Evaluating technology options to mitigate greenhouse gas emissions

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CO_2 Utilisation: Hydrogenation Pathways

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CO_2 UTILISATION: HYDROGENATION PATHWAYS

The aim of this study is to assess the feasibility of select carbon capture and utilisation (CCU) routes based upon CO_2 conversion through hydrogenation, in terms of their climate change mitigation potential. The results of this study will be of interest to organisations/individuals involved with climate-change scenario modelling, as well as RD&D financial sponsors.

The commodities selected for investigation were methanol, formic acid, and middle distillate hydrocarbons (synthetic fuels: diesel, gasoline, jet fuel), with a focus on catalytic hydrogenation pathways. Results of CO_2 emissions, costs and energy consumption for formic acid, however, will not be presented in detail in this Overview, as the analysis has shown that the abatement is limited to 2 $MtCO_2$ due to the small market size. (Results for formic acid are available in the full report.)

Key Messages

- Hydrogenation routes require a supply of hydrogen and CO_2, and the origins of these feedstocks impact the overall cost and emissions of CCU pathways. Hydrogen is the most significant cost and emission component for both methanol and middle distillate hydrocarbon CCU production routes.
- Production of commodities via CCU routes is more expensive than fossil routes. All realistic combinations of feedstocks result in higher costs than the counterfactual route under both near- (2020s) and long-term (2050s) assumptions. In the near-term, CCU commodities were found to be at least twice the cost of their fossil counterparts. In the long-term, cost premiums can decrease significantly due to reductions in the cost of green hydrogen and CO_2 capture.
- Economic competitiveness of CCU routes is reliant on a 'cost of emission' being applied. For the optimal pathways considered, cost parity could be achieved in the long-term by implementing a cost of emissions between USD 120-225/tCO_2.
- CCU can offer a lower emission commodity production pathway provided a low-emission electricity source is used for green hydrogen production. Using grid electricity (representative of current European grid mixes) for electrolysis is expected to result in CCU methanol and middle distillate hydrocarbon routes having greater emissions than their fossil counterparts, the same applies to the use of unabated fossil hydrogen production.
- The method of accounting for utilised CO_2 has important consequences. For routes with higher production emissions than their counterfactual, CCU commodities can only claim to have lower emissions than the counterfactual commodities if they are able to account for the utilised CO_2 as offsetting some of their production or end-of-life emissions.
- Avoiding > 1 $GtCO_2$ requires very high levels of market penetration. CCU methanol and middle distillate hydrocarbons have the potential to abate over 1 $GtCO_2$ but only if methanol captures the entirety of the current market and then expands into the heavy-duty trucks market plus the plastics markets, and if middle distillate hydrocarbons capture the entirety of today's aviation fuels and heavy-duty trucks market. Formic acid does not have the potential to reach 1 $GtCO_2$ as even if the CCU product were to penetrate the entire formic acid market, the abatement currently achievable is limited to approximately 2 $MtCO_2$.

- Energy demands might become a barrier limiting large-scale CCU deployment. Under the investigated 'ambitious CCU' scenario, middle distillate hydrocarbons would require about 26,000 TWh of electricity, almost the entire current electricity production globally.
- CCU pathways must be designed carefully to ensure lower life cycle emissions than the counterfactual. Co-location of assets may reduce costs, particularly in regions with high potential for renewable electricity. CCU could provide an attractive solution in regions with limited CO_2 storage, or with cost or public acceptance challenges for carbon capture and storage (CCS).
- Recommendations:
    - Lab scale research and pilot-demonstrations are necessary to address technical barriers.
    - More life cycle assessment (LCA) and techno-economic assessment (TEA) studies are needed, especially on hydrogen and renewable electricity production.
    - Policies are required to mandate the use of low-carbon products and to increase the cost-competitiveness of CCU products.
    - Streamlining approval processes and standards could help enable timely market entry for new CCU products.
    - Further clarity and global consistency of the accounting of CO_2 in CCU routes is needed.
    - CCU pathways can benefit from advances in CO_2 capture and hydrogen production as well as the sharing of infrastructure with large-scale CCS projects.

Background to the Study

CO_2 can be transformed into a wide range of value-added products, acting as an alternative carbon source to fossil carbon. CO_2 is already used extensively as a direct input for products such as carbonated beverages, fire-extinguishers, and cooling systems. CO_2 can also be chemically transformed into a wide range of value-added products. These CO_2 'conversion' utilisation routes are of increasing interest due to considerations related to climate change, avoidance of fossil fuels, and the circular economy. Carbon capture and utilisation (CCU), uses CO_2 captured from industrial emissions or directly from the atmosphere, thus having potential to reduce net CO_2 emissions relative to conventional production routes. CCU can be used to produce chemicals, materials, polymers and fuels that are direct replacements for existing products, conventionally produced from fossil feedstocks. Therefore, CCU can offer a means of producing conventional products whilst avoiding fossil extraction.

The evaluation of CCU routes is often complex, with emissions and costs variable with feedstock assumptions, and 'benefits' dependent upon comparison to a counterfactual. There is currently a lack of information and/or uncertainty around the role that CCU technologies might play in emissions mitigation and the potential scale of CCU deployment. The assessment of these factors requires an understanding of the total emissions associated with CCU products, the costs, and the energy demands. Depending on the product being investigated, estimates of these factors can vary considerably due to a range of potential options for CCU conversion technology, the origins of feedstocks and energy, and geographical factors. In addition, quantification of emissions mitigation requires assumptions around the counterfactual case for comparison, adding complexity. The allocation of costs and emissions across different aspects of the value-chain also adds uncertainty.

This study highlights the impact of different feedstock choices (hydrogen, electricity, CO_2 capture) on costs, energy demand and CO_2 emissions of CCU routes that involve CO_2 hydrogenation, a particular type of CCU route in which CO_2 is reacted with hydrogen over a specialised catalyst to produce value-added chemicals or fuels (see Figure 1).

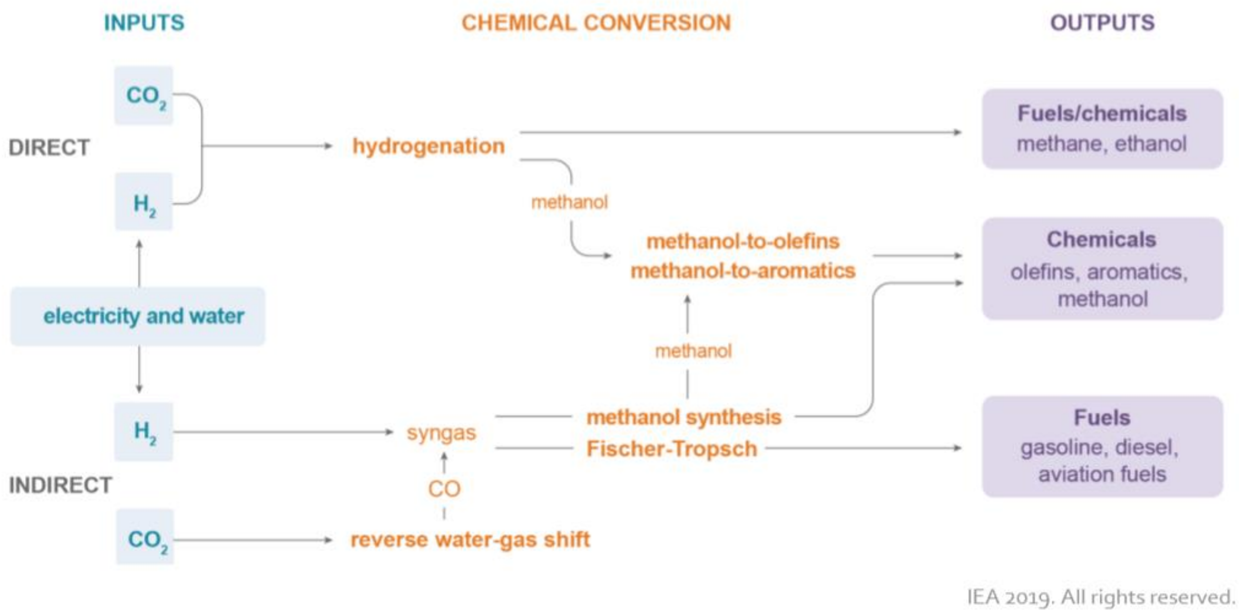


Figure 1 CO_2 conversion routes investigated in this report (IEA, 2019. Putting CO_2 to Use.)

Scope of Work

IEAGHG commissioned Element Energy and the Styring Group at the University of Sheffield, UK, to assess the feasibility of select CCU conversion routes, i.e. conversion by hydrogenation, in terms of their climate change mitigation potential. It should be established whether the investigated routes are a climate change mitigation option or not, and under which conditions. A detailed evaluation of low-carbon hydrogen/electricity production will help answer the questions about the scale and capacity of CCU conversion routes. The scope of work consisted of the following tasks:

1. To collate data on feedstock, energy and CO_2 inputs into the production of commodities as well as their end-use.
2. Identify the circumstances (e.g. source and carbon intensity of electricity/hydrogen) under which CO_2-conversion has climate mitigation potential.
3. Understand the economic competitiveness of CO_2-based products with those produced conventionally, including the required carbon price.
4. Discuss the RD&D and policy gaps required to be closed to enable deployment of CCU at scale.

The commodities selected for investigation were methanol, formic acid, and middle distillate hydrocarbons (synthetic fuels), with the investigated CO_2 conversion routes being catalytic hydrogenation pathways.

This study was carried out in parallel with another study 2021-02 'CO_2 as a feedstock: Comparison of CCU pathways', which provides a broader perspective of CCU routes and their advantages and disadvantages.

Findings of the Study

Methods and approach

The study focuses on evaluating the costs and emissions of various CCU pathways in comparison to counterfactual routes, the resource demand of the CCU pathways, and factors relating to the end-use of these commodities. These factors are considered both for the near-term (2020s) and for the long-term (2050s). This allows for temporal variations in costs of resources and technologies to be considered. The broad range of inputs and pathways considered allows for regional interpretations. Although the scope of the study does not include specific regional analysis, regional interpretations can be made by considering the most likely pathways for each region based on the type of resource inputs available in the region.

The impact of utilising captured CO_2 on the costs and emissions of the system compared to the counterfactual will vary depending on what is considered as the counterfactual case. The method of accounting and allocation of CO_2 emissions is core to ensuring the climate benefits are correctly recognised. Some CCU developers may assume that the utilisation of CO_2 for their pathway may allow them to reduce the overall emissions of their production process by the quantity of CO_2 utilised or equally state that the end-of-life emissions of their product are reduced by this quantity. However, this accounting is highly dependent upon assumptions around what would otherwise happen to that CO_2 if it were not used for utilisation and the allocation of any impacts on system emissions (reduction/avoidance of CO_2) between the utiliser and the capturer/emitter. The main options are illustrated in Figure 2.

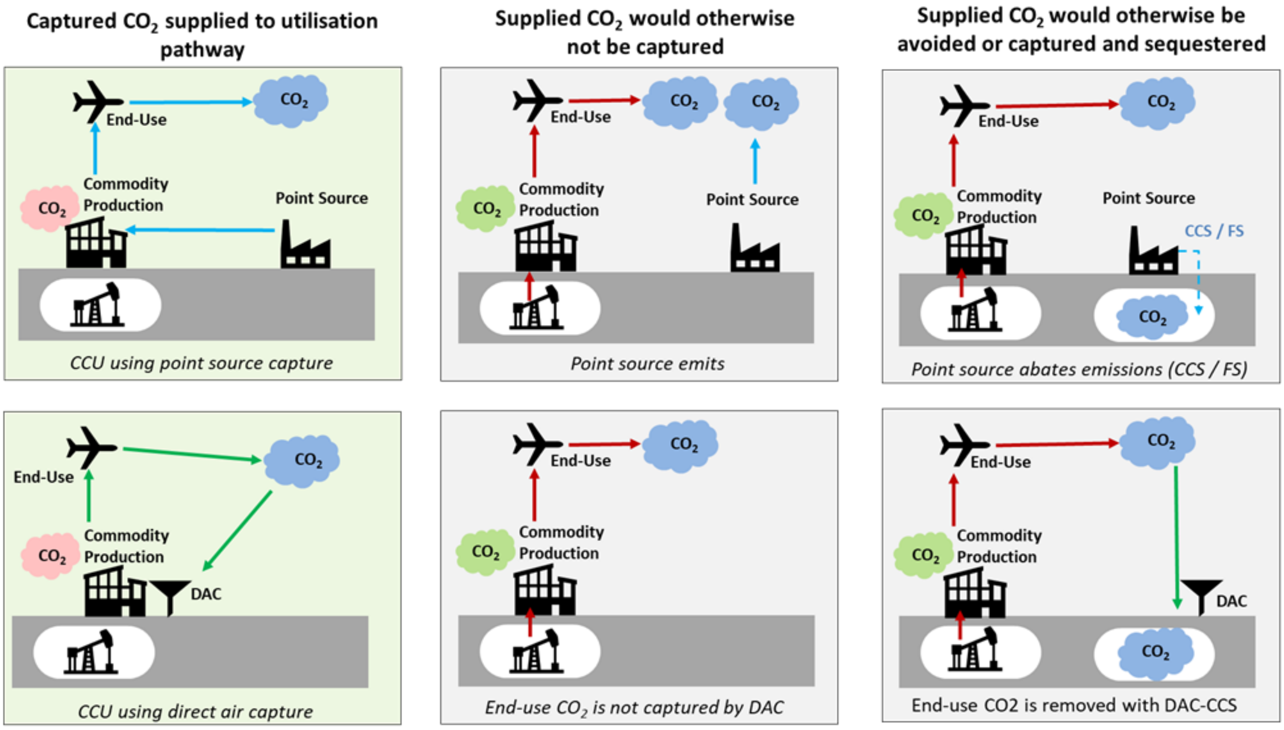


Figure 2 System perspective of CCU pathways compared to counterfactual routes. DAC = Direct Air Capture, CCS = Carbon Capture & Storage, FS = Fuel Switching.

For the purposes of this study, the option is assumed in which the CO_2 utilised would otherwise not be captured. Therefore, an avoided burden of 1 tCO_2 reduction compared to the reference case is assumed for the CO_2 utilised (referred to as 'avoided burden'/'emissions benefit'), with additional emissions that result from CO_2 capture reducing this overall value. (These values are presented separately in graphs with the intention of facilitating interpretations if the reader were to prefer an alternative accounting approach.) A limitation of the analysis is that all origins of CO_2 are considered equivalent, also in having a reference case of no capture. In actuality, the origin of the CO_2 source (biogenic, fossil, atmospheric) is likely to have influence on the reference case for CO_2 supply. For example, in a system where there are strong decarbonisation incentives, it is likely that CO_2 sources of fossil origin would otherwise be abated – such as through capture and geological sequestration, fuel switching, or process change.

In the case of CCU there are three parties that each incur costs and may each wish to claim emission benefits: the capturer of the CO_2; the manufacturer of the commodity; and the end-user of the commodity. There is no consensus on how emission benefits or costs for CO_2 capture may be transferred to a product when that CO_2 is utilised. Thus, it is important to ensure that the emission benefits are not double counted.

When discussing product competitiveness, it is assumed that the climate benefits of CO_2 utilisation are passed to the CCU product and are not claimed by the capture facility. Under this assumption, the capturer is compensated for the cost of capture but does not account its emissions as abated.

The end-use of the commodity is assumed to be independent of the chosen production route, with emissions and costs between the point of production ('gate') and the commodities end-of-life (‘grave’) being identical for both routes. The fossil route represents the conventional pathway for producing commodities. This is a fixed reference route used as a counterfactual.

Knock-on effects outside of this system were not considered. The assumption is made that the use of electricity, hydrogen, and DAC facilities for the CCU route does not detract from the ability of these facilities to supply their products for other uses. This is a simplification as in reality capacity for these resources will likely be constrained.

Implications of CCU feedstock choice

Hydrogenation routes require a supply of hydrogen and CO_2, and the origins of these feedstocks impact the overall cost and emissions of CCU pathways. The key variables are whether CO_2 is captured from a point source (of fossil or biogenic origin) or by direct air capture (DAC), and whether hydrogen is produced via electrolysis or via fossil routes. For hydrogen produced from electrolysis additional variables are whether electricity for electrolysis is from the grid or from dedicated renewables (known as green hydrogen), as well as the emission intensity of these sources. For hydrogen produced via fossil routes such as steam methane reforming, additional variables are whether these routes have carbon capture and storage (CCS) applied (known as blue hydrogen) or whether process emissions are unabated (known as grey hydrogen).

The implications for costs, emissions and energy are discussed primarily for five central pathways (also see Figure 3 for a legend for icons used in coming figures):

1. Point source CO_2 capture and blue hydrogen
2. Point source CO_2 capture and grid electrolysis
3. Point source CO_2 capture and intermittent renewables electrolysis
4. High purity biogenic CO_2 capture and intermittent renewables electrolysis
5. DAC CO_2 and intermittent renewables electrolysis

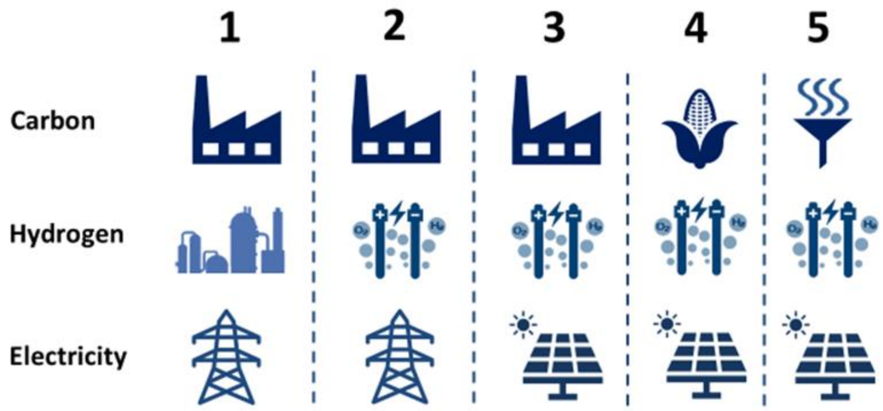


Figure 3 Icons used in this study to identify sources of carbon, hydrogen and electricity in the pathways

For CCU, the study results include emissions and costs associated with the production of hydrogen, generation of electricity, capture of CO_2 and the conversion step to the CCU product. An emissions benefit of minus 1 tCO_2 per tonne of CO_2 utilised is assumed, representing that the CO_2 capture has avoided or removed this amount of atmospheric CO_2 relative to a counterfactual case. The CCU routes are compared to today’s conventional production route for the identical products, which includes fossil extraction and subsequent processing. A carbon price of USD 25 and 160/tCO_2 was assumed in the near- and long-term.

CO_2 emissions and costs

Figure 4 and Figure 5 present the full life-cycle costs and CO_2 emissions of methanol and middle distillate hydrocarbons produced from central CCU pathways compared to the present-day counterfactual routes. Results for formic acid will not be presented in detail in this Overview (but are available in the full report), as the analysis has shown that the abatement is limited to 2 MtCO_2 due to the small market size, although all pathways resulted in significantly lower emissions than the counterfactual. A 'cost of emission' is applied, linked to the determined emissions for production and end-of-life, and the emissions avoided due to CO_2 utilisation. Electricity costs of USD 123/MWh and USD 32/MWh are used for grid and renewables respectively. The utilisation of captured CO_2 is accounted as minus 1 tonne CO_2 per tonne utilised. Electricity emission intensities of 81 gCO_2/kWh and 25 gCO_2/kWh are used for grid and renewables respectively.

Life cycle emissions are split into utilisation, production and end-of-life emissions. Production covers the 'cradle-to-gate' aspects including feedstock production, supply and conversion to the commodity. End-of-life covers indicative values for the distribution of commodities to end-users and their emissions at end-of-life (e.g. combustion for fuels). End-of-life emissions are assumed to be identical for all CCU and counterfactual pathways. Cost of emissions are included and are split into the costs associated with the individual emission components. Utilisation accounts for the emission benefit associated with CO_2 utilisation. Fossil, biogenic and DAC sources of CO_2 are shaded differently to represent the differing climate implications and potential for future differences in CO_2 accounting.

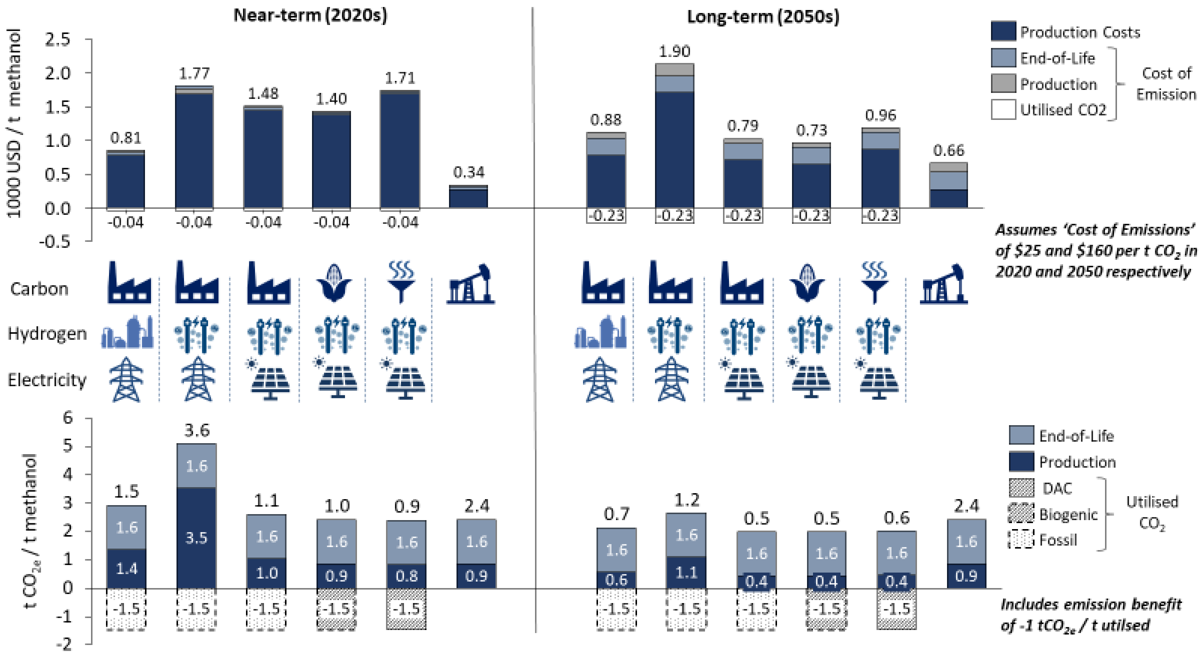


Figure 4 Life-cycle costs (top) and emissions[1] (bottom) for central CCU methanol pathways

[1] A limitation of the accounting approach in this study is that different CO_2 sources (fossil, biogenic, atmospheric) are treated as equivalent.

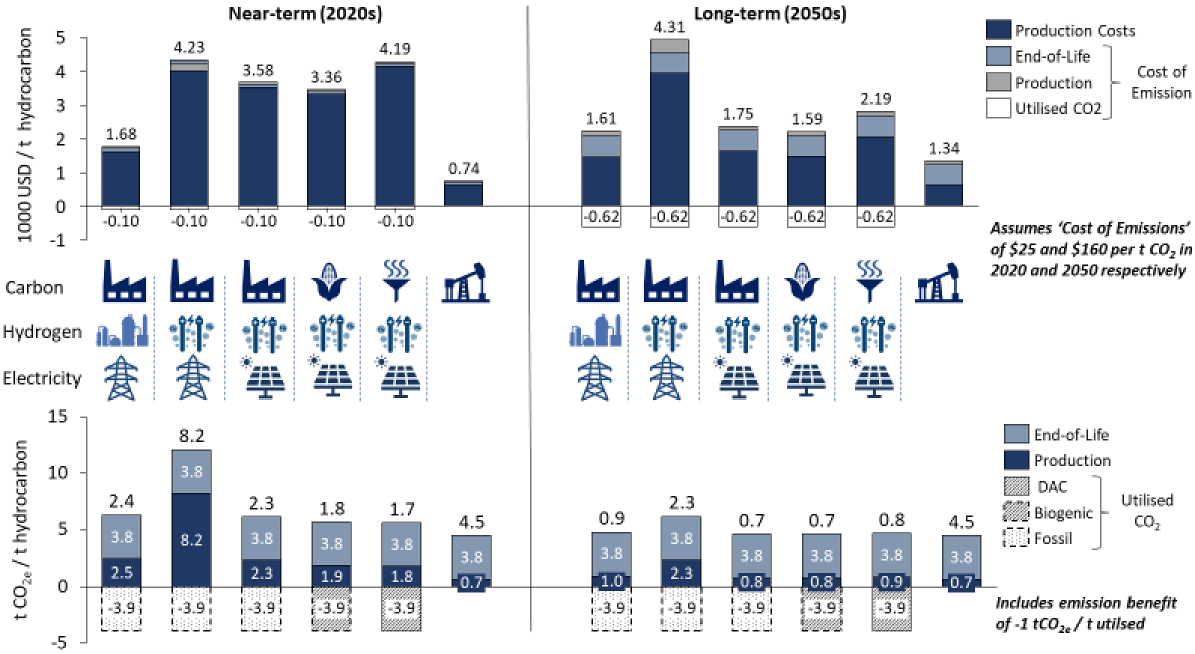


Figure 5 Life-cycle costs (top) and emissions[1] (bottom) for central CCU middle distillate hydrocarbon pathways

For all central cases considered, the cost of methanol produced via CCU pathways is greater than the counterfactual fossil route. In the near-term, total costs are 140-420% greater with the lowest cost option being the point source capture and blue hydrogen pathway and the most expensive option being green hydrogen powered by grid electricity. The cost of emissions has negligible impact in the near term due to the low assumed value of USD 25/tCO_2. In the long-term, the production costs of CCU methanol decrease, with intermittent renewable hydrogen electrolysis pathways seeing the most significant cost reductions. The increase in the cost of emissions leads to a 90% rise in the counterfactual price between the near-term and long-term. Some of the emission costs associated with the CCU routes are offset by the emissions benefit of utilising captured CO_2, making them more competitive. The long-term costs of CCU methanol range from being 10-190% greater than the counterfactual fossil route, after inclusion of emissions costs. The greater imposed 'cost of emissions' of USD 160/tCO_2 in the long-term allows CCU routes to be more economically competitive with the fossil route which does not receive this benefit.

In most cases, the total emissions from CCU methanol pathways are lower than the fossil counterfactual route. In the near-term, all pathways except that using grid electrolysis for hydrogen production have lower total emissions than the counterfactual route. In the near term, emissions are reduced by approximately 60% in the pathways using bio-ethanol point source or direct air capture for CO_2 supply. In the long term, this reduction becomes approximately 80%. Due to reductions in the emission intensity of the grid and improvements in hydrogen generation efficiencies, the grid-electrolysis pathway also has lower emissions than the counterfactual fossil route in the long-term. These reductions are largely due to the emissions benefit associated with the utilisation of CO_2 which partially offsets end-of-life emissions. Even without the emissions benefit from utilisation, several pathways offer lower production emissions than the fossil route. In the near-term, the bio-ethanol point source and direct air capture pathways offer a production route with lower emissions than the counterfactual fossil route. In the long-term, this is true for all routes except for that with grid-electrolysis. This means that emissions associated with hydrogen generation, incomplete capture, and energy for capture and conversion in the CCU pathway are less than the emissions from fossil fuel extraction and conversion in the counterfactual route. Therefore, these routes offer a reduction in emissions even if they cannot claim an emission benefit for utilising CO_2, for example if the CO_2 would otherwise have been abated or if the capture facility were to claim all credit.

All central pathways lead to a cost premium for CCU middle distillate hydrocarbons, with the magnitude of this varying significantly with hydrogen option. In the near-term, the blue hydrogen pathway is almost 130% more expensive than the counterfactual fossil route but is still the lowest cost option, being half the cost of green hydrogen routes. In the long-term, there is a reduction in the cost of intermittent renewable electrolysis pathways with costs becoming comparable to the blue hydrogen pathway. The cost of these pathways is then 20-60% more than the fossil route, with the cost of the grid electrolysis pathway being 220% greater than the fossil route.

In the long-term, the offset in emissions costs due to utilisation make CCU pathways more competitive. For CCU pathways, emission costs from production and end-of-life emissions are partially offset by the emissions benefit of utilising captured CO_2. In the near-term, the low cost of emissions means that this has negligible impact on the overall pathway costs, despite the significant variation in pathway emissions. In the long-term, the greater imposed cost of emissions results in CCU routes becoming more economically competitive with the fossil route which does not receive the utilisation benefit. This competitive advantage relies on the CCU pathways being able to claim the emissions benefit from utilising CO_2. In the near-term, all pathways except that using grid electrolysis for hydrogen production have lower total emissions than the counterfactual route. In the near term, emissions are reduced by approximately 60% in the pathways using bio-ethanol point source or direct air capture for CO_2 supply. In the long term, this reduction becomes approximately 80%. Due to reductions in the emission intensity of the grid and improvements in hydrogen efficiencies, the grid-electrolysis pathway also has lower emissions than the counterfactual fossil route in the long-term. The overall CO_2 reduction associated with CCU pathways over the counterfactual are due entirely to the emissions benefit associated with the utilisation of CO_2 which partially offsets end-of-life emissions. If the emissions benefit from utilisation is excluded, then none of the CCU pathways offer lower emissions than the fossil route. This means that, under the assumptions used here, the emissions associated with hydrogen generation, incomplete capture, and energy for capture and conversion in the CCU pathway are greater than the emissions from fossil fuel extraction and conversion in the counterfactual route. If this emission benefit cannot be claimed, then emissions from the CCU pathways considered result in an increase in emissions of at least 20% (near-term) and 2% (long-term).

Energy consumption

Figure 6 shows the breakdown of energy requirements for the central CCU pathways split across hydrogen production, CO_2 capture and the conversion step, with distinctions for electricity and non-electricity energy inputs. Hydrogen production dominates energy demands and energy for CO_2 from DAC is considerably greater than from point source capture.

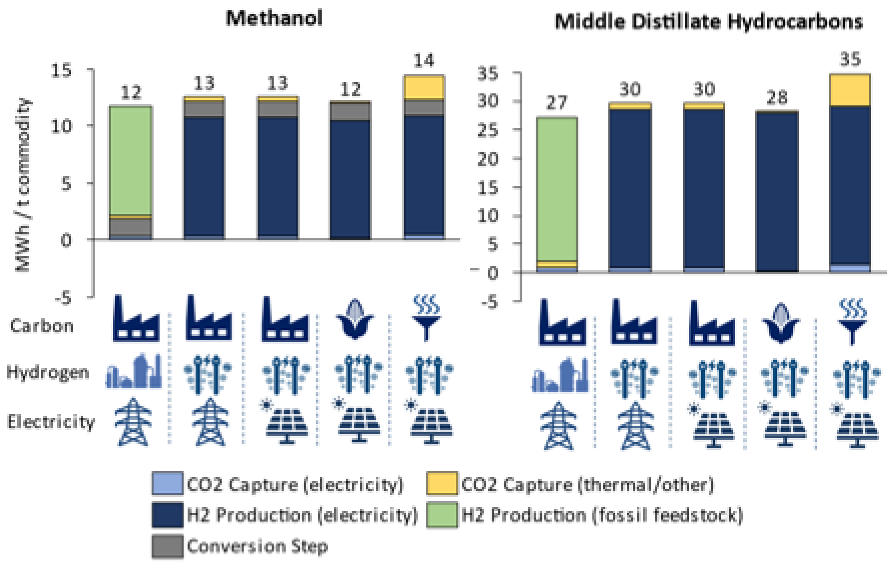


Figure 6 Energy demands for long-term central CCU pathways per tonne of commodity (Assumes efficiencies of 75% for green hydrogen production and 82% for blue hydrogen production.)

Producing one tonne of methanol or middle distillate hydrocarbons from green hydrogen requires an electricity supply for electrolysis of 12 MWh and 32 MWh in the near-term (65% efficiency) and 10 MWh and 28 MWh in the long-term (75% efficiency). For blue hydrogen production via autothermal reforming with CCS (82% efficiency), a natural gas supply of 9.0 MWh and 2.5 MWh is instead required for each commodity respectively.

Using direct air capture leads to a significant additional energy demand compared to routes with point source capture. Energy for CO_2 capture totals 15% and 16% of total energy demand for methanol and middle distillate hydrocarbon DAC-electrolysis pathways respectively (long-term), compared to 3% for standard CO_2 point-source with electrolysis pathways.

Variation between the commodities is mainly due to differences in the quantities of hydrogen and CO_2 feedstocks required to produce a tonne of the commodity, with middle distillate hydrocarbons having higher feedstock demands. Additional minor variations result from differences in energy requirements for the conversion step.

Hydrogen production requires energy either in the form of electricity for electrolysis or a natural gas feedstock for autothermal reforming (ATR) or steam methane reforming (SMR). For coal gasification, a coal feedstock is required. The efficiency of these technologies determines how much of this energy is converted into hydrogen. Efficiencies for electrolysis vary with the type of electrolyser used, however overall efficiencies are expected to improve from approximately 65% in the near-term to approximately 75-80%. Some fossil-based hydrogen generation technologies are more established, with efficiencies of 78%, 82% and 58% assumed for SMR, ATR and coal gasification respectively.

The capture of CO_2 typically requires both electrical and thermal energy inputs, for processes such as solvent thermal regeneration and CO_2 compression. Energy demand varies with the type of CO_2 source, with lower concentration and lower purity gas streams requiring a higher energy input. Capture from a bio-ethanol plant (concentration almost 100%) requires approximately 100 kWh of electricity and minimal heat per tonne CO_2, whereas capture from an iron-and-steel plant (concentration - 17-35%) requires approximately 200 kWh of electricity and 1 GJ thermal energy. The CO_2 source with the greatest energy demand is direct air capture, where atmospheric CO_2 concentrations are around 400 ppm. DAC technology requires approximately 4-6 GJ of thermal energy and 400 kWh of electrical energy per tonne of CO_2 captured. Around 79% of the electrical input is used for compression, whilst the thermal input is required for CO_2 desorption. In the case of solid sorbent DAC technologies, such as that used in the Climeworks process, CO_2 desorption occurs at sufficiently low temperatures that the required thermal energy can be generated by heat-pumps or obtained from waste heat sources. Therefore, the process could be powered entirely from renewable energy. In the case of liquid sorbent technologies, a higher temperature is required for desorption and therefore combustion of natural gas (or alternative) is required which in turn releases CO_2 that must then also be captured.

Within the conversion step, energy is required to power compressors and to separate the final commodity from solvents and by-products via distillation. In the case of methanol, this energy is provided from an electricity supply which for the purposes of distillation is converted to a heat source via a heat pump. In the case of middle distillate hydrocarbons, this energy is provided from the combustion (with carbon capture) of shorter chain hydrocarbons that cannot be refined into fuels. The conversion steps are exothermic and thus generate additional thermal energy that is used within the process once initiated.

Carbon price

Economic competitiveness of CCU routes is reliant on a ‘cost of emission’ being applied. The introduction of a sufficiently high ‘cost of emissions’ (such as a carbon price) can enable low-emission CCU commodities to become cost competitive with their fossil counterparts, due to disproportionate commodity price increases. Using best-case variations, this study estimates that cost parity could be achieved in the long-term by implementing a ‘cost of emissions’ of USD 120/tCO_2 for methanol and USD 150/tCO_2 for middle distillate hydrocarbons (USD 225/tCO_2 for formic acid if this commodity is considered). Under an ambitious ‘cost of emissions’ of USD 300/tCO_2, most electrolysis pathways powered by dedicated renewables could be competitive under long-term assumptions. However, it should be noted that CCU routes may well receive policy support beyond a carbon price, reducing the carbon price required for cost parity. Equally, many regions have direct or indirect fossil fuel subsidies which may be removed in the long-term, increasing the cost of the conventional commodity production routes.

Further considerations

The cost and emissions of the electricity source is of key importance for electrolysis pathways. The source of hydrogen is the main influencing variant for costs and emissions across all pathways. For an optimal long-term DAC pathway with renewables-powered electrolysis, it is estimated here that emissions parity is only reached if the electricity emission intensity is below 180 gCO_2/kWh for methanol and 160 gCO_2/kWh for middle distillate hydrocarbons. Even if electricity emissions are assumed to be zero and a carbon price of USD 160/tCO_2 is applied, it is estimated that cost parity is only reached if electricity costs fall below USD 20/MWh for methanol and USD 15/MWh for middle distillate hydrocarbons. There are significant variations in electricity costs and emissions across regions, including for both grid supply and renewables generation. For example, across the EU emissions ranged from over 900 gCO_2/kWh in some regions to below 10 gCO_2/kWh in others.

Therefore, the electricity source used for hydrogen production via electrolysis has significant influence on the impacts of CCU and currently only in select countries could grid-powered routes lead to emissions benefits.

Emissions associated with blue hydrogen production are variable with technology and capture rates. For blue hydrogen production, emissions arise from the extraction of the fossil input (coal or natural gas) and the incomplete capture of emissions at the hydrogen plant. Technologies with higher efficiencies have lower emissions associated with fossil extraction per tonne of hydrogen. In the future, higher capture rates at blue hydrogen plants could be achievable, resulting in lower emissions. Estimates in this study suggest that increasing the capture rate at an ATR plant from 85% to 99% results in a 34% reduction in CCU methanol production emissions.

CCU mitigation potential

The potential demand for CCU products is discussed in the context of existing markets, new markets, and competing low-carbon alternatives. The purpose is to present the scale of abatement achievable using simple penetration assumptions: current market, competitive and ambitious.

- Current market – If the entirety of existing markets were to be replaced with CCU products.
- Competitive – CCU products penetrate a fraction of markets (existing and new) which currently have limited practical low-carbon alternatives, with other means of production (e.g. bio-routes) accounting for the remainder of demand.
- Ambitious – CCU products penetrate either the entirety or a large proportion of markets (existing and new) which currently have limited practical low-carbon alternatives.

Figure 7 shows the current market sizes and the potential future portion supplied by CCU commodities under different penetration assumptions. The values are for current market sizes, with no predictions made as to the growth of these markets. The abatement that would be achieved in the long-term compared to use of the fossil counterfactual (avoided CO_2) is shown for an illustrative pathway comprising DAC with hydrogen from intermittent renewable electrolysis.

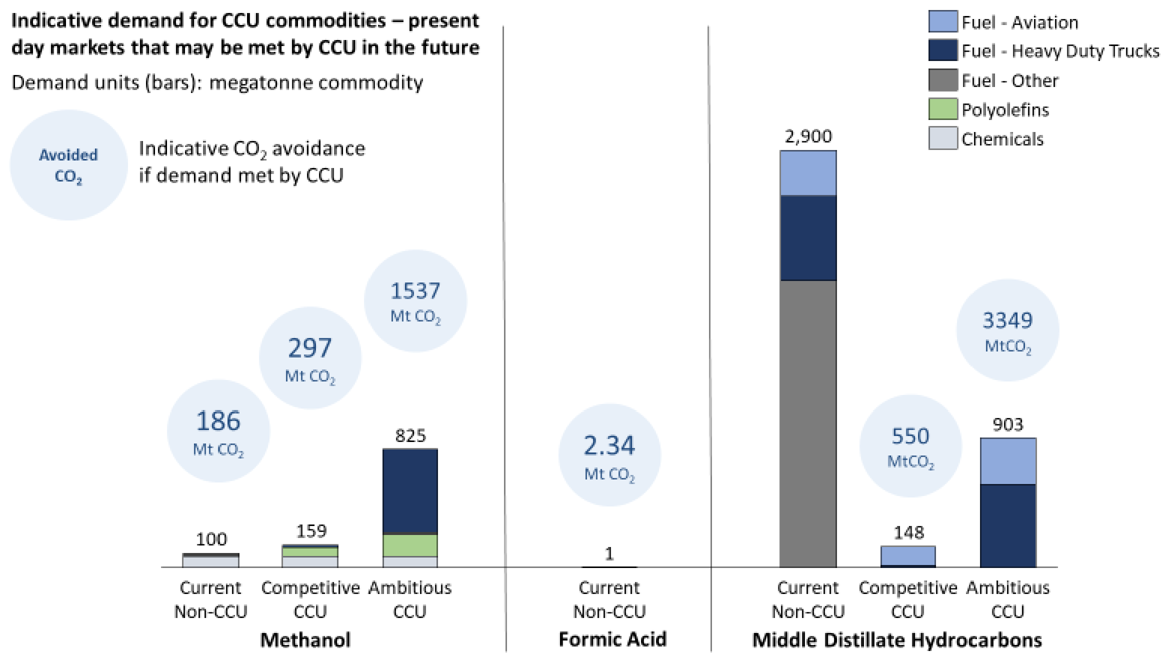


Figure 7 Indicative demand for CCU commodities, based on present day markets that may be met with CCU in the future (The avoided CO_2 is based on the difference between the long-term central CCU pathway comprising DAC with hydrogen from intermittent renewable electrolysis and the counterfactual fossil route.)

The present-day global market for methanol is around 100 Mt per annum, with existing uses including gasoline blending (14%), and production of chemicals such as MTBE (13%) and acetic acid (9%). Methanol can be upgraded to both fuels and chemicals, allowing a broad range of possible end-uses.

CCU methanol can be converted to DME, a potential drop-in replacement for diesel, and gasoline. The abatement potential of CCU based methanol is estimated for the three different penetration assumptions mentioned above. In the competitive case, CCU products penetrate the entirety of the existing methanol market for chemical end-uses (excludes methanol for gasoline blending). In addition to this, CCU methanol penetrates 3% and 30% of present-day medium- and heavy-duty freight trucks and polyolefins markets respectively. This totals an annual demand for CCU methanol of 160 Mt. In the ambitious case, CCU products penetrate the entirety of this freight truck market and 80% the polyolefins markets, alongside the existing methanol markets for chemical end-uses. This totals an annual demand of 825 Mt. If these new markets are not considered, replacing the current non-CCU market with CCU methanol (including methanol for gasoline blending) would give a total demand of 100 Mt per annum. Under these three assumptions, long-term CCU pathways could avoid 297, 1537 and 186 $MtCO_2$ per year respectively.

Formic acid has a variety of niche end-uses with an approximate annual demand of 0.7 Mt per annum. Formic acid is used in agriculture for silage and animal feed (27%), leather and tanning applications (22%), pharmaceuticals & food chemicals (14%), as well as in the textile industry (9%) and for natural rubber production (7%). The abatement potential of CCU based formic acid was estimated for a single penetration assumption. If the entirety of the current non-CCU market for formic acid were to be replaced with CCU products, then the annual demand for CCU products would be 1 Mt. Under this assumption, approximately 2.27 $MtCO_2$ could be avoided per year.

Global demand for the middle distillate products considered (diesel, jet fuel, and gasoline) totalled approximately 2900 Mt in 2018 with 300 Mt for aviation fuels, 1100 Mt for motor gasoline, and 1500 Mt for diesel type products. Synthetic fuels are only expected to penetrate a small percentage of this market, with other decarbonisation options such as electric vehicles and biofuels dominating decarbonisation routes. The present-day market demand for fossil based middle distillate hydrocarbons in these segments is roughly 580 Mt for freight trucks and 323 Mt for aviation fuels. The abatement potential of CCU based middle distillate hydrocarbons for the three different penetration assumptions were estimated. In the competitive case, CCU products penetrate 3% and 40% of present-day medium- and heavy-duty freight trucks and aviation markets respectively, totalling an annual demand for CCU middle distillates of 147 Mt. In the ambitious case, CCU products penetrate the entirety of these markets, with an annual demand of 903 Mt. If the entirety of the current non-CCU market for middle distillates were to be replaced with CCU products, then the annual demand for CCU products would be 2900 Mt. Under the first two assumptions, long-term CCU pathways could avoid 550 $MtCO_2$ and 3 $GtCO_2$ per year respectively. In the highly unrealistic case that the entire current market for middle distillate hydrocarbons were to be replaced by the CCU route then an avoidance of 11 $GtCO_2$ could be achieved compared to the counterfactual.

The associated costs, resource demands and energy required for levels of competitive and ambitious market penetration are presented in Figure 8.

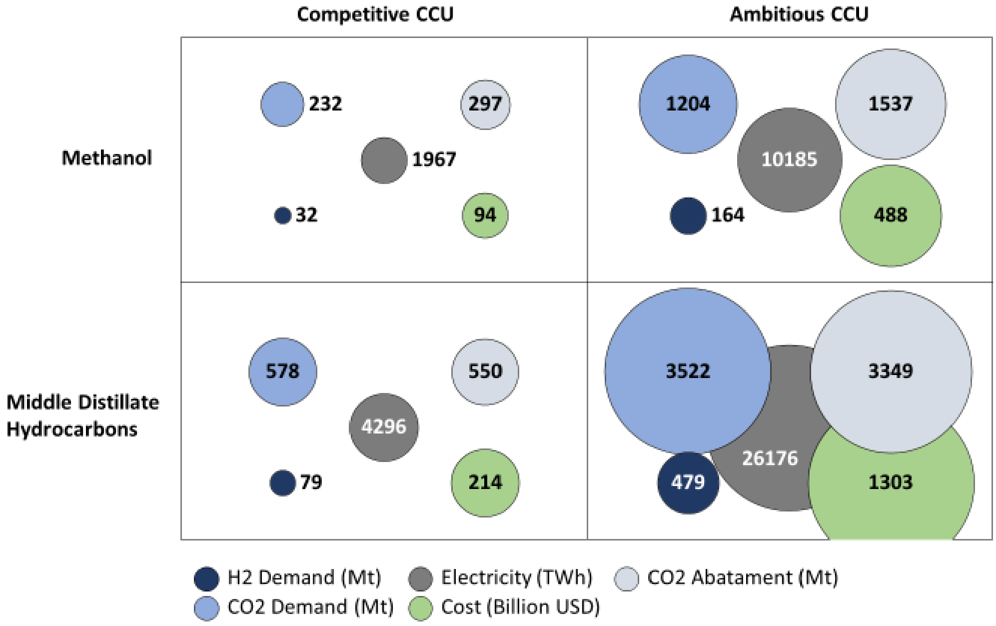


Figure 8 : Implications of scaled deployment of CCU pathways (The CCU pathway used is the long-term central CCU pathway comprising DAC with hydrogen from intermittent renewable electrolysis and the counterfactual fossil route.)

To place these figures into context, current global hydrogen production totals 70 Mt per year with only 2% of this being from renewable electrolysis, hence the required hydrogen for ambitious CCU deployment is many multiples of current production. In 2018, global electricity generation totalled 27,000 TWh of which 26% came from renewables. Although both global electrolyser capacity and renewable electricity generation capacity is upscaling rapidly, the capacities required for CCU production at this ambitious scale would require dramatic increases. Therefore, large scale deployment of CCU may be limited by the generation of these resources, as well as the infrastructure required to distribute them on such large scale.

CCU drivers

CCU can be one of many decarbonisation options within a system of emitters and products. An emitter could abate emissions through switching to low-carbon fuels or capturing CO_2 emissions for storage. Alternatively, CCU can utilise captured emissions, which may be a more immediate option if the emitter doesn't have access to CO_2 storage options. It can also give the captured CO_2 a value and may be preferable in regions where CCS is considered less politically or socially acceptable. Emissions from product use (such as combustion of fuels) could be abated by swapping the product (such as using electric vehicles) or by removing and storing emissions elsewhere in an offsetting approach. Alternatively, CCU can recycle these emissions to reproduce the same product, creating a circular carbon economy. This may be preferable to product swapping if it allows continued use of existing assets, such as refineries or fuel distribution networks, or if comparable properties are difficult to achieve with alternatives (a factor for aviation fuels).

CCU could have additional motivations besides emissions abatement. The use of CO_2 to replace carbon in conventional fossil-derived products avoids the environmental and social impacts associated with the extraction and supply of fossil resources. It could also offer increased security of supply and options for distributed production, as well as benefits over product swapping such as continued use of existing assets and minimal disruption to supply chains. CCU routes may also facilitate renewables deployment by offering co-benefits of energy storage.

Expert Review Comments

Four reviewers from industry, academia and NGOs provided comments on the draft report. The majority of the comments have been addressed by the contractor, including but not limited to:

- Addition of a box to highlight ranges for cost and mitigation potential reported in other studies.
- Adjusting and clarifying narrative on 'emissions credit/benefit' and the accounting used, including minor updates to diagrams and addition of formulas to the appendix.
- Greater distinction of fossil CO_2 source from biogenic and DAC, with addition of a 'what if' box to illustrate implications if the counterfactual were instead non-emission of fossil.
- Inclusion of a table with the assumptions for the central cases in the main body of the report (previously, this data was included in the Appendix).
- Movement of Chapter 8 "Motivations for adopting CCU" to the Appendix, framed as a thought piece.
- Correction of the near-term time frames – mid 2020s rather than immediate.
- Updates to the Executive Summary to provide clarity on methodology and link to the relevant assumptions section.

Conclusions

The choice of feedstocks is key for obtaining benefits from CCU production routes. Hydrogenation routes require a supply of hydrogen and CO_2, and the origins of these feedstocks impact the overall cost and emissions of CCU pathways. The key variables are whether CO_2 is captured from a point source (of fossil or biogenic origin) or by direct air capture, whether hydrogen is produced via electrolysis or via fossil routes, and whether electricity from electrolysis is from the grid or from dedicated renewables. Hydrogen is the most significant cost and emission component for both methanol and middle distillate hydrocarbon CCU production routes.

Production of commodities via CCU routes is more expensive than fossil routes but the cost-premium is expected to decrease in the long term. For the commodities considered, all realistic combinations of feedstocks result in higher costs than the counterfactual route under both near- and long-term assumptions. In the near-term, CCU commodities were found to be at least twice the cost of their fossil counterparts. In the long-term, cost premiums decrease significantly due to reductions in the cost of green hydrogen (driven by lower electricity costs, efficiency improvements, and electrolyser CAPEX reductions) and reductions in CO_2 capture costs.

Economic competitiveness of CCU routes is reliant on a 'cost of emission' being applied. The introduction of a sufficiently high 'cost of emissions' (e.g. a carbon price) can enable low-emission CCU commodities to become cost competitive with their fossil counterparts. For the optimal pathways considered, cost parity could be achieved in the long-term by implementing a 'cost of emissions' between USD 120-225/tCO_2.

CCU can offer a lower emission commodity production pathway, but this is not guaranteed. CCU routes can lead to lower overall emissions than fossil routes provided a low-emission electricity source is used for green hydrogen production or reforming emissions are abated for fossil hydrogen. However, using grid electricity (representative of current European grid mixes) for electrolysis is expected to result in CCU methanol and middle distillate hydrocarbon routes having greater emissions than their fossil counterparts. The same is true for the use of unabated SMR for hydrogen production.

The method of accounting utilised CO_2 has important consequences. The extent to which CCU commodities can claim an emissions benefit for utilising CO_2 impacts the amount of CO_2 avoidance that can be credited to the CCU commodity. For routes with higher production emissions than their counterfactual, CCU commodities can only claim to have lower emissions than the counterfactual commodities if they are able to account the utilised CO_2 as offsetting some of their production or end-of-life emissions.

Avoiding 1 GtCO_2 requires very high levels of market penetration. If CCU products were to capture the full extent of their future possible market segments today, then CCU methanol and middle distillate hydrocarbons have the potential to abate over 1 GtCO_2. This would involve CCU methanol capturing the entirety of the current methanol market, and then expanding into the heavy-duty trucks market and into the plastics market. For middle distillate hydrocarbons, this would entail capturing the entirety of today's aviation fuels market as well as fuels for heavy-duty trucks. Formic acid does not have the potential to reach this 1 GtCO_2 target as even if the CCU pathway were to penetrate the entire formic acid market, the abatement achievable is limited to approximately 2 MtCO_2 due to the currently low market demand.

Energy demands may become a barrier limiting large scale deployment. CCU hydrogenation routes are energy intensive, particularly green hydrogen pathways which require large amounts of renewable electricity for electrolysis. Under the investigated 'ambitious CCU' scenario, middle distillate hydrocarbons would require about 27,000 TWh of electricity, almost the entire current electricity production globally. Deployment of CCU at a competitive market scale would require significant increases in both hydrogen production capacity and low carbon electricity generation capacity, alongside upgrades to the distribution and storage infrastructure.

Conditions for success of CCU include availability of low-cost renewable electricity, access to low carbon hydrogen, high emissions costs, limited CO_2 storage and consumer pressure. The CCU pathways must be designed carefully to ensure lower life-cycle emissions than the counterfactual, alongside sustainable and readily available inputs. Co-location of assets (e.g. DAC, hydrogen production and the CCU facility) may reduce costs, particularly in regions with high potential for renewable electricity. CCU could be an attractive solution in regions with limited CO_2 storage, or with cost or public acceptance challenges for CCS.

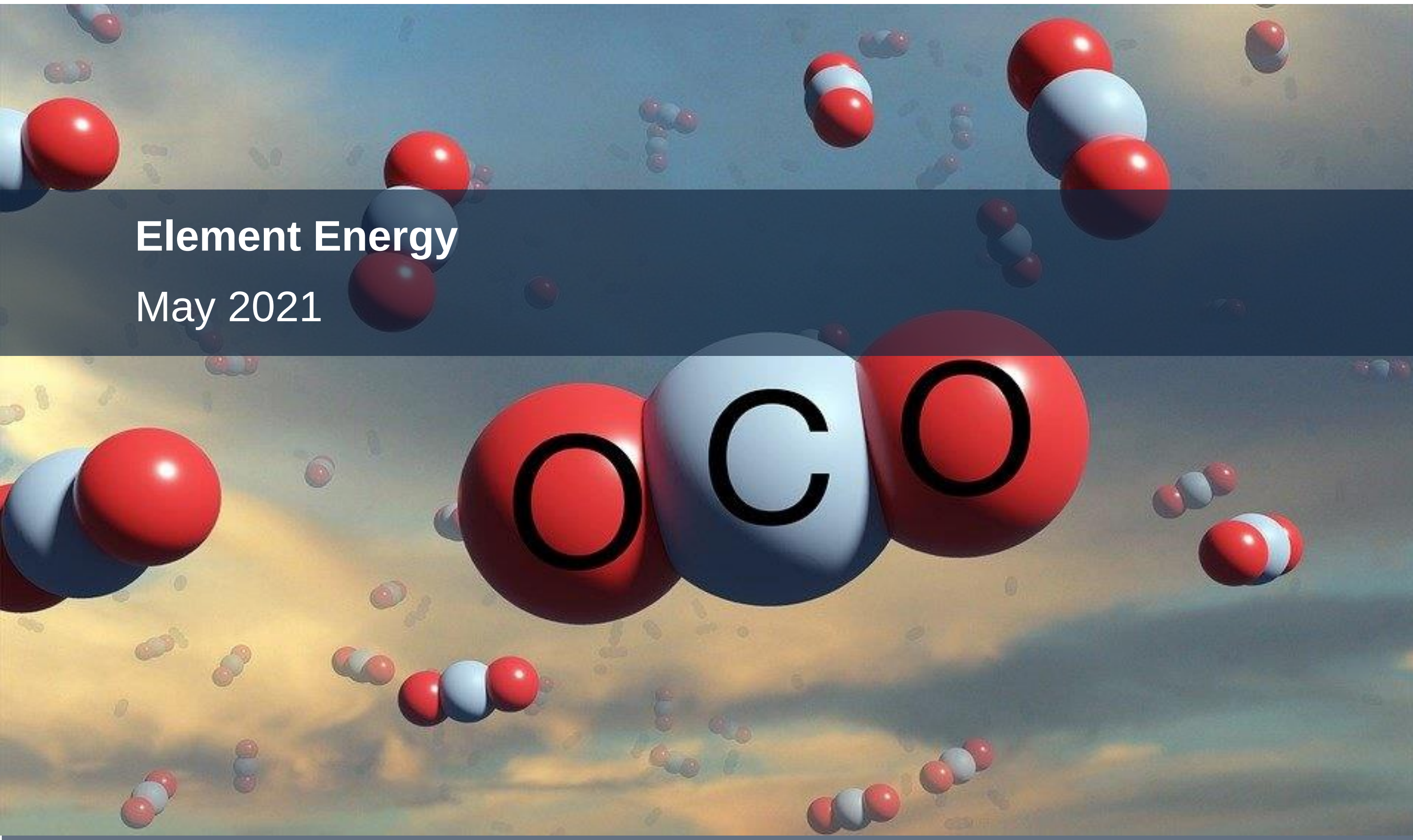
Recommendations

The following recommendations for enabling CCU pathways were identified during the study:

- Lab scale research and pilot-demonstrations are necessary to address technical barriers with conversion steps in order to raise the technology readiness levels of CCU technologies.
- LCA and TEA studies should follow guidelines to facilitate the comparison and evaluation of new technologies. Greater understanding is needed of the life-cycle emissions associated with renewable electricity and pathways for producing hydrogen.
- Establishing the end-uses/services that are most-likely to require CCU to meet climate targets could help to focus developments on markets where demand will be greatest.
- Low existing demands and future demand uncertainty act as a barrier to commercialisation. Policies to mandate the use of low-carbon products or to increase the cost-competitiveness of CCU products could increase demand.
- Regulatory requirements can make market entry difficult for new production routes. Enabling actions for CCU products could be streamlining the approval process for certain products.
- Further clarity is needed from policy makers on the accounting and allocation of CO_2 in CCU routes, with uncertainties in how benefits might be realised. For example, it is uncertain whether direct air capture and point source capture will be accounted differently in future policies, and whether negative emissions technologies will be able to claim credits for carbon removal. Global consistency of approaches and integration of policies become important due to cross-border product trade. With the increasing emergence of ‘carbon border adjustment mechanisms’, this issue becomes increasingly important. It is also important for policies to enable integration along the supply chain, for example, policies which allow the transfer of emission credits between parties, including those located in different countries. (Some of the issues are addressed in 2018-TR01a-c ‘GHG accounting for CCU technologies’, 2019-TR03 ‘Integrated GHG accounting guidelines for CCUS’, and 2021-TR04 ‘CCU as a contribution to national climate change mitigation goals: Japan case study’).
- CCU pathways can benefit from advances in CO_2 capture and low-emission hydrogen generation. Increasing the availability of low cost and low emission electricity for green hydrogen production will enable cheaper and lower emission CCU commodities. This can be achieved through large-scale deployment of renewables, with potential for co-location with CCU facilities.
- The sharing of infrastructure components with large scale CCS projects (for example within clusters) could facilitate smaller scale CCU production.

CO_2 Utilisation Reality Check: Hydrogenation Pathways

A report for



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This report has been prepared by Element Energy, with support from the Styring Group at The University of Sheffield.

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

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Disclaimer

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This study was developed in parallel with '**CO_2 as a Feedstock**', which provides a broader perspective of CCU routes and their advantages and disadvantages. Many readers may find it useful to read the studies together to provide complementary information and perspectives.

Executive summary

Carbon dioxide (CO_2) can be transformed into a wide range of value-added products, acting as an alternative carbon source to fossil carbon. CO_2 is already used extensively as a direct input for products such as carbonated beverages, fire-extinguishers, and cooling systems. CO_2 can also be converted via chemical transformation into a wide range of value-added products; this is an area of increasing interest due to considerations related to climate change, avoidance of fossil fuels, and the circular economy. **Carbon capture and utilisation (CCU)** uses CO_2 captured from industrial emissions, power plants or directly from the atmosphere, thus having potential to reduce net CO_2 emissions relative to conventional production routes. CCU can be used to produce chemicals, materials, polymers, and fuels that are direct replacements for existing products, conventionally produced from fossil feedstocks. Therefore, CCU can offer a means of producing conventional products whilst reducing fossil feedstock consumption.

The evaluation of CCU routes is often complex, with emissions and costs variable with feedstock assumptions, and assessment of benefits dependent upon comparison to a counterfactual. There is uncertainty around the role that CCU technologies might play in system decarbonisation and the potential scale of CCU deployment. The assessment of these factors requires an understanding of the total emissions associated with CCU products, the costs, and the energy demands. Depending on the product being investigated, estimates of these factors can vary considerably due to a range of potential options for CCU conversion technology, the origins of feedstocks and energy, and geographical factors. In addition, quantification of emissions mitigation requires assumptions around the counterfactual case for comparison, adding complexity. The allocation of costs and emissions across different aspects of the value-chain also adds uncertainty.

This study highlights the impact of different resource input choices (hydrogen, electricity, CO_2 capture) on CCU routes that involve CO_2 hydrogenation. The focus of this study is CO_2 hydrogenation, a particular type of CCU route in which CO_2 is reacted with hydrogen over a specialised catalyst to produce value-added chemicals or fuels. The study investigates how different choices for the sources of hydrogen, electricity and CO_2 impact the overall emissions, costs and energy demands of the route, identifying the most dominant factors and highlighting optimal conditions; it does not aim to provide detailed modelling or engineering design, so results should not be taken as accurate predictions of production costs. The study identifies barriers and drivers, discussing broader motivations for CCU within an Annex. **Specific study objectives were:**

- To assess information on feedstock, energy, and CO_2 inputs into the production of CCU commodities as well as their end-use.
- Identify the circumstances (e.g. source and carbon intensity of electricity/hydrogen) under which CO_2-conversion has climate mitigation potential
- Understand the economic competitiveness of CO_2-based products with those produced conventionally, including the required carbon price
- Discuss the RD&D and policy gaps required to be closed to enable deployment of CCU at scale.

The commodities selected for investigation were **methanol, formic acid, and middle distillate hydrocarbons** (synthetic fuels), with a focus on catalytic hydrogenation pathways. This Executive Summary highlights findings from methanol and middle distillate hydrocarbon analysis, with analysis on formic acid available in the main body of the report.

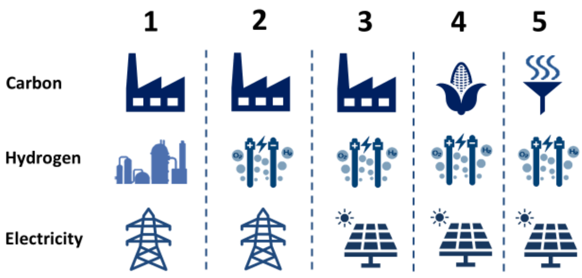
Implications of CCU feedstock and energy choices

Overview of approach

Hydrogenation routes require a supply of hydrogen and CO_2. This study investigates how the origins of these feedstocks impact the overall cost and emissions of CCU pathways. The options investigated are whether CO_2 is captured from a point source (of fossil or biogenic origin) or by direct air capture (DAC), and whether hydrogen is produced via electrolysis or via fossil routes. For hydrogen produced from electrolysis (known as green hydrogen) the impact of whether electricity for electrolysis is from the grid or from dedicated renewables is investigated.

The implications for costs, emissions and energy are investigated for **five central pathways**:

1. Industrial CO_2 capture. Hydrogen from fossil sources with CCS (autothermal reforming).
2. Industrial CO_2 capture. Hydrogen from grid-powered electrolysis ('sustainable' grid mix[1])
3. Industrial CO_2 capture. Hydrogen from intermittent renewables-powered electrolysis.
4. High purity industrial CO_2 capture (bio-ethanol). Hydrogen from intermittent renewables-powered electrolysis.
5. CO_2 from direct air capture and hydrogen from intermittent renewables-powered electrolysis



Key used for central pathways, described left.

Results are presented for both near-term (**mid-to-late 2020s**) and long-term (**2050s**) input assumptions. The assumptions used for the costs, emissions and energy requirements of CO_2 and hydrogen are detailed in the methodology section (Chapter 4) of the main report body. These input values were mostly extracted or derived from available literature.

The boundaries for the analysis are depicted below. The CCU routes include emissions and costs associated with the production of hydrogen (including electricity generation for electrolysis), the supply of CO_2 (capture and transport), and the conversion of these feedstocks to the commodity. The CCU routes are compared to today's conventional production route for identical products as reported in literature, which include fossil extraction and subsequent processing (cradle-to-gate). The CCU and fossil commodities are assumed to have identical end uses.

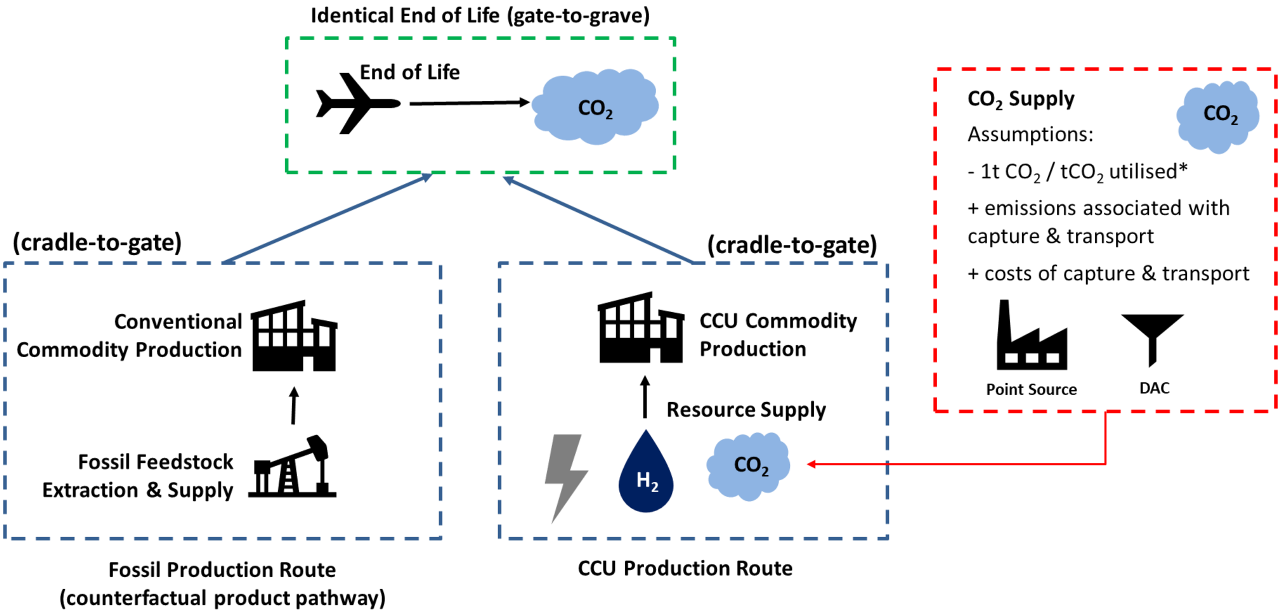


Diagram of system boundaries and the components included in cost, emission, and energy totals. The commodities produced from each production route are assumed to be identical and therefore have the same end-of-life characteristics. * negative emissions associated with CO_2 supply relate to a comparison to a counterfactual for the CO_2 capture system and are dependent upon accounting assumptions and the choice of counterfactual. These are discussed in section 4.2 of the main body of the report.

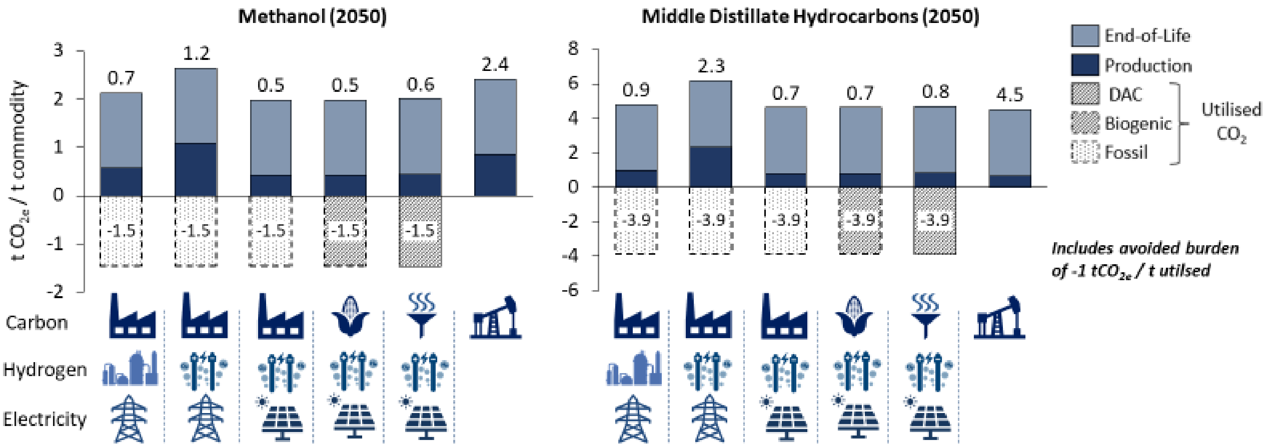
[1] Uses grid emission intensities projected by the IEA World Energy Outlook 2019 [LINK] Sustainable Development Scenario for developed countries. Near-term emissions of 237 g CO_2 / kWh (2030) and long-term emissions of 81 g CO_2 / kWh (2040). In the near-term this is similar to the average EU grid mix, which was 294 g CO_2 / kWh in 2017 - European Environment Agency [LINK].

*** Inclusion of an avoided burden:**

The CO_2 enters the boundaries with an **avoided burden of - 1 t CO_2 per tonne of CO_2 plus additional emissions from capture and transport.** This represents the impact of supplying the CO_2 to utilisation compared to a reference system for that CO_2.The inclusion of the avoided burden of - 1 t CO_2 per tonne of CO_2 assumes that the CO_2 would otherwise be emitted or have remained atmospheric. Therefore, at the point of supply to the CCU pathway, the CO_2 is associated with a benefit of avoided emission or atmospheric removal. It also assumes that this avoidance/removal is allocated to the CCU pathway. The cost of CO_2 capture and transport is therefore also allocated to the CCU pathway, such that overall the capturer/emitter gains no benefits but incurs no additional costs.

Implications for emissions

The life-cycle emissions of commodities produced via the five central pathways under long-term assumptions were lower than that of the counterfactual once the avoided burden of CO_2 capture was considered. However if this avoided burden were to be excluded then the pathway using grid-electrolysis would lead to greater emissions for the product than the conventional route.

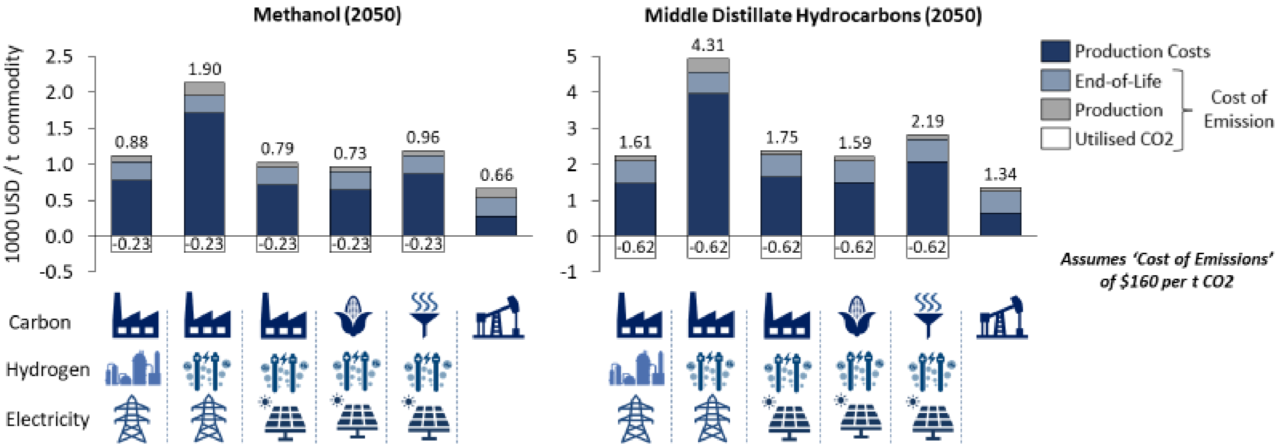


Emissions for central methanol and middle distillate hydrocarbon CCU pathways using long-term emission assumptions, compared to the counterfactual product. The utilisation of captured CO_2 is accounted as minus 1 tonne CO_2 per tonne utilised. Electricity emission intensities of 81 g CO_2 / kWh and 25 g CO_2 / kWh are used for grid and renewables respectively.

Hydrogen production dominates production emissions for all central pathways but is particularly significant for the grid electrolysis pathway where the assumed emission intensity of the grid is 81 g CO_2 / kWh. Emissions associated with CO_2 capture and the conversion step can also be important but to a lesser extent. In the long-term, the lowest emission central pathway is the use of CO_2 from high-purity bioethanol CO_2 capture and hydrogen produced from renewables powered electrolysis.

Implications for costs

Production of commodities via CCU routes is more expensive than fossil routes, but the cost-premium is expected to decrease in the long term. The costs of all central pathways were found to be greater than those of the counterfactual route, both under near-term and long-term assumptions. In the near-term, CCU commodities were found to be at least twice the cost of their fossil counterparts. In the long-term, cost premiums decrease significantly due to reductions in the cost of green hydrogen (driven by lower electricity costs, efficiency improvements, and electrolyser CAPEX reductions) and reductions in CO_2 capture costs.

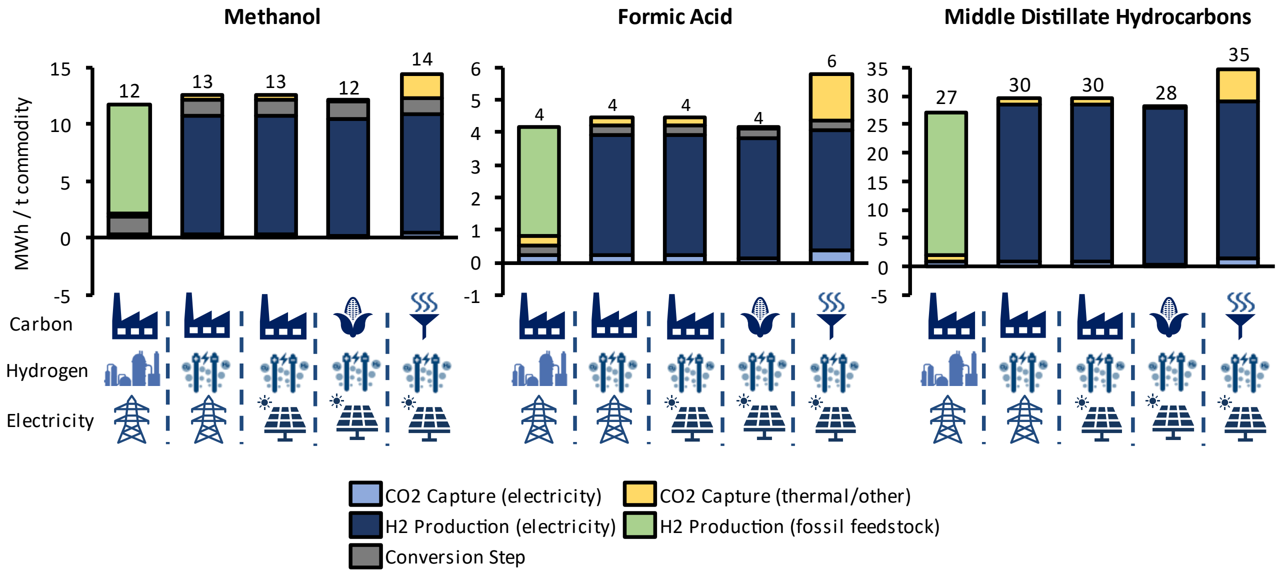


Costs for central methanol and middle distillate hydrocarbon CCU pathways using long-term cost assumptions, compared to the counterfactual product. A 'Cost of Emission' is applied at USD 160 / t CO_2 linked to the determined emissions for production and end-of-life (positive), and the emissions avoided due to CO_2 utilisation (negative). Electricity costs of USD 123 / MWh and USD 32 / MWh are used for grid and renewables respectively.

The cost premium for CCU pathways varies considerably across pathways, being greatest in the long-term for the grid-electrolysis pathway and least for that with renewables-electrolysis with high-purity CO_2 capture. The cost of hydrogen is the dominant cost component for all methanol and middle distillate CCU pathways, accounting for 50-70% and 60-80% of their production costs respectively (long-term). The choice of CO_2 source does not have a significant impact on costs in the near-term, but the distinction between high DAC costs and low costs for concentrated CO_2 capture becomes important in the long-term as hydrogen costs decrease.

Implications for energy consumption

Each of the components of the CCU production routes have an associated energy input requirement. Hydrogen production requires energy either in the form of electricity for electrolysis or a fossil fuel feedstock for blue hydrogen production. The efficiency of these technologies determines how much of this energy is converted into hydrogen. The capture of CO_2 typically requires both electrical and thermal energy inputs, for processes such as solvent thermal regeneration and CO_2 compression. Energy demand varies with the type of CO_2 source, with less concentrated CO_2 streams requiring a higher energy input. Within the conversion step, energy is required to power compressors and to separate the final commodity from solvents and by-products via distillation. The figure below shows the breakdown of energy requirements for the central CCU pathways. It is seen that hydrogen production dominates energy demands, and that energy for CO_2 from DAC is considerably greater than from point source capture.



Energy demands for **long-term (2050)** central CCU pathways per tonne of commodity. Energy is required for hydrogen production, CO_2 capture and the conversion step. Demands are split into electricity and non-electricity (thermal/other) requirements. Assumes efficiencies of 75% for green hydrogen production and 82% for blue hydrogen production. Energy for the conversion step is assumed in the analysis to be electricity but could be a mixture of electricity and thermal energy.

Variations on central cases

In addition to the central pathways, further variations on each variant were investigated to represent the potential for higher or lower costs or emission intensities of different CO_2 point sources, different electricity grid-mixes, different fossil-hydrogen technologies, and different DAC technologies.

The cost and emissions of the electricity source is of key importance for electrolysis pathways. The source of hydrogen is the main influencing variant for costs and emissions across all pathways. For an optimal variant of the long-term DAC pathway with renewables-powered electrolysis, it is estimated here that emissions parity is only reached if the electricity emission intensity is below 180 g CO_2 / kWh for methanol and 160 g CO_2 / kWh for middle distillate hydrocarbons. Even if electricity emissions are assumed to be zero and a carbon price of USD 160 / t CO_2 is applied, it is estimated that cost parity is only reached if electricity costs fall below USD 20 / MWh for methanol and USD 15 / MWh for middle distillate hydrocarbons. There are significant variations in electricity costs and emissions across regions, including for both grid supply and renewables generation. For example, across the EU emissions ranged from over 900 g CO_2 / kWh in some regions to below 10 g CO_2 / kWh in others. Therefore, the electricity source used for hydrogen production via electrolysis has significant influence on the impacts of CCU and currently only in select countries could grid-powered routes lead to reduced emissions compared to counterfactual production routes.

Emissions associated with blue hydrogen production are variable with technology and capture rates. For blue hydrogen production, emissions arise from the extraction of the fossil input (coal or natural gas) and the incomplete capture of emissions at the hydrogen plant. Technologies with higher efficiencies have lower emissions associated with fossil extraction per tonne of hydrogen. In the future, higher capture rates at blue hydrogen plants could be achievable, resulting in lower emissions. Estimates in this study suggest that increasing the capture rate at an autothermal reforming plant from 85% to 99% results in a 34% reduction in CCU methanol production emissions.

Putting a price on carbon

Economic competitiveness of CCU routes is reliant on there being an economic incentive to lower emissions. For example, if a cost penalty (such as a carbon tax) were to be incurred per tonne of CO_2 emitted across a products lifecycle. The introduction of a sufficiently high cost penalty - referred to here as the 'cost of emissions' - can enable low-emission CCU commodities to become cost competitive with their fossil counterparts, due to disproportionate commodity price increases. Using optimal variations, this study estimates that cost parity could be achieved in the long-term by implementing a 'cost of emissions' between USD 120-225 per tonne of CO_2 (USD 120 for methanol, USD 225 for formic acid, USD 150 for middle distillate hydrocarbons). Under an ambitious 'cost of emissions' of USD 300 / t CO_2, most electrolysis pathways powered by dedicated renewables could be competitive under long-term assumptions. However, it should be noted that CCU routes may well receive policy support beyond a carbon price, reducing the carbon price required for cost parity. Equally, many regions have direct or indirect fossil fuel subsidies which may be removed in the long-term, increasing the cost of the conventional commodity production routes.

Scale of CCU mitigation potential

CCU pathways can avoid emissions when compared to a counterfactual pathway. For all commodities investigated, the utilised CO_2 is emitted at the products end-of-life and additional CO_2 emissions result from supply of electricity, hydrogen, and capturing CO_2 for the CCU product. Therefore, all the pathways considered result in overall increases in atmospheric CO_2 concentrations over the full lifecycle of the product. The mitigation potential for CCU pathways is seen when comparing them to a counterfactual pathway. CCU offers the chance to re-use CO_2 that would otherwise be atmospheric and avoid emissions associated with fossil extraction and conventional production routes.

The maximum extent of emissions mitigation possible from CCU pathways can be estimated considering the potential scale of their deployment. If CCU products were to capture the full extent of their potential market segments, then CCU methanol and middle distillate hydrocarbons have the potential to each abate over 1 Gt of CO_2 annually (based on 2019/2020 global market sizes). However, this illustrative calculation of mitigation potential is based on very ambitious assumptions on market penetration. For methanol, it would require the CCU route capturing the entire current methanol market and then expanding its applications to become a fuel for the heavy-duty trucks market (via conversion to DME[2]) and a feedstock for polyolefins in the plastics market. For middle distillate hydrocarbons, this would entail capturing large proportions of both the aviation fuels market and a portion of the heavy-duty truck fuel market. For formic acid, the abatement achievable if the entire existing formic acid market were to use CCU for production is limited to 2 Mt CO_2 annually due to the small market size.

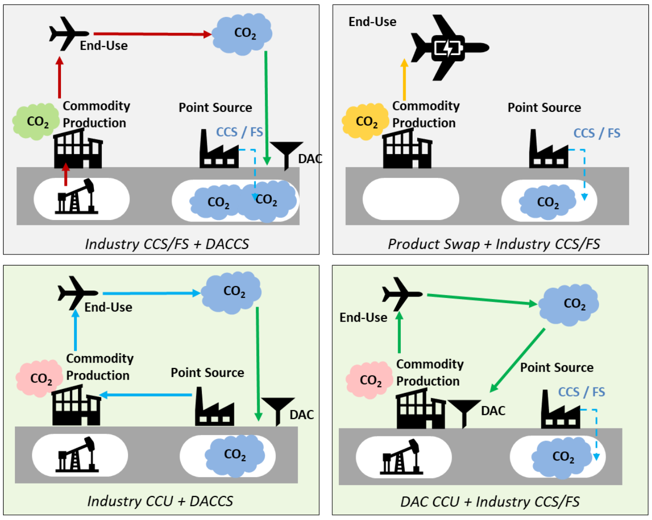
Energy demands may become a barrier limiting large scale deployment. CCU hydrogenation routes are energy intensive, particularly green hydrogen pathways which require large amounts of renewable electricity for electrolysis. Deployment of CCU at scales needed to achieve 1 Gt of avoidance annually would require around 6,600 TWh and 7,800 TWh of electricity per year for methanol and middle distillate hydrocarbons respectively. For context, in 2018, global electricity generation totaled 27,000 TWh of which only 26% came from renewables[29]. Drastic increases in both hydrogen production capacity and low carbon electricity generation capacity would be needed to meet these CCU demands.

Driving CCU: differing motivations

CCU can be one of many decarbonisation options within a system of emitters and products. An emitter could abate emissions through switching to low-carbon fuels or capturing CO_2 emissions for storage. Alternatively, CCU can utilise captured emissions, which may be a more immediate option if the emitter doesn't have access to CO_2 storage options. It can also give the captured CO_2 a value and may be preferable in regions where CCS is considered less politically or socially acceptable. Emissions from product use (such as combustion of fuels) could be abated by swapping the product (such as using electric vehicles) or by removing and storing emissions elsewhere in an offsetting approach. Alternatively, CCU can recycle these emissions to reproduce the same product, creating a circular carbon economy. This may be preferable to product swapping if it allows continued use of existing assets, such as refineries or fuel distribution networks, or if comparable properties are difficult to achieve with alternatives (a factor for aviation fuels).

[2] Dimethyl Ether – a potential alternative for diesel, derived from methanol

CCU could have additional motivations besides emissions abatement. The use of CO_2 to replace carbon in conventional fossil-derived products avoids the environmental and social impacts associated with the extraction and supply of fossil resources. It could also offer increased security of supply and options for distributed production, as well as benefits over product swapping such as continued use of existing assets and minimal disruption to supply chains. CCU routes may also facil itate renewables deployment by offering co-benefits of energy storage.



Potential abatement options for systems containing an industry point source emitter and a product/service. FS denotes fuel switching, CCS denotes carbon capture and storage, CCU for CO_2 utilisation and DAC for direct air capture of CO_2.

Enabling CCU: recommendations

The following recommendations for enabling CCU pathways were identified during the study:

- Lab scale research and pilot-demonstrations are necessary to address technical barriers with conversion steps, such as the development of catalysts that combine efficiency with sustainability, the improvement of knowledge around the reverse water gas shift reaction, and raising the technology readiness levels of CCU technologies.
- LCA and TEA studies should follow guidelines to facilitate the comparison and evaluation of new technologies. Greater understanding is needed of the life-cycle emissions associated with renewable electricity and pathways for producing hydrogen.
- Establishing the end-uses/services that are most-likely to require CCU to meet climate targets could help to focus developments on markets where demand will be greatest.
- Low existing demands and future demand uncertainty act as a barrier to commercialisation. Policies to mandate the use of low-carbon products or to increase the cost-competitiveness of CCU products could increase demand.
- Regulatory requirements can make market entry difficult for new production routes, particularly for synthetic fuels. Enabling actions for CCU fuels could be streamlining the approval process for certain products, setting up a ‘Clearing House’ to support producers, developing small-scale testing, and researching the possibility of expanding the allowable envelope of fuel compositions.[3]
- Further clarity is needed from policy makers on the accounting of CO_2 in CCU routes, with uncertainties in how benefits might be realised. For example, it is uncertain whether direct air capture and point source capture will be accounted differently in future policies, and whether negative emissions technologies will be able to claim credits for carbon removal. Global consistency of approaches and integration of policies is required due to cross-border product trade. It is also important for policies to enable integration along the supply chain, for example, policies which allow the transfer of emission credits between parties, including those located in different countries.
- CCU pathways can benefit from advances in CO_2 capture and low-emission hydrogen generation. Increasing the availability of low cost and low emission electricity for green hydrogen production will enable cheaper and lower emission CCU commodities. This can be achieved through large-scale deployment of renewables, with potential for co-location with CCU facilities.
- The sharing of infrastructure components with large scale CCS projects (for example within clusters) could facilitate smaller scale CCU production.
- Actions to increase awareness of the production of emissions associated with commodities and the advantages of CCU production routes could help facilitate CCU deployment.

[3] EASA 2019, Sustainable Aviation Fuel ‘Facilitation Initiative’

Acronyms

ATR	Autothermal Reforming
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Utilisation, and Storage
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalents
DAC	Direct Air Capture
EU	European Union
FOAK	First-of-a-Kind
NOAK	Nth-of-a-kind
OPEX	Operational Expenditure
GHG	Greenhouse Gas
H_2	Hydrogen
Mt	Mega tonne
NG	Natural Gas
RD&D	Research, Development & Demonstration
SMR	Steam Methane Reforming
T&S	Transport and Storage

Terminology

Blue Hydrogen	Hydrogen produced from fossil-resources with CCS applied. Includes SMR, ATR and Coal gasification options combined with CCS technology.
Green Hydrogen	Hydrogen produced from electrolysis of water.
Grey Hydrogen	
Cradle-to-Gate	Covers stages of a products lifecycle from raw material extraction to the finalised product at the factory 'gate'.
Cradle-to-Grave	Covers stages of a products lifecycle from raw material extraction to the products disposal at end-of-life (inclusive).
Gate-to-Grave	Covers stages of a products lifecycle starting at the point of its creation (factory gate) up to and including its disposal at end-of-life.

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1 Introduction

1.1 Context

With global climate targets becoming more stringent, it is commonly accepted that carbon capture is required to meet climate goals in a cost-effective manner. Carbon capture has numerous applications across a low-carbon energy system; it can help decarbonise power generation and energy intensive industries, as well as heat and transport, when used for hydrogen production. On average across IPCC 1.5 Degrees Scenarios (1.5DS) there are 13 GtCO_2 captured annually by 2060. The IEA estimates that if CO_2 capture were to be limited (due to limited CO_2 storage availability), the decarbonisation cost could be $4 trillion greater globally[4]. CO_2 utilisation offers a destination for captured CO_2 that is complementary to permanent geological CO_2 sequestration. Whilst geological sequestration permanently stores captured CO_2, utilisation routes use CO_2 to produce a carbon containing product.

Carbon capture & utilisation (CCU)

CO_2 utilisation is the use of CO_2 at above atmospheric concentrations to produce valuable products, either through direct use as CO_2 (e.g. carbonated drinks) or through chemical conversion (e.g. to carbon-based chemicals, fuels). CO_2 is already used extensively for urea manufacture in the fertiliser industry, for enhanced oil recovery (EOR), and for food and beverage production, together with other conventional applications including use in fire-extinguishers, greenhouses, and cooling systems.

There is **increasing interest in the chemical transformation of CO_2** to value-added products, motivated partly by climate change considerations but also because CO_2 feedstocks can lead to cheaper or cleaner production processes compared to conventional hydrocarbon feedstocks. Recent commercial developments in CO_2 utilisation are seen in **polymer manufacturing** (polyols & polyurethane), **chemical production** (methanol & formic acid), **construction materials** (aggregates & concrete), and **synthetic fuels**. Often the products could substitute conventional products made from fossil fuels, such as polymers and fuels.

Carbon capture & utilisation (CCU) refers to CO_2 utilisation in which the supplied CO_2 is captured either from an emission point source (e.g. fossil fuel combustion in an industrial plant) or directly from the atmosphere. This allows CO_2 that would otherwise be emitted from a point source to be ‘re-used’, avoiding emissions compared with the conventional system. For many CCU routes (such as synthetic fuels) the utilised CO_2 is emitted to the atmosphere at the commodities end-of-life (such as combustion). For these routes, product lifecycle CO_2 emissions are still net-positive if the utilised CO_2 was of fossil origin but may have lower emissions than a conventional commodity production route. If the CO_2 was instead of biogenic origin or was captured directly from the atmosphere, the overall CCU product lifecycle could be net-neutral providing no additional emissions were associated with commodity production. This latter case where CO_2 is cycled between the atmosphere and temporary storage in commodities is an example of a circular carbon economy.

CCU and CCS differ and can be complementary. The future scale of CO_2 for utilisation is expected to be much smaller than the potential scale for geological sequestration, partially due to limited demand for CCU products. However, whereas the primary aim for sequestration is to store CO_2 emissions, the CCU pathways have a different focus of producing a product in a low-emission manner. This can be achieved partly via re-using CO_2 to avoid additional ‘new’ release at end-of-life, but also through use of an alternative production pathway. There may also be other motivations such as improvements in product performance or security of supply. With large volumes of CO_2 projected to be captured in the longer term, CCU and CCS can play complementary roles in climate change mitigation. CCU may additionally provide a market for capturing CO_2 in regions where CO_2 storage is not available (due to technical constraints, high-costs, or public perception challenges).

[4] The Role of CO2 Storage, IEA 2019 LINK

CO_2 Hydrogenation Pathways

This study considers the commodities methanol, formic acid and middle distillate hydrocarbons (liquid fuels). These commodities are conventionally produced from fossil-based feedstocks. Methanol is used as a chemical (e.g., solvent), for gasoline blending and as a chemical intermediate in the production of other commodities. Middle distillate hydrocarbons, including diesel, gasoline, and jet fuel, are used primarily for transport and produced from refining of crude oil. Formic acid has a variety of smaller scale applications such as use in agriculture, pharmaceutical, food and textile industries. As all the products are conventionally fossil-based and have carbon intensive life cycles, there is interest in alternative production routes such as CO_2 hydrogenation.

CO_2 can be converted to chemicals and fuels using catalytic hydrogenation. Hydrogenation pathways involve the reaction of CO_2 feedstock with hydrogen over a specialised catalyst, typically at high reaction temperatures and pressures. To avoid emissions, a low carbon intensity hydrogen source is necessary, with most developers focusing on green hydrogen from renewable power electrolysis. There are other pathways to produce chemicals and fuels from CO_2 (electrochemical, photocatalytic, fermentation, bio-catalysis), however hydrogenation pathways are one of the most promising, with examples of small-scale commercialisation already in existence.

Many factors influence whether these pathways can avoid emissions relative to the counterfactual and at what cost. A key factor is the production of the resource inputs to the conversion step (e.g., CO_2, hydrogen, electricity), in terms of the generation technology used and the resulting carbon intensity and cost of the resources. There are factors related to the conversion step itself (e.g., energy requirements, conversion efficiency).

In terms of absolute lifecycle CO_2 emissions, the considered routes do not offer the removal of atmospheric CO_2. For all commodities considered, the utilised CO_2 is eventually re-emitted to the atmosphere. Therefore the best possible outcome is that production of the CCU commodity is net-neutral, which occurs if the utilised CO_2 was recently atmospheric and the CCU production pathway involves no additional emissions. This best case requires that the utilised CO_2 was recently atmospheric (DAC or biogenic source) and that there be no emissions associated with the CCU route besides those of the utilised CO_2 being re-emitted at the commodities end-of-life. If the utilised CO_2 is fossil derived, then this fossil CO_2 is eventually emitted to the atmosphere. Depending on accounting, this atmospheric increase may be associated with the original emitter or with the use of the CCU product.

1.2 Objectives and scope

This study highlights the impact of different resource input choices (hydrogen, electricity, CO_2 capture) on CCU routes that involve CO_2 hydrogenation. The focus of this study is CO_2 hydrogenation, a particular type of CCU route in which CO_2 is reacted with hydrogen over a specialised catalyst to produce value-added chemicals or fuels. The study investigates how different choices for the sources of hydrogen, electricity and CO_2 impact the overall emissions, costs and energy demands of the route, identifying the most dominant factors and highlighting optimal conditions; it does not aim to provide detailed modelling or engineering design, so results should not be taken as accurate predictions of production costs. The study identifies barriers and drivers, discussing broader motivations for CCU within an Annex. **Specific study objectives were:**

- To assess information on feedstock, energy, and CO_2 inputs into the production of CCU commodities as well as their end-use.
- Identify the circumstances (e.g. source and carbon intensity of electricity/hydrogen) under which CO_2-conversion has climate mitigation potential
- Understand the economic competitiveness of CO_2-based products with those produced conventionally, including the required carbon price
- Discuss the RD&D and policy gaps required to be closed to enable deployment of CCU at scale.

The commodities selected for investigation were **methanol, formic acid, and middle distillate hydrocarbons** (synthetic fuels), with a focus on catalytic hydrogenation pathways.

Although the scope of the study does not include specific regional analysis, regional interpretations can be made by considering the most likely pathways for each region based on the type of resource inputs available in the region.

1.3 Approach taken

The study investigates the production of methanol, formic acid, and middle distillate hydrocarbons from feedstocks of CO_2 and hydrogen. The sources of these feedstocks are varied to understand the implications for the overall pathway. The costs, emissions, and energy requirements for commodity production via these pathways are assessed for both the near-term (mid-to-late 2020s) and long-term (2050s). The competitiveness of the CCU pathways compared to the counterfactual production routes is investigated.

The approach taken consisted of four steps: data collection, modelling of pathways (costs, emissions, energy), broader analysis of CCU (markets, impacts, motivators), engagement activities.

Data collection

- Literature review used to obtain data on the costs, energy demand, and emission intensity of resource inputs (CO_2, hydrogen, electricity) from different supply routes.
- Literature review used to obtain data on processes for converting CO_2 and hydrogen feedstocks to methanol, formic acid, and middle distillate hydrocarbons.

Modelling of CCU pathways

- Determining the costs, emissions and energy demands for the production of CCU commodities for a variety of resource inputs for both, the near-term and long-term horizons.
- Comparison of CCU pathways with counterfactual costs and emissions, with investigation into the cost of emissions required for economic competitiveness, for both, the near-term and long-term horizons.

Broader analysis of CCU

- Investigation into the future markets for the CCU commodities investigated and determination of potential level of emissions abatement achievable.
- Investigation into the factors that might motivate use of CCU and the circumstances under which CCU pathways could be preferential.

Engagement activities

- Discussions with stakeholders in the fields of carbon capture and utilisation to validate input data, understand motivations and areas of interest.

1.4 Report structure

The remainder of this report is structured into 9 chapters:

Chapter 2 provides descriptions of commodity production for both counterfactual fossil routes and CCU routes, including the requirements for hydrogen and CO_2 supply, energy needs for the conversion step, and costs associated with the conversion technologies.

Chapter 3 outlines the cost and emission of different sources of CO_2, hydrogen, and electricity showing the variation between different options.

Chapter 4 describes the methodology for the cost and emission analysis, explaining the central case pathways considered, the boundaries of the assessment, and the assumptions around the avoided burden of CO_2 supply.

Chapter 5 presents the results of the analysis investigating the impact of different CO_2, hydrogen, and electricity sources on the costs and emissions of CCU pathways.

Chapter 6 discusses energy requirements for hydrogen production, CO_2 capture and the conversion step in more detail, presenting the energy requirements for the central CCU pathways.

Chapter 7 discusses the potential extent of emissions abatement achievable with CCU by considering the potential scale of demand for CCU commodities.

Chapter 8 describes actions and key considerations for enabling CCU developments and deployments.

Chapter 9 presents conclusions from the study.

The report is accompanied by an appendix and an annex:

Appendix details the quantitative assumptions used for the analysis and the literature references.

Annex details a separate thought-piece discussing a variety of possible motivations for CCU from different perspectives and the factors that may influence CCU adoption.

2 Commodity Production Routes

The majority of methanol, formic acid, and middle distillate hydrocarbon commodities are conventionally produced from fossil-based feedstocks. The principle feedstock for conventional methanol production is natural gas, whilst middle distillate hydrocarbons originate from crude-oil. The dominant production route for formic acid is via methanol and carbon monoxide intermediates, which respectively are derived from natural gas and crude-oil feedstocks (typical case). For fossil routes, emissions up to the point of sale (cradle-to-gate) include upstream oil and gas emissions such as venting, flaring and fugitive emissions associated with extraction. Additional cradle-to-gate emissions arise from the energy required to produce the products from the fossil feedstocks, including producing the catalysts, building the production plant itself, and the distribution of the commodities/products to the market. In the future upstream oil and gas emissions are expected to decrease.

Alternatively, the selected commodities can be produced using captured CO_2 as the carbon feedstock. There are several pathways to producing chemicals and fuels from CO_2 (catalytic hydrogenation, electrochemical, photocatalytic, fermentation, bio-catalysis). These offer an alternative to fossil-based production routes, with potential advantages being lower production emissions, circular economy principles, increased security of supply, and potential for distributed production. Most academic studies on the conversion of CO_2 to the investigated commodities focus on catalytic hydrogenation pathways[5,6]. This is selected as the focus for this study.

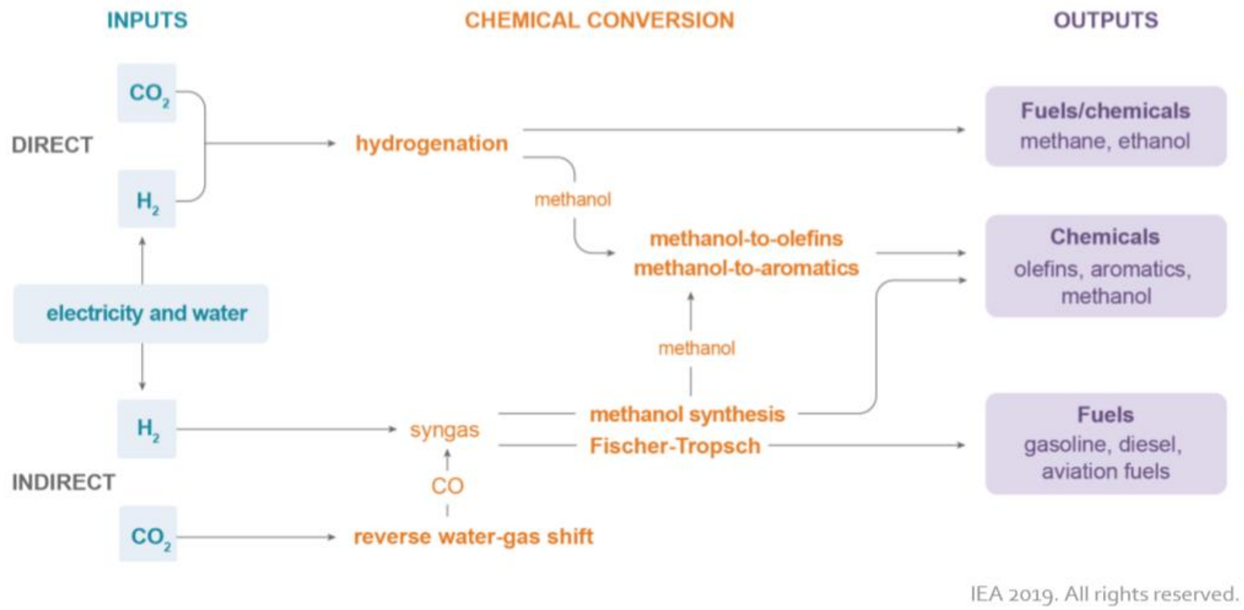

Figure 1: Mature conversion route for CO_2-derived fuels and chemical intermediates. Taken directly from IEA (2019), Putting CO_2 to Use, IEA, Paris https://www.iea.org/reports/putting-co2-to-use.

Costs and emissions for catalytic hydrogenation pathways are determined by the cost and emission intensity of the associated hydrogen and CO_2 feedstocks. These factors can vary significantly across different hydrogen production and CO_2 capture routes, as discussed later in Chapter 3. Hydrogen emissions result from electricity generation if electrolysis is used and from upstream fossil emissions and incomplete capture at reforming/gasification stages if fossil derived hydrogen is used. Emissions from capturing CO_2 originate from the energy requirements for capture and from incomplete capture. Depending on the accounting method, utilisation of CO_2 may count to offset some of the production or end-of-life emissions.

[5] Nguyen et al. 2019, Methanol production from captured CO_2 using hydrogenation and reforming technologies - environmental and economic evaluation. [LINK]
[6] Thonemann 2020, Environmental impacts of CO2-based chemical production: A systematic literature review and meta-analysis [LINK]

For both fossil and CCU routes emissions for usage and end-of-life (gate-to-grave) vary with end-use, distribution and disposal method. If used as a fuel, the commodity is combusted and the carbon contained within it is released to atmosphere, mostly as CO_2 but with a small percentage as carbon monoxide, particulate matter and other volatile hydrocarbons. If used as a chemical intermediate, the commodity is upgraded to a product such as a solvent or polymer building block. Most products eventually break down releasing their carbon to the atmosphere, however the timeframe for this to happen varies depending upon the disposal method. Incineration results in immediate CO_2 emissions, but landfilling some plastic polymers can potentially sequester the carbon for several hundred years while recycling and reusing the polymers delays the emissions for as long as the recycling and reuse continues. In addition to the carbon released from the product itself, there are other emissions resulting from the usage and end-of-life stage, such as distribution of the commodity, subsequent processing, and energy for disposal. In the future, it is likely that these additional emissions will decrease with global decarbonisation efforts, however for the most part the carbon contained within the product molecule will still become atmospheric CO_2 unless carbon is routinely captured from many points of emission.

Details on the conventional and CCU hydrogenation production methods for each investigated commodity are outlined below, with information on assumptions used in the analysis of this study. Further details and assumptions on the specific cost and emissions values used for analysis can be found in the appendix.

Methanol

Methanol is used for gasoline blending, as a chemical (e.g., solvent) and chemical intermediate, and for the production of olefins via the methanol-to-olefins process. Current market demand is estimated at 100 Mt per year[7].

Methanol is conventionally produced from syngas (a mixture of hydrogen and carbon monoxide, with some carbon dioxide), which, in turn, is commonly produced from natural gas (mostly composed of methane). The global warming impact of methanol produced from fossil sources is estimated to be in the range of 0.68 - 1.08 t CO_2 eq/t methanol[8]. The main source of these emissions is the steam methane reforming (SMR) step, during which methane and water are reacted to produce carbon monoxide and hydrogen[9].

There are two possible CCU routes to producing methanol: hydrogenation of CO_2 using low-carbon hydrogen or the reduction of CO_2 to CO followed by reverse water gas shift and methanol synthesis. There is interest in the hydrogenation route in the context of Power-to-Liquids for energy storage. In this route, hydrogen is produced via electrolysis and methanol synthesis occurs via a catalytic exothermic reaction. The methanol is then purified. Production of methanol from CO_2 and hydrogen has been demonstrated at a scale of 4 kt per year ? by Carbon Recycling International and has been sold commercially to clients in Europe and China under the brand name Vulcanol[10]. Commercial-scale projects are planned to be built in China[11] and Norway[12].

This study investigates the direct hydrogenation of CO_2 to produce methanol using a $Cu/ZnO/Al_2O_3$ catalyst. The resource assumptions are that the process requires 1.46 t CO_2 and 0.199 t hydrogen per tonne of methanol, as well as 1470 kWh of electricity for compression and distillation in the conversion step.

Formic Acid

Formic acid has a variety of niche applications including the sillage of crops and tanning of leather, as well as end-uses in pharmaceuticals, food chemicals, and in the textile industry. The market demand for formic acid is low, with current production estimated at less than 1 Mt per year. There is some interest in use of formic acid as a fuel for fuel cells, although this is in the proof-of-concept phase and there are other promising alternatives.[13]

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[7] ICIS 2019 and ICIS 2020 – Methanol Value Chain
[8] Artz et al. 2018, Sustainable Conversion of Carbon Dioxide: An Integrated Review of Catalysis and Life Cycle Assessment..
[9] Philibert, C. 2017, Renewable energy for industry. Paris: International Energy Agency.
[10] Carbon Recycling International website [accessed Feb 2021] – George Olah Renewable Methanol [LINK] and Vulcanol [LINK]
[11] CRI 2019, Press Release: Agreement Signed For CRI's First CO_2-To-Methanol Plant In China [LINK]
[12] CRI 2020, Press Release: Commercial-scale ETL plant under development in Norway [LINK]
[13] Perez-Fortes 2016, Formic acid synthesis using CO_2 as raw material [LINK]

There are two main conventional processes for producing formic acid: via methyl formate hydrolysis and via acidolysis of alkali formates. The methyl formate hydrolysis process dominates with 80-90% of the installed capacity based on this method[14]. Around 70% of the climate change impact of this process is linked to the production of carbon monoxide from fuel oil, which is derived from crude oil. This is followed by the production of heat and electricity. The production process emits around 2 kg CO_2 per kg of formic acid produced[15]. The methyl formate hydrolysis route is chosen as the counterfactual for the analysis in this study.

The CCU route investigated in this study involves the direct hydrogenation of CO_2 using a using a tertiary amine, polar solvent and soluble Ruthenium complexes as the catalyst. The resource assumptions are that the process requires 0.988 t CO_2 and 0.071 t hydrogen, as well as 296 kWh of electricity per tonne of formic acid produced. This route is currently at the lab research stage of development, with further research needed to improve catalyst selectivity and lifetime.

Middle Distillate Hydrocarbons (Diesel, Gasoline, Jet Fuel)

The range of hydrocarbons that are typically used for transport fuels (diesel, gasoline, jet fuel) are conventionally all produced from the refining of crude oil and can be grouped together under the umbrella term of 'middle distillate hydrocarbons'. The 2018 global demand for these hydrocarbons is reported as 2900 Mt per year[16].

Middle distillate hydrocarbons are conventionally produced from the refining of crude oil. This involves locating the oil fields, drilling wells, extracting and refining/distilling the resulting crude into the gasoline, diesel fuel and jet-fuel products. Additives then may need to be added before the product is ready to be sent to the marketplace. The composition of crude oil differs depending on the region of the world where it was extracted and this partially determines the refining required to create the commodities. Also, practices in extraction and refining of the crude differ in different regions (such as flaring of the gases which are released during crude oil extraction). Due to these reasons, the cradle-to-gate emissions (or well-to-tank in fuel terms) for these products do vary across the world. In the UK, overall life cycle emissions are deemed to be split as 20% from production (well-to-tank) and 80% from end-use (tank-to-wheel)[17].

There are two indirect CCU routes to producing middle distillate hydrocarbons from CO_2: (1) via CO with subsequent Fischer–Tropsch synthesis and (2) via methanol with subsequent methanol-to-gasoline (MTG) synthesis. CO can be produced by reduction of CO_2 using the reverse water gas shift reaction. Methanol can be produced by hydrogenation of CO_2 as mentioned above. Both routes require hydrogen. The production of middle distillate hydrocarbons ('synthetic crude') has been demonstrated by Sunfire at a plant in Dresden Germany[18] with an industrial-scale deployment in Norway (Norsk e-fuel) expected to be operational in 2023 if approved[19].

This study investigates the conversion of CO_2 to synthetic middle distillate hydrocarbons via the reverse water gas shift and Fischer-Tropsch synthesis process, using iron and cobalt based catalysts. The resource assumptions are that the process requires 3.9 t CO_2 and 0.53 t hydrogen per tonne of middle distillate hydrocarbons produced, assumed equivalent for all fuels. The counterfactual reference product is taken as jet fuel. External electricity requirements are assumed to be negligible.

[14] Hietala et al. 2016, Formic Acid, In: Ullmann's Encyclopedia of Industrial Chemistry.
[15] Ahn et al. 2019, System-level analysis and life cycle assessment of CO_2 and fossil-based formic acid strategies.

[16] IEA, World demand by product groups, 2017-2018 [online chart, accessed Oct 2020] [LINK]
[17] According to figures from the UK government GHG conversion factors for company reporting
[18] Sunfire 2017, Press release: Sunfire produces sustainable crude oil alternative. [LINK]
[19] Norsk e-Fuel 2020, Press Release: Norsk e-Fuel is planning Europe's first commercial plant for hydrogen-based renewable aviation fuel in Norway [LINK]

3 Sources of hydrogen, CO_2 and electricity for CCU pathways

The CO_2 utilisation production routes include the input of CO_2 and hydrogen feedstocks, and energy for the conversion step of these feedstocks to the commodity. Each of these 'resource' inputs has an associated cost and emission intensity which varies depending on the origin of the input. This chapter describes some of the main options for the source of these three resources and highlights the differences in cost and emissions intensity of each, based on a review of literature. In some cases a range of values is included for one option; this represents not only the uncertainty in these variables (e.g. future technology development), but also reflects the differing cost and carbon intensity in distinct global regions.

3.1 Source of CO_2

This study considers two different types of CO_2 capture: point source capture (PSC) and direct air capture (DAC). Point source capture encompasses capture of CO_2 from industrial emitters at a variety of CO_2 concentrations, with emissions originating either from the combustion of fuel (fossil or biomass origin) or being process emissions generated from industrial processes (e.g. calcination of limestone for cement). Direct air capture encompasses the capture of CO_2 from the atmosphere using aqueous or solid sorbent technologies. In both cases, the CO_2 is purified and compressed to obtain a concentrated CO_2 stream for sequestration or utilisation. Figure 2 highlights the variation in cost and emission intensity for different potential CO_2 sources.

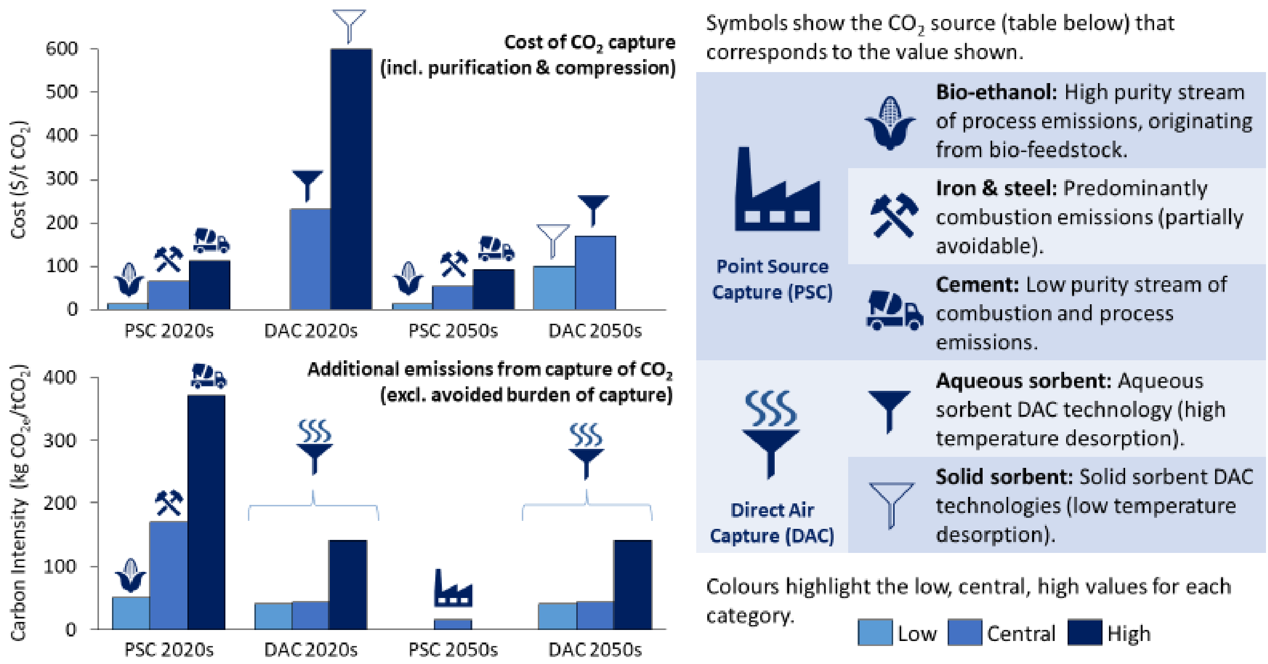


Figure 2: Cost and emissions associated with different CO_2 capture sources.

Point source capture is a more established technology than direct air capture, with several capture techniques available. CO_2 can be captured using a chemical absorption solvent (e.g. amines) or other separation methods, such as physical absorption solvents or calcium looping. In an absorption-based approach, once absorbed by the solvent, the CO_2 is released, often by heating, to form a high purity CO_2 stream[20]. There are around 20 large-scale CO_2 capture facilities operating today, with another 30 under development; those in operation and construction have the capacity to capture and permanently store around 40 million tonnes of CO_2 every year.[21]

[20] GCCSI and Element Energy for DECC
[21] GCSSI Global status report 2019

The costs and emissions for point source capture vary with the type of point source, with CO_2 from low purity and/or multiple outlet streams being more costly to capture and typically incurring lower capture rates or having higher energy demands. Capture from a bio-ethanol plant is used as a best case to represent an essentially pure CO_2 stream incurring minimal capture costs and optimal capture rates. Similar optimal conditions occur at fertiliser/ammonia plants and natural gas processing plants. Capture from a cement plant is used as a worse case to represent the high capture costs and low capture rates associated with multiple low purity emission streams. Capture from an iron & steel plant is used as the central case with post-blast furnace emission streams having intermediate CO_2 concentrations and capture costs. Similar central conditions occur at power stations.

Point source CO_2 emissions may have fossil, biogenic or process origins. The majority of current point sources of CO_2 emissions are due to the combustion of fossil fuels, such as natural gas or coal, in industrial plants or power generation facilities. As the carbon in the 'fossil CO_2' originates underground, combustion of this leads to increasing atmospheric CO_2 concentrations if unmitigated. However, some plants burn or process biogenic material (e.g. wood or crops), where the CO_2 has originated from organics matter, which has ultimately extracted this CO_2 from the atmosphere. In this case, the full process merely returns that CO_2 to the atmosphere. In our third case of process emission, the emissions are inherently part of the physical or chemical process, such as decomposition of raw materials. The key distinction between process emissions and fossil combustion emissions, is that process emissions cannot be avoided if that production process is ongoing, whereas combustion emissions can be mitigated by switching to low carbon fuels.

Direct air capture is a novel technology with ongoing development. DAC is relatively low maturity technology, with its large scale feasibility and economic viability uncertain. There are currently 15 DAC small-scale plants operating worldwide, capturing around 10 kt CO_2 / year, with a 1 Mt CO_2 / year capture plant in advanced development in the United States[22]. The CO_2 in the atmosphere is much more dilute than, for example, the flue gas from a power station or a cement plant. This contributes to the higher energy needs and costs for direct air capture relative to other CO_2 capture technologies and applications. Today, two technology approaches are being used to capture CO_2 from the air: Liquid systems pass air through chemical solutions (e.g. a hydroxide solution), which removes the CO_2 while returning the rest of the air to the environment; solid direct air capture technology makes use of solid sorbent filters that chemically bind with CO_2 until they are heated to release it.

Cost predictions for direct air capture vary widely but are expected to decrease with further research and scale deployment. Costs estimates in the literature for DAC can vary from as little as USD 50 / t CO_2 to as much as USD 600 / t CO_2. The assumptions for this analysis are based on recently published papers associated with Carbon Engineering[23] and Climeworks[24]. Both estimate a decrease in costs in the long-term with increasing scale of deployment being a contibuting factor as well as further technology optimisations.

3.2 Source of electricity

This study considers two different types of electricity supply: dedicated intermittent renewables and connection to grid electricity. Intermittent renewables encompass renewable power sources such as wind and solar photovoltaics that generate power on an intermittent basis. We have therefore assumed that hydrogen production from intermittent renewables has a limited number of hours where operations can occur at full-load, impacting the cost of hydrogen[25]. Grid electricity encompasses continuous power supply through connection to a grid supplied by a mixture of power sources, with grid balancing and transmission requirements. Figure 3 shows the cost and emission intensity assumptions for the options considered.

[22] IEA 2020 DAC
[23] Joule 2018, A Process for Capturing CO_2 from the Atmosphere
[24] Beuttler et al 2019, The Role of Direct Air Capture in Mitigation of Anthropogenic Greenhouse Gas Emissions
[25] The potential for intermittent hydrogen production is discussed in the IEA 2019 Future of Hydrogen report [LINK]

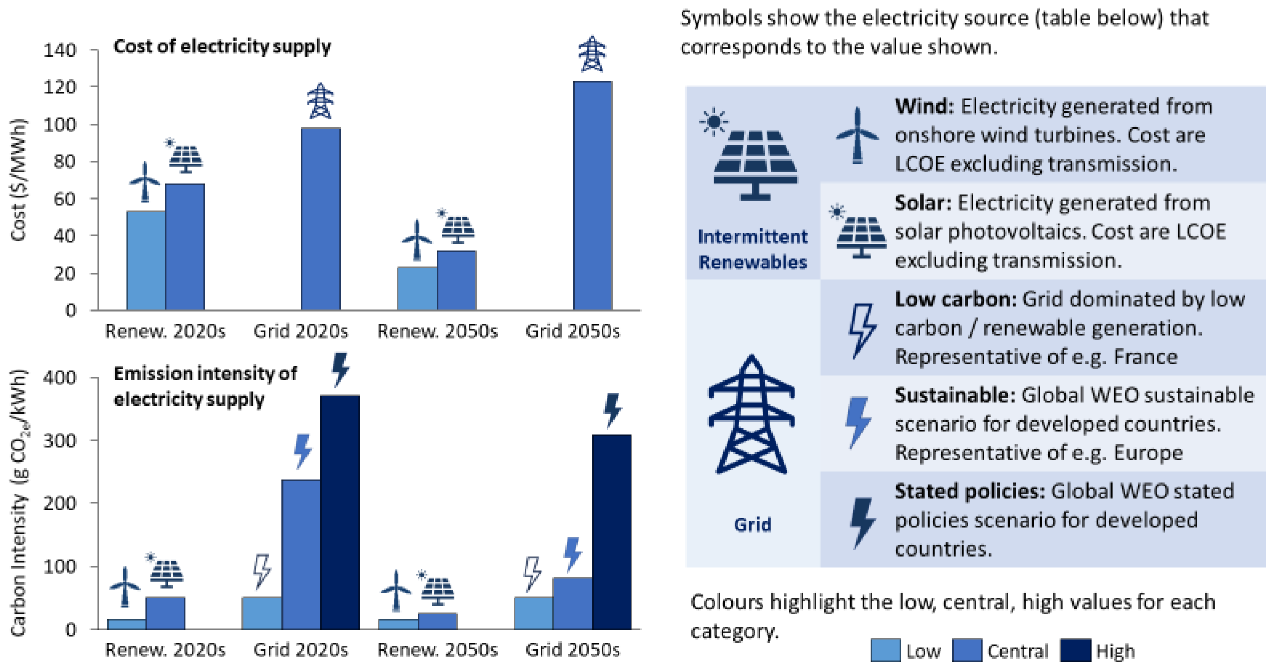


Figure 3: Cost and emissions associated with electricity generation options.

Whilst electricity generation costs from renewables are expected to decrease, projections suggest that grid electricity prices will increase. The levelized cost of electricity generation from wind and solar plants is expected to decrease with future installations[26]. However, the cost of grid electricity is projected to increase[27] with higher levels of demand resulting in greater requirements for grid balancing and additional infrastructure for higher capacity transmission.

The emission intensity of grid electricity varies markedly by region. Emissions associated with grid electricity depend on types of power generation technologies which feed into the grid mix in that region. Countries including France, Sweden, and Norway with high levels of renewables, such as wind or hydro-electric power, and/or nuclear power have low emission intensity grid mixes. Countries that still rely heavily on fossil power plants, particularly coal, such as Greece, Poland, and Germany, have high emission intensity grid mixes. Figure 4 shows estimates for the 2017 electricity grid intensities for EU countries[28].

[26] IRENA Power 2019
[27] IEA 2019, The Future of Hydrogen
[28] Data sourced from the European Environment Agency – current members (EU27) plus the United Kingdom (member until 31/1/2020)

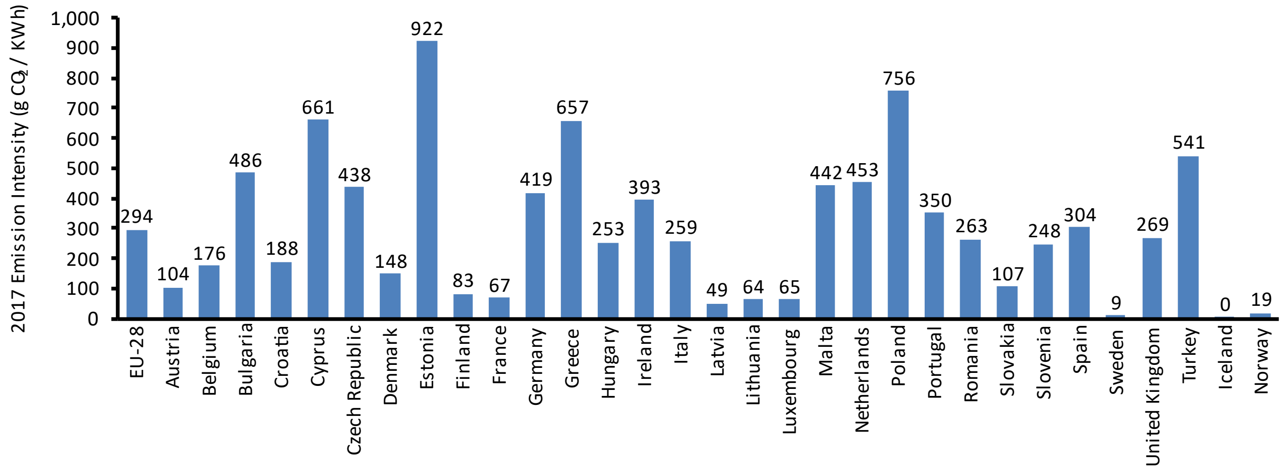


Figure 4: Reported emission intensities of grid electricity for EU countries in 2017 (Source: European Environment Agency)[28].

The emission intensity of grid electricity will decrease as countries decarbonise their power sectors. The IEA World Energy Outlook 2019[29] projects that under its sustainable development scenario, global average emissions from power generation could lower to 237 g CO_2 / kWh in 2030 and 81 g CO_2 / kWh in 2040 compared to 475.6 g CO_2 / kWh in 2018.

Limited data was identified on the projected life-cycle emissions for renewables, however reductions in emission intensity are likely. There is some evidence to suggest that the emission intensity of solar photovoltaics will decrease due to a combination of factors including improved efficiencies, increases in operating lifetimes, and lower emission manufacturing routes.[30]

In specific locations, it may be possible to utilise surplus electricity at reduced costs. As outlined in the IEA's The Future of Hydrogen report[27], hydrogen production could be operated intermittently to take advantage of surplus electricity available at lower costs. The report conducted an analysis to assess the optimal full-load hours balancing per unit CAPEX costs (decreasing with increasing load-hours) and per unit electricity costs (increasing with increasing load-hours). Optimal full-load hours vary with differing electricity-cost profiles, but the general conclusion is that mid-load operation (2500 – 6000 hours per year) is economically preferable.

3.3 Source of hydrogen

This study considers both fossil and electrolysis options for hydrogen generation. Most of the hydrogen produced today comes from fossil routes such as the reforming of natural gas, the dominant route, or the gasification of coal. These routes are emission intensive but can produce low carbon hydrogen – known as 'blue hydrogen' - if combined with CCS technology. Alternatively, electrolysis routes that use renewable electricity to split water into hydrogen and oxygen are considered as 'green hydrogen' producers. As green hydrogen no longer requires the use of fossil fuels and doesn't rely on CCS, it is sometimes considered the more sustainable long-term solution, although currently the electrolyser scale is limited. Green hydrogen emission intensity is dependent upon that of the electricity used. Figure 5 shows the cost and emission intensity assumptions for the various options considered.

Fossil options are selected to represent a range of costs and emission intensities. We first consider hydrogen production from steam methane reforming (SMR) without any emission abatement. This is the most established production route today and represents a more immediate, low cost but emission intensive option. Autothermal reforming (ATR) is a more efficient but less established method of producing hydrogen from natural gas. ATR combined with CCS is considered as an option representative of future low-emission blue hydrogen production. In regions with an abundance of low cost coal reserves, coal gasification is likely to be a

[29] IEA World Energy Outlook 2019
[30] Itten et al. 2015 Life cycle assessment of future photovoltaic electricity production from residential-scale systems operated in Europe

lower cost option, as is being explored in Australia. Therefore, coal gasification with CCS is also considered as an alternative future low-emission option, albeit more costly and more emission intensive than ATR with CCS. For these options, the final emission intensity is primarily dependent upon the upstream fossil fuel extraction emissions and the CO_2 capture rate for CCS. Further details on the assumptions used can be found in the appendix[31].

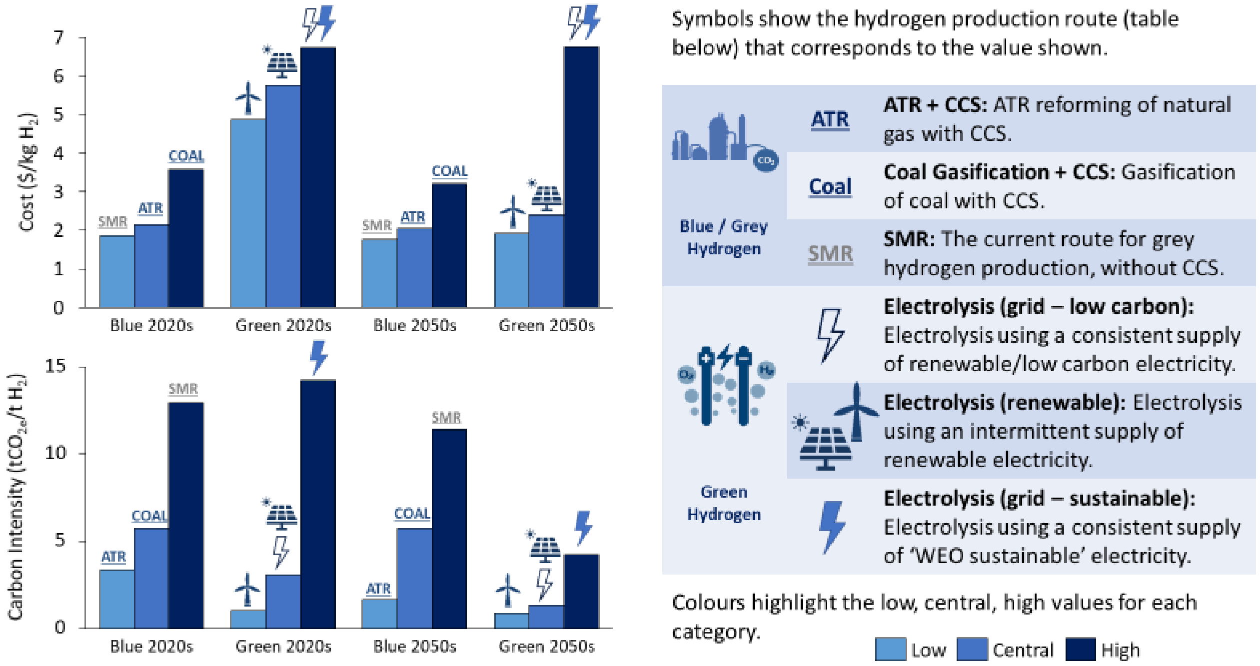


Figure 5: Costs and emissions associated with different hydrogen production routes.

Fossil routes may offer a lower cost and more immediate pathway but should be sense-checked. In most cases, converting fossil resources to hydrogen to then recombine this later with carbon during utilisation does not make sense from an energy perspective, particularly if the commodity could instead be produced from the original fossil resource (e.g. synthetic fuels). However there may be certain circumstances in which this route could make sense, for example if large scale hydrogen production with CCS already exists in one region and hydrogen can be transported to another region where point sources do not have access to CCS or alternative hydrogen production. Fossil hydrogen routes may be considered a gateway to electrolysis options, allowing CCU technologies to be developed ahead of large-scale deployment of electrolysis facilities.

Low emission intensity electricity is necessary for electrolysis to offer lower emissions than blue hydrogen production. The electrolysis options presented in Figure 5 are based on the electricity cost and emission intensities discussed in the previous section (see Figure 3). Using the near-term central 'sustainable grid' assumptions, representative of average European grid mixes today, leads to greater emissions for electrolysis than unabated SMR. The high electricity case ('stated policies') is therefore not included as it is considered too emission intensive to be interesting in CCU from a climate perspective.

ATR with CCS could have comparable emission intensities to renewable electrolysis. There are large uncertainties in the emissions associated with both fossil and renewable-electrolysis hydrogen routes; regional variations are expected in fossil fuel supply, manufacturing routes and renewable electricity costs as well as uncertainty in future technology developments and the potential CO_2 capture rates that could be achieved. The central assumptions used here present hydrogen from solar powered electrolysis as having a lower emission

[31] Main assumptions: efficiencies (SMR - 78%, ATR - 82% , coal gasification - 58% , electrolysis – 65% near / 75% long), capture rates (ATR – 95% near / 98% long, coal gasification – 90%), upstream emissions (natural gas – 0.06 kg/kWh near / 0.03 kg/kWh long, coal – 0.05 kg/kWh)

intensity than ATR with CCS, however some literature sources suggest that under certain conditions, such as high capture rates, ATR with CCS could be comparable[32,33].

Unit costs for electrolysis are dependent upon electrolyser CAPEX, electrolyser efficiencies, and the full load hours achievable. The cost of green hydrogen is expected to decrease significantly over the next few decades due to reductions in capital costs of electrolysers as well as increasing efficiencies resulting in lower electricity demands per unit of hydrogen. The unit costs of hydrogen are also dependent upon the full load hours achievable, with fixed costs being divided across annual production volumes. The intermittency of renewables is dependent upon location; however, it is assumed here that use of intermittent renewables allows for approximately 2500 full load hours per year (corresponding to 29% availability). This contrasts to typical use with a continuous electricity supply in which 5000 full load hours per year (57% availability) is achievable[27, 34]. This results in a doubling of CAPEX costs per unit of product produced. Further details on the assumptions used can be found in the appendix.

[32] Antonini et al. 2020, Hydrogen production from natural gas and biomethane with carbon capture and storage [LINK]
[33] SINTEF 2019, Hydrogen for Europe – Final report of the pre-study [LINK]
[34] IRENA 2019, Hydrogen: A Renewable Energy Perspective

4 Analysis Methodology

4.1 Selection of pathways

Five central pathways for hydrogen and CO_2 supply combinations have been selected for investigation. There are many possible combinations for hydrogen and CO_2 feedstock sources for hydrogenation pathways. Some distinct key choices are whether CO_2 is captured from a point source or from direct air capture, whether hydrogen is from fossil routes or electrolysis routes, and whether the electricity used for electrolysis is from the grid or from dedicated intermittent renewables. There is also a distinction within industrial capture as to whether the CO_2 is of biogenic or fossil origin. Five combinations of these options have been selected as central pathways to present in this report. These are illustrated in Figure 6 and described below. Variations of these pathways considering the full-range of different technologies, costs, and emission intensities highlighted in Chapter 3 were also investigated and are included in the full-range analysis sections of the report.

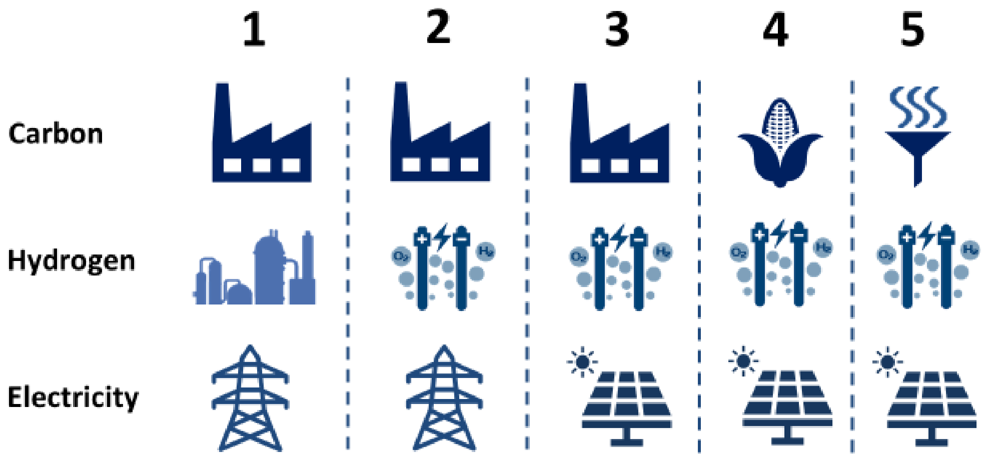


Figure 6: Visual representation of the five central pathways investigated – used as a key for subsequent graphics. The carbon row refers to the selected source of CO_2 – point-source of fossil origin, point-source of biogenic origin (high purity), or direct air capture. The hydrogen row refers to the hydrogen production method – fossil derived or water electrolysis. The electricity row refers to both the electricity supply to electrolysis (where this occurs) and to the electricity requirements for conversion of CO_2 and hydrogen to the commodity. The electricity options are grid supply or intermittent renewables.

Five central cases are considered:

1. **Point source CO_2 capture and blue hydrogen:** Considers CO_2 captured from an iron and steel plant and hydrogen produced from ATR with CCS. Electricity for the conversion step is provided from the grid, using the 'sustainable' grid emission assumptions. Both hydrogen and CO_2 must be transported, within the same region (200km), to the commodity production facility.
2. **Point source CO_2 capture and grid-electrolysis:** Considers CO_2 captured from an iron and steel plant and hydrogen produced onsite from electrolysis. Electricity for both electrolysis and the conversion step is provided from the grid, using the 'sustainable' grid emission assumptions. CO_2 must be transported, within the same region (200km), to the commodity production facility.
3. **Point source CO_2 capture and intermittent renewable electrolysis:** Considers CO_2 captured from an iron and steel plant and hydrogen produced onsite from electrolysis. Electricity for both electrolysis and the conversion step is provided from dedicated intermittent solar photovoltaics. CO_2 must be transported, within the same region (200km), to the commodity production facility.
4. **High purity CO_2 capture (biogenic) and intermittent renewable electrolysis:** Considers CO_2 captured from the fermentation process of a bioethanol plant (high concentration) and hydrogen produced onsite from electrolysis. Electricity for both electrolysis and the conversion step is provided from dedicated intermittent solar photovoltaics. CO_2 must be transported, within the same region (200km), to the commodity production facility.

5. **Direct air capture of CO_2 and intermittent renewable electrolysis:** Considers onsite direct air capture of CO_2 and onsite hydrogen production from electrolysis. Electricity for both electrolysis and the conversion step is provided from dedicated intermittent solar photovoltaics.

Note that the energy requirements for CO_2 capture were not separated out for the analysis, and therefore the costs and emissions associated with capture are fixed at values reported in the literature and do not vary with electricity supply. This is a limitation of the analysis, with the study focusing on electricity supply to hydrogen electrolysis and the conversion step. For context, the electricity requirements for the capture technologies considered are approximately 0.025-0.25 MWh / tCO_2 for point-source capture and about 0.4 MWh / tCO_2 for direct air capture[35]. This compares to 50-60 MWh / t H_2 produced by electrolysis.

The assumptions used for calculations of the central pathways are included in Table 1 below. Further details on datapoints for variations of the central pathways are provided in the appendix.

Table 1: Cost and emission intensity assumptions used for central pathways calculations.

Electricity					
		Cost $ / kWh	Source	Emissions kg CO2 / kWh	Source
Near-Term	Solar PV	0.068	IRENA Power 2019	0.0509	reinvestproject.eu
Near-Term	Grid - Sustainable	0.098	IEA Future of Hydrogen - Assumptions Annex	0.2370	IEA 2019 WEO Annex A
Long-Term	Solar PV	0.032	IRENA Solar PV 2019 (average)	0.0250	reinvestproject.eu
Long-Term	Grid - Sustainable	0.123	IEA Future of Hydrogen - Assumptions Annex	0.0810	IEA 2019 WEO Annex A

CO_2					
		Cost $ / t CO2	Source	Emissions t CO2 / t CO2	Source
Near-Term	PSC - Iron & Steel	66	GCCSI Global cost of CCS 2017	0.170	RSC 2020, The carbon footprint of the carbon feedstock
Near-Term	PSC - Bio-ethanol	14.4	GCCSI Global cost of CCS 2017	0.050	RSC 2020, The carbon footprint of the carbon feedstock
Near-Term	DAC -Aqueous sorbent	232	Joule 2018 DAC - Carbon Engineering	0.043	Lui et al. 2020
Long-Term	PSC - Iron & Steel	54	GCCSI Global cost of CCS 2017	0.015	RSC 2020, The carbon footprint of the carbon feedstock
Long-Term	PSC - Bio-ethanol	13	GCCSI Global cost of CCS 2017	0.015	RSC 2020, The carbon footprint of the carbon feedstock
Long-Term	DAC -Aqueous sorbent	170	Joule 2018 DAC - Carbon Engineering	0.043	Lui et al. 2020

Hydrogen - excluding electricity for electrolysis*					
		Cost $ / t H2	Source	Emissions t CO2 / t H2	Source
Near-Term	ATR + CCS	2159	Estimates based on broader data points (see appendix)	3.33	Estimates based on broader data points (see appendix)
Near-Term	Electrolysis – Grid	844*	Estimates based on broader data points (see appendix)	0.00*	Estimates based on broader data points (see appendix)
Near-Term	Electrolysis - Intermittent	1686*	Estimates based on broader data points (see appendix)	0.00*	Estimates based on broader data points (see appendix)
Long-Term	ATR + CCS	2050	Estimates based on broader data points (see appendix)	1.62	Estimates based on broader data points (see appendix)
Long-Term	Electrolysis - Grid	366	Estimates based on broader data points (see appendix)	0.00	Estimates based on broader data points (see appendix)
Long-Term	Electrolysis - Intermittent	731	Estimates based on broader data points (see appendix)	0.00	Estimates based on broader data points (see appendix)

*Electrolysis data is combined with electricity data (above) assuming an efficiency (HHV) of 65% 2020 and 75% 2050

Gas Transport - Regional Transport (200km) – Pipeline		
	Cost	Reference
CO_2 Transport ($ / t CO_2)	5	Element Energy 2018, Shipping CO_2 - UK Cost Estimation Study
H_2 Transport ($ / t H_2)	24	Cadent 2017, Liverpool-Manchester Hydrogen Cluster Report

[35] Von der Assen et al. 2016, Selecting CO2 Sources for CO2 Utilization by Environmental-Merit-Order Curves

4.1 Comparison of commodity production routes (CCU vs fossil)

The quantitative analysis focuses on **commodity production aspects**, comparing the production of a commodity via CO_2 utilisation routes with the production of an identical commodity via conventional fossil routes on the basis of cost and emissions. The end-use of the commodity is assumed to be independent of the chosen production route, with emissions and costs between the point of production ('gate') and the commodities end-of-life ('grave') being identical for both routes.

The CO_2 utilisation production route includes the supply of CO_2, hydrogen, and energy for the conversion step of these feedstocks to the commodity. Each of these resource inputs has an associated cost and emission intensity which varies depending on the origin of the input. The total cost and emissions of the production route are calculated for select combinations of resource origins, based on data obtained from literature, as described above.

The fossil route represents the conventional pathway for producing commodities. This is a fixed reference route used as a counterfactual. Emissions are taken from life-cycle assessment literature and include all emissions from the extraction of fossil feedstocks ('cradle') to the production of the commodity ('gate'). Market prices for the commodities are used as the counterfactual costs.

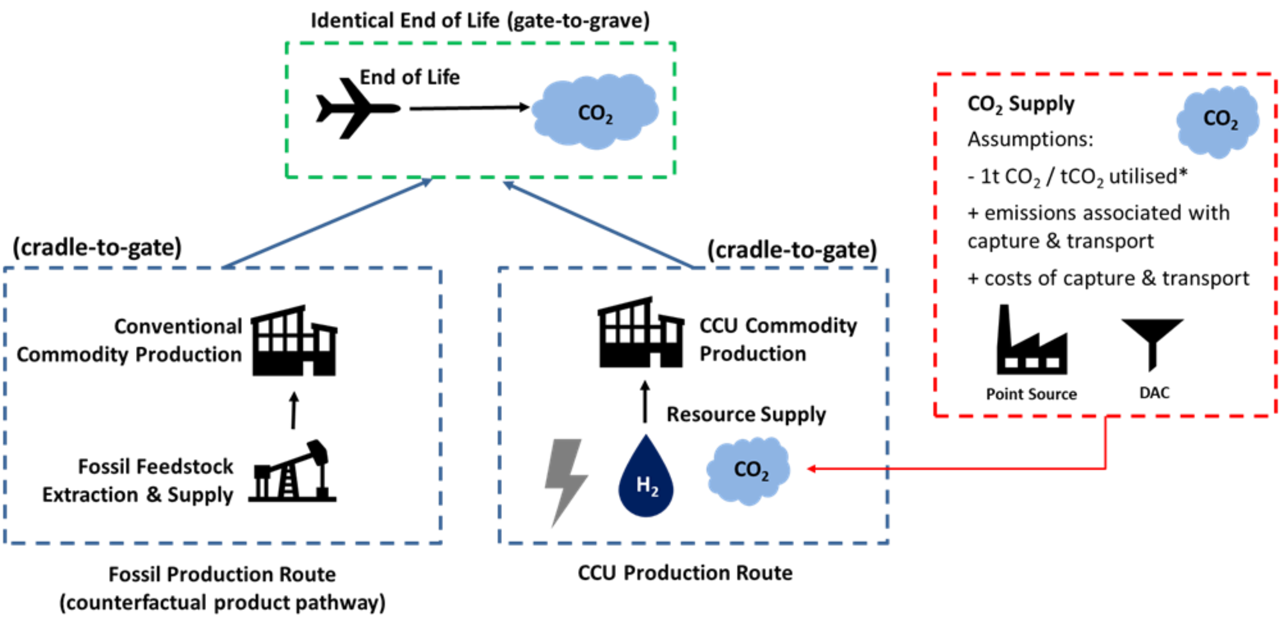


Figure 7: Visual of system boundaries and the components included in cost, emission, and energy totals. The commodities produced from each production route are assumed to be identical and therefore have the same end-of-life characteristics. * negative emissions associated with CO_2 supply relate to a comparison to a counterfactual for the CO_2 capture system and are dependent upon accounting assumptions and the choice of counterfactual. These are discussed in section 4.2.

Box 1: Inclusion of an avoided burden

The CO_2 enters the boundaries with an **avoided burden of - 1 t CO_2 per tonne of CO_2 plus additional emissions from capture and transport.** This represents the impact of supplying the CO_2 to utilisation compared to a reference system for that CO_2.The inclusion of the avoided burden of - 1 t CO_2 per tonne of CO_2 assumes that the CO_2 would otherwise be emitted or have remained atmospheric. Therefore, at the point of supply to the CCU pathway, the CO_2 is associated with a benefit of avoided emission or atmospheric removal. It also assumes that this avoidance/removal is allocated to the CCU pathway. The cost of CO_2 capture and transport is therefore also allocated to the CCU pathway, such that overall the capturer/emitter gains no benefits but incurs no additional costs.

The analysis in this report includes an **'avoided burden' of -1 tCO_2** per tonne of CO_2 utilised. This refers to the reduction in emissions occurred by capturing the CO_2 in comparison to the counterfactual system for the

CO_2 supply route. The extent of this reduction is however highly dependent upon accounting assumptions and the choice of reference case for what would otherwise happen if the CO_2 were not supplied to the CCU route. It should be noted that **under some assumptions there may be zero avoided burden associated with the CO_2 supply**. These details are discussed further in the following section (Section 4.2). All graphs are presented with the avoided burden associated with 'CO_2 utilised' shown separately to facilitate alternative interpretations by the reader.

Knock-on effects outside of this system were not considered. For the purpose of the analysis, the assumption is made that the use of electricity and hydrogen for the CCU route does not detract from the supply of electricity or hydrogen to the wider system. The electricity and hydrogen supply are therefore considered as dedicated supplies for the CCU route, meaning for example that the use of hydrogen for CCU does not limit the use of hydrogen for industrial fuel switching, district heating, or transport. This is a simplification as in reality capacity for these resources will likely be constrained. The feasibility of dedicated supply is discussed further in chapter 7.

4.2 Accounting CO_2 – determining the 'avoided burden' of CO_2 supply

The **method of accounting and allocation of CO_2 emissions is core** to ensuring the climate benefits are correctly recognised, and the differing routes are compared fairly. Some CCU developers may assume that the utilisation of CO_2 for their pathway may allow them to reduce the overall emissions of their production process by the quantity of CO_2 utilised or equally state that the end-of-life emissions of their product are reduced by this quantity. However, this accounting is highly dependent upon assumptions around what would otherwise happen to that CO_2 if it were not used for utilisation and the allocation of any impacts on system emissions (reduction/avoidance of CO_2) between the utiliser and the capturer/emitter.

Reference case for CO_2 supply

Two examples of different counterfactual assumptions are illustrated below in Figure 8.

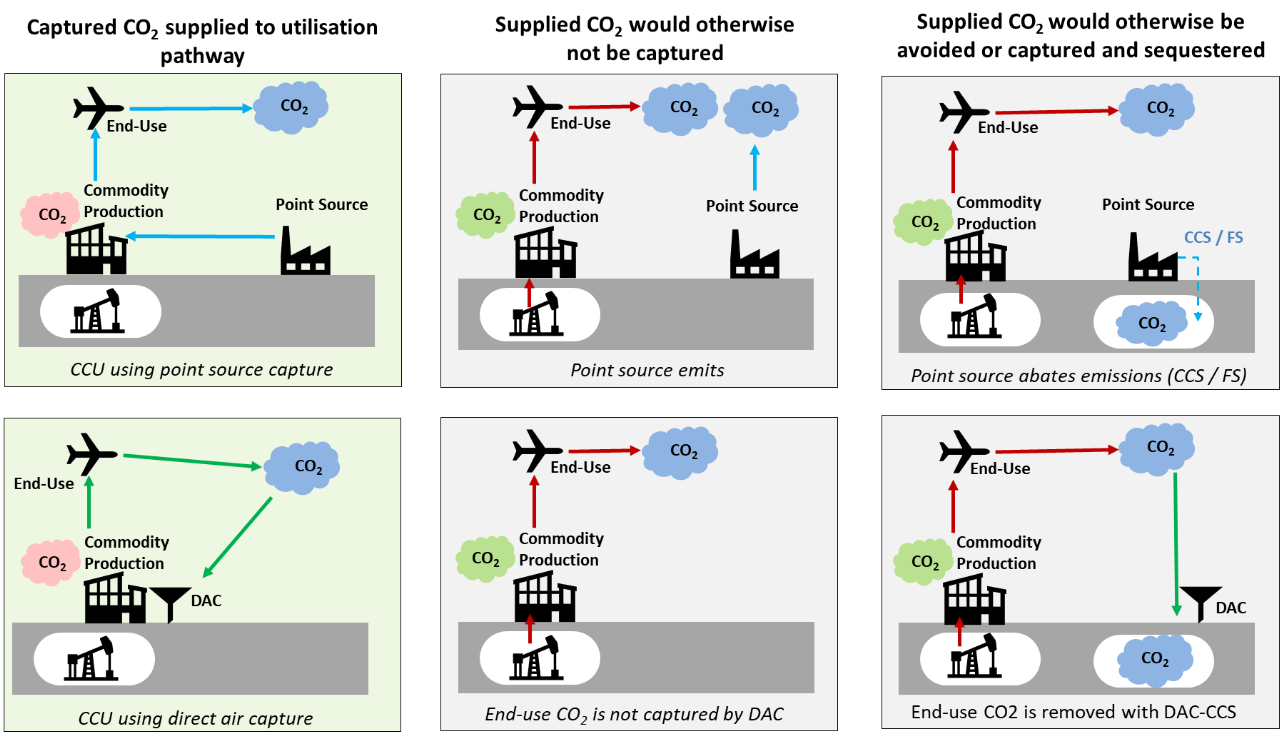


Figure 8: The choice of reference case for CO_2 supply determines the avoided burden. The impact of utilising CO_2 depends on whether the CO_2 utilised would otherwise have become or remained atmospheric, or whether it would otherwise have been abated or removed. The reference case that the CO_2 would otherwise have not been captured is used for the purpose of the analysis. DAC = Direct Air Capture. CCS = Carbon Capture & Storage. FS = Fuel Switching.

The difference between the CCU pathways and the non-CCU pathways are firstly the production method for the commodity, with the non-CCU route involving extraction of fossil resources with conventional processing compared to the CCU route which involves hydrogen and CO_2 supply, followed by conversion to the commodity. These differences are explored as the focus of this study. The second difference between the CCU pathways and non-CCU pathways is in the existence of atmospheric CO_2 or point source emissions. In the CCU pathway these emissions are utilised, whereas in the non-CCU pathway these emissions may or may not be atmospheric depending on assumptions for this reference case.

In the case where CO_2 would otherwise not be captured, the impact of capturing and supplying CO_2 is to either avoid the immediate emission of this CO_2 to the atmosphere (point source capture) or to remove this CO_2 from the atmosphere (direct air capture). In either case, at the point of supply to the utilisation pathway the CO_2 is associated with a reduction in atmospheric emissions (compared to the CO_2 reference) of 1 tCO_2 per tonne of CO_2 utilised, less the additional emissions incurred as a result of the capture technology (energy requirements, incomplete capture).

In the case where CO_2 would otherwise be avoided or captured and sequestered, the impact of capturing and supplying CO_2 is the difference between the emissions incurred in capture and transport to the utilisation facility, and the emissions incurred in capture, transport, and permanent sequestration. If these impacts were comparable then, at the point of supply to the utilisation pathway, the CO_2 is associated with no reduction in atmospheric emissions compared to the CO_2 reference but no additional emissions from capture and transport.

For the purposes of this study, the first option is assumed in which the CO_2 utilised would otherwise not be captured. Therefore, **an avoided burden of 1 t CO_2 reduction compared to the CO_2 reference case is assumed** for the CO_2 utilised (referred to in text as the 'avoided burden'), with additional emissions that result from CO_2 capture reducing this overall value. These values are presented separately in graphs with the intention of facilitating interpretations if the reader were to prefer an alternative accounting approach.

A limitation of the analysis is that all origins of CO_2 are considered equivalent in having a reference case of no capture. In actuality, the origin of the CO_2 source (biogenic, fossil, atmospheric) is likely to have influence on the reference case for CO_2 supply. For example, in a system where there are strong decarbonisation incentives, it is likely that CO_2 sources of fossil origin would otherwise be abated – such as through capture and geological sequestration, fuel switching, or process change. This would align with the second reference case.

Allocation between parties

It is important to ensure that the emission benefits are not double counted. In the case of CCU there are three parties that may each wish to claim the emission benefits: the capturer of the CO_2, the manufacturer of the commodity, and the end-user of the commodity. There is no consensus on how emission benefits or costs for CO_2 capture may be transferred to a product when that CO_2 is utilised. In order to assess the market competitiveness of CCU compared to counterfactual products from the perspective of an end user, an assumption is needed on whether or not benefits are passed to the CCU product (and subsequently filtered to the end-user).

For the purposes of this study, it is assumed that the emission benefit of CO_2 utilisation is passed to the CCU product and is therefore not claimed by the capture facility. This approach was taken to allow clear comparison of the CCU commodity with a conventional commodity, but it includes limitations. Under this assumption, the capturer does not account captured emissions as abated/removed and the avoided burden associated with the avoidance/removal of this emission is allocated to the CCU product, thus lowering the CCU life-cycle emissions but not those of any products produced by the capturer.

Implications for cost of CO_2 supply

The CO_2 reference case and allocation of emissions avoidance/removal between parties has implications for the price that a CCU pathway would likely pay for the CO_2 supply:

- For an industrial emitter that would otherwise emit its emissions, the additional cost of CCU supply is that of capture and transport to the CCU pathway (excluding desired profits). However, if this industrial emitter would otherwise have captured and permanently sequestered CO_2, then the cost is both the difference in capture and transport requirements and any additional 'cost of emission' associated with the difference in how the CO_2 is accounted. For example, if the emitter can no longer claim that this CO_2 has been avoided (due to this impact instead being claimed by the CCU pathway) then they could incur costs associated with emission, such as a carbon tax.
- For a direct air capture facility that would otherwise not capture the CO_2, the additional cost of CCU supply is that of capture and transport to the CCU pathway (excluding desired profits). However, in the case where the direct air capture facility might otherwise sequester this CO_2, then the facility might incur an opportunity cost associated with not being able to claim net-removals of CO_2.

The analysis takes the reference case as being that the industrial emitter would otherwise emit, and therefore the CCU route claims an avoided burden. To align with this the CO_2 is supplied to the CCU route at the cost of capture and transport, such that the capturer/emitter incurs no additional cost compared to the CO_2 reference case of non-capture.

5 Analysis of CCU emissions and cost implications

This section details the variation of the costs and emissions of CCU pathways compared to their fossil derived counterfactual, both for the near-term (mid-to-late 2020s) and the long-term (2050s).

For central cases, breakdowns of CCU costs and emissions are presented. The costs associated with CCU pathways are broken down into those associated with the supply of the main feedstocks (CO_2, hydrogen), operational costs for the conversion process (electricity demand, OPEX), and costs for the construction of the conversion facility (CAPEX, cost of CAPEX / financing). Emissions are split into those associated with CO_2 capture, hydrogen production, emissions associated with CO_2 conversion (electricity, other) and an avoided burden for utilisation of CO_2. The individual cost components are discussed in Chapter 3 with the methodology discussed in Chapter 4. The specific data points used in the analysis are included in the Appendix.

Box 2: Cost of emissions

As countries move towards a net-zero future, it is expected that economic incentives will be used to motivate emission reductions across industries, for example the introduction of a tax on carbon emissions or the provision of subsidies for low-emission products. These incentives will result in a relative cost associated with continued emission of greenhouse gases, with these relative costs expected to increase over time. It is likely that each region or country will apply their own incentives giving rise to geographic variations in the cost of emissions and the potential need for border adjustments.

The analysis presented here follows the approach of a carbon price and assumes a 'cost of emissions' that is applied as a cost per tonne of CO_2 emitted. For central case pathways, a carbon price of USD 25 / t CO_2 is assumed in the near-term (mid-to-late 2020s), increasing to USD 160 / t CO_2 in the long-term.

Symbols are used to indicate the resource input options for each central pathway. More detail on the meaning of symbols and the central pathways analysed can be found in section 4.1. The CO_2 supply routes considered are point source capture of fossil origin CO_2, point source capture of biological origin CO_2, and direct air capture. The hydrogen supply routes considered are blue hydrogen (ATR with CCS), hydrogen from electrolysis using grid electricity, and hydrogen from electrolysis using intermittent renewable electricity. Electricity supply for the conversion process is taken as either grid electricity or intermittent renewable electricity.

The 'cost of emissions' that would be required for competitiveness of the CCU routes with the current counterfactual is estimated by assessing the cost premium of the CCU routes alongside the reduction in emissions compared to the counterfactual (emissions abatement).

5.1 Methanol

Central case pathways (methanol)

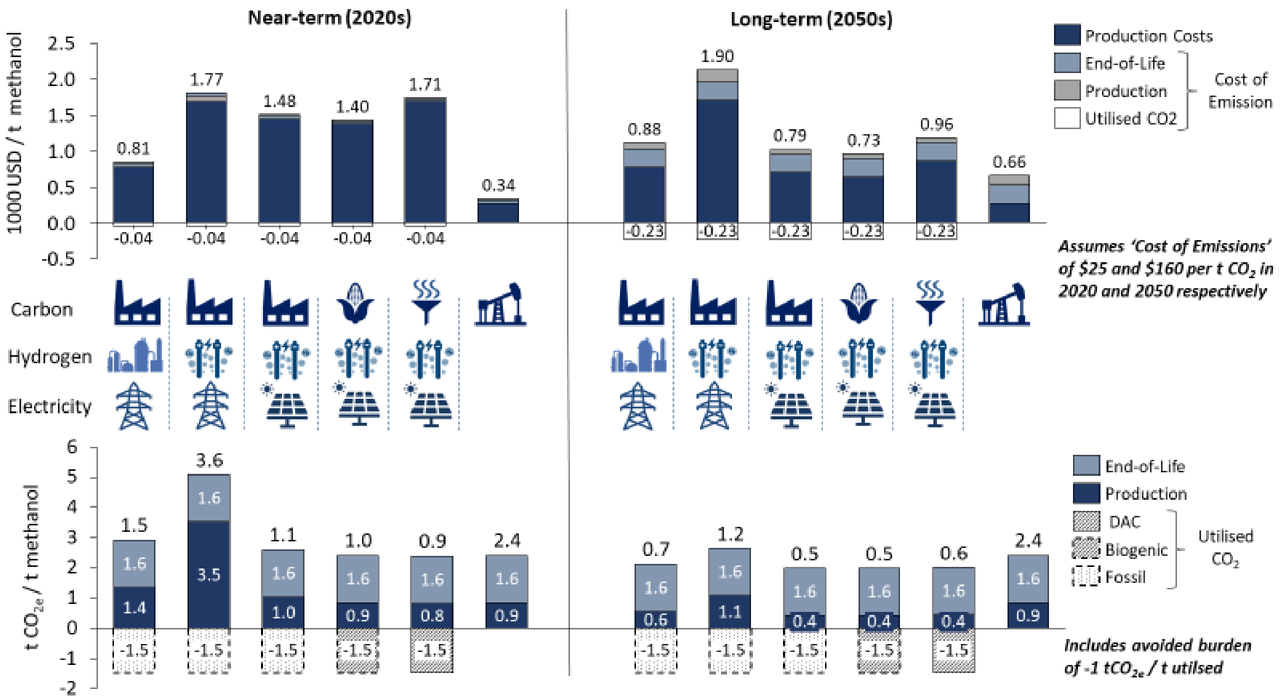


Figure 9 presents the full life-cycle costs and emissions of commodities produced from central CCU pathways compared to the present-day counterfactual route. See Box 3 for an explanation of interpreting the graph.

Box 3: Life-cycle costs and emissions (graph interpretation)

Life cycle emissions are split into utilised CO_2, production, and end-of-life emissions. Production covers the 'cradle-to-gate' aspects including feedstock production, supply, and conversion to the commodity. End-of-life covers indicative values for the distribution of commodities to end-users and their emissions at end-of-life (e.g. combustion for fuels). End-of-life emissions are assumed to be identical for all CCU and counterfactual pathways. Cost of emissions are included and are split into the costs associated with the individual emission components. Utilised CO_2 accounts for the avoided burden associated with CO_2 supply. Fossil, biogenic and DAC sources of CO_2 are shaded differently to represent the differing climate implications and potential for future differences in CO_2 accounting.

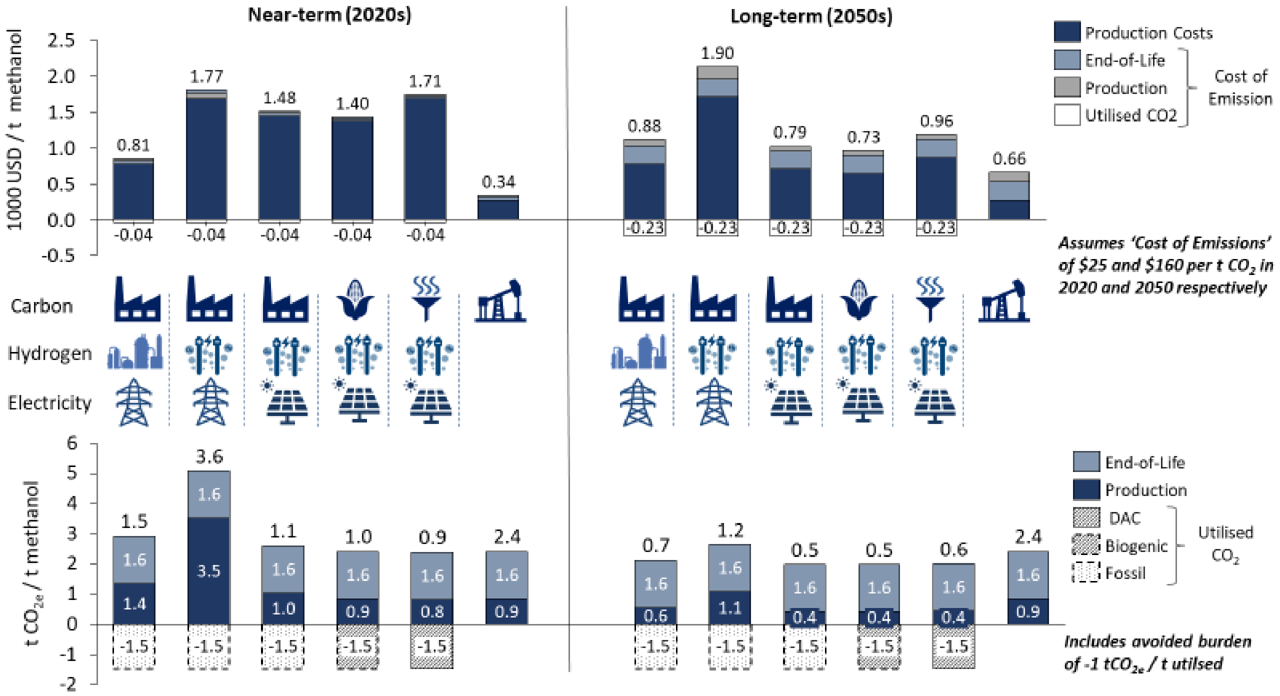


Figure 9: Life-cycle costs (top) and emissions (bottom) for central CCU methanol pathways.

For all central cases considered, the cost of methanol produced via CCU pathways is greater than the counterfactual fossil route. In the near-term, total costs are 140-420% greater with the lowest cost option being the point source capture and blue hydrogen pathway and the most expensive option being green hydrogen powered by grid electricity. The cost of emissions has negligible impact in the near term due to the low assumed value of USD 25 / t CO_2. In the long-term, the production costs of CCU methanol decrease, with intermittent renewable hydrogen electrolysis pathways seeing the most significant cost reductions. The increase in the cost of emissions leads to a 90% rise in the counterfactual price between the near-term and long-term. The reduction in total emissions due to the included avoided burden from utilising captured CO_2 leads to lower total costs of emission, allowing CCU routes to become more competitive. The long-term costs of CCU methanol range from being 10-190% greater than the counterfactual fossil route, after inclusion of emissions costs.

In the long-term, the offset in emissions costs due to utilisation make CCU pathways more competitive. For CCU pathways, the reduction in total emissions due to the included avoided burden from utilising captured CO_2 leads to reduced total costs of emission. Therefore, the higher 'cost of emissions' of USD 160 / t CO_2 in the long-term allows CCU routes to be more economically competitive with the fossil route. This competitive advantage relies on the CCU pathways claiming an avoided burden from utilising CO_2. If this were not the case, for example if the CO_2 would otherwise have been abated or if the capture facility were to claim the avoidance of emissions, then long-term costs of CCU methanol pathways would instead be 50-220% greater than the counterfactual fossil route.

In most cases, the total emissions from CCU methanol pathways are lower than the fossil counterfactual route. In the near-term, all pathways except that using grid electrolysis for hydrogen production have lower total emissions than the counterfactual route. In the near term, emissions are reduced by approximately 60% in the pathways using bio-ethanol point source or direct air capture for CO_2 supply. In the long term, this reduction becomes approximately 80%. Due to reductions in the emission intensity of the grid and improvements in hydrogen generation efficiencies, the grid-electrolysis pathway also has lower emissions than the counterfactual fossil route in the long-term. These reductions are largely due to the avoided burden associated with the utilisation of CO_2 which partially offsets end-of-life emissions.

Even without the inclusion of an avoided burden from utilisation, several pathways offer lower production emissions than the fossil route. In the near-term, the bio-ethanol point source and direct air capture pathways offer a production route with lower emissions than the counterfactual fossil route. In the long-term, this is true for all routes except that with grid-electrolysis. This means that emissions associated with hydrogen generation, incomplete capture, and energy for capture and conversion in the CCU pathway are less than the emissions from fossil fuel extraction and conversion in the counterfactual route. Therefore, these routes offer a reduction in emissions even if the avoided burden is removed, for example if the CO_2 would otherwise have been abated or if the capture facility were to claim the benefits of avoidance.

Breakdown of production costs and emissions (methanol)

Figure 10 shows the cost and emission breakdowns for the production stage of the commodity life-cycle indicated in the previous figure. See Box 4 for an explanation of the graph components.

Box 4: Breakdown of production costs and emissions (graph interpretation)

The graph shows the cost and emission breakdowns for the commodity production stage of the commodity life-cycle. Costs are split across the costs for production and supply of feedstocks (CO_2 and hydrogen), and costs for the conversion of these feedstocks to the commodity (including CAPEX, OPEX, and electricity demands for the conversion process). The cost of emissions associated with the production stage is also included. Similarly emissions are split across the production and supply of feedstocks, and the conversion step (electricity and other). The magnitude of the costs and emissions associated with the production of the present-day counterfactual route is also shown for comparison.

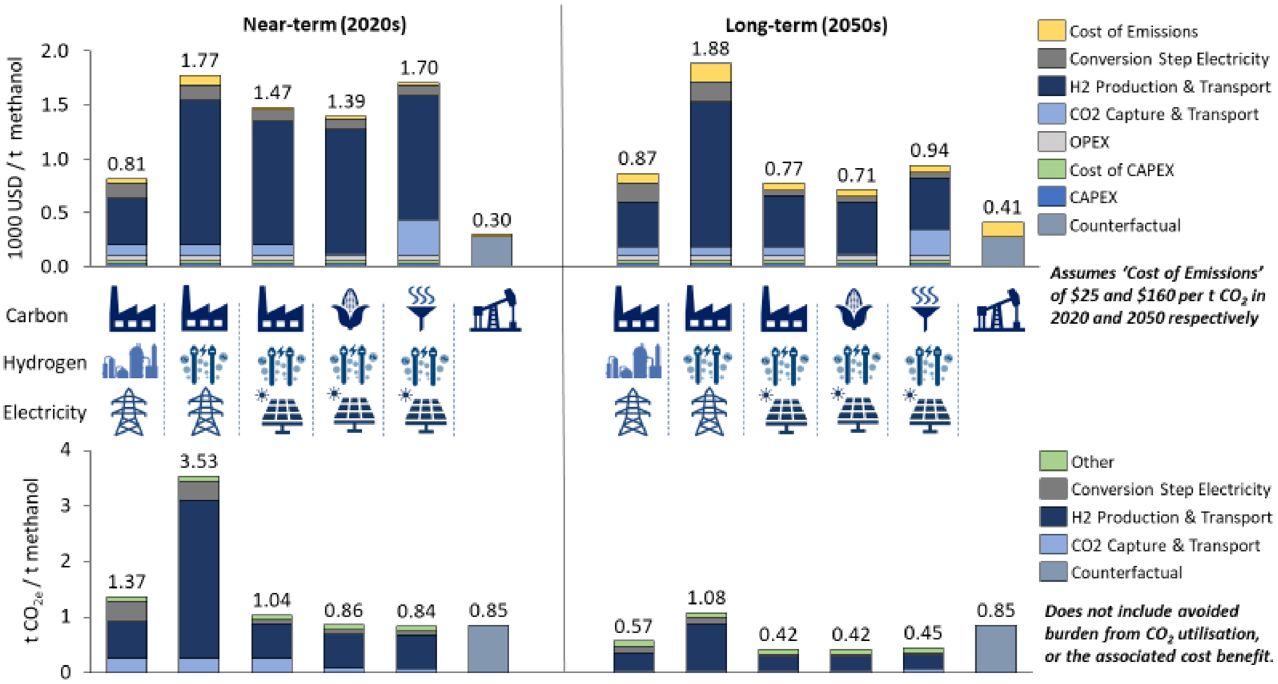


Figure 10: Breakdown of commodity production costs and emissions for central CCU methanol pathways.

Production costs for electrolysis pathways are dominated by hydrogen production. The cost of hydrogen is the dominant cost component for all pathways accounting for 50-80% of production costs in the near-term and 50-70% in the long-term. With CO_2 from the central point source, use of hydrogen from grid-electrolysis and renewable-electrolysis results in 120% and 80% greater near-term production costs than using hydrogen from ATR with CCS respectively. In the long-term, the cost from renewable electrolysis becomes comparable to hydrogen from ATR with CCS. More details on hydrogen costs can be found in chapter 3.

The choice of CO_2 source does not have a significant impact on CCU methanol costs in the near-term. The large unit cost difference (USD / t CO_2) between point source capture and direct air capture becomes less significant when placed in the context of the full production costs. In the near-term, the choice of CO_2 supply has a much lower impact than the choice of hydrogen supply. However, in the long-term DAC costs do become a significant cost component, accounting for 20% of total production costs.

Electricity is the dominant cost component of the conversion step, with CAPEX and catalyst costs being negligible. The process for conversion of the input feedstocks of hydrogen and CO_2 to methanol has minimal costs in comparison to the costs of the feedstocks. The dominant factor is the cost of electricity, which is used for compression, water circulation, heating and cooling[36]. The CAPEX and other OPEX components (such as catalysts) are negligible when assessed on a per unit of product basis, accounting for a maximum of 10% of production costs.

Emissions are dominated by hydrogen production, with conversion electricity and capture emissions significant for some pathways. In the near-term, emissions from hydrogen-production using grid-electrolysis are significant due to the emission intensity of grid electricity. These reduce with time as a greater proportion of the grid-mix becomes renewable, however in the long-term the hydrogen production emissions for this pathway are still equivalent to 80% of total counterfactual emissions. Hydrogen dominates the emissions of the other CCU pathways but to a lesser extent; conversion electricity emissions are significant with grid electricity and capture emissions are significant for point source CO_2 capture pathways.

Analysis of full range of CCU pathways (near-term) (methanol)

Figure 11 shows the cost premium of near-term CCU pathways plotted against the abated emissions of the pathway when compared to the counterfactual route. See Box 5 for details on how to interpret the graph.

Box 5: Cost of abatement (graph interpretation)

The graph shows the costs of CCU pathways plotted against the abated emissions of the pathway. A variety of pathways are plotted using different combinations of hydrogen supply and CO_2 supply, including the high, low and central variations detailed in chapter 3. The graph is shifted to show values relative to the counterfactual cost (the cost premium) and emissions abated compared to the counterfactual. The 'cost of abatement' for each pathway can be assessed from their plotted position (cost premium divided by emissions abated). Lines of equivalent 'cost of abatement' are shown on the graphs to illustrate this, with steeper lines corresponding to greater costs of abatement. Points below the lines have lower costs of abatement than that shown on the line and points above have a higher cost of abatement. Pathways achieve cost parity with the counterfactual route if the imposed 'cost of emissions' equates to or exceeds their 'cost of abatement'.

[36] Perez-Fortes 2016, Methanol synthesis using captured CO_2 as raw material: Techno-economic and environmental assessment [LINK]

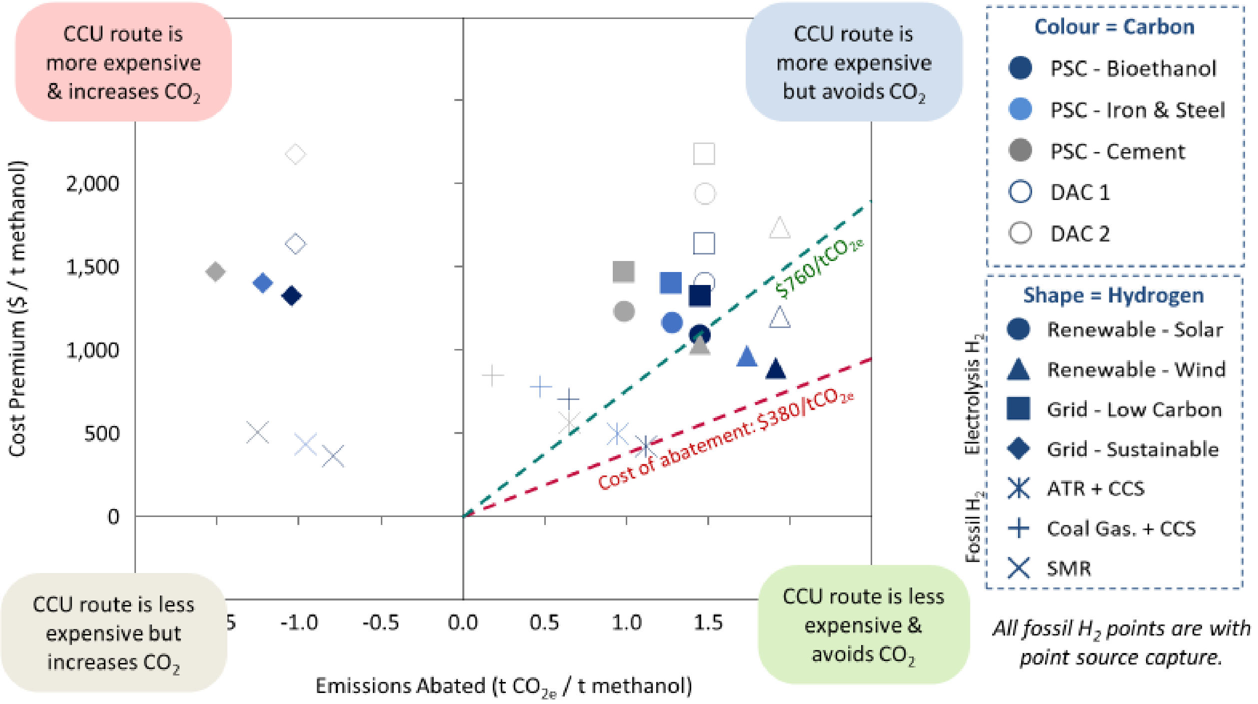


Figure 11: Cost and emissions difference between the near-term CCU and fossil production routes for methanol. Cost premium is the cost of the CCU production pathway minus the cost of the fossil production pathway (**excluding cost of emissions**). Emissions abated shows the total emissions for fossil production minus the total emissions for CCU production (assuming identical end-of-life stages). Note that the supply of CO_2 to the CCU pathway is included as a reduction of **1 t CO_2/t CO2** utilized, plus additional emissions from capture and transport (see section 4.2).

Key near-term insights:

- **From a cost perspective, all options result in higher production costs for the CCU route.** The lowest cost options out of the combinations considered are unabated SMR or ATR+CCS with CO_2 from point source capture.
- **From an emissions perspective, most options lead to some level of emission abatement**. However, unabated SMR hydrogen and all options using 'sustainable' grid electricity give rise to an increase in emissions compared to the counterfactual. The pathways with the greatest levels of emissions abatement involved either CO_2 from DAC or bioethanol point source capture combined with hydrogen from wind powered electrolysis.
- **A carbon price or alternative of USD 380 / t CO_2 would be required to make these routes cost competitive with the counterfactual.** From a cost of emissions abated perspective, the hydrogen options of ATR+CCS and electrolysis from wind power are almost comparable. The absolute best cases occur when these are combined with point source capture from bioethanol, where there is a cost of abatement of USD 380 / tCO_2 and USD 460 / tCO_2 for ATR+CCS and wind-powered electrolysis respectively.

Analysis of full range of CCU pathways (2050s) (methanol)

Figure 12 shows the cost premium of long-term CCU pathways plotted against the abated emissions of the pathway when compared to the counterfactual route. See Box 5 for details on how to interpret the graph.

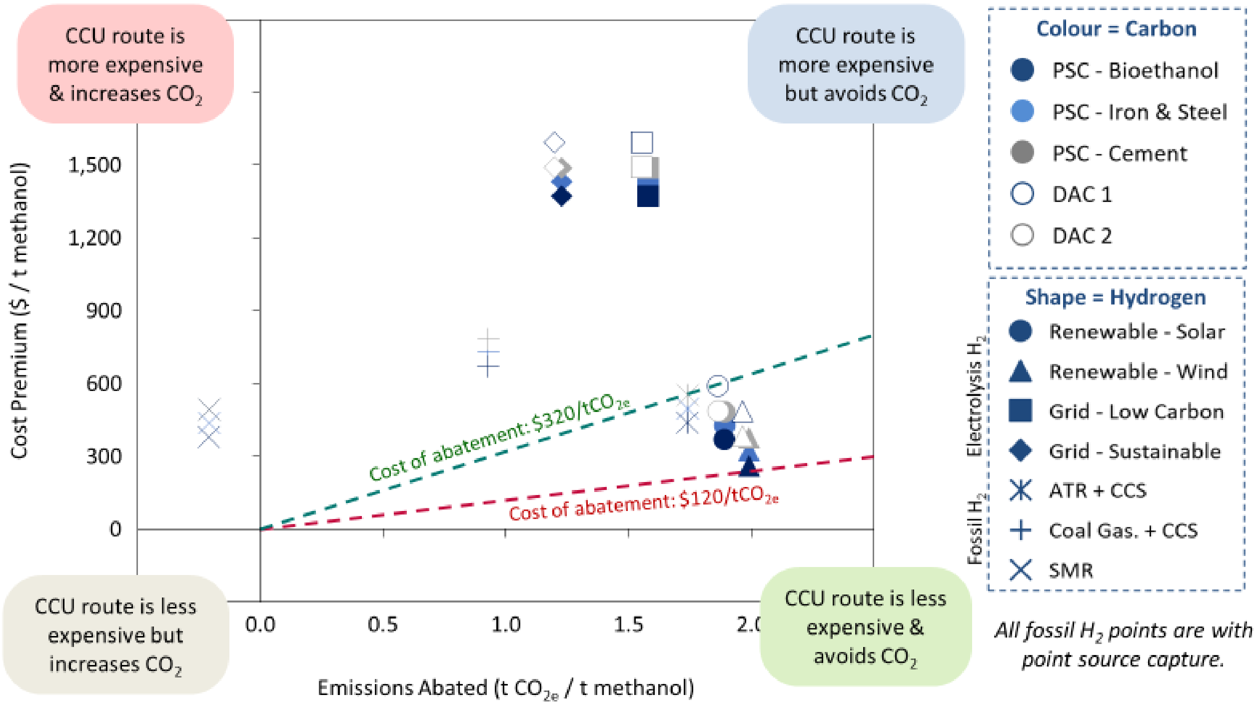


Figure 12: Cost and emissions difference between the **long-term** CCU and fossil production routes for methanol. Cost premium is the cost of the CCU production pathway minus the cost of the fossil production pathway (**excluding cost of emissions**). Emissions abated shows the total emissions for fossil production minus the total emissions for CCU production (assuming identical end-of-life stages). Note that the supply of CO_2 to the CCU pathway is included as a reduction of **1 t CO_2/t CO2** utilized, plus additional emissions from capture and transport (see section 4.2).

Key <u>long-term</u> insights:

- Decreases in the cost of wind electrolysis mean that these pathways offer the lowest cost option when combined with point source capture. These routes also have the greatest emissions abatement and therefore also have the lowest cost of abatement.
- A cost of emissions, such as a carbon price, of USD 120-320 / t CO_2 would be required to make renewable electrolysis routes cost competitive with the counterfactual. The best-case occurs with wind-powered electrolysis and point source capture from a high concentration CO_2 stream (bioethanol plant). This is a feasible 'carbon price' in the long-term for countries with strong climate policies.

5.2 Formic acid

Central case pathways (formic acid)

Figure 13 presents the full life-cycle costs and emissions of commodities produced from central CCU pathways compared to the present-day counterfactual route. See Box 3 for an explanation of interpreting the graph.

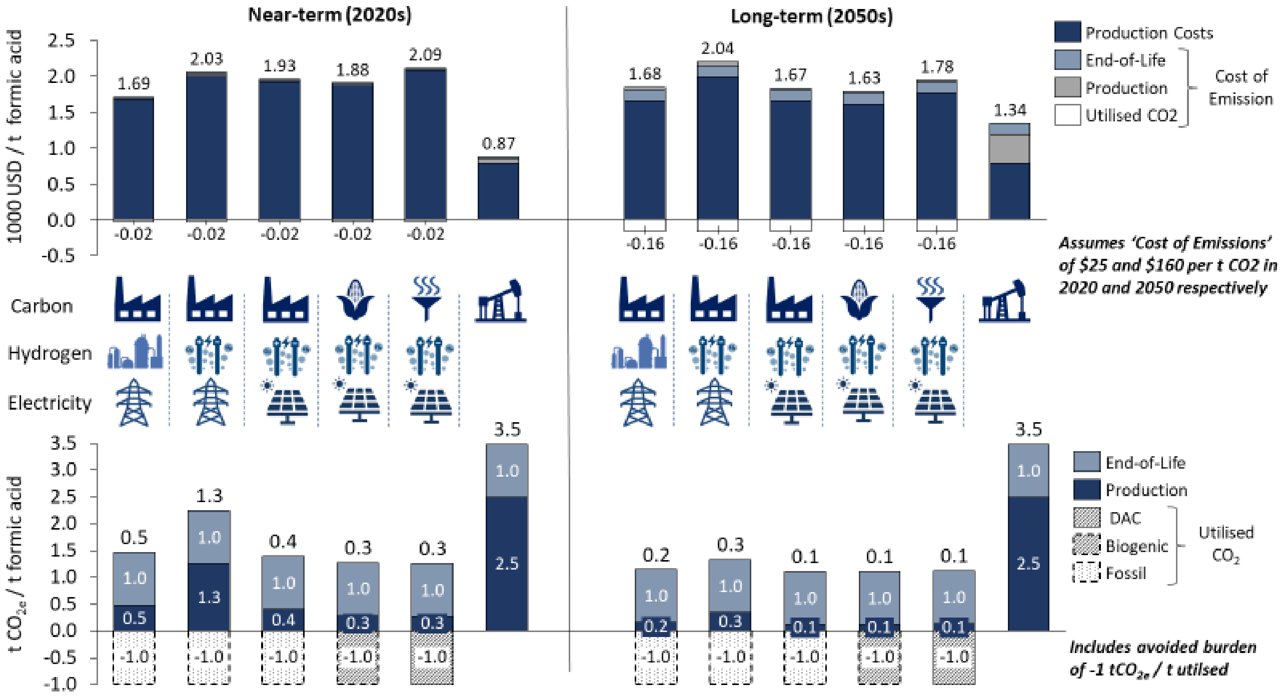


Figure 13: Life-cycle costs (top) and emissions (bottom) for central CCU formic acid pathways.

For all central cases considered, the cost of formic acid produced via CCU pathways is greater than the counterfactual fossil route. In the near-term, total costs are 90-140% greater with the lowest cost option being the point source capture and blue hydrogen pathway and the most expensive option being green hydrogen powered by grid electricity. The cost of CCU pathways decreases slightly with time however the main change in the long-term is the 150% increase in the cost of the counterfactual due to the increase in the cost of emissions. This increase disproportionately impacts the fossil route due to its significantly greater production emissions. Furthermore, the reduction in total emissions due to the included avoided burden from utilising captured CO_2 leads to lower total costs of emission. The long-term costs of CCU formic acid range from being 20-50% greater than the counterfactual fossil route.

The offset in emissions costs due to avoided burden of utilisation has limited impact, even in the long-term. For formic acid CCU pathways, the sum of emission costs associated with production and end-of-life emission is only a small fraction (approximately 10%) of the total pathway costs in the long-term. Therefore, the impact of not being able to partially offset these costs with the emissions cost benefits from utilisation is limited to increasing total CCU pathway costs by 10%.

The total emissions from CCU formic acid pathways are significantly lower than the fossil counterfactual route in all near-term and long-term cases. The counterfactual fossil route for formic acid is emission intensive, allowing CCU pathways to offer a drastic reduction in emissions. When including the avoided burden from utilisation, a reduction of 60-90% is achieved in the near-term and over 90% in the long-term. The intermittent renewable electrolysis pathways have the lowest emissions with the grid-electrolysis pathway having the highest. Emissions from all CCU pathways decrease with time, principally due to reductions in the emission intensity of electricity sources.

Production emissions for CCU formic acid pathways are much less than that of the counterfactual. This means that even when the avoided burden from utilisation is excluded, all CCU pathways still offer a reduction in emissions. This reduction ranges from 30-60% in the near-term and 60-70% in the long-term.

In most cases, emissions from production of formic acid via CCU pathways are much less than the end-of-life emissions. These end-of-life emissions are mostly offset by the emission benefit associated with CO_2 utilisation.

Breakdown of production costs and emissions (formic acid)

Figure 14 shows the cost and emission breakdowns for the production stage of the commodity life-cycle indicated in the previous figure. See Box 4 for an explanation of the graph components.

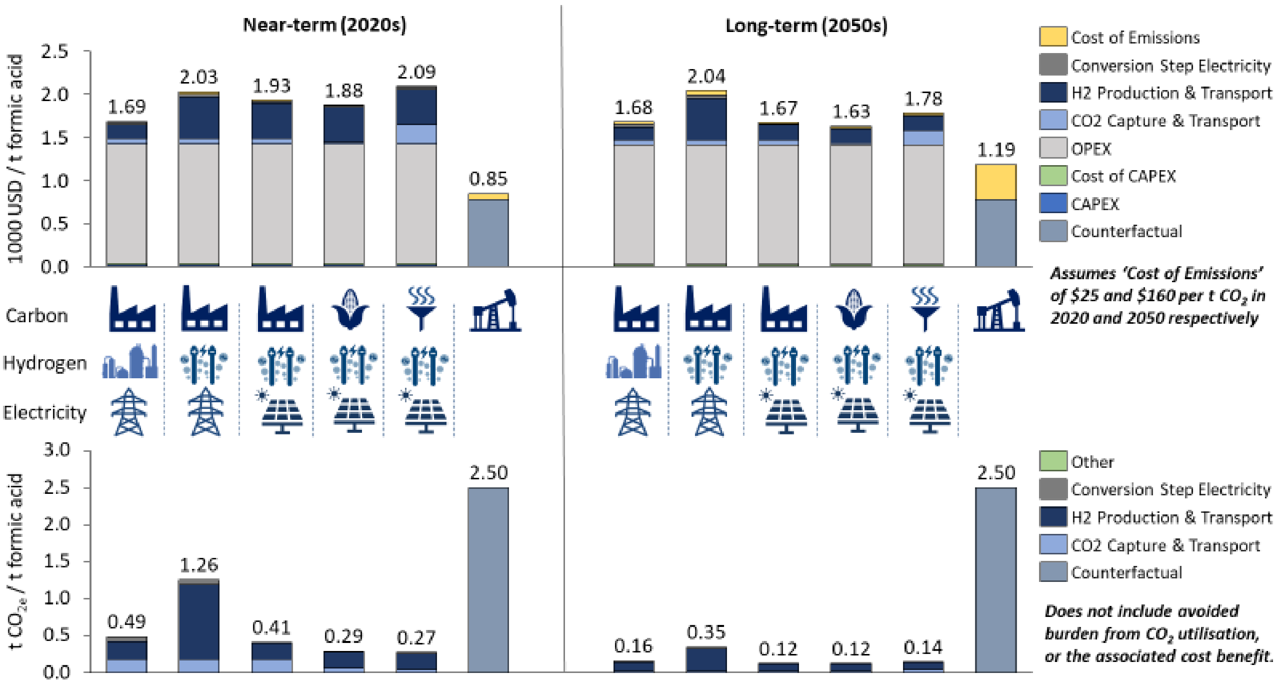


Figure 14: Breakdown of commodity production costs and emissions for central CCU formic acid pathways.

OPEX costs alone are greater than the counterfactual costs. The cost of regularly replacing the expensive Ruthenium based catalyst required for the catalytic hydrogenation of CO_2 results in large operational costs for the CO_2 conversion process. This factor dominates the cost of CCU pathways, accounting for 70-80% of total production costs. There is some uncertainty in the cost of this catalyst, with the current estimate based on lab-scale quantities, however it is unlikely that this could be drastically reduced due to the scarcity and restricted nature of Ruthenium . Options to reduce operational costs include improving the retention / recovery of catalyst materials such that they must be replaced less frequently, and the development of alterative catalysts.

Hydrogen costs are the next largest cost component, with CO_2 capture costs also being significant for DAC pathways. For the central pathways considered, production of hydrogen accounts for 10-20% of total costs in the near- and long-term. For the direct air capture pathway, the costs due to CO_2 capture account for 10% of costs in the near-term and become comparable to those due to hydrogen production in the long-term. CAPEX costs are negligible when assessed on a per unit of product basis. More detail on hydrogen and CO_2 costs can be found in chapter 3.

In the near-term, both hydrogen and CO_2 capture emissions are important. The contribution to production emissions ranges from 50-80% for hydrogen and 10-40% for CO_2 capture. In the long-term, emissions from both hydrogen and CO_2 capture are reduced, with hydrogen becoming the dominant emission component. Use of grid electricity for the conversion step also makes a considerable contribution to emissions, accounting for over 10% of emissions in the near-term blue hydrogen pathway.

Analysis of full range of CCU pathways (near-term) (formic acid)

Figure 15 shows the cost premium of near-term CCU pathways plotted against the abated emissions of the pathway when compared to the counterfactual route. See Box 5 for details on how to interpret the graph.

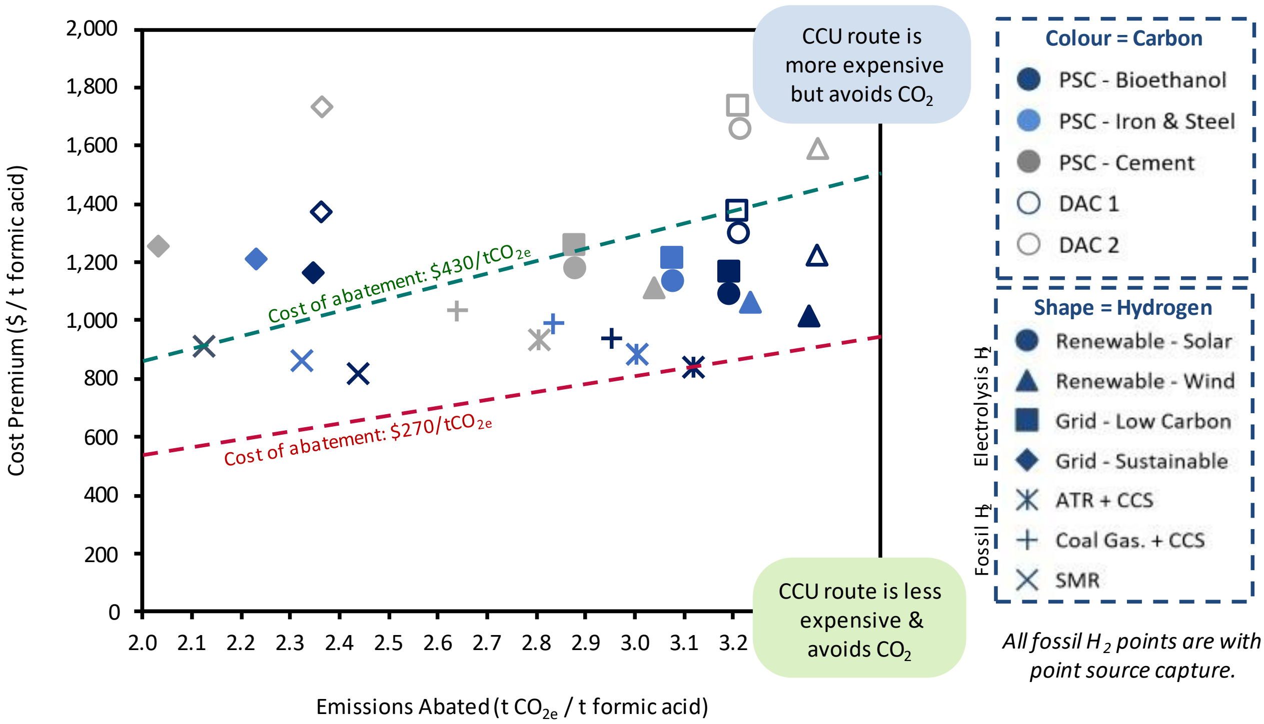


Figure 15: Cost and emissions difference between the **near-term** CCU and fossil production routes for formic acid (FA). Cost premium is the cost of the CCU production pathway minus the cost of the fossil production pathway (**excluding cost of emissions**). Emissions abated shows the total emissions for fossil production minus the total emissions for CCU production (assuming identical end-of-life stages). Note that the supply of CO_2 to the CCU pathway is included as a reduction of **1 t CO_2/t CO2** utilized, plus additional emissions from capture and transport (see section 4.2).

Key near-term insights:

- **From a cost perspective, all options lead to higher costs for the CCU route.** The lowest cost routes considered are those using blue hydrogen, with ATR+CCS combined with concentrated bioethanol point source capture being the cheapest.
- **From an emissions perspective, all options achieve significant levels of abatement.** Notably unabated SMR options also achieve emissions reductions compared to the counterfactual route. DAC or bioethanol CO_2 with wind electrolysis achieve the greatest emissions abatement. Electrolysis solar and electrolysis with low carbon grid are comparable next best options.

1. **CCU could be competitive at a carbon price of USD 270 / t CO_2.** From a cost of abatement perspective, ATR+CCS with bioethanol point source capture is the best near-term option with an abatement cost of USD 270 / t CO_2. The best-case green hydrogen route has a cost of abatement of USD 300 / t CO_2. For most options, excluding grid electrolysis and some DAC options, the cost of abatement falls below USD 430 / tCO_2.

Analysis of full range of CCU pathways (2050s) (formic acid)

Figure 16 shows the cost premium of long-term CCU pathways plotted against the abated emissions of the pathway when compared to the counterfactual route. See Box 5 for details on how to interpret the graph.

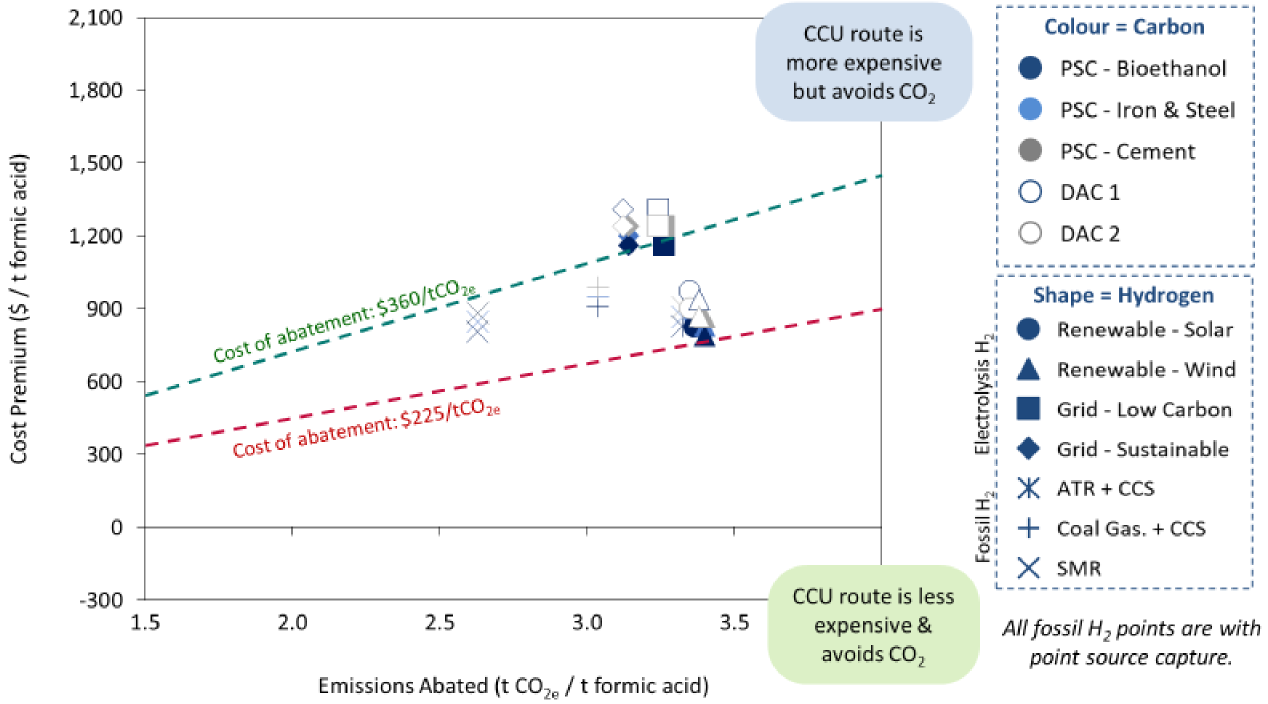


Figure 16: Cost and emissions difference between the **long-term** CCU and fossil production routes for methanol. Cost premium is the cost of the CCU production pathway minus the cost of the fossil production pathway (**excluding cost of emissions**). Emissions abated shows the total emissions for fossil production minus the total emissions for CCU production (assuming identical end-of-life stages). Note that the supply of CO_2 to the CCU pathway is included as a reduction of **1 t CO_2/t CO2** utilized, plus additional emissions from capture and transport (see section 4.2).

Key long-term insights:

- All options lead to higher costs for the CCU route but they also achieve significant levels of abatement.
- The lowest cost route uses bioethanol CO_2 with wind powered electrolysis. However, there is little variation between the costs of routes using electrolysis with intermittent renewables and those using ATR+CCS.
- From an emissions perspective, wind electrolysis routes achieve the greatest emissions abatement. ATR+CCS is the next best option.
- From a cost of abatement perspective, wind powered electrolysis with bioethanol CO_2 has the lowest cost of emissions abatement at USD 225 / t CO_2.
- Grid electrolysis options become cost competitive with the counterfactual route when a cost of emissions of USD 360 / t CO_2 is imposed.

5.3 Middle Distillate Hydrocarbons

Central case pathways (hydrocarbons)

Figure 17 presents the full life-cycle costs and emissions of commodities produced from central CCU pathways compared to the present-day counterfactual route. See Box 3 for an explanation of interpreting the graph.

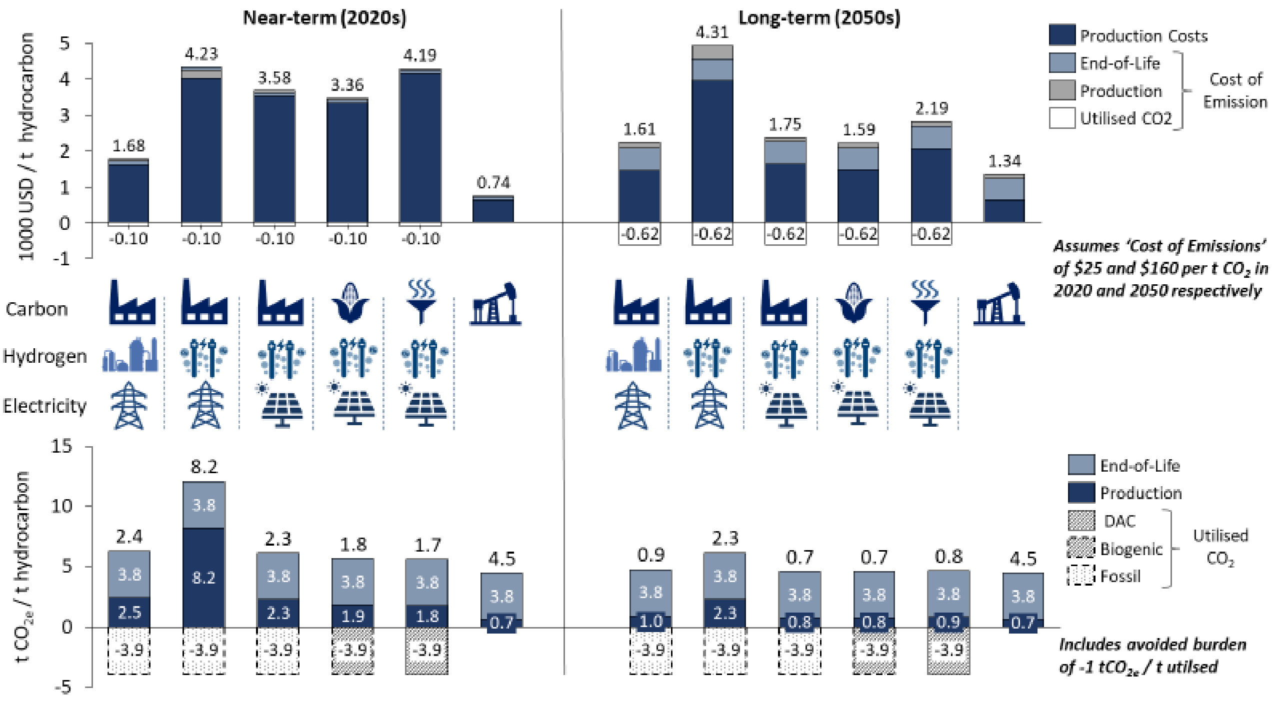


Figure 17: Life-cycle costs (top) and emissions (bottom) for central CCU middle distillate hydrocarbon pathways.

All central pathways lead to a cost premium for CCU middle distillate hydrocarbons, with the magnitude of this varying significantly with hydrogen option. In the near-term, the blue hydrogen pathway is almost 130% more expensive than the counterfactual fossil route but is still the lowest cost option, being half the cost of green hydrogen routes. In the long-term, there is a reduction in the cost of intermittent renewable electrolysis pathways with costs becoming comparable to the blue hydrogen pathway. The cost of these pathways is then 20-60% more than the fossil route, with the cost of the grid electrolysis pathway being 220% greater than the fossil route.

In the long-term, the offset in emissions costs due to the avoided burden of utilisation make CCU pathways more competitive. For CCU pathways, emission costs from production and end-of-life emissions are partially offset due to the included avoided burden from utilising captured CO_2 that reduces the total emissions. In the near-term, the low cost of emissions of USD 25 / t CO_2 means that this has negligible impact on the overall pathway costs, despite the significant variation in pathway emissions. In the long-term, the greater imposed 'cost of emissions' of USD 160 / t CO_2 results in CCU routes becoming more economically competitive with the fossil route which does not receive the utilisation benefit. This competitive advantage relies on the CCU pathways being able to claim the avoided burden from utilising CO_2.[37]

In most cases, the total emissions from CCU middle distillate hydrocarbon pathways are lower than the counterfactual fossil route. In the near-term, all pathways except that using grid electrolysis for hydrogen production have lower total emissions than the counterfactual route. In the near term, emissions are reduced by approximately 60% in the pathways using bio-ethanol point source or direct air capture for CO_2 supply. In the long term, this reduction becomes approximately 80%. Due to reductions in the emission intensity of the

[37] If this were not the case, for example if the CO_2 would otherwise have been abated or if the capture facility were to claim all credit, then long-term costs of CCU middle distillate pathways would instead be 60-270% greater than the counterfactual fossil route.

grid and improvements in hydrogen efficiencies, the grid-electrolysis pathway also has lower emissions than the counterfactual fossil route in the long-term. The overall CO_2 reduction associated with CCU pathways over the counterfactual are due entirely to the avoided burden associated with the utilisation of CO_2 which partially offsets end-of-life emissions.

If the avoided burden from utilisation is excluded, then none of the CCU pathways offer lower emissions than the fossil route. In all near-term and long-term cases considered, the production emissions for CCU pathways are greater than those associated with the counterfactual fossil route. This means that, under the assumptions used here, the emissions associated with hydrogen generation, incomplete capture, and energy for capture and conversion in the CCU pathway are greater than the emissions from fossil fuel extraction and conversion in the counterfactual route. Therefore, a reduction in life-cycle emissions only occurs if the utilised CO_2 can be counted as offsetting the CO_2 that is emitted at the middle distillate hydrocarbons end-of-life (e.g. combustion emissions). If this emission benefit cannot be claimed, then emissions from the CCU pathways considered result in an increase in emissions of at least 20% (near-term) and 2% (long-term).

Breakdown of production costs and emissions (hydrocarbons)

Figure 18 shows the cost and emission breakdowns for the production stage of the commodity life-cycle indicated in the previous figure. See Box 4 for an explanation of the graph components.

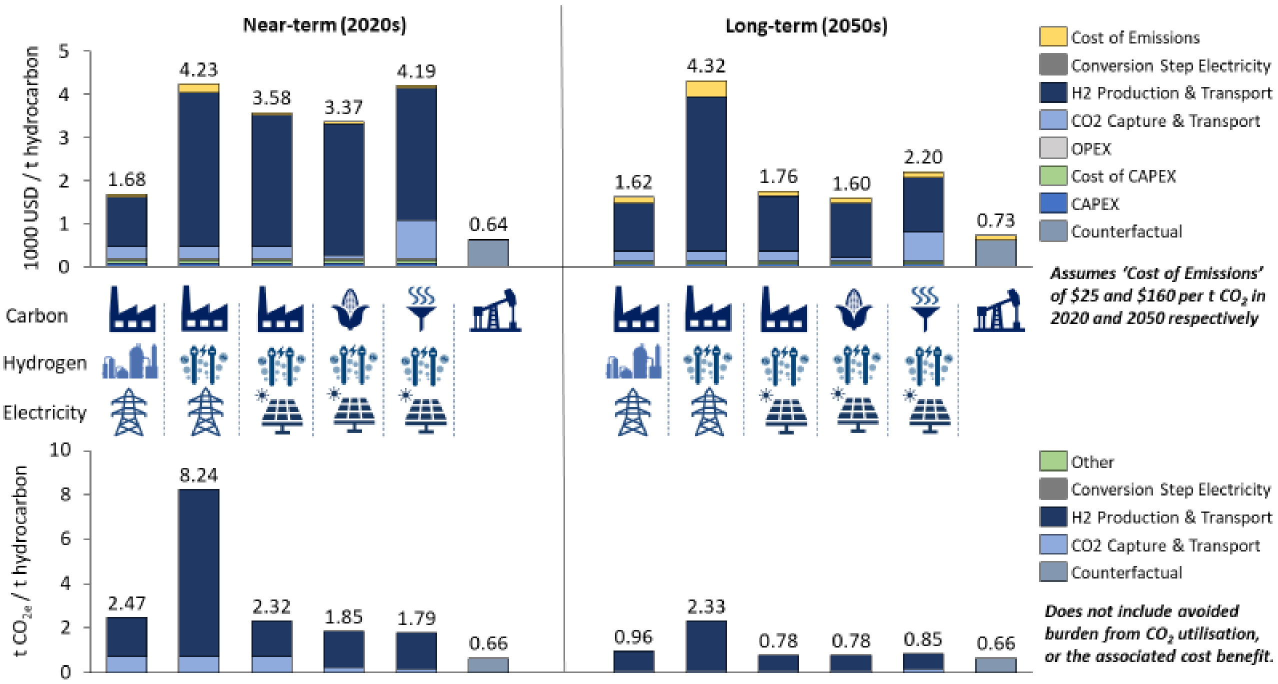


Figure 18: Breakdown of commodity production costs and emissions for central CCU middle distillate hydrocarbon pathways.

Costs are dominated by the cost of hydrogen production. Compared to the other commodities investigated, middle distillate hydrocarbons have more hydrogen as a percentage of total mass. The cost of hydrogen is the dominant cost component for all pathways accounting for 60-90% of production costs in the near-term and 60-80% in the long-term. This is the main cause of variations between pathways and over-time, with the assumed cost of blue hydrogen production being over 2.5 times less expensive than green hydrogen in the near term, and costs reducing by 60% for intermittent renewable hydrogen in the long-term. More details on hydrogen costs can be found in chapter 4 and in the appendix.

The choice of CO_2 source becomes important in the long-term. In the near-term, the large unit cost difference (USD / t CO_2) between point source capture and direct air capture is of minimal significance when placed next to the cost of hydrogen generation. Near term CO_2 costs account for 10-30% of production costs.

In the long-term, hydrogen costs decrease meaning that the choice of CO_2 source has a greater impact on overall production costs. Compared to the standard point source, use of direct air capture in the long-term increases production costs by 25% whereas use of a concentrated point source such as bio-ethanol decreases them by 10%.

Fixed and operational costs for the conversion step are negligible. The cost of hydrogen and CO_2 feedstocks is the most important factor for middle distillate hydrocarbon production via CCU pathways. CAPEX and OPEX components associated with the conversion step are negligible when assessed on a per unit of product basis, accounting for a maximum of 10% of production costs.

In the near-term, both hydrogen and CO_2 capture emissions are important. The contribution to production emissions ranges from 70-90% for hydrogen with the remainder being from CO_2 capture. Hydrogen emissions dominate all pathways but are particularly significant for the grid electrolysis pathway due to the high emission intensity of grid electrolysis. CO_2 capture emissions are significant for the point source capture pathways with lower hydrogen emissions, accounting for 30% of the standard point source and intermittent renewable pathway.

Long-term emissions for CCU pathways mainly arise from hydrogen production. Emissions for hydrogen production decrease in the long-term due to improvements in efficiencies and decreases in the emission intensity of solar photovoltaics. However, these emissions are still greater than CO_2 capture emissions which also decrease due to changes in point source characteristics and capture rates.

Analysis of full range of CCU pathways (near-term) (hydrocarbons)

Figure 19 shows the cost premium of near-term CCU pathways plotted against the abated emissions of the pathway when compared to the counterfactual route. See Box 5 for details on how to interpret the graph.

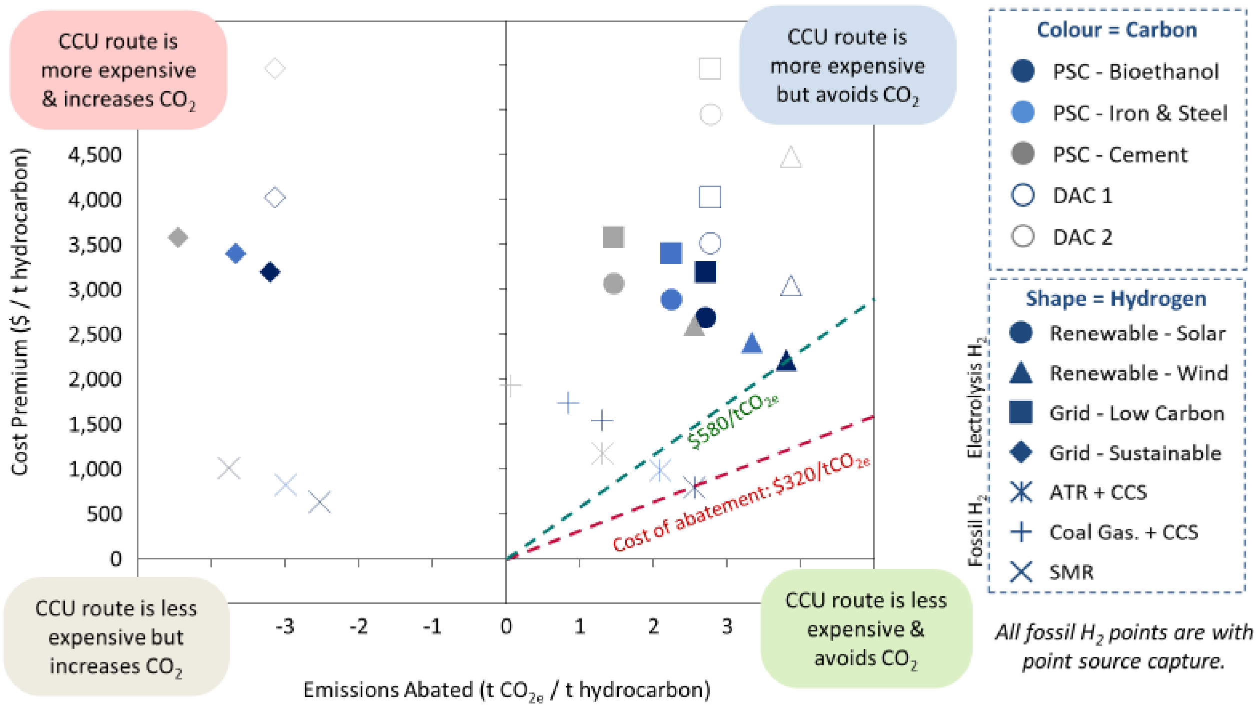


Figure 19: Cost and emissions difference between the **near-term** CCU and fossil production routes for middle distillate hydrocarbons. Cost premium is the cost of the CCU production pathway minus the cost of the fossil production pathway (**excluding cost of emissions**). Emissions abated shows the total emissions for fossil production minus the total emissions for CCU production (assuming identical end-of-life stages). Note that the supply of CO_2 to the CCU pathway is included as a reduction of **1 t CO_2/t CO2** utilized, plus additional emissions from capture and transport (see section 4.2).

Key near-term insights:

- **From a cost perspective, all options lead to higher costs for the CCU route.** The cheapest routes considered are SMR or ATR+CCS with CO_2 from point source capture. Green hydrogen routes are all more expensive than blue routes.
- **From an emissions perspective,** SMR (no-CCS) and options using 'sustainable' grid electricity give rise to an increase in emissions. DAC CO_2 with hydrogen from wind powered electrolysis leads to the greatest emissions abatement. Bioethanol PSC with wind powered electrolysis leads to similar levels of abatement but at a lower cost premium.
- **From a cost of abatement perspective,** ATR+CCS with bioethanol or iron & steel CO_2 offers the best option. The next best is then electrolysis from wind power. For these options to be cost competitive with the counterfactual, a carbon price or alternative of **USD 320 / t CO_2** and **USD 580 / t CO_2** respectively would be required. This is ambitious for the near-term.

Analysis of full range of CCU pathways (2050s) (hydrocarbons)

Figure 20 shows the cost premium of long-term CCU pathways plotted against the abated emissions of the pathway when compared to the counterfactual route. See Box 5 for details on how to interpret the graph.

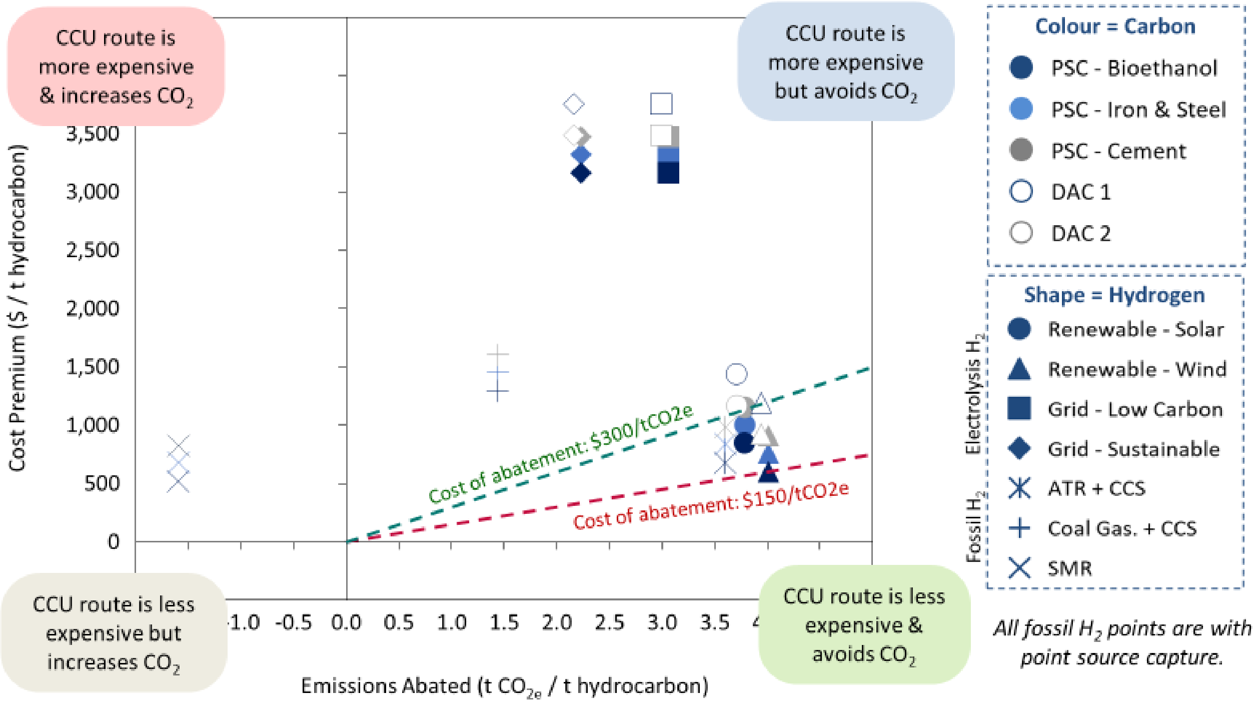


Figure 20: Cost and emissions difference between the **long-term** CCU and fossil production routes for middle distillate hydrocarbons. Cost premium is the cost of the CCU production pathway minus the cost of the fossil production pathway (**excluding cost of emissions**). Emissions abated shows the total emissions for fossil production minus the total emissions for CCU production (assuming identical end-of-life stages). Note that the supply of CO_2 to the CCU pathway is included as a reduction of **1 t CO_2/t CO2** utilized, plus additional emissions from capture and transport (see section 4.2).

Key long-term insights:

- In the long term, the cost of intermittent renewable electrolysis reduces making it cost competitive with blue hydrogen routes. Grid powered electrolysis have the highest cost premiums.
- From both an emissions and cost perspective, electrolysis with wind power and CO_2 from bioethanol offers the best option.
- From a cost of abatement perspective, this best-case option requires a carbon price or equivalent of USD 150 / t CO_2 to become competitive with the counterfactual route. This is below our assumed long-term 'cost of emissions' of USD 160, so the route could become competitive, particularly within countries with strong climate policies.

- Most intermittent renewable electrolysis options and all ATR+CCS options are cost competitive when a cost of emissions of USD 300 / t CO_2 is applied.

5.4 Sensitivities

This section explores the implications of altering the emission intensities and costs of electricity inputs, the capture rates for ATR with CCS, and discusses impacts of differing end-uses.

Emission intensity and cost of electricity

Considerable variations in electricity cost and emissions are possible. The cost and emission intensity of electricity will vary regionally due to differing generation costs of the technologies and differing technology mixes in the grid. For renewable electricity, costs and emissions intensity will vary with the type of renewable energy, the manufacturing route, and the annual capacity for electricity generation. These variations are considerable and while we have selected a few options to explore as central cases, the graphs below depict the full range and impact.

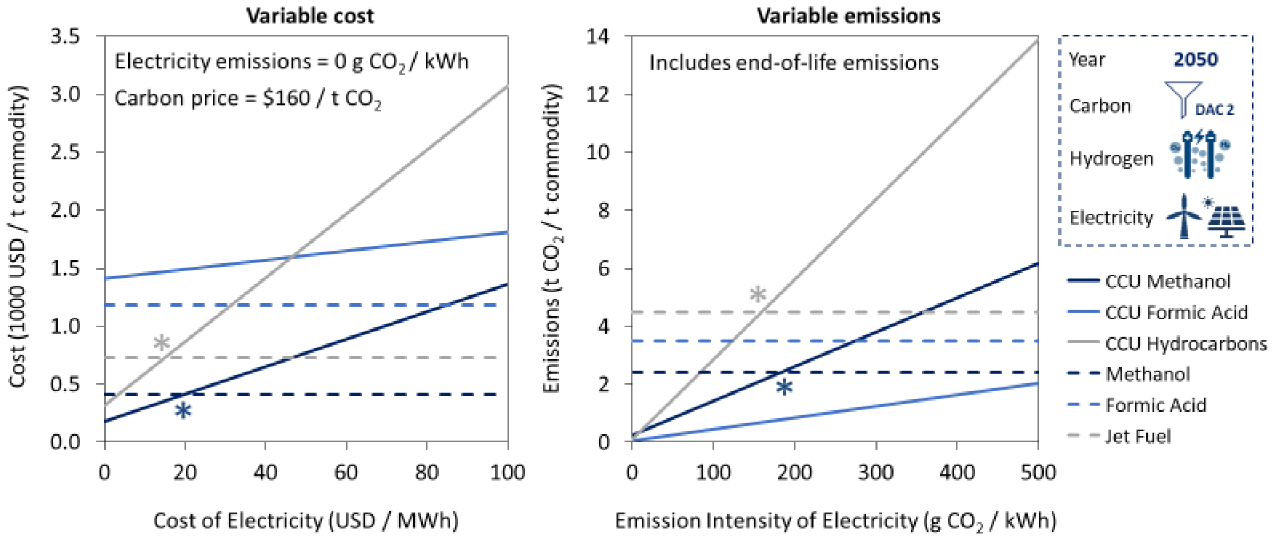


Figure 21: Impact of varying electricity assumptions on the cost and emissions of CCU pathways. Solid lines are used for the CCU pathway considered (long-term optimistic DAC with intermittent renewables) and dashed lines the indicate fixed costs and emissions assumed for counterfactual fossil routes (not accounting for changes in electricity cost and carbon intensity). The points at which the CCU (solid) and conventional (dashed) lines cross (*) is where these routes meet cost and emission parity.

Figure 21 shows the variation of commodity cost with electricity price (left) and the variation of commodity emissions with the emission intensity of the electricity supply (right). The pathway used is a long-term green hydrogen and DAC CO_2 capture pathway with the lower cost DAC predictions, and the emission benefit from utilisation included. In the cost analysis, a long-term carbon price of USD 160 / t CO_2 is included but with electricity emissions set to zero to represent a best-case scenario.

To reach cost parity under these assumptions, methanol requires an electricity price of less than USD 20 / MWh and hydrocarbons require a price of below USD 15 / MWh, whereas formic acid CCU pathways do not reach cost parity even at zero cost of electricity. For CCU routes to have lower emissions than their counterfactual routes, an electricity emission intensity of below 180 g CO_2 / kWh is required for methanol whereas 160 g CO_2 / kWh is required for hydrocarbons. Formic acid CCU routes lead to lower emissions for all intensities considered.

As can be seen by the gradients of the CCU lines, variations in electricity price and emissions have the greatest impact on CCU hydrocarbons and the least impact on formic acid. This results from differences in hydrogen demand per tonne of commodity, as electricity is predominantly used for electrolysis.

Capture rates for ATR with CCS

Higher ATR CCS capture rates could be achieved. The main analysis assumes a capture rate for CCS at the ATR plant of 95% in the near-term and 98% in the long-term, meaning that 5-2% of emissions from reforming natural gas are released to the atmosphere. This is in addition to the upstream emissions from extracting natural gas. It is possible that higher capture rates could be achieved with further developments or new technologies, with the potential to reach 99% capture.

The impact of changing the capture rate on hydrogen emissions is shown in Figure 22: (left) for the near-term and long-term, with temporal differences due to a 50% reduction in upstream natural gas emissions in the long-term. Figure 22: (right) shows the impact of varying ATR CCS capture rates on CCU methanol emissions. The pathway considered is a long-term optimal pathway, in which CO_2 is supplied from capture at a bio-ethanol plant (high concentration) and low-carbon grid electricity is used (51g / kWh). It can be seen that increasing the capture rate from 85% to 99% results in a 34% reduction in CCU methanol production emissions.

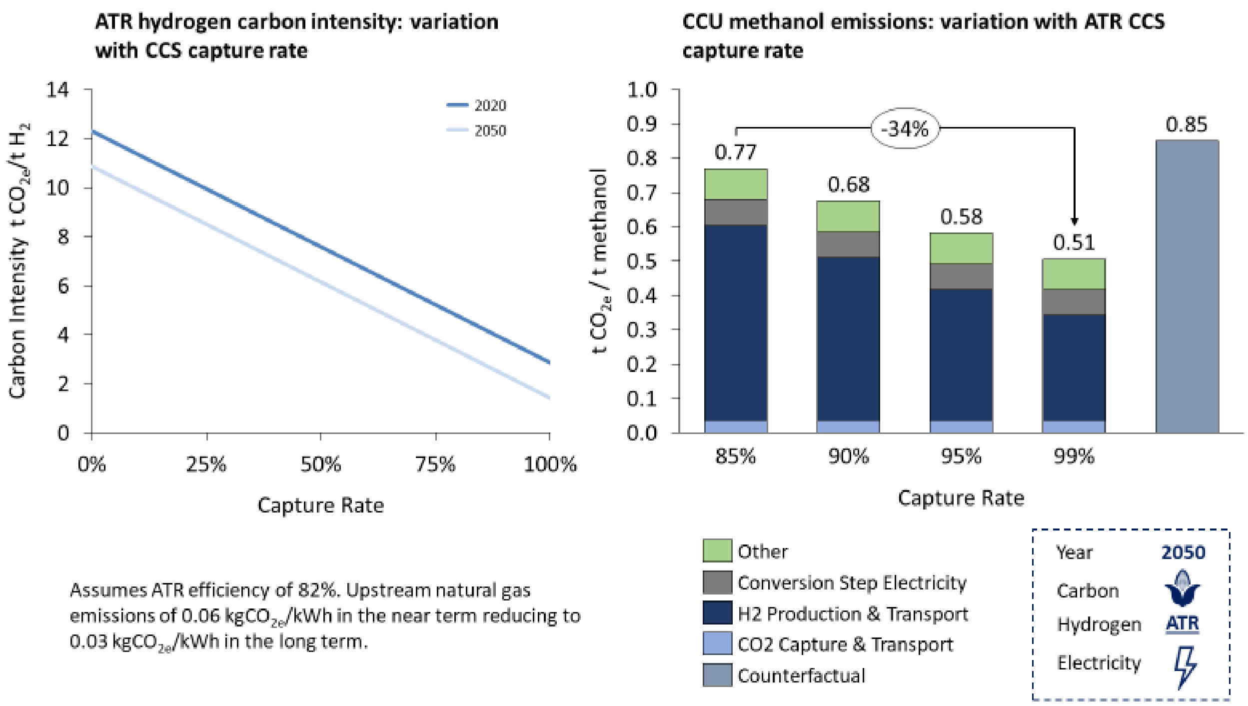


Figure 22: Impact of capture rate on emissions from blue hydrogen production (ATR with CCS) and subsequent impact on CCU methanol pathways. Left: Variation of ATR hydrogen emission intensity with CCS capture rate. Right: Variation of CCU methanol emissions with ATR CCS capture rate.

End-use counterfactuals and end-of-life emissions

CCU hydrocarbons may have different end-of-life characteristics to conventional fuels. In the main analysis it is assumed that the CCU routes produce an identical commodity to the counterfactual routes, and that therefore the end-of-life emissions are equivalent for both routes. This is likely to be true for methanol and formic acid, however there is some evidence to suggest that synthetic (CCU) middle distillate hydrocarbons could have better combustion properties and therefore lower end-of-life emissions compared to the counterfactual fossil routes[38]. Furthermore, synthetic fuels are thought to be less polluting with lower NOx and SOx emissions.

For indirect replacements, alternative counterfactuals could be considered. The counterfactuals used in this analysis are the fossil routes to producing methanol, formic acid, and hydrocarbons. However future possible end-uses of methanol include conversion to DME for use as a diesel replacement or conversion to olefins via the methanol-to-olefins process and subsequent use in plastics. An alternative approach would be

[38] Gill *et al*, 2011 Combustion characteristics and emissions of Fischer-Tropsch diesel fuels in IC engines

to determine cost and emission results for a specific end-use and compare this to the most appropriate counterfactual for that end-use. This is relevant for select end-uses, where commodities are not directly replacing a fossil counterpart, and could be the subject of future analysis.

End-use distribution emissions may differ for CCU pathways. Implicit in the assumption of identical end-use is the assumption that CCU and counterfactual products have the same cost and emissions for product distribution. However, it may be possible for the production of CCU commodities to be more distributed, with localised production near to the end-user. This is due to CCU routes not relying on geographically concentrated fossil resources, and instead being able to capture CO_2 onsite and generate hydrogen onsite. However, there are still uncertainties over the likely scale of localised facilities and the impacts on production economics.

6 Impacts of CCU on Energy and Resources

Hydrogen production requires energy either in the form of electricity for electrolysis or a natural gas feedstock for autothermal reforming (ATR) or steam methane reforming (SMR). For coal gasification, a coal feedstock is required. The efficiency of these technologies determines how much of this energy is converted into hydrogen. Efficiencies for electrolysis vary with the type of electrolyser used, however overall efficiencies are expected to improve from approximately 65% in the near-term to approximately 75-80%. Some fossil-based hydrogen generation technologies are more established, with efficiencies of 78%, 82% and 58% assumed for SMR, ATR and coal gasification respectively.[39,27]

The capture of CO_2 typically requires both electrical and thermal energy inputs, for processes such as solvent thermal regeneration and CO_2 compression. Energy demand varies with the type of CO_2 source, with lower concentration and lower purity gas streams requiring a higher energy input. Capture from a bio-ethanol plant (concentration almost 100%) requires approximately 100 kWh of electricity and minimal heat per tonne CO_2, whereas capture from an iron-and-steel plant (concentration - 17-35%) requires approximately 200 kWh of electricity and 1 GJ thermal energy.[40]

The CO_2 source with the greatest energy demand is direct air capture, where atmospheric CO_2 concentrations are around 400 ppm. DAC technology requires approximately 4-6 GJ of thermal energy and 400 kWh of electrical energy per tonne of CO_2 captured. Around 79% of the electrical input is used for compression, whilst the thermal input is required for CO_2 desorption. In the case of solid sorbent DAC technologies, such as that used in the Climeworks process, CO_2 desorption occurs at sufficiently low temperatures that the required thermal energy can be generated by heat-pumps or obtained from waste heat sources. Therefore, the process could be powered entirely from renewable energy. In the case of aqueous sorbent technologies, a higher temperature is required for desorption and therefore combustion of natural gas (or alternative) is required which in turn releases CO_2 that must then also be captured by the technology.[23,24]

Within the conversion step, energy is required to power compressors and to separate the final commodity from solvents and by-products via distillation. In the case of methanol and formic acid, this energy is provided from an electricity supply which for the purposes of distillation is converted to a heat source via a heat pump. In the case of middle distillate hydrocarbons, this energy is provided from the combustion (with carbon capture) of shorter chain hydrocarbons that cannot be refined into fuels. The conversion steps are exothermic and thus generate additional thermal energy that is used within the process once initiated.

Figure 23 shows the breakdown of energy requirements for the central CCU pathways split across hydrogen production, CO_2 capture and the conversion step, with distinctions for electricity and non-electricity energy inputs. Variation between the three commodities is mainly due to differences in the quantities of hydrogen and CO_2 feedstocks required to produce a tonne of the commodity, with middle distillate hydrocarbons having the highest feedstock demands and formic acid the lowest. Additional minor variations result from differences in energy requirements for the conversion step.

[39] ENA 2020, Gas Goes Green, Hydrogen: Cost to Customer
[40] Von der Assen et al. 2016, Selecting CO2 Sources for CO2 Utilization by Environmental-Merit-Order Curves

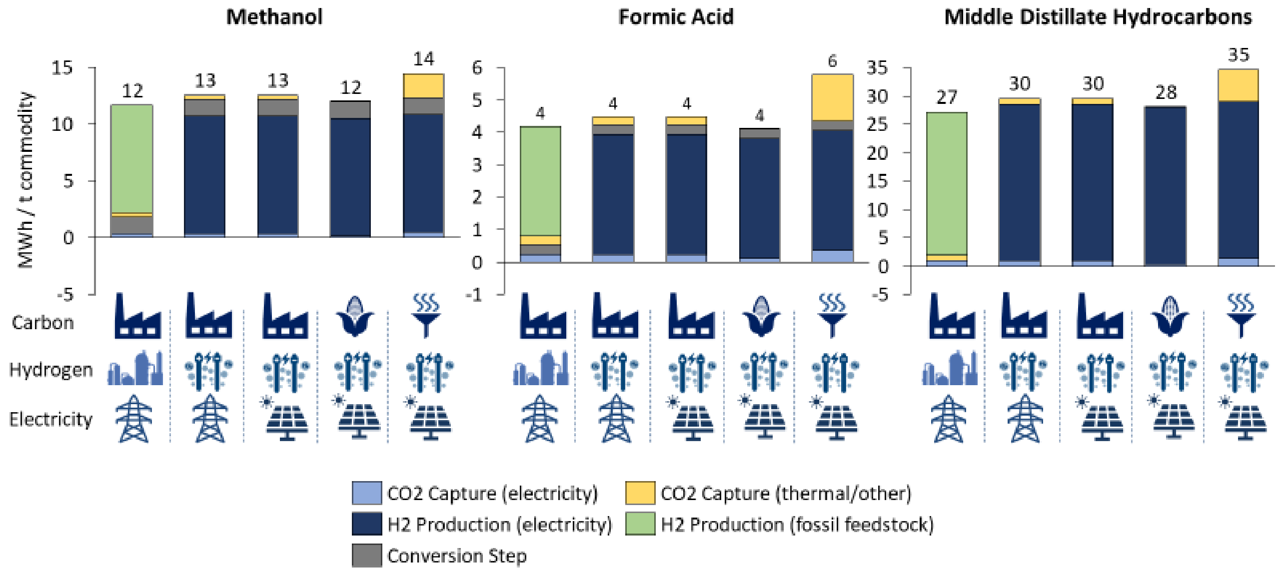


Figure 23: Energy demands for **long-term** central CCU pathways per tonne of commodity. Energy is required for hydrogen production, CO_2 capture and the conversion step. Demands are split into electricity and non-electricity (thermal/other) requirements. Assumes efficiencies of 75% for green hydrogen production and 82% for blue hydrogen production. Energy for the conversion step is assumed in the analysis to be electricity but could be a mixture of electricity and thermal energy.

As can be seen in Figure 23, energy demand is dominated by hydrogen production. Producing one tonne of methanol, formic acid, or middle distillate hydrocarbons from green hydrogen requires an electricity supply for electrolysis of 12 MWh, 4 MWh and 32 MWh respectively in the near-term (65% efficiency) and 10 MWh, 4 MWh and 28 MWh in the long-term (75% efficiency). For blue hydrogen production via ATR with CCS (82% efficiency), a natural gas supply of 9.0 MWh, 3.4 MWh and 2.5 MWh is instead required for each commodity respectively.

Using direct air capture leads to a significant additional energy contribution compared to routes with point source capture. Energy for CO_2 capture totals 15%, 25% and 16% of total energy demand for methanol, formic acid, and middle distillate hydrocarbon DAC-electrolysis pathways respectively (long-term), compared to 3%, 6% and 3% for standard CO_2 point-source with electrolysis pathways.

7 Reaching target levels of abatement (market considerations)

This chapter presents a high-level thought-experiment on the total level of present-day emissions that could be abated by the CCU pathways investigated. The potential demand for CCU products is discussed in the context of existing markets, new markets, and competing low-carbon alternatives. The purpose is to present the scale of abatement achievable using simple penetration assumptions: competitive and ambitious.

- **Competitive –** CCU products penetrate a fraction of markets (existing and new) with other means of production (e.g. bio-routes) accounting for the remainder of demand.
- **Ambitious –** CCU products penetrate either the entirety or a large proportion of markets (existing and new).

For methanol and formic acid, the abatement if the entirety of existing markets were to be replaced with CCU products is also presented in the **current non-CCU** case. The values are for current market sizes, with no predictions made as to the growth of these markets.

Figure 24 shows the current market sizes and the potential future portion supplied by CCU commodities under different penetration assumptions. The abatement that would be achieved compared to use of fossil middle distillates (avoided CO_2) is shown for the central pathway comprising DAC with hydrogen from intermittent renewable electrolysis. Further explanations of potential market penetration assumptions and the results for other central pathways are included in the commodity sections below. The resource and energy implications of deploying these CCU commodities at scale is discussed in the final section.

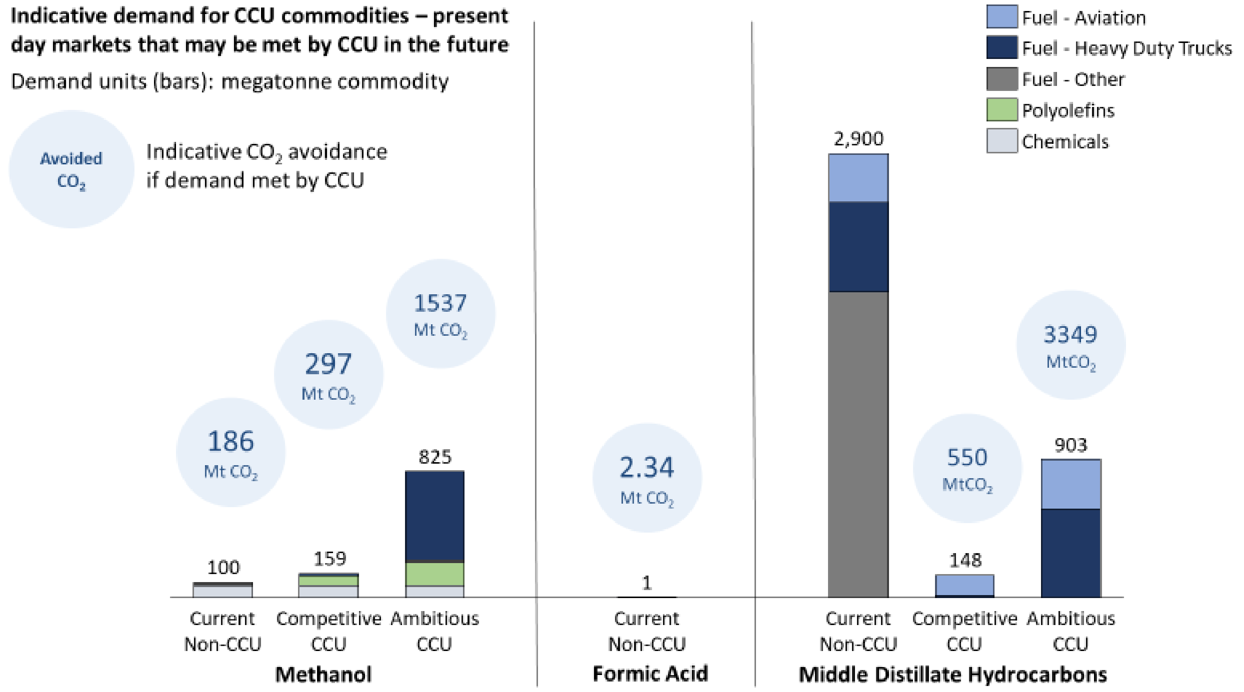


Figure 24: Indicative demand for CCU commodities, based on present day markets that may be met with CCU in the future. The graph depicts fractions of present-day market segments that could eventually be met by CCU commodities, under three basic penetration assumptions. The avoided CO_2 is based on the difference between the long-term central CCU pathway comprising DAC with hydrogen from intermittent renewable electrolysis and the counterfactual fossil route.

Note that the study has not investigated the full-CCU route to producing the end-use (e.g. polyolefins) nor the counterfactual fossil pathway for this end-use. The avoidance is calculated for direct substitution of the main commodity assessed (e.g. replacing fossil methanol with CCU methanol in the methanol-to-olefins production route) with the end-use simply a tool to indicate the potential scale of CCU market demand.

Methanol

The present-day global market for methanol is around 100 Mt per annum, with existing uses including gasoline blending (14%), and production of chemicals such as MTBE (13%) and acetic acid (9%)[41].

Methanol can be upgraded to both fuels and chemicals, allowing a broad range of possible end-uses. To date, pathways from fossil methanol to high value chemicals and fuels have proved attractive in regions with abundant coal or gas reserves but with little or no domestic oil production. In the long-term, if fossil feedstocks are to be avoided then CCU methanol provides a pathway to the production of polymers, such as polyethylene (polyolefins), and fuels, such as di-methyl ether (DME) and gasoline,.

CCU methanol can be converted to DME, a potential drop-in replacement for diesel, and gasoline. These conversion pathways require minimal additional energy and are already established for the conversion of fossil or bio-methanol. Oberon Fuels has a pilot production facility producing fuel-grade DME from methanol in North America. DME is seen as a potential drop-in replacement for diesel, particularly for freight trucks, and has been used in global vehicle trials by Volvo Trucks, Mack Trucks and Ford. The methanol-to-gasoline (MTG) process was first introduced in 1977 by Mobil researchers as a response to the 1970s energy crisis. The fossil-MTG process continues to be developed by Exxon Mobil, with a 2,500 bpd coal-to-gasoline plant having begun operations in China in 2009.

CCU methanol provides a low-carbon route to producing polyolefins such as polyethylene. The methanol-to-olefins (MTO) process is an interruption of the aforementioned MTG process and was first introduced in 1981 by Union Carbide (now Honeywell UOP). Several commercial scale plants exist for the conversion of fossil-methanol to olefins, most prevalently in China for coal-to-olefins, with capacities up to 0.8 Mt per annum. This same technology could be used to upgrade CCU methanol to light olefins (ethylene, propylene), which can then be polymerised to common plastics such as (high-density) polyethylene. This is an alternative to the conventional fossil route of steam cracking crude-oil derivatives. It is estimated that currently 12% of fossil-methanol produced is used for the MTO process.[42]

In the long-term, 30-80% of olefins could be produced using CCU methanol. A 2017 report for CEFIC[43] investigated low carbon feedstocks for the European chemical industry, including modelling of deployment scenarios. In their notably ambitious intermediate scenario (steadily increasing deployment of breakthrough technologies), olefins produced via the CCU route of hydrogen-based methanol accounted for 30% of European olefin production in 2050, with remaining production from bio-based routes or continued fossil use. In their maximum scenario (100% deployment of new technologies), the CCU route to olefins accounted for 85% of olefin production, with the remaining 15% from bio-based routes. The total present-day global market for polyolefins is roughly 150 Mt.

In the long-term, hydrogen based synthetic fuels could account for 3% of fuels for medium- and heavy-duty freight trucks. This is based on the The IEA's Energy Technology Perspectives[44] Sustainable Development Scenario. This market is currently dominated by diesel use, for which DME could be a viable alternative.

As a thought-experiment we consider the abatement potential of CCU based methanol under three different penetration assumptions (illustrated in Figure 24):

- In the **competitive case**, CCU products penetrate the entirety of the existing methanol market for chemical end-uses (excludes methanol for gasoline blending). In addition to this, CCU methanol penetrates 3% and 30% of present-day medium- and heavy-duty freight trucks and polyolefins markets respectively. This totals an annual demand for CCU methanol of 160 Mt.

[41] ICIS 2019 and ICIS 2020 – Methanol Value Chain
[42] Makarand R. Gogate 2019, Methanol-to-olefins process technology: current status and future prospects
[43] DECHEMA 2017, Low carbon energy and feedstock for the European chemical industry
[44] IEA 2020, Energy Technology Perspectives

- In the **ambitious case**, CCU products penetrate the entirety of this freight truck market and 80% the polyolefins markets, alongside the existing methanol markets for chemical end-uses. This totals an annual demand of 825 Mt.
- If these new markets are not considered, replacing the **current non-CCU** market with CCU methanol (including methanol for gasoline blending) would give a total demand of 100 Mt per annum.

Under these three assumptions, long-term CCU pathways could avoid 297 Mt, 1537 Mt and 186 Mt of CO_2 per year respectively in the case where DAC with hydrogen from intermittent renewable electrolysis is used. The associated costs, resource demands and energy required for levels of competitive and ambitious penetration are presented in Figure 25.

Formic Acid

Formic acid has a variety of niche end-uses with an approximate annual demand of 0.7 Mt per annum. Formic acid is used in agriculture for silage and animal feed (27%), leather and tanning applications (22%), pharmaceuticals & food chemicals (14%), as well as in the textile industry (9%) and for natural rubber production (7%)[45].

Unique properties make formic acid difficult to replace in these applications. ; being strongly acidic and a valuable reducing agent. This makes it unlikely that formic acid could be substituted with an alternative product.

As a thought-experiment we consider the abatement potential of CCU based formic acid under a single penetration assumption (illustrated in Figure 24):

- If the entirety of the **current non-CCU** market for formic acid were to be replaced with CCU products, then the annual demand for CCU products would be 1 Mt.

Under this assumption, approximately 2.27 Mt of CO_2 could be avoided per year under the long-term CCU pathway in which DAC with hydrogen from intermittent renewable electrolysis is used.

Middle Distillate Hydrocarbons

Global demand for the middle distillate products considered (diesel, jet fuel, gasoline) totaled approximately 2900 Mt in 2018 with 300 Mt for aviation fuels, 1100 Mt for motor gasoline, and 1500 Mt for diesel type products. Synthetic fuels are only expected to penetrate a small percentage of this market, with other decarbonization options such as electric vehicles and biofuels dominating decarbonization routes.

Long-term markets for synthetic middle distillates are expected to be freight truck and aviation fuels. The Sustainable Development Scenario in the International Energy Agency's Energy Technology Perspectives 2020[44] report projects synthetic fuels to be a long-term abatement option for medium- and heavy-duty freight trucks and aircraft, entering these markets in the late 2020s. The present-day market demand for fossil based middle distillate hydrocarbons in these segments is roughly 580 Mt for freight trucks and 323 Mt for aviation fuels. The IEA's projections indicate that in the long-term (2070) synthetic fuels could meet around 3% and 40% of these markets respectively. The report projects a total annual demand for synthetic fuels of 254 Mt in 2070.

As a thought-experiment we consider the abatement potential of CCU based middle distillate hydrocarbons under three different penetration assumptions (illustrated in Figure 24):

- In the **competitive case**, CCU products penetrate 3% and 40% of present-day medium- and heavy-duty freight trucks and aviation markets respectively, totaling an annual demand for CCU middle distillates of 147 Mt.
- In the **ambitious case**, CCU products penetrate the entirety of these markets, with an annual demand of 903 Mt.

[45] Ullmann's Encyclopedia of Industrial Chemistry: Formic Acid, 2016

- If the entirety of the **current non-CCU** market for middle distillates were to be replaced with CCU products, then the annual demand for CCU products would be 2900 Mt.

Under the first two assumptions, long-term CCU pathways could avoid 550 Mt and 3 Gt of CO_2 per year respectively in the case where DAC with hydrogen from intermittent renewable electrolysis is used. In the highly unrealistic case that the entire current market for middle distillate hydrocarbons were to be replaced by the CCU route then an avoidance of 11 Gt could be achieved compared to the counterfactual. The associated costs, resource demands and energy required for levels of competitive and ambitious penetration are presented in Figure 25.

Demand for aviation fuel is projected to see continued growth into the long-term, approximately doubling by 2050. If this market growth is accounted for then under the ambitious assumptions a total abatement of 7 Gt per year compared to baseline projections.

Implications of large-scale deployment – energy and resources

Figure 25 summarises the associated resource and energy requirements for these pathways under the competitive and ambitious demand assumptions described above.

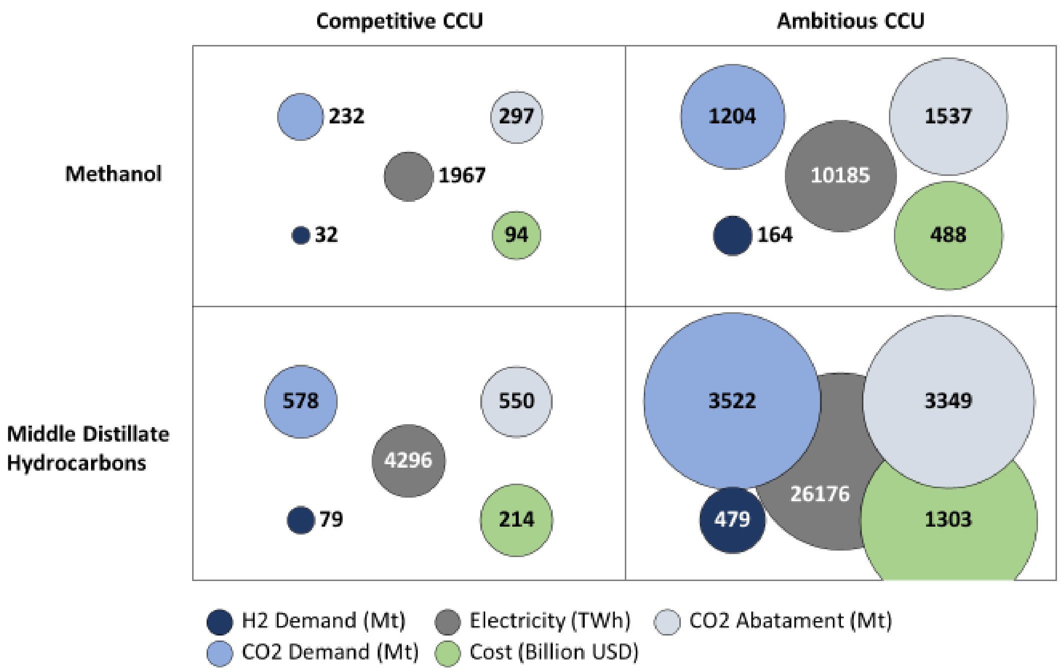


Figure 25: Implications of scaled deployment of CCU pathways. The circles show the costs, resource demands and renewable electricity requirements (including electrolysis and conversion step) for levels of competitive and ambitious penetration of present-day markets. The CCU pathway used is the long-term central CCU pathway comprising DAC with hydrogen from intermittent renewable electrolysis and the counterfactual fossil route.

To place these figures into context, current global hydrogen production totals 70 Mt per year with only 2% of this being from renewable electrolysis[27]; hence the required hydrogen for ambitious CCU deployment is many multiples of current production. In 2018, global electricity generation totaled 27,000 TWh of which 26% came from renewables[29]. Although both global electrolyser capacity and renewable electricity generation capacity is upscaling rapidly, the capacities required for CCU production at this ambitious scale would require dramatic increases. Therefore, large scale deployment of CCU may be limited by the generation of these resources, as well as the infrastructure required to distribute them on such large scale.

8 Actions for enabling CCU hydrogenation pathways (RD&D and policy)

8.1 Technical and RD&D considerations

Lab scale research and pilot-demonstrations are necessary to address technical barriers with conversion steps. Focus areas for research include the development of catalysts that combine efficiency with sustainability, the improvement of knowledge around the reverse water gas shift (RWGS) reaction, and raising the technology readiness level of alternative routes.

- **Catalysts** – Currently the most efficient catalysts for conversion of CO_2 to formic acid require rare and restricted metals, making the pathway expensive and acting as a barrier to production at scale. Improvements in catalyst selectivity and stability could also improve yields and lower energy requirements for all CO_2 hydrogenation routes.
- **RWGS reaction** – Further research is required to improve understanding of the reverse water gas shift reaction which constitutes the first step of middle distillate hydrocarbon synthesis from CO_2. The subsequent F-T step is already commercialized, but the RWGS is not widely deployed at scale and could face engineering challenges.
- **Alternative routes** – The co-electrolysis of H_2O and CO_2 is an alternative route to producing syngas, a required first component of many hydrogenation routes. This route when combined with a waste heat source is expected to produce syngas more efficiently than the current combination of low-temperature PEM electrolysis and RWGS. Advancing this technology further through pilot demonstrations could bring increases in efficiency that reduce production emissions and lower costs.

Technologies need to be efficient and adaptive to accommodate near-term intermittency and emissions of electricity supply. Developments in CCU conversion technologies should focus on accommodating intermittent hydrogen supply (from intermittent electrolysis) and being as efficient as possible to reduce hydrogen demands.

Greater clarity is needed on the life-cycle emissions associated with renewable electricity and pathways for producing hydrogen. The emissions associated with a CCU pathway are highly dependent upon the emission intensity of renewable electricity generation and subsequent hydrogen production. There is limited robust data available on the full life-cycle emissions of these technologies and how life-cycle emissions might change with location or over time with technology developments. Emissions from renewable electricity and green hydrogen generation are often over-looked when discussing CCU pathways.

LCA and TEA studies should follow guidelines to facilitate the comparison and evaluation of new technologies. Differences in input assumptions, choice of counterfactual, accounting methods, and system boundaries can lead to widely different estimates for the emissions and costs associated with identical CCU pathways. To facilitate the comparison of different pathways and the understanding of impacts, authors should follow guidelines when presenting data and include a sufficient level of detail such that different assumptions could be applied. Efforts should also be made to ensure that results are interpreted correctly by non-experts. Existing guidelines for the reporting of LCAs for CO_2 utilisation and CO_2 accounting for CCU include those developed by CO_2 *Sciences* and the *Global* CO_2 *Initiative* - “Guidelines for CO_2 Utilization”[46] – and those published by the IEAGHG – “Greenhouse Gas Accounting Guidelines for CCU” [47].

Establishing the priority pathways for CCU as a mitigation option would help to focus developments on markets where demand will be greatest. In some areas where CCU might be a necessary component for achieving climate targets, either due to there being no practical alternatives or because supply of alternatives could be constrained (e.g. biofuels). Establishing the end-uses that are most-likely to require CCU to meet these targets could help drive CCU developments in these areas.

[46] Zimmermann et al. 2018, Techno-Economic Assessment & Life-Cycle Assessment Guidelines for CO_2 Utilization. [LINK]
[47] IEAGHG 2018, 2018-TR01b – Greenhouse Gas Accounting Guidelines for CCU [LINK]

8.2 Policy considerations

Low existing demands and future demand uncertainty acts as a barrier to commercialisation. The component reaction technologies might be well-understood in some areas, but the current lack of market demand for CCU products has hindered movement towards large-scale demonstrations and subsequent deployment. Placing requirements on the percentage of fuels or chemical feedstocks that must be from sustainable sources is one action that might address this barrier. For example, Norway has set a quota for 0.5% of aviation fuel to be sustainable (e.g. advanced biofuels) in 2020 rising to 30% in 2030[48]. Another action would be to improve the cost-competitiveness of CCU products such that demand is market driven. This could be achieved through a financial support mechanism for CCU or through raising the costs of non-sustainable products, for example via a carbon price.

Regulatory requirements can make market entry difficult for new production routes. In the case of aviation fuel, regulatory approval is required for any new production pathway and requires rigorous testing to demonstrate that the fuel behaves sufficiently similarly to conventional jet fuel. The process is long, costly, and requires large volumes of fuel to be produced. As well as being a barrier to commercialisation, this can lead sustainable fuel producers to favour markets with lower performance requirements such as marine or road fuels. Actions to address this barrier include streamlining the approval process for certain products, setting up a 'Clearing House' to support producers, developing small-scale testing, and expanding the allowable envelope of fuel compositions.[49]

Policies must ensure carbon benefits of CCU are realised but CO_2 is accounted/allocated correctly without double counting. As reduction in emissions and increased sustainability are often dominant drivers for the development of CCU products, it is vital that the products receive correct recognition and associated benefits for these achievements. This is particularly the case for pathways where production is more costly than the counterfactual route and where competitiveness might rely on carbon pricing. One challenge for CCU product manufacturers is a lack of certainty on how policy might perceive utilisation of CO_2 and how any avoided burden from CO_2 supply or responsibilities could be transferred between the capturer, the producer, and the end-user. It is also uncertain whether direct air capture and point source capture will be accounted differently, and whether negative emissions technologies will be able to claim credits for carbon removal.

Global consistency of approaches and integration of policies is required. Commodities are traded globally, with the potential for capturers, producers, and end-users to be distributed across separate countries. Therefore, there should be globally consistent approach to the accounting of CO_2 and allocation of benefits. It is also important for policies to enable integration along the supply chain, for example, policies which allow the transfer of emission credits across borders.

The challenges of CO_2 accounting for CCU are detailed further in the IEAGHG's 2018 'Greenhouse Gas Emissions Accounting for Carbon Dioxide Capture and Utilisation (CCU) Technologies' reports[50,51]. The parallel IEAGHG study on "CO_2 as a Feedstock" includes a broader discussion on enabling policy mechanisms for CCU.

8.3 Other considerations

CCU pathways will benefit from advances in CO_2 capture and low-emission hydrogen generation. CCU pathways can benefit from the increased scale of deployment, lower costs, and increased efficiency of CO_2 capture and hydrogen generation technologies. Actions could incentivise RD&D and scaled deployment activities within these areas including point source capture, direct air capture, and low-emission hydrogen

[48] https://www.regjeringen.no/en/aktuelt/mer-avansert-biodrivstoff-i-luftfarten/id2643700/

[49] EASA 2019, Sustainable Aviation Fuel 'Facilitation Initiative'
[50] 2018-TR01a – Characterizing CCU Technologies, policy support, regulation and emissions accounting
[51] 2018-TR01b – Greenhouse Gas Accounting Guidelines for CCU

production. The RD&D should also be extended to the transport and storage of hydrogen and CO_2 to facilitate the supply chain.

CCU could benefit from shared infrastructure with CCS and industrial clusters. Capture and transport of CO_2 is a component of both CCU and CCS. The sharing of infrastructure components with large scale CCS projects (for example within clusters) could facilitate smaller scale CCU production, which otherwise might not be able to justify the high CAPEX of capture and transport infrastructure.

Large scale renewable electricity generation is necessary for green-hydrogen hydrogenation pathways. Increasing the availability of low cost and low emission electricity for green hydrogen production will enable cheaper and lower emission CCU commodities. This can be achieved through large-scale deployment of renewables, with potential for co-location with CCU facilities. CCU itself can also facilitate the deployment of renewables through the 'Power-to-X' concept, allowing temporary storage of excess renewable energy via conversion to stable energy vectors; the economics of this option should be explored through detailed system analysis.

Consumer perceptions could drive demand in niche markets. In some markets, the branding of products as low emission or as having been produced 'from the air' via direct air capture could be sufficient to overcome the high cost-premiums of CCU routes. This is seen for high value products such as AirCo's Air Vodka, which is marketed as "carbon-negative with indisputable impact". Consumers may also be individually be motivated to avoid higher emission products due to increased awareness of global warming. Therefore, actions to increase public awareness both of the production emissions associated with commodities and the advantages of CCU production routes could help facilitate CCU deployment by increasing demand.

9 Conclusions

Impact of CCU routes on cost and emissions of commodities

The choice of feedstocks is key for obtaining benefits from CCU production routes. Hydrogenation routes require a supply of hydrogen and CO_2, and the origins of these feedstocks impact the overall cost and emissions of CCU pathways. The key variables are whether CO_2 is captured from a point source (of fossil or biogenic origin) or by direct air capture, whether hydrogen is produced via electrolysis or via fossil routes, and whether electricity from electrolysis is from the grid or from dedicated renewables.

Production of commodities via CCU routes is more expensive than fossil routes, but the cost-premium is expected to decrease in the long term. For the commodities considered, all realistic combinations of feedstocks result in higher costs than the counterfactual route under both near- and long-term assumptions. In the near-term, CCU commodities were found to be at least twice the cost of their fossil counterparts. In the long-term, cost premiums decrease significantly due to reductions in the cost of green hydrogen (driven by lower electricity costs, efficiency improvements, and electrolyser CAPEX reductions) and reductions in CO_2 capture costs.

Economic competitiveness of CCU routes is reliant on a 'cost of emission' being applied. The introduction of a sufficiently high 'cost of emissions' (e.g. a carbon price) can enable low-emission CCU commodities to become cost competitive with their fossil counterparts, due to disproportionate commodity price increases. For the optimal pathways considered, cost parity could be achieved in the long-term by implementing a 'cost of emissions' between USD 120-225 per tonne of CO_2. Under an ambitious 'cost of emissions' of USD 300 per tonne of CO_2, most electrolysis pathways powered by dedicated renewables could be competitive under long-term assumptions. However, it should be noted that CCU routes may well receive policy support beyond a carbon price, reducing the carbon price required for cost parity. Equally, many regions have direct or indirect fossil fuel subsidies which may be removed in the long-term, increasing the cost of the conventional commodity production routes.

CCU can offer a lower emission commodity production pathway, but this is not guaranteed. CCU routes can lead to lower overall emissions than fossil routes provided a low-emission electricity source is used for green hydrogen production or reforming emissions are abated for fossil hydrogen. However, using grid electricity (representative of current European grid mixes) for electrolysis is expected to result in CCU methanol and middle distillate hydrocarbon routes having greater emissions than their fossil counterparts. The same is true for the use of unabated SMR for hydrogen production. All formic acid CCU pathways are seen to have lower emissions than their fossil counterpart.

The method of accounting utilised CO_2 has important consequences. The extent to which CCU commodities can claim an avoided burden for utilising CO_2 impacts the amount of CO_2 avoidance that can be credited to the CCU commodity. This in turn has an impact on commodity costs due to the 'cost of emissions' applied. For routes with higher production emissions than their counterfactual, CCU commodities can only claim to have lower emissions than the counterfactual commodities if they are able to account the utilised CO_2 as offsetting some of their production or end-of-life emissions.

Key factors influencing costs and emissions

Hydrogen production is the dominant factor influencing CCU costs and emissions. Hydrogen is the most significant cost and emission component for both methanol and hydrocarbon CCU production routes. Hydrogen is also a significant factor for formic acid, however costs here are dominated by catalyst costs. Because the cost and emission intensity of hydrogen varies significantly across production options, the choice of hydrogen production route is the most dominant factor influencing CCU commodity costs and emissions.

Electricity costs and emissions are key for green hydrogen, whereas capture rates and upstream emissions are key for blue hydrogen. The cost of electricity is the main factor determining the cost of green hydrogen production, and this cost may vary significantly across regions and with different technologies. Under best-case conditions, an electricity price of USD 20 / MWh and 15 / MWh is required respectively for CCU methanol and CCU hydrocarbons to be economically competitive. Green hydrogen emissions result primarily from electricity generation, with a low carbon grid or dedicated renewables being necessary for significant climate benefits. CO_2 capture rates and upstream natural gas emissions are key factors determining emissions for blue hydrogen production.

Choice of CO_2 source has limited impact on costs in the near-term, however emissions may be perceived or accounted differently, and future availabilities may differ. The large unit cost difference (USD / t CO_2) between point source capture and direct air capture becomes less significant when placed in the context of full production costs. This is particularly true in the near-term where hydrogen costs are a much more influential factor. Therefore, the optimal CO_2 source for CCU routes may instead be selected based on perceptions, accounting, or availability. Utilisation of recently atmospheric CO_2, through DAC or biogenic sources, is likely to be perceived more favorably than CO_2 from fossil sources as it conforms to circular principles. Depending on policy perceptions, there may also be carbon accounting differences for these CO_2 sources. CO_2 from points sources is captured on the largest scale today and has greater availability in the short-term, although some industries may choose to abate their emissions in other ways in the longer term. DAC is currently only deployed at small scale, but is expected to grow significantly in the longer term as climate targets become more pressing.

The competitiveness of CCU routes could be improved with further RD&D and demonstration projects. The cost of formic acid from CCU routes is dominated by catalyst costs for the conversion step. Cost reductions could be achieved through lab research to identify a sufficiently selective catalyst that uses lower cost catalyst materials. Improvements in the efficiencies of electrolysers and developments in CO_2 capture technologies would also lower CCU costs and increase their competitiveness. Pilot and larger scale demonstration projects could be used to optimise processes and realise costs at scale.

Achieving large scale abatement: motivations and barriers

Avoiding 1 Gt of today's CO_2 emissions requires high levels of market penetration, but new markets might become available. If CCU products were to capture the full extent of their future possible market segments today, then CCU methanol and middle distillate hydrocarbons have the potential to abate over 1 Gt of today's emissions. This would involve CCU methanol capturing the entirety of the current methanol market, and then expanding into the heavy-duty trucks market through conversion to DME fuel and expansion into the plastics market through conversion to polyolefins. For middle distillate hydrocarbons, this would entail capturing the entirety of today's aviation fuels market as well as fuels for heavy-duty trucks. Formic acid does not have the potential to reach this 1 Gt target as even if the CCU pathway were to penetrate the entire formic acid market, the abatement achievable is limited to approximately 2 Mt due to the low market demand.

Energy demands may become a barrier limiting large scale deployment. CCU hydrogenation routes are energy intensive, particularly green hydrogen pathways which require large amounts of renewable electricity for electrolysis. Deployment of CCU at a competitive market scale would require significant increases in both hydrogen production capacity and low carbon electricity generation capacity, alongside upgrades to the distribution and storage infrastructure.

Note that the following additional remarks arise from a thought-piece included below as an annex to this report. They are not direct outcomes from the main analysis.

Emission reductions are not the only driver for CCU, there are various other benefits to avoiding a fossil supply chain. The CCU routes considered provide an alternative to routes that rely on fossil feedstocks. They can avoid the price volatility and supply insecurities associated with these feedstocks, as well as the ecological impacts caused by fossil extraction and supply. Fossil sources are remote and geographically concentrated, requiring transmission of the feedstock to the point of use. CCU offers the benefit of distributed production, as CO_2 can be sourced near the point of use. Fossil feedstocks may also be politically or socially unacceptable in a net-zero world.

CCU commodities can directly replace, or ‘drop-in’, to current commodity end-uses. Once produced, CCU commodities are almost identical to conventional products, so they can be easily integrated with existing supply chains and drop-in to existing end-uses. Compared to the substitution of an end-use with a different low-emission product, CCU may have benefits such as job/asset retention or quicker scale-up potential.

CCU products will face competition from alternative low-emission products. There are likely to be alternative low-emission solutions for products/services that will compete with CCU as abatement technologies. For example, use of CCU transport fuels must compete with biofuels, hydrogen fuel cell vehicles, and electric vehicles. Due to the high cost-premium of CCU products, CCU is more likely to succeed in areas where there are no practical low-carbon alternatives, where supply of low-carbon alternatives is limited, or where CCU can offer a superior product/service.

Benefits of CCU will vary with perspective: motivations will differ between emitter, capturer, commodity manufacturer, and end-user. Each party that may be involved with CCU has a different challenge which CCU could address and different alternative solutions. For an emitter, CCU may be an alternative to fuel-switching, CCS, or continued emission. For a commodity manufacturer, CCU may be a solution to volatile fossil feedstocks, to the cost of emissions, or to issues with public acceptability. For an end-user, CCU may be one out of several low-emission solutions to their service. The challenges, benefits, and potential motivations for CCU will therefore differ with perspective.

Conditions for success of CCU include availability of low-cost renewable electricity, access to low carbon hydrogen, high emissions costs, limited CO_2 storage and consumer pressure. The CCU pathway must be designed carefully to ensure lower life-cycle emissions than the counterfactual, alongside sustainable and readily available inputs. Co-location of assets (e.g. DAC, hydrogen production and the CCU facility) may reduce costs, particularly in regions with high potential for renewable electricity. CCU will provide an attractive solution in regions with limited CO_2 storage, or with cost or public acceptance challenges for CCS. End-uses which rely on carbon-based commodities (e.g. aviation) and the associated supply chains are key, but where the financial or consumer pressure to use clear alternative.

*This study was developed in parallel with ‘**CO_2 as a Feedstock**’, which provides a broader perspective of CCU routes and their advantages and disadvantages. The parallel report also highlights existing developments, drivers, barriers, enabling factors and regional variations for a wide range of CO_2 utilisation opportunities. Many readers may find it useful to read the studies together to provide complementary information and perspectives.*

Appendix

This appendix contains the input data assumptions for calculations in the study.

Electricity		Cost $ / kWh	Source	Emissions kg CO_2 / kWh	Source
Near-Term	Wind	0.053	IRENA Power 2019	0.016	reinvestproject.eu
	Solar PV	0.068		0.051	
	Grid - Low Carbon	0.098	IEA Future of Hydrogen - Assumptions Annex	0.051	Estimate - Europa, France
	Grid - Sustainable			0.237	IEA 2019 WEO Annex A
	Grid - Stated Policies			0.370	
Long-Term	Wind	0.023	Irena Hydrogen 2019	0.016	reinvestproject.eu
	Solar PV	0.032	IRENA Solar PV 2019 (average)	0.025	
	Grid - Low Carbon	0.123	IEA Future of Hydrogen - Assumptions Annex	0.051	Estimate - Europa, France
	Grid - Sustainable			0.081	IEA 2019 WEO Annex A
	Grid - Stated Policies			0.308	

CO_2		Cost $ / t CO_2	Source	Emissions t CO_2 / t CO_2	Source
Near-Term	PSC - Bio-ethanol	14	GCCSI Global cost of CCS 2017	0.05	RSC 2020, The carbon footprint of the carbon feedstock
	PSC - Iron & Steel	66		0.17	
	PSC - Cement	113		0.37	
	DAC -Aqueous sorbent	232	Joule 2018 DAC - Carbon Engineering	0.043	Lui et al. 2020, A life cycle assessment of greenhouse gas emissions from direct air capture and Fischer–Tropsch fuel production
	DAC - Solid sorbent	600	GCCSI 2019 Global Status CCS - Climeworks		
Long-Term	PSC - Bio-ethanol	13	GCCSI Global cost of CCS 2017	0.015	RSC 2020, The carbon footprint of the carbon feedstock
	PSC - Iron & Steel	54			
	PSC - Cement	92			
	DAC -Aqueous sorbent	170	Joule 2018 DAC - Carbon Engineering	0.043	Lui et al. 2020, A life cycle assessment of greenhouse gas emissions from direct air capture and Fischer–Tropsch fuel production
	DAC - Solid sorbent	100	GCCSI 2019 Global Status CCS - Climeworks		

Hydrogen - excluding electricity for electrolysis*		Cost $ / t H_2	Source	Emissions t CO_2 / t H_2	Source
Near-Term	ATR + CCS	2159	Estimates based on broader data points (see below)	3.33	Estimates based on broader data points (see below)
	Coal Gasification + CCS	3577		5.70	
	SMR (no CCS)	2226		12.92	
	Electrolysis - Grid	844*		0.00	
	Electrolysis - Intermittent	1686*		0.00	
Long-Term	ATR + CCS	2050		1.62	
	Coal Gasification + CCS	3209		5.70	
	SMR (no CCS)	2122		11.42	
	Electrolysis - Grid	366*		0.00	
	Electrolysis - Intermittent	731*		0	

*Electrolysis data is combined with electricity data (above) assuming an efficiency (HHV) of 65% 2020 and 75% 2050. The cost of hydrogen from electrolysis shown excludes the cost of electricity, which is applied separately.

Gas Transport - Regional Transport (200km)

	Cost	Reference
CO_2 Transport ($ / t CO_2)	5	Element Energy 2018, Shipping CO_2 - UK Cost Estimation Study
H_2 Transport ($ / t H_2)	24	Cadent 2017, Liverpool-Manchester Hydrogen Cluster Report

Basis for hydrogen estimates

Fuel	Natural Gas	Coal
Cost ($ / kWh)	0.027	0.004
Upstream Emissions (kgCO_2/kWh)*	0.060	0.052
Carbon Intensity (kgCO_2/kWh)	0.198	0.330

*50% reduction in natural gas upstream emissions applied for long-term estimates

	SMR		ATR + CCS		Coal Gasification + CCS	Electrolysis	
	Near-term	Long-term	Near-term	Long-term		Near-term	Long-term
Efficiency (% HHV)	78	78	82	82	58	65	75
CAPEX ($ / KW H_2)	663	452	1115	895	2780	940	408
Annual OPEX ($/kW/yr)	32	32	61	61	139	14	6
Variable OPEX ($/kWh)	0.00016	0.00016	0.00016	0.00016			
Lifetime (yrs)	25	25	25	25	25	25	25
Availability (%)	90	90	90	90	90	57 / 29*	57 / 29*
Capture Rate (%)	0	0	95	98	90		

Additional 100% cost of capex and 50% civils factor applied (% of CAPEX)
*Grid / Intermittent

References:
Solid and gaseous bioenergy pathways: input values and GHG emissions, EC JRC, 2015
BEIS 2019, GHG Conversion Factors
IEA 2019, Future of Hydrogen
ENA 2020, Gas Goes Green - Hydrogen: Cost to customer
CCC 2018, Hydrogen in a low carbon economy
Exchange value for conversions: £0.80/$ (2019)

Conversion of CO_2 and Hydrogen To Products

Values per tonne of product

	Methanol	Formic Acid	Hydrocarbons
CAPEX* ($)	27	20	82
Long-term (% reduction)	0%	18%	32%
OPEX* ($)	41	1380	24
Electricity Demand** (kWh)	1470	296	0
Hydrogen Demand (t)	0.20	0.07	0.53
CO_2 Demand (t)	1.46	0.99	3.90
Emissions* (t CO_2e)	0.09	0.00	0.00

*Excludes data for the inputs of hydrogen, CO_2 and electricity
**For the conversion step only. Excludes electricity for hydrogen production and CO_2 capture.

References
Ecoinvent datasheet for formic acid production

Perez-Fortes 2016, Methanol synthesis using captured CO_2 as raw material: Techno-economic and environmental assessment
Umwelt Bundesamt 2016, Power to liquids: Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.
IEA 2019, Future of Hydrogen
IEA 2019, Putting CO_2 To Use
Von der Assen et al 2016, Selecting CO_2 Sources for CO_2 Utilization by Environmental-Merit-Order Curves
DECHEMA 2017, Low carbon energy and feedstock for the European chemical industry

Counterfactual Data		
	Value (/ t)	**Source**
Methanol		
Cost ($)	276	Methanex data - Europe June 2020
Cradle-to-Gate Emissions (t CO_2e)	0.85	DECHEMA 2017
Gate-to-Grave Emissions* (t CO_2e)	1.56	Breiki et Bicer 2021
Formic Acid		
Cost ($)	786	ceicdata.com - Europe, 2014
Cradle-to-Gate Emissions (t CO_2e)	2.50	Estimate based on Ecoinvent datasheet
Gate-to-Grave Emissions* (t CO_2e)	0.99	Estimate
Hydrocarbons (jet fuel)		
Cost ($)	625	IATA Jetfuel Price Monitor - Global Average
Cradle-to-Gate Emissions (t CO_2e)	0.66	BEIS 2019, GHG Conversion Factors
Gate-to-Grave Emissions* (t CO_2e)	3.84	BEIS 2019, GHG Conversion Factors

*Example included for illustrative purposes. Used for both CCU and counterfactual.

Annex - motivations for adopting CCU

This annex provides a thought-piece on the broader motivations for CO_2 adoption, highlighting reasons why differing parties may be interested in CCU.

CCU: one of many pathways

As countries and industries work towards lowering emissions in line with the Paris Agreement and meeting climate targets, decisions will need to be made on how to decarbonise point sources and end-products/services. A range of potential options are illustrated in Figure 26 and described below.

For industrial point sources, decarbonisation options include:

- Use of **alternative technologies to eliminate emissions**, for example changing the industrial process or switching to cleaner energy sources such as electricity or hydrogen **(fuel switching, FS)**.
- **Capturing and permanently sequestering CO_2 emissions (CCS)**. This could be by directly capturing emissions at the point source, or through carbon-offsetting activities such as paying for DA-CCS elsewhere.
- **Capturing and utilising CO_2 (CCU)**. The captured CO_2 might be utilised by the point-source itself or it might be sold as a feedstock.

For an end-product or service, decarbonisation options include:

- Using an **alternative low-carbon commodity** to deliver the same product or service, for example, electric vehicles for transport **(product swap)**
- Producing the **same commodity via a low-emission pathway**. This might include bio-based production routes (e.g. bio-ethanol) or using captured CO_2 **(CCU)** as an alternative to the fossil feedstock.
- Carbon-offsetting activities to **remove end-use emissions** from the atmosphere, for example paying for **DACCS**.

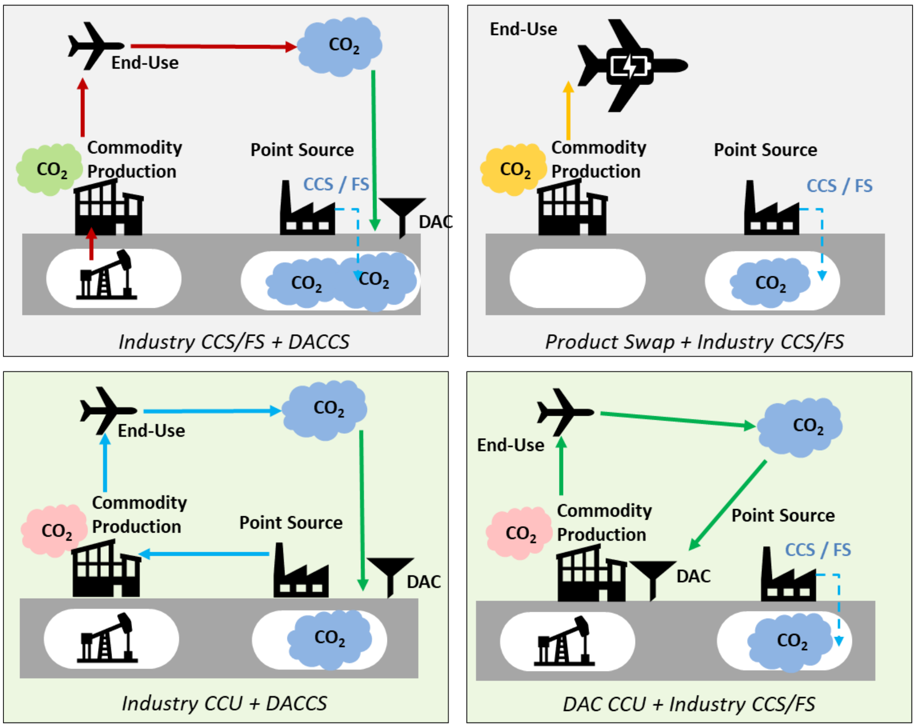


Figure 26: Abating both point source and product end-of-life emissions: illustration of the combinations of options available to allow abatement of both point source and product end-of-life emissions.

Factors influencing CCU adoption

Numerous factors influence the circumstances under which CCU pathways may be preferable to pathways that do not include CCU. These influencing factors may vary with region, end-use market, over time and with CO_2 source. Potential motivations for adopting CCU will be different depending upon the perspective from which the routes are viewed, whether that be from the perspective of a point source, the perspective of a commodity manufacturer, the perspective of an end-user, or the perspective of policy makers. Key factors to consider when determining whether CCU might be a successful abatement pathway are described below. These considerations are categorised into: source of CO_2; CO_2 transport and storage infrastructure; fossil feedstock; resources; CCU commodity production; end-use (commodity/service); and other benefits.

Supply of CO_2

The below factors are considerations for a potential CCU production facility needing to receive a supply of CO_2 and also for a CO_2 capturer (such as an emitter with carbon capture) determining whether CCU could be a suitable destination for its captured CO_2.

- **Availability of CO_2 supply:** Production of CCU commodities requires a reliable supply of CO_2 at required purity levels. In a net-zero world, point sources may be limited as industries reduce emissions via fuel switching or alternative technologies. DAC-CCU is reliant on the deployment of DAC technology, which is currently at the demonstration stage.
- **Location of CO_2 capture:** The proximity of the CO_2 source to potential utilisation facilities compared to its proximity to storage infrastructure may influence whether CCU or CCS is preferable.
- **Purity of CO_2 supply:** While CCS requires a relatively pure CO_2 stream, the purity and pressure required for CCU can vary, with some routes able to use flue-gases directly. This may favour CCU if capture costs or associated capture risks are reduced.

A motivating factor for CCU might be having an available CO_2 source located near to a potential utilisation facility which can provide CO_2 at the required purity for an acceptable cost.

CO_2 transport and storage (T&S) infrastructure

The below factors are considerations for a CO_2 capturer determining whether CCU could be a suitable destination for its captured CO_2. They are also considerations for those looking at the national or regional infrastructure and system integration aspects such as governments, regions or industrial clusters.

- **Availability of CO_2 T&S:** CCS requires access to permanent storage sites with associated transport infrastructure. A point source may not have access to a storage site, either due to location or lack of infrastructure development.
- **Capacity for CO_2 storage:** Continued use of fossil-based fuels requires increased capacity of CO_2 storage (or negative emissions technologies) for a net-zero world compared to re-using existing CO_2 sources. The ability of storage sites to hold additional CO_2 from continued fossil extraction should be considered.
- **Relative costs and risks** of CCS compared to CCU. In terms of cross-chain integration and liabilities.
- **Social / political acceptance:** The perception of CCS within a region, market, or organization may influence whether CCS is considered an acceptable abatement option.

A motivating factor for CCU might be an environment where CCS is expensive or unavailable, or where CCS is considered less politically or socially acceptable.

Fossil feedstock

The below factors are considerations for a manufacturer considering CCU as an alternative route to conventional production or for a procurer of the commodity. They are also considerations for regions and governments considering security of supply and acceptability of fossil feedstocks.

- **Volatility of feedstock supply:** Prices of fossil feedstocks are volatile and future availability is uncertain. Countries and/or industries may want to reduce their dependency on fossil imports. CCU offers an alternative source of carbon.
- **Environmental impact of feedstocks:** Fossil fuel extraction and shipping comes with environmental and ecological impacts including fugitive emissions and risks to natural habitats. These impacts may be difficult to mitigate. CCU offers an alternative carbon source.
- **Acceptance of feedstocks:** Use of fossil feedstocks may be politically or socially unacceptable in a net-zero world.
- **Distribution of feedstock supply:** Fossil sources are remote and geographically concentrated, requiring transmission of the feedstock to the point of use. CCU offers the benefit of distributed production, as CO_2 can be sourced near the point of use.

A motivating factor for CCU might be that the non-CCU production route for a commodity relies heavily on fossil feedstocks and may be significantly impacted by price volatilities or supply uncertainties, or where manufacturers may be under pressure from consumers to reduce fossil consumption.

Resources

The below factors are considerations for a potential CCU production facility that will need hydrogen for commodity production. They are also considerations for those looking at the bigger-picture or system integration aspects such as governments, regions or industrial clusters.

- **Electricity:** Some CCU routes have a significant demand for renewable electricity (e.g. to produce green hydrogen or operate DAC technology). The availability and cost of this resource will vary with location. In some areas it may be possible to utilize excess renewable electricity.
- **Hydrogen:** Hydrogenation routes require a reliable supply of blue or green hydrogen. Developments in hydrogen production technologies and transport infrastructure, as well as proximity of the utilisation plant to the hydrogen production facility may influence the feasibility of some CCU routes.
- **Water:** Green hydrogen production requires a fresh water supply. DAC and utilisation technologies may also require water for heating/cooling purposes. Scarcity of water could therefore be a barrier to CCU in some regions.

An enabling factor for CCU would be the availability of low-cost renewable electricity and hydrogen production, allowing costs for CCU commodities to decrease. A barrier could be the scarcity of fresh water in some regions.

CCU commodity production

The below factors are considerations for manufacturers or procurers considering CCU as an alternative commodity production route, as well as CCU developers aiming to commercialise the technologies. They are also considerations for those looking at the wider environmental and social implications.

- **Integration/parallelism:** CCU routes that use existing production techniques or can be easily integrated into existing supply chains may have benefits such as job/asset retention or quicker scale-up potential. This is a potential advantage of CCU compared to end-use substitution (e.g. synthetic fuels compared to electric vehicles).
- **Sustainable credentials:** Whether the CCU route is more sustainable compared to the counterfactual fossil route is an important consideration. This includes difference in GHG emissions and resource depletion compared to the counterfactual, as well as other environmental and social impacts.
- **Price premium:** The price premium of a CCU commodity compared to the counterfactual could be a barrier for CCU commodities used for low value-added end-uses (where the commodity price is a significant factor of the end-use market price).
- **Catalysts:** CCU routes may require expensive, scarce or restricted catalyst materials.

A motivating factor for CCU may be a desire to re-use existing infrastructure and distribution networks. Enabling conditions would be that the CCU pathway is sustainable, low cost, and uses readily available catalysts.

End-use (final product/service)

These factors are additional considerations specific to procurers or end-users of the existing commodities. They impact market demand for CCU products and are therefore also considerations for technology developers or governments considering routes to decarbonisation.

- **Alternative low-carbon solutions:** In many cases there may be alternative low-carbon solutions for products/services that procurers or end-users could swap to if they aim to decarbonize. The strengths and weaknesses of CCU products should be compared to alternative options, for example electric vehicles or biofuels.
- **Comparison to conventional products:** Products produced via the CCU route may have strengths and weaknesses compared to the conventional product. For example, they could have superior performance or environmental qualities but with greater costs.

A motivating factor for CCU might be the lack of alternative abatement options for a particular end-use, or superior product quality of a CCU product compared to alternatives.

Other benefits

Potential co-benefits of CCU may be considerations for developers of CCU technologies or for governments, regions or clusters considering implementing CCU. For example, the Power-to-X concept of using CCU as a means to make use of surplus electricity and potentially facilitate scale-up of renewables. Other considerations may relate to environmental, social or economic factors. For example, continued use of existing assets, job creation in an area, or circular economy principles.

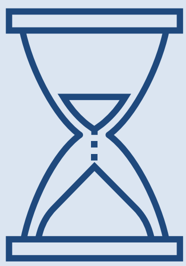
The influencing factors above may vary with region, end-use market, or over time:

Regional Variations

- Distribution of industry (point sources and utilisation facilities)
- Access to CO_2 storage
- Security of fossil supply
- Acceptance of CCS and of continued fossil fuel extraction
- Market demand and market price for commodities
- Availability and cost of resources
- Incentives for low-carbon products or specific technologies

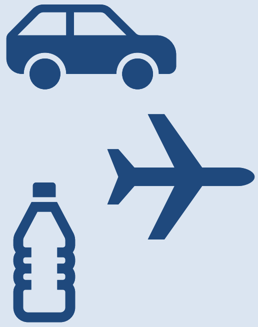
Temporal Variations

- Distribution of industry (point sources and utilisation facilities)
- Access to CO_2 storage
- Security of fossil supply
- Acceptance of CCS and of continued fossil fuel extraction
- Market demand and market price for commodities
- Availability and cost of resources
- Incentives for low-carbon products or specific technologies



End-Use Variations

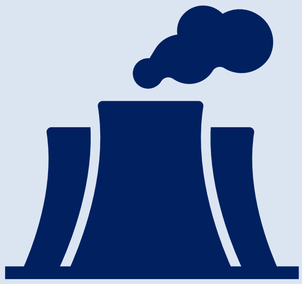
- Existing reliance on fossil feedstock and ability to absorb price volatility
- Emissions avoidance achievable (life-cycle emissions)
- Incentives for low-carbon products (regulatory requirements, subsidies, carbon tax, industry targets/motivation, market demand)
- Existence of competitive low-carbon solutions
- Integration with existing manufacturing and distribution networks
- Additional benefits (e.g. improved performance or reduced other environmental impacts)



Potential motivations for adopting CCU will be different depending upon the perspective from which the routes are viewed. Factors that might drive the adoption of CCU are highlighted below from a variety of perspectives. Note that the aim is to **highlight circumstances under which CCU may be favourable**. These drivers may occur under niche-circumstances and there will also be many cases where these factors are not applicable and where CCU is less favourable (e.g. where CCS or alternative low carbon solutions are favoured).

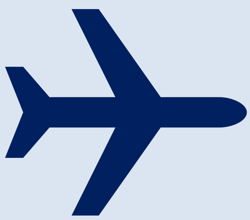
Point source perspective – comparison to CCS

- **CCU may be a more immediate solution compared to CCS.** CCU can be deployed at a small scale with a low initial investment and conventional business models. In comparison, CCS requires the existence of CO_2 transport & storage infrastructure (currently limited), high initial investment and new types of business models.
- **CCU could be located onsite.** CCU can be integrated within existing point source sites whereas for CCS the CO_2 must be transported to a storage facility. With CCU it is possible for all aspects (CO_2 source, renewable electricity, hydrogen generation) to be located onsite.
- **CCU can give value to CO_2.** The sale of CO_2 for use may provide a revenue stream for the capturer, as exemplified by EOR uses of CO_2. In comparison, storage of CO_2 comes at an additional cost, with business case drivers reliant on an imposed cost of carbon or alternative drivers.



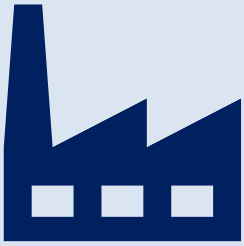
End-user perspective – comparison to alternative low carbon products

- **CCU products directly replace their counterpart.** This allows utilisation of the same supply chain and distribution infrastructure, with associated benefits of asset and job retention, and an easier scale-up/roll-out phase.
- **CCU may be the only practical alternative.** If fossil sources are to be avoided in a net-zero world, then utilising CO_2 may be the only option for products requiring carbon as a building block (e.g. polymers) or where carbon offers properties that can't currently be achieved through low-carbon alternatives (e.g. aviation fuels).



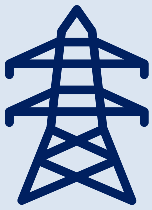
Manufacturer perspective – Comparison to counterfactual (with DACCS)

- **CCU could offer additional environmental benefits.** CCU routes avoid the environmental, ethical and ecological impacts associated with fossil extraction. Products from CCU may offer environmental benefits on use (e.g. synthetic fuels burning cleaner and being less polluting).
- **CCU could have economic incentives.** Under specific conditions such as very cheap feedstock costs or electricity, CCU routes could have lower production costs than conventional routes. Furthermore, imposed 'costs of emissions' could provide an economic driver. In a system where end-use emissions must be abated, 'offsetting' end-of-life emissions via CO_2 utilisation may have advantages over paying for offsets elsewhere.
- **CCU may allow for distributed production.** CCU has flexibility in deployment location. This could allow synthetic crude to be produced where it is needed, as opposed to the geographical concentration of fossil crude which then requires transport to the point of use.
- **CCU may offer greater security of supply.** Fossil feedstocks are subject to volatile prices, uncertainty in supply, and political interventions such as tariffs on imports.



Wider system perspectives

- **Power-to-X:** CCU could be used to store excess renewable electricity or convert electricity to alternative energy vectors.
- CCU may have additional driving factors associated with social, environmental or system-integration aspects. For example, motivations could relate to job creation, asset re-use or retention, circular economy principles, or wider environmental factors.



A broader perspective on CCU is the focus of the parallel study "CO_2 as a Feedstock". The parallel report highlights the strengths and weaknesses of a range of CCU opportunities as well as existing developments, drivers, barriers, enabling factors, co-benefits and regional variations.

Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

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