The Sixth Carbon Budget

Fuel supply

This document contains a summary of content for the Fuel supply sector from the CCC's Sixth Carbon Budget Advice, Methodology and Policy reports.

Introduction

The Committee is advising that the UK set its Sixth Carbon Budget (i.e. the legal limit for UK net emissions of greenhouse gases over the years 2033-37) to require a reduction in UK emissions of 78% by 2035 relative to 1990, a 63% reduction from 2019. This will be a world-leading commitment, placing the UK decisively on the path to Net Zero by 2050 at the latest, with a trajectory that is consistent with the Paris Agreement.

Our advice on the Sixth Carbon Budget, including emissions pathways, details on our analytical approach, and policy recommendations for the Fuel supply sector is presented across three CCC reports, an accompanying dataset, and supporting evidence.

- **An Advice report**: *The Sixth Carbon Budget – The UK's path to Net Zero*, setting out our recommendations on the Sixth Carbon Budget (2033-37) and the UK's Nationally Determined Contribution (NDC) under the Paris Agreement. This report also presents the overall emissions pathways for the UK and the Devolved Administrations and for each sector of emissions, as well as analysis of the costs, benefits and wider impacts of our recommended pathway, and considerations relating to climate science and international progress towards the Paris Agreement. Section 1 of Chapter 2 contains an overview of the emissions pathways for the Fuel supply sector.
- **A Methodology Report:** *The Sixth Carbon Budget – Methodology Report*, setting out the approach and assumptions used to inform our advice. Chapter 1 of this report contains a detailed overview of how we conducted our analysis for the Fuel supply sector.
- **A Policy Report:** *Policies for the Sixth Carbon Budget and Net zero*, setting out the changes to policy that could drive the changes necessary particularly over the 2020s. Chapter 3 of this report contains our policy recommendations for the Fuel supply sector.
- **A dataset** for the Sixth Carbon Budget scenarios, which sets out more details and data on the pathways than can be included in this report.
- **Supporting evidence** including our public Call for Evidence, 10 new research projects, three expert advisory groups, and deep dives into the roles of local authorities and businesses.

All outputs are published on our website (www.theccc.org.uk).

For ease, the relevant sections from the three reports for each sector (covering pathways, method and policy advice) are collated into self-standing documents for each sector. A full dataset including key charts is also available alongside this document. This is the self-standing document for the Fuel supply sector. It is set out in three sections:

1) The approach to the Sixth Carbon Budget analysis for the Fuel supply sector
2) Emissions pathways for the Fuel supply sector
3) Policy recommendations for the Fuel supply sector

Chapter 1

The approach to the Sixth Carbon Budget analysis for the Fuel supply sector

The following sections are taken directly from Chapter 6 of the CCC's Methodology Report for the Sixth Carbon Budget.[1]

Introduction and key messages

This chapter sets out the method for the fuel supply sector's Sixth Carbon Budget pathways. The scenario results of our costed pathways are set out in the accompanying *Advice report*. Policy implications are set out in the accompanying *Policy report*.

For ease, these sections covering pathways, method and policy advice for the fuel supply sector are collated in *The Sixth Carbon Budget – Fuel Supply*. A full dataset including key charts is also available alongside this document.

The key messages from this chapter are:

- **Background.** Existing emissions in the Fuel Supply sector come largely from fossil fuel supply. These are expected to reduce over time, as North Sea oil and gas production declines and as demand for fossil fuels declines across the energy system, with knock-on impacts for output of refineries.
- **Options for reducing emissions.**
  - There are opportunities to reduce existing fossil fuel supply emissions, through measures to improve efficiency, electrify offshore platforms, apply carbon capture and storage (CCS) and reduce venting, flaring and leakage of methane.
  - Production of low-carbon hydrogen and bioenergy play roles in displacing emissions from fossil fuel combustion elsewhere in the economy. Hydrogen can be produced in the UK in a range of low-carbon ways, either from electrolysis or with CCS applied to fossil gas or biomass. A variety of routes from biomass to fuels exist (including biojet, biodiesel, bio-heating fuels and biomethane), many achieving negative emissions with the use of CCS (see Chapter 12).
- **Analytical approach.**
  - Opportunities to reduce emissions from fossil fuel supply are largely covered by the modelling by Element Energy set out in Chapter 4, with some further inclusion of information from the Oil and Gas Authority on opportunities to electrify offshore oil and gas platforms.
  - The low-carbon hydrogen supply mix varies across scenarios, according to the level of electrolytic production (determined in the power sector modelling – see Chapter 6) and allocation of biomass to hydrogen supply, as well as the level of demand. Hydrogen production from fossil gas with CCS is assumed to fill most of the remaining supply gap, with a smaller role for imported hydrogen.
  - Bioenergy and waste supply estimates have been updated to align with latest Land use, Agriculture and Waste sector analysis. Resources are allocated to end-use sectors starting from known 2018 positions, transitioning to best use (maximal GHG savings) by 2050.

- Our analysis of the best uses of bioenergy has been updated and still supports the need for bioenergy to maximise sequestered CO_2 and displace high-carbon fossil fuels. As with wastes, the availability of CCS causes strong convergence between all routes in terms of GHG abatement.

- **Uncertainty.**
  - Uncertainty in the low-carbon hydrogen supply mix is reflected in considerable variation across our scenarios. The role for electrolysis depends on developments in the power system and use of biomass with CCS on developments in gasification technology. The contribution from fossil gas with CCS depends on achieving sufficiently low lifecycle emissions.
  - Cost competitiveness of domestic biomass production vs biomass imports and developments in the global bioenergy market remain key uncertainties. Our biomass import dependency in the Balanced Pathway is not assumed to change from today, although our scenarios explore a doubling in import dependency to phasing out imports.

We set out our analysis in the following sections.

1. Sector emissions
2. Options for reducing emissions
3. Approach to analysis for the Sixth Carbon Budget

1. Sector emissions

a) Current emissions

Greenhouse gas emissions from fuel supply were 39 $MtCO_2e$ in 2018, 7% of the UK total (Figure 6.1).

These were all produced from fossil fuel supply, from a combination of refining, oil and gas platforms, oil and gas processing terminals, gas distribution, coal mines (open and closed), and other fossil fuel production.

- Refining represents one third (13 $MtCO_2e$) of these emissions.
- Oil and gas platforms comprise 40% (16 $MtCO_2e$) of these emissions. This includes gas any production of onshore petroleum.
- Gas transmission and distribution contributes 13% (5 $MtCO_2e$) of these emissions. These emissions almost all come from methane leakage in the gas transmission and distribution networks.
- Oil and gas processing terminals, including for LNG, are 11% (4 $MtCO_2e$).
- Most (80%, 31 $MtCO_2e$) emissions were of CO_2, 19% (7 $MtCO_2e$) were of methane (CH_4) and 1% (0.4 $MtCO_2e$) of nitrous oxide (N_2O).

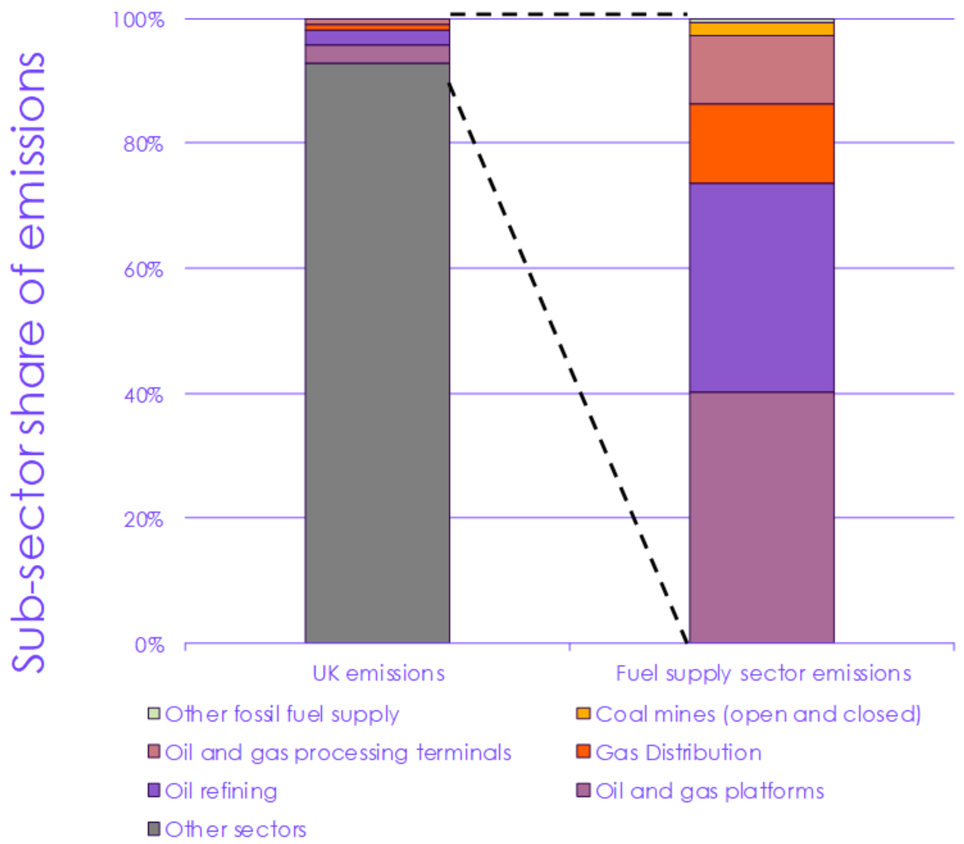
We also include within the sector direct emissions from production of low-carbon hydrogen, low-carbon ammonia and synthetic fuel production for energy use. However, our best estimate of emissions from these is currently zero, with most hydrogen and ammonia being produced for feedstock purposes, and no synthetic fuel produced commercially in the UK.

As such, all emissions from existing production of hydrogen and ammonia, used mainly in refineries and fertiliser production, are included within manufacturing and construction (see Chapter 4).

Emissions from existing UK production of bioenergy are either included within manufacturing and construction (see Chapter 4) for pre-processing and conversion, within surface transport for trucking of feedstocks and fuel, and within LULUCF and Agriculture sectors for any land-use change, cultivation and harvesting of UK forestry and perennial energy crops. This categorisation remains for all parts of the supply chain (i.e. these other sectors account for their parts of the supply chain emissions in our scenarios), except for new conversion facilities.

We include within the fuel supply sector direct emissions from the conversion facilities of new bioenergy vectors (e.g. biojet, bioLPG, biohydrogen), although as all these new facilities have been modelled as being energy self-sufficient (using their feedstock to provide power and heat onsite), only conversion facilities that convert waste to jet fuel will have some associated fossil emissions. We also include GHG savings from additional biomethane injection into the gas grid to offset fossil gas, as part of the sector emissions.

Figure M6.1 Breakdown of fuel supply emissions ($39\ MtCO_2e$ in 2018)



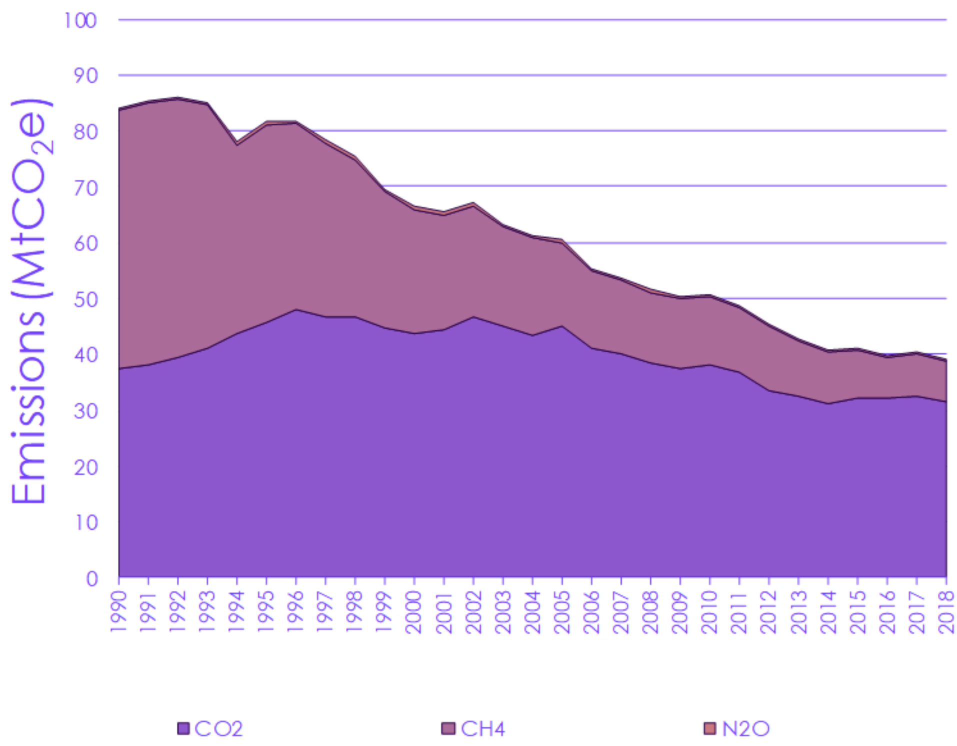
Source: CCC analysis.

Notes: All emissions are from fossil fuel supply. Groupings are based on Element Energy (2020) *Deep-decarbonisation pathways for UK Industry, report for the Climate Change Committee.*

b) Trends and drivers

Direct emissions from fossil fuel supply rose by 1% in 2019. Emissions were 53% below 1990 levels (Figure 6.2). More detailed sectoral data are produced with a one-year lag. The 1% rise in emissions in 2017 was largely due to rises in the production and transport of fossil fuels; emissions from refineries over this period were static. There are currently no significant emissions from production of low-carbon hydrogen or ammonia for energy use.

Figure M6.2 Trends in fuel supply emissions



Source: National Atmospheric Emissions Inventory (2020) Breakdown of UK GHG emissions by source and greenhouse gas; CCC analysis.
Notes: All emissions are from fossil fuel supply.

2. Options for reducing emissions

This section sets out the different options for reducing emissions from existing fuel supply in the UK (i.e. those from fossil fuel supply).

a) Resource efficiency and energy efficiency

We detail our approach to resource and energy efficiency savings in section 2 of Chapter 4. In the fossil fuel supply sector, there are small direct savings to be made from resource and energy efficiency, although efficiency measures from across the economy can flow through to reduced demand for oil from refineries. Fossil fuel supply facilities can also become more energy efficient through measures such as heat recovery in refineries.

b) Fuel-switching

Electricity, hydrogen and bioenergy can all be used to meet heat, motion (and electrical) demands, thus replacing the use of fossil fuels and reducing GHG emissions in the fuel supply sector.

- There are a range of hydrogen and electrical heating technologies, which are designed to provide different types of heat demand.
- Some fuels or heating technologies have wider potential than others. The applicability of fuels in the fuel supply sector is informed by Element Energy's 2019 report on fossil fuel production.[2]
- Fuel switching of processes on offshore platforms can be limited by the lack of connection to onshore electricity (or potentially in future, hydrogen) networks. This currently results in onsite generation of electricity using fossil fuels. Connecting platforms to the mainland grid or offshore wind turbines can allow them to reduce direct emissions.
- Biomass should only be used in energy applications with CCS (i.e. BECCS) in the long-term, based on the assessment of best use in our Biomass Review.[3] BECCS has the net effect of removing CO_2 emissions from the atmosphere. These removals are counted in our Greenhouse Gas Removals sector (see Chapter 12).

Fuel-switching away from petroleum elsewhere in the economy results also results in lower demand for petroleum from oil refineries, which can reduce emissions.

c) Carbon Capture and Storage (CCS)

CCS can be used to capture CO_2 produced by industrial point-sources, and transport it to a storage site, thus reducing emissions to the atmosphere. The captured CO_2 may alternatively be used in Carbon Capture and Use (CCU), although the potential amount of CO_2 that could be used is expected to be substantially smaller than that which could be stored.

CCS can capture non-combustion process CO_2 emissions (from refineries, reforming and offshore fossil fuel production) and combustion emissions, including those arising from the combustion of internal fuels (gases that are produced as part of the industrial process).

d) Reduced methane venting, flaring and leakage

The amount of methane that is vented or flared from oil and gas production, and from exploration and leaked from the gas pipe network, can be reduced through a series of measures. Venting and flaring from oil and gas production can be reduced by recovering the gas and selling it.

When safety requires that methane cannot be recovered, an alternative way to reduce venting emissions is to flare the methane instead of venting. Venting from exploration wells can be reduced through reduced emissions completions. Leakage of methane from the gas network can be reduced through periodic leakage detection and repair or continuous monitoring, to find the leaks as early as possible and limit the volume of methane released.

e) Low-carbon hydrogen supply

Four main routes for hydrogen supply were included in this analysis:

- **Fossil gas reforming with carbon capture and storage (CCS).** Hydrogen can be produced by autothermal reforming of methane, plus a shift reaction, to produce hydrogen and CO_2. The CO_2 is assumed to be captured and stored geologically. Although the efficiency (85%) and CO_2 capture rate (95%) of this process are both assumed to be relatively high, even then this process would only provide hydrogen with a lifecycle emissions saving of up to 85% compared to unabated use of fossil gas due to the emissions from upstream fossil gas production.[4] Costs of hydrogen supply via this route are assumed to be £38/MWh.
- **UK-based electrolysis.** This supply route entails using electricity generation that would otherwise be 'curtailed' from renewable and/or nuclear capacity at times when generation from these sources exceeds other 'direct' demands for electricity. The electricity is used with 80% efficiency to produce hydrogen. Costs of electrolytic hydrogen depend on the capital cost of the electrolyser, its utilisation (or 'load factor') and the non-electricity operating costs, as curtailed power is assumed to be available at no added cost (see Chapter 5). The cost of hydrogen from fossil gas reforming with CCS is used as a threshold for electrolytic hydrogen costs produced with curtailed electricity. The cost assumed in the fuel supply sector is therefore on average below that for fossil gas reforming with CCS, varying depending on electrolyser capacity factors.
- **Imported hydrogen.** Hydrogen could be produced outside the UK (e.g. from low-cost solar in sunnier latitudes) and supplied, potentially via ammonia, at similar costs to domestic hydrogen production from fossil gas reformation.[5] We have assumed that a modest proportion of hydrogen/ammonia supply is from these routes. Assuming that these imports will only occur if competitive with UK-based production, we have costed them at the same cost as fossil gas reformation.

- **Bioenergy with CCS.** Hydrogen can be produced from biomass with CCS, via gasification and catalytic shift reactions. Sequestration of this biological CO_2 means that this supply route has negative lifecycle emissions. Costs of hydrogen supply via this route are assumed to be £86/MWh today falling to £71/MWh by 2050 as efficiency improves and deployment scales up. In the fuel supply sector this is counted as having zero emissions, with both the CO_2 removal and the added costs of this route compared to a low- (rather than negative-) carbon hydrogen supply alternative accounted for in the Greenhouse Gas Removals sector (see Chapter 12).

Two further processes using low-carbon hydrogen are also modelled within the fuel supply sector:

- **Ammonia for shipping**. Ammonia is produced from combining nitrogen (from air separation) with low-carbon hydrogen (supplied as outlined above), in the Haber-Bosch process. With some of the hydrogen used for on-site power and process heating, plant efficiencies are 75% from hydrogen to ammonia (HHV basis). Given the commercial maturity, we have not assumed improvement in ammonia capital or operating costs over time, only changes in the hydrogen costs. Ammonia costs are around £75/MWh in the Balanced Pathway.

- **Synthetic jet fuel for aviation**. Direct Air Capture is used to extract CO_2 from the atmosphere, catalytically combined with low-carbon hydrogen to form syngas, and then Fischer-Tropsch (FT) catalysis to jet fuel. Process efficiency from hydrogen to jet, including the low-carbon used for Direct Air Capture, is 43% today rising to 52% by 2050. Synfuel costs fall to £114/MWh by 2050 in the Balanced Pathway.

f) Bioenergy and waste supply

A number of different bioenergy production routes were included in our analysis, along with the use of wastes. Feedstock costs have been held fixed over time, whereas conversion processes have been assumed to become cheaper and more efficient over time. All our bioenergy conversion processes are assumed to be energy self-sufficient (i.e. no external inputs of fuel or electricity required), which is reflected in the conversion efficiencies used. The addition of CCS increases conversion costs and lowers efficiencies. Costs are set out in section 3.

- **Solid biomass.** Domestic feedstocks (forestry residues, perennial energy crops, straw & waste wood) and imported biomass feedstocks are supplied directly (without conversion) to the Power, Manufacturing & Construction, Residential & Non-residential Buildings and Agriculture sectors. These end-uses increasingly transition to CCS, or phase out over time. Current informal supplies of biomass for building heating (~8 TWh/year) are assumed to phase out in line with biomass combustion boilers in buildings.

- **Residual waste**. After re-use & recycling, any residual waste not exported or landfilled is predominantly used in energy-from-waste plants (in the Waste sector, with CCS being fitted to all plants by 2050), plus some small use in Manufacturing. Use in waste to jet plants is also possible.

- **Biohydrogen**. Solid biomass feedstocks are gasified then catalytically converted into hydrogen, with CCS.

- **Biojet**. Waste fats/oils can be hydrotreated into biojet. Solid biomass or residual waste feedstocks can also be gasified then undergo FT catalysis for conversion into biojet, with CCS.

- **Heating biofuels.** A range of liquid biofuels made from biomass (with CCS) or from waste fats/oils can be used for home heating, including bio-LPG and biokerosene (heating oil). We assume some use with hybrid heat pump systems situated in homes off the gas-grid.
- **Biodiesel**. Biodiesel is used in surface transport, off-road machinery and agricultural equipment Conventional routes to biodiesel involve trans-esterification or hydrotreatment of waste fats/oils. Solid biomass feedstocks can also be gasified then undergo FT catalysis for conversion into biodiesel, with CCS.
- **Bioethanol**. Arable crops are fermented into bioethanol in existing facilities.
- **Biomethane & biogas.** Biogas is produced from anaerobic digestion of food waste, sewage sludge & animal manures, plus captured landfill gas. Maize biogas is assumed to phase out by the mid-2030s from ~10 TWh/year today. Biogas is used in power and manufacturing, but can also be upgraded to biomethane for gas grid injection, along with the capture of biogenic CO_2 for sequestration.

3. Approach to analysis for the Sixth Carbon Budget

We have drawn together a range of new evidence to underpin the analysis of long-term decarbonisation that is presented in the *Advice report*. This predominantly updates and adds to the evidence base collated for our 2019 advice on Net Zero, which considered decarbonisation to 2050.

a) Fossil fuel supply

The Balanced Net Zero Pathway and the four exploratory scenarios in this sector differ in several ways, including their energy mix and rates of decarbonisation. More information on this is in Chapter 3 of the *Advice report*, and the dataset that accompanies the report. These scenarios are underpinned by updated evidence and analysis.

- We commissioned Element Energy to undertake new research on the deep decarbonisation of industry and produce a model for location-specific decarbonisation options (for more information, see Box 4.2 and Chapter 4, section 3). This included deep decarbonisation of fossil fuel supply, building on the Element Energy (2019) study produced for our 2019 Net Zero advice, 'Assessment of options to reduce emissions from fossil fuel production and fugitive emissions'.
- New evidence on the possible abatement from the electrification of offshore platforms and its costs was applied to the model outputs.
- We have also updated our synthesis of evidence on resource and energy efficiency options, and our baselines.

The structure of our analysis follows the following steps:

- It starts by considering a baseline world where there is no new climate change mitigation policy beyond 2019.
- From the emissions baseline in this world we deduct, in sequence, demand reductions from across the economy, abatement from resource efficiency and energy efficiency.
- This is followed by deducting abatement from 'deep decarbonisation' options - fuel switching, CCS and measures to reduce methane flaring, venting and leaking.
- We set out the approaches we have taken for each of these steps, below.

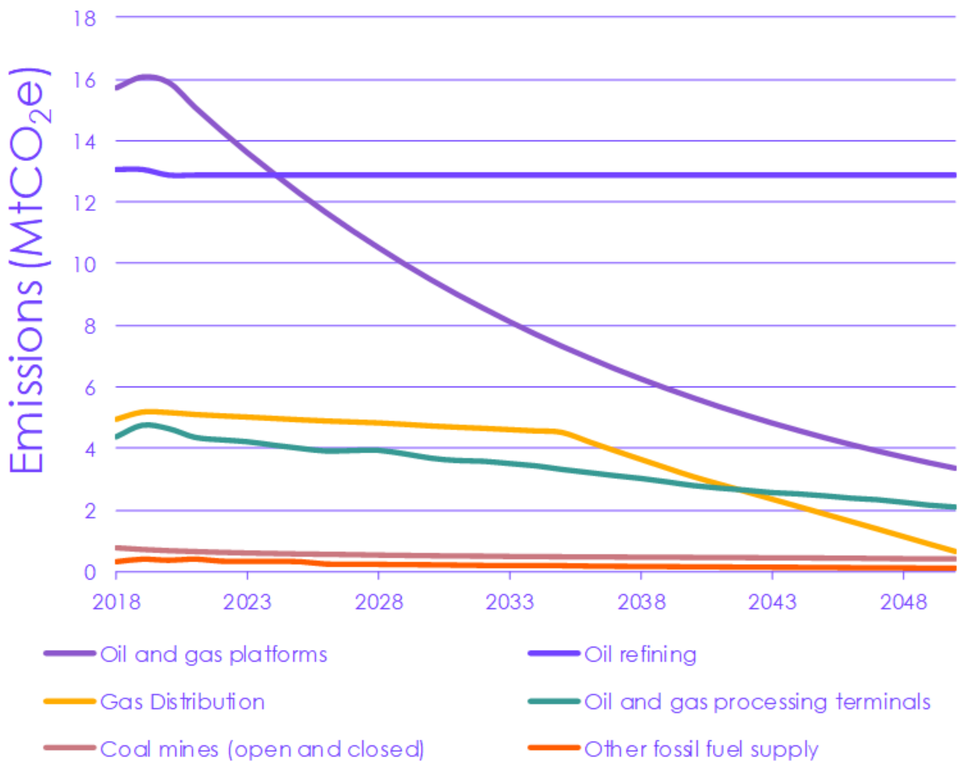
Baseline projections

Our emissions baseline starts aligned to historical emissions for 2018, the latest year with fully reported data, based on the National Atmospheric Emissions Inventory (NAEI).[6] For combustion emissions, corresponding energy data is drawn from a mix of the NAEI and the Digest of UK Energy Statistics (DUKES),[7] allowing for the inclusion of existing electricity use (which is not reported in the Inventory).

Future refinery energy and emissions are projected from the historical 2018 data using the scaling (% change from 2018) of the BEIS Energy and Emissions Projections 2019 reference case.[8] Future emissions from other fuel supply sectors (excluding refining) are projected using a 2019 study from Element Energy.[9]

Figure 6.3 shows our baseline projections. Baseline emissions from these sources are projected to reduce to 19.5 $MtCO_2e$ in 2050.

Figure M6.3 Baseline projections for subsectors in fuel supply



Source: CCC analysis.
Notes: All emissions are from fossil fuel supply. Groupings based on Element Energy (2020) *Deep-decarbonisation pathways for UK Industry, report for the Climate Change Committee*.

Resource efficiency, energy efficiency and fuel-switching from across the economy

To establish pathways for abatement from resource efficiency, energy efficiency and fuel-switching across the economy we refreshed our synthesis of evidence on the abatement potential of these measures.

From the baseline, first we accounted for significant changes across the economy that would affect demand.

Decreased use of petroleum for transport and other applications leads to large reductions in demand for oil refineries. In all scenarios, this demand reduction equates to 0.4 $MtCO_2e$ of abatement in 2019, rising to 9.5 $MtCO_2e$ of abatement in 2050.

Next, we applied resource efficiency savings; in fossil fuel supply, these are very small and spread across the subsectors. Energy efficiency for refineries is based on the 'Max Tech' scenarios from the '2015 BIS Industrial Decarbonisation and Energy

Efficiency Roadmaps to 2050'.[10] We also assume some small additional energy efficiency in sub-sectors that are not covered by the Roadmaps.

Deep decarbonisation measures

To establish our pathways for abatement from deep decarbonisation measures, we commissioned Element Energy to substantially extend previous analysis produced for the CCC and BEIS and develop pathways for the CCC. This involved gathering new evidence and using this within a new Net Zero Industrial Pathways (N-ZIP) model. Further details of the Element Energy evidence-gathering and N-ZIP modelling are presented in Chapter 4 and Box 4.2.

Some amendments were applied to the deep decarbonisation abatement measures coming from the fuel supply pathways and scenarios from the Element Energy analysis, resulting in a difference between the results reported in the Element Energy report and our final results.

In particular, new evidence from the Oil and Gas Authority (OGA) on the electrification of platforms was also included at this stage.[11]

- The OGA study sets out cost-effective electrification of platforms and sets out a potential pathway that could abate 3 $MtCO_2e$ per year.
- In all scenarios, we have applied their pathway and used grid electricity to provide power to generators and compressors on oil and gas platforms.
- Use of grid electricity keeps open the future option of using dedicated renewables (e.g. wind) to power these platforms.

We also adjusted CCS capture rates in the period pre-2040 to 90%, from higher rates used in the Element modelling (that now apply from 2040 only).

b) Low-carbon hydrogen supply

End-use sectors were given hydrogen costs to use in their analysis for the decarbonisation pathway in their sectors. Due to different assumed hydrogen costs between scenarios, but also different assumed end-use sector choices in the different scenarios, there is considerable variation in hydrogen demands by sector, and in aggregate, across scenarios.

Once the hydrogen demands at the sectoral level had been determined, an assessment was made of the mix of hydrogen supply routes to meet these:

- **Electrolysis.** Supply of hydrogen from electrolysis was co-optimised with electricity supply, as outlined in Chapter 5, by placing a value on the hydrogen produced via electrolysis from electricity generation that would otherwise be curtailed. This value is based on the avoided cost of producing hydrogen from reforming of fossil gas with CCS.
  - The largest volume of electrolytic hydrogen supply by 2050 is in Widespread Innovation, as the lower costs of renewable electricity mean it is more economic to build more renewable capacity to meet a combination of electricity and hydrogen demands.
  - Headwinds, which has the lowest share of variable renewable generation, also sees the lowest volume of electrolytic hydrogen production.

- **BECCS.** Hydrogen production from BECCS relies on biomass gasification technology, which is not fully mature. As such, less biomass was used for hydrogen production in each scenario than for BECCS power generation, where technology readiness is higher.
  - The largest volume of BECCS hydrogen production is in Tailwinds, where low renewable electricity costs made BECCS less valuable to the power sector, but where demands for hydrogen significantly exceeded electrolytic hydrogen supply alone.
  - Widespread Engagement does not feature any hydrogen production from BECCS, which is instead prioritised for power generation.
- **Fossil gas reforming and imports.** Once contributions to UK hydrogen supply that are limited by economics and build rates (electrolysis) and available resource (BECCS) were established, the remaining requirement for hydrogen supply was allocated between domestic production from fossil gas reforming with CCS, and imports of low-carbon hydrogen. In each scenario, imports represented less than 20% of overall hydrogen supply, while fossil gas reforming with CCS comprised the remainder.
  - Fossil gas with CCS made by far the biggest contribution to hydrogen supply in the Headwinds scenario, partly due to the much higher hydrogen demand in that scenario and partly due to the lesser contribution of electrolysis.
  - The contribution from fossil gas with CCS in other scenarios such as Tailwinds and Widespread Innovation was much smaller by 2050, due to the high share of electrolysis. However, fossil gas with CCS has an important transitional role in both scenarios in providing low-carbon hydrogen during the period when hydrogen demands grow faster than electrolytic hydrogen supply.

Supply of low-carbon hydrogen in the baseline is assumed to be zero.

Low-carbon ammonia and synfuel production

Low-carbon hydrogen is used in a variety of end-use sectors, but some is also converted into ammonia for shipping and synthetic jet fuel for aviation in our scenarios.

- **Zero-carbon ammonia**. Ammonia production is commercially mature, as is the distribution and storage infrastructure. All of our shipping scenarios require 70 TWh/year of zero-carbon ammonia by 2050, although profiles to 2050 vary. Most of this ammonia is assumed to be produced in the UK from the available low-carbon hydrogen, however, we also assume there will be imports of renewable ammonia. In the Balanced Pathway, these imports are 25% of UK demand, with 0% in Headwinds (self-sufficiency with fossil gas with CCS) or 50% in other scenarios (to reflect higher global innovation in renewable energy costs).
- **Synthetic jet fuel**. Synthetic fuel production is at early demonstration scale at present, as is Direct Air Capture. By 2050, our aviation scenarios require 30 TWh/year of synthetic jet in Widespread Innovation and Tailwinds, and 10

TWh/year in the Balanced Pathway. We assume the same proportion of imports across the scenarios as for ammonia above.

Supply of zero-carbon ammonia and synthetic jet fuel in the baseline is assumed to be zero.

c) Bioenergy and waste supply

Emissions in the sector fall into two categories: additional GHG savings from increased biomethane injection into the gas grid, or fugitive fossil emissions from waste to jet fuel plants. All other emissions are either nil or are accounted for outside of the fuel supply sector (hence our baseline has nil emissions). The focus of the bioenergy analysis is therefore on supply and use, and new conversion technology costs.

Bioenergy supply estimates from CCC's 2018 *Biomass in a low-carbon economy* were used as the starting point for our analysis. These biomass, biogas, biofuel and waste supply estimates for 2018-2050 were then updated for each scenario, based on the latest assumptions and results from the LULUCF, Agriculture, Waste and fossil fuel supply sectors.

- New forestry and perennial energy crop harvest data from the Land Use sector analysis, based on new work on yield classes and planting rates with the Centre for Ecology & Hydrology.
- Straw, poultry litter and livestock manures are scaled over time with respective arable crop production, poultry numbers and livestock numbers from the Agriculture sector scenarios.
- Total waste wood arisings held flat, as previously.
- Landfill gas estimates now use the devolved administration landfill gas modelling in the Waste sector, with new assumptions on waste prevention and recycling rates, and ban dates on landfilling different wastes. This resource shows significant declines.
- Food waste arisings scale with population, before waste prevention efforts from the Waste sector scenarios are applied. Collection rates for anaerobic digestion rise to 90% by 2030.
- Sewage sludge scales with population, and biogas production increases with shift to advanced anaerobic digestion in the Waste sector.
- Municipal solid waste (MSW) and commercial & industrial (C&I) waste arisings were updated using latest Defra statistics, rescaling previous Defra projections, before waste prevention and recycling efforts from the Waste sector scenarios are applied to calculate residual wastes not landfilled or exported (exports phase out by 2030). Biogenic and fossil fractions vary over time from the Waste sector analysis with the different landfilling bans.
- Informal biomass supplies from DUKES are phased out in line with Residential buildings use of solid biomass.
- The difference in 2018 between our waste sector biogas supply and DUKES UK biogas production is assumed to be maize silage anaerobic digestion (this also matches Defra statistics on maize silage areas for AD). Maize AD is assumed to phase out by 2035.
- Bioethanol production and imports match the demand for bioethanol in light duty vehicles, which increases in 2021 with higher bioethanol blending

in petrol. As petrol demand falls over time, bioethanol imports are assumed to phase out first before domestic bioethanol production.

- Waste fats/oils biodiesel production and imports match the near-term demand for biodiesel. UK supplies are assumed to vary with used cooking oil supply (held fixed) and tallow (declines with Agriculture sector livestock numbers). These waste fats/oils biofuel imports increasingly become biojet as biodiesel demands fall.
  - The Balanced Pathway follows a 'fair share' of a global biofuel resource scenario from 2035, which is not dissimilar to Widespread Innovation which holds these imports fixed.
  - Widespread Engagement phases these imports out by 2040.
  - These imports in Tailwinds and Headwinds increase 70-80% from today by the early 2030s (as a 'fair share' of a more ambitious global scenario), before Tailwinds holds these fixed and Headwinds returns to close to 2018 levels.
- Biomass imports have a maximum availability which varies by scenario.
  - Headwinds follows a 'fair share' of an ambitious global bioenergy governance world, resulting in biomass imports increasing to 155 TWh/year by 2050 (as in Scenario 4 of our 2018 *Biomass* report). Tailwinds also assumes this same high level of imports is available.
  - Widespread Innovation focuses strongly on UK biomass production, so phases out biomass imports by 2050 (similar to Scenario 3 of our 2018 *Biomass* report).
  - Widespread Engagement and the Balanced Pathway hold the current biomass import availability of 52 TWh/year steady to 2050, ensuring sufficient supply to reach Net Zero.*
  - Actual biomass imports in any year are determined by the balance of total UK biomass supply and total UK biomass demand, and so biomass imports in all years before 2050 are lower than the maximum scenario availability.

Once these biomass and waste availabilities were established, the next step was to allocate these resources to each of the sectors to use in their pathway analysis.

- Our starting position was the 2018 split of bioenergy and waste use by sector from DUKES and NAEI.
- This allocation was accompanied by bioenergy costs and emission intensities for each product consumed by the end-use sectors, from 2020-2050 (a summary is given in Table 6.1).
  - Bioenergy costs, efficiencies and emissions intensities can change over time, but are not assumed to vary across the scenarios.
  - Feedstock costs come from industry benchmarks, with bioenergy conversion plant costs and efficiencies taken from the Energy System Catapult's ESME model, using the same feedstock costs. The added costs of CCS include £15/tCO_2 for downstream transport and storage of CO_2. All conversion plants of one type

* 52 TWh/year is based on 2018 biomass import levels plus new biomass power plants built since 2018 or under construction, in effect an estimate of 2021 potential biomass import levels.

are assumed to run at their given utilisation rate, which is fixed over time. An investment interest rate of 8% is applied.

Plant lifetimes are assumed to be 30 years for all plants converting biomass, and 20 years for those converting wastes.

– Constant properties over time from Defra[12] are assumed for biomass, waste, biogas, biofuels and biomethane densities, calorific values and combustion values (only residual waste varies with biogenic vs. fossil fractions over time).

– Emission intensities of the delivered fuels (only used for sector £/tCO_2e calculations, not for direct emissions) are derived using these feedstock factors, supply chain emissions (see section 3(f)), and our CO_2 capture rates (Chapter 12).

Table M6.1
Bioenergy conversion technology and feedstock assumptions

	£/MWh 2020	£/MWh 2050	Efficiency 2020	Efficiency 2050	gCO_2e/kWh 2020	gCO2e/kWh 2050
Domestic biomass	22	22	NA	NA	7	1
Imported biomass	31	31	NA	NA	33	3
Residual waste	0	0	NA	NA	8	1
Biogas	29	29	NA	NA	22	2
Bioethanol	64	64	NA	NA	93	28
Waste fats/oils biodiesel	91	91	NA	NA	28	3
Waste fats/oils to biojet	105	102	88%	90%	28	3
Biomass to FT biodiesel with CCS	127	86	34%	42%	-457	-485
Biomass to FT biojet with CCS	132	89	34%	42%	-457	-485
Residual waste to FT jet with CCS	89	48	29%	37%	-250	-285
Biomass to heating fuel (2020 without, 2050 with CCS)	72	70	52%	54%	28	-400
Biogas to biomethane	38	35	92%	94%	43	4
Biogas to biomethane with CCS	49	46	88%	90%	-49	-118
Biomass to bioSNG with CCS	61	52	60%	66%	-229	-286
UK biomass to H2 with CCS	86	71	51%	55%	-508	-571
Imported biomass to H2 with CCS	103	87	51%	55%	-460	-567

Sources: Defra (2020) Greenhouse gas reporting: conversion factors 2020; Argus (2020) Biomass Markets; ESC (2019) ESME Data References Book; Ofgem (2019) Biomass Sustainability Dataset 2017-18; CCC analysis.
Notes: All values are in HHV. Emissions intensities are full lifecycle emissions, not what the fuel supply sector or end-use sector accounts for. Residual waste costed at £0/MWh, as we do not include landfill tax/transfers.

Some sector analysis then phases out the use of bioenergy as end-use efficiencies improve and as other low-carbon alternatives (e.g. heat pumps, electric vehicles, low-carbon hydrogen, offshore wind) become available.

- These phase-outs include solid biomass in buildings heating, agriculture and unabated power, along with bioethanol and biodiesel in surface transport, off-road machinery and agricultural equipment.

- Manufacturing also has a gradual decline in unabated bioenergy use over time, but not a full phase-out.

This led to sectors returning unused bioenergy resources for reallocation. Along with the growth in available supplies which are also available to be allocated, these new allocations to sectors were based on the findings from our analysis of best uses of bioenergy, discussed in section 3(f) below.

- 2050 was the focus, as this is the Net Zero date and when all available feedstocks are used. We reallocate to BECCS applications in power, biohydrogen, biojet and industrial heating, to maximise GHG savings. Differences between these allocations also reflect the different scenario framings, as discussed in the *Advice Report*, Chapter 3, section 5.

- We then worked backwards in time to scale-up different supply chains and conversion technologies from their starting points in the late 2020s or early 2030s, to meet the 2050 allocations. Some routes, such as BECCS power, can reach sector limits around 2040 in some scenarios, and are assumed to not increase further beyond 2040.

- This ramping up to 2050 means that there is typically a modest surplus of biomass in earlier years (as several existing uses of biomass tend to ramp down faster/earlier). We therefore reduce biomass imports accordingly so that demand matches actual supply in each year.

- Several conversion technology ramp-ups in the late 2020s and early 2030s are constrained by technology readiness and the number of developers globally, in order to ensure early growth is realistic.

- Some bioenergy conversion facilities are built in the 2020s without CCS but retrofit CCS during the 2030s. All new conversion facilities from the early 2030s are built with CCS.

- It is technically feasible that some plants built during the 2020s and early 2030s could transition to a different product spread at relatively low marginal capital cost. During the 2030s, we model a biodiesel to biojet transition (both for plants based on waste fats/oils and biomass FT gasification) and from bioSNG to biohydrogen (if bioSNG is deployed). However, any early pre-transitional capacity increases are typically very modest given that biodiesel use is declining during the 2030s, as is fossil gas use, and technology scale-up constraints still apply. Biojet and biohydrogen facilities are still constructed on the original timelines, but there is also a minor boost during the 2030s with these transitions. There is no significant surge into one sector, and then wide-spread retrofitting of capacity 10 years later.

- We do not allow overbuilding of conversion technologies (i.e. there is no early scrappage or early retirement of plants).

The waste allocation analysis is carried out separately. After accounting for niche uses in manufacturing, fuel supply and clinical/chemical waste incineration, the remaining residual waste tonnages are sent to energy-from-waste plants in all scenarios, except in Widespread Engagement when 70% is sent to jet fuel production by 2050. Unlike for biomass where supply can exceed demand (and biomass imports fall), we assume all waste must be used each year.

The final allocation of bioenergy and waste to end-uses therefore differs across scenarios, as set out in the *Advice Report*, Chapter 3, section 5. The resulting volumes of biogenic CO_2 captured from BECCS applications are given in Chapter 12 of this report.

The capital and operating costs of the different bioenergy conversion routes are then calculated bottom-up from the added capacity in a year, and the total deployment of a route (and hence feedstock consumption).

- Our analysis assumes increasing efficiencies and capture rates, and declining capital and operating costs over time. Given the complexities of handling 24 different routes, it was only possible to implement a fleet/sales approach for capital costs (i.e. plants built earlier cost more) and the added capital costs of transitioning a plant to another output (e.g. biodiesel to biojet in a particular year).
- It was not possible to implement this approach for other metrics – this means that in each year, the efficiency, operating costs and capture rate of a route is the same across all the plants in that route, regardless of when each plant was built.
  - Our assumptions regarding efficiency improvements are therefore relatively modest to account for this fleet impact.
  - Operating costs are expected to fall over time with experience and greater automation, sharing overheads across a fleet of plants, and as plants scale up in size with commercialisation.
  - Capture rates could be improved after installation, with process optimisation, new equipment or improved materials/solvents.

d) Devolved administrations

The use of site-level data in the N-ZIP model provided emissions, abatement and costs data that could be attributed to the devolved administrations (DA). We have used this data to produce a pathway for each DA for each scenario.

For hydrogen supply, the only relevant allocation to devolved administrations are the fugitive emissions from fossil gas reforming with CCS, due to CO_2 capture rates being below 100%. We distribute UK-wide gas reforming proportionately to the DAs, based on their share of industrial CCS in our scenarios. In the Balanced Pathway that is 15% and 25% for Scotland and Wales respectively in 2050.

For bioenergy conversion, our approach to allocating biogenic CO_2 captured is detailed in Chapter 12. We do not specifically allocate BECCS plants to the devolved administrations, but present DA trajectories without engineered GHG removals and then discuss the amount of BECCS or DACCS (Direct Air Capture of CO_2 with storage) that would have to be assumed to be built within each devolved administration. This approach also extends to the capital and operating costs of BECCS plants not being specified within the DAs. The exception is the use of biomass with CCS in Manufacturing & Construction, which will be location-specific, and follows the Element Energy N-ZIP model results.

There is some abatement in Fuel Supply from the injection of additional biomethane into the gas grid at above baseline levels, displacing fossil gas. This abatement and cost is allocated to the DAs according to the location of the biogas resources.

For bioenergy supply, each DA is assumed to produce:

- Forestry and perennial crop feedstocks according to DA data from the Land use sector.
- Straw, poultry litter and livestock manures are split by respective arable crop production, poultry numbers and livestock numbers from the Agriculture sector scenarios.

- Landfill gas is from DA specific landfill gas modelling in the Waste sector.
- Food waste, sewage sludge, waste wood, MSW and C&I waste arisings are assumed to be split by population, and waste prevention and recycling efforts from the Waste sector scenarios.
- Informal biomass supplies are assumed to be apportioned to existing forestry areas, and maize biogas is apportioned to maize areas.
- Bioethanol and waste fats/oils biofuels are assumed to be apportioned to DAs based on existing facilities and their assumed production over time.

e) Uncertainties

Fossil fuel supply

We have used the results of our analysis to inform our recommendations around future deployment of deep-decarbonisation measures and CO_2 and hydrogen infrastructure. However, there is much uncertainty about many of the assumptions that we have used in our analysis. Therefore, we have considered a range of sensitivities to the assumptions, to form different pathways, with the purpose of identifying a range of different futures and the most – and least – robust conclusions of the analysis. More detail on the model parameters is given in the accompanying report by Element Energy[13]. Some model sensitivities are described in Chapter 4, section 5.Uncertainties for fossil fuel supply also include those that have been seen in the past, relating to the volatility of global prices.

Low-carbon hydrogen supply

Uncertainties in our assessment of low-carbon hydrogen supply options could imply a different supply mix and/or supply costs in the future:

- **The role for electrolysis.** The role for electrolysis depends on both its interaction within the electricity system and its cost-competitiveness with other ways to supply hydrogen.
    - While our modelling of the electricity system using the BEIS Dynamic Dispatch Model (DDM) considers in sufficient detail the potential for electrolysis to utilised otherwise 'curtailed' generation, it does not include a sufficiently wide range of alternative electricity storage options that might have lower costs and/or higher efficiencies. However, while a larger role for other electricity storage technologies may imply a lesser role for electrolysis, these alternative forms of storage would also reduce the need for back-up generation, implying lower hydrogen demand from the power sector.
    - As the economics of electrolytic hydrogen in our analysis rely on the electricity being otherwise curtailed and therefore available at no additional cost, the cost of electrolytic hydrogen is driven by the capital cost and utilisation of these electrolysers. Both of these factors are uncertain.
    - Electrolytic hydrogen production from a given set of electricity system capacities will tend to have some year-to-year variation, depending on the weather and therefore levels of wind and solar generation. Our analysis represents a typical year. In years with significantly higher renewable generation, the surplus from

the electricity system may be substantially greater, and vice-versa in a year with low renewable generation.

The availability of capacity to produce hydrogen and electricity from fossil gas with CCS, which has relatively low-utilisation by 2050 in a typical year, ensures that sufficient capacity is available to meet electricity and hydrogen demands in a low-carbon way.

- **Hydrogen production from biomass gasification with CCS.** While our analysis assumes some use of biomass gasification to produce hydrogen, with up to 90% of the biogenic CO_2 captured and sequestered, biomass gasification technology is not yet mature.

  While it is desirable to have a diverse mix of hydrogen supply routes and minimise reliance on imported fossil gas, the same demands for hydrogen can be met with a supply mix that excludes biomass gasification with very similar emissions. This is assuming that biomass used in hydrogen production can otherwise be used for other BECCS applications (see Chapter 12).

- **Hydrogen production from fossil gas with CCS.** Reforming of fossil gas can provide large-scale low-carbon production of hydrogen. Its role depends on it being sufficiently low-carbon on a lifecycle basis and on economics:

  – We have previously estimated that this would provide an emissions saving of up to 85% compared to unabated direct use of fossil gas (e.g. in gas boilers) on a lifecycle basis. This saving depends on both achieving a 95% CO_2 capture rate at the gas reformation stage, but also on upstream emissions from fossil gas production being at the bottom end of our estimated range of 15-70 gCO_2e/kWh.[14] While Equinor has suggested that upstream emissions from Norwegian fossil gas production could be considerably lower than 15 g/kWh,[15] it is possible that a substantial fraction of fossil gas imported to produce hydrogen could be in the form of liquefied natural gas (LNG), which could have a considerably larger footprint.[16] Higher residual lifecycle emissions from fossil gas reforming would imply a more limited role.

  – The large majority of the costs of hydrogen supply via this route are from use of fossil gas. These means that its economics are highly dependent on future gas prices.

- **Cost competitiveness and domestic production vs imports**. A key uncertainty is the future relative cost-competitiveness of UK low-carbon hydrogen production vs. other world regions, and transport logistics. This will determine whether UK is entirely self-sufficient for its hydrogen, ammonia and synfuel production, or imports the majority of its hydrogen, ammonia and synfuels from world regions with even cheaper renewable power than in the UK. On the basis that we need to show the costs of UK decarbonisation to Net Zero, including the associated network impacts on UK power generation, and without over-relying on low-carbon energy sourced from other countries that will also be looking to decarbonise, we have limited imports in the Balanced Pathway to only 14% of hydrogen supply, 25% of ammonia supply and 25% of synthetic jet fuel supply.

Bioenergy and waste supply

- **COVID-19**. We have not attempted to calculate a long-term reduction in energy demand due to structural changes in GDP due to COVID-19; nor have we considered any potential reductions in supply via failures of feedstock suppliers, supply chain actors or potential plant operators. There remain some uncertainties as to the size of the energy industry that will emerge after COVID-19, and the level of investor appetite for less mature technologies.
- **Best use of bioenergy.** The best use of bioenergy analysis relies on CCS being widely available from the late 2020s onwards. A significant delay in CCS becoming available that significantly constrains BECCS deployment by 2050 may, depending on CCS readiness of these uses, shift the balance of best uses away from power and hydrogen (where 90-95% of feedstock carbon is captured, but the counterfactual product is increasingly low-carbon) and towards industry heating (displacing fossil fuels) and transport biofuels (where less feedstock carbon is captured in processing, but fossil fuels are displaced).
- **Cost competitiveness and domestic production vs imports**. A key uncertainty is the future relative cost-competitiveness of UK sustainable bioenergy production vs. other world regions, and transport logistics. This will determine whether UK is entirely self-sufficient for its biomass production, or imports a significant share of its biomass from world regions with larger biomass basins and more established supply chains. On the basis that we need to show the costs of UK decarbonisation to Net Zero, without over-relying on energy sourced from other countries, we have limited biomass imports in the Balanced Pathway to only 21% of total biomass supply (the same import dependency level as in 2018).
- **Sustainability criteria**. Tighter sustainability standards including GHG thresholds could potentially favour UK biomass over imports, given shorter distances and faster decarbonisation of energy inputs to UK supply chains than in many other world regions.
- **Perennial energy crop and short-rotation forestry biomass characteristics**. While being high-yielding than long-rotation forestry, fast growing biomass resources also typically grow containing higher contents of ash, halides and alkali metals. These chemical components can present operational issues in biomass combustion boilers and gasification plants. Solutions typically fall into modifying existing assets, designing new-build plant specifically for these feedstocks, or pre-treatment to remove/reduce some of these components. These solutions may add costs to the use of these feedstocks.
- **Application of costs**. Our costs for bioenergy conversion plants are indicative. There is likely to be a broad range of costs around our estimates, given differences in site size, location, existing equipment, cost of capital and lifetimes. Smaller projects or projects further from feedstock sources or CCS hubs might cost significantly more than modelled.

f) Best use of bioenergy and waste

Best use of bioenergy

As detailed in Chapter 5 of the CCC's (2018) *Biomass in a low-carbon economy* report, the highest GHG savings when using biomass are achieved with high CO_2 sequestration rates and displacement of high-carbon alternatives. This analysis was focused on woody biomass in 2050, for use in timber frame buildings, industry, hydrogen, power, aviation and cars, and was also conducted prior to the UK's Net Zero target being set.

In the Sixth Carbon Budget analysis, we have extended and updated this 'best use of bioenergy' analysis:

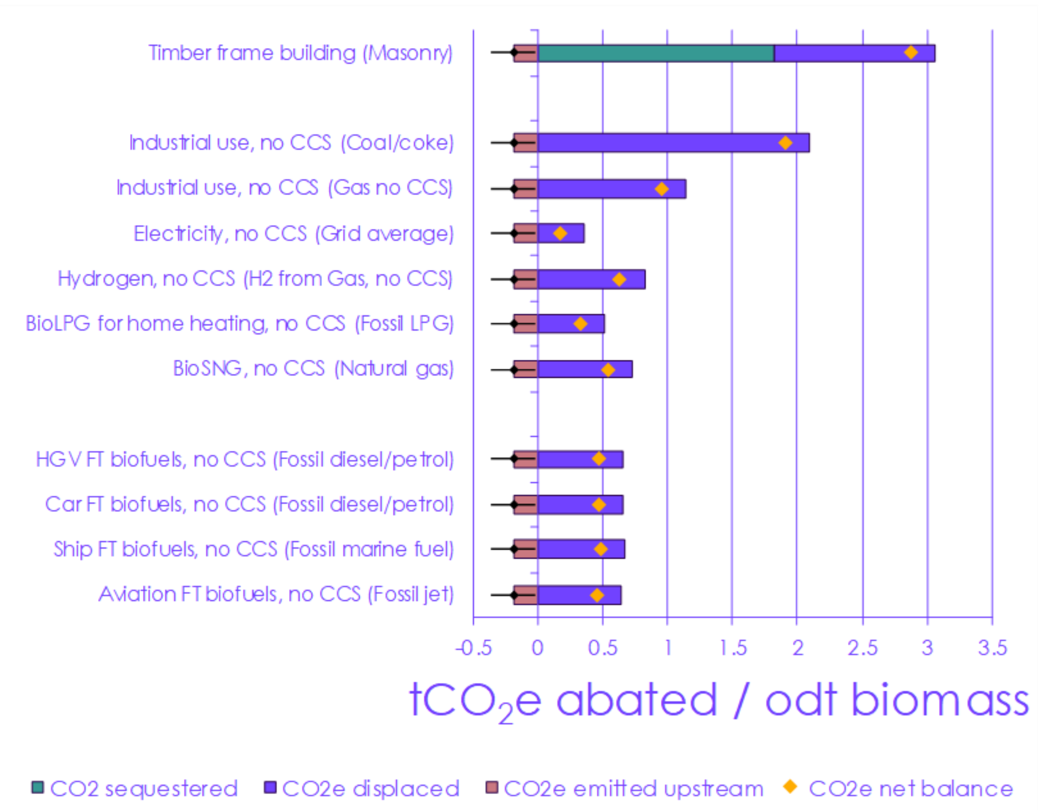
- Analysis has been conducted in 2020, 2035 (the mid-point of the Sixth Carbon Budget period) and 2050.
- The scope of the routes considered has been broadened, to cover woody biomass use in aviation, shipping, cars, HGVs, gas grid, home heating liquid fuels, hydrogen, power, industry and timber frame & wood panel construction. Best use of wastes across power, aviation, gas and hydrogen have also been considered for the first time.
- Assumptions regarding route efficiencies and c apture rates have been updated to be aligned with the latest evidence from the end-use sectors and GHG removals sector analysis, and these rates improve over time. For transport biofuels, we are assuming gasification and Fischer-Tropsch (FT) catalysis, although other similar routes would achieve a similar outcome.
- The number of potential counterfactuals (i.e. high-carbon or low-carbon alternatives to the use of bioenergy in a sector) have been increased, and the counterfactual GHG intensities have been updated to align to the Balanced Net Zero Pathway.
- Estimates of upstream biomass supply chain GHG emissions have been added to the analysis, from Ofgem sustainability data,[17] as these were previously missing. Assumptions are made that these upstream emissions will decline over time as supply chain energy and chemical input components decarbonise, in line with the Balanced Pathway. Upstream biomass supply chain emissions are assumed to reduce by 66% from today's values by 2035 and 90% by 2050.
- No land-use change emissions or sequestration have been accounted for in this analysis, despite UK forestry and perennial energy crops both being expected to lead to significant carbon sinks (Chapter 7).
- Abatement for timber construction is calculated based on a whole-house unit designed to meet the same SAP ratings, implying lifetime operational emissions for each house equal to masonry counterfactuals. Counterfactual emissions for concrete, cement & brick are assumed to reduce by 69% from today's values by 2035, and by 95% by 2050, in line with our Balanced Pathway for the manufacturing & construction sector.

The following set of charts show the estimated GHG abatement provided by one oven dried tonne of biomass used in various sectors, considering the most appropriate counterfactual in each sector for that year.

We show abatement broken down by sequestered carbon (the amount of CO_2 stored and/or not released into the atmosphere due to CCS technology); displaced carbon (the amount of fossil CO_2 that would have been emitted to the atmosphere in the counterfactual case had biomass not been used); and upstream carbon (from the feedstock supply chain).

With no CCS available in 2020, the best use of biomass is currently either locking up biogenic CO_2 as wood in construction, or displacing coal in industrial applications (Figure 6.4). The UK electricity grid has already decarbonised significantly, hence additional use of biomass in unabated power is not a best use of biomass.

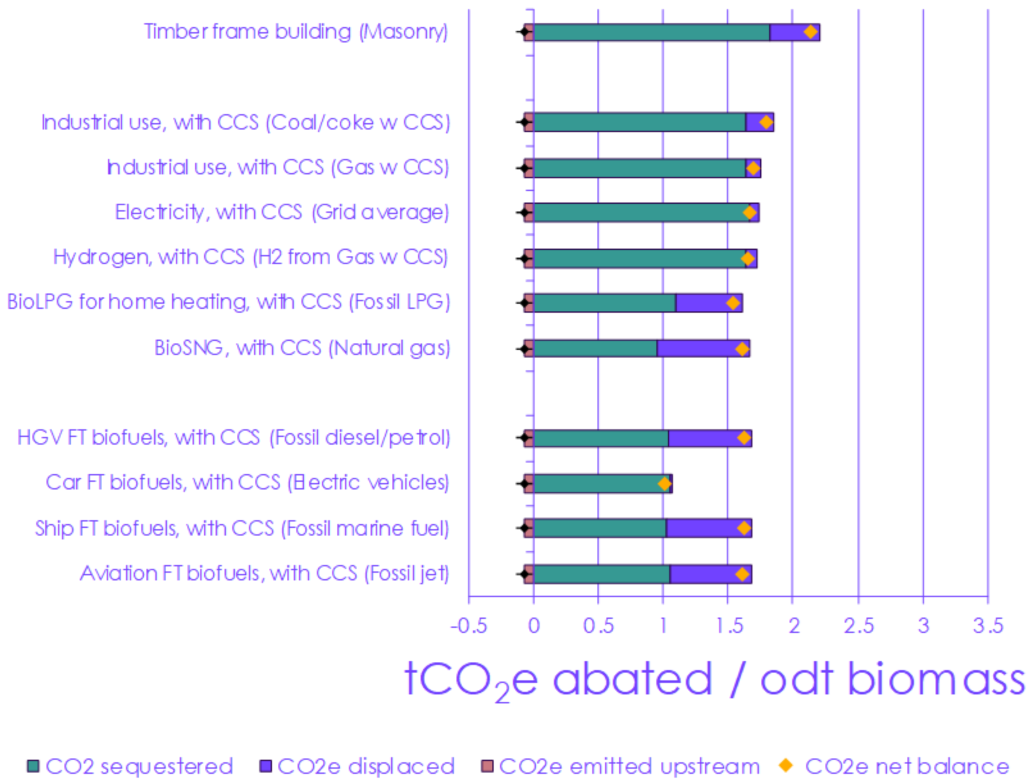
Figure M6.4 Best use of biomass in 2020



Source: Ofgem (2018) *Biomass Sustainability Dataset 2016-17*; CCC analysis.
Notes: Counterfactuals given in brackets. Upstream emissions include cultivation, processing, transportation and direct land-use change, but indirect land-use change and changes in land carbon stocks when no land-use change occurs are excluded. Upstream min-max range from Ofgem feedstock data (sawmill co-products, Miscanthus, SRC, wood pellets, forest residues and brash bales).

By 2035 (Figure 6.5), CCS is assumed to be widely available and deployed at bioenergy conversion facilities. Use of biomass in industry, power and hydrogen result in similarly high total levels of abatement, due to high CO_2 capture rates, although there is little abatement from displacement of fossil fuels as the grid has decarbonised and CCS has been added to much of industry (Figure 6.5).

Figure M6.5 Best use of biomass in 2035



Source: Ofgem (2018) *Biomass Sustainability Dataset 2016-17*; CCC analysis.
Notes: Counterfactuals given in brackets. Upstream emissions include cultivation, processing, transportation and direct land-use change, but indirect land-use change and changes in land carbon stocks when no land-use change occurs are excluded. Upstream min-max range from Ofgem feedstock data (sawmill co-products, Miscanthus, SRC, wood pellets, forest residues and brash bales).

Use of biomass in bioliquids/bioLPG for home heating, gas grid injection, and transport biofuels* can achieve high overall abatement, but only if high-carbon fuels are being displaced, since sequestration is lower (due to carbon remaining in the final fuel). If the counterfactual is a low-carbon option, such as electric cars, then this displacement abatement disappears – so the use of biomass in the car fleet is not a best use by the 2030s.

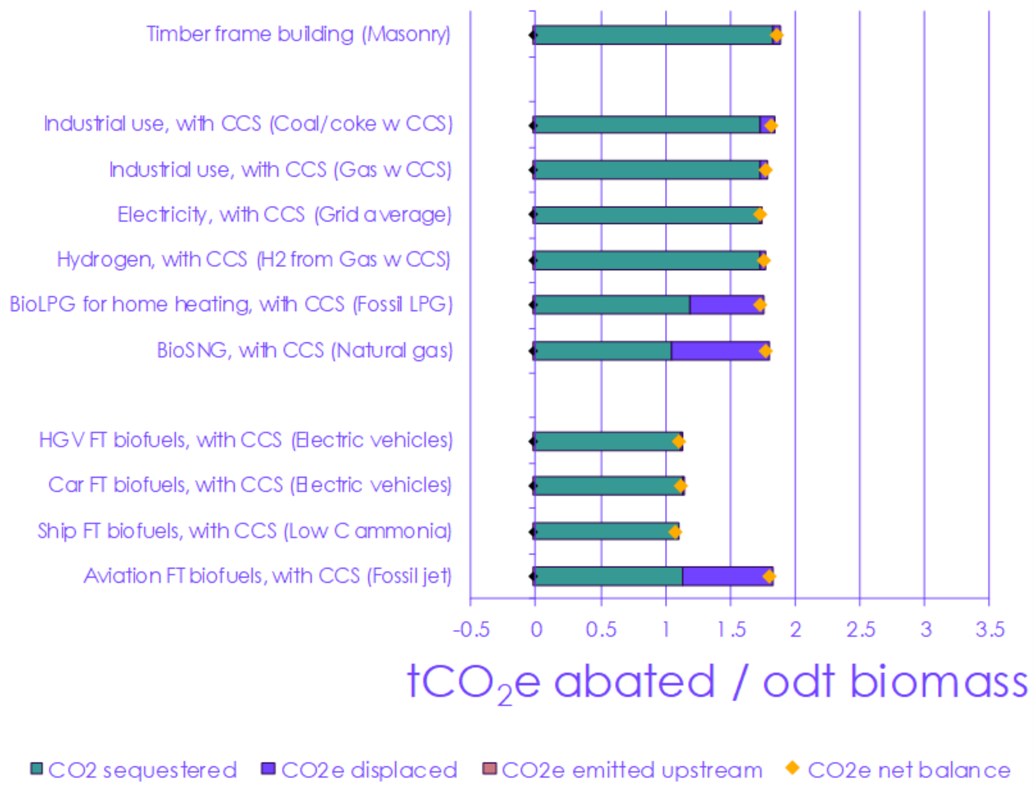
The use of wood in construction is still a best use, although the displaced emissions associated with production of the counterfactual (e.g. bricks, cement) are expected to fall in line with UK manufacturing & construction sector emissions. Upstream GHG emissions have also fallen, in line with the improved carbon intensity of biomass transport and any pre-processing.

* For example in aviation. Shipping & HGVs are starting to decarbonise with use of low-carbon ammonia in shipping and electricity/hydrogen use in HGVs by 2035, so the counterfactual may be lower than shown.

By 2050 (Figure 6.6), the main change is that the counterfactual in some sectors will have changed – for example, HGVs and shipping will be fully decarbonised using electricity and low-carbon hydrogen/ammonia fuels. The use of biomass in industry, power and hydrogen remains a best use (Figure 6.6), and the use of biomass in producing fuels is only a best use if high-carbon fuels are still being displaced, as in aviation.

There might still be a small niche for bioliquids/bioLPG for home heating if still displacing fossil fuels off-gas-grid, although these opportunities will be very limited due to efficiency and electrification. Fossil gas will still be used in the UK in 2050, however, as much of this fossil gas is going to hydrogen production (with CCS), it would be a more efficient use of biomass to make biohydrogen directly, instead of via bioSNG.

Figure M6.6 Best use of biomass in 2050



Source: Ofgem (2018) *Biomass Sustainability Dataset 2016-17*; CCC analysis.
Notes: Counterfactuals given in brackets. Upstream emissions include cultivation, processing, transportation and direct land-use change, but indirect land-use change and changes in land carbon stocks when no land-use change occurs are excluded. Upstream min-max range from Ofgem feedstock data (sawmill co-products, Miscanthus, SRC, wood pellets, forest residues and brash bales).

In summary, the findings from this new analysis support and strengthen the conclusions reached in the 2018 CCC Bioenergy report. Upstream emissions will diminish, best uses in 2035 already align well with those in 2050, and new bioenergy conversion facilities have to either be built with CCS or CCS ready, and their output products already aligned, or able to align, to long-term best uses.

- Upstream biomass supply chain GHG emissions (excluding land-use change*) will not significantly change the benefits of BECCS if policy & governance frameworks are well designed, and will improve significantly over time as harvesting, transport, storage and pre-processing steps decarbonise.
- With the widespread use of CCS on bioenergy facilities by the mid-2030s, the 2035 outlook is similar to 2050, as improvements in bioenergy process efficiencies and CO_2 capture rates are only modest. Changes in counterfactuals or their emissions intensities are a much bigger factor over this period.* However, BECCS applications that have high sequestration rates are not significantly impacted by the choice of counterfactual.
- Bioenergy use in the UK, which will be driven by policy incentives, already needs to focus on long-term best uses. There is unlikely to be sufficient time to undergo an intermediate transition before another final transition occurs, given assets built in the 2020s will still likely be operational by 2050.
    - There is therefore limited scope to develop biofuels for HGVs or shipping, given these are not best uses from the mid-2030s. Biofuel plants will need to focus on maximising biojet instead – although recognising that biojet plants may also output some heavier fuel co-products for HGVs or shipping, and lighter co-products such as bioLPG.
    - There is also likely to be a limited role for bioSNG, given the use of fossil gas will be declining to 2050, although bioSNG plants can be retrofitted to biohydrogen production to ensure best use.

* Land-use change emissions are covered under the LULUCF sector.

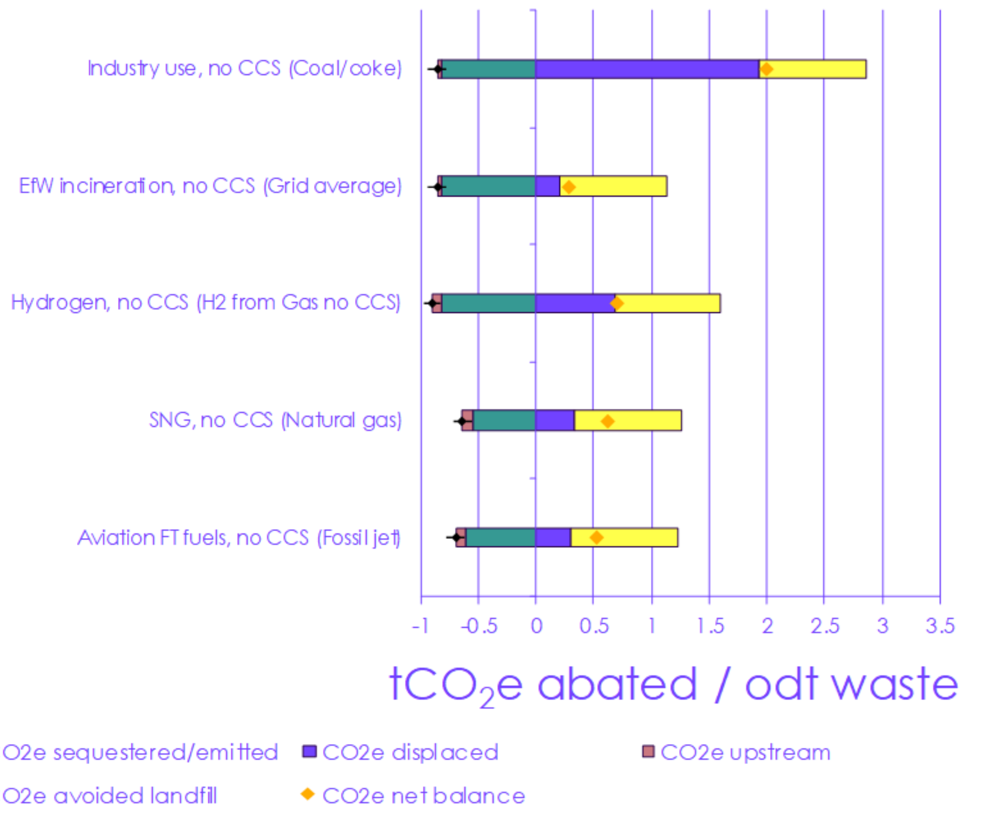
* This analysis is simplistic in terms of choosing a set of snapshot counterfactuals, whereas a more sophisticated analysis might consider blended counterfactuals to match sector decarbonisation profiles (without the use of bioenergy).

The following set of charts show the estimated GHG abatement provided by one oven dried tonne of residual waste (with mixed biogenic/fossil fractions) used in various sectors, considering the most appropriate counterfactual in each sector for that year.

Today (Figure 6.7), without CCS, conversion of waste into different energy vectors results in fossil CO_2 emissions (negative sequestration bars). These emissions are, however, offset by the methane emissions avoided from diversion away from landfill.

Upstream supply chain emissions in waste transport and pre-processing are small. The largest displacement savings are achieved in industry, via displacing high-carbon feedstocks. Savings in other applications are more modest – particularly energy-from-waste power plants, as UK electricity is now lower carbon than other vectors. Use of waste in energy-from-waste plants is still just about better than landfilling today, but other routes are able to achieve higher abatement in the near-term.

Figure M6.7 Best use of waste in 2020

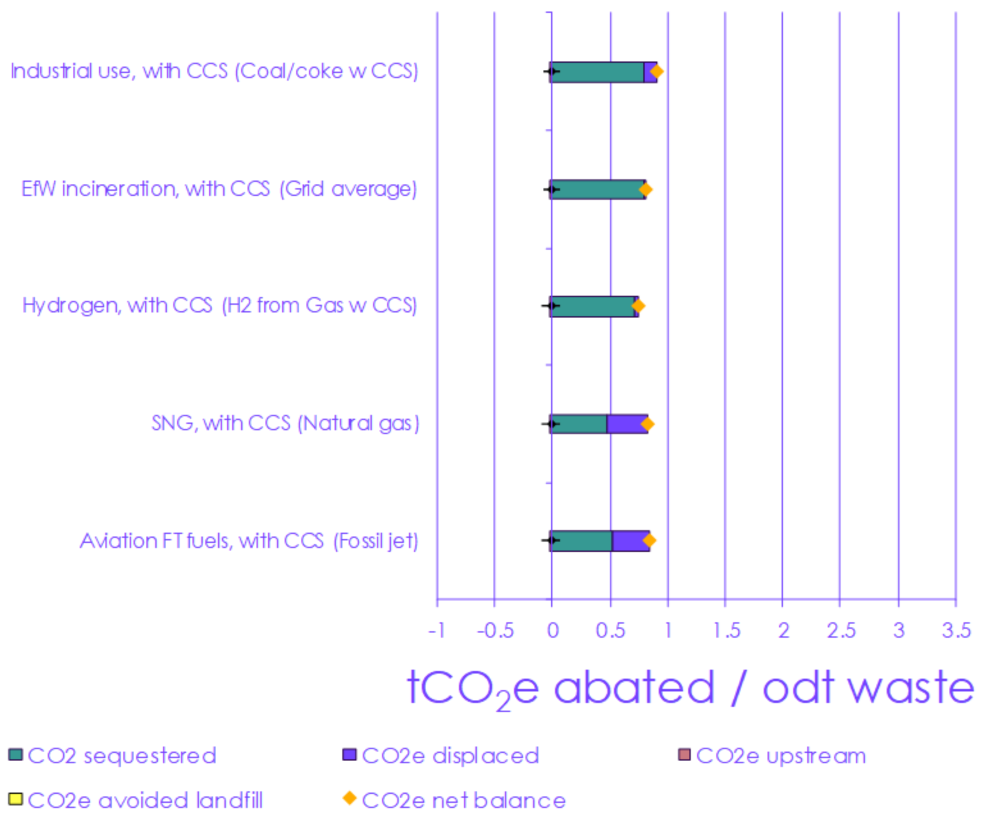


Source: CCC analysis.
Notes: Counterfactuals given in brackets. Upstream emissions include processing and transportation. Indicative min-max range given.

However, by 2050 (Figure 6.8), there is strong convergence between all the routes. High capture rates mean that 5-10% fugitive fossil CO_2 emissions in conversion are small compared to the 90-95% of biogenic CO_2 sequestered from conversion. Given no waste is sent to landfill from 2040 (under the Balanced Pathway), the landfill counterfactual savings no longer apply to this 2050 snapshot. The abatement from displacing fossil fuels has shrunk in several sectors due to the addition of CCS to the counterfactuals, and further decarbonisation or fuel-switching. This leads to the different routes achieving similar levels of overall abatement by 2050 (well within the uncertainty range of this analysis).

Our analysis of the best use of waste is more limited in scope than for biomass but has identified that adding CCS to energy-from-waste power plants leads to similar GHG savings outcomes as waste to jet fuel plants with CCS or other routes to hydrogen or gas. The addition of CCS is critical in turning fossil emissions from waste into net biogenic CO_2 sequestration, and given asset lifetimes, all waste conversion facilities have to either be built with CCS or CCS ready, and their output products already aligned, or able to align, to long-term best uses.

Figure M6.7 Best use of waste in 2050



Source: CCC analysis.
Note: Counterfactuals given in brackets. Upstream emissions include processing and transportation. Indicative min-max range given.

Endnotes

[1] CCC(2020) *The Sixth Carbon Budget – Methodology Report*. Available at: www.theccc.org.uk

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[17] Ofgem (2018) *Biomass Sustainability Dataset 2016-17*

Chapter 2

Emissions pathways for the Fuel supply sector

The following sections are taken directly from Chapter 3 of the CCC's Advice Report for the Sixth Carbon Budget.[1]

Introduction and key messages

Our Balanced Net Zero Pathway for Fuel Supply involves a transition from producing 1,100 TWh of fossil fuels and 170 TWh of bioenergy in 2018 to producing 425 TWh of low-carbon hydrogen and bioenergy in 2050, for sectors of the economy that are likely to use fuels, rather than electricity. Production of fossil fuels will be much lower by 2050.

Renewable electrolysis plays an increasingly important role in hydrogen supply, with CCS important in the medium term.

Recent cost reductions for renewables mean that electrolytic hydrogen plays a greater role than in our previous work, especially after 2035. However, there is an important role for hydrogen produced from fossil gas with CCS in the medium term to enable applications for hydrogen to grow as necessary.

Growth in UK forestry and perennial energy crops is needed to supply sustainable biomass across the economy.

Bioenergy resources increase in line with expanding UK production of forestry residues and perennial energy crops, with a wholesale shift to use with CCS accelerating during the 2030s.

The Balanced Pathway also requires action to reduce emissions from the remaining fossil fuel supply (the main source of Fuel Supply emissions) by 75% by 2035 from 2018 levels. Mitigation actions include fuel switching, CCS and technologies to reduce methane flaring, venting and leakage.

The analysis draws on new consultancy work from Element Energy, existing bioenergy resource work from our 2018 *Biomass in a low-carbon economy* report, and aligns with our new waste resource assumptions from the Waste sector (section 9). Further details are set out in our Methodology Report.

This section is split into three sub-sections:

a) The Balanced Net Zero Pathway for Fuel Supply

b) Alternative pathways to delivering abatement and fuel supplies

c) Scenario impacts

a) The Balanced Net Zero Pathway for Fuel Supply

The Balanced Pathway also requires action to reduce emissions from the remaining fossil fuel supply.

The Balanced Net Zero Pathway includes actions to i) reduce emissions from Fuel Supply, which mainly derive from fossil fuel supply ii) scale up hydrogen supply to enable decarbonisation in other sectors iii) provide bioenergy to other sectors while managing sustainability and achieving negative emissions.

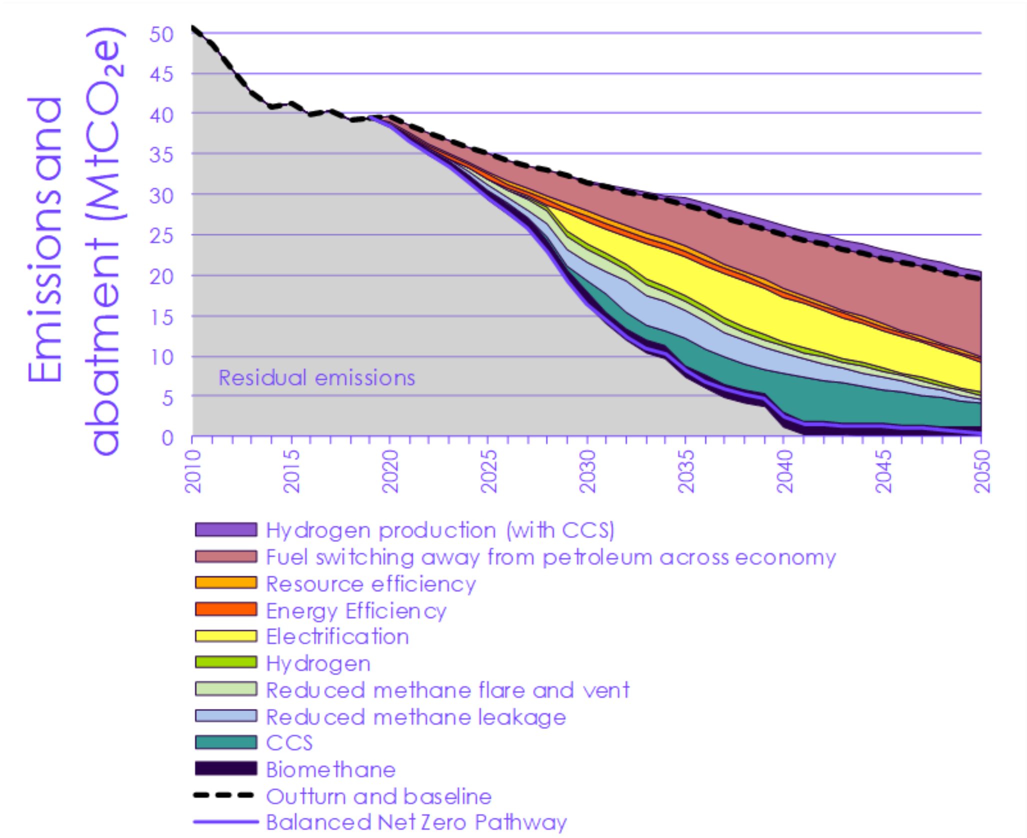
i) Decarbonising fuel supply

Our Balanced Net Zero Pathway requires fossil fuel supply emissions to be reduced by 75% by 2035 from 2018 levels. While the Fuel Supply emissions category is dominated by emissions from fossil fuel supply, there are also some new emissions arising from future production of low-carbon hydrogen fuel.* This is reflected by the emissions wedge from hydrogen production above the baseline in Figure 3.5.a.

* Existing UK high-carbon hydrogen production for use as an industrial feedstock is included within our manufacturing sector. Our Fuel Supply sector contains low-carbon hydrogen to be used as a fuel.

In our pathway, emissions from fossil fuel supply are reduced by 75 % by 2035 from 2018 levels, through fuel switching, CCS and reduction of methane flaring, venting and leakage.

Figure A3.5.a Sources of abatement in the Balanced Net Zero Pathway for the fuel supply sector



Source: BEIS (2020) *Provisional UK greenhouse gas emissions national statistics 2019*; CCC analysis.
Notes: New hydrogen supply arising due to climate mitigation policy increases emissions relative to the baseline, so emissions appear above the baseline. As a result the Balanced Net Zero Pathway appears slightly above the bottom of the lowest wedge of emissions abatement. The biomethane abatement reflects biomethane use displacing residual natural gas use across the economy, not only in the fuel supply sectors. This means that the lowest emissions wedge drops slightly below zero in 2050.

In this report, we have also accounted for abatement from the additional use of biomethane to displace fossil gas across the economy.* After accounting for hydrogen production and biomethane abatement, our Balanced Pathway for the whole Fuel Supply sector requires emissions to be reduced by around 80% by 2035 from 2018 levels (Figure 3.5.a).

Refinery output will fall as a result of decarbonisation in the transport sector. Remaining refinery sites can be largely decarbonised.

The emissions from fossil fuel supply include those directly from oil refining, oil and gas production, oil and gas processing terminals, gas transmission and distribution networks and open and closed coal mines (see Methodology report for further details).Oil refineries emissions are abated through reduced oil demand, CCS and energy efficiency improvements.

- Fuel switching away from petroleum across the economy, such as in surface transport, is the largest emissions reduction action. This reduces oil refining in the UK and the associated emissions by 5 $MtCO_2e$/year by 2035. (Figure 3.5.a).

* While we have aggregated biomethane abatement and included this all within Fuel Supply, in practice the biomethane would abate emissions within the sectors where the use of fossil gas is displaced by biomethane.

- CCS is the main emissions reduction measure for the remaining emissions from oil refineries, with 1.5 $MtCO_2e$/year of abatement in 2030, 3 $MtCO_2e$/year in 2035 and 4.5 $MtCO_2e$/year in 2040. Energy efficiency measures also reduce emissions by 0.5 $MtCO_2e$/year in 2035.

Emissions from oil and gas production can be reduced by measures including increased electrification and reduced venting and flaring of gas.

Emissions from oil and gas production, predominantly from offshore platforms and from onshore processing terminals, are decarbonised mainly by fuel switching and measures to reduce methane flaring and venting:

- Electrification of offshore platforms and processing terminals contributes 5 $MtCO_2e$/year of abatement in 2035. This involves 4 $MtCO_2e$/year of electrification of compressors and generators on oil and gas platforms, which requires connecting the platforms to either the onshore electricity grid or offshore wind generation. The remaining 1 $MtCO_2e$/year of electrification is at oil and gas processing terminals. These actions start in the mid-2020s, with some action electrification of platforms assumed to occur within our baseline.
- Use of hydrogen plays a smaller role in the fossil fuel abatement pathways, providing 1 $MtCO_2e$/year of abatement across platforms and terminals.
- Measures to reduce methane flaring and venting, such as capturing the gas and selling it, and switching from venting to flaring (where safety requires at least one or the other) save 1.5 $MtCO_2e$/year in 2030 and 1 $MtCO_2e$/year in 2035.

Monitoring systems are important to catch methane leaks from the gas network quickly.

Methane leaks from the gas distribution and transmission networks are reduced in the Balanced Pathway using a combination of Leakage Detection and Repair (LDAR) technologies and continuous monitoring technologies, resulting in 3.5 $MtCO_2e$/year in 2035.

Other abatement measures in the fuel supply Balanced Pathway include 0.5 $MtCO_2e$/year of abatement in 2035 from a variety of resource efficiency measures across the economy and 1.5 $MtCO_2e$/year of abatement from the use of biomethane to displace fossil gas in the gas grid.

The largest sources of remaining emissions from fossil fuel supply in 2050 is from closed coal mines (0.4 $MtCO_2e$/year). From the wider Fuel Supply sector, there is also 1 $MtCO_2e$/year remaining from hydrogen production in 2050.

ii) Low-carbon hydrogen supply

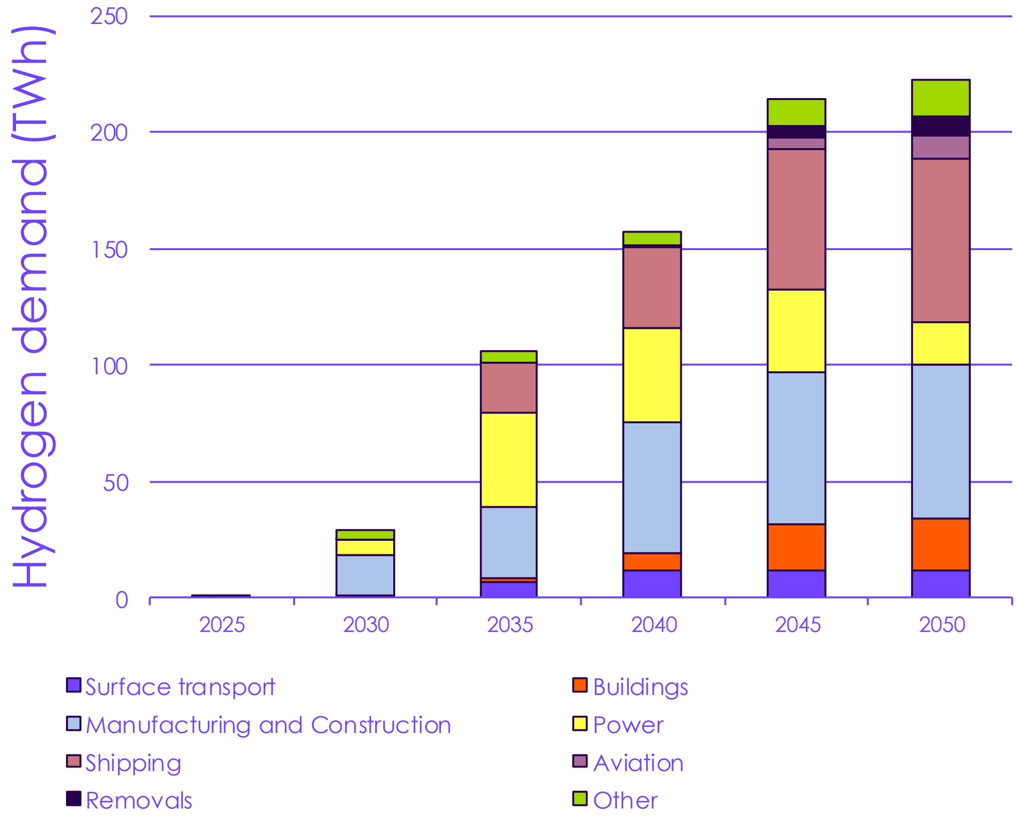
The role for the hydrogen supply sector is to enable decarbonisation in other sectors while managing costs and wider energy system impacts. Hydrogen appears to be essential for reaching Net Zero, but it is important for it to be focused on the applications of highest value, where electrification is less feasible, and for it to be produced in a low-carbon way.

Low-carbon hydrogen will mainly be used in manufacturing, shipping and back-up power.

Hydrogen demands in the Balanced Pathway start growing in the second half of the 2020s, before strong growth over the period 2030 to 2045. Manufacturing, shipping (as ammonia), and back-up power generation are the largest three sectors in terms of demand, with smaller contributions from other sectors including buildings and surface transport.

Hydrogen starts being used at scale in the late 2020s, ramping up significantly to 2045.

Figure A3.5.b Hydrogen demands in the Balanced Net Zero Pathway



Source: CCC analysis.
Notes: Demand in shipping is likely to be as ammonia rather than compressed hydrogen. Demand given is for H2 produced in the UK or for imports of H2. Imports of ammonia (used in shipping) and imports of synfuels (used in aviation) are not included, but on a H2 feedstock basis would equate to another 23 and 5 TWh respectively by 2050 (i.e. 18 TWh of ammonia and 2.6 TWh of synfuels).

Hydrogen is supplied to UK users from a mix of renewable electrolysis, fossil gas with CCS, bioenergy with CCS, and imports.

In the Balanced Net Zero Pathway, hydrogen production is from a mix of supply routes, with differing contributions over time:

- **Electrolysis:**
  - The relatively low costs of variable renewables, especially offshore wind, make it attractive to err on the side of 'over-building' renewable capacity relative to electricity demands, which generates a surplus of generation at some points of the year. Some of this generation that would otherwise be curtailed is then used to produce hydrogen, providing extra value from the renewable capacity.
  - However, over the period to 2035 the volumes of electrolytic hydrogen are constrained by how much renewable capacity can be built and contribute economically to meeting demands for electricity as well as hydrogen. Electrolysis comprises 21% of hydrogen supply by 2035, but this rises to 44% by 2050 as costs fall and supply constraints ease.

Hydrogen made from fossil gas with CCS will have an important supply role, particularly in the 2030s while electrolysis ramps up.

- **Fossil gas with CCS:** Reformation of fossil gas with CCS is capable of producing low-carbon hydrogen at scale. However, it is not zero-carbon, with lifecycle emissions savings of up to 85% relative to unabated fossil gas.[2] So, while reforming of fossil gas with CCS is important in establishing a mass market for hydrogen, providing around 60% of hydrogen supply by 2035, it falls into more of a supporting role by 2050, providing 32% of hydrogen supply. The smaller share for hydrogen from fossil gas in 2050 limits emissions from the production process and upstream emissions from fossil gas supply.

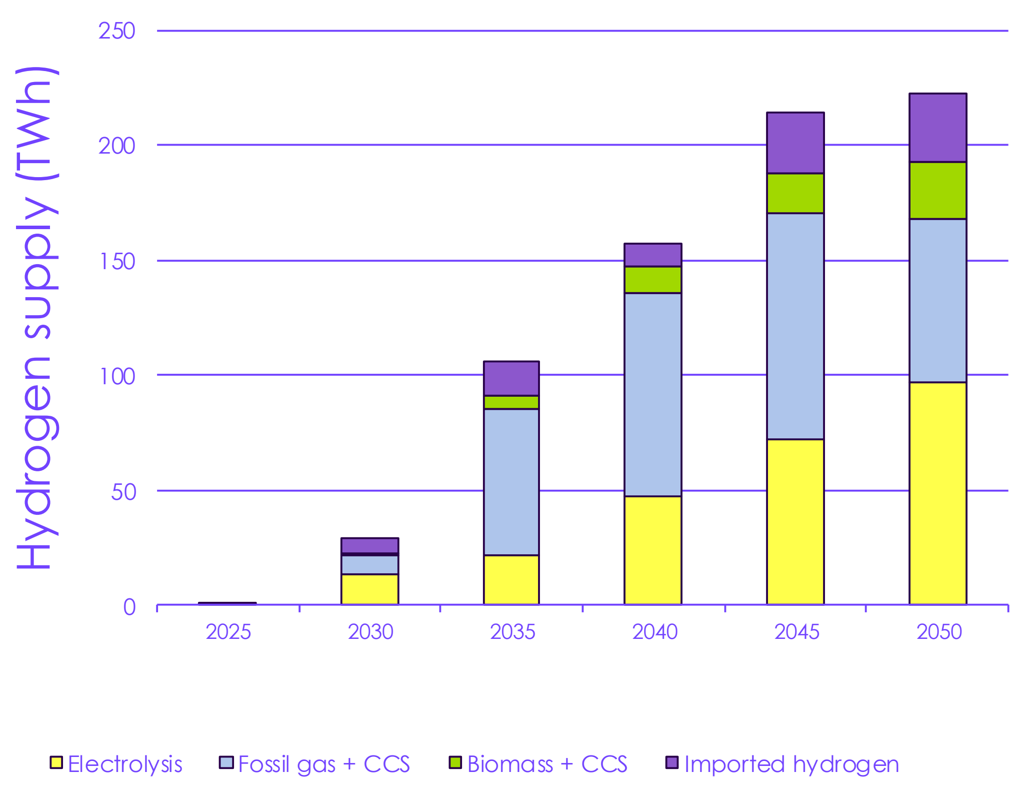
Hydrogen made from bioenergy with CCS can also provide negative emissions.

- **Bioenergy with CCS (BECCS):** Biomass undergoes gasification to produce biohydrogen, with the biogenic CO_2 being captured and stored. This route provides 5% of supply by 2035 and 11% by 2050.

- **Imports:** In the Balanced Pathway, imports of hydrogen made from renewable electrolysis abroad amount to 13% of total hydrogen consumption by 2050. There are also further imports of renewable ammonia used for shipping, and imports of synthetic jet fuel used for aviation.

The contribution of electrolysis increases over time, but reforming of fossil gas with CCS has an important transitional role.

Figure A3.5.c Hydrogen supply in the Balanced Net Zero Pathway



Source: CCC analysis.
Notes: This only includes H2 produced in the UK, or imports of H2. Imports of ammonia and synfuels are not plotted, but on a H2 feedstock basis would equate to another 23 TWh and 5 TWh respectively by 2050 (i.e. 18 TWh of ammonia and 2.6 TWh of synfuels).

iii) Bioenergy supply

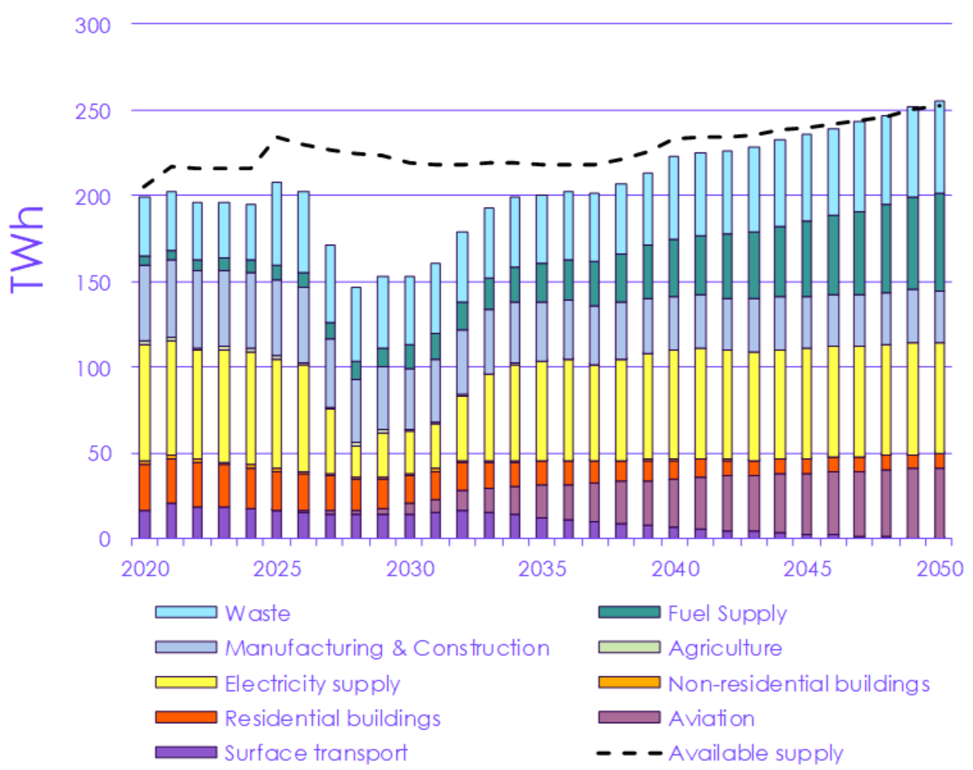
Sustainable bioenergy supply limitations mean that GHG savings from the use of biomass must be maximised.

Sustainable bioenergy is essential for reaching Net Zero. Given resource supply limitations, it must be used in those applications with the highest GHG savings (those with CO_2 sequestration and/or displacement of high carbon alternatives).

By 2050, the large majority (85%) of bioenergy will need to be used with CCS, achieving negative emissions, across electricity generation, industrial heating, biohydrogen production, biofuel production and waste incineration (Figure 3.5.d).

Biojet and biohydrogen are significant growth markets for bioenergy with CCS. Biomass power transitions to with CCS starting in the late 2020s.

Figure A3.5.d Bioenergy and waste use in the Balanced Net Zero Pathway



Source: CCC analysis.
Notes: These values are TWh/yr HHV, given as the starting CCC 'Primary' bioenergy and waste resources, i.e. solid biomass, gaseous biogas, liquid bioethanol and waste biodiesel, and solid wastes. There are minor differences between these total supply estimates and the total use estimates due to manufacturing and energy from waste modelling approximations.

In the Balanced Pathway, bioenergy production occurs via a mix of supply routes, with differing contributions over time (Figure 3.5.e). A number of these routes involve CCS, with further details of the GHG removals involved given in section 11:

The majority of UK bioenergy supplies are currently solid biomass feedstocks. Use in building heating and unabated power plants will phase out.

- **Solid biomass.** Domestic and imported biomass feedstocks are supplied directly (without conversion) to the Power, Manufacturing & Construction, Residential & Non-residential Buildings and Agriculture sectors. Use of solid biomass in combustion boilers phases out in Buildings and Agriculture by the early 2040s. Manufacturing & Construction continues to use biomass, with a gradual decline over time, and with a small amount also used with CCS by 2050.

Use in unabated biomass power plants quickly phases out in the late 2020s, while use in power with CCS starts to slowly ramp-up from the late 2020s (via retrofits and newbuild BECCS plants) to reach significant levels by 2040, providing 4% of electricity generation. Biomass imports comprise 21% of total bioenergy & waste supplies by 2050.

- **Biohydrogen**. Solid biomass feedstocks are gasified then converted into hydrogen, with CCS. Deployment starts in 2030, and ramps-up as described in section ii) above.

Waste fats/oils currently used for road transport biodiesel will transition to biojet during the 2030s.

- **Biojet**. Solid biomass feedstocks are gasified then converted into aviation biofuel, with CCS. Starting from the mid-2020s, this route ramps-up to meet 11% of aviation fuel demand by 2050. In addition, waste fats/oils are converted into biojet, with a transition from biodiesel in the 2030s, with their use alongside limited biojet imports ultimately meeting 6% of aviation demand by 2050.

Biodiesel has a potential transitional role in HGVs and buses, but over time will increasingly focus on biojet for aviation.

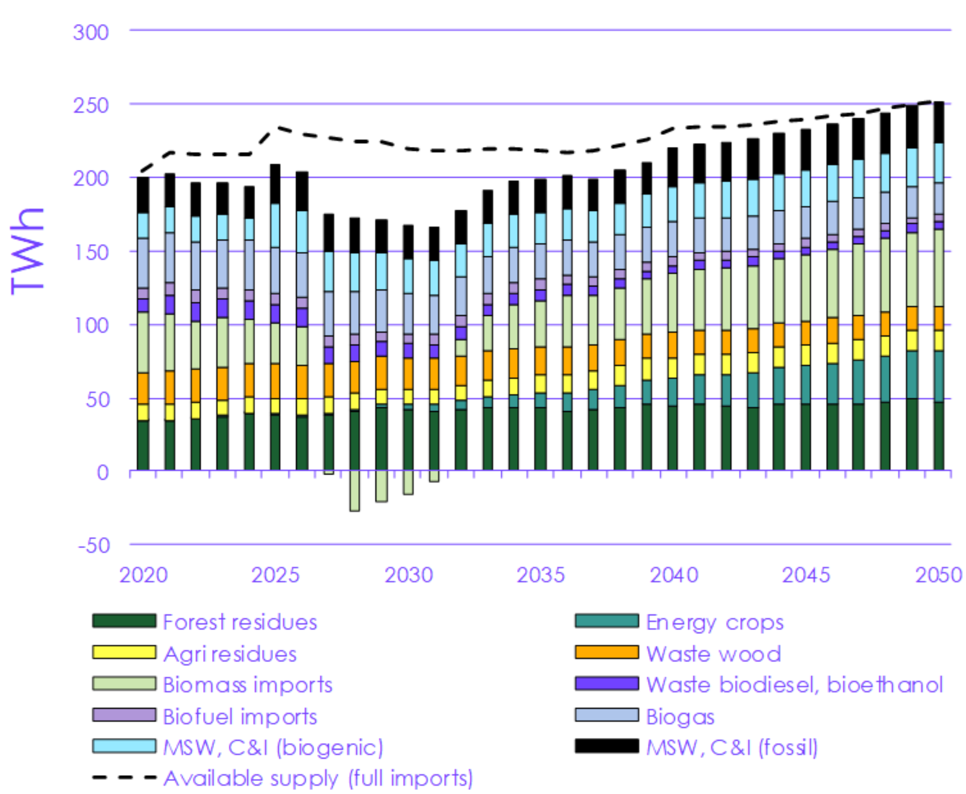
- **Biodiesel**. Solid biomass feedstocks are gasified then converted into biodiesel, with CCS. Starting from the mid-2020s, this route increases production to meet 2% of car/van diesel demand by the early 2030s, and 10% of HGV/bus diesel demand by 2040. As liquid fuel volumes fall in each road transport mode, these plants transition to focus on biojet production. Biodiesel made from waste fats/oils in existing facilities, and imports, continue to supply 3% of road diesel. There is some additional use in off-road machinery and agricultural equipment ramping up to the early 2030s, before phasing out by 2040.
- **Heating biofuels.** A range of liquid biofuels made from biomass (with CCS) or from waste fats/oils can be used for home heating, including bio-LPG and biokerosene amongst other options. Starting from the mid-2020s, use of bioliquids ramps up to 5 TWh/year in the 2040s, supplying hybrid heat pump systems situated in homes off the gas-grid.
- **Bioethanol**. Arable crops are fermented into bioethanol in existing facilities. After the 2021 increase of bioethanol blended into petrol (to 10% by volume, 7% by energy), supplies stay at this % of road petrol use.

Biomethane & biogas could displace up to 10% of UK gas demand, and biomethane injection into the gas grid more than trebles in the next 10 years.

- **Biomethane & biogas.** Biogas produced from anaerobic digestion of food waste, sewage sludge & animal manures, plus captured landfill gas, can be upgraded to biomethane for gas grid injection, along with the capture of biogenic CO_2 for sequestration. Biomethane injection more than trebles by 2030 from today's levels. Biogas also continues to be used in Power and Manufacturing, although its use declines in the near-term with the fall in landfill gas. Combined, these routes could displace 10% of fossil gas in 2050.
- **Residual waste**. After re-use & recycling, any residual waste volumes not exported or landfilled are predominantly incinerated in energy from waste plants, with some small use in Manufacturing. All energy from waste plants fit CCS by 2050, to capture the fossil and biogenic CO_2 emissions resulting from the mixed fossil/biogenic waste fractions.

Imports are expected to go negative (i.e. the UK becomes a net biomass exporter) for a few years around 2030 if unabated biomass power plants close down faster than BECCS power plants start operating.

Figure A3.5.e Bioenergy and waste supply in the Balanced Net Zero Pathway



Source: CCC analysis.
Notes: These values are TWh/yr HHV, given as the starting CCC 'Primary' bioenergy and waste resources, i.e. solid biomass, gaseous biogas, liquid bioethanol and waste biodiesel, and solid wastes. The dashed line shows the supply available to the UK were the UK to, in all years, use all of its fair share in the globally traded sustainable resource.

b) Alternative pathways to delivering abatement and fuel supplies

Our Fuel Supply scenarios i) set out different abatement pathways; ii) present a variety of hydrogen supply mixes; and iii) use different allocations of bioenergy for each end use sector.

i) Decarbonising fuel supply

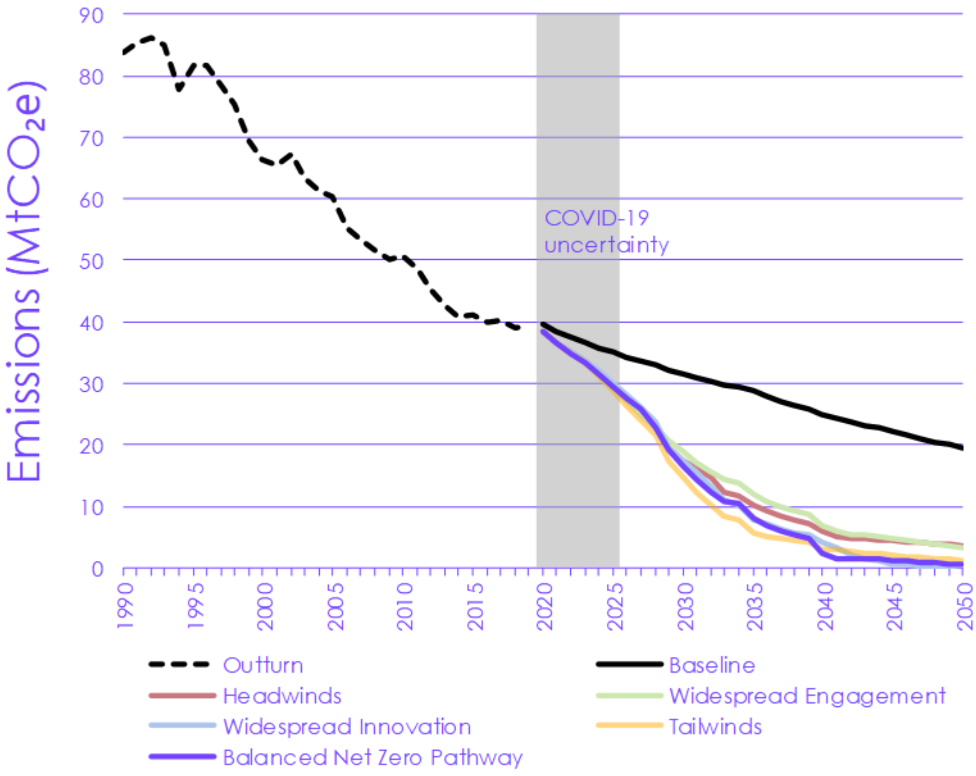
Hydrogen could play a role in decarbonising oil and gas platforms.

The four exploratory pathways contain similar emissions abatement measures (concentrated in fossil fuel supply) to the Balanced Pathway. There could however be a greater role for hydrogen in the reducing emissions from offshore platforms and onshore processing terminals than reflected in the scenarios. Decarbonisation of emissions from increased onshore petroleum production, such as shale gas, is considered in our Widespread Innovation Scenario.

The pace of decarbonisation differs slightly between scenarios, as a result of different future energy prices, supply-chain capacities and the varying levels of hydrogen production (Figure 3.5.f).

The rate of progress decarbonising Fuel Supply since the 1990s to today needs to continue until the 2040s.

Figure A3.5.f Emissions pathways for the fuel supply sector



Source: BEIS (2020) *Provisional UK greenhouse gas emissions national statistics 2019*; CCC analysis.

ii) Low-carbon hydrogen supply

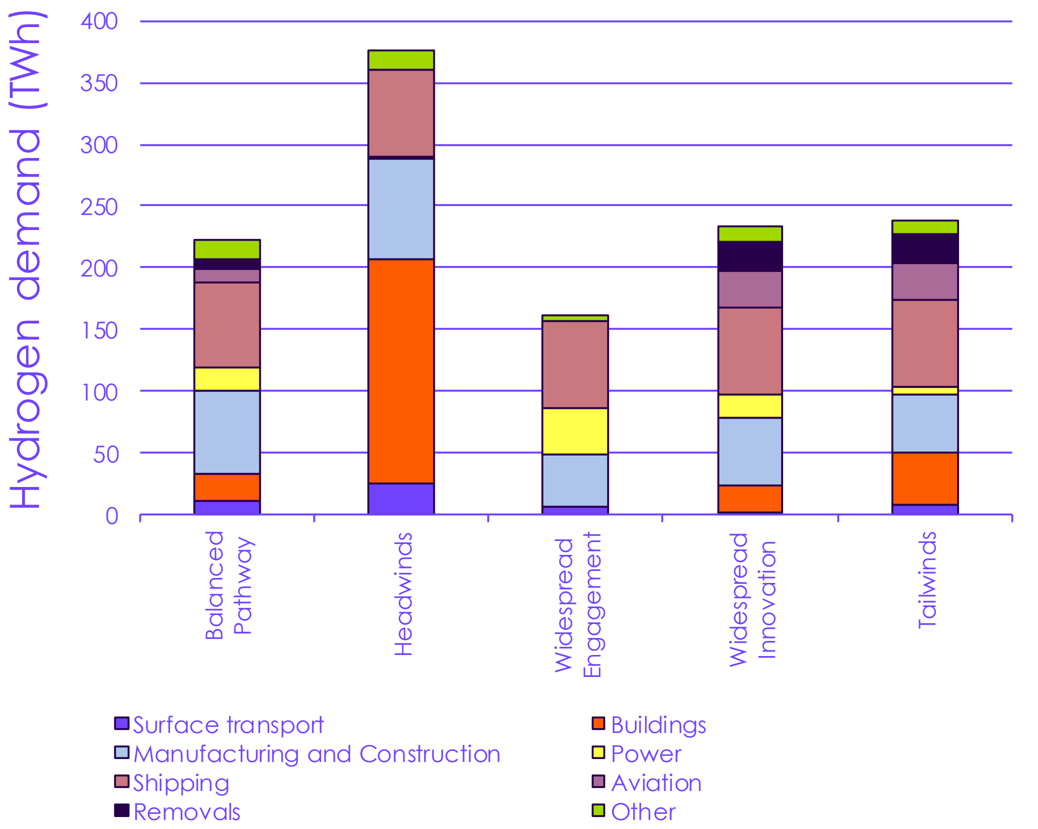
Our exploratory scenarios have a wide range for low-carbon hydrogen use in 2050, due to end-use sector choices.

Low-carbon hydrogen demands vary considerably across the exploratory scenarios, with a range for total demand in 2050 of 160-375 TWh/year (Figure 3.5.g). This reflects different mixes of decarbonisation solutions being applied in the end-use sectors, with the role in buildings heating particularly contributing to the upper end of demand. Hydrogen is also used in Direct Air Capture with CCS or synthetic jet fuel production in the Widespread Innovation and Tailwinds scenarios.

Based on our assessment of available supply routes for hydrogen and the challenges they face, our scenarios for hydrogen demand are considerably lower than could be the case if hydrogen were used in all conceivable uses across the energy system (e.g. exceeding 800 TWh in 2050 compared to 225 TWh in the Balanced Pathway).

This is due to limits on scaling up further the contributions on hydrogen supply from electrolysis (e.g. due to build rates for zero-carbon capacity and costs) and from BECCS (i.e. due to finite bioenergy supplies) – as a result, higher hydrogen demand would be likely to lead to much greater dependence on reforming fossil gas with CCS. In turn, this would increase residual emissions from hydrogen production and fossil fuel production, as well as increasing reliance on CCS and imported fossil gas.

Figure A3.5.g Sectoral hydrogen demands in 2050



Source: BEIS (2020) *Provisional UK greenhouse gas emissions national statistics 2019*; CCC analysis.
Notes: Demands in shipping is likely to be as ammonia rather than compressed hydrogen. Demand given is for H2 produced in the UK or for imports of H2. Demands for imports of ammonia (for shipping) and imports of synfuels (for aviation) are not included.

Scenarios demanding a lot of low-carbon hydrogen use more fossil gas with CCS, whereas scenarios with lots of renewables on the grid use more electrolysis.

The mix of hydrogen supply routes that meet these demands also vary, depending on total hydrogen demand, technology costs and the development of the electricity system. High demand for low-carbon hydrogen leads to a higher contribution from fossil gas with CCS, whereas more renewables on the grid leads to more electrolysis (Figure 3.5.h):

- In **Headwinds**, low-carbon hydrogen demand is relatively high (around 375 TWh in 2050). This is primarily due to the high demand from buildings, which is around half of the total. The role of variable renewables on the electricity grid is lower than in other scenarios, which limits the role of electrolysis in 2050 to 13% of supply. There are also relatively modest roles for BECCS (11%) and imports (14%). As a result of the higher demand, there is an increased role for hydrogen supply from reforming of fossil gas (63%), leading to a relatively high reliance on fossil gas imports and CCS.

- In **Widespread Engagement**, low-carbon hydrogen demand is relatively low (around 160 TWh/year in 2050). Electrolysis supply follows a similar path to the Balanced Pathway, but due to the lower level of total hydrogen demand, electrolysis plays a bigger relative role in this scenario, meeting 59% of supply by 2050. However, there is an important role for fossil gas with CCS, especially in the transition, which contributes 34% of supply in 2035 and falls to 18% in 2050. Imports are also 23% in 2050, and there is no BECCS hydrogen assumed in this scenario.

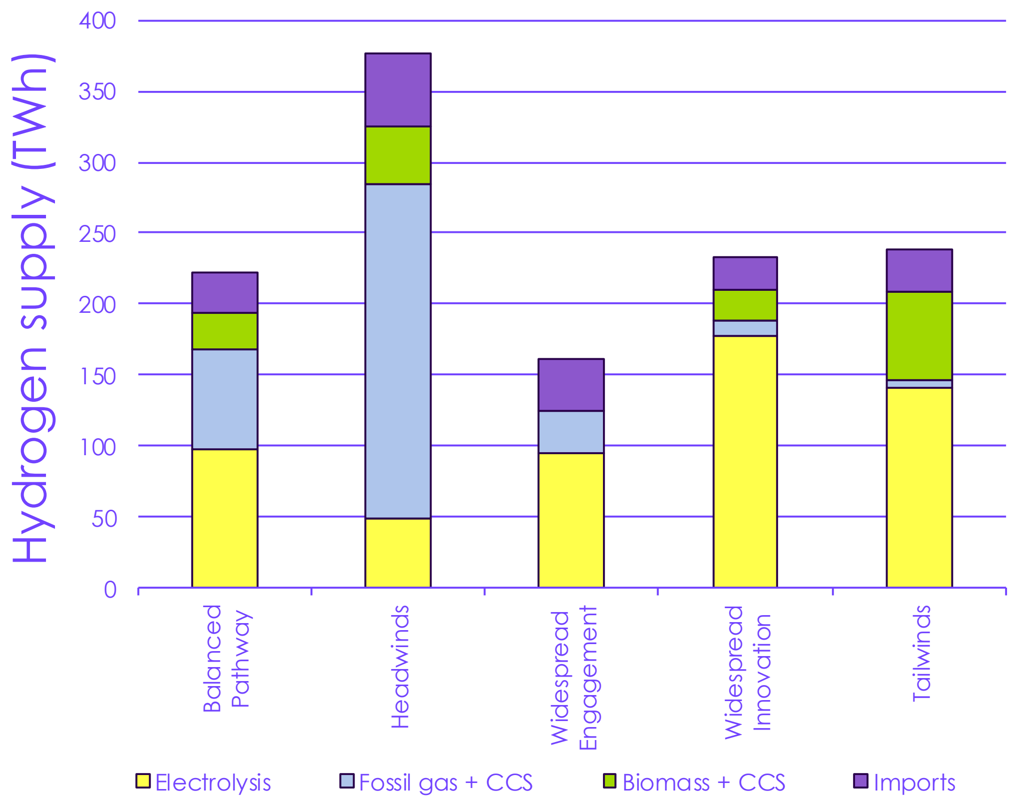
Low cost renewables on the grid leads to cheaper electrolysis but also cheaper electrification of end use sectors. Electrolysis can dominate hydrogen supplies by 2050.

- **Widespread Innovation** has a similar overall level of low-carbon hydrogen demand (233 TWh/year in 2050) as in the Balanced Pathway, as low-cost renewables enable electrification to outcompete hydrogen across a number of applications. However, the high share of low-cost variable renewables in the power system also means that electrolysis is particularly cost-effective compared to other low-carbon hydrogen supply options, and so electrolysis contributes strongly to UK supply (76% by 2050). Again, there is an important role for fossil gas with CCS in the transition, which provides 46% of supply in 2035 before falling into a back-up role supplying just 5% in 2050. The contribution of BECCS hydrogen production rises to 9% by 2050, and imports supply 10%.

Scenarios with a very rapid uptake in demand for low-carbon hydrogen will rely on fossil gas with CCS in the transition.

- **Tailwinds** is similar to the Widespread Innovation scenario by 2050, although it has significantly higher total hydrogen demand in earlier years, peaking at just over 250 TWh at the point this scenario reaches Net Zero in the early 2040s. Electrolysis dominates the supply mix again, reaching 59% by 2050, with BECCS supplying much of the rest (26%). Due to the more rapid uptake of hydrogen in the period to 2035, fossil gas with CCS plays a crucial transitional role, supplying 66% of hydrogen in 2035 before falling into a back-up role of 2% by 2050. Imports provide 12% of supply in 2050.

Figure A3.5.h Hydrogen supply in 2050 across the scenarios



Source: CCC analysis.
Notes: This only considers H2 produced in the UK, or imports of H2. Imports of ammonia and synfuels are not plotted.

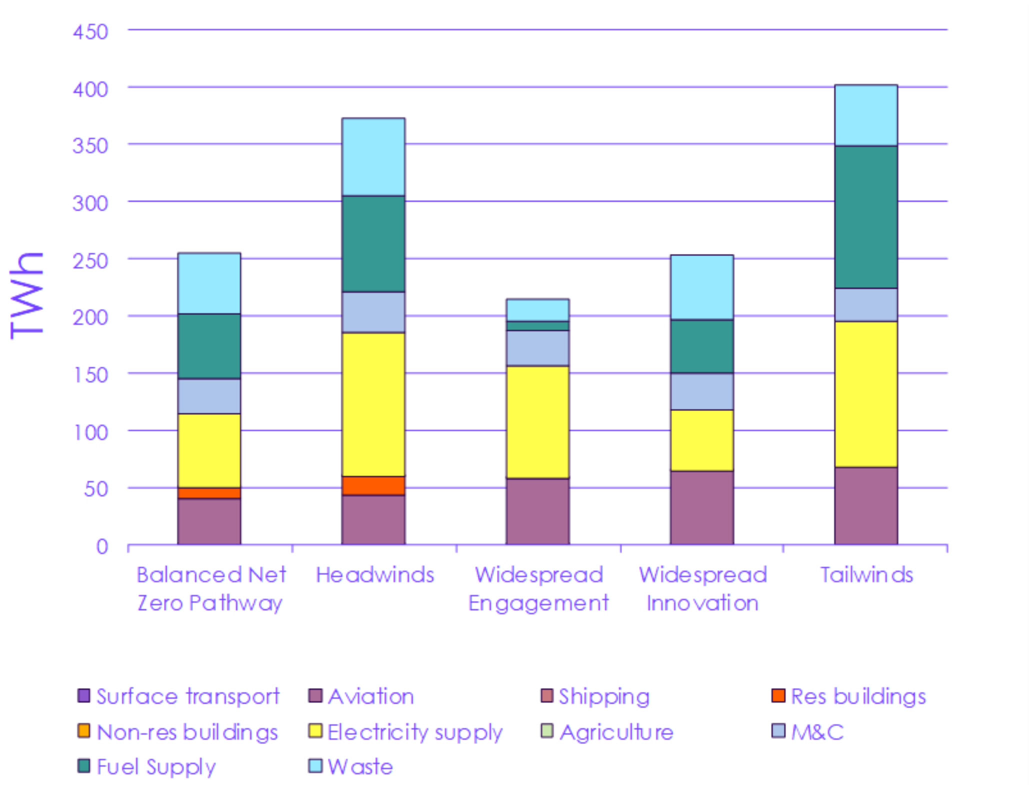
iii) Bioenergy supply

Our exploratory scenarios have a wide range for bioenergy use by 2050, due to different assumptions on supply availabilities.

Demands for bioenergy and waste vary considerably across the exploratory scenarios, with a range for total primary bioenergy supplies used in 2050 of 210-390 TWh/year (before any further conversion within the Fuel Supply sector). This reflects different mixes of feedstocks, conversion technologies and end-use solutions, with the role of BECCS power and BECCS hydrogen contributing to the largest differences between the scenarios.

The largest differences between the scenarios are due to differing use in BECCS power, hydrogen and energy-from-waste.

Figure A3.5.i Bioenergy and waste use in 2050 across the scenarios



Source: CCC analysis.

Notes: These values are HHV, given as the starting CCC 'Primary' bioenergy and waste resources, i.e. solid biomass, gaseous biogas, liquid bioethanol and waste biodiesel, and solid wastes.

Domestic feedstocks have a larger role than biomass imports, which only contribute significantly in high bioenergy demand scenarios.

Domestic bioenergy compromises the large majority of our supply estimates, with biomass imports only contributing significantly to the higher supply scenarios. The mix of domestic bioenergy and waste supplies that meet these demands also vary:

- In the **Headwinds** scenario, bioenergy demand is relatively high. The role of variable renewables in electricity is lower than in other scenarios, allowing a larger role for BECCS power, and high hydrogen use allows a large role for BECCS hydrogen. Less waste prevention & recycling also leads to more use in energy from waste. By 2050, 42% of total supply is from biomass imports.

Waste could be used in jet fuel production instead of generating electricity in energy-from-waste plants.

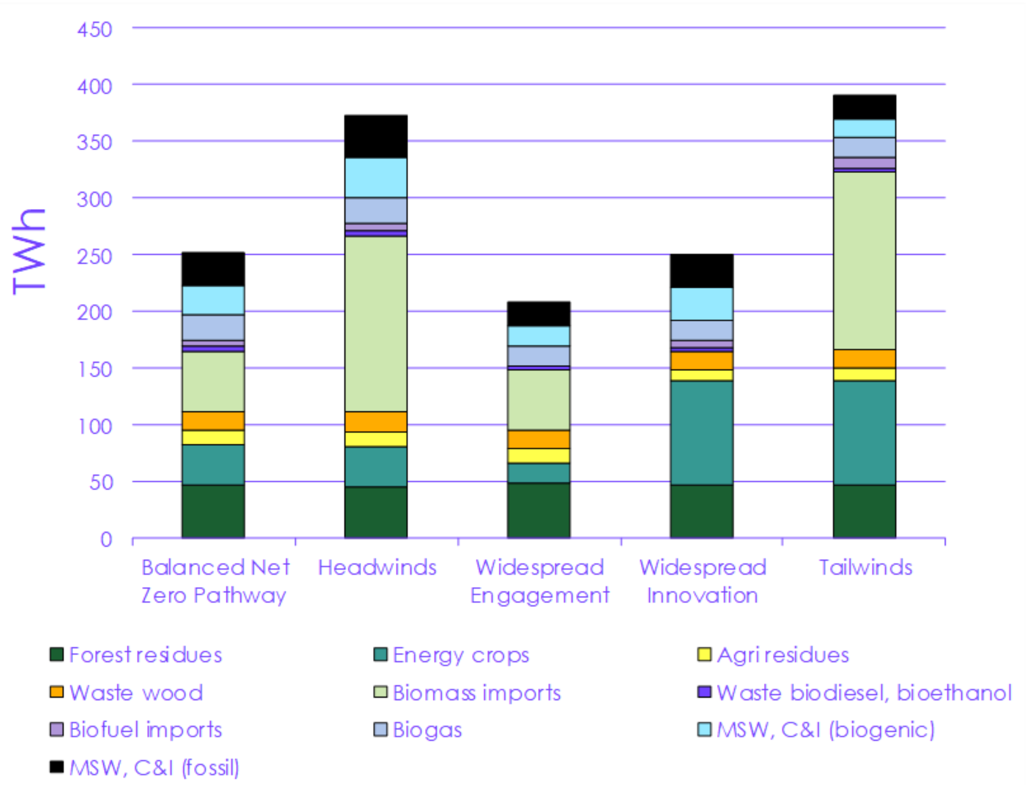
- In **Widespread Engagement**, bioenergy demand is low. Due to lower hydrogen demand, there is no role for BECCS hydrogen. Waste prevention and recycling, and allocation to jet production, results in low use in energy from waste plants. By 2050, 25% of total supply comes from biomass imports, with very limited uptake of domestically grown perennial energy crops.

Biomass imports can be phased out by 2050 if UK supplies of forestry and perennial energy crops are expanded significantly.

- The **Widespread Innovation** scenario has less hydrogen demand across the economy, and very high levels of low-cost renewable electricity, resulting in more modest roles for BECCS power and BECCS hydrogen by 2050. There is earlier use of biomass gasification to biomethane, before these plants transition to biohydrogen and retrofit CCS from the mid-2030s. This scenario relies heavily on domestically grown perennial energy crops, making up 36% of total supply by 2050, and biomass imports phase out by 2050.
- The **Tailwinds** scenario combines the most ambitious elements of the above three scenarios, with the high biomass imports from Headwinds (providing 40% of total supply by 2050), the high deployment of domestically grown perennial energy crops in Widespread Innovation (providing 23% of total supply by 2050), and ambitious action on waste prevention & recycling as in Widespread Engagement. The result is significantly more biomass available for BECCS power and hydrogen. As in Widespread Innovation, there is also a transitional role for biomass gasification to biomethane.

Across our scenarios, biomass imports make up between 0% and 42% of total supply. The Balanced Pathway has 21%.

Figure A3.5.j Bioenergy and waste supply in 2050 across the scenarios



Source: CCC analysis.
Notes: These values are HHV, given as the starting CCC 'Primary' bioenergy and waste resources, i.e. solid biomass, gaseous biogas, liquid bioethanol and waste biodiesel, and solid wastes. There are minor differences between these total supply estimates and the total use estimates due to manufacturing and energy from waste modelling approximations. MSW = Municipal Solid Waste. C&I = Commercial and Industrial.

c) Scenario impacts

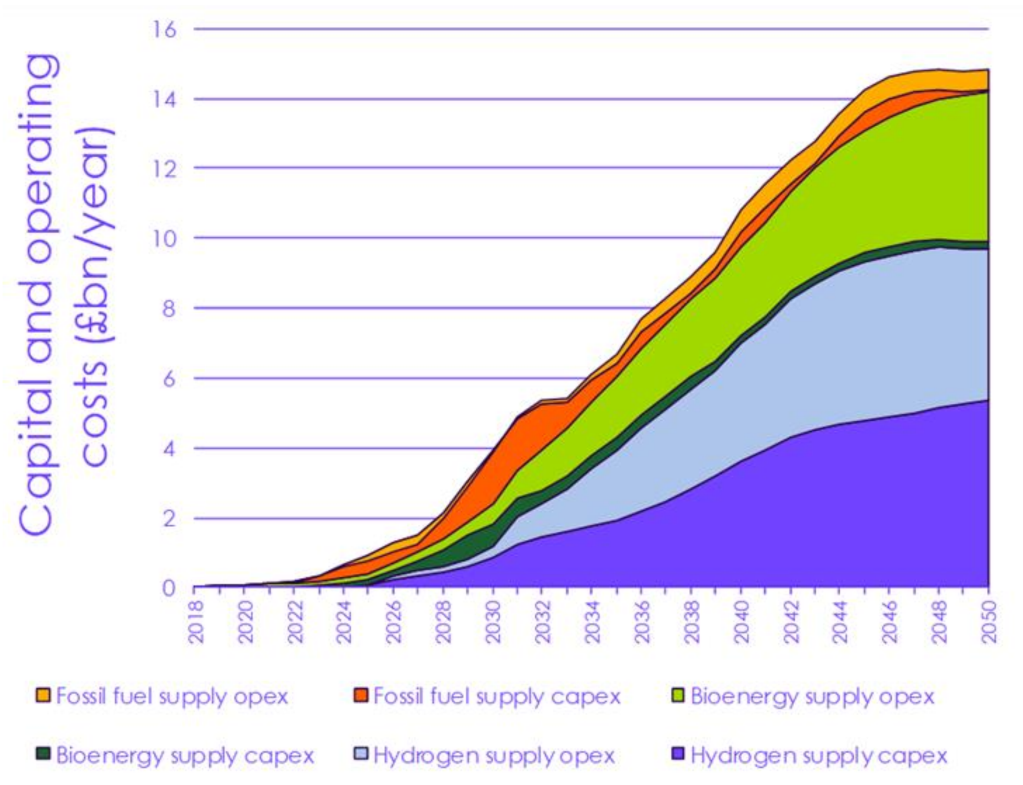
The Balanced Pathway will incur additional financial costs in the Fuel Supply sector associated with reducing emissions from fuel supply, and the production of low-carbon fuels. Essential to this transition from fossil fuel production to low-carbon fuel production, is a just transition for workers in the declining fossil fuel sectors (see Chapter 6).

We estimate the annualised cost of our Balanced Pathway to decarbonise fossil fuel supply is around £1 billion/year in 2030.

We estimate the annualised cost of the Balanced Pathway for decarbonising (mainly fossil) fuel supply to be around £1 billion /year in 2030, peaking just below £2 billion/year in 2040 before declining to £1 billion/year in 2050s. In 2035, this represents an average cost of abatement across all measures of around £70/tCO_2e. The costs of producing hydrogen and bioenergy supply are accounted for in abatement costs in those sectors in which the hydrogen and bioenergy are used to reduce emissions.

Figure 3.5.k sets out the capital and operational costs across the Fuel Supply sector. This includes the capital and operating costs of low-carbon fuels – these costs are also accounted for in the operational fuel costs paid for by sectors that use low-carbon fuels (e.g. shipping, aviation, manufacturing).

Figure A3.5.k Additional capital and operating costs for the fuel supply sector in the Balanced Net Zero Pathway



Source: CCC analysis.
Notes: Hydrogen supply wedges also account for costs associated with production of ammonia and synthetic fuels. Opex costs are positive in the fuel supply sector.

Low-carbon hydrogen supply investment costs are dominated by storage and network costs.

Investment costs for hydrogen supply result from development of hydrogen storage and network infrastructure, plus investment in electrolysis and fossil gas with CCS capacity. Overall capital investment for hydrogen supply increases to around £4 billion/year by the 2040s, with operating costs peaking at around £4 billion/year during the 2040s.

Ammonia and synthetic jet fuel plants will require significant investment, and local low-cost hydrogen sources.

These hydrogen supply cost wedges include the investment and operating costs for new ammonia (for shipping) and synthetic jet fuel (for aviation) production facilities, that use some of the low-carbon hydrogen produced in the Fuel Supply sector. In the Balanced Pathway, building UK ammonia plants will require capital investment of around £400 million/year in the early 2030s and early 2040s, and UK synthetic jet fuel plants will require investment of £250 million/year by 2040.

There is also a share of ammonia and synthetic jet supplied via imports (25% assumed for both sectors in the Balanced Pathway). These imports are assumed to be produced from renewable electrolysis and air separation/direct air capture, and this fuel cost is only counted in the relevant end-use sectors.

Investment costs for bioenergy supply result from the construction of new biojet, biodiesel, heating bioliquids, biomethane and biohydrogen conversion facilities. These are capital intensive, as well as having significant ongoing operating costs due to biomass feedstock costs. However, the added costs of installing CCS onto a biofuel/biohydrogen plant are generally modest, given the availability of high concentration CO_2 streams at these facilities.

Bioenergy conversion costs within the Fuel Supply sector are dominated by biohydrogen and biojet routes

Bioenergy conversion plant investment costs peak at £670 million/year around 2030, due to this being the fastest period of growth in these bioenergy facilities, before falling to £200 million/year by 2050. Operating costs, including biomass feedstock costs, ramp-up over time to reach £2.8 billion/year by 2050. On both capital and operating metrics, biojet and biohydrogen conversion plants dominate these bioenergy fuel supply costs.

Endnote

[1] CCC(2020) *The Sixth Carbon Budget – Advice Report*. Available at: www.theccc.org.uk
[2] CCC (2018) *Hydrogen in a low-carbon economy*

Chapter 3

Policy recommendations for the Fuel supply sector

The following sections are taken directly from Chapter 6 of the CCC's Policy Report for the Sixth Carbon Budget.[1]

Table P6.1
Summary of policy recommendations for fuel supply

Decarbonising fossil fuel supply	
Implementation of lower-cost measures	• Set a requirement that from 2021 any new plans for offshore oil and gas platforms and associated installations must use low-carbon energy for their operations. As a result, all new oil and gas platforms should have no direct emissions from operational energy use by 2027, at the latest. • From 2025, flaring and venting should only be permitted when necessary for safety reasons.
Reducing UK and consumption emissions	• Develop a policy to reduce emissions from existing oil and gas platforms in line with our Balanced Pathway. • Develop carbon-intensity (or broader) measurement standards for gas and oil, by working with industry and the international community • Facilitate increased collaboration between the UK's offshore oil and gas and offshore wind sectors, exploring the potential for direct power connections to platforms. • Set ambitious requirements for reductions in leakage of methane from the gas grid.
Hydrogen	
Strategy	• Focus hydrogen demand on areas where that cannot feasibly decarbonise without it. • Pursue proven solutions (e.g. electrification) in the 2020s, in parallel with developing hydrogen. • Set out vision for contributions of hydrogen production from different routes to 2035.
Demonstration / near-term deployment in end-uses	• Power. Establish and grow market for decarbonised dispatchable power solutions (H_2 turbines + gas CCS) to support unabated gas phase-out in power generation by 2035. • Manufacturing. Incentivise hydrogen use, but on level playing field with electrification. • Buildings. Research and pilot projects are needed to provide evidence for strategic decisions. • Surface transport. Build towards decisions on zero-carbon HGVs by undertaking large-scale trials. • Shipping. Incentivise hydrogen/ammonia use and aim to develop a 'clean maritime cluster' by 2030.
Demonstration / near-term deployment in supply	• Get on with low-carbon production to establish low-carbon hydrogen supply chain, and also drive innovation in cost and performance. • Blue hydrogen. It is important to deploy fossil gas CCS early to prove that it can deliver suitable emissions reductions vs. fossil gas (i.e. at least 95% CO_2 capture, 85% lifecycle GHG savings). • Gasification. Support commercialisation of biomass gasification with an aim to establish hydrogen production from bioenergy with CCS. • Electrolysis. An RD&D programme is required to improve the cost and performance of electrolysers.
Regulation	• All new power capacity should be hydrogen- and/or CCS-ready as soon as possible and at the latest by 2025, including being located where hydrogen/CO_2 infrastructure will be available. • Mandate boilers in buildings to be hydrogen-ready from 2025 at the latest, without pre-judging the respective roles of hydrogen and electrification. • Government should consider at what point and what level it would make sense to set a maximum carbon-intensity for hydrogen supply.

Incentives	• Ensure that low-carbon hydrogen capacity is incentivised to contribute emissions reductions (including mixing with fossil gas) at least for power generation, industrial clusters and grid injection. • Ensure that incentives for hydrogen use, together with electricity pricing, don't bias solutions towards hydrogen where electrification is competitive. • Avoid incentivising electrolysis based on (non-curtailed) grid electricity, as likely to push up emissions – focus on curtailed generation and dedicated renewable electrolysis.
Bioenergy and waste	
Align policies with long-term best-uses	• GHG savings from bioenergy and waste to be maximised to achieve Net Zero, via use of CCS and displacement of fossil fuels (in line with our best-use analysis from Chapter 6 of the *Methodology Report*). Scale-up and new applications to be aligned with 2050, or able to transition at low cost. • Develop new support schemes for GHG removals, sustainable aviation fuels, biohydrogen and growing perennial energy crops in the UK.
CCS readiness requirements	• Set new requirements for CCS-readiness at bioenergy & waste conversion facilities (even at small scale), with dates beyond which new facilities should be built with CCS, and dates for when CCS will need to be retrofitted to biomass & waste facilities already in operation.
International leadership on GHG removals	• Follow recommendations on sustainability, governance and monitoring from our 2018 report on *Biomass in a low carbon economy*[2] and 2020 report on *Land Use*.[3]

To meet our Balanced Net Zero Pathway, policies will be required to 1) minimise emissions from fossil fuel supply, even as consumption of fossil fuels falls due to decarbonisation in other sectors 2) enable decarbonisation in other sectors by ensuring that production of hydrogen and bioenergy are low-carbon and sustainable, and that their uses are focused where most valuable to meet Net Zero. Table 6.1 summarises our key recommendations for fuel supply policy.

Policy should also help to ensure a just transition for the fossil fuel supply sectors. The Government's planned North Sea Transition Deal can enable workers in the oil and gas sector to transition to the hydrogen sector. Chapter 6 of our *Advice report* sets out our detailed advice.

We set out the existing policy and policy needs for different parts of the fuel supply sector in three sections:

1. Decarbonising fossil fuel supply
2. Low-carbon hydrogen supply and use
3. Sustainable bioenergy supply

1. Decarbonising fossil fuel supply

Policy will need to enable fuel switching, CCS, and reduced methane venting, flaring and leakage, to decarbonise direct emissions from fossil fuel supply.

Our Balanced Net Zero Pathway requires fossil fuel supply emissions to be reduced by 75% by 2035 from 2018 levels.

- Emissions from offshore oil and gas platforms and from onshore processing terminals, are decarbonised mainly by fuel-switching and measures to reduce unnecessary methane flaring and venting.
- Oil refineries are decarbonised through CCS and energy efficiency improvements.
- Methane leaks from the gas distribution and transmission networks are reduced using a combination of Leakage Detection and Repair (LDAR) technologies and continuous monitoring technologies.

Chapter 3, Section 5 of our *Advice report* and Chapter 6 of our *Methodology report* set out more detail on our Balanced Pathway and exploratory scenarios. To achieve these measures will require a shift in gear in policy to decarbonise fossil fuel supply with policies designed to consider a just transition, carbon leakage and international leadership.

In this section we set out:

a) Existing fossil fuel supply decarbonisation policies;

b) Policies required to deliver our Balanced Pathway.

Our assessment of policy for decarbonising oil refineries and oil and gas processing terminals is mostly captured by Chapter 4, since these emissions sources will mostly be within the scope of the Government's planned Industrial Decarbonisation Strategy. The following subsections focus on policy for decarbonising oil and gas platforms and tackling methane leaks from the gas grid.

a) Existing fossil fuel supply decarbonisation policies

The EU ETS and Oil and Gas Authority's consenting regime can reduce emissions from oil and gas production.

Currently, the key mechanisms to reduce emissions from oil and gas production are through the EU emissions trading system (EU ETS) and the Oil and Gas Authority (OGA) consenting regime for flaring and venting. There is significant scope to strengthen policy in this area.

- The EU ETS covers energy generation and flaring on offshore installations with a rated output of more than 20MW. This has not provided a strong enough incentive for operators of either planned or existing installations to switch to low-carbon energy generation.
- The OGA's current policy on flaring and venting allows for justification of these practices on economic and technical grounds, not solely based on safety considerations.
- Various environmental regulations cover the release of emissions from oil and gas facilities.

There are opportunities for the UK to draw on international experience at reducing emissions in this sector.

While the carbon intensity of UK offshore oil and gas production has been declining in recent years it remains higher than the European average, with Norwegian production having less than half the carbon intensity of UK production.[4]

Norway's ability to connect many of its offshore installations to its onshore electricity grid, which is close to 100% low-carbon, has been a key factor in decarbonising the sector, but it has also adopted strong policies which the UK could draw on, such as:

- requiring developers to consider whether they can provide power to their platforms from onshore sources at the development consent phase.
- applying a carbon tax on top of the EU ETS to further incentivise decarbonisation. The tax is levied on all combustion of gas, oil and diesel in petroleum operations on the continental shelf and on releases of CO_2 and fossil gas.
- permitting flaring of gas only when necessary for safety reasons.

Government and industry have recognised the need for the UK's oil and gas sector to change in order to support the UK's transition to Net Zero. Government is developing a new North Sea Transition Deal in partnership with industry to support the North Sea oil and gas industry in transitioning as part of the UK's move to Net Zero. Government is also reviewing its future licensing arrangements for new oil and gas production, whilst the Oil and Gas Authority (OGA) are reviewing how they can support the industries' transition as part of Net Zero.

On leakage of methane from the gas grid, Ofgem sets out requirements for the network operators through its price control frameworks.

b) Policies needed to decarbonise fossil fuel supply

Government should set a requirement that from 2021 any new plans for offshore oil and gas platforms and associated installations must use low-carbon energy for their operations.

To meet our Balanced Pathway, policy should require lower-cost measures, such as reduce flaring and venting and electrifying new platforms, to be implemented as soon as possible. Higher-cost measures, such as electrifying existing platforms, should also be implemented, taking into consideration how this can be achieved without carbon leakage so that UK consumption emissions do not increase. These should be included in the North Sea Transition Deal.

- Set a requirement that from 2021 any new plans for offshore oil and gas platforms and associated installations must use low-carbon energy for their operations, for example through platform electrification. As a result, all new oil and gas platforms should have no direct emissions from operational energy use by 2027, at the latest.

From 2025, flaring and venting should only be permitted when necessary for safety reasons.

- From 2025, flaring and venting should only be permitted when necessary for safety reasons.
- Develop a policy to reduce emissions from energy generation on existing oil and gas platforms in line with our Balanced Pathway.*

* As outlined in our *Methodology report*, this is aligned with pathway set out on page 10 of: Oil and Gas Authority (2020) *UKCS Energy Integration – Final Report – Annex 1 – Offshore Electrification*.

Government should work with industry and the international community to develop carbon-intensity (or broader) measurement standards for gas and oil.

To ensure the UK has a full set of options for reducing its consumption emissions and for enabling higher-cost measures without causing carbon leakage, the Government should develop the option of applying either border carbon tariffs or minimum standards to imports. Further detail on these policy options is set out in Chapter 6 of the Advice report, which covers their application to a wider set of products.

- Develop carbon-intensity (or broader) measurement standards for gas and oil, by working with industry and the international community.
- Foster international consensus surrounding future carbon border/trade policy for products, using the UK 2021 G7 and COP presidencies. This will likely require engagement with the WTO, to ensure future policy is developed to be WTO compliant.

The Government should also deliver enabling policies to support the UK's upstream oil and gas sector to decarbonise:

- Facilitate increased collaboration between the UK's offshore oil and gas and offshore wind sectors, for example exploring the potential for direct power connections to provide platforms with renewable electricity.
- Take steps to improve the measurement and monitoring of fugitive emissions, venting and flaring.

On leakage of methane from the gas grid, Ofgem should set ambitious requirements for reductions in leakage of methane from the gas grid.

2. Low-carbon hydrogen supply and use

Hydrogen will only make a significant contribution to Net Zero with Government support.

The emergence of hydrogen as a low-carbon energy vector from essentially zero use now to making a crucial contribution to Net Zero will require a concerted, coordinated push from Government.

The Government's Hydrogen Strategy, due to be published in spring 2021, will need to set out a vision for hydrogen's role in meeting Net Zero, together with the actions across end-use applications and supply to develop hydrogen's role over the next decade, and the roles for regulation and incentives in hydrogen deployment.

This section brings together issues across hydrogen supply with our recommendations on hydrogen end-use from other sectors. It is in two parts:

a) Challenges for hydrogen policy and strategy

b) What is needed from the Government's Hydrogen Strategy

a) Challenges for hydrogen policy and strategy

While hydrogen has been discussed for many years as a potential contributor to reducing greenhouse gas emissions, very little progress has been made on its deployment to date. In the UK, although hydrogen is used within some industrial processes currently, this hydrogen production is not low-carbon.

In order for hydrogen to contribute to decarbonisation, it will need to shift from being a theoretical option to a commercial reality, as part of a strategic approach to decarbonising the energy system. Challenges include:

Hydrogen should not be prioritised ahead of proven solutions to reduce emissions.

- **Developing the hydrogen option while deploying established technologies in the 2020s.** Developing the hydrogen option could greatly facilitate the transition to Net Zero. However, even a concerted push to establish hydrogen as a proven decarbonisation option is unlikely to deliver large emissions reductions over the next decade. Rather it would pave the way for reductions in the 2030s and 2040s. Given the need for strong emissions reductions in the next decade and the availability of more established ways to do so, development of the hydrogen option should not be at the expense of pursuing proven decarbonisation options, such as electrification, in the 2020s.

Hydrogen should be targeted in applications where it provides most value.

- **A targeted role.** Focusing hydrogen end-uses in the areas that provide the most value (i.e. where other solutions such as electrification are not feasible or are prohibitively expensive), given challenges with providing sufficient volumes of low-carbon hydrogen.
  - Realistically, extra demand for hydrogen would likely be met at the margin by reforming of fossil gas with carbon capture and storage (CCS). In our Hydrogen Review,[5] we estimated this supply route to reduce emissions by only 60-85% compared to unabated use of fossil gas (e.g. in boilers) – these residual emissions limit its role as we move towards Net Zero. Heavy reliance on this route would also mean increasing reliance on gas imports as well as pushing the amount of CCS required to meet Net Zero to levels that may not turn out to be feasible.

– A scenario with widespread use of hydrogen across potential applications could have demand of 800 TWh (compared to the demand of 225 TWh in our Balanced Net Zero Pathway), implying 100-150 GW of gas reforming capacity and 175 $MtCO_2$ per year of CCS just for hydrogen supply (or alternatively 300 GW of offshore wind dedicated to electrolysis).

– Therefore, where options are available to reduce emissions through zero-carbon routes, such as electrification, these are strategically preferable to use of hydrogen. Hydrogen's role should therefore be focused in those areas where it is likely to be infeasible or prohibitively expensive to pursue electrification.

Getting past the 'chicken and egg' barrier will require coordination led by Government.

- **Coordination of supply, demand and infrastructure.** Currently, the UK neither has supplies of low-carbon hydrogen, nor demands for hydrogen from the energy system. A future hydrogen contribution to Net Zero will need both, as well as infrastructure to connect the two and business models that work. Getting from here to there will be challenging, as there is a 'chicken and egg' barrier that means that neither supply or demand can sensibly be developed in the absence of the other – fundamentally this is a coordination challenge, which it falls to the Government to address. There are two key approaches to doing so:

  – **Establish low-carbon hydrogen supplies.** It will be important to get low-carbon hydrogen production facilities in place, so that they are able to meet hydrogen demands as and when they arrive. Putting this capacity in place in anticipation of new demands also provides an opportunity to use hydrogen to reduce emissions from existing uses of fossil gas where this can be done with few barriers (e.g. blending it into the gas grid or mixed with fossil gas in turbines for power generation).

  – **Require new gas appliances to be 'hydrogen ready'.** Requiring new fossil gas boilers and power plants to be 'hydrogen ready' would provide ready-made markets for new low-carbon hydrogen supplies as well as limiting risks of stranding high-carbon assets.

- **Financial support.** It is likely that supplies of low-carbon hydrogen in the UK will remain more expensive than fossil gas without a carbon price, probably all the way to 2050, even with considerable cost reductions to electrolysers and zero-carbon electricity generation.*

* Hydrogen produced from fossil gas with CCS is inherently more expensive than simply burning fossil gas, due to the energy losses and capital costs entailed in producing hydrogen.

b) What is needed from the Government's Hydrogen Strategy

The Government has committed to publishing a Hydrogen Strategy in spring 2021.

Before hydrogen's full role across the economy can be fully established, further work will be required including finalisation of the safety case for hydrogen use in buildings and strategic decisions in the middle of this decade around the balance of hydrogen and electrification in decarbonising buildings in different parts of the country.

Nevertheless, the Hydrogen Strategy is an opportunity to push forward development of the hydrogen option. The following sections set out areas where progress can be made.

i) Developing hydrogen end-uses

Action is required in the 2020s across a range of sectors in order to develop the hydrogen option.

Hydrogen end-use applications will need to be grown steadily over time. It will be essential to make good progress in the 2020s, in order for hydrogen to be able to contribute fully to achieving Net Zero. Within this, it is important to focus on areas where hydrogen can bring greatest value:

- **Power.** Hydrogen turbines are one of the technologies for decarbonised back-up capacity, enabling full decarbonisation of electricity generation. While the Government should aim to phase out unabated fossil generation by 2035, the focus in the near term should be to develop and deploy the options, including hydrogen turbines, to displace unabated gas-fired capacity (see Chapter 5).

- **Manufacturing.** Hydrogen can have an important role in decarbonising industrial clusters, alongside electrification and carbon capture and storage (CCS). Its use should be incentivised on a level playing field with other options, including reforming electricity pricing to be cost-reflective (see Chapter 4).

- **Buildings.** A programme of research will be needed to identify priority candidate areas for hydrogen, along with areas which are unlikely to be suitable, to inform development and network investments. One or more hydrogen trials will be needed at a representative scale in the early 2020s (e.g. 300-3000 homes), to inform decisions on low-carbon zoning from 2025. All new boilers should be hydrogen-ready by 2025 at the latest. Further pilots should follow in the late 2020s, where this is valuable to inform large-scale take-up of hydrogen (see Chapter 3).

- **Surface transport.** Large-scale trials of zero-emission HGVs will be necessary in the early-2020s to demonstrate the commercial feasibility of zero-emission heavy goods vehicle (HGV) technologies, including fuel cell HGVs, and establish the most suitable and cost-effective technology mix ahead of phasing out sale of diesel HGVs by 2040 at the latest (see Chapter 2).

- **Shipping.** Incentives should be put in place for uptake of zero-carbon fuels (i.e. hydrogen and ammonia) in shipping. The UK should aim to have a 'clean maritime cluster' operational and supplying zero-carbon fuels by 2030, as a prelude to potential widespread adoption of these fuels in shipping in the 2030s (see Chapter 8).

ii) Hydrogen production

A strategic priority for the 2020s in developing hydrogen as a decarbonisation route is to develop its low-carbon production. This will help to move past the 'chicken and egg' barrier and enable a range of hydrogen end-uses to develop, while also helping to establish and drive improvements in the costs and performance of low-carbon hydrogen production routes.

Our assessment of path for build rates in the electricity system is that it will be highly challenging to provide very substantial volumes of electrolytic hydrogen over the period to 2040, while also meeting strongly growing demands for electricity during the 2030s. Thereafter, we anticipate that the rate of electricity demand growth will slow, enabling a more rapid scaling-up of electrolytic hydrogen supply with further deployment of zero-carbon generation.

In the interim, there is a choice between:

- **'Green hydrogen only'.** Limiting the role of hydrogen over the next 20 years only to what can be supplied via electrolysis from zero-carbon sources, likely placing substantial limits on hydrogen's potential contribution to getting to Net Zero; or

There is an important transitional role for hydrogen production from fossil gas with CCS in order to enable hydrogen to meet a range of emerging demands.

- **'Blue hydrogen bridge'.** This would entail supplementing electrolysis with scalable production from routes involving carbon capture and storage (CCS) to enable sufficient low-carbon hydrogen production to meet a fuller range of emerging demands.

We recommend the latter approach, as this will both reduce emissions more quickly in the near-term (compared to lesser use of hydrogen to displace unabated fossil fuels) as well as developing the role of hydrogen across a range of sectors, reducing risks around achieving Net Zero.

In its Hydrogen Strategy, the Government should set out its vision for the respective balance between hydrogen produced from electrolysis and from CCS out to 2035. Policy mechanisms will also need to be designed to pull through supply from both routes, rather than just whichever is least-cost.

The role for hydrogen from fossil gas with CCS will depend on it having sufficiently low lifecycle emissions.

However, production of hydrogen from fossil gas with CCS is not zero-carbon. In deploying hydrogen supplies in the 2020s from fossil gas with CCS, it will be important to demonstrate that it can achieve at least the potential 85% lifecycle emissions saving we have estimated it could provide versus unabated use of fossil gas. Doing so will ensure that this form of hydrogen production can have an enduring role as we approach Net Zero. The strategy should also set out how research and development and commercialisation programmes can help to deliver performance/cost improvements for hydrogen production via biomass gasification and electrolysis.

iii) Regulation

In order to ensure that new infrastructure is compatible with Net Zero, we are approaching the point when any new fossil-fuelled appliances risk becoming stranded assets unless they are designed to ensure that they can be converted to being low-carbon later on. Regulation has an important role to ensure that the risk of stranded assets is minimised, through prohibiting investments in high-carbon assets after a certain point in time and/or by mandating that they can be converted for operation in a low-carbon way.

Requiring gas turbines and boilers to be hydrogen ready would reduce risks of them becoming stranded assets and would provide ready-made markets for low-carbon hydrogen.

Requiring hydrogen-readiness for gas appliances such as boilers and turbines would reduce the risk of stranded high-carbon assets and can provide ready-made markets for new low-carbon hydrogen supplies. However, beyond a certain point in time, it will no longer by appropriate to invest in assets designed to operate on fossil fuels:

- **Boilers.** Making new gas boilers hydrogen ready is expected to add a low premium to the upfront cost of a boiler, while reducing the hassle and cost of switching the local gas distribution network over to 100% hydrogen (see Chapter 3).
  - Based on projected additional costs of £100 or less per boiler, and with a view to minimising scrappage, we recommend appliance standards for hydrogen-ready boilers from 2025. Should costs prove higher or safety considerations materialise, this should be reviewed.

    Early commitments and widespread standards would be expected to drive costs down through competition and economies of scale.
  - Outside of zones designated for the gas distribution network to switch to hydrogen, all new heating appliances will need to be low-carbon by 2033.
- **Turbines.** Once dispatchable low-carbon generation solutions have been proven, it is likely that a combination of economic incentives and regulation together will best enable a phase-out of unabated gas-fired electricity generation (see Chapter 5). The role for regulation comes in three phases:
  - Ensure new gas plant are properly CCS-ready and/or hydrogen-ready as soon as possible and certainly by 2025. Properly ready means located in areas that will be supported by CO_2 and/or hydrogen infrastructure.
  - From 2030, once further progress has been made and more information is available on the relative economics of different options, the Government should plan to regulate so that all additional capacity built from 2030 onwards is low-carbon.
  - By 2035, the plan should be that the electricity system can run entirely on low-carbon generation. The precise role for regulation here could take different forms (e.g. a declining emissions intensity standard or an 'hour limit' on unabated gas generation).

It may also make sense to regulate for a limit to the carbon-intensity of hydrogen supplies at some point. The Government's Hydrogen Strategy should consider whether and when it might be sensible to set such a limit. In the meantime, it is important to ensure that all hydrogen supplies are incentivised to be low-carbon.

iv) Incentives

Financial incentives will be important in driving hydrogen uptake.

Costs of hydrogen supply will remain well above that of fossil gas supply before any carbon price, probably all the way to 2050. This means that hydrogen uptake will only occur if a policy framework is put in place to incentivise its use. In doing so, it is important to pull through demand, while attempting to avoid perverse or biased outcomes:

- **Incentives for early use-cases.** In developing the low-carbon hydrogen capacity necessary in the 2020s, it is important use of this hydrogen is incentivised to contribute emissions reductions. This includes blending hydrogen with fossil gas in the gas grid and potentially in gas turbines, as well as 100% hydrogen applications in power generation, industrial clusters and parts of transport.
- **Avoid perverse incentives.** Incentivising electrolysis is sensible where this is based on low-carbon generation that would otherwise be curtailed or from renewable capacity dedicated to hydrogen production. However, it is important to avoid putting in place incentives that lead to a significant increase in fossil-fired electricity generation, as this would increase overall emissions.
- **Level playing field for decarbonisation.** Ensure that incentives for hydrogen use are designed, alongside a shift towards more cost-reflective electricity pricing (see Chapter 6), so that bias is not introduced towards hydrogen solutions where electrification is competitive.

3. Bioenergy supply and use

Bioenergy's role needs to transition to long-term best uses.

Bioenergy is used across many sectors of the UK today, but to contribute fully to Net Zero it will need to grow and transition to uses that maximise available GHG savings. This will require a coordinated approach from multiple Government departments.

The Government's Biomass Strategy, due to be published in 2022, will be critical to setting out this transition, with a clear vision needed for bioenergy's role in meeting Net Zero. This Strategy will need to set out the required actions across end-use applications and support the growth in domestic feedstock supplies over the next decade, as well as ensuring sustainability.

This section brings together issues across bioenergy supply with our recommendations on bioenergy end-use from other sectors. It is in two parts:

a) Challenges for bioenergy policy

b) What is needed from the Government's Biomass Strategy

a) Challenges for bioenergy policy

Our Balanced Net Zero Pathway requires overall primary bioenergy supply (including biomass, biogas, biofuels and the biogenic fraction of waste) available to the UK to grow from 175 TWh/year today to 225 TWh/year by 2050. This includes phasing out of informal and less sustainable feedstock supplies, a significant ramping-up of UK forestry residues and perennial energy crops, large increases in anaerobic digestion as landfill gas declines, and waste prevention, re-use and recycling efforts.

More than 80% of total bioenergy will have to be used with CCS by 2050.

By 2050, CCS will need to be applied to over 80% of the total bioenergy used in the UK. The majority of uses with CCS are likely to be in power, hydrogen and biojet production (and at remaining energy-from-waste facilities), although there are other uses with similar overall GHG savings that may be deployed as well. Chapter 5 of our *Advice report* and Chapter 6 of our *Methodology report* set out more detail on our Balanced Pathway and exploratory scenarios.

A significant investment programme will be required, with construction of new bioenergy facilities with CCS occurring in the late 2020s and early 2030s, across multiple end-use sectors – transport fuels, hydrogen, manufacturing and power.

Key challenges facing bioenergy policy are:

- There are legacy policies across multiple departments, and much of the UK's biomass supply is inherently tied to land use policies (and planting from previous decades). Bioenergy policies can therefore take decades to realise the potential benefits, and there remain 'chicken and egg' issues of feedstock growers not planting before they see local demand. With the transition to new support schemes for land managers (e.g. ELMs), it remains to be seen what the relative economics of biomass production versus other uses of land will be, and the availability of agricultural residues such as straw.

- It is uncertain how bioenergy policies will develop in Europe, North America and other world regions, and long-term what the available potential and costs of any imported supplies will be. Unlike other renewables with high capex and low operating costs, bioenergy feedstock costs are often significant and variable, which can necessitate different policy choices.

- Different power/heat/fuels policies have developed different GHG emission savings thresholds and calculation methods for bioenergy, making it challenging to assess whether certain feedstocks or supply chains will be able to transition to new uses and still meet the required sustainability criteria.

- Successfully achieving emissions reduction and other environment objectives in the waste sector will significantly reduce supplies of landfill gas and residual waste for bioenergy uses. These waste sector objectives need to be prioritised over the utility of the bioenergy resources produced. The biogas resource lost can be compensated for by an increased focus on anaerobic digestion of food wastes, sewage sludge and animal manures.

- Policy gaps remain with limited support for growing perennial energy crops in the UK, no bespoke market-based support for aviation biofuels within wider transport policy, biohydrogen suffering from 'chicken and egg' barriers (section 2 above), and a price signal for GHG removals still lacking.

b) What is needed from the UK's Biomass Strategy

The UK's Biomass Strategy, and subsequent cross-departmental policy realignment, should include:

Best-use of biomass and wastes are those that maximise GHG savings on the path to Net Zero. New applications need to be aligned to 2050 already.

- Examination of the **best-use of biomass and waste** resources on the path to Net Zero that maximises GHG savings, in line with our analysis from Chapter 6 of the *Methodology Report*, and consider how to orientate policy towards these best uses. Scaling up or creating new applications for bioenergy during the 2020s should already be aligned with long-term best-use applications or be able to make sufficient GHG savings before transitioning at low cost to these best-use applications.
- **Develop new support schemes**, including for biogenic CO_2 capture and sequestration, sustainable aviation fuels, biohydrogen and UK production of biomass feedstocks.

CCS should eventually be installed on all applicable bioenergy & waste facilities.

- **Requirements for CCS-readiness** from today, with clear dates beyond which new bioenergy & waste facilities should be built with CCS (not just CCS-ready), and dates for when CCS will need to be retrofitted to UK biomass & waste facilities already in operation, linking to the regional roll-out of CCUS under wider BEIS plans.
- Development of UK and international **governance and sustainability criteria** for bioenergy feedstocks, taking a global lead on their application to GHG removals, in line with our recommendations on sustainability, governance and monitoring from the Committee's 2018 report on *Biomass*[6] and 2020 report on *Land Use*.[7]
- The potential for use of **wood in construction**, existing market barriers and what changes in buildings regulations or support would be required to maximise its use.
- The potential for emerging uses of **biomass in the wider bio-economy** (such as bioplastics and bio-based chemicals), how any new sustainability concerns arisings from these applications should be addressed, and if specific support is recommended, providing a common framework for assessing GHG emissions savings (given the diversity of metrics in use).

Support schemes and CCS measures need to start being developed now, not starting after the Strategy is published in 2022.

However, some of the above work on developing support schemes and CCS requirements needs to progress at pace. Waiting until the Biomass Strategy is published during 2022 before starting to formulate new policies will put at risk the required conversion technology investment programme to 2030, and will delay the ramping-up in biomass supplies.

Endnotes

[1] CCC (2020) *Policies for the Sixth Carbon Budget and Net Zero*. Available at: www.theccc.org.uk
[2] CCC (2018) *Biomass in a low-carbon economy*.
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