can be partially dissolved through exposure to CO_2 when mixed with water, leading to risk of CO_2 escaping back up the well.[155] Solutions proposed to improve the physical and mechanical properties of the cement against CO_2 degradation include changing the water-to-cement ratio, employing pozzolanic materials, the use of nano-materials and considering non-Portland cements.[156] Cement plugs which do degrade can be replaced and will need to be inspected and replaced where necessary, during the field's operational lifetime.

- **Natural disasters.** There are concerns that CO_2 storage could cause seismic activity and/or that seismic activity could cause leaks, but available evidence suggests that these risks are minimal.

  - **Induced seismic activity:** Previous research suggested that carbon storage in deep saline formations could potentially trigger large seismic activity, which may damage the caprock and allow CO_2 release.[157] This understandably raised significant concerns and led to additional investigation. Subsequent research has argued that earthquakes due to geologic CO_2 storage are unlikely because (i) sedimentary formations, which are softer than the crystalline basement, are rarely critically stressed; (ii) the least stable situation occurs at the beginning of injection, which makes it easy to control; (iii) CO_2 dissolution into brine may help in reducing overpressure; and (iv) CO_2 will not flow across the caprock because of capillarity, but brine will, which will reduce overpressure further.[158]

  - **Earthquake damage**: There is also the possibility that a naturally occurring earthquake may strike at a location sufficiently proximate to a storage facility to cause damage and induce leakage. However, experience to date suggests this is a not major danger. In 2018, an earthquake with a moment magnitude of 6.6 took place 37 km from a Japanese offshore CO_2 storage location, with research showing that the earthquake was not caused by the CO_2 injection and that no leakage of CO_2 occurred.[159] The implication is that an earthquake would need to strike the storage site itself to produce large scale CO_2 release, with the probability of a direct strike being relatively low.

153 Alcalde et al. (2018) *Estimating geological CO_2 storage security to deliver on climate mitigation.*
154 Ibid.
155 Gouedard (2006) *Mitigation strategies for the risk of CO_2 migration through wellbores.*
156 Tiong (2019) *Cement degradation in CO_2 storage sites: a review on potential applications of nanomaterials.*
157 Zoback et al. (2012) *Earthquake triggering and large-scale geologic storage of carbon dioxide.*
158 Villarosa V. & Carrera J. (2015) *Geologic carbon storage is unlikely to trigger large earthquakes and reactivate faults through which CO_2 could leak*; METI & NEDO & JCCS (2020) *Report of Tomakomai CCS Demonstration Project at 300 thousand tonnes cumulative injection.*
159 Sawada et al. (2021) *Overall Review of Tomakomai CCS Demonstration Project ~Target of 300,000 tonnes CO_2 injection achieved.*

Although the risk of leakage is small, it is not zero. Effective management and strong regulation will be vital to ensuring good project design, accurate monitoring and effective maintenance.

- **Oil and gas firms can offer effective management**. These firms have extensive experience in pumping CO_2 underground in order to enhance oil and gas production. Equally the industry has extensive experience in disposing of other liquid and waste products arising from oil and gas production, such as acid gas or oil field brines, by pumping them underground. This experience in drilling, pumping, simulation of geological behaviours and well management means the expertise required to inject and store CO_2 underground is widely available.

- **Strong regulation will however be essential to ensure best practice**. Fossil fuel companies have naturally arising incentives to maximise oil and gas extraction, but CO_2 leaks are an externality which will only be minimised if strong regulation is enforced. Furthermore, well publicised accidents have and do occur when managing oil and gas extraction. Strong safety and regulatory regimes will need to be put in place to ensure the risk of these accidents is limited, with parties held accountable, when managing large volumes of CO_2.

2.4.3 Storage capacities available

Global theoretical geological storage volumes are vast and exist in nearly all regions. Potential storage volumes have been estimated at exceeding 10,000 $GtCO_2$ which would be enough to store today's total annual CO_2 emissions (ca. 40 $GtCO_2$) each year for more than 250 years.[160] A typical site today only injects 0.5–5 $MtCO_2$/year but larger scale sites of 10–50 $MtCO_2$/year may become feasible in the future.[161] Of total theoretical volumes, around 85% are in saline aquifers, with 12% in depleted gas fields and 3% in depleted oil fields.[162]

Although storage is available in most geographies (Exhibit 37) estimates are not always comprehensive, and some questions remain around the storage potential of certain locations such as India, Japan and South Korea where further research may be required to establish more reliable estimates (Exhibit 38). In those locations where local storage is not possible, other CO_2 transportation options such as shipping may be viable, which can have low costs even over long distances (see section 2.3).

Depleted oil and gas fields are typically the lowest cost storage options since they are already easily accessible. Furthermore, data collected during oil and gas exploration and recovery phase reduces the need for basin appraisal. In contrast, most of the deep saline aquifers being considered for storage are 'virgin' formations and structures in which little or no geological characterisation has taken place.[163]

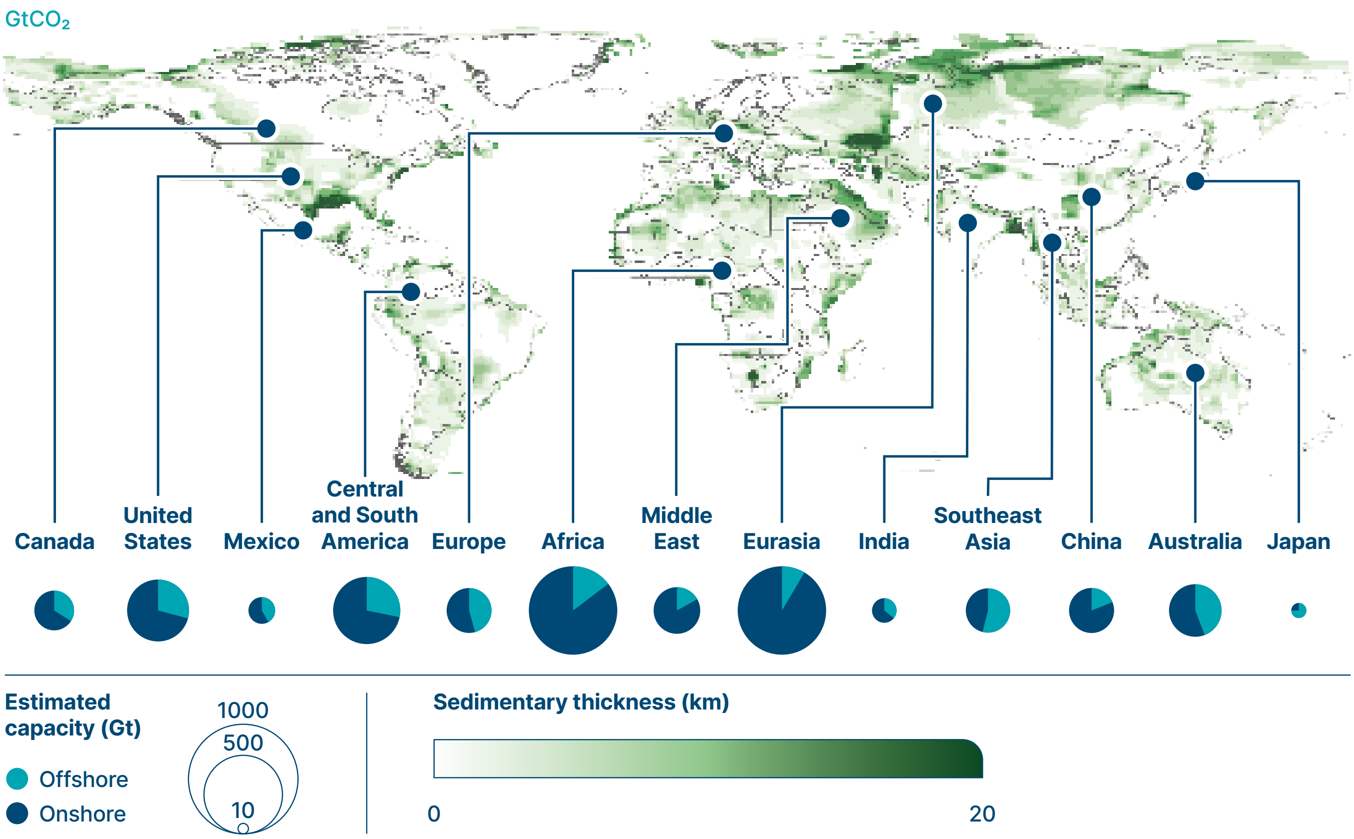
Therefore, considerable exploratory work will be required before such structures can be considered as "fit for purpose" for CO_2 storage. Though theoretical storage is high, commercial developments have to date been limited and only 0.25 $GtCO_2$ of storage is estimated to be 'injection-ready' today.[164]

Given the time required to characterise most geological storage sites, this represents a critical bottleneck and a potential area where targeted government support (in the form of direct finance or tax breaks for example) can have a meaningful impact. Work should begin in this regard as soon as possible, given that saline aquifers account for the vast majority of CO_2 storage potential but are typically least well understood (see Box 5: Characterising geological storage sites – a critical bottleneck in delivering CCS and engineered CDR at scale).

160 Pale Blue Dot (2021) *CO_2 Storage Resource Catalogue – Cycle 2*; IEA (2020) *CCUS in the energy transition.*
161 Ibid.
162 GEOExPro (2018) *Growth and Future of Carbon Capture & Storage (CCS) in Europe.*
163 Global CCS Institute (2008) *Aquifer storage: development issues.* Site characterisation and assessment is required when permits are requested from the legal authorities in the process of starting a CO_2 storage process at a given site. The goal is to assess whether a proposed CO_2 storage site can indeed be used for permanent storage while meeting the safety requirement. Typical characterisation process includes steps such as data collection and analysis on geology and geophysics, hydrology, reservoir engineering, seismicity, presence of man made and natural pathways to the surface; modelling of the geological structure and trap, and of the flow properties of the reservoir; assessment of possible injection rates, reactive processes. Nepveu et al (2015) *CO_2 Storage Feasibility: A Workflow for Site Characterisation*
164 Global CCS Institute (2022) *Global Status of CCS in 2021.*

Regions with high volumes of sedimentary basin are correlated to higher CO_2 storage potential

Theoretical CO_2 Storage Capacity



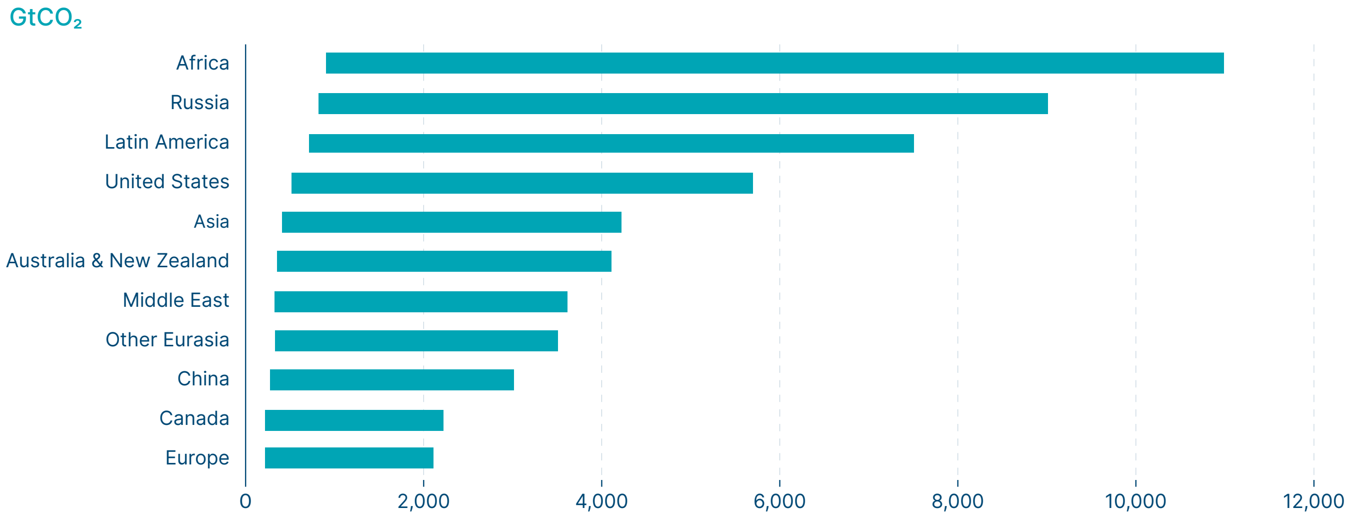
NOTES: Map shows onshore basins and practically accessible offshore basins. Regions with high volumes of sedimentary basin are correlated to higher CO_2 storage capacities. The offshore capacity estimates exclude sites in water depths of more than 300 metres and more than 300 kilometres offshore. The Arctic and Antarctic regions are also excluded.

SOURCE: IEA (2020), *Energy Technology Perspectives 2020: Special report on Carbon Capture Utilisation and storage*; adapted from Kearns, J.et al., (2017) *Developing a Consistent Database for Regional Geologic CO_2 Storage Capacity Worldwide*

Exhibit 37

Estimated storage capacity exceeds 25,000 $GtCO_2$

Range of estimated practical onshore and offshore geological storage capacity



SOURCE: Kearns et al. (2017) *Developing a Consistent Database for Regional Geologic CO_2 Storage Capacity Worldwide*; OGCI (2021) *CO_2 storage catalogue*

Exhibit 38

Characterising geological storage sites – a critical bottleneck in delivering CCS and engineered CDR at scale

Recognising the benefits of collaboration and coordination in the field, widespread efforts are already well underway to foster growth in storage resource development. Over 13,000 potential storage sites have now been listed in the CO_2 Storage Resource Catalogue, compiled by the Oil and Gas Climate Initiative and Pale Blue Dot.[165] However, characterising geological storage can take years and involves many different stages. Progress along this path builds confidence amongst potential customers in the future performance of the reservoir, provides better estimates of the storage volumes and injectivity, and confidence of the integrity of the site and lack of leakage pathways: this confidence is critical to investing in new capture and transport capacity. Equally ambiguity on these issues can undermine confidence, potentially presenting a bottleneck to other CCS assets' development.

It is therefore helpful for parties considering investment into CCS assets (which are contingent upon storage capacity being commercially available) to have a consistent terminology for describing how far along a storage site is in terms of characterisation and regulatory approval. To this end, a team led by the British Geological Survey has developed a scale to measure CO_2 storage assets' progress towards commercial viability.[166] The Storage Readiness Levels (SRL) is modelled on NASA's Technology Readiness Level scale but instead of technological maturity, the STL presents a standardised approach to comparing a CO_2 storage site's appraisal and outstanding requirements before commercial operations can commence (Exhibit 39).

The Storage Readiness Level index shows progress in developing new storage capacity

Storage Readiness Levels (SRL) framework, stages and thresholds in the storage site permitting process and storage project technical appraisal and planning

SRL	Description	Stages & thresholds in the storage site permitting process	Stages & thresholds in the technical appraisal & project planning
1	First pass assessment of storage capacity at country wide or basin scale	Gathering information for an exploration permit if required	Technical Appraisal
2	Site identified as theoretical capacity		
3	Screen study to identify individual storage site and project concept		
4	Storage site validated by desktop studies and project concept updated	Exploration Permit	
5	Storage site validated by detailed analyses then in a relevant "real world" setting	Planning for a storage permit	Well Confirmation
6	Storage site integrated into a feasible CCS project or in a portfolio of sites		Project planning & permitting iterations All planning completed
7	Storage site is permit ready or permitted	Storage Permit	Construction & Testing
8	Commissioning of the storage site and test injection in operational environment	Injection permit application	Site construction completed
9	Storage site injection commercially operating	Injection Permit	Operation & monitoring

SOURCES: Akhurst et al (2021) *Communicating site technical, permitting and planning readiness for CO_2 storage operations using the ALIGN-CCUS framework of Storage Readiness Levels*

Box 5

Exhibit 39

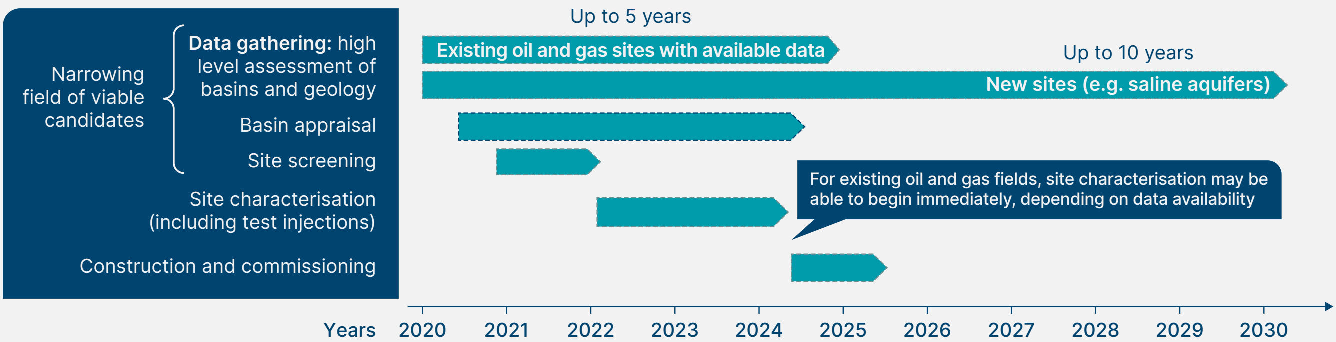
165 Global CCS Institute (2022) *Global Status of CCS in 2021.*
166 Akhurst et al. (2021) *Storage Readiness Levels: communicating the maturity of site technical understanding, permitting and planning needed for storage operations using CO_2.*

Stages 1 – 4 entail early assessment first at a country then basin then asset level. At these stages, the process is limited principally to information gathering and appraisal. Between stages 5 – 6, data gathering gives way to planning and engineering design. The developer will also be seeking a storage permit at this stage. Finally, at stages 7 – 9, the storage infrastructure is installed, test injections take place and the asset is commissioned. TRL 9 is achieved when the asset enters commercial operation.

Geological characterisation will become more important as depleted oil and gas wells are used up and saline aquifers (about which much less is known) account for a greater share of new developments. Exhibit 40 illustrates the typical lead times involved in developing a new storage asset.

Long lead times in storage infrastructure may present a bottleneck in wider CCS development

Illustrative CO_2 storage Project Timeframe



SOURCE: SYSTEMIQ analysis for the ETC (2022)

Box 5

Exhibit 40

2.4.4 Costs

The costs of developing an individual large scale storage site are likely to be in the range of $200 million for a ~5 Mt/annum site, with additional ongoing costs of $10 million per year. However, spread over the volume of storage in this site this would equate to just $10/tCO$_2$.[167]

Per-unit storage costs vary according to the precise geology of the storage site, the annual volume of CO_2 being stored and the site location, including whether it is on- or offshore.

- **Costs for volumes over 1 Mt/year are estimated to be around $10-20/tCO$_2$**, however costs reduce substantially with economies of scale, and costs to store smaller volumes are likely to be higher.[168]

- **Costs for onshore storage will typically be lower than for offshore**: The IEA estimates that in the United States, more than half of onshore storage capacity could be available below $10 per tonne of CO_2, with higher costs for offshore.[169] However, offshore storage projects may face less opposition, making possible faster implementation

- **Costs of storage can be negative today, when CO_2 is used for Enhanced Oil Recovery.** The negative section of the onshore cost curve shown in Exhibit 41 reflects the fact that EOR field operators are often willing to pay for CO_2 in order to boost final oil recovery. Whether and under what conditions EOR should play a role in future is considered in Section 2.6.

In most cases, therefore, carbon storage costs are likely to be significantly less than capture cost. But the cost of developing storage sites and the pace at which they can be developed will be an important factor in determining how quickly CCS can be scaled in some regions. This may be especially true in locations where there has been no previous CO_2 storage, or recent oil and gas extraction.[170]

Typical underground storage costs in the United States are around $10/tCO$_2$

Indicative CO_2 storage cost curve for the United States (onshore and offshore)

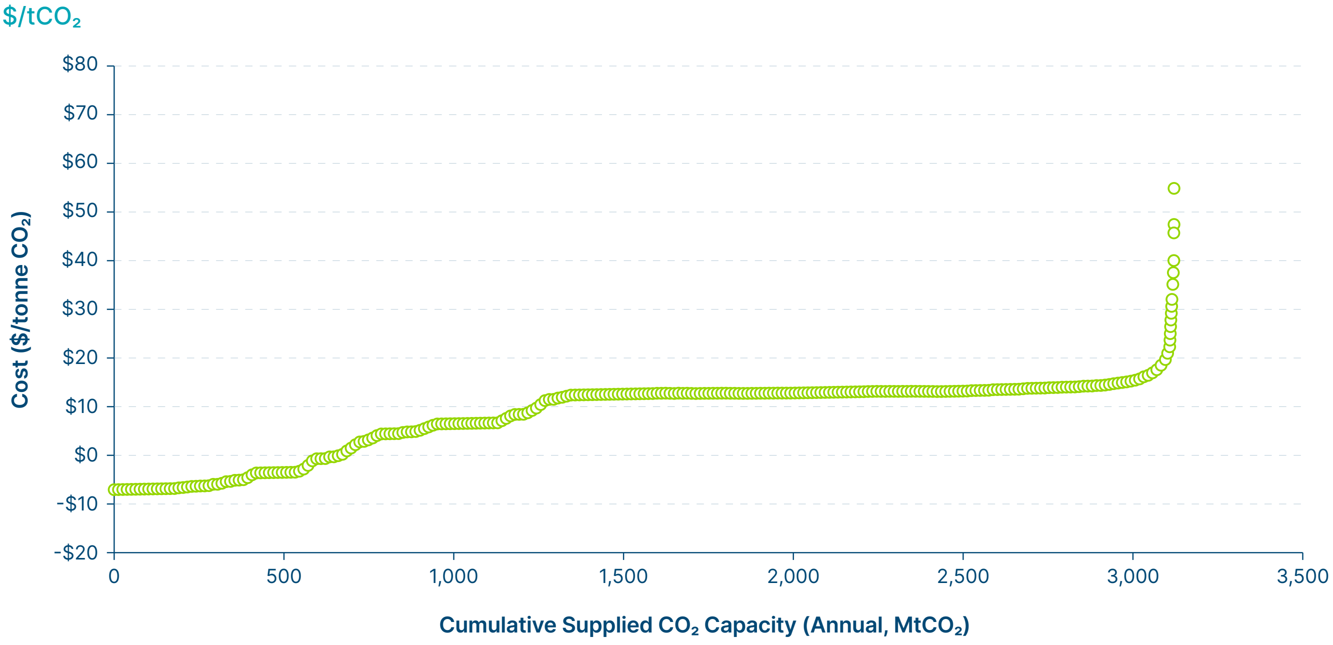


Exhibit 41

SOURCE: IEA GHG R&D Programme (2005) *Building the cost curve for CO_2 storage: North American sector*

167 SYSTEMIQ calculations for the ETC, based on Global CCS Institute (2021) *CO_2 Storage Costs*.
168 IEA (2020) *Energy Technology Perspectives 2020: Special report on Carbon Capture Utilisation and storage*.
169 Ibid.
170 Ibid.

2.5 The role of carbon utilisation

Utilisation refers to all applications in which CO_2 is not stored in a dedicated geological storage site but embedded in a product. This might be more economic than storage if:

- The use of captured CO_2 in a product substitutes for fossil fuel inputs, with product producers therefore willing to pay for the CO_2 input.
- The use of CO_2 improves the product and increases the price that can be charged.
- Embedding CO_2 in the product costs less than storing it in a geological formation.

This section first describes existing CO_2 uses and then covers in turn:

- The impact of CO_2 utilisation on total atmospheric concentrations – short versus long-term uses.
- The maximum potential scale of CO_2 utilisation.
- Cost competitiveness of utilisation versus CO_2 storage.

Boxes at the end of this section provide more detailed information on two key potential applications – mineralisation of CO_2 in construction aggregates and conversion into synthetic aviation fuel. Section 2.6 then considers the special and controversial case of Enhanced Oil Recovery, and Section 2.7 presents a possible scenario for the balance between CO_2 storage and utilisation in 2050.

2.5.1 Existing uses of CO_2

Although CO_2 is principally thought of as a pollutant, it is also a traded commodity, with a global market value of around $8 billion in 2021.[171] Around 200 $MtCO_2$ are sold every year, mostly into captive markets: the CO_2 is piped from source to a single buyer, as a private transaction, where prices in these trades are rarely disclosed. The remaining ~15% is traded on a merchant basis (i.e., on an open market at a publicly available price) typically in the range of $1.5–4.5 per $kgCO_2$.[172]

Exhibit 42 shows the sources of CO_2 demand today. Captive demand is dominated by urea production (which is in turn underpinned by demand for fertilizer) and Enhanced Oil Recovery (EOR). The two largest categories of CO_2 sold on a merchant basis are used in the food processing and carbonated beverage industries.

Urea production and enhanced oil recovery account for over 85% of worldwide CO_2 demand today

CO_2 demand by market and application 2020

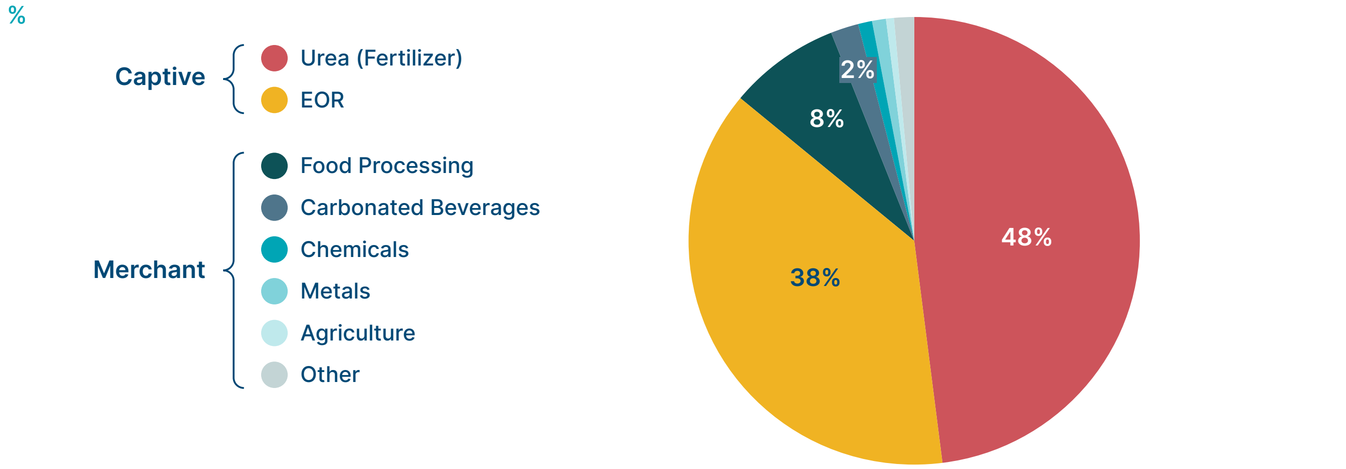


Exhibit 42

SOURCE: HSBC Global Research (2021) *Carbon Capture & Sequestration: back in the debate but no silver bullet*

171 Grand View Research (2021) *Carbon Dioxide Market Report.*
172 Soliman T. (2021) *Carbon Capture & Sequestration: back in the debate but no silver bullet.*

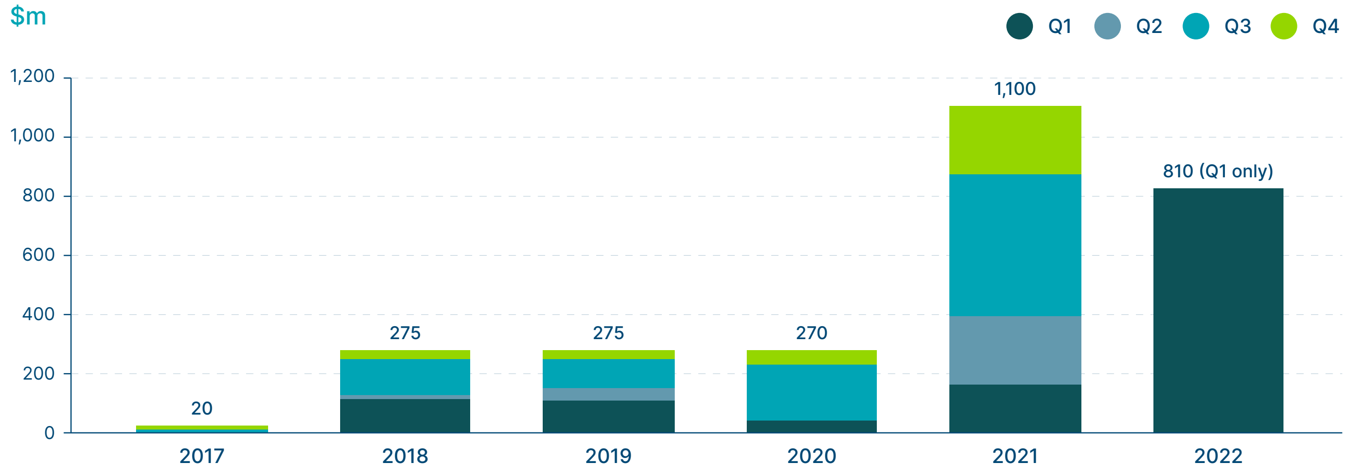
2.5.2 New uses of CO_2 – short and long term sequestration

As the need to use carbon capture to reduce emissions has become clear, interest in CO_2 utilisation has grown. Investment into carbon utilisation technology firms jumped to over $1.1bn in 2021 and exceeded $0.8bn in Q1 of 2022 alone, having stood at ~$275m for the previous 3 years (Exhibit 43).[173]

Exhibit 43

CCU investments increased sharply in 2021 and have grown even faster in 2022 to date

CCU venture capital and corporate investment



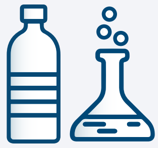
SOURCE: i3 Connect (2022)

173 Cleantech Group via i3 Connect (https://i3connect.com/tags/carbon-capture-utilisation-and-storage-ccus/757/activity) accessed July/2022.

Most forms of novel CO_2 utilisation can be categorised under one of the following headings:

Fuel: the utilisation of CO_2 to produce synthetic fuels such as methane or kerosene for use in internal combustion engines (see Box 6: Synthetic aviation fuel: utilising CO_2 to decarbonise air travel).

Mineral: converting CO_2 into various forms of rock or other mineral via reaction with alkalines such as calcium oxide for use in building materials such as cement or aggregates (see Box 7: Carbon mineralisation: long term sequestration in concrete).



Chemical: the conversion of CO_2 into high value chemicals such as methanol, ethylene, olefins and BTX – often as a feedstock for plastics (see Section 1.2.5).

As described in Section 2.1, the impact of CCUS on atmospheric concentrations of CO_2 and thus on global temperatures depends on both the source from which CO_2 is derived and on the end-of-life outcome. Storage can result in either carbon removals (if the CO_2 was derived from photosynthesis or DACC) or in decarbonisation (i.e. emission reductions) if the CO_2 is derived from fossil fuel combustion or a chemical reaction within an industrial process. In the case of utilisation, the impact depends not only on the source but on whether utilisation is long or short-term:

- Long-term utilisation (i.e., 50+ years) is equivalent to storage and depending on source, can result in either a net removal or reduction in emissions.
- Short-term utilisation (i.e., less than 50 years) does not achieve permanent sequestration, since the CO_2 is released into the atmosphere after a relatively short period. If the CO_2 released was originally derived from a biomass or DACC source, short-term use enables net-zero-emissions economic activity. If the CO_2 is derived from fossil fuel or a chemical reaction, short-term use improves "carbon efficiency" by using the same molecule twice but does not deliver a net-zero-emissions result.[174]

The actual duration of CO_2 sequestration in different major uses is illustrated in Exhibit 44:

- CO_2 integrated into building materials can deliver sequestration for such long periods that they can be considered equivalent in permanence to storage. The materials typically remain part of the built environment for many decades and even at end of economic life, releasing CO_2 from the materials would require deliberate chemical treatment and is unlikely to occur.
- The duration of sequestration when CO_2 is used to produce plastics depends on what happens at the end of the plastic product's life. Unabated incineration results in immediate CO_2 release. Landfills can sequester CO_2 for hundreds of years but if poorly managed this can lead to methane leaks or the release of micro plastics and other pollutants into the environment. Recycling alongside CCU can prolong the sequestration duration but will only be permanent if recycling is ubiquitous and limitless (See Section 1.2.5).
- Using CO_2 in either urea or synthetic fuels produces only a very short duration sequestration. Carbon in urea is released to the atmosphere within days of the urea fertilizer being applied. And synthetic fuels release CO_2 when combusted.

174 Theoretically short-term utilisation of fossil derived CO_2 could lead to zero emissions if the short-term application ends with the CO_2 being recaptured and either stored or recycled indefinitely. This argument principally applies to plastics. See Section 1.2.5.

Carbon mineralisation techniques can sequester CO_2 into building materials for very long periods

Duration of CO_2 lock-in by utilisation application

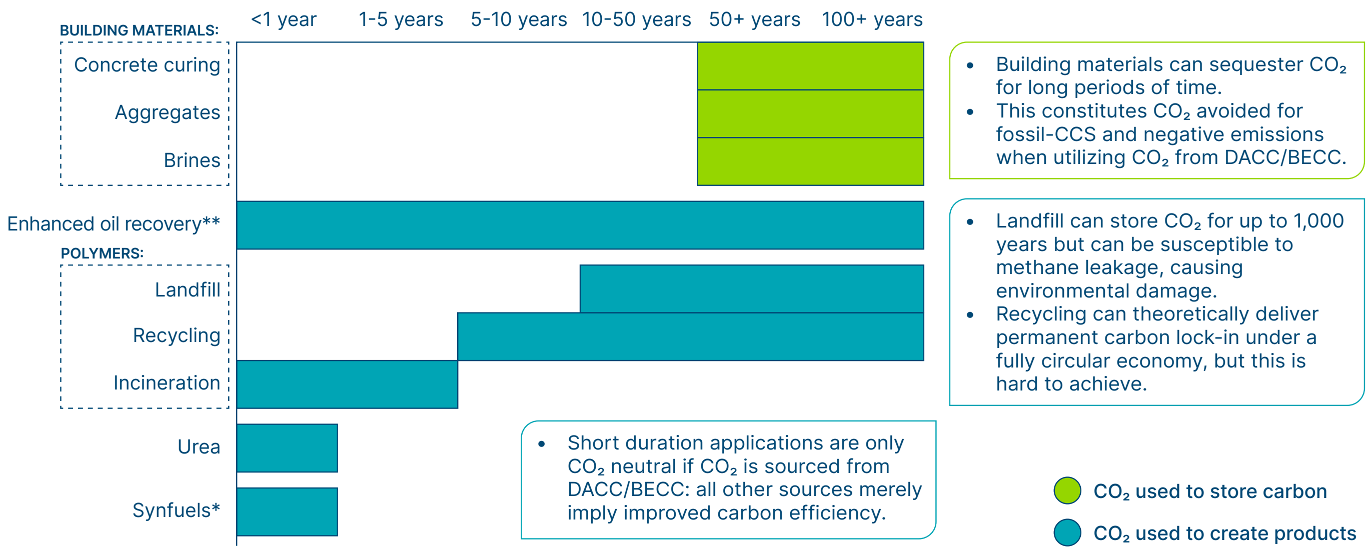


Exhibit 44

NOTES: *Synfuels refers to fuels such as methane, methanol and jet-kerosene. **Duration shown for EOR refers to sequestered CO_2 only, not that which is released immediately upon combustion.

SOURCE: SYSTEMIQ Analysis for the ETC (2021)

2.5.2 Maximum potential use in different applications

The maximum potential scale of CO_2 utilisation for any one category is limited by the total volume of end products involved. Exhibit 45 shows the total potential volume of CO_2 utilised in 2050, if all the relevant products were made using sequestered carbon (e.g., if all synthetic fuel were produced utilised captured CO_2). The results show that:

- For most product uses the maximum potential utilisation is relatively modest compared with potential volumes of CO_2 captured.
- By far the largest potential use lies in the sequestration of CO_2 via mineralisation into construction aggregates, which in principle could absorb all of the CO_2 which Chapter 1 suggested would need to be captured in 2050.

The technical potential for CO_2 sequestration in aggregates significantly exceeds all other applications

Technical maximum CO_2 offtake volume under 100% market uptake (2050)

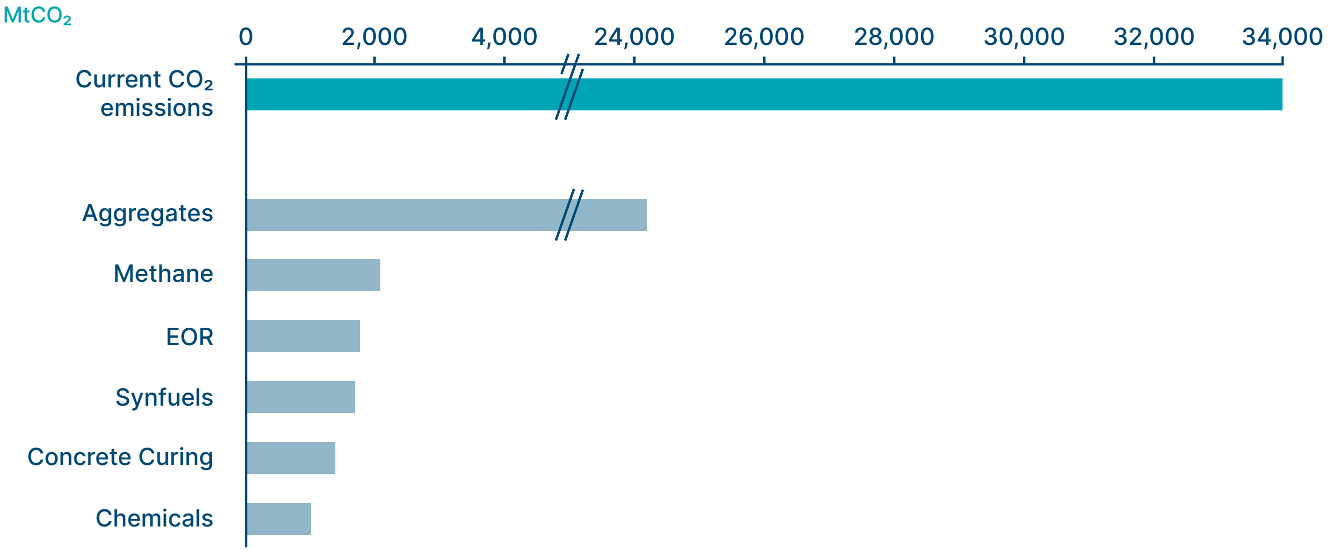


Exhibit 45

NOTES: Technical maximum refers to potential CO_2 utilised if 100% of each product were manufactured using CO_2 utilisation techniques – does not represent expected volumes.

SOURCE: Hepburn, C. et al. (2019) *The technological and economic prospects for CO_2 utilization and removal*; Woodall et al. (2019) *Utilization of mineral carbonation products: current state and potential*; SYSTEMIQ for the ETC (2022)

2.5.3 Costs versus other decarbonisation options or storage.

Exhibit 46 presents a supply cost curve for carbon utilisation, showing the cost of achieving utilisation on the vertical axis and the quantity of sequestration potential on the horizontal. It is important to understand the different meanings of the "cost" of sequestration, and the different relevant comparators, in three different cases:

- **CO_2 is used today as an input to a product.** In the case of urea and EOR, the CO_2 input is either essential in a production process which would in any case occur (urea production) or delivers value via increased production (EOR). The cost of utilisation is therefore negative since the urea producers or EOR operators will pay for the CO_2 delivered, even if there is no carbon price. Whether and under what conditions EOR is desirable is considered in Section 2.6.

- **CO_2 may be required as an input to a product, but the resulting cost is higher than the conventional option.** In the case of synthetic fuel (and also synthetic methane, methanol or plastics) the captured CO_2 is used instead of fossil fuels to produce an economically valuable product, but the total production cost is higher than the conventional route. As a result, a carbon price (or equivalent regulation) is necessary to make CO_2 sequestration cost competitive with fossil fuel inputs. Assuming that such policies are in place to drive decarbonisation, the crucial question then becomes how this cost of decarbonisation compares with alternative decarbonisation vectors. Box 6: "Synthetic aviation fuel: utilising CO_2 to decarbonise air travel" describes why synthetic fuels are likely to be a cost effective option for the decarbonisation of aviation.

- **CO_2 has no economic value.** In the case of construction aggregates, the CO_2 sequestration is not essential to the economic function or quality of the aggregates delivered, so there is no value to the CO_2. Essentially therefore "using" CO_2 in construction aggregates is just another form of storage, and the relevant comparison is between the cost of achieving sequestration within aggregates versus the cost of transport and storage in geological formations (assuming there is a decarbonisation incentive to do both).[175] This "within the value chain" storage may however be a cost competitive solution for a significant share of cement industry emissions, since the distributed location of cement plants will tend to increase CO_2 transport costs to storage sites. Box 7: "Carbon mineralisation: long term sequestration in concrete" describes the aggregate case in more detail.

175 Note that in some cases carbon minerlisation can be used as a valorisation process, by in avoiding gate fees or landfill costs associated with industrial waste streams. In such cases, the first bullet point is applicable.

Most CCU applications cost more than storage

CCU supply cost curve

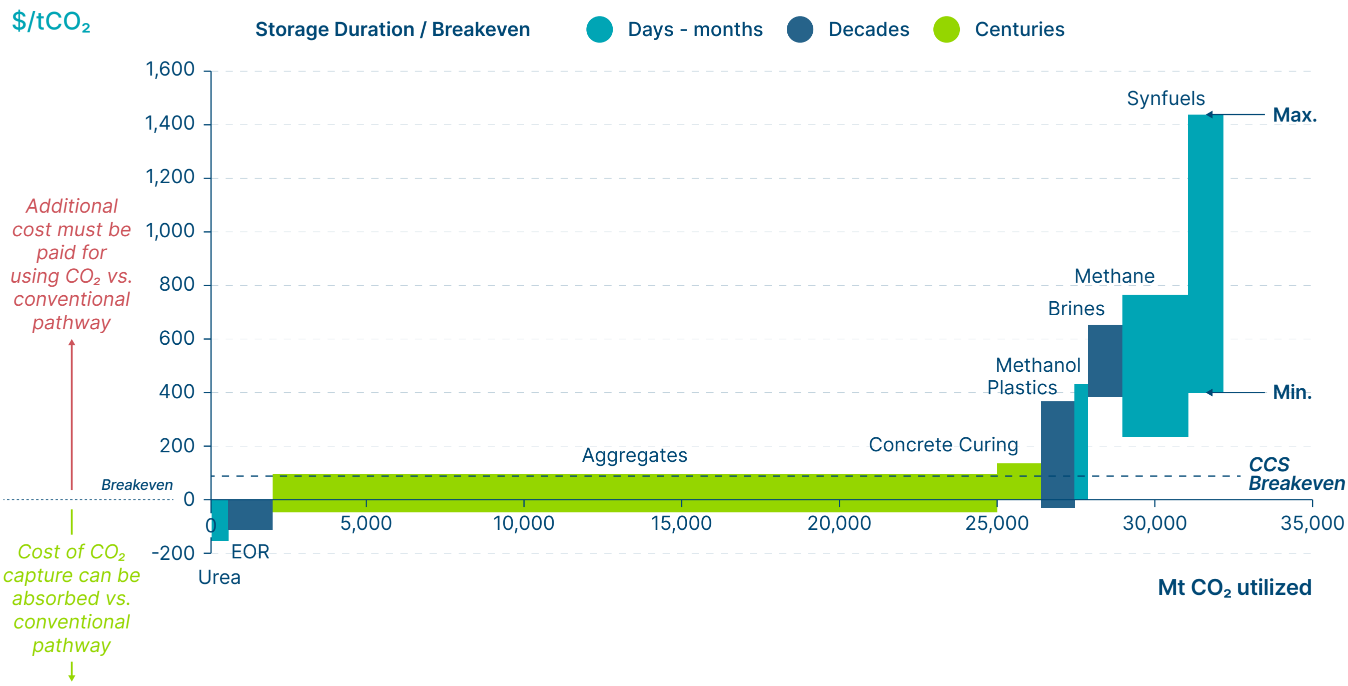


Exhibit 46

SOURCES: SYSTEMIQ analysis for the ETC (2022); Hepburn, C. et al. (2019) *The technological and economic prospects for CO_2 utilization and removal;* J.-L. Gálvez-Martos et al. (2020) *Techno-economic assessment of a carbon capture and utilization process for the production of plaster-like construction materials*

Synthetic aviation fuel: utilising CO_2 to decarbonise air travel

What are synthetic aviation fuels and how are they made?

Synthetic aviation fuels (SAF) are liquid fuels obtained from a mixture of carbon monoxide and hydrogen (known as syngas). The syngas can be derived either from biomass (producing biojet) or hydrogen (yielding synthetic kerosene. In the case of green hydrogen, this is sometimes known as a e-kerosene). The production of synthetic fuels via different versions of the Fischer-Tropsch process is well documented and relatively mature (through still more expensive than producing kerosene via conventional fossil methods).[176] The advantage of SAF is that it produces 70–100% less net CO_2 than fossil kerosene, depending on the production pathway[177] and can "drop in" to existing infrastructure and equipment with only minor modifications.[178]

As described in Section 1.2.8, limits to or constraints on other technologies make it highly likely that synthetic jet fuel will play a major role in the decarbonisation of aviation despite the high green cost premium versus conventional jet fuel. This is because;

- Low energy densities will limit hydrogen and electricity's role to short haul flights.
- And while biofuels will play a significant role, it will be constrained by competing demands for a limited available supply of truly sustainable bioresources.

What determines the CO_2 emissions arising from SAF?

If SAF is produced using carbon captured from DACC or BECC, it can be considered zero-carbon. Fuels produced with carbon captured from point source fossil combustion or process emission can deliver some improvement in carbon efficiency ("using the same molecule twice") but do not achieve a zero-carbon solution.

Why not continue to with fossil kerosene and simply offset with DACCS?

Synthetic jet fuel will need to compete on cost versus the alternative of simply using DACCS to offset continued use of fossil jet fuel. This "fossil jet fuel + DACCS" option enjoys an inherent cost advantage versus "DACC into synthetic fuel" since the cost of CO_2 storage will almost always be less than that of any conversion process, including Fischer-Tropsch.

However, to achieve net-zero aviation we need to not only eliminate or offset CO_2 emissions but also address other non-CO_2 related radiative forcing effects. Fossil based kerosene contains impurities such as nitrous oxide and soot. When released at high altitude, these interact with the ozone layer and give rise to additional radiative forcing and thus global warming. This non-CO_2 based radiative forcing impact is roughly the same as the CO_2 effect.

Taking non-CO_2 effects into account therefore roughly doubles the cost of offsets required to make "fossil + DACCS" a zero emissions solution.[179] Synthetic jet fuel emits substantially less NOx and particulates. Estimates suggest that once we account for non-CO_2 related warming effects "DACC into synthetic jet fuel" can become offer a lower carbon alternative than "fossil jet fuel & DACCS".[180]

Our scenarios presented in Chapter 1 assumes that by 2050 e-kerosene will account for over 50% of aviation sector energy demand.[181] This translates into ~850 Mtpa of CO_2 being utilised.

Box 6

176 Marchese et al. (2021) *CO_2 from direct air capture as carbon feedstock for Fischer-Tropsch chemicals and fuels: Energy and economic analysis.*
177 World Economic Forum (2022) *Clean Skies for Tomorrow: Delivering on the Global Power-to-Liquid Ambition.*
178 IEA (2021) *Aviation.*
179 Lee et al. (2021) *The contribution of global aviation to anthropogenic climate forcing for 2000 to 2018.*
180 Cames et al. (2021) *E-fuels versus DACCS: a study on behalf of T&E.*
181 Based on modelling of optimal fuel sources for different flight distances carried out in World Economic Forum (2020) *Clean Skies for Tomorrow.*

Carbon mineralisation: long term sequestration in concrete

What is carbon mineralisation and how can it 'use' captured CO_2?

Carbon mineralisation is the process by which carbon dioxide is converted into a solid, carbonate material. Carbon mineralization can be carried out either *in-situ or ex-situ*.

- *In-Situ* refers to processes which involve injecting a CO_2 solution underground where it reacts with alkaline rocks and solidifies.[182]

- *Ex-Situ* refers to the above-ground conversion of alkaline minerals (usually calcium- or magnesium-bearing silicates) as they are reacted with CO_2 to form magnesium or calcium carbonates.[183]

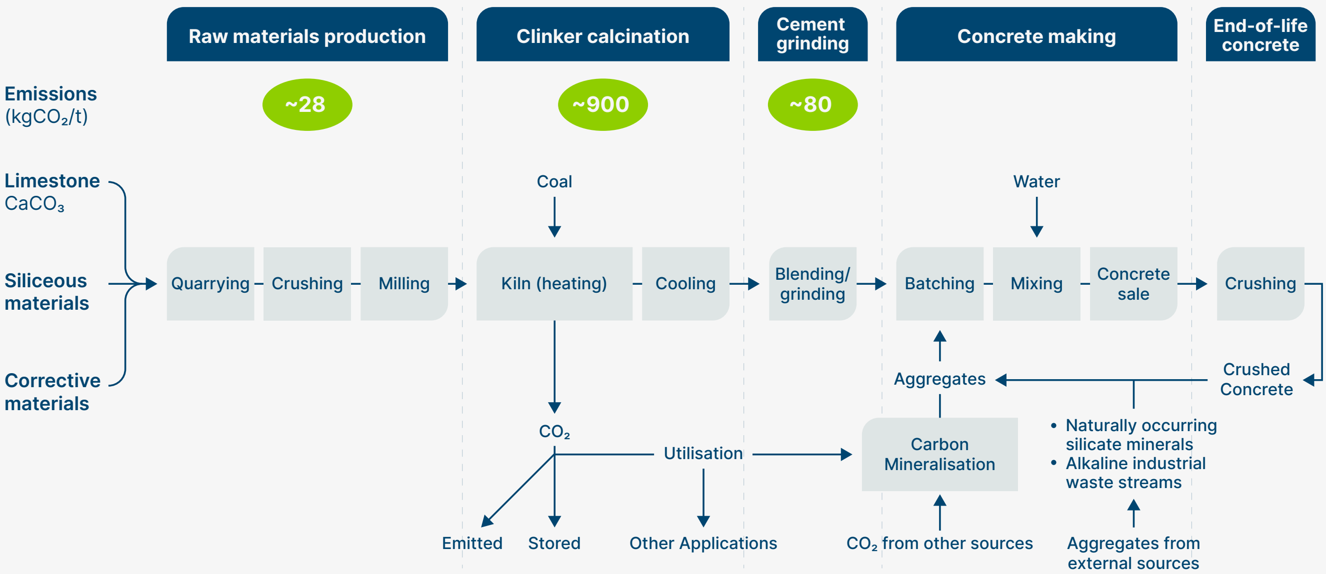
In the context of CCU, the resultant minerals can be used in various applications, including as aggregates in the production of concrete.[184]

How can carbon mineralisation be used in concrete production?

Concrete is produced from cement, aggregates and water, typically in a ratio of 1:2:3. Aggregates are inert granular materials such as sand, limestone, gravel, crushed stone or waste materials such as recycled cement. They are added to cement and water to create concrete. (Exhibit 47).

CO_2 generated in the cement production process can be mineralised in aggregates and utilised in concrete production

Cement and concrete production schematic



SOURCE: ClimateWorks Foundation (2021) *Decarbonizing concrete*; SYSTEMIQ for the ETC (2022)

Box 7

Exhibit 47

182 Kelemen et al. (2019) *An Overview of the Status and Challenges of CO_2 Storage in Minerals and Geological Formations.*

183 Gadikota G (2016) *Commentary: Ex Situ Aqueous Mineral Carbonation.*

184 The other principal application of ex-situ carbon mineralization is "enhanced weathering" in which vast quantities of alkaline minerals are pulverized and distributed, naturally reacting with atmospheric CO_2 and storing it indefinitely. This type of geo-engineering is still highly theoretical and is not assessed in detail here. For more detail see Bach et al. (2019) *CO_2 Removal with Enhanced Weathering and Ocean Alkalinity Enhancement.*

Carbon-mineralisation of aggregates entails coating an existing mineral particle or substrate, with a solution of CO_2, water and alkaline feedstock. This locks in the captured CO_2, coating the particle and forming a carbon-sequestering layer (Exhibit 48). The final particle can be up to 44% CO_2 by mass.[185] Given that global annual demand for crushed stone aggregates in construction is around 22.5 $GtCO_2$, this implies potentially significant quantities of CO_2 could be sequestered in this way, for a period often in excess of 50 years.[186]

Mineral particle is coated in solution, leaving a carbonate layer

Illustrative carbonation treatment of mineral particle

SOURCE: Blue Planet Systems

Exhibit 48

What materials can be used as the basis of the carbon mineralisation process?

In practice sourcing materials which can be used as a substrate presents a limit on CO_2 utilisation in aggregates. The substrate material must start with a reactant source containing sufficient alkalinity (i.e. Mg2+ and Ca2+ cations), with two main options:

- Naturally occurring silicate materials such as quartz, mica or olivine are widely abundant (resources range from 100's of millions to billions of tonnes).[187] However, generally their concentration is low meaning very large quantities would need to be recovered and processed, increasing cost.

- Industrial waste materials with characteristics which meet the alkalinity criteria can also be used as a substrate. Such industrial waste streams include materials such as brines, cement kiln dust, concrete, steel slags, fly ash, red mud or mine tailings, and air pollution control residues (APCr) generated through municipal solid waste incineration. The solid particles from each of these waste streams typically satisfy size requirements without additional grinding.[188] Moreover, these wastes are widely produced as a byproduct of their respective industrial processes, presenting a steady feedstock for minerlisation.[189]

The annual production volumes of these waste streams and the technical potential for CO_2 sequestration is shown in Exhibit 49. In practice utilisation of these materials for carbon minerlisation purposes is constrained by variance in the quality of the waste streams.

Box 7

185 Constanz B. (2016) *Carbon Capture and Mineralogic Sequestration - Addressing the Worldwide Epidemic on a Worldwide Scale.*
186 Woodall et al. (2019) *Utilisation of mineral carbonation products: current state and potential.*
187 National Academies of Science Engineering and Medicine (2019) *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda.*
188 Bobicki et al (2012) *Carbon capture and storage using alkaline industrial wastes.*
189 Woodall et al (2019) *Utilisation of mineral carbonation products: current state and potential.*

Global industrial waste streams have the potential to absorb around 1.2GtCO_2 via carbon mineralisation

Global abundance and carbonation potential of industrial waste

Feed	Production rate per year (Mt/year)	CO_2 Absorption Capacity ($kgCO_2$/t feed)	Potential CO_2 Sequestration ($MtCO_2$/year)
Brine	51,700	6	285
Cement kiln dust	500	570	285
Recycled concrete	27,000	10	275
Steel slags	400	410	165
Fly Ash	660	220	145
Red Mud	120	17	20
APCr[1]	10	330	5
TOTAL			1,180

NOTES: The annual CCS potential presented is based solely on feed abundance and carbonation capacity. This does not include any measure for efficiency and, as such, should therefore be viewed as a technical limit. [1] APCr = air pollution control residues.

SOURCES: Woodall et al. (2019) *Utilization of mineral carbonation products: current state and potential;* Revathy (2021) *Sequestration of CO_2 by red mud flue gas using response surface methodology;* Bobicki et al. (2012) *Carbon capture and storage using alkaline industrial wastes*

Exhibit 49

What are the economics of mineralising aggregates?

The process of mineralisation (i.e. locking in CO_2 on the aggregate particles) adds around 20% to the cost of aggregates, excluding the cost of carbon capture (although there is wide variation in this figure).[190] Despite this cost penalty, storing the CO_2 within aggregates would add only slightly to end-user construction costs, and would therefore be an economic option if alternatives were not available. Still, in most cases, it will be more expensive to sequester CO_2 via mineralisation than to store it underground as described in Section 2.4.

The economic case for mineralisation can be enhanced in two key ways:

- **Where CO_2 storage is not available:** In most cases it will be more expensive to sequester CO_2 via mineralisation than to store it underground as described in Section 2.4.; however, where geological storage is not readily available, and/or where development of CO_2 transport and storage infrastructure is likely to be slow and expensive, the fact that aggregate mineralisation can be implemented on a smaller scale decentralised basis may make it an attractive option.

- **Where waste streams are used:** In some cases the waste product itself is hazardous and carbon mineralisation can render it inert – e.g. red mud.[191] This could improve the economics of carbon-utilisation via aggregates relative to storage since waste producers will be willing to pay the CCU plant operator to take the waste (thus avoiding other forms of waste disposal cost). However, i) accessing a supply of such waste streams with consistent features may be difficult, ultimately limiting overall volumes, and ii) in many jurisdictions, there is currently little regulation or guidance regarding the quality of carbon-mineralised aggregates which can be used in construction, or certification that the process itself provides long term CO_2 sequestration.

Reflecting the constraints arising from cheaper storage alternatives and inconsistency in the quality of the waste streams, we assume roughly only around a third of aggregates produced in 2050 are produced utilising carbon minerlisation. This gives rise to ~0.4 GtCO_2 utilised in aggregates in 2050 (Exhibit 52).

Box 7

190 Hepburn et al. (2019) *The technological and economic prospects for CO_2 utilisation and removal.*
191 Supply of recycled concrete in particular is likely to grow steadily in the coming years, providing a ready stream of material suitable for carbon mineralisation.

2.6 EOR – a specific and controversial application

Enhanced Oil Recovery is one of the few commercially mature forms of CO_2 utilisation in operation today. The process involves injecting CO_2 (or other substances such as water or nitrogen) into existing oil reservoirs, thereby increasing the well pressure and allowing for a larger share of total oil reserves to be recovered. Typically, EOR can increase oil recovery from a well by 5%–20%. There are ~375 EOR projects operating globally, producing just over 2 Mb/d of oil. Of these around 100 are using CO_2. CO_2 based EOR therefore accounts for ~0.5% of global oil supply (about 0.5 Mb).

The CO_2 injected underground can come from an array of sources (Exhibit 50). Today, around 70% of the of CO_2 used in EOR is mined from naturally occurring underground CO_2 deposits. Operators recover CO_2 from these reservoirs and then pump it back underground to recover the oil. Around 30% of the CO_2 injected into EOR wells is captured from point source (industry or fossil-fuelled power plants). In the future, as DACC technology matures, CO_2 captured directly from the air can be pumped underground. But today DACC accounts for a very small share of EOR CO_2 supply, with just one pilot project in operation at the time of writing.

The use of captured CO_2 to support EOR is controversial. Proponents argue that it reduces the cost of oil recovery (by reducing the need for new oil exploration) but does not increase the total amount of oil eventually exploited, since this is determined by demand which will reduce as the world decarbonises (e.g. the shift to electric vehicles). They also argue that EOR can serve as a platform for build up of industry expertise in both DACC and CO_2 storage.[192]

Opponents argue that EOR supports continued use of fossil fuels and undermines decarbonisation by enabling cheaper oil production. They also argue that any claim that CO_2 based EOR can deliver "carbon-neutral" or "zero-carbon" oil is greenwashing, and that public support for EOR diverts resources from true decarbonisation. Finally, the utilisation of a decarbonisation technology for the purposes of producing new fossil fuels can create negative attitudes towards and public opposition.

In determining an appropriate policy approach it is vital to note that the impact of CO_2-EOR on carbon emissions depends on two factors – the carbon intensity of the injection operation and the source from which the CO_2 was derived;

- **Carbon intensity of injection:** In most current EOR operations the CO_2 used is treated as an economic cost, and the goal of most CO_2-EOR today is to produce as much oil with as little CO_2 as possible. However, if the goal is to store CO_2, operators can adjust their practices to increase the CO_2 injected per barrel of oil produced. This can be achieved via operational changes and techniques such as miscible flooding or water removal to create space for further CO_2 injection.[193] The IEA notes that conventional EOR achieves about 0.3 tonnes CO_2 per barrel of oil, with more advanced EOR increasing the CO_2 intensity to 0.6 tCO_2/bbl, up to a maximum of around 0.9 tCO_2/bbl.

- **Source of CO_2:** As with all forms of CCU, the impact of EOR on emissions and on the climate is a function of the source of the CO_2. Exhibit 51 shows the impact on net CO_2 emissions per barrel for four different cases. In the first three the carbon intensity of injection is 300 kg per barrel and in the fourth 600 kg.

  - In the first case, the CO_2 is mined from a naturally occurring CO_2 reservoir so that injection of 300 kg simply returns the CO_2 to the ground. Production of a barrel of oil produces about 100 kg of emissions and combustion another 400 kg, giving net emissions of 500 kg per barrel of oil consumed.[194]
  - In the second case, the CO_2 is derived from an industrial combustion process and therefore originally from a fossil fuel combustion. As with case one, injection simply returns the same quantity of CO_2 to the ground, while production and combustion of oil results in 500 kg of emissions per barrel. In this case however the economy also collects the benefit of the industrial output produced: improved carbon efficiency.
  - In case three, which still assumes the conventional carbon intensity of 300 kg per barrel, the source is DACC (i.e. CO_2 is removed from the air), so that DACC plus injection achieves 300 kg of 'negative emissions', offset by 500 kg from production and combustion to produce a 200 kg net CO_2 emissions.
  - Only in case four, where DACC is combined with higher CO_2 intensities (600-900 kg per barrel) does the full system produce negative emissions. The "breakeven" point for zero net emissions is where DACC is combined with a carbon intensity injection of around 500 kg per barrel.

However, in all cases it is likely to be the case that DACC used for enhanced oil recovery will produce more emissions per barrel than conventional DACCS (where CO_2 is permanently, without EOR).

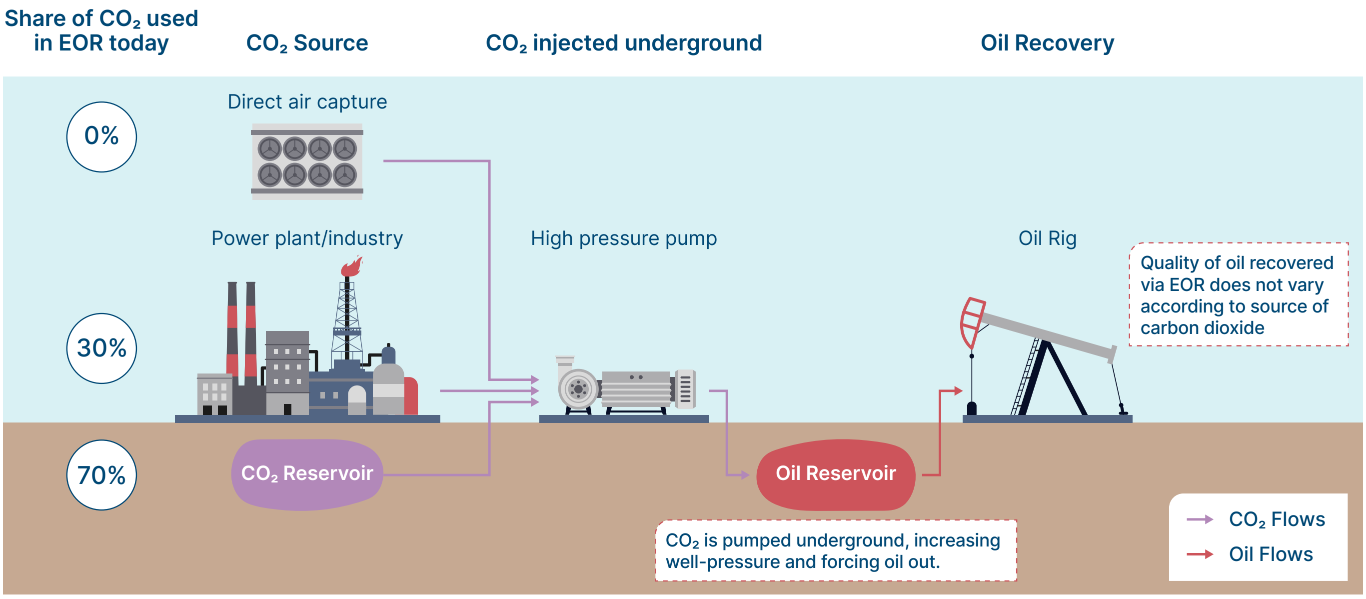
192 For example, Occidental Petroleum plans to use legacy enhanced oil recovery operations as a springboard to launch a DACC business focussed on selling carbon offsets and producing synthetic fuels – see Energy Intelligence (2022) *Occidental all in on Carbon Capture.*

193 IEA (2015) *Storing CO_2 through Enhanced Oil Recovery.*

194 IEA (2018) *World Energy Outlook*; IEA (2019) *Can CO_2 -EOR really provide carbon negative oil?* Note that these numbers will vary significantly between oil plays.

The majority of CO_2 utilised in EOR today comes from naturally occurring subsurface reservoirs

Schematic of CO_2 utilisation through enhanced oil recovery



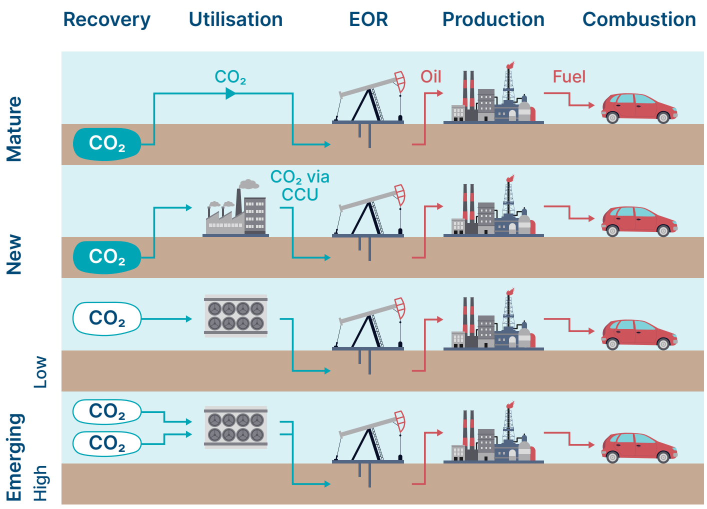
SOURCE: Adapted from IEA (2019) *Can CO_2-EOR really provide carbon-negative oil?* by SYSTEMIQ for the ETC (2022)

Exhibit 50

Net CO_2 emissions from oil produced via EOR vary according to where the CO_2 is sourced from and the ratio of CO_2 injected to oil recovered

CO_2 emissions from EOR by recovery source and intensity

kgCO_2/bbl



Source	CO_2 source	Injection	Production	Combustion	Net emissions
CO_2 resevoir	300	-300	100	400	**500**
Point source capture	300	-300	100	400	**500+ utility**
DACCS & low case CO_2 ratio	0	-300	100	400	**200**
DACCS & high case CO_2 ratio	0	-600	100	400	**-100**

NOTE: Production includes processing, refining, transmission, distribution and retail.

SOURCE: Adapted from IEA (2019) *Can CO_2-EOR really provide carbon-negative oil?*

Exhibit 51

Responsible investment, optimal public policy and appropriate claims of "low-carbon", "zero-carbon", or "carbon-neutral" oil should therefore differentiate clearly between different potential types of CO_2-EOR. The ETC believes that:

- Public policy should strongly favour other forms of CO_2 CCUS other than EOR.
- Public policy should never support (and ideally discourage) mining CO_2 for EOR purposes.
- It should only support CO_2-EOR where the combination of CO_2 source and carbon intensity of injection delivers zero or negative net life cycle emissions from source through to oil product combustion.
- Claims of "carbon-neutral" or "zero-carbon" oil should only be made if the net emissions effect can be proven to be zero or negative. If these claims are made without strong regulation, standards and monitoring there is a high risk of undermining wider public confidence in CCUS as a decarbonisation technology.
- EOR should play only a minor role in the path to net-zero. In our scenarios we assume that 0.6 $GtCO_2$ will be injected into EOR operations in 2050. At a carbon intensity of 500 kg per bbl this will support the production of around 3.3 Mb/d.

2.7 A 2050 scenario for storage and utilisation

In Chapter 1 we described CCUS's vital but limited role within a zero-carbon economy, and proposed that the world might need to capture 7–10 $GtCO_2$ per annum by 2050. The expected sources of this CO_2 might be about 3–5 $GtCO_2$ from the air (DACC), 1 $GtCO_2$ from photosynthesis (bioresources) and 3–4 $GtCO_2$ resulting from fossil fuel combustion or chemical reactions within industrial processes.

This chapter has considered the end-of-life balance between storage and various forms of utilisation. The middle bar of Exhibit 52 (which repeats Exhibit 4 in Chapter 1 and is shown here for ease of reference) presents for the Base Deployment (7 $GtCO_2$) scenario in which;

- Storage accounts for the clear majority of overall CO_2 captured – about 4.5 $GtCO_2$.
- Non-EOR utilisation accounts for about 2 $GtCO_2$, with aviation fuels the biggest application, together with smaller roles in plastics and aggregates.
- There is a limited role for EOR, with about 0.5 $GtCO_2$ captured and used in this fashion.[195] This would be compatible with the scenario in which total oil production had by 2050 fallen below 10 million barrels per day.

Varying combinations of CO_2 capture and end of life imply different impacts on CO_2 emissions

CCUS volumes in 2050 under Base scenario

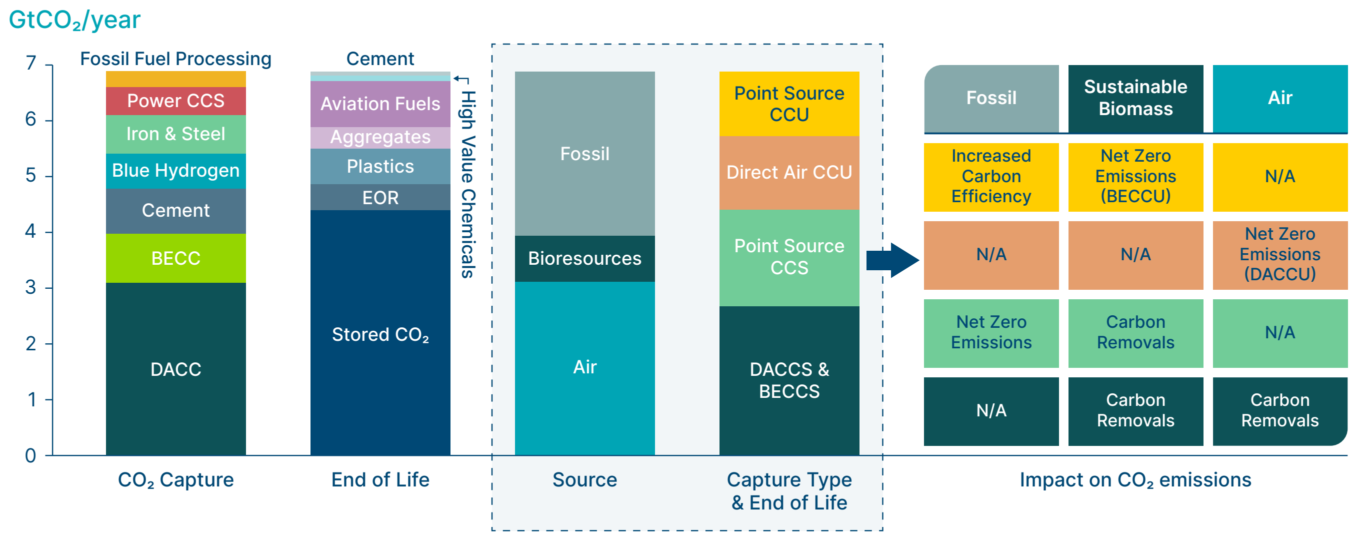


Exhibit 52

NOTES: Volume shown refer to Base Scenario in which demand side measures are fully implemented. Fossil Fuel Processing includes natural gas processing, oil products refining and production of high value petrochemicals (methanol, ethylene, propylene, butadiene, benzene, toluene, xylene). EOR = enhanced oil recovery. CCU = carbon capture and utilization. CCS = carbon capture and storage. DACCS = direct air carbon capture and storage. DACCU = direct air carbon capture and utilization. BECCS = bioenergy with carbon capture and storage. Note that the majority of point source CCS emissions will come from fossil processes and combustion. In the "Source" bar chart, process emissions are included in Fossil.

SOURCE: SYSTEMIQ for the ETC (2022)

195 Assumes 25% of all oil produced in 2050 uses Advanced EOR (600 $kgCO_2$ /bbl).

Accelerating CCUS deployment in the 2020s

- 7 to 10 Gt of annual carbon dioxide capture capacity will be needed by 2050, compared with less than 40 million tons per annum (mtpa) in operation in 2020.
- Much of the growth – particularly of DACC – will occur after 2030 but significant development in the 2020s is needed to "derisk" the technology and make the subsequent path feasible.
- The costs associated with building and operating the necessary CCUS capacity by 2050 are significant: between $3.3tn to $4.9tn cumulatively to 2050. However, these costs are manageable (c. 0.1% of global GDP over the period), and likely represent a modest share (<5%) of overall costs associated with the energy transition.
- Past growth has been slow with multiple project cancellations and disappointing cost-reduction. This partly reflects improved economics for other decarbonisation levers but also policy and coordination failures which must be addressed.

Chapters 1 and 2 concluded that 7-10 Gt per annum of CCUS will be needed and is possible by 2050. This compares with 37 million tons per annum (Mtpa) of CO_2 capture capacity in 2020, with approximately 30 facilities currently operating worldwide. Projects already under development, if fully implemented, will only take this to 160 Mtpa by 2030.

Much of the required growth – particularly of DACC – is likely to come in the 2030s and 40s. But significant growth must start in the 2020s for two reasons:

- Early deployment can help reduce cumulative CO_2 emissions, lowering the risk of overshooting the carbon budget.[196]
- Development in the 2020s would drive technological innovation and supply chain development, reducing future capital and operating costs.

This chapter therefore assesses the pace of growth required in the 2020s and identifies the actions needed to make it possible. It covers in turn:

- Indicative sectoral pathways from now to 2050.
- Projected capital investment required to deliver the necessary capacity – on average $110–160bn per annum.
- Projects currently under development – far short of required growth.
- Slow progress over the last 15 years – reasons and lessons learned.

3.1 Pathways from now to 2050

Optimal sector pathways will reflect both the technological readiness of carbon capture by sector and the economics of alternative decarbonisation vectors (and the policy environment in individual countries). These are in turn a function of uncertain future trends and technology costs. As a result, decade by decade sector pathways are even more uncertain than estimates of the scale of CCUS needed in 2050. But analysis of published sector decarbonisation plans and assessment of technological readiness and potential cost competitiveness supports the indicative growth path by sector shown in Exhibit 53, suggesting a need to scale from 0.04 Gt/year today, to 0.8 Gt/year by 2030 and ~4 Gt/year by 2040. Key features are:

- Growth from today's minimal scale to around 0.8 Gt by 2030 will be driven by point source capture across multiple sectors – mainly fossil fuel processing, cement, hydrogen, power and BECCS.
- Accelerating expansion to 3.6 Gt per annum by 2040, will require continued significant growth in cement, BECCS and power, together with growth of DACC to 0.6 Gt per annum by 2040.
- Growth in the 2040s is dominated by the expansion of DACC as the role of CCUS in end use sectors reaches maturity.

196 ETC (2021) *Keeping 1.5°C Alive: Actions for the 2020s.*

By 2050 direct air capture accounts for the largest share of CO_2 captured

CO_2 captured by sector in Base scenario

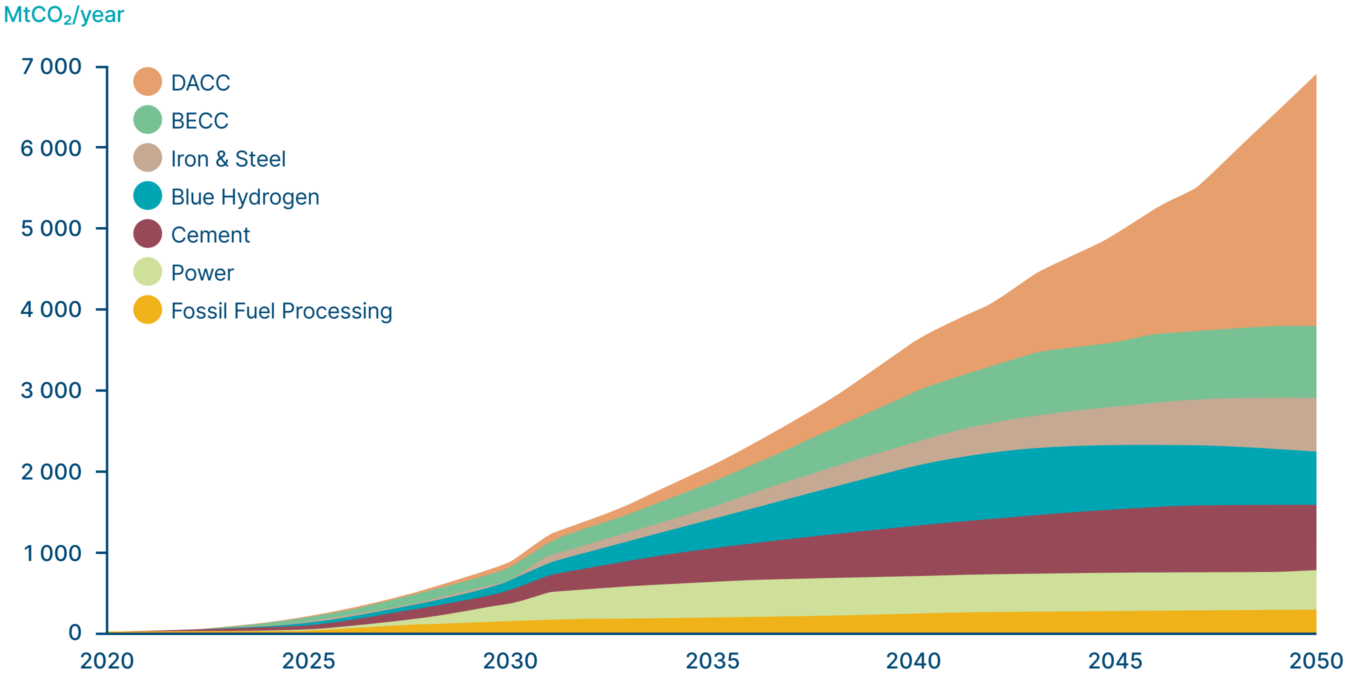


Exhibit 53

SOURCE: SYSTEMIQ analysis for the ETC (2022)

3.1.1 Technology readiness

The technology readiness level (TRL) of specific carbon capture technologies strongly determines the expected sectoral deployment for the coming 2 decades. Respective TRLs vary substantially, with some technologies still at prototype stage while others have been in commercial use for years. Unsurprisingly, the capture technologies with highest TRLs tend to be associated with sectors already operating commercial CCUS capacity. Similarly, technologies at a low TRL are often best suited to sectors with limited CCUS uptake so far. Exhibit 54 presents the volumes of CO_2 captured under the Base scenario, broken down by TRL. The majority of the CO_2 captured by the mid-2030s will come from technologies which are already either mature or at early adoption stage.

- Early potential for the take-off of CCUS lies in power generation, natural gas processing, hydrogen, methanol, BECC and High Value Chemicals production.
- CCUS is currently at demonstration stage in cement and high-value chemicals; this will make possible significant ramp-up in the 2030s.
- Applications at prototype stage include DACC and iron & steel. Further R&D is required in the 2020s and 2030s to support subsequent growth in these sectors.

High TRL CCS sectors drive capacity growth in the 2020s with less mature capture technologies ramping up in the 2030s and 40s

CO_2 captured by TRL in Base scenario

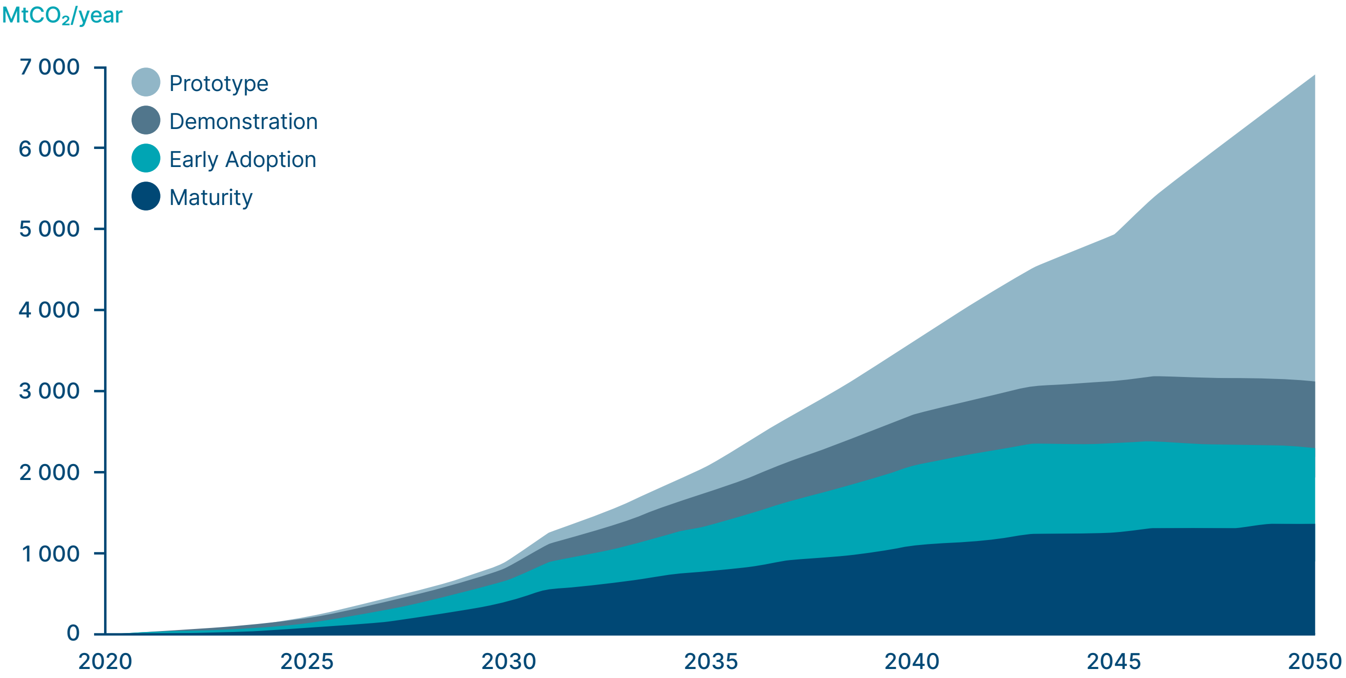


Exhibit 54

SOURCE: SYSTEMIQ analysis for the ETC (2022)

3.1.2 Indicative sector pathways

Actual sectoral pathways will not only reflect technological readiness, but also the cost competitiveness of CCUS relative to other decarbonisation levers. But indicative pathways can be developed which suggest which sectors are likely to emerge at each stage.

Carbon dioxide removal

DACCS: In section 2.2.3, we noted that while DACC costs are much higher than other forms of capture today, they are likely to fall significantly over time. This will make DACC an economic option to deliver carbon removals and to support CO_2 utilisation (notably in the production of synthetic jet fuel) over the medium to long-term. This will determine the pace of scale up of the technology over time (alongside any potential constraints from supply of clean electricity).

However, given the time taken for new technologies and supply chains to be developed,[197] and expected cost reductions to be achieved, our Base scenario assumes only limited growth of DACC operations to 60 Mt in 2030 (equivalent to around 60 plants) with 0.6 Gt/year achieved by 2040, followed by rapid growth to 3.1 Gt per annum by 2050.

BECCS: Multiple bioenergy plants are in operation around the world today, with plants combusting bioenergy to produce power and heat, or processing bioenergy to produce fuels such as bioethanol.[198] However, CO_2 is produced onsite during the production of these fuels, power or heat, presenting an opportunity to capture this CO_2 in order to achieve lower or indeed negative emissions.[199] Today there is just one BECCS plant in operation – the Illinois Industrial Carbon Capture and Storage plant in the US, capturing 1 Mt/year from bioethanol emissions.[200]

197 Realmonte et al. (2020) *An inter-model assessment of the role of direct air capture in deep mitigation pathways summarizes the potential constraints on annual growth rates.*
198 For a full list of biofuel plants in the US see https://biomassmagazine.com/plants/listplants/biomass/US/
199 Though relatively small in scale, emissions from the pulp and paper industry also come under this heading – see Santos et al. (2021) *Unlocking the potential of pulp and paper industry to achieve carbon-negative emissions via calcium looping retrofit.*
200 Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet (https://sequestration.mit.edu/tools/projects/illinois_industrial_ccs.html)

Scale up of BECCS plants will be driven by the overall need to scale up negative emissions and dispatchable renewable power, with policy regimes under development in multiple countries. At the same time constraints on sustainable biomass availability will limit the potential for BECCS. A plausible estimate of BECCS scale up over time suggests around 45 plants could be operational by 2030, capturing around 170 Mt CO_2/year, increasing to 0.9Gt CO_2/year by 2050, delivered through a roughly even split of dedicated energy crops and forestry residues.[201]

Cement

As described in Chapter 1, the high share of process emissions in cement's overall emissions mean that the cement industry is likely to be especially dependent on carbon capture technologies. Yet as of today only one cement-with-CCUS plant – Heidelberg's Norcem Brevik, in Norway – is under construction, with another two under consideration.[202]

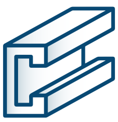
Progress in reducing emissions from cement plants, via CCUS, will need to accelerate. Chapter 2 highlighted the role carbon utilisation via aggregates might play in improving the business case for CCUS deployment.

However, given the technology's relatively low TRL and the scope for reducing emissions through other measures (see Section 1.2.2) build out is set to be backloaded; a plausible pathway for CCUS deployment on cement in the 2020s may mean just ~0.04 $GtCO_2$/year is captured from cement plants by 2030. Nevertheless, this is equivalent to deployment of CCUS at around 30 large cement facilities.

Blue hydrogen

As discussed in Chapter 1, over the long-term green hydrogen is likely to be more cost competitive than blue in most locations and our scenario therefore envisages that by 2050 85% hydrogen will be made via the green route (Section 1.2.3). Indeed, since the ETC published its hydrogen study in April 2021, green hydrogen cost declines and the scale of green hydrogen ambitions unveiled by policy-makers have exceeded our assumptions. In Europe and some other regions, moreover, the price of natural gas has increased sharply in response to the war in Ukraine, materially improving the relative economics of green versus blue hydrogen.

But blue H_2 may still be a key growth sectors for CCUS in the 2020s, particularly in regions that can benefit from low gas production costs. 7 commercial plants are in operation today with another 17 already in the pipeline. A plausible pathway for CCUS deployment could see around another ~50 added in the next decade, with total annual capture capacity of ~1.5 $GtCO_2$/year by 2030. This growth reflects the fact the blue hydrogen is currently still lower cost than green in several locations, particularly in cases where existing "grey" (unabated) production can be retrofitted via the addition of CCS.[203]



Iron and steel

Steel based CCUS is still relatively nascent – there is currently just one, very small plant in commercial operation today,[204] and a further two under development. Reflecting the emerging status of steel-CCUS and the focus on alternative decarbonization vectors such as hydrogen-DRI, no additional plants are expected to be commissioned before 2030 (beyond those already in the pipeline). However in some cases CCUS on steel plants will be the most economic decarbonisation option by 2050. Therefore steel CCUS capacity is expected to ramp up in the 2030s & 40s to reach ~600 Mtpa by 2050, equivalent to ~25% of total steel being produced using CCUS technology.[205]

201 ETC (2022) *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*
202 Global CCS Institute (2021) *The Global Status of CCS.*
203 Mission Possible Partnership (2021) *Making the Hydrogen Economy Possible.*
204 The Al'Reyahdah plant in the UAE, which is capturing 0.8 Mtpa from the Emirates Steel production facility and injecting the CO_2 for enhanced oil recovery (EOR) in the Abu Dhabi National Oil Company's nearby oil fields. Average plant capacity in the 2030's is expected to be around 4 times the size of Al'Reyahdah.
205 Based upon the "Tech Moratorium" scenario in the MPP's (2021) *Net Zero Steel Transition* report which assumes investments into steel plant capacity are confined to (near-) zero-emissions technologies from 2030 onwards. The model optimises steel assets at each major investment decision, according to whichever technology offers the lowest TCO.

Fossil fuel processing and petrochemicals

The use of carbon capture technology in the production of petroleum products today is widespread. CCUS has been used in processing natural gas since the 1970s to separate CO_2 from methane and today captures ~30 MtCO_2 per year. Refineries can also apply CCUS to the segments in their operation which emit CO_2. These include steam methane reformers that produce hydrogen, catalytic crackers and Combined Heat and Power (CHP) units.[206] In the high value chemicals sector, CCUS is still nascent but considered a plausible candidate for decarbonisation in the coming decades as other technologies gestate (see Section 1.2.5).

Assuming there is no change in the volume of CO_2 removed per unit of natural gas produced over time, and cost-effective, and a steady rollout of CCUS at refineries, total CO_2 capture from fossil fuel processing could rise to ~90 MtCO_2 per annum by 2030 and reach 170 MtCO_2 in 2050.

- CCUS capacity is likely to be a function of natural gas demand. The Base scenario projects natural gas production between ~100 EJ in 2030 and ~70 EJ in 2050, in turn implying 30 MtCO_2 and 20 MtCO_2 respectively (assuming that the share of natural gas which requires processing and thus CO_2 capture remains constant).

- For oil products, we assume around 10% of refineries by 2030 are using CCUS technology. Sharply reduced oil product demand by 2050 (owing to electrification of transport and other decarbonisation measures) implies fewer refineries in operation but all of them will be utilising CCUS technology for process emissions. This yields a total carbon capture volume of capture volume of 65 MtCO_2 per annum by 2030 and 150 MtCO_2 per annum in 2050.

- As noted in Chapter 1, decarbonising petrochemicals requires decarbonising both energy consumed during their production and emissions resulting from production process itself. A plausible pathway for CCUS deployment at petrochemical plants would see 70 Mt of CO_2 captured per year in 2030, equivalent to deployment at around 80 petrochemical plants. This would then double to 140 MtCO_2 per year by 2050.

Power generation

There are relatively few CCUS fossil fuel power plants in operation today, despite the technology's high TRL and relatively straightforward options for retrofit. 41 power CCS plants are currently under development: 13 are on gas, 10 are on coal and 18 are on biomass (see above for discussion of BECCS).[207] These facilities have a potential combined capture capacity of ~60 MtCO_2 per year.

As discussed in Chapter 1 wind and solar are both cheaper than fossil power with CCS in most geographies (Exhibit 11). Therefore the role of CCS in power is limited principally to abating peaking/grid-balancing assets – not baseload generation, except in the case of BECCS plants with ready access to sustainably sourced bioresource supplies.[208] However in some instances build-out of renewables is constrained (e.g. in emerging markets where demand growth is extremely strong) or retrofitting of coal/gas assets is cheaper than early retirement. In such cases there may be a role for CCUS in baseload or intermediate generation.

A plausible pathway for CCUS deployment in the power sector, consistent with the renewables-led vision in the ETC's (2021) *Making Clean Electrification Possible* report, could see 5% of coal and gas-fired generation fitted with CCUS technology by 2030 capturing 220 MtCO_2/year in 2030 at around 50 large power stations. By 2050, any remaining fossil fuel use in the power sector would need to be abated, leading to capture volumes of 500 MtCO_2/year.

206 Turan G. (2020) *CCS: Applications and Opportunities for the Oil and Gas Industry.*
207 IEA (2021) *CO_2 capture projects in power generation under development by technology and region.*
208 Assuming the potential technical limitations arising when applying CCS technology to a peaking unit can be overcome – see discussion in Section 1.2.7

3.2 Investment required to deliver ramp up by 2050

CCUS investment in 2020 stood at c. \$3bn.[209] The costs associated with building and operating the necessary CCUS capacity by 2050 require annual investment to increase to over \$100bn/year by 2030. These costs are significant but manageable and likely represent a modest share of overall costs associated with the energy transition.

Investment needs will be determined by the total capacity of CCUS eventually required (i.e. the Base and High Deployment scenarios discussed in Section 1) and the costs associated with the three types of investment which must be made: point source capture, transport & storage infrastructure and DACC (Exhibit 55). Each cost type will follow its own distinct trajectory from now to 2050.

- **Investment in point-source capture** costs account for 32% of total expenditure, c. \$1–1.5tn from now to mid-century. Point source CAPEX grows steadily throughout the period, peaking in the mid-2030s. With the decline in required non-DACC investment after 2040 somewhat reflecting the increased technological maturity and competitiveness of alternative decarbonisation technologies.
- **Investment in transport and storage infrastructure** each account for c. 10% of expenditure, with cumulative capital investment of between \$0.8–1.3tn. Transport and storage investments are slightly front loaded, reflecting the need to make spare capacity available.
- **Investment in DACC** takes the largest share of costs (if associated power infrastructure investments are included) but are inherently uncertain. DACC and associated power investments account for just under half of cumulative CAPEX requirements over the outlook.
    - Future DACC CAPEX cost declines could drive investment needs anywhere from \$0.4–0.9tn in the Base case (3.5 $GtCO_2$ by 2050) to \$0.6–1.3tn in the High deployment scenario (4.5 $GtCO_2$).[210] These conclusions are highly sensitive to assumptions concerning capital costs today, learning rates and efficiency gains (further discussion in Section 2.2.3).

Point source capture CAPEX peaks 2030 – 45 whereas DACC and associated power investment ramps up in the late 2040s

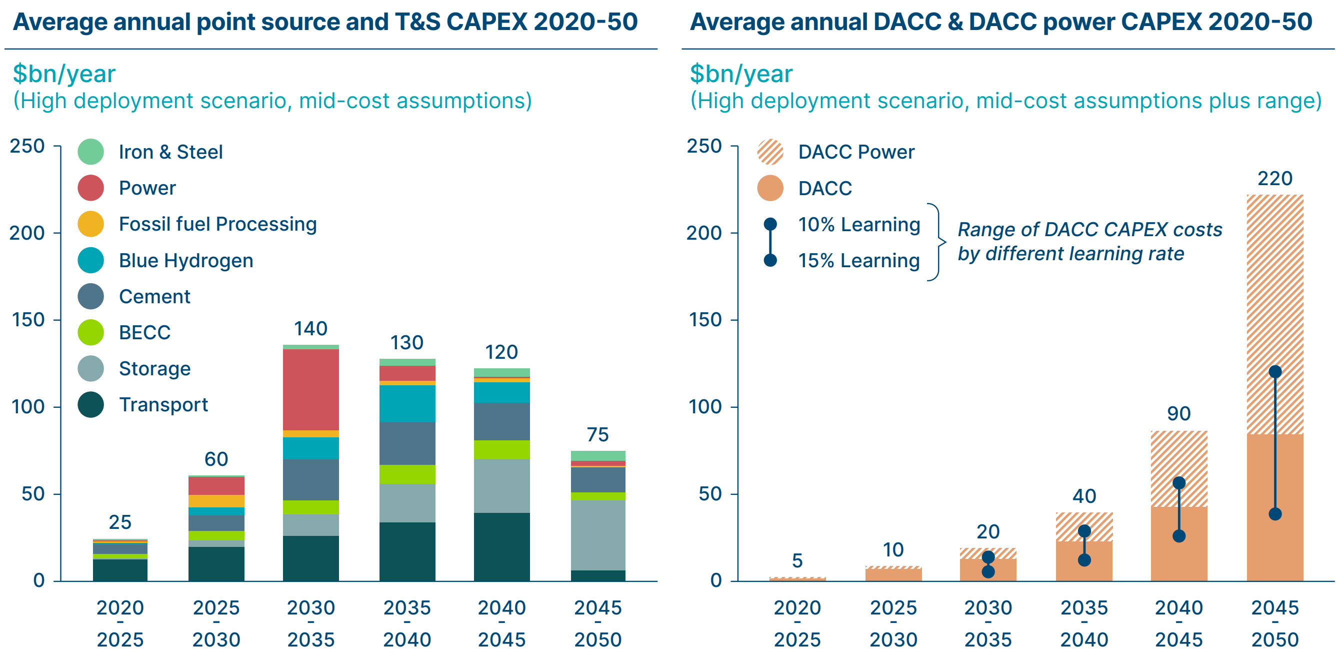


Exhibit 55

NOTES: Both charts show average annual CAPEX costs for "High Scenario" in which installed capacity reaches 4.5Gt by 2050. DACC power is shown owing to the especially high energy costs associated with collecting CO_2 from low concentration levels. For point source capture methods, energy consumption relatively trivial and is treated as an operational expenditure, therefore not shown here. DACC CAPEX bars show 12% learning rate, range indicates 15% learning (lower dot) and 10% learning rate (upper dot).

SOURCE: SYSTEMIQ analysis for the ETC

209 BNEF (2021) *Energy Transition Investment Report.*
210 This range reflects high (15%) and low (10%) learning rates applied to different capacities.

◦ DACC CAPEX costs are realised primarily in the 2040s, when the technology is able to grow rapidly, with annual investments average between $60bn to $85bn per annum by 2045–50.

◦ Electricity investments required to build the wind and solar generation required to power DACC required an additional investment of between $0.9–1.2tn, in addition to the DACC.[211]

Together, this could represent cumulative investment requirement for CCUS between now and 2050 at $3.3–4.9tn, or roughly $110–165bn on average, per annum, taking a mid-point of DACC CAPEX costs (Exhibit 56).[212] The wide range in potential DACC cost pathways underscores the importance of early deployment across all sectors, in order to drive early cost savings and thus lower overall costs in the long run.

Whilst these figures imply significant investment requirements, they represent a relatively modest share of total costs associated with the energy transition:

- Average annual CAPEX requirements for all CCUS (including investment into renewable power necessary to meet DACC energy requirements) are estimated between $110–165bn.
- This compares with an estimated average annual CAPEX requirement of $3.6tn for other energy and infrastructure assets necessary to achieve net zero by 2050 ($2.9tn of which is underpinned by clean electrification).
- Even at the top end estimate, average annual CCUS CAPEX requirement only represents ~25% of average annual CAPEX into the oil and gas sector today.[213]
- Finally, most of the investment comes in the 2040s reflecting DACC's back-loaded deployment schedule. By this point, much of the heavy lifting with regards to investment into other aspects of the energy transition will be well underway, implicitly creating room for CCUS investment to grow.

Average annual CAPEX reaches c. $300bn per annum in the late 2040s driven by DACC capacity deployment and associated power investment

Average annual CAPEX by sector 2020-50

$bn/year (High deployment scenario)

Cumulative CAPEX by sector and scenario 2020-50

$bn

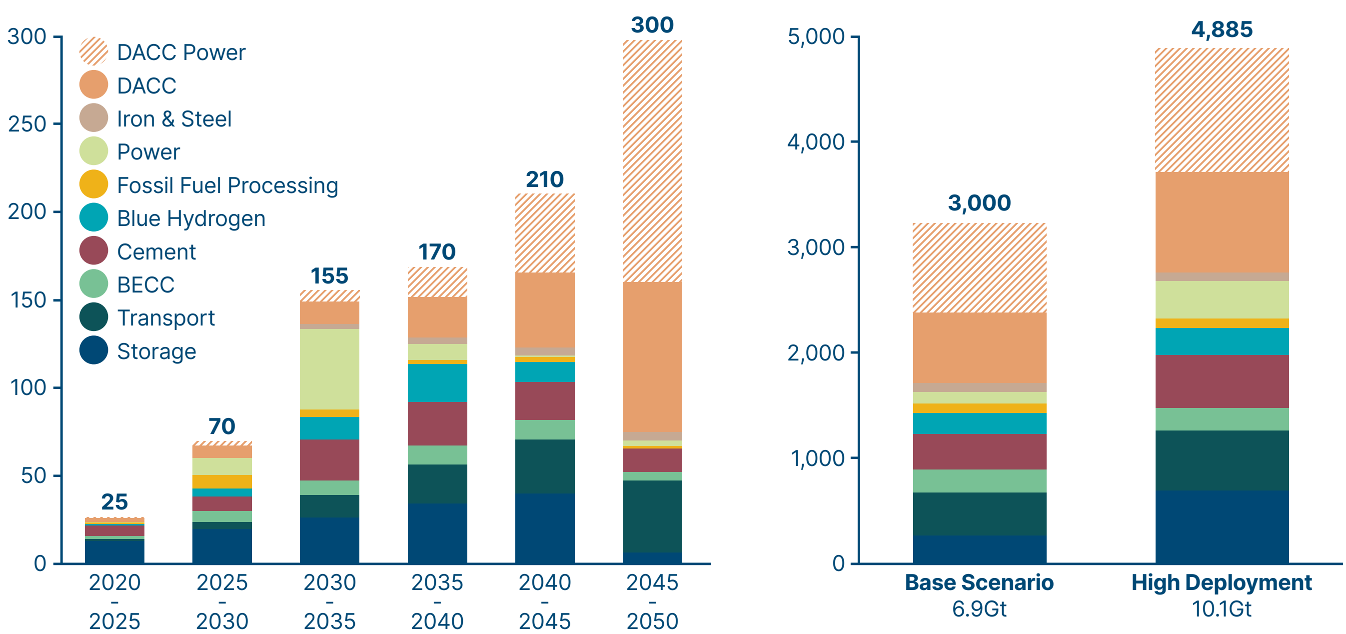


Exhibit 56

NOTES: DACC power is modelled owing to the especially high energy costs associated with collecting CO_2 from low concentration levels. For point source capture methods, energy consumption relatively trivial and is treated as an operational expenditure, therefore not shown here. High deployment scenario refers to 10.1GtCO_2 CCUS capacity by 2050 in which supply side decarbonisation measures only are deployed. Base Scenario sees 6.9GtCO_2 CCS capacity by 2050 as supply side decarbonization supported by energy productivity improvements as well.

SOURCE: SYSTEMIQ analysis for the ETC

211 DACC power is modelled owing to the especially high energy costs associated with collecting CO_2 from low concentration levels. For point source capture methods, energy consumption relatively trivial and is treated as an operational expenditure, therefore not shown here.

212 Assuming a learning rate of 12% and a starting CAPEX of $1,500/t$CO_2$

213 Average annual CAPEX in the oil and gas industry averaged ~$533bn 2015 – 2020. High range projected average annual CCUS CAPEX requirement ($140bn) amounts to 26% of this figure. Fitch Solutions (2021) *Oil and Gas Global CAPEX Outlook July 2021.*

3.3 Current plans by sector – falling far short of 2030 requirements

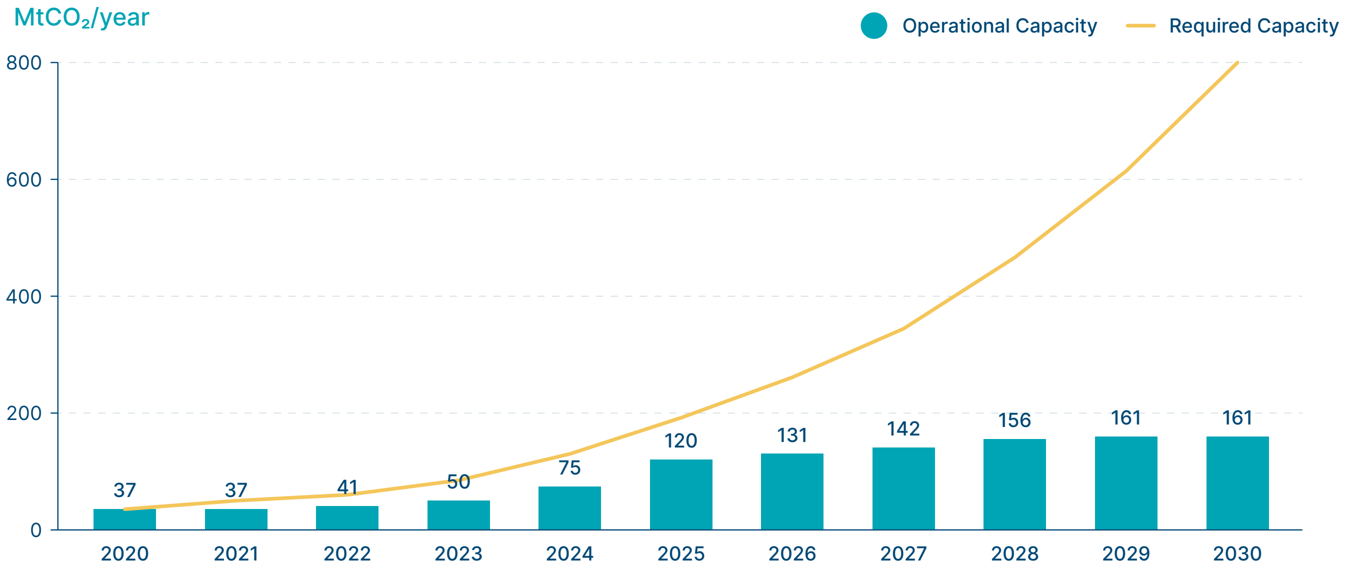
The combination of the sectoral assumptions described above results in the overall growth profile shown in Exhibit 57, which implies an aggregate volume of 800Mtpa across all sectors by 2030. This compares with a pipeline of ~160 Mtpa today, implying a deficit of ~640 Mtpa. Meeting this shortfall will require around 175 additional CCUS-capable facilities to enter service by 2030.[214]

Some growth will be required in all sectors if the subsequent pathways to 2050 implied by our scenarios are to be credible. However, the extent of the shortfall varies by sector, reflecting the interplay between TRL, economics and policy choices. Exhibit 58 shows an indicative view of CCUS capacity outlook by sector and how many additional facilities would be needed by 2030 to deliver the growth path described above.[215]

Required versus planned carbon capture capacity increase 2020-30

Exhibit 57

Required versus planned carbon capture capacity increase 2020-30



SOURCE: SYSTEMIQ analysis for the ETC (2022)

214 This figure is derived from the 2030 sectoral breakdown of CCUS capacity requirements, divided by the expected average CCUS plant capacity (by sector) minus the number of plants already in operation and in the pipeline.

215 The average sizes of new plants are based on the average plant size of the largest 20% plants in the US and EU and applies to all sectors except BECCS where we assume the majority of early plants will be conversions from coal and thus draw upon Drax in the UK as a typical plant size. For DACCS, based on Carbon Engineering and 1point5's plans to build 70 DACC plants by 2035, each with a CO_2 capture capacity of 1 Mtpa.

Over 200 additional projects need to enter the CCUS project pipeline in the early 2020s

CCS facilities needed by 2030

Million tonnes CO_2 per annum

Sector	CO_2 Removed in 2021	CO_2 Removal Needed 2030	Estimated CCS Plant Size	CCS Facilities Needed in 2030
Iron & Steel	1	10	4	2
Power CCS	1	220	4	55
Fossil fuel processing	33	160	2	80
Blue H_2/ Ammonia	3	125	1.5	75
Cement	<1	40	1.5	30
BECCS	0	170	4	40
DACCS	<1	60	1	60
Total	37	800	-	

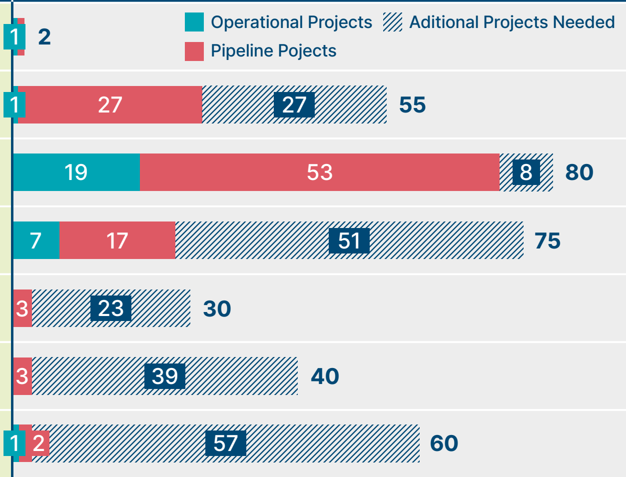


Exhibit 58

NOTES: Average size of new plants is based on the average plant size of the largest 20% plants in the US and EU. This applies to all sectors except BECCS where we assume the majority of early plants will be conversions from coal and thus draw upon Drax in the UK as a typical plant size. For DACCS, based on Carbon Engineering and 1point5's plans to build 70 DACC plants by 2035, each with a CO_2 capture capacity of 1Mtpa. Totals are rounded.

SOURCE: SYSTEMIQ Analysis; EEA; EPA; Global Cement and Concrete Association; MPP; IEA (2020) *CCUS in the transition to net zero emissions*; Global CCS Institute (2021) *Global Status of CCS 2021*

3.4 Slow progress over the last 15 years – lessons learned

Achieving the growth required in the 2020s would entail a dramatic change in trend, after a decade in which the number of operating plants has grown at a glacial pace and many announced projects have been mothballed or abandoned entirely.[216] (Exhibit 59). Total investment in CCUS projects has been only $7 billion over the last decade compared to $3.4 trillion into renewable energy over the same period.[217]

It is therefore important to understand why past growth has fallen far below expectations and what lessons can be learned for policy and focus going forward.

This section presents an understanding of the reasons for slow progress in CCUS development over the past decade, suggesting four key causes of slow progress and high project failure rate can be discerned (Exhibit 60):[218]

- Unfavourable economics relative to alternative technologies.
- Technical challenges.
- Coordination challenges across the value chain.
- Public opposition.

216 Abdulla et al. (2021) *Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments*; Robinson R. (2016) *Offshore Megaprojects - Why we fail and how to fix it.*

217 BNEF (2022) *Energy Transition Investment Trends.*

218 Although the following section focuses principally on the problems which caused delays and project failures, it is important to note that not all CCS projects ended with delays or cancellations. Projects such as Air Products SMR in Texas or ADM's ethanol plant in Illinois are often cited as successes.

Global CCUS project cancellations peaked in the mid-2010s but the pipeline is recovering sharply in the early 2020s

Global CCUS project pipeline and cancellations

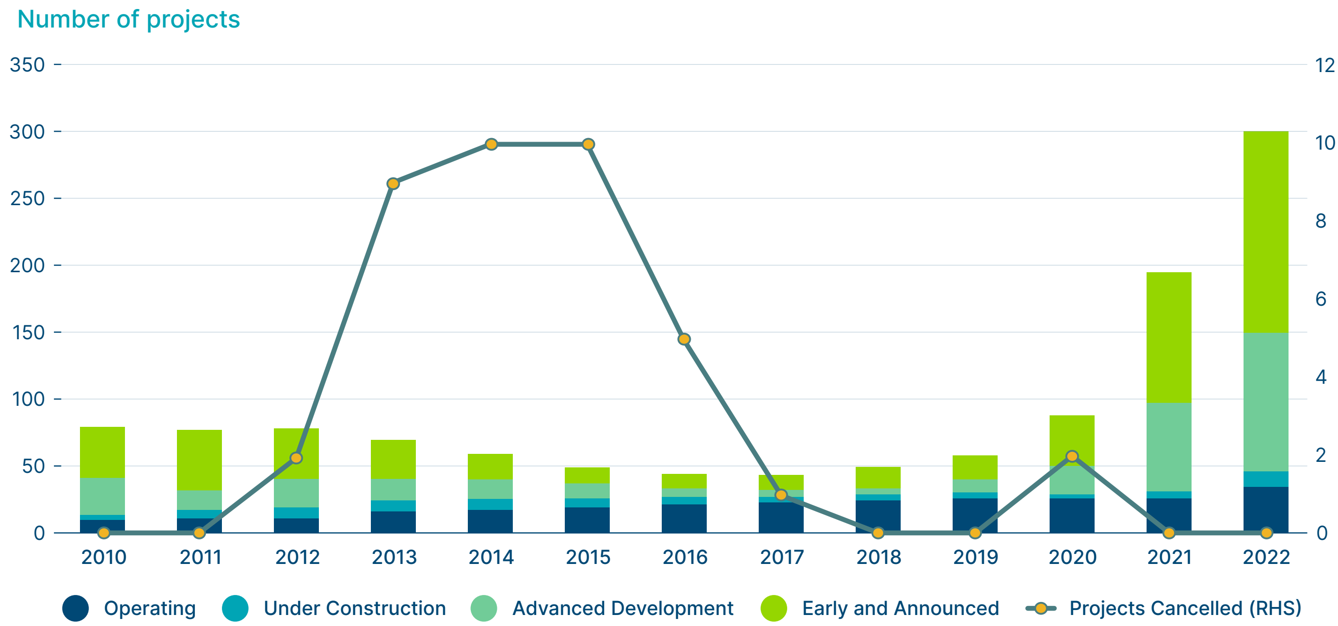


Exhibit 59

SOURCES: IEA (2021) *Global pipeline of commercial CCUS facilities operating and in development, 2010-2021* and Global CCS Institute (2022) *Facilities Database*

Challenging economics, technical problems, a lack of coordination and public opposition were the principal causes underlying high CCUS project cancellation rates in the 2010s

Causes of CCUS project cancelations

Economic role of CCUS		2 Technical Challenges	3 Coordination of asset buildout	4 Public Acceptance
1a Costs of CCUS	1a Cost of Alternatives			
• Inherently high project costs which did not decline • Government funding either scarce or unreliable • Weak carbon price signal • Oil price collapses undermined business case	• Steep declines in renewable costs displaced coal from merit, undermining CCS' role in decarbonizing baseload power • Clarity on niche role for CCS in industry and need for CCS-based removals did not emerge until later	• Scaling up from pilot to large scale projects proved very difficult • Capture rates frequently below expectations • Many industrial CCUS technologies still low TRL	• Inherent cross chain risks imply danger of counterparty default, stranded assets, under-utilization • First mover disadvantage	• Widespread opposition to technology seen as legitimising continued reliance on fossil fuels • Negative feedback loop; failed projects reinforce perceptions that technology does not work

Exhibit 60

SOURCES: SYSTEMIQ analysis for the ETC (2022)

3.4.1 Economics relative to the alternatives

Understanding the reasons

One reason why many CCUS projects have been abandoned, particularly in the power sector, is actually welcome: the cost of alternative decarbonisation routes has declined (Exhibit 61). Before 2010 many analysts anticipated a major role for CCS in the decarbonisation of coal and gas-based generation.[219] But dramatic falls in the cost of renewables have led to many fossil fuel power projects being abandoned. In 2015 the pipeline of coal generation projects stood at 1550 GW: by 2021 this had fallen to 480 GW (Exhibit 62). As a result many plans to apply CCS to coal generation were also abandoned.

Wind costs have declined by 60% and solar costs by 90% in the past decade

Solar PV and wind LCOE

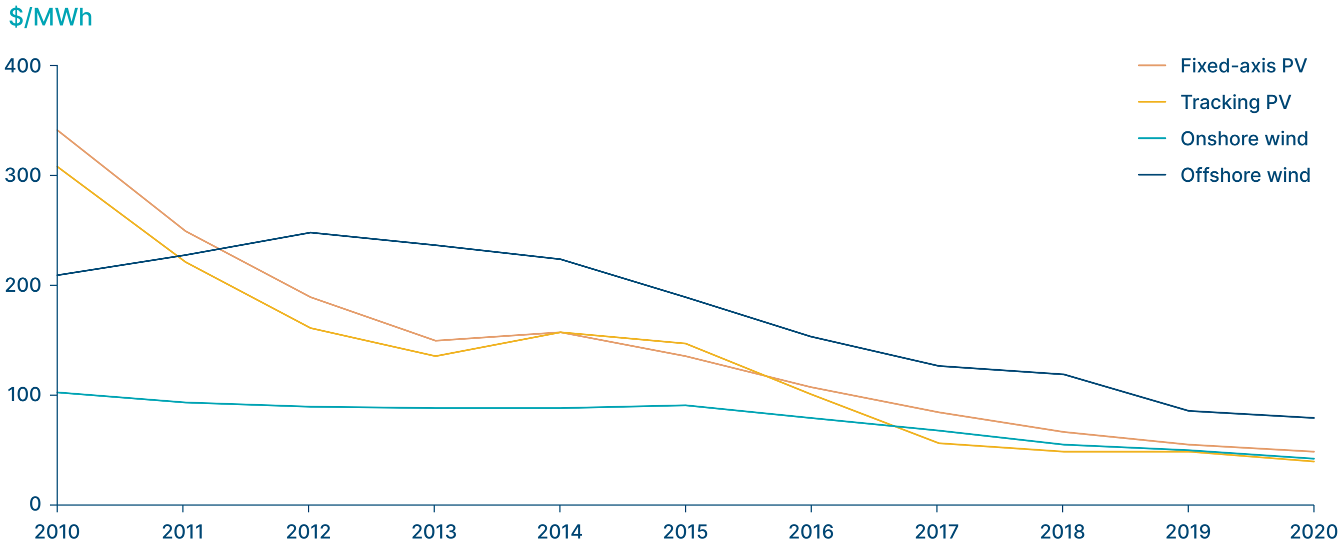


Exhibit 61

SOURCES: BNEF (2021)

219 A survey in 2010 found that ~70% of all CCS projects under development worldwide were in the power sector IEA/GCCSI (2010) *Carbon Capture and Storage: Progress and Next Steps.*

The global coal generation capacity pipeline has declined dramatically since 2015

Global coal generation capacity pipeline

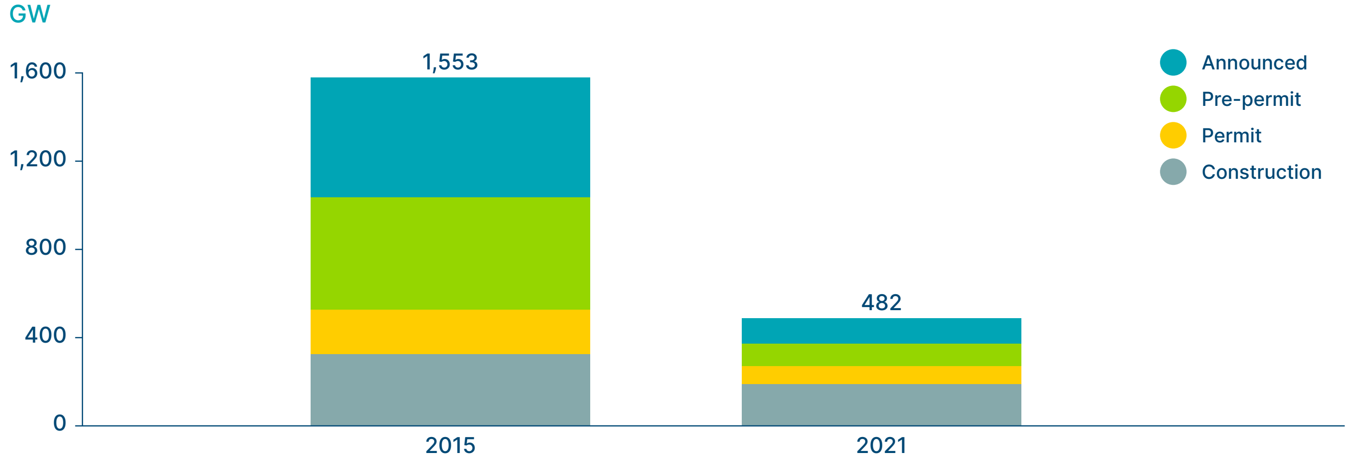


Exhibit 62

SOURCES: E3G (2021) *No New Coal by 2021: The collapse of the global coal pipeline*

In addition, however, the costs of CCUS projects have not declined as anticipated and in many projects have faced cost overruns versus initial plans. Data availability is limited and comparability difficult because of the inherent differences in cost by specific application discussed in Chapter 2. But Exhibit 63 which shows cost per tCO_2 captured for projects launched in the period 2008-16 suggests if anything that costs were higher at the end of the period than the beginning. Future projects are expected to achieve lower capture costs, but this could reflect either a different mix of project type or overambitious expectations from project developers.

Some projects have also been abandoned because commodity or other prices moved in ways which undermined the economic rationale.[220]

- **Power:** very low carbon prices within the EU ETS in the aftermath of the 2008 financial crisis undermined the economics of CCS projects even while other policy levers (such as feed in tariffs and CFDs) supported continued renewable electricity investment. For instance E.ON's coal CCS plant at Killingholme's in the UK was cancelled in the face of both low wholesale electricity and low carbon prices.[221]

- **Oil**: projects which supplied CO_2 for EOR became economically unviable during the oil price collapse of 2014 (as OPEC and shale oil competition led to a glut in supply) and in 2020 (when COVID-related travel restrictions sharply reduced oil demand). For example, NRG's Petra Nova coal fired CCS & EOR facility in Texas was forced to close after the collapse in the price of oil caused by the Covid pandemic wiped out its revenues.[222]

  - **Steel**: The sharp contraction in the European steel sector 2010 – 2015 forced Arcelor Mittal to pull out of the ULCOS project in France in 2012.[223]

  - **Methanol**: The surge in shale gas production gave rise to a glut in methanol production on the US Gulf coast. This depressed prices forced the suspension of the Lake Charles methanol CCS projects (although this has since been resurrected).[224]

Looking forward, the relative economics of CCUS versus alternative decarbonization options will continue to evolve, sometimes in unpredictable ways. But it is important to base plans on best possible assumptions about the future role of CCUS. This suggests a considerably smaller role in the power sector than seemed likely 10 years ago.

220 Abdulla A. et al. (2021) *Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments.*
221 AT Kearney Energy Transition Institute (2021) *Carbon Capture Utilisation and Storage: Towards Net Zero.*
222 Reuters (2020) *Problems plagued U.S. CO_2 capture project before shutdown.*
223 AT Kearney Energy Transition Institute (2021) *Carbon Capture Utilisation and Storage: Towards Net Zero*
224 Ibid.

CCUS capture costs broadly increased in the 2010s

CCUS projects by capture capacity, cost and status

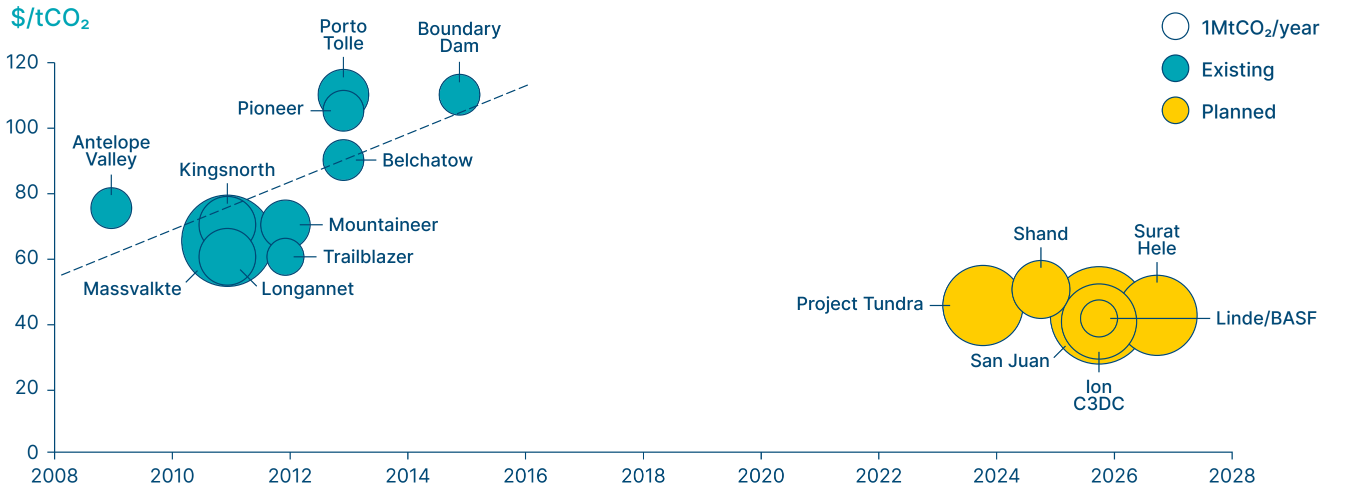


Exhibit 63

SOURCES: Global CCS Institute (2020) *Global Status of CCS report*

Addressing the risks

CCUS products are inherently more expensive than their conventional product equivalent – for example cement produced using CCUS technology can never be cheaper than ordinary cement, without regulatory intervention.

Therefore CCUS will always require some form of regulatory support – be it financial or regulatory, e.g. in the form of mandates for low carbon end products (Exhibit 64). In the short term, capital grants and state backed loans for specific projects are an acceptable means of helping first of a kind (FOAK) projects. Tax credits, production incentives and contracts for difference are also a viable option for the medium term.

In the longer term, investment into carbon capture can be supported through technology agnostic mechanisms which advantage low-carbon materials (Exhibit 65). These include public procurement, mandates for low-carbon end products (e.g. aggregates produced using captured CO_2) and strong carbon pricing.[225] Examples include:

- Public procurement in particular offers a convenient means of generating significant demand for low carbon products. For example, nearly 40% of concrete sold in North America is ultimately paid for by the state[226] – this represents a substantial opportunity to support scale up.
- Blending mandates for jet which ensure synthetic aviation fuel constitutes a minimum (but growing) share of volumes sold. For example Norway introduced an SAF blending mandate of 0.5% in 2020, increasing to 30% by 2030.[227]

Some stakeholders have advocated for the introduction of a Carbon Storage Obligation (CSO). This would require fossil fuel suppliers to store an increasing fraction of the carbon contained in the fossil fuels they supply. The obligation would be small to start with and rise to 100% to deliver net-zero. However, such measures also singles out CCUS at the expense of other (potentially more efficient) means of decarbonisation. However this implicitly imposes a carbon price at the same price of CCUS, which if higher than alternative decarbonisation options would not represent the lowest-cost option available. Therefore CSOs may not be the first choice policy but if used must be considered alongside policy support measures aimed at reducing demand for oil products (see exhibit 64)

225 In economic theory, strong carbon pricing is the most efficient way to drive decarbonisation decisions across the economy, however, in practice a range of policy tools is likely to be required.

226 Total cement consumption in the U.S. was 98.5 million tonnes (Mt) in 2018. From that, around 45 Mt was used in public constructions, paid for ultimately by the government. Global Efficiency Intelligence (2021) *Federal Buy Clean for Cement and Steel: Policy Design and Impact on Industrial Emissions and Competitiveness.*

227 World Economic Forum (2020) *Clean Skies for Tomorrow.*

Support for carbon capture should evolve over time from targeted measures to technology-agnostic mechanisms

Support measures for new carbon capture projects

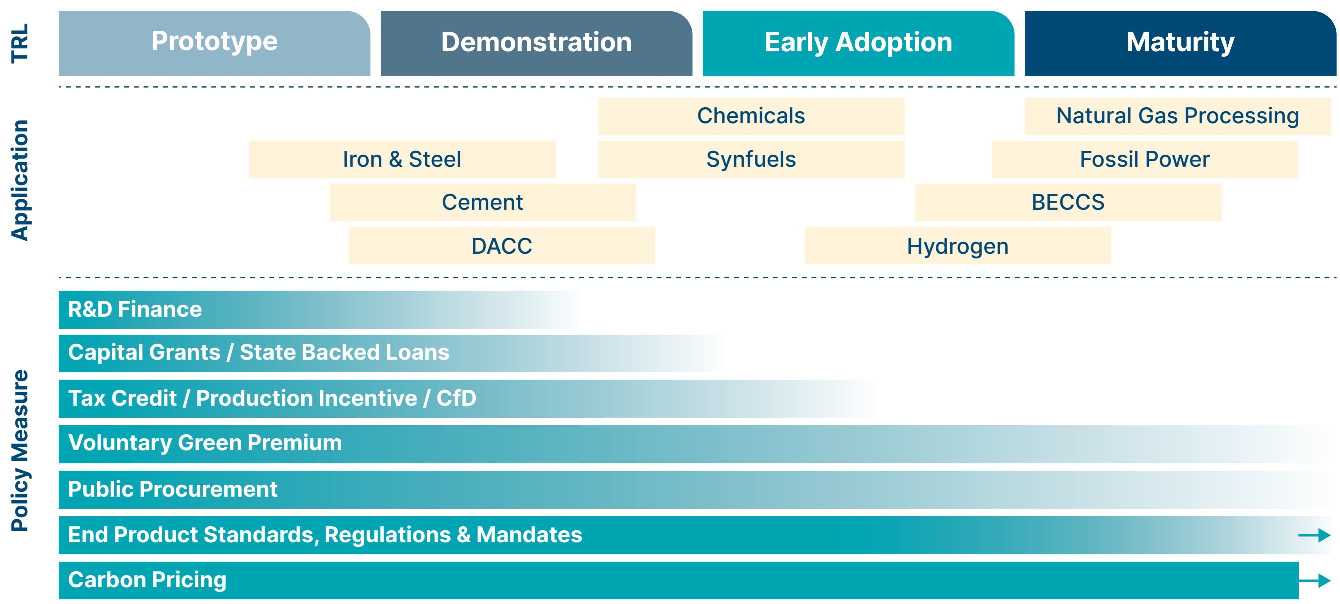
Carbon Pricing / CBAM	Carbon costs render carbon-intensive products less competitive, thereby boosting demand for carbon neutral/negative materials. CBAM impose costs on imports from countries with less stringent emissions targets in order to prevent carbon leakage. Applicable principally to industrial products.	**OPEX**	**Permanent**, with ramp up in most cases
End Product Standards or Mandates	Gradual tightening in regulations for sectors which rely upon industrial materials covered here drives demand for carbon neutral/negative products.		
Public Procerement	Government contracts for construction and maintenance (new buildings, roads, infrastructure, etc) mandate maximum carbon intensity, boosting demand for carbon neutral/negative materials.		**Permanent**, with possible scaling back later on
Voluntary Green Premiums	Corporations and individuals vote with their feet by buying carbon neutral/negative products, despite higher prices.		
Tax Credit / Production Incentive / CfD	Capture technology-specific feature of regulatory regime which enhances asset's profitability. Examples include 45Q in the US or ICC contracts in the UK (effectively CfDs reimbursing CCS costs).	**CAPEX**	**Additional** at an early stage
Capital Grants / State-Backed Loans	One-off funding for technologies which demonstrate capacity to advance knowledge through learning and thereby reduce technology costs. E.g. EU Innovation fund €1bn for 7 CCUS projects.		
Carbon Storage Obligation	Systems of Carbon Storage Obligations would require fossil fuel suppliers to store an increasing fraction of the carbon contained in the fossil fuels they supply. The obligation would be small to start with and rise to 100% to deliver net zero. Drives demand for BECCS/DACCS. CSOs may offer an additional alternative means to support decarbonisation of residual oil products. However this implicitly imposes a carbon price at the same price of CCUS, which if higher than alternative decarbonization options would not represent the lowest-cost option available. Therefore CSOs may not be the first choice policy but if used must be considered alongside policy support measures aimed at reducing demand for oil products (e.g. electrification).	**OPEX**	**Only consider in some circumstances**

SOURCE: SYSTEMIQ analysis for the ETC (2022)

Exhibit 64

Technology specific support should gradually decline as technologies mature; carbon pricing, standards and mandates can remain indefinitely

Evolution of support for carbon capture



NOTES: These support measures pertain to carbon capture projects only. Regulated revenue streams are required in order to deliver – and share the costs of - the supporting T&S infrastructure (see Section 3.4.3).

SOURCE: adapted from IEA (2020) *Energy Technology Perspectives 2020: Special report on CCUS*

Exhibit 65

3.4.2 Technical challenges

Understanding the reasons

The low TRL of many CCUS projects in the 2010s increased the chances of project failure. Projects which sought to apply cutting edge technologies typically suffered more delays and budget over-runs than projects focused on sectors where the technology was more mature, such as natural gas processing.

Equally, the challenge of scaling up a specific technology – that is going from laboratory to demonstration to an industrial scale – has proven to be challenging as real-world conditions differ from a carefully controlled laboratory environment. For example, inducing solvent/sorbent regeneration in commercial settings entails a different set of inputs and equipment since the heat transfer properties of capture media alter at scale.

Moreover, there is evidence that these technical challenges have been greatest, and the rate of project cancellation higher, for mega-projects.[228] This may reflect the inherent challenge of applying CCS in large complex and interrelated industrial plants which require bespoke design and implementation. For example, the Gorgon project in Australia was intended to apply a relatively mature form of carbon capture (natural gas processing) at a large scale. Yet the sheer size of the project increased complexity and the scope for disruptions, such that between 2017-2021 the project only captured and stored 42% of CO_2 emissions, significantly lower than its 80% target (see Box 4: Carbon capture rates: separating fact from fiction).[229]

Addressing the risks

Moving low TRL CCUS applications from pilot projects to commercial operation continues to present challenges. In particular projects which entail retrofitting to large plants or industrial processes, continue to face the risk of “lock-in” effects intrinsically associated with being connected to a greater technological system.[230] Attachment to the larger system requires more sophisticated implementation and customisation, which increases difficulty and time to completion – these challenges are inherent and remain a significant risk to CCUS projects today. Equally large-scale projects also still tend to rely upon policy support, in turn necessitating longer stakeholder negotiation and decision-making processes.[231]

However, lessons have been learned from the previous decade. For example, there is now an emerging consensus amongst industry players on the potential for modularisation of capture units as a means to facilitate scale up.[232] This avoids complications arising from changed physical behaviours properties when equipment is simply expanded (e.g. heat transfer properties) but also allows for off-site fabrication and incrementally lowers marginal costs via increased unit output.[233]

Business innovation plays a key role in overcoming the technical challenges associated with scaling up CCUS technologies. In practice this ultimately means delivering cost reductions which can ensure CCUS offers a competitive means to decarbonisation. This will come via:

- Technology breakthroughs (for example the use of Electro Swing Adsorption in lowering DACC costs).

- Economies of scale offer pathways to lower cost too – for example modularisation of capture assets implies a rapid build-up of expertise and cost reduction potential via repeat production of the same unit, even if the technology itself does not change.

- Innovative business models such as Carbon capture as a Service (CaaS). Throughout the 2010’s much of the funding for CCS was directed towards mega-projects in which a single vertically integrated entity or a joint venture of large corporations would seek to deliver the entire CCS value chain (capture, transport and storage). Whilst this approach afforded some benefits with regards to construction synchronisation and eliminating transactions costs along the value chain, it did little to develop industry supply chains, much less foster CCS capacity elsewhere. By contrast the CaaS model sees plant operators pay a third party to capture, transport and store/utilise/sell the CO_2 at a fixed rate. Often the CaaS provider will also help arrange finance the project, based on existing relationships with financial entities with a deep understanding of the model and thus strong lending capacity. This opens CCUS up to a significantly wider range of mid-cap businesses which otherwise lack the financial or managerial capacity to execute such a project.

- There is also a greater focus on reducing the industrial footprint of the carbon capture equipment (frequently to less than the size of a shipping container) thereby reducing installation and fabrication costs.

228 Wang et al. (2021) *What went wrong? Learning from three decades of carbon capture, utilisation and sequestration (CCUS) pilot and demonstration projects.*
229 The Sydney Morning Herald (2021) *Chevron’s five years of Gorgon carbon storage failure could cost $230 million.*
230 Grubler, A. (2012) *Energy transition research: insights and cautionary tales.*
231 Wang et al. (2021) *What went wrong? Learning from three decades of carbon capture, utilisation and sequestration (CCUS) pilot and demonstration projects.*
232 Krishnamoorti R. (2019) *Modularization & Intensification of Carbon Capture Utilisation & Storage.*
233 Oxburgh L. (2016) *Lowest cost decarbonisation for the UK: The critical role of CCS.*

Finally, deployment of CCUS technologies to date has been sporadic and largely bespoke. A programme of scale deployment of CCUS is expected to lead to some opportunities for resolving technical challenges through learning-by-doing, repeat design and industry knowledge-sharing.

3.4.3 Coordination challenges across the value chain

Understanding the reasons

CCUS projects are by nature multi-stage processes, requiring coordinated development and installation of capture technologies, transportation and storage or use infrastructure. Indeed CCUS projects typically take at least 7 years with identification and preparation of storage sites a 3+ year process (see Box 5: Characterising geological storage sites – a critical bottleneck in delivering CCS and engineered CDR at scale for further discussion) and installation of capture and transport a further 4+ years (Exhibit 67).

Given the economies of scale for transport and storage infrastructure outlined in Chapter 2, CCUS projects are likely to benefit from the coordinated development of shared infrastructure – referred to as industrial CCUS hubs or clusters. A CCUS hub or cluster network brings together multiple CO_2 emitters/offtakers and at least one storage operator, through shared transportation infrastructure. Regions offering both a high concentration of emitting industries and a nearby capacity to store emissions are considered prime sites for hub and cluster developments.[234] They can also act as import hubs for CO_2 shipped from overseas, thereby enabling new capture projects around the globe. So-called 'anchor' projects, which account for a significant proportion of the total CO_2 captured at a hub may further accelerate CCUS development, by providing a large early-user of transport and storage infrastructure and assuming a proportionate share of upfront capital costs.[235] Today, power projects (including BECCS) are often considered plausible candidates as anchor projects given their typically large capture capacity (especially where the CCUS technology is being retrofitted onto a large plant).

Hubs can enable:

- **Reduced transport and storage costs**. 'Clustered' industrial sources can utilise shared transport and storage infrastructure thus reducing the cost of CCUS for individual customers[236] – particularly smaller entities which do not have the capacity to undertake major T&S infrastructure investments.[237] In many cases transport and storage development will only be economic if the capacity is to be used by many different capture projects.[238] Hubs also enable easier linkages between CO_2 capture and CO_2 utilisation facilities.

- **Active cross-value chain collaboration between corporates**, including risk-sharing and co-funding agreements (as is occurring in many CCUS 'hubs' today).

- **Tactical project location and delivery to shorten overall project delivery times**. For example, selective storage site development to reduce data gathering and appraisal, combined with accelerated capture technology and transport infrastructure delivery timelines can reduce overall project timelines from 7-10 years to as little as 5 years (Exhibit 67).

- **Coordinated public policy support** which otherwise may not occur due to the dispersed nature of the benefits. The role that governments can play in helping to coordinate developments is also increasingly understood.[239]

Hubs therefore have lower investment and lifetime costs and could ultimately lower the costs of CCUS compared with "point to point" projects (Exhibit 66).[240] Indeed, without access to shared infrastructure, T&S costs for small users may be prohibitive, meaning few if any projects are likely to see one company as the sole investor in each step of the chain.

There is therefore an inherent coordination challenge, with capture projects unable to proceed without clarity on transport and storage costs, while transport and storage infrastructure will not be built without some certainty about future capture developments. Inability to achieve adequate coordination has been a factor in some project cancellations such as the White Rose project in the UK. It is worth noting that these challenges are likely to increase over time: early projects tend to be located in areas that have close access to secure geologic storage, but over time projects will be needed in regions that do not have that close access and will require more extensive transportation infrastructure development.

234 Global CCS Institute (2016) *Understanding Industrial CCS Hubs and Clusters.*
235 Ibid.
236 Ibid.
237 Global CCS Institute (2015) *The importance of CCS Hubs and Clusters.*
238 The United Kingdom CCS Cost Reduction Task Force found that CO_2 transport costs could be reduced by 50% with the deployment of large pipelines, noting that even lower costs could be seen in the longer run if even higher volumes of CO_2 from multiple large capture plants were feeding into an interconnected right-sized network: IEA GHG R&D Programme (2015) *Carbon capture and storage cluster projects: review and future opportunities.*
239 Temperton I. (2018) *CCS: new enthusiasm, old uncertainty and the need for a Delivery Body.*
240 Wood Mackenzie (2021) *Carbon capture and storage: how far can costs fall?*

Hubs could lower CCUS breakeven thresholds by 20-25% through reduced transport and storage costs

CCUS levelised costs by standalone project and multi-user hubs

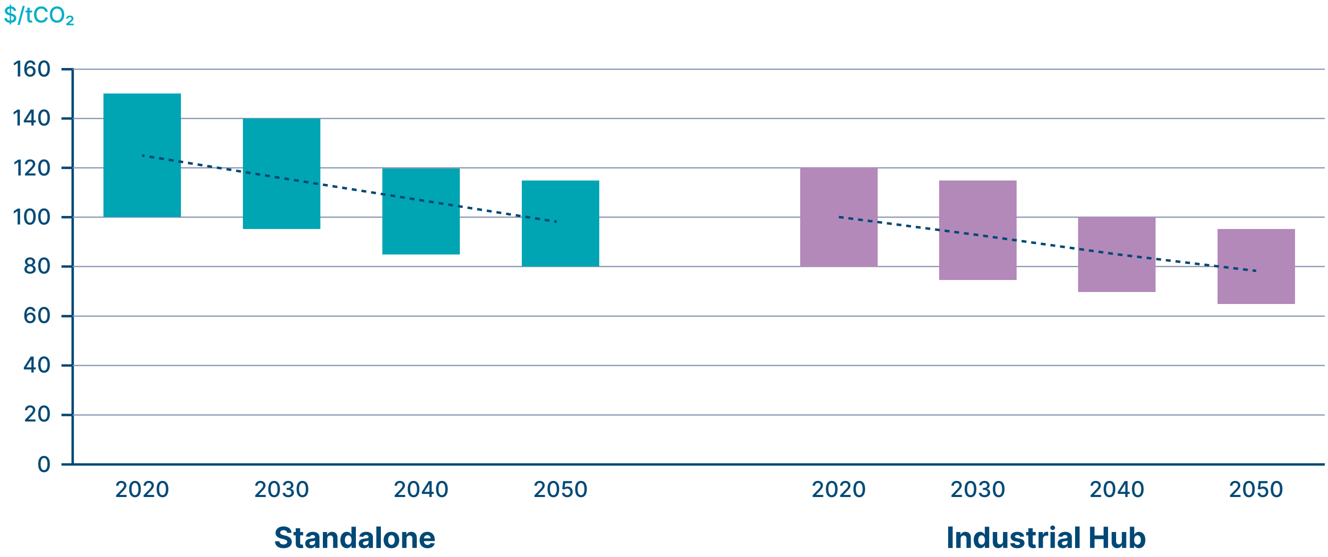


Exhibit 66

NOTES: Hub refers to a CO_2 transportation and storage service which is developed and operated separately from the capture project.

SOURCE: Wood Mackenzie (2021) *Carbon capture and storage: how far can costs fall?*

Long lead times in CCS infrastructure rollout could challenge 2030 capacity ambitions

Standard timeline for CCUS asset development

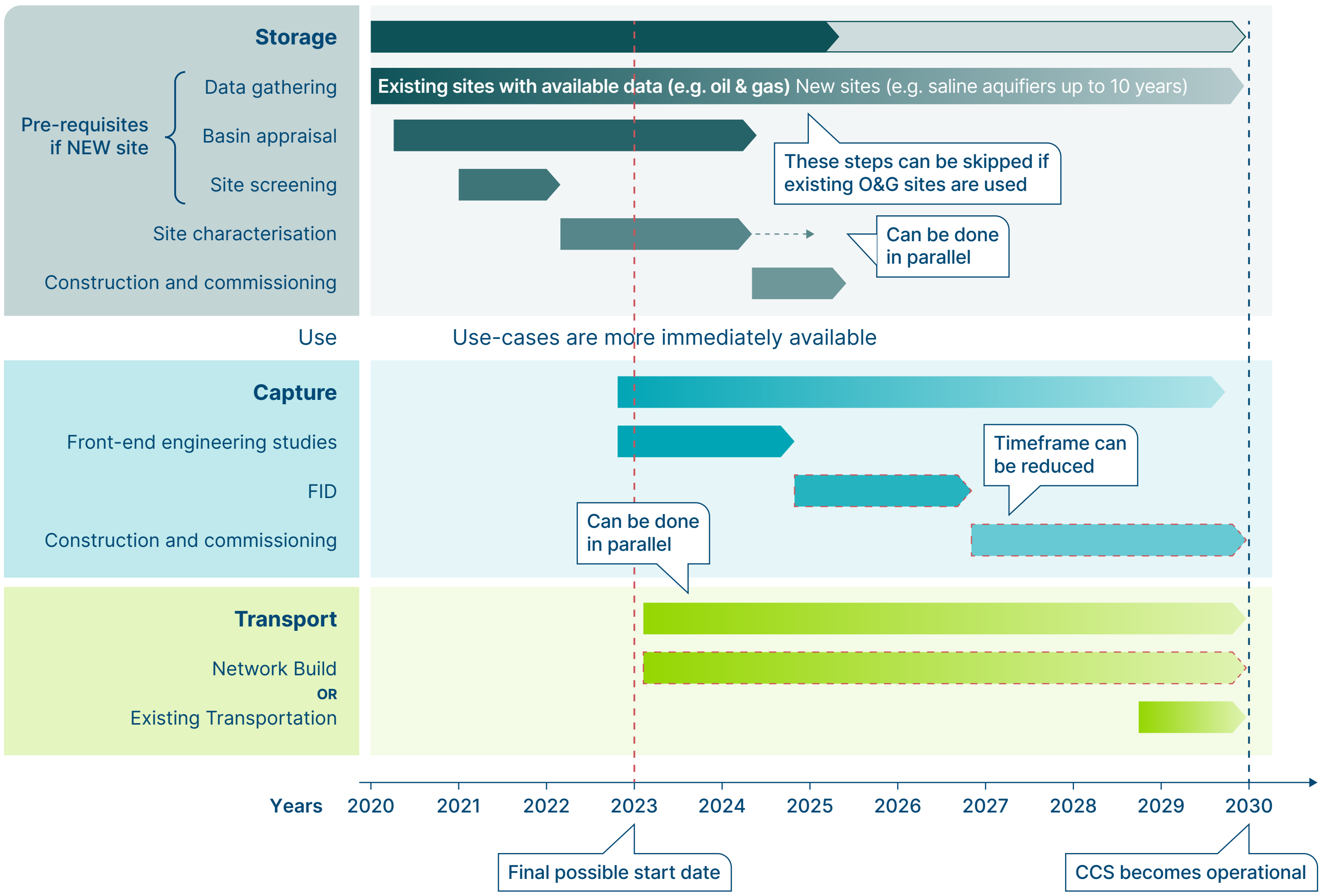


Exhibit 67

SOURCES: SYSTEMIQ analysis for ETC (2022)

Addressing the risks

The specific challenges involved in developing the CCUS value chain argue for focusing on the development of initial CCUS industrial clusters, where the simultaneous development of capture, storage, transport and end use can de-risk investment and drive self-reinforcing developments.

Government support can play several roles in the development of industrial clusters which can drive a scaled CCUS industry:

- **Designation of industrial zones and expedite planning processes** (at both the national and regional levels) associated with industrial cluster development.

- **Development of pipelines and storage** assets can be accelerated by government. These assets are natural monopolies – a platform which carbon capture assets require for development – hence it is optimal for a single operator to provide shared T&S services to all users (i.e. capture entities) since this lowers users' T&S cost.[241] Lack of storage capacity is already emerging as a bottleneck in some regions – notably Europe.[242] Governments should prioritise the delivery of shared T&S infrastructure.

241 The development of T&S capacity is a necessary precondition to individual users' capture investments but the reverse does not hold since these users operate in a competitive market.
242 Clean Air Task Force (2022) *Europe's gap between carbon storage development and capture demand.*

- For storage, governments can help foster investment into new capacity through direct targeted support and/or tax relief for storage surveys and test injections.
- For pipelines, price regulation offers a viable means to deliver new capacity whilst protecting capture entities. Multiple examples exist of regulatory models which have successfully delivered investment into energy networks, telecoms or water, whilst providing users with lowest cost network access (e.g. RAB, RPI-X or Cost +).[243]

- **Reduction of project failure rates by providing template contracts** allocating responsibilities, bypassing the need for legal negotiations. Contract negotiations both at the outset of the project and during construction if/when problems arise can be extremely time consuming. Governments to offer a template commercial agreement in which risk and reward are clearly allocated between the various parties, including the government. This "over the counter" contract model provides a checklist for eventualities such as asset under-utilisation, construction delays, T&S outages, decommissioning liabilities and cost over-runs.[244] This approach has been adopted in the UK, where the government has developed a set of model contracts for power, industrial carbon capture, blue hydrogen and transport & storage, providing a set of standard terms of reference to help overcome various risks.[245]

Time saving measures could potentially reduce the CCS infrastructure timeline by as much as five years

Illustrative Accelerated CCS Project Timeframe

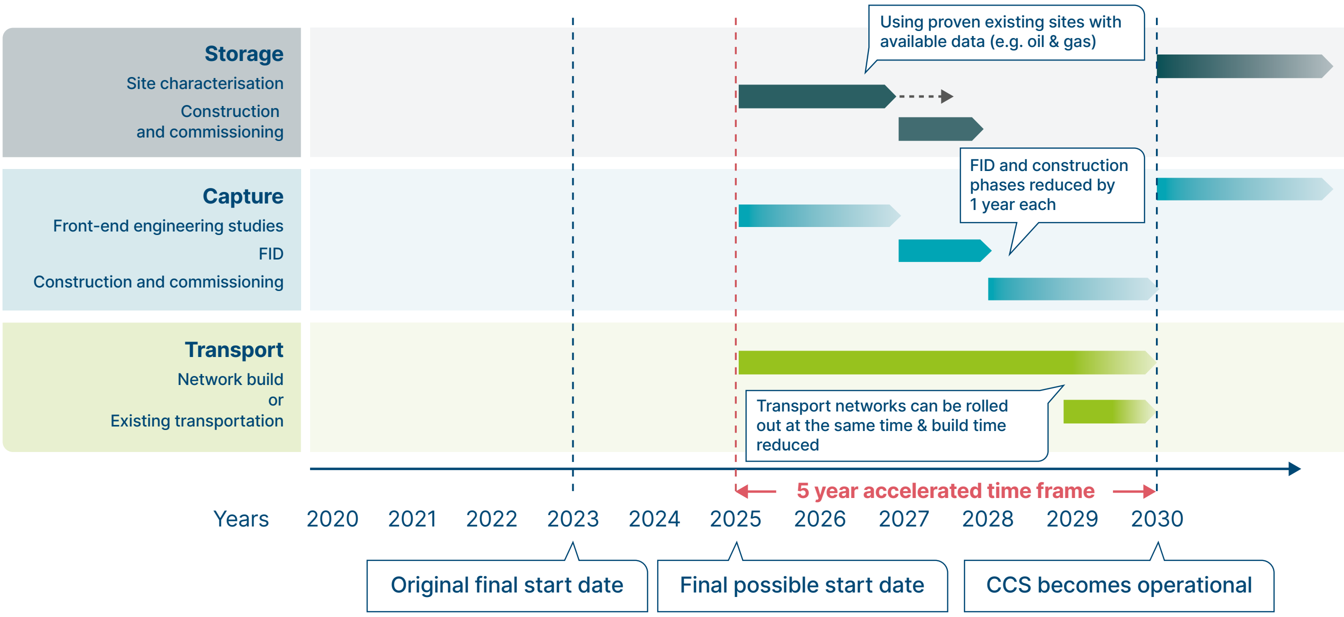


Exhibit 68

SOURCE: SYSTEMIQ analysis for the ETC (2021)

3.4.4 Public opposition

Understanding the reasons

Public opposition to CCUS can delay projects, causing cost overruns or even the scrapping of entire projects.[246] Public opposition has probably contributed to the cancellation of some projects such as the Barendrecht project in the Netherlands,[247] and some countries, for instance Austria, have clear public policies to prohibit CCS development.[248]

243 Typically under these models: i) Operators receive a license to charge a regulated price to emitters; ii) Investors are guaranteed a given rate of return, lowering cost of capital; iii) The model mitigates against the operator charging excessive rates.
244 The template can serve as a benchmark for typical risk/reward allocations, reducing negotiation time. These benchmarks might be based upon earlier projects – although the parties will still need to agree the specific terms, the inclusion of benchmarks can provide a starting point. Slaughter and May (2021) *Carbon capture, usage and storage: managing co-dependency is key to success.*
245 UK Department for Business, Energy & Industrial Strategy (2019) *Carbon capture, usage and storage (CCUS): business models.*
246 In some instances – notably in the application of CCS in power in the US – this line of causality has been reversed: opposition to CCS emerged amid concern that end user prices would increase, impacting low-income groups.
247 Global CCS Institute (2010) *What happened in Barendrecht? Case study on the planned onshore carbon dioxide storage in Barendrecht, the Netherlands.*
248 European Commission (2020) *Austria Improving financial security in the context of the Environmental Liability Directive (11.3).*

While the capture of CO_2 from industrial emitters might enjoy support due to job creation, the storage of CO_2 is more controversial. Fears are often expressed about potential leaks or induced seismic activities such as earthquakes, especially for onshore storage.[249]

Opposition to CCUS also reflects concerns that it may be used as an excuse to maintain and expand fossil fuel production, creating “facts on the ground” which make it more difficult to achieve energy transition to a zero-carbon economy. This is fuelled by widespread mistrust of oil and gas companies among many environmental NGOs and exacerbated by the significant role which EOR has played in early stages of CCS development.

In some instances, the cost of carbon capture technology and the perceived impact on end-user prices has generated opposition as well.[250]

Addressing the risks

Overcoming public opposition to CCUS is likely to be contingent on:

- Setting out clearly the case for believing that CO_2 can be safely and permanently stored if projects are well managed (as discussed in Section 2.4).
- Putting in place strong regulatory and monitoring systems to ensure that storage projects use best management techniques and that project developers face clear liability for project failure.
- Ensuring that CCS projects are focused on their vital but limited role, and are in addition to (not instead of) a rapid decline in fossil fuel use.
- Recognising local benefits such as job creation.[251]
- Severely restricting any support for EOR in the way described in Chapter 2 Section 5.

3.5 Mapping the Risks

The risks which the next generation of CCUS projects face are similar but not identical to those of the previous two decades. Exhibit 69 illustrates the extent to which these challenges apply to the critical CCUS sector in the 2020’s.

- **Iron & Steel**: the complex nature of Iron & Steel CCS and low TRL means CCS will compete against a range of other decarbonisation options, including hydrogen direct reduction. In regions where those alternatives are constrained or not economic, Iron & Steel plants have the advantage of being relatively large, meaning they can either stand alone (without relying on clusters) or serve as an anchor CCUS project for industrial clusters.
- **Power CCS**: The availability of low-cost clean electricity supply continues to significantly challenge CCS in power, especially as a source of baseload capacity.
- **BECC**: The potential dual role as both a source of dispatchable, renewable power and carbon dioxide removals effectively implies two different revenue streams, easing the risks arising from competition. However, high costs and limits on sustainable biomass supply serve as a constraint.
- **Fossil Fuel Processing**: Demand for oil and eventually natural gas will decline. However, robust demand for plastics and relatively high TRL implies lower risk for high-value chemicals.
- **Blue Hydrogen:** In the near term blue hydrogen faces relatively limited competition as electrolyser costs are yet to decline sufficiently. However, blue hydrogen faces potentially significant public opposition if concerns around the impact of methane leakage cannot be addressed.
- **Cement**: An absence of proven alternatives for decarbonising process emissions implies little challenge to CCS in cement in the near term. Demand for underlying product theoretically challenged by circular economy measures and substitutes such as wood in some regions.

249 Akerboom et al. (2021) *Different this time? The prospects of CCS in the Netherlands in the 2020s.*
250 Rübbelke, D. and Vögele, S. (2012) *Effects of Carbon Dioxide Capture and Storage in Germany on European Electricity Exchange and Welfare.*
251 Gough & Mander (2022) *CCS industrial clusters: Building a social license to operate.*

- **DACC**: Technology is expensive today and seen by some as an attempt to legitimise continued fossil reliance. However, there are few scalable CDR alternatives offering long term sequestration with limited input constraints.

Clarity on the barriers faced by different CCUS sectors aids the tailored application of the actions discussed above to overcome these challenges. The next chapter outlines the key actions for the 2020s necessary to rapidly scale CCUS to meet its 2050 role as a complementary decarbonisation technology.

How do new CCUS applications perform against these challenges?

CCUS project risks by sector and level

Risk to CCUS today: High / Medium / Low

	Economic role of CCUS: 1a Cost of Technology	Economic role of CCUS: 1b Alternatives	2 Technical Challenges	3 Coordination	4 Public Acceptance
Iron & Steel	Expensive owing to complex technical requirements. CCS competes against H_2 and bio based decarbonisation based on location factors and price of hydrogen.		Multiple sources of process emissions complicate capture.	Typically large asset so able to stand alone (without cluster).	Largely untested.
Power CCS	RES challenge to baseload and batteries/H_2 potential challengers for peaking. Key focus retrofit of young coal in China & India – only alternative early retirement, unmet demand.		Technically relatively straightforward: High TRL.	Coordination potentially required for T&S and industrial hub development.	Potential opposition to fossil CCS.
BECC	Although no commercial plants in operation, TRL still relatively high. Serves dual role as CDR and seasonal/ peaking dispatch: costs high, alternatives for seasonal power H_2 or fossil CCS, alternatives for CDR nature based NCS or DACCS.				Potential opposition on grounds of land use (e.g. food, biodiversity concerns).
Fossil fuel processing	CCUS in petrochemical production cheaper than alternatives in near term. Demand for oil products and eventually natural gas set to decline amid competition from clean electricity and H_2.		Very high TRL for refining and gas process. High for HVC.		Association with plastics potentially harmful.
Blue H_2	Clean H_2 key to decarbonise parts of industry, transport, storage. Green H_2 likely cheaper in the long term (except regions with very cheap gas), transition role in the 2020s, esp. retrofitting grey.		Gas reforming mature, but few commercial ops. with CO_2 capture (esp. high capture rates).		Opposition growing regarding methane leakage.
Cement	Strong demand outlook for cement and concrete. CCS critical to decarbonising cement production process. Limited alternative building materials available. High cost and technical challenges important to overcome.				Largely untested.
DACC	FOAK very expensive – cost declines dependent on RES/ electrolyser innovation.	Limited CDR scalable alternatives which offer long term CO_2 lock in.	Still low TRL for low energy technologies (e.g. ESA).	Limited coordination required: dependent on geography, not industry.	Seen by some as a license to persist with emissions.

NOTES: ESA = electro swing adsorption.

SOURCE: SYSTEMIQ analysis for the ETC (2022)

Exhibit 69

Next steps: actions for policy makers and industry

Progress on CCUS has been slow to date, but given the vital role CCUS will play in reaching net-zero globally by mid-century, development must accelerate rapidly in the 2020s.

There is no global body which can set targets for CCUS deployment and the precise, appropriate pace of capacity additions and infrastructure growth will reflect the continuing evolution of relative costs, amongst other factors. Nevertheless, it is useful to describe the scale of carbon capture, utilisation and storage which is likely to be needed by 2030 if CCUS is to deliver its potential in achieving a zero-carbon economy. Box 8 sets out an indicative scenario.

Box 8

Scale of CCUS deployment needed by 2030

CAPTURE

- 0.8 $GtCO_2$/year of capture across a suite of technologies by 2030, including carbon dioxide removal, cement, blue hydrogen, iron and steel, petrochemicals and fossil fuel processing, power generation and synthetic jet fuel.
- Active carbon capture at over 300 large industrial, energy production or carbon dioxide removal facilities, up from just 30 today.
- High capture rates at the majority of facilities, targeting 90%+ capture rate.

TRANSPORT & STORAGE

- ~5 $GtCO_2$ storage capacity will be required for the period to 2035 bringing the sites from theoretical potential to injection ready, with 0.5 $GtCO_2$/year being injected in 2030, and additional test injections at sites under development.
- At least 100 CCS hubs in operation around the world, benefitting from economies of scale and shared access to CO_2 transportation networks and storage.[252]

RESEARCH & DEVELOPMENT

- R&D and demonstration stage support targeting high efficiency, high capture rates and cost reductions across the CCUS value chain.
- Demonstration scale projects in cement, iron and steel and DACC ready for commercial scale deployment in the 2030s and 2040s.

INVESTMENT

- Investment into CCUS capacity and supporting infrastructure needs to increase from $3bn annually today to ~$70bn per annum in the 2030s.

252 There will be some overlap between the 100 CCS hubs and the 300 large industrial players, though not 100%.

4.1 Key actions for the 2020s

Governments and companies can facilitate scale up through an array of policies and actions. Rapid implementation of such measures will be crucial to achieving rapid build out in the 2020s and achieving cost reductions and continued deployment beyond 2030, in order to ensure that CCUS can play its vital but limited role in global decarbonisation by 2050.

Specific policies to drive this scale of development will need to reflect national and regional circumstances and should be informed by indicative targets for development at a national/regional level. Six categories of policy action should be deployed:

1. Overcoming the green premium to make early CCUS deployment economic.
2. Building enabling infrastructure.
3. R&D and deployment support for key technologies.
4. Actions to regulate and manage risks.
5. Standards and monitoring to ensure high capture rates.
6. Actions to build public support for CCUS's appropriate role.

4.1.1 Overcoming the green premium to make early CCUS deployment economic

CCUS has a key role to play in a low-cost transition to a zero-carbon economy. But unlike some other decarbonisation technologies, where cost reduction will eventually make the new technology cheaper than fossil fuel equivalents, adding CCUS to existing processes will always add some cost: and this cost will be significant in the early stages of deployment.

Policies to cover this "green premium" and to make CCUS economic are therefore required. Some mix of the following policies should be deployed:

- **Carbon pricing.** Set a substantive economy-wide carbon price to provide a common, long-term decarbonisation signal for both energy-using sectors and the power sector itself. In geographies where carbon pricing exists to date, its level may be insufficient, or its future level too uncertain, creating investment risk. Given the risks to competitiveness of industries in international markets Carbon Border Adjustment Mechanisms (CBAM) may be an appropriate supplement to regional or national carbon prices, in the absence of a global carbon price.

- **Other actions to overcome the 'green premium'** of fitting CCUS to a carbon intensive facility may be appropriate in the absence of meaningful carbon prices, but also to supplement them where they are in place.

    - **Final product standards or mandates** for products which utilise captured CO_2 (such as building materials) or for low-carbon products (such as green steel, decarbonised cement or sustainable aviation fuels) can be developed by industry and possibly enforced by governments to enable the costs of CCUS to be passed through to end users, providing an incentive for facilities to capture carbon. Where these standards or mandates are announced in advance, often with 'ratchet' mechanisms over time they can provide powerful signals for future markets for decarbonised products and thus investment today.

    - **Voluntary green premiums** can also be a powerful signal in the absence of government or industry standards. Some companies may choose to purchase low-carbon goods, paying voluntary premiums to producers. There are a growing number of these schemes, e.g. the First Movers Coalition announced at COP26.[253]

    - **Public procurement** (e.g., in roads, schools, public buildings and other infrastructure) can be used by governments to build early markets for low-carbon products produced using CCUS.

253 The First Movers Coalition is a global initiative harnessing the purchasing power of companies to decarbonise seven "hard to abate" industrial sectors that currently account for 30% of global emissions: Aluminium, Aviation, Chemicals, Concrete, Shipping, Steel, and Trucking; along with innovative Carbon Removal technologies. See https://www.weforum.org/first-movers-coalition

- **De-risking mechanisms such as Contracts-for-Difference, tax credits or incentives** may reduce risk to investors, lowering overall costs and accelerating investment. Such measures are already being used by governments in some geographies to support CCUS development and are another useful tool to incentivise CCUS.

- **Direct public financial support for capture technologies.** Technology specific measures will be necessary to overcome First-of-a-Kind costs. This is not unique to CCUS – many technologies essential to the Energy Transition have benefitted and continue to benefit from direct government support. Aid for all such technologies is justifiable on a temporary basis given their status as a public good.[254] Technology specific supports (such as capital grants and state backed loans) can be phased out as technologies mature with more technology agnostic market mechanisms become the dominant remaining form of policy support. For example,

  - Direct support for CCUS in power is increasingly unnecessary in some regions as the TRL is relatively high, hence plants with CCUS technology should be expected to compete with other low carbon forms of generation.

  - EOR presents a special case where support is appropriate only in very specific circumstances (see discussion in section 2). However, where strict criteria are met, there may be value in public support given knowledge and expertise building related to CO_2 storage and DACC in particular.

4.1.2 Building the enabling infrastructure

Given that the majority of CO_2 will be stored and not utilised, the development of sufficient T&S capacity is critical to investment into capture assets. This is of especially high priority given T&S' role as an enabling technology: it is a necessary precondition to other assets' investment approval.

T&S (especially storage) is already presenting a bottleneck in the development of CCUS in some regions. This reflects not only financial challenges of developing expensive, complex assets but also the general lack of geological data, beyond spent oil and gas wells.

These challenges can be overcome by:

- **Shared cost models for T&S infrastructure**: shared cost models can deliver investment into new transport and storage infrastructure and protect end users from high prices but require effective regulation.[255] Storage requires coordination between governments to encourage geological surveys and make the data available as well as transparent on the status of new developments. This is a public good which can unlock important positive externalities at relatively low cost.

- **Storage surveys and test injections:** It is critical to move beyond reliance on legacy oil & gas exploration and production data and develop a detailed, freely available, atlas of saline aquifers. Accelerating the development of 'injection-ready' storage sites will be a critical factor in CCUS deployment. This may require a role for public funding or even a state-backed entity in actively exploring storage sites (e.g. through geological surveys, test-injections) before transferring them to private operators.

- **Reusing oil and gas infrastructure.** Repurposing decommissioned oil and gas infrastructure (both on and offshore) can significantly reduce the costs of CCUS scale up.[256] Depleted oil and gas reservoirs are likely to have been appraised and monitored extensively as part of previous oil and gas operations, meaning that the subsurface geology is well understood and there is no requirement for further investigation. Re-use of old assets also typically lowers the carbon footprint of the infrastructure as well, hence projects such as Porthos in the Netherlands and Acorn and HyNet in the UK are seeking to reuse hydrocarbon pipelines and depleted reservoirs for CO_2 transport and storage.[257]

- **Developing large volumes of renewable electricity and green hydrogen** will be an important enabler of carbon capture and utilisation (especially DACC). Recommendations relevant to the scale up of these technologies are covered in the ETC's 2021 reports on Making Clean Electrification Possible and Making the Hydrogen Economy Possible.

254 Woo & Jane (2021) *Why and Where to Fund Carbon Capture and Storage.*
255 Regulated cost models for networks in the energy and water sectors around the world offer good examples of best practice here.
256 DNV (2021) *Re-Stream: Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe.*
257 Leveraging old infrastructure also poses risks, particularly with regards to corrosion arising from high CO_2 exposure. Trendafilova P. (2021) *Can Oil Wells Be Reused for CO_2 Storage?*. Therefore stringent regulation and detailed screening processes are necessary. Regulators must define a qualification process based on clear parameters (such as well integrity, CO_2 stream composition (i.e. tolerance for impurities) risk of leakage or damage, well pressure etc.).

4.1.3 R&D and deployment support for new technologies

The principal technologies (blue hydrogen, fossil fuel processing and power)[258] necessary to drive the majority of CCUS scale up in the 2020s are already at sufficiently high TRL levels. However investment is still required to drive further cost reductions and improve capture rates in these fields, and boost TRL in key growth sectors (cement, chemicals, iron & steel, DACC and BECCS).

- **Support capture innovation through R&D and industrial scale demonstrations:** public funding through grants, competitions and regulatory models is crucial to driving breakthrough innovations and lowering costs. Such actions have already yielded positive results (e.g. EU financing for new cement CCS technologies is helping deliver the next generation of plants).[259] Future funding should focus on low TRL technologies such as Iron & Steel and DACC. Funding should also target improvements in higher TRL technologies' performance: boosting capture rates and reducing the energy consumption of CO_2 capture facilities.

- **Business model innovation** plays a key role in overcoming the practical challenges associated with scaling up CCUS technologies. The development of new commercial models which can lower technology costs – e.g. through replicable designs, modularisation, or smaller industrial footprints – are critical to ensuring CCUS offers a competitive means to decarbonisation. As discussed in section 3, Carbon capture as a Service can play a key enabling role here.

4.1.4 Clear risk allocation to ensure responsible and secure CCUS development

Clear delineation of responsibilities and liabilities is a crucial prerequisite to CCUS scale up.[260] This is true of all links in the value chain but is especially the case with regards to storage and the potential for leakage. Rollout of best practice risk allocation can establish clear roles, responsibilities and assignment of liabilities ahead of active project development, delivering safe and responsible development of long-term storage.

- **Regulation and assignment of liability:** Well defined standards and penalties for non-adherence (i.e. carbon leakage) are critical not only for building business confidence and encouraging investment but also in overcoming public opposition (see below). Well defined, stable regulatory regimes will provide certainty to investors and help boost scale up in CCS. Long-term liabilities for CO_2 storage over time should also be established.

    - Whilst this point is principally applicable to carbon capture, transportation and storage, it also applies in terms of utilisation: clear regulations regarding the quality and properties of products which utilize CO_2 (such as building materials or synthetic fuels) are essential to widespread uptake of such products (in turn stimulating investment into capture and utilisation).

- **State backed insurance for storage:** low risk but high consequence events such as civil nuclear accidents are prohibitively expensive to insure against for private entities and often require state backing. The same is true of some of the risks associated with CCUS, notably the potential for carbon leakage after sequestration. In this respect, regulations which govern the liabilities associated with active nuclear power plants could serve as a useful template for the development of CO_2 storage, and could be considered as a model to be rolled out by Governments around the world. In the European Union, for example, liability for the storage site is transferred from the operator to the national government, after an initial period of operation.[261]

- **Counter-party risk mitigation** very few entities have sufficient financial capacity to develop the entire CCS value chain single-handedly. More typically, multiple capture entities will depend upon shared T&S infrastructure or hub facilities. Yet even shared T&S infrastructure models do not eliminate counter-party risk entirely: should one side of the transaction fail to deliver, the other is exposed (e.g., retrofitting a power plant with CCS technology will be a waste of money if the pipeline and storage operator fails to develop the infrastructure to collect and store the CO_2). Governments can help mitigate this risk of stranded assets and first-mover disadvantage through guarantees and infrastructure coordination. For example in the UK, the government has agreed to reimburse operators (within limits) if counterparties fail to deliver for key CCUS infrastructure projects.[262]

258 This applies principally to combined cycle gas turbine and ultra-critical coal units – one aspect of CCS in power generation which stands to benefit from increased R&D is in overcoming technical difficulties in applying CCS technology to peaking generators.

259 Global CCS Institute (2021) *Four CCS Projects to be Funded through the EU Innovation Fund.*

260 Havercroft I. (2019) *Lessons and Perceptions: adopting a commercial approach to CCS liability.*

261 Figueiredo et al. (2007) *The liability of carbon dioxide storage*. Figueiredo et al. (2007) *The liability of carbon dioxide storage*; Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide.

262 UK Department for Business, Energy & Industrial Strategy (2020) *Carbon Capture, Usage and Storage: an update on business models.*

4.1.5 Developing standards and monitoring to ensure lowest carbon CCUS

Well defined regulations and penalties for non-adherence are critical not only for building business confidence and encouraging investment but also in overcoming public opposition. Meaningful penalties for polluters helps build confidence in institutions and policies underpinning CCUS build out; conversely failure to enforce the rules will erode trust and reinforce negative public perceptions. Monitoring and verification can support the implementation of standards.

- **Monitoring for CO_2 leakage:** real time monitoring of pipelines and storage sites can facilitate enforcement of the rules, further boosting public acceptance. Therefore, governments should delineate clear responsibilities for CO_2 management at all stages in the value chain and regulators must be free to impose meaningful fines when those rules are broken. Regulators should enforce these standards e.g., through the use of satellite imagery which is already widespread in other applications such as monitoring flaring.[263]

- **Validating the emissions intensity of the energy being used.** Where inputs to CCS or CCU processes use electricity (e.g., in DACCS) the source of this electricity will determine the ultimate carbon balance of the process.[264] Similarly, where fossil fuels are used, emissions that aren't captured during the process and emissions associated with fossil fuel supply chains will need to be accounted for. There is an active debate around blue hydrogen on the grounds that if methane leakage rates in the supply chain are high (pre-conversion) and capture rates low (post conversion), this undermines the technology's climate benefits.[265] Governments and companies should ensure that monitoring is in place throughout the supply chain, and ensure higher levels of associated emissions are driven down through regulation, industry standards and/or limits on eligibility for public funding.

4.1.6 Building public support for an appropriate and focused use of CCUS

Whilst there is some ambiguity as the precise extent to which public opposition has compromised CCUS development to date, it is nonetheless regularly cited by developers as a potential obstacle.[266] Therefore governments and business both have an interest in addressing public concerns through enhanced transparency and clarity on policy rationale.

- **Clear policy on role of CCUS.** Arguably some public opposition to carbon capture projects in the past has been rooted in the preconception that the technology is a means for legitimising coal fired power generation. Governments can help overcome such opposition through clear messaging on the limited but vital role CCUS can play in decarbonising hard to abate sectors and delivering negative emissions, whilst acknowledging the dominant role of wind and solar in the provision of electricity (Exhibit 70). Industry also has a role to play here in terms of publicising the economic and environmental benefits of applying CCUS in their operations.

263 IEA (2021) *Flaring Emissions.*
264 For detailed discussion of the impact of the carbon intensity of power used in DACC, please refer to the technical annex.
265 Howarth & Jacobson (2022) *Reply to comment on "How Green is Blue Hydrogen?*
266 EU CCS Projects network (2020) *Public perception of CCS: A Review of Public Engagement for CCS Projects.*

- **Transparency on performance:** it is critical that industry be forthcoming in regards to instances where CCUS falls short. Making data freely available on metrics such as final capture rates, impacts on end user prices, leaks and other accidents will likely not only build public trust but also helps identify areas for improvement where necessary. Governments can help support this aim through tying support to performance and demanding transparency in such fields to allow for public scrutiny.

Policy makers' understanding of CCUS' role in the energy transition has evolved

Changes in policy-makers' understanding of CCUS' role in the energy transition

	2000 - 2015	2020s
Underlying climate ambitions	Emerging consensus on climate change science but no agreement on targets	Net Zero by 2050 widely accepted as critical to limiting global warming to 1.5°C
Electricity	Assumed renewables would remain uncompetitive: CCS essential to decarbonizing baseload	Wind and Solar already outcompete thermal in most geographies
Industry	Widespread uncertainty on how to decarbonize industry	Clarity on options to deliver; CCS competes with other routes – clear cement dependent on CCS for decarbonization
Carbon dioxide removals	Limited focus on emissions removals	Recognition of need for removals to reach 1.5°C
Role of CCUS in the Energy Transition	Limited principally to coal & gas baseload; industry as a secondary priority	Complementary role for CCS along side clean electrification; • Essential role in non-fossil decarb (cement and CDR); • Small role in other industry and grid balancing

Exhibit 70

SOURCE: SYSTEMIQ analysis for the ETC (2022)

4.2 Actions needed from key stakeholders

Achieving the outcomes outlined in this report will require action by governments – acting either directly or as regulators – by oil and gas companies, other industries and finance providers. The role for each of these parties is summarised below and shown in Exhibit 71.

4.2.1 Governments

Governments have an essential part to play in setting policy which clearly defines CCUS' role (and its limits) in the Energy Transition and providing financial support where necessary – notably with regards to carbon pricing but also in the form of public funding for R&D into low TRL capture, geological appraisal of potential storage sites and state backed insurance.[267] Government also has a role to play in facilitating development through centralised coordination and helping to overcome risks (e.g. contract templates, industrial cluster planning or counter-party guarantees).

4.2.2 Regulators

Regulators are key to defining the details and ensuring compliance. Well defined standards, responsibility for CO_2 at each stage of the value chain and penalties for non-adherence (i.e., carbon leakage) are critical not only for building business confidence and encouraging investment but also in overcoming public opposition. In the same vein, regulators must be allowed to monitor industry's performance (notably capture rates and leakage from T&S) and where necessary impose meaningful fines for non-compliance.

267 Vinca et al. (2018) *Bearing the Cost of Stored Carbon Leakage*.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4.2.3 Industry

Industry (capture facilities, T&S operators and supply chain) is the engine of innovation. Significant cost declines and capacity scale up are required in order to meet the carbon capture volumes set out in this report: industrial innovation has a key role not only in delivering technological improvements (improving capture rates and reducing costs) but also in regard to business models: innovative approaches such as Capture as a Service will be critical to extending CCUS from very large players to mid-cap entities. Effective coordination between industry and government is also critical the rapid development of hubs.

4.2.4 Oil and gas firms

Oil and gas firms in particular have a key role to play in driving CCUS expansion. The sector's knowledge and expertise regarding geology, gas transportation and subterranean sequestration are likely to be valuable in this endeavour. The industry is likely to be involved in blue hydrogen development, and in fossil fuel processing and refining.

4.2.5 Finance

The scale of the investment required in delivering CCUS growth means that financial firms must play a key part: although government has a role to play in supporting FOAK projects, R&D and underwriting some niche liabilities, the vast majority of finance for the CCUS industry will come from the private sector. In particular, financial entities can leverage expertise in ensuring credit flows to the necessary sectors whilst utilising innovative financial tools (such as Advance Market Commitments) to help mitigate risks.

Exhibit 71

Public and private sector entities have different roles to play in delivering CCUS scale up

6 strategies to drive CCUS expansion in the 2020s

Strategic category	Actions	Government	Regulators	Industry	O&G firms	Finance Players
1 Overcoming the green premium to make early CCUS deployment economic	Carbon Pricing	●	●			
	Direct state financial support for capture	●				
	Other (public procurement, CfD, voluntary green premiums)	●		●	●	●
2 Building the enabling infrastructure	Shared cost models for T&S infrastructure	●	●	●		●
	Massive scale up of energy and T&S infrastructure	●		●		●
	Storage surveys & test injections	●		●	●	
	Reusing oil and gas infrastructure			●	●	
3 R&D and deployment support for new technologies	Support capture innovation through R&D	●		●	●	●
	Funding for industrial scale demonstrations	●				●
	Business model innovation			●	●	●
4 Clear risk allocation to ensure responsible and secure CCUS development	Regulation and assignment of liability	●	●	●		
	State backed insurance	●	●			●
	Counter party risk mitigation	●	●			●
5 Developing standards & monitoring to ensure lowest carbon CCUS	Monitoring for CO_2 leakage		●	●	●	
	Validating the emissions intensity of the energy being used		●	●	●	
6 Building public support for an appropriate and focused use of CCUS	Clear policy on role of CCUS	●		●	●	●
	Transparency on performance	●	●	●	●	●

SOURCE: SYSTEMIQ analysis for the ETC (2022)

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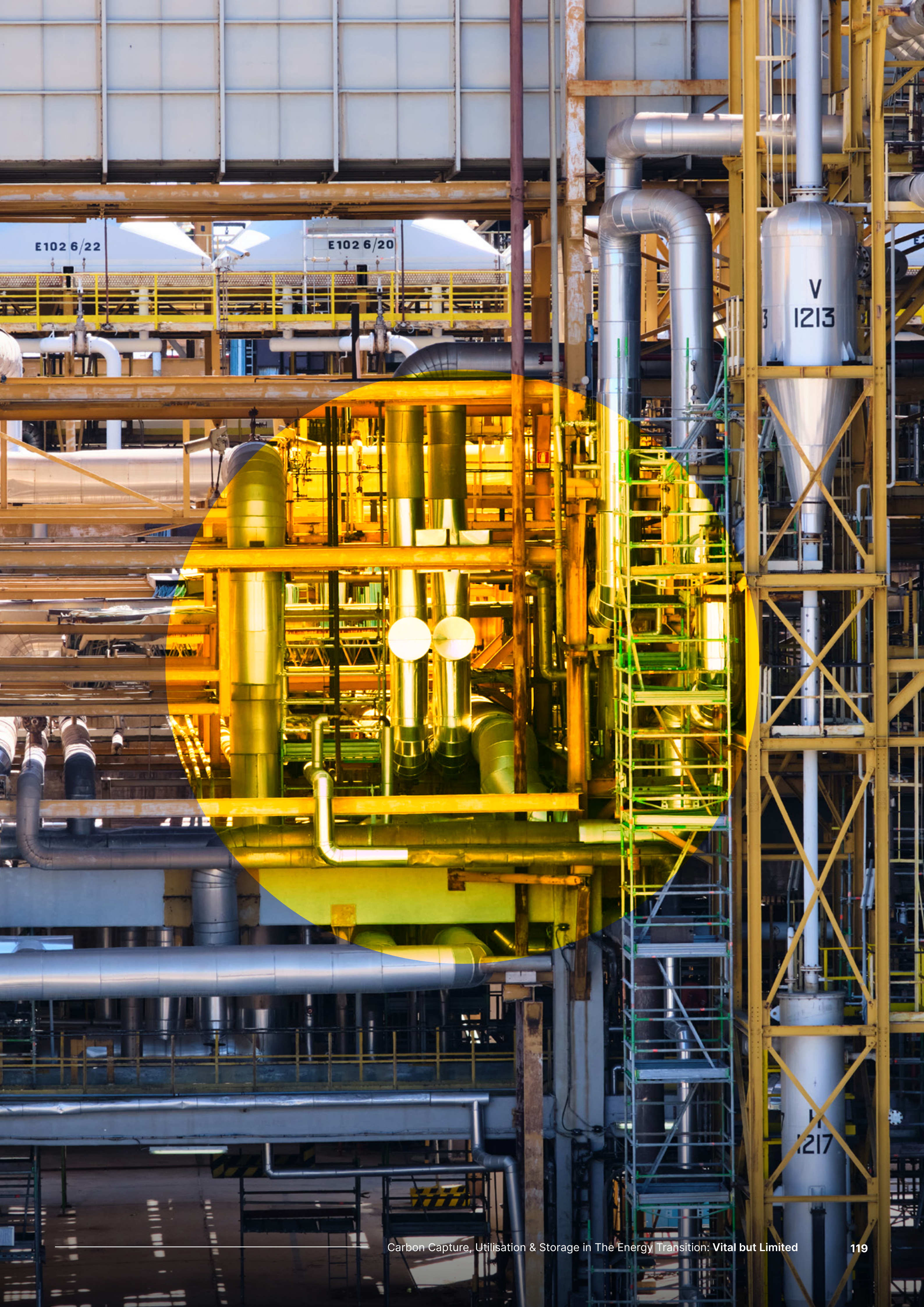
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