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Options for a UK low carbon hydrogen standard

Final report

E4tech (UK) Ltd and Ludwig-Bölkow-Systemtechnik GmbH for the UK's Department for Business, Energy & Industrial Strategy (BEIS)

May 2021

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Acknowledgements

The authors would like to acknowledge the input of individual interviewees, members of the UK's Hydrogen Advisory Council and members of the UK's Hydrogen Advisory Council Working Group on Standards & Regulations for their contributions to this study's findings.

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1 Executive Summary

This project was commissioned by BEIS to identify and compare options for a UK standard that defines low carbon hydrogen.

This report is the final deliverable from the 'Low carbon hydrogen standard project' for the UK's Department for Business, Energy & Industrial Strategy (BEIS). The aim of the project was to identify and compare options for a standard that defines low carbon hydrogen, allowing BEIS to incentivise and support low carbon hydrogen production for supply across the energy system.

The project was delivered in Q1 2021 by E4tech and LBST, through four work packages:

- **WP1**: Through interviews and research, identify challenges to be addressed through the development of a low carbon hydrogen standard in the UK, and global lessons learnt. Provide case studies of relevant schemes. Discuss and agree on a set of criteria to be used in assessing different options for a standard (in WP3).
- **WP2**: Conduct lifecycle GHG assessments for representative hydrogen production and downstream distribution chains in the UK, including a sensitivity analysis.
- **WP3**: Using the criteria developed in WP1, define and evaluate the possible options for a standard, and make recommendations for a UK standard.
- **WP4**: Provide a high-level view of considerations for the delivery and administration of a standard.

There are several standards today that can be applied to low carbon and/or renewable hydrogen, which differ in their aims, application, and greenhouse gas (GHG) methodology.

These include voluntary standards developed specifically for hydrogen (e.g. CertifHy and TÜV SÜD) and renewable/low carbon transport fuel mandates for which hydrogen can be eligible (e.g. the UK's Renewable Transport Fuel Obligation and California's Low Carbon Fuel standard). These examples and the work of the IPHE's H2PA Taskforce are profiled, along with a discussion of other standards also in development. For most methodological choices, such as the boundaries of the lifecycle GHG analysis, the level of GHG savings that must be met, and the chain of custody approach used, these standards differ considerably. This is because the standards have been developed for very different purposes. In several areas they are aligned: all use a functional unit of gCO_{2e}/MJ_{LHV}, they all generally use energy allocation to account for co-products, and none include the embodied emissions of the equipment used in the supply chain. Assessing the approaches taken by each standard provides important context for the assessment of options for a UK low carbon hydrogen standard.

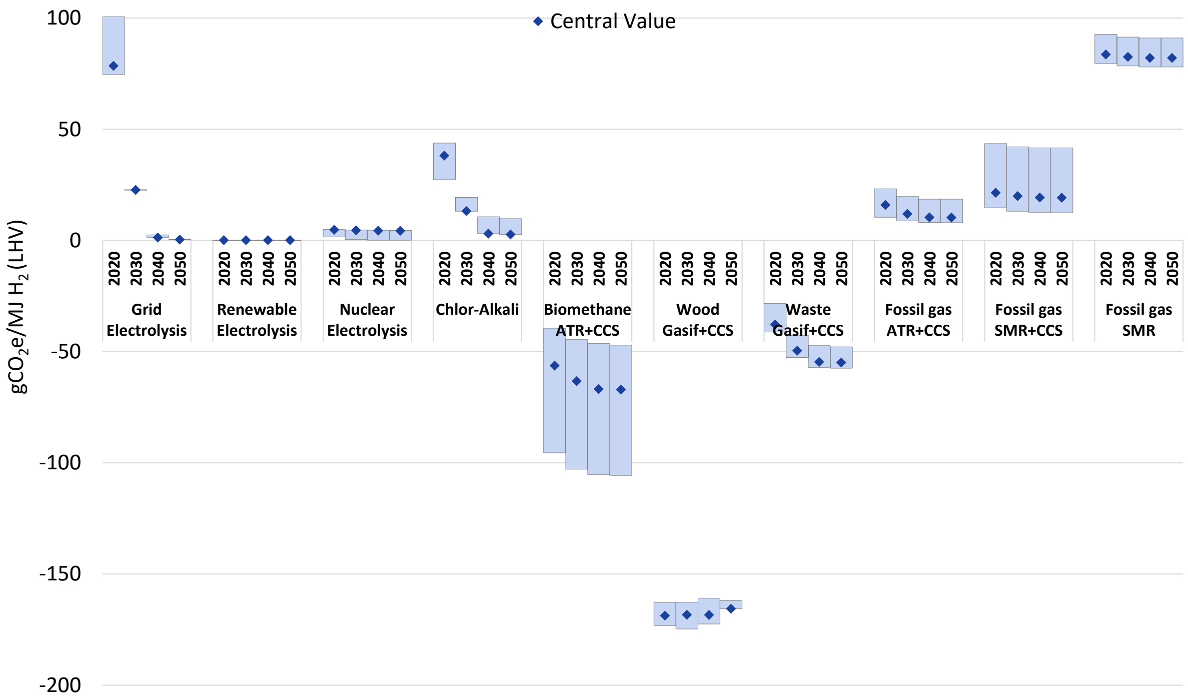
Eight criteria were defined for assessing different options when developing a UK low carbon hydrogen standard.

Eight criteria were defined, through consultation with BEIS and industry stakeholders: that the standard should be inclusive, accessible, transparent, compatible with other standards, ambitious, accurate, robust and predictable. These criteria were then applied to the methodological options considered for a UK standard.

Modelling within this project showed that lifecycle GHG emissions from hydrogen production pathways vary considerably, and are expected to decrease over time for some pathways.

This study provides lifecycle greenhouse gas (GHG) estimates for a selection of hydrogen production pathways and downstream distribution chains, and explores the key factors that influence these estimates. The pathways include those from renewable, nuclear and grid electricity, biomass and natural gas, plus by-product hydrogen, through a variety of conversion processes, several of which include carbon capture and storage (CCS). The default assumption is that hydrogen is produced (and distributed) within the UK, with results presented in ten year time steps to 2050. The GHG methodology used is an attributional LCA, with the system boundary being to the point of hydrogen production ('cradle-to gate'), plus separate emissions calculations for downstream distribution steps.

The GHG emissions results for hydrogen production pathways vary widely, from 75-100 gCO_2e/MJ for grid electrolysis in 2020 or unabated natural gas pathways, to around 10-45 gCO_2e/MJ for abated natural gas pathways, to 0-5 gCO_2e/MJ for renewable and nuclear electricity. Biomass pathways with CCS have negative results, as biogenic CO_2 is sequestered during hydrogen production. Some pathways improve considerably over time, such as the grid electrolysis and chlor-alkali pathways, as a result of decarbonisation of UK grid electricity.



Hydrogen production emissions (scenario ranges, 2020 to 2050)

Adding downstream emissions from distribution adds between 0.4 and 25 gCO_2e/MJ to final delivered hydrogen emissions in 2020, with the highest figures for liquification and high trucking distances. By 2030 this decreases to under 5 gCO_2e/MJ for most chains, mainly as a result of decarbonisation of the UK grid electricity. Longer-term decreases for road distribution chains are achieved with vehicle decarbonisation. Chapter 5 explores multiple sensitivities of these results to changing input assumptions, and discusses the impacts of setting a GHG threshold at different levels.

Methodological choices for a low carbon hydrogen standard are clear in some cases, but in other cases depend on the way in which the standard will be used, or on compatibility with other schemes.

Options for the methodological choices used within a low carbon hydrogen standard are discussed in detail, giving advantages and disadvantages of these options, and drawing conclusions intended to help in development of a standard, together with further work from BEIS and the outcomes of stakeholder consultation.

For many of the factors related to the system definition and GHG calculation requirements, the choice of option is clear, or the analysis shows that one approach is strongly preferred. These include using units of $gCO2_e/MJ$ LHV, defining a threshold on an absolute basis, and using a hybrid approach to the data used to calculate GHG emissions.

However, there are some decisions that are not clear, either because the option chosen depends heavily on how the standard is intended to be used, or because of uncertainties related to the options. Several of these decisions also depend on each other, with the choice made for one factor reducing the options available for another. The key decisions to be made on these more complex, interacting factors include whether the standard is applied at the point of hydrogen production, or at the point of use (the 'system boundary'), and how this interacts with the approach used for the chain of custody, requirements for hydrogen purity and pressure, and the geographical boundary of the scheme – whether it covers UK production and use only or also hydrogen imports and/or exports. Overall, two main types of approach could be taken - albeit with intermediate approaches possible:

- A point of production system boundary, with requirements for purity and pressure requirements/adjustments and with a book & claim chain of custody, analogous to a CertifHy Guarantee of Origin type approach.
- A point of use system boundary with mass balance chain of custody, with no purity and pressure requirements, analogous to the RTFO approach.

For several other factors, alignment with other schemes are important:

- Allocation of emissions to non-energy co-products – the outcomes of decision made at IPHE should be taken into account when making this decision.
- Use of low carbon electricity – we recommend allowing low carbon electricity based on traded activities such as power purchase agreements with cancellation of guarantees of origin or equivalent. However, additional criteria to mitigate potential

risks are in development at UK and EU level, and so need to be reviewed once agreed.

- Treatment of mixed inputs – should be reviewed after decisions in RED II and the RTFO.

In many cases the decision depends on the intended scheme in which the standard is used, or on decisions made in other UK policy mechanisms such as the RTFO. These include the number and form of GHG thresholds, requirements to show additionality of renewable electricity use, treatment of ILUC emissions for biomass, treatment of waste fossil feedstocks, the choice of global warming potentials used and the approach to use of low carbon gas.

The options for assurance, communication and claims and governance of a standard depend heavily on the way in which the standard is used.

The standard could be used in a variety of ways: for example to support a one-off assessment (such as eligibility for a capital grant) or to support an ongoing certification scheme or policy mechanism. These uses have an impact on the assurance approach used: how demonstrable evidence is provided that the requirements of the standard have been met. Assurance can have different levels of stringency, defined as reasonable or limited, which affect factors such as the type and frequency of verification (audits) and documentation for proof of compliance. There is a trade-off between the level of rigour and credibility versus the burden placed upon economic operators implementing the standard, and the number of participants. Options are discussed for the type and frequency of reporting and verification, and compared with the approach taken in other low carbon/renewable hydrogen standards. Options for governance of the standard are discussed: whether it would be delivered and administered by BEIS, as done for the RTFO by DfT, or by an independent industry-led or multi-stakeholder organisation.

Recommended next steps for BEIS are to consult on and finalise the design of the low carbon hydrogen standard, to continue relevant harmonisation discussions and to reduce emissions uncertainties.

Following publication of this report, there are a number of recommended next steps for BEIS. These include BEIS leading a process to consult more widely with stakeholders, to finalise the low carbon hydrogen standard design, to revise the GHG emission estimates and to set the final GHG threshold(s), before further work to operationalise the new scheme. In parallel, inter-department and international discussions should be held to ensure alignment between schemes where required, and further research supported to reduce uncertainties regarding hydrogen GHG emissions estimates.

2 Introduction

This report is the final deliverable arising from the ‘Low carbon hydrogen standard project’ for the UK’s Department for Business, Energy & Industrial Strategy (BEIS). This project was delivered by E4tech and LBST during January to April 2021, and was split into four work packages:

- **WP1**: Through interviews and research, identify challenges to be addressed through the development of a low carbon hydrogen standard in the UK, and global lessons learnt. Provide case studies of relevant schemes. Discuss and agree on a set of criteria to be used in assessing different options for a standard (in WP3).
- **WP2**: Conduct lifecycle GHG assessments for representative hydrogen production and downstream distribution chains in the UK, including a sensitivity analysis.
- **WP3**: Using the criteria developed in WP1, define and evaluate the possible options for a standard, and make recommendations for a UK standard.
- **WP4**: Provide a high-level view of considerations for the delivery and administration of a standard.

This final report summarises the findings of the work from all four work packages. The report is structured into six main sections plus two appendices:

- Chapter 3: A synthesis of the WP1 research and interview findings presenting the experience from other sectors and countries.
- Chapter 4: The agreed set of criteria from WP1 to be used in assessing different options for a standard.
- Chapter 5: GHG emission results and sensitivity analysis highlights from WP2.
- Chapter 6: Options and recommendations for a standard from WP3.
- Chapter 7: Delivery and administration aspects from WP4.
- Chapter 8: Recommended next steps.
- Appendix A: Data collection for the lifecycle GHG assessments from WP2.
- Appendix B: Sensitivity analysis detailed results from WP2.

The WP2 results are based on the outputs of an unpublished Excel workbook LCA tool delivered to BEIS, containing further charts and tables not shown in this report, greater detail including breakdowns of chain emissions by component, as well as references and assumption logs.

3 Experience from other sectors and countries

Summary

There are several standards today that can be applied to low carbon and/or renewable hydrogen. These include voluntary standards developed specifically for hydrogen (e.g. CertifHy and TÜV SÜD) and renewable/low carbon transport fuel mandates for which hydrogen can be eligible (e.g. the UK's Renewable Transport Fuel Obligation and California's Low Carbon Fuel standard). Each of these examples and the IPHE's H2PA Taskforce are profiled in this chapter, along with a discussion of other standards also in development. For most methodological choices, such as the boundaries of the lifecycle GHG analysis, the level of GHG savings that must be met, and the chain of custody approach used, these standards differ considerably. This is because the standards have been developed for very different purposes. In several areas they are aligned: all use a functional unit of gCO_2e/MJ_{LHV}, they all generally use energy allocation to account for co-products, and none include the embodied emissions of the equipment used in the supply chain. This chapter explains the approaches taken by each standard, which is important context for the assessment of options for a UK low carbon hydrogen standard in Chapter 6.

A number of interviews were conducted within the UK, Europe and globally to establish which low carbon hydrogen standards have been developed, and the key challenges addressed and lessons learnt. During Q1 2021, interviews were conducted with:

- International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE): Hydrogen Production Analysis (H2PA) Taskforce
- Ludwig-Bölkow-Systemtechnik (LBST), consortium member of CertifHy
- UK Renewable Transport Fuels Obligation (RTFO)
- California Low Carbon Fuel Standard (LCFS)
- TÜV SÜD
- CEN/CENELC Joint Technical Committee (JTC) 6: Hydrogen in Energy Systems
- Joint Research Centre (JRC)
- Prof Paul Dodds, UCL & co-chair of the UK's Hydrogen Advisory Council Regulations & Standards Working Group
- Ofgem (Office of Gas and Electricity Markets)
- Association of Issuing Bodies (AIB)
- Chair of the Standards Australia's Hydrogen Technology Technical Committee

- Origin Energy (Chair of the certification committee of Australia's Hydrogen Council)
- UK's Climate Change Committee

The majority of these interviews were held with government officials, standards administrators and expert advisors – those closest to the development of each standard, its GHG methodology and certification approach. Other than taking input from the Hydrogen Advisory Council, we have not consulted widely with the industry, as this is expected to follow the conclusion of this study and be led by BEIS.

Detailed research was conducted on five relevant case studies, and these findings have been incorporated into this chapter, along with the findings from the other interviews conducted. A summary of the case study findings is provided in Table 1. These five case studies are:

- CertifHy – voluntary Guarantee of Origin scheme within the EU, EEA and Switzerland[1]
- TÜV SÜD – voluntary renewable hydrogen standard in Germany[2]
- RTFO – Renewable Transport Fuel Obligation in the UK[3]
- LCFS -- Low Carbon Fuel Standard in California, USA[4]
- IPHE H2PA Taskforce -- International Partnership for Hydrogen and Fuel Cells in the Economy, Hydrogen Production Analysis (H2PA) Task Force[5]

In each of the case studies, we have summarised the information specifically relevant to hydrogen production and use, rather than providing full details for the RTFO & LCFS where other energy vectors such as liquid biofuels, fossil fuels, electricity, etc. (or projects such as direct air capture) are also within scope.

3.1 Status of relevant standards

Of the five case studies, four are already operational standards, while the IPHE H2PA Task Force is an international governmental partnership working to develop a mutually agreed upon GHG methodology for hydrogen production by mid-2021, but is not formally developing a standard.

China Hydrogen Alliance released a new low carbon hydrogen standard in late 2020, that appears to be operational, but with limited details available.[6] Other low carbon hydrogen

[1] www.CertifHy.eu
[2] https://www.tuvsud.com/de-de/branchen/energie/erneuerbare-energien/energiezertifizierung/gruener-wasserstoff-zertifizierung
[3] https://www.gov.uk/guidance/renewable-transport-fuels-obligation
[4] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard
[5] https://www.iphe.net/working-groups-task-forces
[6] TTBZ (2021) Chinese standard T/CAB 0078-2020 "Standards and Evaluations for Low Carbon Hydrogen, Clean Hydrogen and Renewable Hydrogen", available at: http://www.ttbz.org.cn/Pdfs/Index/?ftype=st&pms=42014

standards are also in development globally, such as ongoing work by the federal government in Australia (which may lead to pilot activities in 2022)[7].

CertifHy and TÜV SÜD are voluntary standards, while the UK's RTFO and California's LCFS are legal systems defining requirements that certain transport fuel suppliers must comply with. The overall objectives of the different schemes reflect their voluntary or compulsory status:

- CertifHy's mission is "to advance and facilitate the production, procurement, and use of hydrogen fulfilling ambitious environmental criteria".
- The TÜV SÜD standard CMS 70 aims at satisfying a demand for reliable certification of renewable hydrogen.
- The RTFO's stated aim is to support the UK government's policy on reducing GHG emissions from UK vehicles, by encouraging the production and use of renewable transport fuels.
- The LCFS aims to reduce the carbon intensity of transport fuels sold in California by at least 20% by 2030.

3.2 Scope

Geography

The geographical scope is generally clearly defined by each case study standard:

- CertifHy: The scope geographically covers the European Union plus the European Economic Area plus Switzerland (status: 11 March 2019); coverage of UK may be subject to a future revision of the CertifHy scope.
- The TÜV SÜD standard is applicable world-wide, but is mainly significant within Germany and Europe, since it refers to German and European regulation.
- The RTFO mandates that larger transport fuel suppliers selling fuel within the UK must each year show that a certain percentage of their fuel comes from renewable and sustainable sources. Renewable fuels must be sold in the UK to gain certificates, but can be produced globally.
- The LCFS mandates annual average carbon intensity reductions for transport fuels sold in California. Suppliers of low carbon fuels must sell these fuels in California to gain credits, but these fuels can be produced outside California. Project-based credits (e.g. from refineries) can be generated outside California but the savings must be pro-rated to the quantity of fuel from the project sold in California.

[7] Australian Government (2021) National Hydrogen Strategy priorities and delivery, available at: https://www.industry.gov.au/news/national-hydrogen-strategy-priorities-and-delivery

Categorisation

There are differences in how different hydrogen routes are categorised between standards, with a variety of terminology employed to describe hydrogen with different GHG intensities, but also to cover other attributes such as renewability.[8] GHG thresholds are discussed further below.

- CertifHy has created two labels: "green hydrogen" (covering low-carbon renewable pathways) and "low-carbon hydrogen" (covering low-carbon fossil and nuclear pathways). "Grey" hydrogen refers to hydrogen with a GHG intensity above the CertifHy threshold.
- TÜV SÜD uses the "green" hydrogen label for low-carbon renewable hydrogen.
- The RTFO uses "Development fuel", "Crop" or "General" labels for its three categories of Renewable Transport Fuel Certificates (RTFCs). "Development fuel" RTFCs correspond to certain strategic fuel types, including hydrogen, made from waste/residue biomass or from renewable electricity. Crop RTFCs refer to fuels made from starch/sugar/oil crops, and General covers the rest. Only hydrogen from renewable sources (renewable electricity or certain biomass types) is counted under the RTFO, with non-renewable hydrogen not currently counting (although a consultation is underway to potentially include two waste fossil "recycled carbon fuel" routes within the scope of the RTFO).[9]
- The LCFS does not use labels for their certified fuel pathways, as fuels only report their GHG intensity, route and feedstock. However, the LCFS does define "renewable hydrogen" as being able to be used in their project-based refinery credit program – this is defined as being derived from renewable electrolysis, biomethane reforming/cracking, or thermochemical conversion of biomass or biogenic waste (although not all these H_2 routes are certified yet).
- IPHE is not developing categories for hydrogen yet.
- China Hydrogen Alliance's standard has established three labels: "Low-carbon hydrogen", "Clean hydrogen" and "Renewable hydrogen". Threshold definitions are given in Section 3.5 below.
- Australia's proposals currently appear more likely to focus on reporting of GHG intensity, route and feedstocks, rather than any aggregation into a single label or category.

Pathways considered

Most schemes operate an approved list of production technology pathways, with the main difference between schemes being whether any pathway can apply to be added to the list

[8] Velazquez Abad & Dodds (2020) Green Hydrogen Characterisation Initiatives: Definitions, Standards, Guarantees Of Origin, And Challenges, Energy Policy 138
[9] DfT (2021) Targeting net zero – Next steps for the Renwable Transport Fuels Obligation, available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/973041/targeting-net-zero-rtfo.pdf

(and there is a defined process to go through to be accepted), or whether this approved list is only expanded by the standard administrator itself.

In CertifHy, any technology that can provide evidence that the defined requirements are met can be included within the scope of the scheme (whether biogenic, fossil or renewable). CertifHy covers both designated hydrogen production technologies, and by-product technologies (provided transparent and unambiguous information about the main product is included in the Guarantee of Origin (GO) and the basis of the GHG emissions allocation complies with the principles of the CertifHy scheme). Certifications already carried out include water electrolysis based on wind power, chlor-alkali electrolysis with hydrogen produced as by-product, and biomethane steam reforming with (partial) carbon capture. CertifHy does not set any restrictions on the downstream use of the hydrogen.

The TÜV SÜD standard currently covers four hydrogen production and by-product pathways, all of which are renewable: biomethane reforming, glycerine reforming, renewable electrolysis and renewable chlor-alkali electrolysis. The standard covers mobile and stationary applications of hydrogen including storage ("power-to-gas"), injection into the gas grid, use as feedstock and/or for chemical purposes. Both CertifHy and TÜV SÜD will be expanding their coverage of hydrogen production pathways in the coming years, although glycerine reforming is no longer commercially relevant and may therefore be dropped from the TÜV SÜD standard.[10]

Under the RTFO there are defined rules about which routes will count towards which of the three sub-mandates (provided GHG and other sustainability criteria are met). Crop-based routes would count towards Crop RTFCs (e.g. maize biomethane reforming), hydrogen based on waste fats/oils or single-counting non-crop biomass feedstocks would be assigned general RTFCs,[11] and hydrogen based on double-counting biomass feedstocks (except waste fats/oils) or renewable electricity would be assigned development RTFCs. Supply of H_2 under the RTFO is currently only occurring at small volumes, mainly via renewable electrolysis. The RTFO unit is responsible for assessing new RTFC applications, and also answering enquiries regarding eligibility for the different RTFC categories.

In the LCFS, any fuel pathway could be included, but to be included a fuel pathway must be certified. LCFS currently has several certified routes to gaseous and liquid hydrogen (with a broad range of GHG intensities - some low, some high), including solar PV electrolysis, landfill gas biomethane reforming, manure biomethane reforming, fossil gas reforming and chlor-alkali by-product H_2. The California Air Resources Board (CARB) assesses and often publicly consults on new route applications.

[10] Glycerine reforming is a technically feasible route (similar to steam methane reforming), but has not been assessed in WP2 of this study due lack of commercial interest.
[11] These single-counting feedstock or waste fats/oils routes to hydrogen are technically possible, but lack commercial interest and are unlikely to be viable given high feedstock costs, so have not been considered in WP2 of this study. We have considered maize biomethane reforming to hydrogen in WP2 given its current importance in the biogas market.

IPHE Taskforce activities are currently focused on SMR with CCUS, electrolysis, by-product H_2, biomass and coal gasification with CCUS in the five sub-groups established to date. However, there are no production pathways that have been explicitly excluded.

3.3 System boundaries, eligibility rules and certification

None of the standards examined appear to include embodied GHG emissions from equipment manufacture, construction or decommissioning (including the new China Hydrogen Alliance standard) – the view of interviewees was also that this data would be highly uncertain, expensive to calculate, challenging to fairly assign to individual batches of H_2 produced over time, and of relatively limited added value given the modest scale of these embodied emissions.

CertifHy relies on Guarantees of Origin for certifying the origin of the feedstock, via a book & claim system.[12] CertifHy has established a European GO scheme covering the entire upstream supply chain to the exit gate of the production site. GHG calculations follow the methodology defined by ISO standards 14044 and 14067, as well as RED II Annexes V & VI (for bioenergy and fossil fuels) as applied analogously to hydrogen. CertifHy, in terms of wider eligibility rules beyond GHG emissions, does not have rules for biomass feedstock sustainability; for a future voluntary scheme aligning to RED II, the relevant sustainability provisions of RED II will be adopted within CertifHy. The same holds for renewable energy additionality requirements.

CertifHy is putting a strong emphasis on European harmonisation of hydrogen GOs, to be achieved through supporting the establishment of the gas scheme within the European Energy Certificate System (EECS) of the Association of Issuing Bodies (AIB), and CertifHy also seeks to be recognised as EECS-compliant voluntary gas scheme. For EU member states, RED II requires, in addition to the existing renewable electricity GO schemes, that GO schemes for renewable gases (e.g. ‘green’ hydrogen and biomethane) are established, where producers request GOs to be issued, with a minimum set of details specified. Most of the general characteristics that apply to renewable electricity GOs also apply to ‘green’ hydrogen. The requirements of GO systems need to comply with the standard CEN - EN 16325, which is currently under revision to included renewable gases.

RED II covers renewable fuels of non-biological origin (RFNBOs) under the transport sector target and related fuel supplier obligations. Certification of hydrogen (and other RFNBOs) has similar, but more extensive requirements for certification than GOs, which is required to be carried out by national or voluntary schemes[13]. CertifHy is therefore also

[12] Book & claim systems are not based on physical tracking of products, but transfer environmental characteristics. Compliant operators deliver their products onto the market and “book” equivalent volumes of compliant products, via a dedicated certificate platform. At the other end of the chain, buyers may acquire compliance certificates and “claim” a contribution to the production of an equivalent volume of compliant products. See also section 6.8.
[13] Voluntary schemes according to RED II are privately organised schemes approved by the European Commission for verifying renewable transport fuels for complying with the EU sustainability criteria.

developing a mass balancing[14] voluntary scheme for RFNBOs and is seeking recognition of this new scheme by the European Commission.

The TÜV SÜD standard offers two alternative certification options, with either book & claim at the point of hydrogen production, or point of use certification with a mass balancing approach (following RED II). TÜV SÜD uses the dena biogas register in Germany for biogas tracking (including the sustainability requirements according to RED or RED II); whereas for electricity, Guarantees of Origin are used.

TÜV SÜD requires additionality for renewable electricity, with three options for satisfying this requirement (at least >30% from new renewable energy sources, a €2/MWhe payment into a development fund, or sufficiently high grid shares for certain renewables types that it can be assumed renewables are not being displaced).

The RTFO system boundary is well-to-wheel (although only considers renewable transport fuel chains), i.e. from renewable feedstock origin through fuel production and distribution to final use. Mass balance accounting is required throughout, and a number of voluntary schemes accredited by DfT provide the main avenue for certification. The RTFO follows RED II biomass feedstock sustainability rules. The RTFO's renewable electricity rules currently require a physical proximity between a renewable power generator and an electrolyser, either off-grid, or with evidence that renewable electricity is not being used. These rules may be relaxed to allow market-traded Power Purchase Agreements instead of a local connection. The RTFO also includes additionality rules: the supplier must provide actual data such as records of historical generation from the electricity production site (where applicable), planning proposals for new sites that will be constructed at the same time or after the fuel production plant (where applicable), or evidence of curtailment.

The LCFS system boundary is similarly well-to-wheel (including tailpipe fossil emissions), but covers all transport fuel routes, not just renewable fuels. Book & claim accounting is used for renewable or low-carbon electricity, and for biomethane injection into pipelines, i.e. all the input energies to low-carbon hydrogen routes currently certified. Power contracts are required to prove use of renewable electricity, with renewable certificates retired to avoid double-claiming, but there are no additionality requirements (e.g. new build). Third party verification was added in 2020 to increase confidence in LCFS data and streamline the use of CARB staff resources, with a list of verified bodies accredited by CARB. Prior to 2020, all reported data was subject to audit by CARB staff.

China Hydrogen Alliance's standard indicates that the LCA system boundary covers raw material acquisition & transport, hydrogen production, onsite storage and transportation (i.e. it appears to extend to point of use).

The Australian Government have proposed an initial certification scheme to track the production technology, production location and scope 1 & 2 GHG emissions, covering well-

[14] Mass balance systems allow the physical mixing of compliant and non-compliant products. Operators are required to monitor and keep records of the balance of compliant and non-compliant batches of inputs to their operation. They are then allowed claim compliance on outgoing products in the same proportion as the entering inputs (taking into account process efficiencies, losses, etc.). See also section 6.8.

to-gate emissions (including onsite hydrogen storage at the production site). Some scope 3 emissions might be added at a later date, but this is not being discussed for the near-term.[15]

The system boundaries for the standards described above are summarised below in Figure 1.

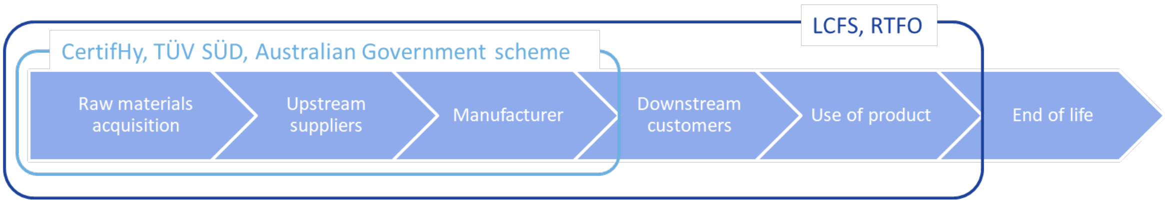


Figure 1: System boundaries schematic for the different hydrogen standards

3.4 GHG methodology decisions

Units

Most existing standards assessed use gCO_2e/MJ LHV as the functional unit for calculating GHG intensities – this applies to UK, German, EU and Californian schemes. IPHE have also agreed to work in gCO_2e/MJ LHV. China Hydrogen Alliance has recently released a new standard[16] using $kgCO_2e/kg\ H_2$, and Australia's National Hydrogen Strategy[1724] for developing a potential new standard also used these units.

It is however noted that the UK gas industry buy and sell gas on a HHV basis (due to e.g. condensing boilers quoting HHV efficiencies), and typically report their emissions on a $kgCO_2e/MWh$ (HHV) basis. Given this report uses gCO_2e/MJ LHV throughout, the hydrogen conversion factor required is **1.0 gCO_2e/MJ LHV = 3.04 $kgCO_2e/MWh$ HHV**.

The existing mandatory transport schemes investigated do not set a reference flow purity or pressure, leaving this to market demands – but the voluntary H_2 standards typically set a 99% or 99.9% purity and 3 MPa pressure (TÜV SÜD also allows lower than 3 MPa for gas grid injection).

Most schemes currently cover CO_2, CH_4 and N_2O gases using IPCC 4th assessment report (AR4) global warming potentials (GWP) , or are due to within a year, although the LCFS also covers volatile organic compounds (VOC) and carbon monoxide (CO) gases. IPHE is proposing to use IPCC 5th assessment report (AR5) values without climate feedbacks, and UK inventory emissions reporting is likely to transition to IPCC AR5 values (whether with or without climate feedbacks is still to be determined). China Hydrogen Alliance also uses

[15] The scope 1, 2, 3 emissions are defined by the Australian National Greenhouse and Energy Reporting Regulation; this approach is not consistent with a Life-cycle Assessment approach.

[16] TTBZ (2021) Chinese standard T/CAB 0078-2020 "Standards and Evaluations for Low Carbon Hydrogen, Clean Hydrogen and Renewable Hydrogen", available at: http://www.ttbz.org.cn/Pdfs/Index/?ftype=st&pms=42014

[17] Australian Government (2019) National Hydrogen Strategy: Issue 4, Guarantees of Origin, available at: https://consult.industry.gov.au/national-hydrogen-strategy-taskforce/national-hydrogen-strategy-issues-papers/supporting_documents/NationalHydrogenStrategyIssue4GuaranteesofOrigin.pdf

IPCC AR5 (unclear whether with/without feedbacks). Moving from AR4 to AR5 values (particularly if AR5 with climate feedbacks) is likely to slightly increase the GHG emissions associated with hydrogen pathways that have fugitive methane emissions, due to the higher methane GWP values derived from these later studies.

Allocation choices

Allocation methodologies define how to allocate upstream and process GHG emissions to products of a process if there is more than one product. These methodologies also show some alignment, with energy allocation[18] generally used throughout, although there are exceptions where energy allocation cannot be used, and this is typically where schemes differ:

- For chlor-alkali electrolysis, where energy allocation cannot be used as chlorine and caustic soda have no energy content, a value-based allocation[19] (averaging the last 5 years of Eurostat data) is being used in CertifHy as an interim solution, with agreement to use the ODC process[20] as a benchmark as soon as robust data are available. By contrast, TÜV SÜD uses an enthalpy-based allocation[21] or allows benchmarking against the ODC process (where third-party validated data are available). The RTFO is yet to consider issuing certificates to renewable chlor-alkali by-product hydrogen.
- In line with RED, the RTFO has to date chosen to use a system expansion[22] approach for combined heat & power (CHP) units, awarding a CHP credit for the avoided emissions compared to generating the same heat & power separately – although DfT are consulting on removing this CHP credit and returning to an energy allocation approach. The RED and RTFO also choose to allocate nil impacts to biogenic residues/wastes (only allocating emissions to products and co-products), to simplify GHG emissions calculations and prevent there being an incentive to produce more residues/wastes.
- The LCFS generally uses energy allocation for energy co-products, but for processes producing a mix of energy and non-energy co-products, a displacement (system expansion) method is often chosen for the non-energy products. However, the choice of the most appropriate allocation option for each certified route is made

[18] Energy allocation assigns upstream and process emissions to all products according to the proportion of output energy that they have. Where e.g. a process has two outputs such as heat (representing 67% of the total output energy) and electricity (representing 33% of the total output energy), 67% of the upstream and process emissions are allocated to the heat, and 33% are allocated to the electricity.
[19] GHG emissions are allocated to the products based on their market value.
[20] In the oxygen-depolarized cathodes (ODC) chlor-alkali electrolysis process, oxygen is introduced to the cathode side suppressing the formation of hydrogen. Thus, the ODC process is similar to the conventional process, but does not produce any by-product hydrogen. Benchmarking the ODC process against the conventional process is done by subtracting the energy consumption of the two processes to give the energy related to the hydrogen formation in the conventional process (and furthermore taking into account the energy needed for oxygen production for the process).
[21] In this allocation method, the standard enthalpy of formation of water from hydrogen and oxygen (so the inverse of the electrolysis process), which is equal to the negative higher heating value of hydrogen, is divided by the sum of all standard enthalpies of formation for the full chlor-alkali reaction. In essence, this is the theoretical share of the input energy needed to produce hydrogen assuming the absence of any technical losses.
[22] System expansion enlarges the system under analysis to a level where no allocation needs to be made. A CHP system could be expanded to cover a pure heating appliance, which is substituted by the heat from the CHP unit. Subtracting the environmental burden related to the heating appliance from the environmental burden of the CHP unit gives the environmental burden related to the power produced by the CHP unit. The example demonstrates that this method does not provide for unique results as different system expansions are possible; in this example, the system could also be expanded to cover a pure electricity producing unit.

by CARB, and the overall philosophy is to make conservative allocation choices that allocate more emissions to the certified fuel.

- In IPHE, discussions are ongoing, and agreement on a prioritised list of allocation options is not yet clear.

Other impacts

The treatment of CCS (carbon capture and permanent geological sequestration), allowing a reduction in lifecycle GHG emissions of hydrogen, is commonly applied in standards. CertifHy, IPHE, RTFO and LCFS allow CCS to be included (as it appears does the China Hydrogen Alliance), whereas TÜV SÜD is yet to consider any production pathways that include CCS.

The treatment of CCU (carbon capture and utilisation) is much more contentious. There are also no clear and consistent rules for CCU in international standards such as ISO and CEN, nor European regulations. The RTFO and RED II currently permit biogenic CCU to lower fuel GHG intensities, provided fossil CO_2 is displaced in a commercial application. However, TÜV SÜD does not allow for CCU benefits, and LCFS generally does not either. Both CertifHy and IPHE are currently debating this topic. Key questions revolve around the lifetime of the temporary storage, how to account for displaced sources and the system boundary, who takes the liability for the eventual CO_2 release to atmosphere, which party accounts for capture, compression & transport emissions, and how rules might vary for CO_2, CO or solid carbon.

Only the biogenic fraction of mixed wastes (part biogenic, part fossil) are currently considered as being in scope by the RTFO, CertifHy and TÜV SÜD, based on the LHV share of the feedstock fractions. LCFS go further by also awarding fuels the avoided emissions from any landfill of biogenic wastes (a system expansion approach), whereas other schemes do not assign this avoided landfilling benefit.

The fossil fractions of some residual wastes are being considered for potential support by the RTFO, provided the existing use of the waste feedstock meets certain criteria (to be consulted on, but may include that the waste carbon was expected to reach the atmosphere anyway). It also remains to be seen what GHG methodology rules for ‘recycled carbon fuels’ RED II will adopt in 2021 under its delegated acts, and whether a similar system expansion approach is taken. CertifHy and TÜV SÜD do not currently consider the fossil fraction of wastes, but do generally align to RED II rules.

In terms of end use, the LCFS also provides an incentive for use of hydrogen in fuel cell vehicles, by assigning these routes an ‘energy economy ratio’ to account for the higher efficiency of FCEVs compared to ICEs, which reduces the hydrogen GHG intensity reported by a factor of 2.5. Other schemes do not apply an end use multiplier.

3.5 GHG emission thresholds

There is little agreement between schemes regarding the required GHG emissions threshold that has to be met by lower carbon hydrogen routes. UK and European schemes typically advertise these thresholds as a % savings versus a fossil comparator, rather than an absolute emissions value, but it is the absolute emissions value that is used to assess compliance with the standard.

- CertifHy requires at least a 60% GHG saving versus a natural gas SMR benchmark of 91gCO_2e/MJ_{LHV}, i.e. <36.4gCO_2e/MJ. This will likely be updated to 70% once RED II rules are confirmed through delegated acts. As well as a threshold for each green or low-carbon H_2 batch, for a plant to be eligible to generate green or low-carbon H_2, the overall production plant must be below the benchmark level over 12 months.
- TÜV SÜD sets various GHG saving thresholds depending on the technology, hydrogen use, age of the production site and chain of custody certification. The benchmark for transport use is 94gCO_2e/MJ_{LHV}, and for non-transport use is 89.7gCO_2e/MJ_{LHV}, and these values are independent of the system boundary chosen. However, different savings are required if point of production certification is used (book & claim), or point of use certification (with a mass balancing approach following RED II). Mass balancing requires 60% savings for biomethane or glycerine reforming (<37.6gCO_2e/MJ for transport or <35.9gCO_2e/MJ for non-transport), and 75% for renewable electrolysis (<23.5gCO_2e/MJ for transport or <22.4gCO_2e/MJ for non-transport). Book & claim at the point of production requires savings of 80% for biomethane or glycerine reforming (<18.8gCO_2e/MJ for transport or <17.9gCO_2e/MJ for non-transport) and 90% for renewable electrolysis (<9.4gCO_2e/MJ for transport or <9.0gCO_2e/MJ for non-transport), i.e. is 15-20 %-points tighter for production only compared to end user delivery. Older biomethane or glycerine reforming sites (built pre-2017) are given 10%-points leeway on the above values.
- The RTFO requires at least a 60% saving for any production facility built after 2015 (or 50% for those built before 2015, i.e. a similar 10%-points leeway as in TÜV SÜD). This 60% saving equates to a maximum GHG intensity of 33gCO_2e/MJ of renewable fuel, based on a fossil transport counterfactual of 83.8gCO_2e/MJ. These will be revised during 2021 to a minimum 65% saving vs. a 94gCO_2e/MJ counterfactual, i.e. a maximum GHG intensity of 32.9gCO_2e/MJ of fuel from 2022 will apply within the UK.
- The LCFS does not specify a maximum GHG threshold. Fuels sold generate a credit if their GHG intensity is less than the target value for that year[23], and a deficit if higher. For example, if 20 MJ of fuel has a GHG intensity 5% below the target value for a given year, this will generate as much credit as two MJ of a different fuel having

[23] The LCSF defines a target value for the GHG intensity of transport fuels as a whole; these target values decrease year over year following a pre-defined trajectory.

a GHG intensity 50% below the target value, or one MJ of another fuel with a GHG intensity 100% below the target value.

- IPHE is focusing on a GHG emissions methodology, rather than specifying required thresholds or benchmark values.
- There have been discussions in Australia regarding copying CertifHy, but the federal government appears to be keen to be significantly more ambitious than CertifHy's current 60% GHG saving threshold, and have decided to proceed with developing a new standard for Australia, particularly in light of potential Asian export markets.[24]
- China Hydrogen Alliance's standard sets "Low-carbon hydrogen" as ≤14.51kgCO_2e/kgH_2 (120.9gCO_2e/MJ_{LHV}), "Clean hydrogen" as ≤4.9kgCO_2e/kgH_2 (40.8gCO_2e/MJ_{LHV}) and "Renewable hydrogen" also as ≤4.9kgCO_2e/kgH_2 (40.8gCO_2e/MJ_{LHV} but from renewable sources). The "low-carbon" GHG threshold is much higher than in other national schemes, reflecting the current dominance of coal routes in China.

None of the schemes set out a future trajectory for their GHG thresholds, and these thresholds are most likely to be updated as and when required based on wider policy changes (e.g. REDII). The partial exception is the LCFS, which while not setting GHG thresholds for a particular fuel, does specify overall fuel supply target values to be met out to 2030.

A summary of the GHG emission thresholds currently used to assess compliance of hydrogen routes with the standards described above is given in Figure 2.

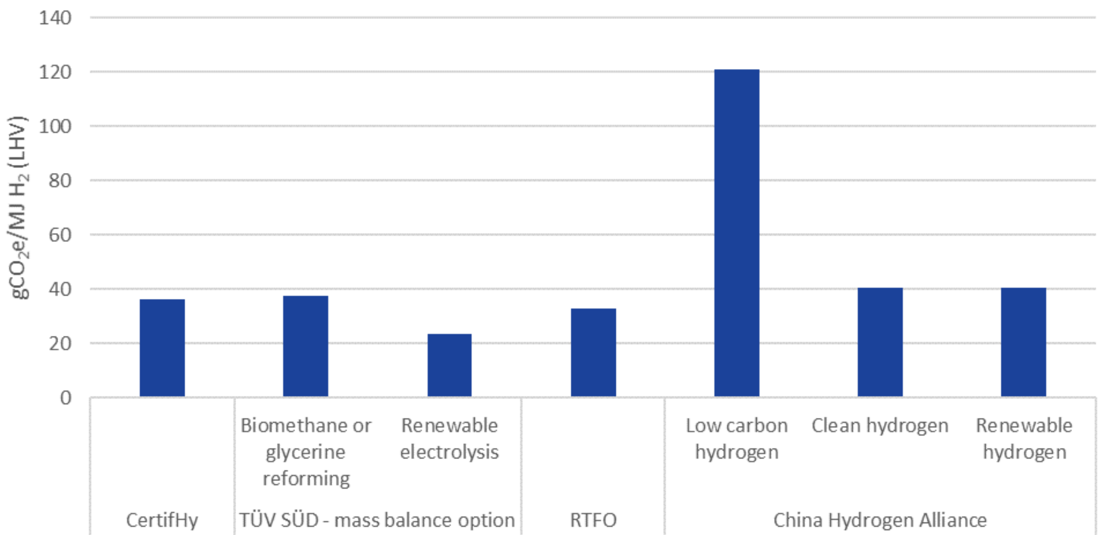


Figure 2: Current GHG emission thresholds for different hydrogen standards

[24] Australian Government (2019) National Hydrogen Strategy: Issue 4, Guarantees of Origin, available at: https://consult.industry.gov.au/national-hydrogen-strategy-taskforce/national-hydrogen-strategy-issues-papers/supporting_documents/NationalHydrogenStrategyIssue4GuaranteesofOrigin.pdf

3.6 Compliance costs

Compliance costs can be borne by the scheme administer, or by the end users, or by the producers, or by a combination of these parties. The different schemes assessed in WP1 use a variety of approaches and have different cost structures, due to the mix of voluntary hydrogen schemes and government-run obligations.

Compliance costs for companies seeking certification from CertifHy have three elements: a) internal efforts for data gathering and management as well as LCA calculations, b) third-party auditing costs (CertifHy set out an audit fee schedule that varies by pathway complexity), and c) fees for GO management (recouped via annual account fees, device registration fees and GO issuing fees of €0.05/MWh_{H2}). The first two elements are similar in the TÜV SÜD standard, while the exact costs correlate with the complexity of the requirements of the standard.

TÜV SÜD requires annual reporting and auditing, while CertifHy has no specific reporting requirements, and allows production device operators to define the frequency of production batch auditing as either annual or more frequent. The RTFO also has flexibility, with monthly up to annual batch reporting and auditing possible, dependent on producers' cashflow needs. The LCFS requires annual fuel pathway reports, but quarterly fuel transaction reports.

TÜV SÜD estimates the effort for administering the standard to be 20% of certification costs, while for CertifHy no information is yet available. The RTFO relies on a team of 8 full-time staff to run the RTFO, plus 14 staff dealing with future RTFO policy changes. The LCFS has a team of 28 staff. Ofgem's administration of REGOs in Great Britain has an estimated cost of under £1m/year, although this includes cost savings from Ofgem also running the Renewables Obligation and Feed-in-tariffs in parallel.

For all the standards considered, LCA expertise is required both for developing the LCA for each production batch (plant operator or consultant) and for auditing it (using a certification body).

3.7 Challenges and uncertainties

CertifHy is a voluntary GO scheme and has a European scope. At the same time, national GO schemes are currently being set up based on the provisions of RED II Article 19. CertifHy is therefore working to harmonise national GO schemes across Europe in close co-operation with AIB to overcome this challenge, and a key remaining question is the mechanism for import/export of GOs with third countries. Work on electricity GOs is becoming increasingly granular, with hourly certificates piloted by EnergyTag[25].

[25] EnergyTag (2021) https://www.energytag.org/

In terms of IT development, Australia and China Hydrogen Alliance are both actively considering the use of blockchain technology for their standards' IT service platforms, due to transparency and cost drivers, but blockchain approaches are yet to be actively pursued in other H_2 standards. The use of blockchain (distributed ledgers) is expected to assist with data collection and processing in hydrogen GO schemes, allowing e.g. aggregation of small producer batches and more automation of administrator functions, along with other benefits[26]. However, this does not necessarily get round the need for GHG calculations and measurement systems to provide the necessary data, both of which can still be complex (as experienced by e.g. TÜV SÜD) and need to be audited.

Since RED II was published in 2018, there has been uncertainty as to what renewable additionality rules, GHG methodologies and savings thresholds might be set via a series of delegated acts – these will impact several hydrogen production routes (and users of hydrogen in e.g. refineries). Finalised rules are expected during 2021. Both CertifHy and TÜV SÜD plan to adjust their rules to follow RED II as soon as the details are defined through these delegated acts. The RTFO is also expected to align with most of the key aspects of RED II, although post-Brexit, there remains more uncertainty regarding what exactly the RTFO will adopt (e.g. regarding renewable electricity additionality rules).

Indirect land use change (iLUC)[27] has been a contentious issue in the development of crop-based biofuels, leading to policies such as the LCFS targets being frozen for two years, although iLUC is now seen as either an integrated part of GHG calculations (as in the LCFS), or else separately reported and being dealt with through promotion of waste-based routes (as in RED II and the RTFO). However, iLUC is not considered under CertifHy or TÜV SÜD, as few hydrogen pathways are likely to be impacted (potentially only maize biomethane reforming currently).

Standards can take a significant amount of time to be developed. CertifHy took around three and a half years to set up, including extensive stakeholder interactions and an 18-month pilot phase, while TÜV SÜD took approximately one year to establish initially (although this did not involve any consultation). Broader policy mechanisms involving standards within them can take longer to be developed: the RTFO took around two and a half years from concept to going live, and the LCFS needed around four years from Executive Order to implementation.

[26] Velazquez Abad & Dodds (2020) Green Hydrogen Characterisation Initiatives: Definitions, Standards, Guarantees Of Origin, And Challenges, Energy Policy 138

[27] Indirect land use change (ILUC) is the conversion of land to agricultural production induced by the increasing price of agricultural products and land as a result of use of agricultural products and land for energy purposes. For some biofuels based on vegetable oils, the impact of ILUC is estimated to be large enough to warrant progressive reduction and ultimately exclusion from policy support in the EU.

Table 1: Summary of case study findings

	CertifHy	TÜV SÜD	RTFO	LCFS	IPHE
Type	Voluntary H_2 standard	Voluntary H_2 standard	Renewable transport fuel mandate	Transport fuel carbon intensity mandate	International harmonisation effort
Categories	"Green" or "Low-carbon"	"Green"	"Development fuel", "Crop" or "General"	No labels	No labels
System boundary	Upstream plus H_2 production (well to gate)	Upstream plus H_2 production (well to gate); optional inclusion up to point of use	Well to wheel	Well to wheel	Upstream plus H_2 production (well to gate)
End uses	NA	Transport and non-transport	Road, off-road or aviation	Transport (FCEV bonuses)	NA
GWPs (CH_4, N_2O)	25, 298	25, 298	23, 296 (25, 298 soon)	25, 298	28, 265
Reference flow	3MPa, 99.9% purity	3MPa, 99.9% purity	Market driven	Market driven	3MPa, 99% purity
Embodied emissions	Not included	Not included	Not included	Not included	Not included
Biofuel ILUC	Not included	Not included	Reported alongside GHGs	Included in GHGs	Not yet discussed
CCS	Included	Not included yet	Included	Generally permitted	Included
CCU	Debated but TBC	Not included	Included	Generally not permitted	Still TBC
Waste fossil fuels	Not yet discussed	Not included	Likely included from 2022	Appears to be included	Not yet discussed
Allocation method	Energy allocation; value-based for chlor-alkali (later will use ODC benchmark)	Energy allocation; enthalpy for chlor-alkali (or ODC benchmark)	Energy allocation; system expansion for CHP (currently; residues nil impact	Mixed. Mostly by energy, or system expansion where non-energy outputs	Discussions ongoing
Units	gCO_2e/MJ_{LHV}	gCO_2e/MJ_{LHV}	gCO_2e/MJ_{LHV}	gCO_2e/MJ_{LHV}	gCO_2e/MJ_{LHV}
Benchmark	91 (soon to be revised for REDII)	Transport 94, others 89.7	83.8 (94 soon)	None	None

	CertifHy	TÜV SÜD	RTFO	LCFS	IPHE
Threshold	60% saving (soon likely to be 70% for REDII)	50-90% saving depending on pathway, site age and CoC	50-60% (soon 65%) depending on site age	None	None
Chain of custody (CoC)	Book & claim (future RNFBO scheme will use mass balance)	Mass balance or Book & claim allowed	Mass balance	Book & claim	Not yet discussed
Guarantees of origin for input energy	Cancelling GOs	Cancelling GOs	Cancelling GOs (inc GB REGOs)	PPA for power GHG intensity	Set within each country
RE power additionality	Cancelling GOs (REDII changes soon)	30% from new, funding pots, or tech mix	Off-grid, curtailed or no grid import (soon PPAs?)	Retire power RECs	Still TBC
Reporting	None set	Annual	Monthly up to annual	Quarterly and annual	Still TBC
Staffing to run scheme	Still ramping up (including future RNFBO scheme)	Unknown, scheme still expanding	7 (ops) + 14 (future) FTEs	28 FTEs	Part-time staffing across 11 countries
Set up time	2 years defining, 1.5 years pilot	1 year (no consultation)	~2.5 years	4 years from order to start	~1.5 years for common method
Challenges	Linking with national GO schemes, and RED II changes	RED II changes	Renewable power additionality, iLUC	Legal challenges, iLUC	Global taskforce, limited time

4 Criteria to be met by a UK low carbon hydrogen standard

Summary

This chapter defines the criteria against which each of the methodological options considered in Chapter 6 for a low carbon hydrogen standard should be assessed when developing the standard. Eight criteria are defined: that the standard should be inclusive, accessible, transparent, compatible with other standards, ambitious, accurate, robust and predictable.

A set of criteria or design principles need to be established to guide the choices made when developing a low carbon hydrogen standard. Through the input of the UK's Hydrogen Advisory Council's Standards & Regulations Working Group, working sessions with BEIS and the findings from the WP1 interviews, as well as information from the ISEAL credibility principles[28], we have developed an agreed list of criteria.

The criteria cover a range of topics, and these have been grouped together where there is strong overlap between them, to keep the total number of criteria manageable. Some criteria are complementary (e.g. Accurate and Predictable) whereas many criteria involve some level of trade-off (e.g. Robust vs. Accessible). Below we set out the developed criteria, the topics they are intended to cover and their proposed definitions.

1. **Inclusive**
    - Open to all possible routes and scales (including H_2 imports/exports).
    - Treating all technology pathways equally based on GHGs alone.
    - Able to be used by different end users.
    - Flexible and able to deal with the addition of new and more complex routes or unique circumstances.

2. **Accessible**
    - Cost-effective, with appropriate and acceptable costs of compliance for operators and for the scheme administrator.
    - Simple, user-friendly and adapted to business requirements.

3. **Transparent**
    - Information is freely available about the approach, assumptions, impacts and process for making future changes.
    - Impartiality is maintained in all decision making.
    - Stakeholders can actively engage with governance, assurance, monitoring and proposed changes.

[28] ISEAL (2013) Credibility Principles, available at: https://www.isealalliance.org/sites/default/files/resource/2017-11/ISEAL_Credibility_Principles.pdf

4. **Compatible**
   - Can operate alongside UK schemes for other energy vectors (e.g. fuels, power), has the ability to convert certificates between vectors, and uses comparable GHG emission metrics.
   - Is compatible with other countries' H_2 standards, facilitating international trade.

5. **Ambitious**
   - Consistent with the UK's Net Zero pathway requirements.
   - Low threshold for GHG emissions, with other sustainability criteria defined where needed.
   - Use of conservative assumptions if defining default GHG emission values.
   - Supporting innovation and improved chain lifecycle GHG savings over time.

6. **Accurate**
   - Low uncertainties regarding GHG emissions estimates and any categorisations or labels.

7. **Robust**
   - Avoidance of fraud and mis-use, with strong penalties in place.
   - Frequency of reporting and auditing is adapted to the complexity of supply chains and identified risk levels, implementing at least a "limited" assurance level.
   - Priority is given to auditors' skills and training, and strong grievance procedures established.

8. **Predictable**
   - Providing investment security for the industry, and the ability to reliably forecast compliance.
   - Limited likelihood of large swings in GHG emission values which may tip marginal chains close to a threshold over in certain years.

Topics such as avoiding double-counting of emissions savings between policies, or avoiding double-subsidies between power/heat/fuels and H_2 were discussed. Whilst important, these are considerations for how Government and industry use a low carbon hydrogen standard, and not considerations for the content of the standard itself.

The criteria are used in Chapter 6, to evaluate the potential options for a standard, and scope these options down to a set of recommendations for the UK.

5 Lifecycle GHG emissions

Summary

This chapter provides lifecycle greenhouse gas (GHG) estimates for a selection of hydrogen production pathways and downstream distribution chains, and explores the key factors that influence these estimates. The pathways include those from renewable, nuclear or grid electricity, biomass and natural gas, plus by-product hydrogen, through a variety of conversion processes, several of which include carbon capture and storage (CCS). The default assumption is that hydrogen is produced (and distributed) within the UK, with results presented in ten year time steps to 2050. The GHG methodology used is an attributional LCA, with the system boundary being to the point of hydrogen production ('cradle-to gate'), plus separate emissions calculations for downstream distribution steps.

The GHG emissions results for hydrogen production pathways vary widely, from 75-100 gCO_2e/MJ for grid electrolysis in 2020 or unabated natural gas pathways, to around 10-45 gCO_2e/MJ for abated natural gas pathways, to 0-5 gCO_2e/MJ for renewable and nuclear electrolysis. Biomass pathways with CCS have negative results, as biogenic CO_2 is sequestered during hydrogen production. Some pathways improve considerably over time, such as the grid electrolysis and chlor-alkali pathways, as a result of decarbonisation of UK grid electricity.

Adding downstream distribution adds between 0.4 and 25 gCO_2e/MJ to final delivered hydrogen emissions in 2020, with the highest figures for liquification and high trucking distances. By 2030 this decreases to under 5 gCO_2e/MJ for most chains, mainly as a result of decarbonisation of the UK grid electricity. Longer-term decreases for road distribution chains are achieved with vehicle decarbonisation.

This chapter explores multiple sensitivities of these GHG emissions results to changing input assumptions, and discusses the impacts of setting a GHG threshold at different levels.

The purpose of this chapter is to provide lifecycle GHG assessments of different hydrogen production pathways and downstream distribution chains. This chapter also explores the key factors that influence these lifecycle GHG estimates for the different hydrogen chains – such as future electricity grid decarbonisation, improved technology efficiency, different carbon capture rates and upstream fossil supply emissions, among others.

The GHG assessments are guided by ISO 14040 and ISO 14044. These standards provide the framework to conduct lifecycle assessments. Figure 3 represents the main phases of an LCA, as defined by ISO standards. Each of these phases are presented in the following sections:

- Goal and Scope: Section 5.1 – defines key methodological choices selected for the GHG assessments.
- Inventory Analysis: Section 5.2 and 0 – describe the data used to conduct the assessments and any key assumptions required.
- Impact assessment and Interpretation: Section 5.3, Section 5.4 and Section 5.5 – provide the results from the GHG assessment, followed by a sensitivity analysis and key conclusions.

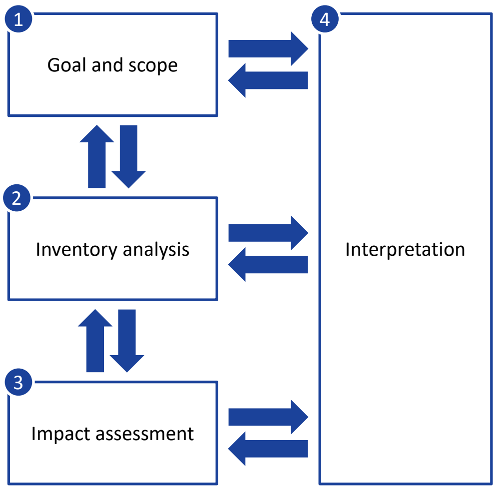


Figure 3: Lifecycle assessment framework defined by ISO standards

An Excel model was developed to calculate the GHG impacts of the different hydrogen production and downstream distribution chains. Data is inputted into three tabs:

- **H_2 Chain Definition:** In this tab, the hydrogen production pathways and downstream distribution chains are defined. The chains are split up into blocks (e.g. transport, production, compression etc.), with the level of disaggregation based on data availability. The model is built to allow for changes in the order of the steps (e.g. compression can be defined as occurring after or before a first transport step), and an additional transport step can also be introduced.
- **Foreground Data**: In this tab, process inputs and outputs are defined. For example, transport distances for feedstock collection, steam methane reforming efficiencies or the amount of electricity required for waste gasification are defined.
- **Background Data**: In this tab, the GHG impacts associated with the Foreground Data (i.e. process inputs and outputs) are defined. For example, GHG impact factors for grid electricity, natural gas, chemicals and road transport are defined here.

Data from 'H2 Chain Definition', 'Foreground Data' and 'Background Data' tabs are then fed into the GHG assessment calculation tabs. The results from individual calculation tabs are then fed into a results calculation tab, in which final GHG estimates are calculated for each hydrogen production and downstream distribution chain. Results are presented in a Summary tab. Figure 4 provides a high-level representation of the model structure.

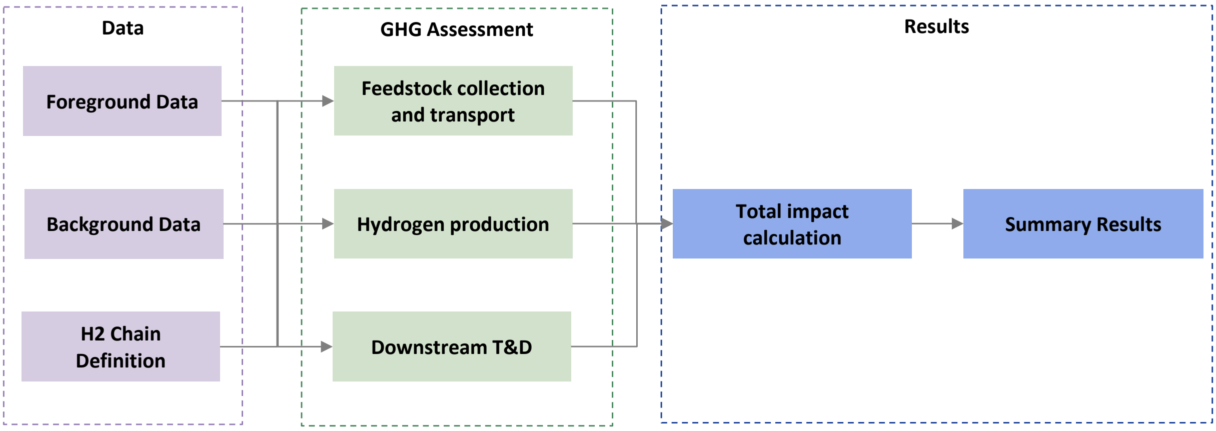


Figure 4: Map of the hydrogen production and downstream distribution GHG assessment model

The model was developed to allow for changes to the input parameters (e.g. changes to $MJ_{electricity}/MJ_{H2}$ for electrolysis, or gCO_2e/MJ_{H2} for grid electricity). Results are calculated for different scenarios which can be defined by the user. Greater discussion about the scenarios is provided in Section 5.3 below.

5.1 Goal and scope

This section outlines the goal and scope of the GHG assessment. It covers the assumed system boundaries, impact categories considered, pathways modelled, type of LCA, functional unit, solutions to multifunctionality and other key assumptions. Choices were selected in a Goal and Scope meeting with BEIS on 13th January 2021. Some of these choices will be explored further in sensitivity analyses (see Section 5.4).

5.1.1 System boundary

The LCA for the hydrogen production pathways uses a “cradle-to-gate” system boundary, i.e. the environmental impacts are assessed from raw material extraction up to the point at which hydrogen can leave the production facility.

Further, the main system boundary choices for key inputs are as follows:

- Fossil gas: includes extraction, processing and transportation.
- Nuclear energy: includes impacts from uranium extraction to nuclear electricity (and heat) production.
- Grid electricity: includes the combustion emissions of generation plants on the UK grid, and transmission and distribution losses from generation to use. Upstream emissions before these UK generation plants are not included in this study (due to data availability), but should be included within the scope of a future standard, in order to be consistent with e.g. fossil gas assumptions.

- Biomass and crops: includes impacts from cultivation, harvesting and transport. No direct or indirect land-use change has been assumed. Impacts related to avoided landfill emissions of food gas and MSW are not included.
- Waste feedstocks: includes impacts from the point of collection.
- Carbon capture and storage (CCS): includes impacts from CO_2 capture, compression, pipeline transport and injection into geological storage. Note that any pathway that captures CO_2 is assumed to transport this CO_2 to geological storage by pipeline in our analysis. Alternative CO_2 transport options such as trucks or ships were not considered in this study but could be considered in future work (and under the standard). Any uncaptured CO_2 emissions in the production processes are accounted for (as either biogenic or fossil CO_2 emissions, depending on the feedstock). We have not explicitly modelled carbon capture and utilisation (CCU) in this study, only running sensitivities of CO_2 capture rates as a proxy for CO_2 emissions liabilities, but CCU could be considered in more detail in future work.

All pathways: embodied impacts associated with manufacturing, construction and decommissioning of equipment are not included (including for renewable power generation). BEIS also wished to understand the potential GHG impacts of downstream distribution of hydrogen to a consumer. Therefore, several archetypal distribution chains have also been modelled, with combined production and distribution results presented (taking into account downstream efficiencies). This is further detailed in Section 5.1.3. The full combined LCA therefore uses a “cradle-to-point-of-use” system boundary.

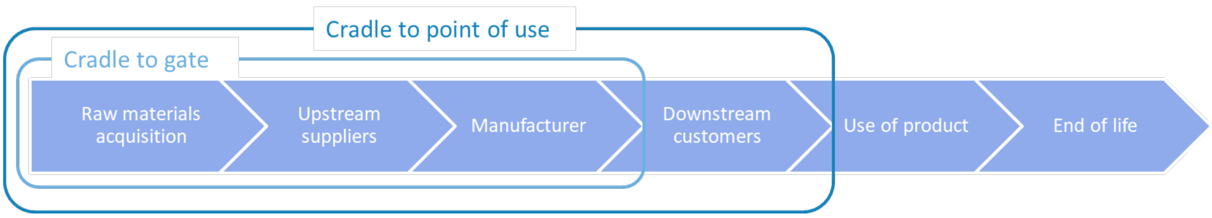


Figure 5: Illustrative example of the system boundaries employed in this analysis

5.1.2 Impact category

The assessment is only considering the Global Warming impacts of the different hydrogen production and downstream distribution chains. Therefore, the impacts related to CO_2, CH_4 and N_2O emissions are quantified. Further, based on work conducted by and for BEIS, the impacts associated with hydrogen emissions to atmosphere are also included. Emissions of volatile organic compounds (VOC) and carbon monoxide (CO) gases are not currently considered within the UK’s basket of greenhouse gases for reporting under the Climate Change Act 2008, and so were not included. Quantifying the impacts of CH_4, N_2O and H_2 atmospheric emissions into a CO_2 equivalent requires the use of Global Warming Potential (GWP) factors. GWPs are used to estimate the radiative forcing of 1 unit of a greenhouse gas compared to 1 unit of CO_2. The IPCC release GWPs in their Assessment Reports, updating these in line with the latest climate science. Table 2 outlines the different GWPs by IPCC, as well as those used in key energy policy GHG methodologies (the UK’s

Renewable Transport Fuels Obligation (RTFO) and the EU's Renewable Energy Directive (RED and REDII). Note that GWPs are also sensitive to the selected time-horizon. Generally in GHG accounting context, the selected time horizon is 100 years. If the time horizon were reduced to e.g. 20 years, the GWP for methane would increase, while the factor for N_2O would decrease.

Within the LCA tool, it is possible to generate results with the different GWP values from IPCC's AR4 and AR5 with and without carbon feedbacks (where the input datasets break out the different gases). A sensitivity will be presented on this in Section 5.4.

Table 2: GWP values from IPCC, as used by the RTFO and RED/REDII

	GWP values for 100-year time horizon		
	CO_2	CH_4	N_2O
IPCC Fifth Assessment Report (AR5)	1	28-34*	265-298*
RTFO (current) and RED	1	23	296
IPCC Fourth Assessment Report (AR4), REDII and RTFO (proposed)	1	25	298

* Higher estimates include climate-carbon feedbacks

The GWP impacts from direct hydrogen emissions to atmosphere are also included in the assessment, with sensitivities shown in Section 5.4. Data estimated from early research was provided directly from BEIS on which GWP factors to use in this study. Similarly to GWP values for CH_4 and N_2O, the LCA tool allows results to be generated using the following GWP values for hydrogen emissions:

- Baseline H_2 – GWP of 10.
- Low H_2 – GWP of 0.
- High H_2- GWP of 14.

5.1.3 Pathways assessed

For the GHG assessments of hydrogen production, 10 production pathways are modelled within the LCA tool, based on those pathways with available, reliable datasets that currently have the most commercial activity or are expected to have a significant role in UK Net Zero decarbonisation. This is not an extensive list of all likely or potential hydrogen production pathways (e.g. we have not modelled nuclear with low temperature electrolysis), but the LCA tool is used to provide a useful evidence base for BEIS as they consider what GHG emissions threshold could be set under a UK low carbon hydrogen standard.

Figure 6 illustrates the different production pathways with their central choice of feedstocks. Greater detail on the data used to model each production pathway is presented in Section

5.2 and Appendix A, including the different feedstock sensitivities assessed. As mentioned in Section 5.1.1, several archetypal downstream distribution chains are also modelled. These are illustrated in Figure 8, with greater information on the data used presented in Section 5.2. Within the LCA tool, a hydrogen production pathway can be matched to a hydrogen downstream chain to estimate the total GHG impacts from cradle-to-point-of-use.

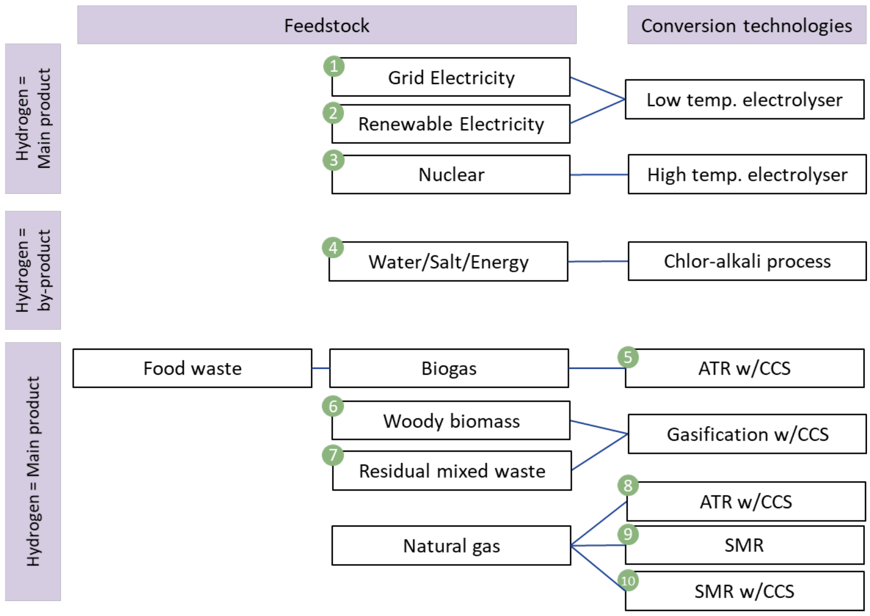


Figure 6: Hydrogen production pathways modelled

It was only possible to assess a limited number of pathways within this project, and many more options are possible. These alternative pathways could include nuclear power with low-temperature electrolysis (this study only looked at nuclear power with high temperature electrolysis, due to wanting to assess potential heat integration benefits), steam cracking, by-product hydrogen generated from oil refineries, acetic acid or carbon monoxide production processes, the water-gas shift reaction of steel mill waste carbon monoxide, pyrolysis/gasification of waste plastics or tyres, methane pyrolysis, glycerine reforming and landfill gas reforming (although different biomethane feedstocks are looked at in the sensitivity analysis). Retrofitting of CCS to existing SMR plants could also be looked at in more detail for specific sites (given available datasets were for new build SMR+CCS).

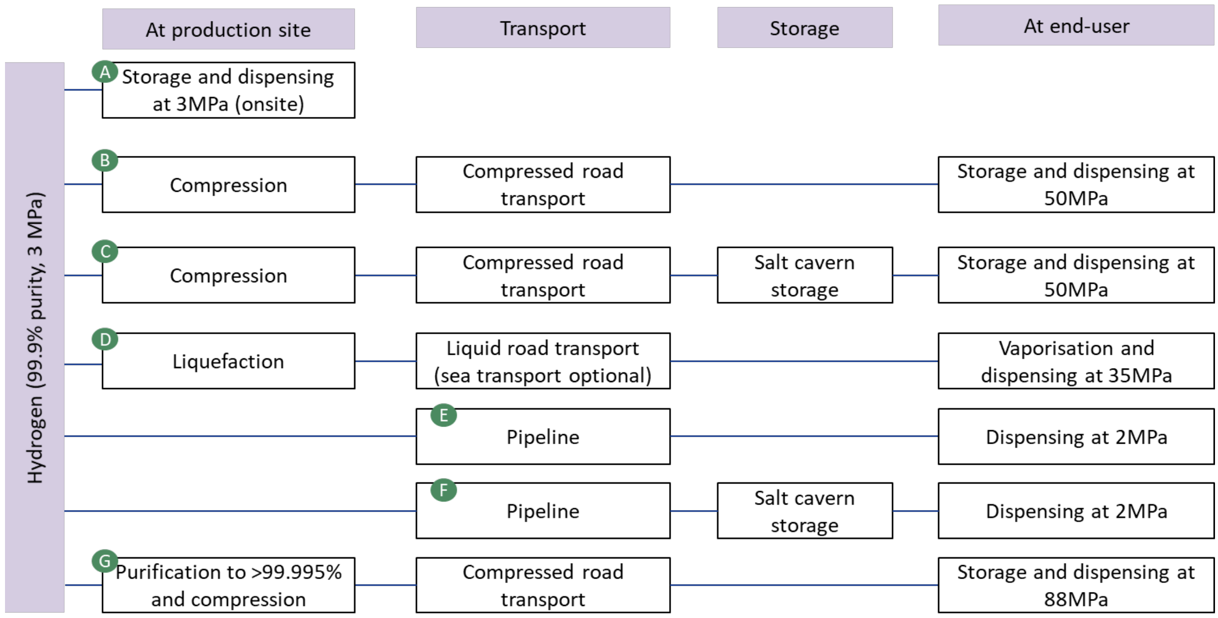


Figure 7: Downstream chains modelled, delivering at the various pressures of the final transport step

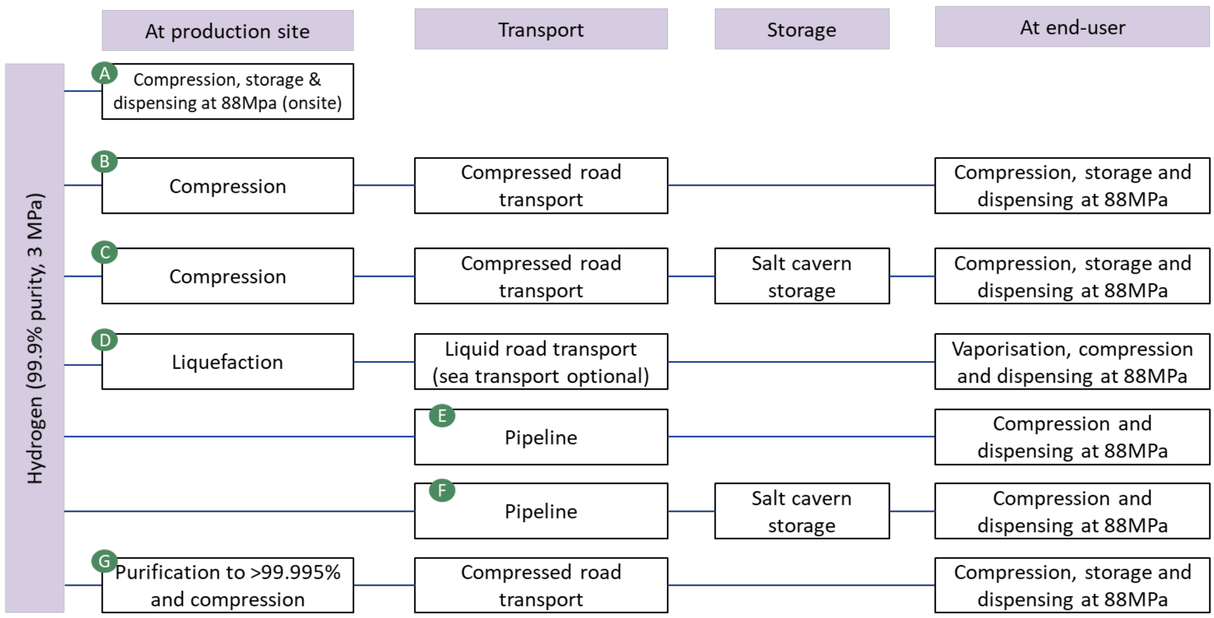


Figure 8: Downstream chains mo5delled, when compressing to 88 MPa at the user

5.1.4 Type of LCA

There are two main modelling principles in LCA: attributional and consequential. They represent two different ways of modelling the analysed system and are trying to answer two fundamentally different questions:

- Attributional LCA aims to quantify the environmental impacts that can be attributed to a system over its life cycle. Key question an attributional LCA tries to answer: What are the total, life cycle environmental impacts arising from the production, use and/or disposal of a product? Attributional LCA therefore typically uses average data. With only very limited exceptions (e.g. the treatment of CHP outputs where the system boundary is expanded to avoid the need for allocation), the RED and RTFO (and other UK low carbon support schemes) follow this attributional LCA approach.
- Consequential LCA aims to understand how decisions in the product system affect other processes and systems in the economy. Key question a consequential LCA tries to answer: what are the changes to total environmental impacts of a system (e.g. economic) as a result of the production, use and/or disposal of a product? Consequential LCA therefore typically uses marginal data and counterfactuals. For example, estimating the emissions associated with new consumption of grid power in a transport fuel production process using a consequential LCA would tend to assume increased generation at marginal fossil fuel plants on the grid, rather than using a grid average intensity.

The selected modelling principle affects a number of other methodological choices, for example how to treat multifunctionality within a process. For the GHG assessment of the different hydrogen production and distribution pathways in this study, an attributional approach was undertaken, as the aim of the assessment is to understand the GHG impacts of different hydrogen pathways, rather than understanding the system wide impacts of producing hydrogen.

5.1.5 Functional unit and reference flow

An LCA is anchored in a description of the function provided by the product system which is being investigated. While functional units are defined for all LCAs, they are particularly important for comparative LCAs, where results are presented for more than one product system. In comparative LCAs, the functional unit needs to be clearly defined, measurable and applicable across all relevant technologies. Note that the functional unit is not a prescription of the delivery conditions of the hydrogen, but is used to assess all the production pathways equally in an LCA. This GHG assessment has two functional units – one for the end of the hydrogen production pathways and one for the end of the downstream distribution chains:

- Hydrogen production: 1 MJ (LHV), with a 99.9% purity (by volume) and at 3 MPa pressure. Temperatures are not specified.
- Downstream distribution: 1 MJ (LHV), with a purity of 99.9% (by volume) and various final pressures depending on the end user:
    - Onsite scenarios assume hydrogen is delivered at 3MPa
    - Compressed road transport scenarios assume hydrogen is delivered at 50MPa
    - Liquid road transport scenarios assume hydrogen is delivered at 35MPa

  - Pipeline scenarios assume hydrogen is delivered at 2MPa
  - Purification and compression for road transport scenarios assume hydrogen is delivered at 88MPa (required for dispensing to vehicle tanks at 70 MPa). In this one archetypal downstream chain, the hydrogen purity has also been increased to >99.995% to allow use in fuel cell vehicles.

It is important to define a single functional unit to compare chains against, ensuring that results are compared on a like-for-like basis, which is the approach taken for the production pathways. However, caution needs to be taken when comparing the different downstream distribution chains (and those whole routes involving production and downstream combined), as they have different final pressures (and purities), given the need to look at different end user requirements in this study.

5.1.6 Multifunctionality

The GHG assessment models a number of pathways, as well as allowing for many additional pathways to be modelled in future. Some of these production pathways produce or may produce other useful products, for which GHG impacts can be allocated to. The default allocation method in the LCA tool is an energy allocation. This type of allocation is already used in key UK LCA methodologies (e.g. RTFO, Renewable Heat Incentive, Renewables Obligation), as well as the EU's REDII.

There are two notable co-product exemptions, which require a different allocation method:

- **Oxygen from electrolysis**: Oxygen is produced in significant quantities as a by-product of electrolysis, and could be considered a useful product. However, the by-product oxygen does not have an LHV energy content and therefore is not allocated emissions in an energy allocation. The LCA tool currently assumes the oxygen is vented to atmosphere, so no emissions need to be allocated to this stream. However, if the oxygen were captured and sold/used, allocating emissions to oxygen on an economic basis could be considered – a sensitivity for this is presented in Section 5.4.
- **Hydrogen from chlor-alkali:** In the chlor-alkali process, hydrogen is produced as a by-product to chlorine and sodium hydroxide. However, chlorine and sodium hydroxide do not have LHV energy contents. Therefore, it was decided that an economic allocation would be used for the chlor-alkali chain, in line with the EU's CertifHy and other proposals. This will be further discussed in Section 5.4.

5.1.7 Geography

In the GHG assessment, the default assumption is that hydrogen is produced (and distributed) within the United Kingdom. This selected geography impacts key parameters such as projected electricity grid mixes, upstream impacts of natural gas, biomethane mixes in gas grids, among others. These will be discussed further in Section 5.2.

5.1.8 Time period

Results from the GHG assessment will be presented for 2020, 2030, 2040 and 2050. This will allow reflection of both:

- Decarbonisation of electricity and gas grids
- Improved technology efficiencies over time

It should be noted that results for a specific year (e.g. 2030) reflect a plant commissioned and operating in that specific year. Data on efficiencies increase over time to reflect the efficiency of a new plant built in that year – as opposed to a fleet average efficiency across all operational plants. While a plant built in 2020 is likely to have a decreased GHG impact by 2030 (due to energy grid decarbonisation), the GHG impacts of that existing plant are still likely to be slightly higher than those presented for 2030 in this GHG assessment. This is because the plant from 2020 will (approximately) maintain the same efficiency over time, whereas the data for 2030 uses the higher efficiency of a brand new plant. For example, if an electrolyser built in 2020, with an efficiency of 65%, was operated in 2030, the production impacts would be 19.2gCO_{2e}/MJ H_2. Comparatively, an electrolyser built in 2030, with an efficiency of 68%, would have production impacts of 18.50 gCO_{2e}/MJ H_2.

5.1.9 Factors not included in the modelling

During the Goal and Scope meeting with BEIS, a number of factors were discussed, such as embodied GHG emissions, hydrogen deblending and methane pyrolysis. While these are not included within the scope of the LCA tool, they are discussed in this section, with quantitative estimates of impacts given where possible.

Embodied GHG emissions

In a 2021 study conducted by LBST for the Hydrogen Council,[29] well-to-gate GHG emission estimates included capex-related/embodied impacts for the manufacturing of energy supply assets (e.g. solar PV, wind turbines) and hydrogen production technologies (but only where robust enough data was available). The impacts of material recycling, as well as construction and decommissioning impacts were also included subject to data availability.

Figure 9 illustrates the different GHG impacts of different production pathways considered, and separates out these capex-related/embodied emissions (orange and white boxes). Note that 1.0 kgCO_2e/kg$_{H2,\ LHV}$ equals 8.3gCO_2e/MJ$_{H2,\ LHV}$.

[29] Hydrogen Council (2021) Hydrogen decarbonisation pathways: A life-cycle assessment. Available at: https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf

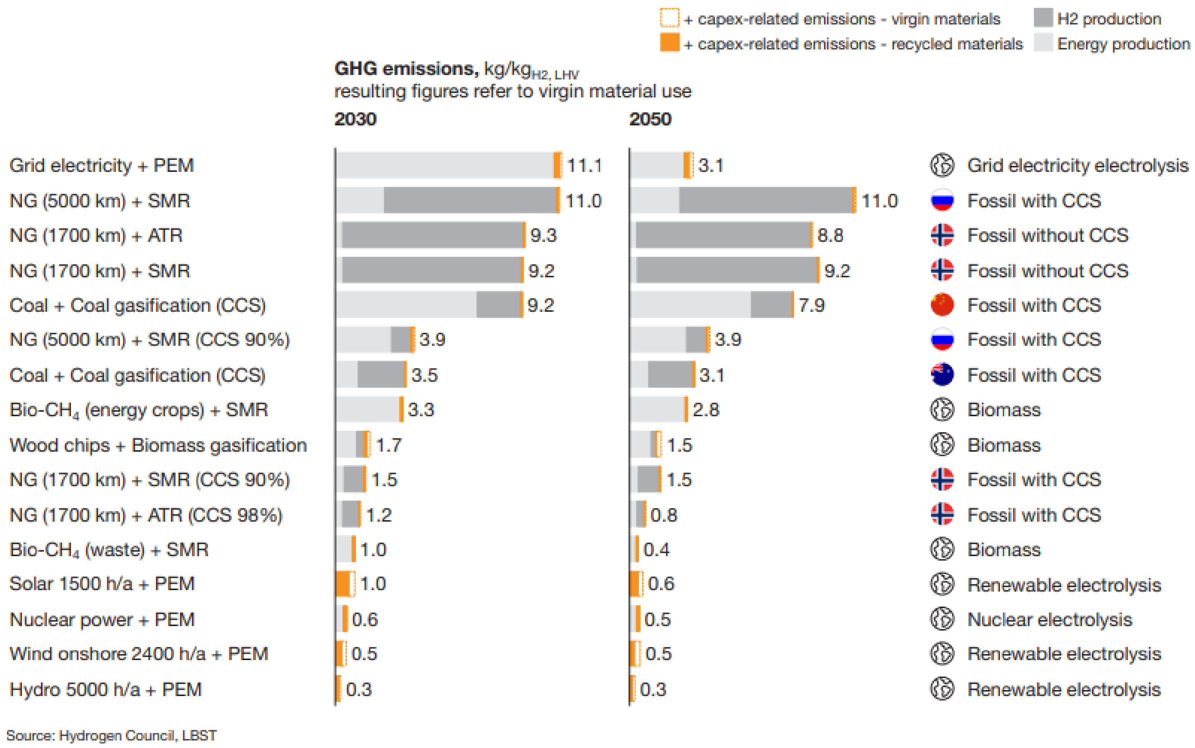


Figure 9: GHG impacts of different hydrogen production pathways, including capex-related emissions (Hydrogen Council/LBST, 2021)

According to these results, in absolute terms, the contribution from embodied emissions is expected to be modest and decreasing over time – in the low single digits of gCO_2e/MJ_{LHV} H_2 for most pathways, except solar PV + electrolysis. Some indicative global average values from the study are:

- Solar PV + electrolysis = ~8.3 gCO_2e/MJ_{LHV} H_2 in 2030, falling to ~5.0 in 2050
- Wind + electrolysis = ~4.2 gCO_2e/MJ_{LHV} H_2
- Wood gasification = ~2.5 gCO_2e/MJ_{LHV} H_2
- Hydroelectric + electrolysis = ~2.5 gCO_2e/MJ_{LHV} H_2
- Nuclear + electrolysis = ~1.8 gCO_2e/MJ_{LHV} H_2
- ATR+CCS and SMR+CCS = ~0.9 gCO_2e/MJ_{LHV} H_2

In the wind and solar chains, the majority of these embodied emissions arise from the renewable power generation technology, not from the hydrogen production technology. Whilst there is good coverage of different renewable electrolysis and fossil gas reforming options, the Hydrogen Council study does not cover all the pathways examined in this project – in particular, there are no biomass + CCS, waste + CCS or chlor-alkali chains considered, and the nuclear electrolysis chain uses low temperature instead of high temperature electrolysis.

The Hydrogen Council report concludes that capex-related emissions are small compared to the incumbent fossil comparators. However, whilst these embodied emissions are modest in absolute terms, they might be significant relative to the overall operational emissions of a renewable electrolysis chain. These capex-related emissions are calculated using average, global energy carbon intensities for manufacturing, so as energy production continues to decarbonise, capex-related emissions will also decarbonise. Furthermore, some manufacturers may already be using low-carbon energy sources for their manufacturing facilities, achieving significantly lower emissions than the global average estimates given in Figure 9.

LBST also state in the report that data availability to calculate capex-related embodied emissions is generally poor. Therefore, the results they present should be interpreted as representing the potential magnitude of embodied emissions impacts.

It was therefore decided to not include these impacts into the LCA tool, as robust data could not be sourced for all hydrogen production pathways. Other data received from BEIS on the manufacturing, construction and decommissioning emissions associated with different UK power generation technologies similarly confirmed that these upfront manufacturing and construction emissions are modest, and that decommissioning emissions are an insignificant part of total embodied emissions.

The exclusion of these embodied emissions from the LCA tool does not necessarily preclude them from being part of the GHG emissions assessment for a new low carbon hydrogen standard. However, if all hydrogen supply chains were required to include these embodied emissions, then in order to provide a fair and consistent comparison, competing UK decarbonisation approaches such as electricity, CCS and bioenergy should also include these embodied emissions within their GHG emissions calculations. Expecting hydrogen to account for these embodied emissions when other sectors do not would place additional burdens on the hydrogen sector, and could also lead to incorrect evaluation of various policy cost-effectiveness metrics.

Significance of switching between electrolyser types

The efficiency of electrolysis is determined by the amount of electricity used to produce an amount of hydrogen. The efficiency of commercially available pressurized alkaline (ALK) electrolysers ranges between 56% and 69% on a LHV basis. Polymer electrolyte membrane (PEM) electrolysers currently achieve 52-68%, hence there is wide overlap between these two technologies. The Hydrogen Supply Chain Evidence Base indicates continued overlap and strong convergence in base case efficiencies as both PEM and ALK technologies continue to improve over time.[30] Comparing the LCA of different low-temperature electrolyser technologies (where operating conditions such as temperature, pressure, current density and lifetime factors vary among technologies) would only be possible if sub-components of the electrolyser system were analysed in detail, and engineering data available. For the purposes of this study, to assist in developing a standard, modelling of a representative low-temperature electrolyser over time will more

[30] Element Energy (2018) Hydrogen Supply Chain Evidence Base, prepared for BEIS

than suffice for the grid and renewable electrolysis chains, and differences between ALK and PEM systems are likely to be small.

High-temperature solid oxide electrolysers (SOEL) are modelled separately as part of the nuclear electrolysis chain, as SOELs are able to use external heat to achieve significantly higher electrical efficiencies. SOEL electrical efficiencies are currently 0.83-0.90 MJ_{LHV} H_2/MJ_e input (or 0.60-0.74 MJ_{LHV} $H_2/(MJ_e + MJ_{th}$ input) if counting both the power and heat inputs), with further improvements over time modelled in this study.

Impact of different purities and pressures at the point of production

Producing hydrogen at higher pressures and higher purities than a technology's typical design point requires additional energy inputs, typically additional power for compression and to run purification steps (although there are a wide variety of purification technologies, not all of which will use power inputs). Depending on its source, this additional energy can lead to higher pathway GHG emissions. Decreasing the output pressure or purity may or may not lead to GHG savings, depending on the production technology's typical design point (e.g. cannot reduce pressures or purities further).

This section looks at the size of the impact of further compression and purification, highlighting that these impacts are relatively modest (and typically decreasing over time as the UK grid decarbonises). However, there are significant uncertainties, particularly for purification.

For water electrolysis, the main impurity in the H_2 stream is O_2, which is removed using a DeOxo drier. Machens (2004)[31] estimate that to achieve a purity of greater than 99.995%, starting at 99.9% purity, the following inputs to the drier are required:

- Hydrogen: 1.042 MJ $H_{2\ input}$/ MJ $H_{2\ output}$. This loss is due to H_2 combustion in the drier.
- Electricity: 0.014 MJ_e/MJ $H_{2\ output}$

Using the central grid electricity factor, the impacts from the power input to the DeOxo drier is equivalent to 0.70 gCO_2e/MJ H_2 and 0.04 gCO_2e/MJ H_2 in 2020 and 2050, respectively. Note that GHG impact does not include additional hydrogen which would need to be produced to account for hydrogen consumption in the drier, as this is dependent on the hydrogen production pathway. Comparatively, the JEC WTT v5 report notes that electrolyser efficiency decreases from 61.2% to 57.7-60.0% when the purity is increased from 99.9% to 99.998%. This additional electricity requirement represents an increase of 0.033-0.099 MJ_e/MJ H_2, equivalent to 1.6-5.0 gCO_2e/MJ H_2 in 2020 and 0.09-0.27 gCO_2e/MJ H_2 in 2050 (assuming the central grid electricity factor).

For the SMR, ATR and gasification processes, estimating the additional inputs to increase the output hydrogen purity is challenging, as it depends on the design of the plant. It is not

[31] Pers. Comm. to Weindorf, W. (LBST) on 12 October 2004

as simple as adding an additional electricity input as in the water electrolysis chains. However, some general conclusions can be made, although not quantified for this report:

- For an SMR plant, tail gases are recycled within the process, and it is likely that achieving higher purity hydrogen does not significantly increase the natural gas consumption.
- For an ATR plant, achieving higher purity hydrogen is likely to decrease the yield per unit of natural gas. However, increased tail gases could be used to cover auxiliary electricity demand.

To ensure comparability of the hydrogen production pathways, the GHG assessment reference flow is based on hydrogen produced at a pressure of 3 MPa, as most of the data has hydrogen produced at 3 MPa. Furthermore, this in line with the existing CertifHy standard. It is, however, possible to estimate the additional electricity required to go from 2 MPa to 3 MPa, based on data provided in GREET (2017). An additional 0.0071 $MJ_e/MJ\ H_2$ is required to compress hydrogen from 2 MPa to 3 MPa, equivalent to 0.35 and 0.02 $gCO_2e/MJ\ H_2$ in 2020 and 2050, respectively.

Based on the above engineering complexities, and relatively modest impacts in the long-term, it was decided that it was not possible to set purity and pressure as free-choice input parameters to the model – set values had to be specified (as per the reference flow). However, one downstream distribution chain does include increasing the purity of the hydrogen to >99.995% for use in a fuel cell. And one sensitivity looks at different delivered pressures for the downstream distribution chains. This will be discussed further in Section 5.4.

Deblending H_2 from natural gas

With the proposed large-scale injection of hydrogen into the UK natural gas grid (subject to a proven safety case and cost-benefit analysis), deblending is increasingly being discussed. Deblending involves separation of hydrogen and natural gas to provide streams of different compositions to meet different customer requirements. There are two reasons why deblending may occur:

- Some downstream consumers (e.g. older gas turbine power stations) cannot use a blended gas with more than low levels of hydrogen present, and therefore are likely to require >98% natural gas[32]; and
- Some downstream users will require a >99.999% hydrogen gas (e.g. fuel cell vehicles), and therefore cannot have any natural gas components.

There are impacts associated with deblending hydrogen and natural gas. However, to whom impacts should be allocated is in part a policy question – i.e. should the impacts be split between both parties (user and pipeline operator) or only be allocated to the party who requires the deblended gas.

[32] National Grid Gas Transmission (2020) Hydrogen Deblending in the GB Gas Network Final Technical Report. Available at: https://www.smarternetworks.org/project/nia_nggt0156/documents

There is limited data availability on the inputs and outputs required for deblending. Therefore, this has not been included as a downstream option in the LCA tool. A 2020 report by National Grid Gas Transmission[33] looked at hydrogen deblending in the gas network of Great Britain. The report provides some information on utilities for two types of deblending: cryogenic separation and membrane + PSA separation. Table 3 outlines the utilities required (showing those case study configurations with the highest and lowest impacts), and provides the GHG impact using the central 2020 and 2050 grid electricity figures. While the impacts could be significant in 2020, particularly for smaller systems, these impacts should also decrease significantly by 2050 due to grid decarbonisation.

Table 3: Power needs and indicative GHG impacts for H_2 deblending (cases from National Grid, 2020)[33]

Separation technology	Power consumption (kW$_e$)	Hydrogen production (kg/hr)	Power consumption (MJ$_e$/MJ H_2)	GHG impacts (gCO_2e/MJ H_2)	
				2020	2050
Cryogenic (case 1B)	2,600	947	0.08	4.14	0.23
Cryogenic (case 2A)	1,500	2,756	0.02	0.82	0.05
Membrane + PSA (case 1B)	2,070	612	0.10	5.09	0.28
Membrane + PSA (case 1A)	1,650	612	0.08	4.06	0.22

Gas network storage buffer

Currently the amount of gas held in the higher-pressure tiers of the UK's gas network transmission and distribution pipelines (the 'linepack') varies across the day, with typically decreasing pressures throughout each day, and increasing pressures at night. Linepack is used to match gas supply and demand within a day, with pressures controlled by network operators.

There is significantly more gas in the National Transmission System (3,740 GWh on average) in comparison to the Local Gas Network (660 GWh on average), but the amount of within-day linepack flexibility (the useful daily operational storage) is typically higher in the Local Gas Network.[34] However, discussions with gas network operators suggest that pressure levels in the gas grid (particularly in the Local Gas Networks) are needed for balancing, and are unlikely to be suitable as a means of bulk long-term storage of hydrogen, so have not been considered in the analysis.

[33] National Grid Gas Transmission (2020) Hydrogen Deblending in the GB Gas Network Final Technical Report. Available at: https://www.smarternetworks.org/project/nia_nggt0156/documents
[34] UKERC (2019) https://ukerc.ac.uk/publications/linepack/

Furthermore, a gas grid that transports large proportions of hydrogen or 100% hydrogen would also require detailed network analyses to understand how much hydrogen linepack pipelines could hold, and the potential within-day flexibility of hydrogen linepack. Dodds & Demoullin (2013) suggest that existing pipelines transporting hydrogen would have reduced capacity and much lower linepack storage compared to natural gas. New hydrogen pipelines could however be sized appropriately and wider pressure operating ranges considered to mitigate some of these impacts. Safety concerns regarding higher hydrogen pressures are currently being addressed via a number of research and demonstration programmes.[35]

If linepack in the high pressure distribution network were possible, a network operator choosing to increase the pressure by ~1.1MPa would currently incur extra electrical compression emissions of 0.36 gCO_2e/MJ H_2, based on use of 2020 grid electricity, which is not a significant increase on the results found. This would only be possible at certain time periods during each day, and only at certain periods of the year.

Imported hydrogen routes

BEIS may consider imported hydrogen in a scheme using this standard, but for this GHG emissions assessment work we were asked to focus on UK production and use routes. As such, we have only included liquid hydrogen imports as a single sensitivity in one downstream chain, and have not considered other import routes, such as those involving ammonia or liquid organic hydrogen carriers. The structure of the LCA tool provided to BEIS is such that these could be added easily in future work.

5.2 Data collection

For the GHG assessment two types of data were collected:

- **Foreground data:** This represents the inputs and outputs to the hydrogen production and downstream distribution systems. Examples of foreground data include MJ electricity required per MJ H_2 produced via electrolysis or kg wastewater/MJ H_2.
- **Background data**: This represents the impacts associated with production of inputs or the impacts of outputs to atmosphere. Examples of background data include gCO_2e/MJ electricity or gCO_2e/kg of wastewater.

Appendix A highlights the key data sources used in building the foreground and background datasets. It also highlights any key assumptions that were required. All assumptions and data sources are referenced within the assumptions log of the LCA tool.

[35] Dodds & Demoullin (2013) Conversion of the UK gas system to transport hydrogen, Int Journal of H2 Energy 38, 7189-7200, available at: https://core.ac.uk/download/pdf/82709079.pdf

5.3 GHG emission results

The following sections present the results from the GHG assessment of the different hydrogen production pathways, as well as the different downstream distribution chains.

For hydrogen production results, the hydrogen is at 3 MPa and has a purity of at least 99.9%. For the downstream distribution chains, the hydrogen is modelled as being delivered to the final consumer with a purity of at least 99.9% and pressure of the final distribution step[36] - with an exception of one chain with an additional purification step to >99.995% and final compression to 88 MPa for fuel cell vehicle applications. A sensitivity is carried out in Section 5.4, where the impacts of compressing all downstream chains to 88 MPa are calculated.

The Excel model allows for up to three scenarios to be modelled at the same time. Table 4 defines the parameter selection for the three scenarios which are represented in the following results sections. The Foreground data and Background data ranges are discussed in Appendix A, and GWPs in Section 5.1.2. For this results section, we have kept GWPs unchanged, but a sensitivity analysis is conducted in Section 5.4.

Table 4: Parameter selection for three scenarios modelled

	Foreground data	Background data	CH_4 & N_2O GWPs	Hydrogen GWP
Scenario 1	Central (e.g. median efficiency, capture rate, feedstock impact, leakage and distances)	Baseline impact	AR5 with feedback	Baseline H_2
Scenario 2	Best case (e.g. highest efficiency, highest capture rates, lowest impact feedstocks, lowest leakages, lowest distances)	Low impact	AR5 with feedback	Low H_2
Scenario 3	Worst case (e.g. lowest efficiency, lowest capture rates, highest impact feedstocks, highest leakages, highest distances)	High impact	AR5 with feedback	High H_2

For the foreground production data, the scenarios are defined based on the choice of feedstocks, process efficiencies and CO_2 capture rates of the chains. Best represents a scenario with the highest process efficiency and capture rates and lowest impact feedstocks; worst represents a scenario with the lowest process efficiency, lowest capture rates and highest impact feedstocks; and central represents an in-between set of values. In

[36] For hydrogen produced onsite, the final delivered hydrogen is assumed to be at 3MPa. For hydrogen transported by compressed road truck, the final delivered hydrogen is assumed to be at 50MPa. For hydrogen transported by liquid road truck, the final delivered hydrogen is assumed to be at 35MPa. For hydrogen transported by pipeline, the final delivered hydrogen is assumed to be at 2MPa. For hydrogen transported by compressed road truck and delivered to the transport market, the hydrogen is assumed to be at 88 MPa.

some cases, no technological differences were modelled between the different scenarios, and therefore process efficiencies, as well as carbon rates and other inputs and outputs, remain the same.

For the foreground data for downstream distribution chains, the scenarios are defined based on the compression efficiencies, transport distances and leakage rates of the chains. Best represents a scenario with the highest compression efficiency, shortest distances and lowest leakage; worst represents the opposite; and central represents an in-between set of values. In some cases, no differences were modelled between the different scenarios, and therefore parameters remain the same.

For the background data, the scenarios are defined based on the data availability for each parameter. The central impact represents the most likely impact factor for the parameter, whereas the low impact and high impact reflect the range seen in the data for some parameters. In some cases for a parameter, the baseline impact, low impact and high impact are the same. Further information on the GWP and Hydrogen GWP scenarios can be found in Section 5.1.2.

For chains involving CO_2 capture, all captured CO_2 is modelled as being sent to geological storage (CCS). Similar results in terms of hydrogen GHG emissions would be achieved if the captured CO_2 instead goes to be utilised (CCU) e.g. in industry, horticulture or beverages, but only if the CO_2 producer takes none of the CO_2 liability (and the user assumes the full emissions liability). However, whether this is possible is not yet clear, since which party in each CO_2 utilisation supply chain takes the emissions liability for the captured CO_2 is not yet firmly established in UK, EU or international policy. If the CO_2 producer has to take some or all of the CO_2 liability, then compared to sending the CO_2 to geological storage, this would add significant emissions onto the GHG emissions results presented below for those chains involving CO_2 capture. For simplicity, we have therefore focused only on CCS, but future work could look at CCU chains.

5.3.1 Production pathway results

Figure 10 presents results for the GHG impacts of the different hydrogen production pathways modelled. The bars represent the range of impacts across the scenarios, where in most cases the bottom of the bar represents results from Scenario 2 (Best, Low impact) and the top of the bar represents results from Scenario 3 (Worst, High impact). The dark blue dot represents the results from Scenario 1 (Central, Baseline impact).

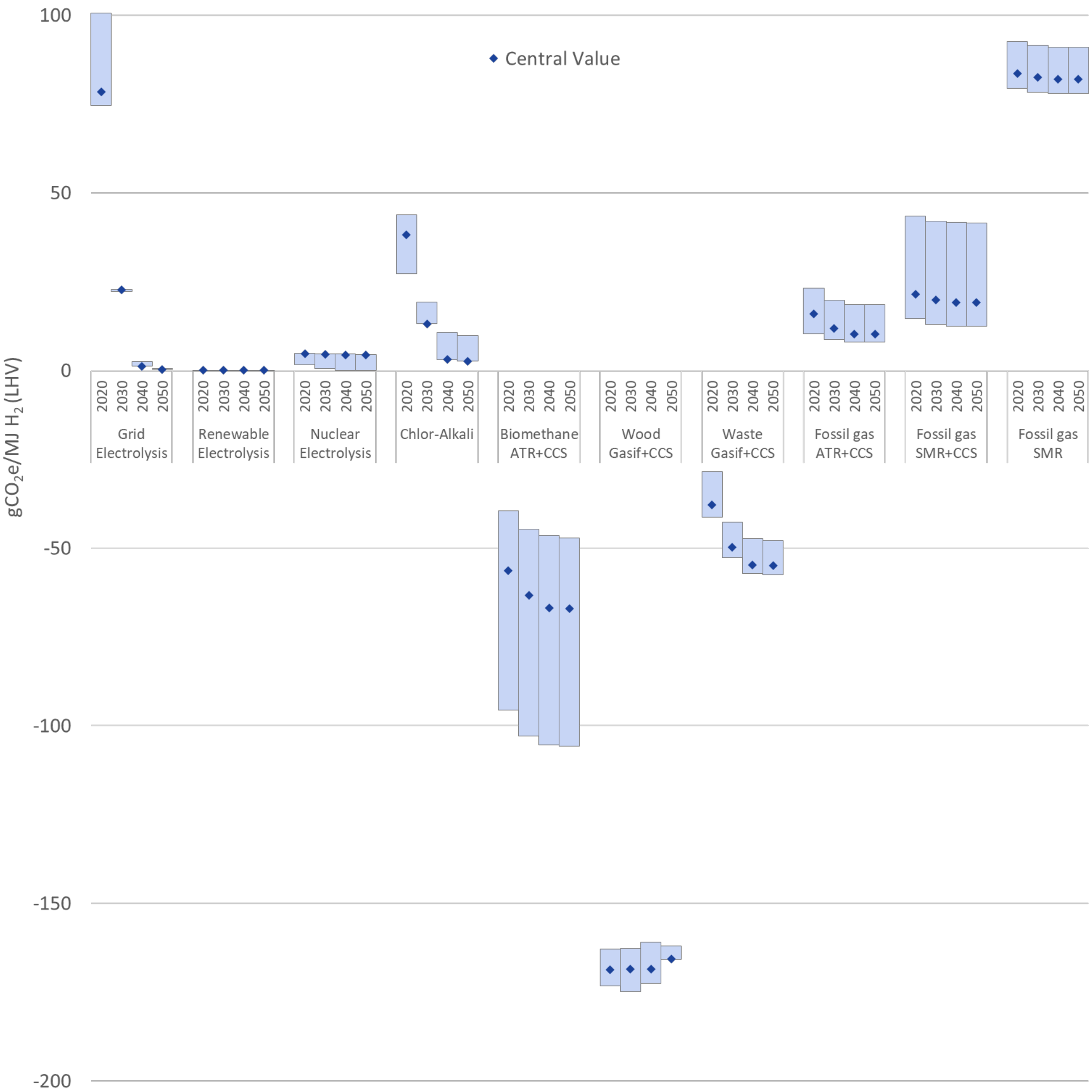


Figure 10: Hydrogen production emissions (scenario ranges, 2020 to 2050)

Figure 10 also illustrates how the GHG impacts of the hydrogen production change over time, from 2020 to 2050. Some hydrogen production pathways are likely to rapidly decarbonise due to their significant reliance on input electricity (taking projected UK national grid average intensities instead of technology or location specific factors) – e.g. grid electrolysis and chlor-alkali. Conversely, other chains are less likely to benefit from UK electricity grid decarbonisation, as they require much less electricity for production – e.g. fossil gas SMR. The ATR+CCS and waste gasification pathways also use some input grid electricity, so show some improvement over time. Decarbonisation of grid electricity is expected to be the largest GHG saving across most production pathways, with other improvements over time due to higher efficiencies or capture rates less important.

Figure 11 separates the GHG impacts for the hydrogen production pathways according to impacts arising from feedstock extraction, collection and transportation, and the impacts of hydrogen production processing facilities. The results compare Scenario 1 (central case) with Scenario 3 (worst case) in 2020. In the first four chains, the feedstock is the input electricity to the process plant, whereas for the biogenic chains, the feedstock is the solid biomass/waste feedstock, and for the fossil gas chains, the feedstock is the input fossil gas. These feedstock emissions can be very significant for some chains, particularly grid electrolysis and chlor-alkali pathways in 2020. Another potentially large source of GHG emissions arise when biomethane is produced from maize to use in an ATR with CCS plant (Scenario 3), where the impacts from feedstock cultivation, harvesting and transport (prior to the biogas plant) are 30.3 gCO_2e/MJ H_2. Comparatively, for food waste, feedstock impacts (prior to the biogas plant) are only 0.93 gCO_2e/MJ of H_2. Natural gas upstream emissions are also a significant contributor to the fossil gas SMR and ATR chains in Scenario 3, as fossil gas in this scenario is assumed to be imported liquified natural gas (LNG).

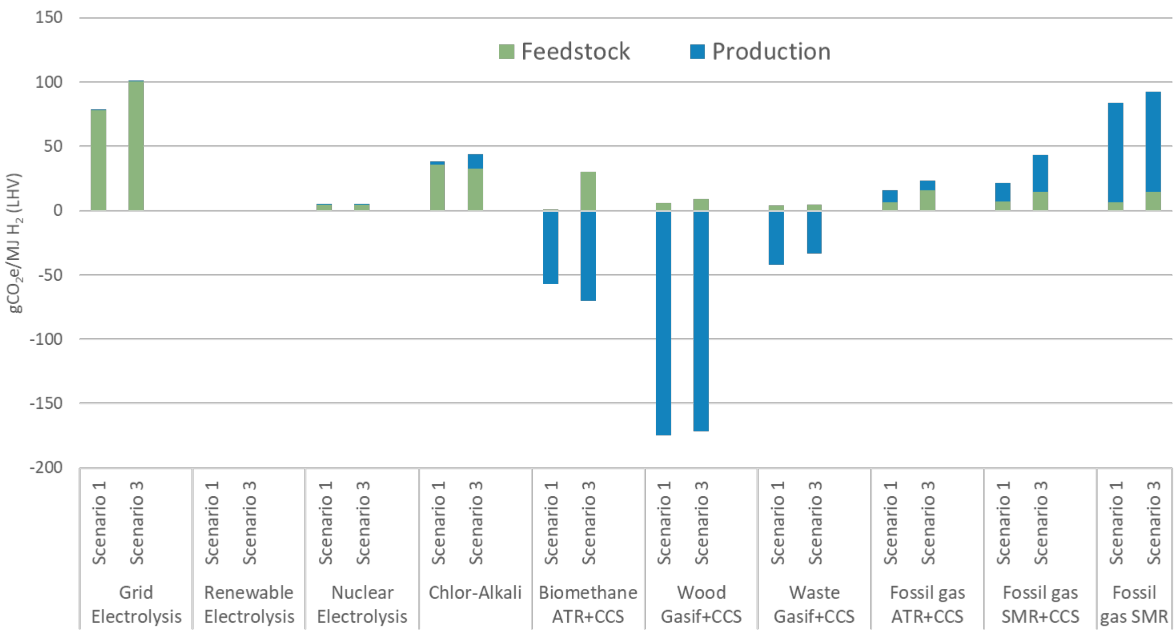


Figure 11: Hydrogen production emissions split between feedstock and processing emissions (Scenarios 1 and 3, 2020)

5.3.2 Downstream chain results

Figure 12 below represents the range of GHG impacts from different archetypal downstream distribution chains. Similar to Figure 10, the bars represent the range of impacts across the scenarios, with the bottom of the bar generally representing results from Scenario 2 and the top of the bar representing results from Scenario 3. The central value represents results from Scenario 1. Note that these results do not include the additional upstream impacts related to losses of hydrogen along the distribution chain – these are accounted for in the combined whole chain results presented in Section 5.3.3.

In 2020, the additional impacts from downstream distribution range between 0.40 gCO_2e/MJ delivered H_2 (Scenario 2 pipeline transportation) and 25.46 gCO_2e/MJ delivered H_2 (Scenario 3, liquid H_2 imported by ship). The rapid decarbonisation of the UK electricity grid between 2020 and 2030 results in some decreases in overall GHG impacts for all the downstream chains between 2020 and 2030, especially those with high compression requirements prior to trucking. However, significant falls in GHG emissions in the chains involving road transport are also seen, due to HGV decarbonisation over time (with HGVs either ending up as hydrogen fuelled or fully electric in the period 2030 to 2050, depending on the scenario).

The liquid transportation chain has by far the highest electricity requirements of all the downstream chains, due to liquefaction being used, with its large 2020 range due to different liquefaction electrical efficiencies in the different scenarios. This chain therefore experiences the faster decarbonisation in line with the UK average grid intensity. Scenario 3 of this chain also assumes long distance shipping, but these shipping emissions are small (~1gCO_2e/MJ when using Heavy Fuel Oil in 2020 and 2030, before shipping is assumed to switch to H_2 fuelled shipping by 2040).

By 2030, almost all chains are under 5 gCO_2e/MJ delivered H_2, except for the compressed road transport and salt cavern chain due to the doubled road transport distance (300km) and re-compression before the second transport step.

The very large majority of remaining GHG emissions in 2050 are due to an estimated 2% fugitive hydrogen emissions in compressed hydrogen dispensing at the end user (the exception being 0% dispensing losses assumed for liquid hydrogen refuelling). Up to a further 1% of fugitive hydrogen emissions are also estimated occur in salt cavern and pipeline chains, although these estimates are also highly uncertain and sensitivities have therefore been explored (see Appendix B). These fugitive emissions to atmosphere therefore effectively set the lower bound downstream chain emissions in the long-term, assuming all transport steps and energy use can be decarbonised.

Note that comparisons between the archetypal downstream chains in Figure 12 should be approached with caution, as the final pressure of the delivered hydrogen is different between chains, due to differences in end user requirements and how the hydrogen is delivered to the end user site (see section 0 for full details). For example, road transport by tube trailer requires hydrogen to be compressed to 50MPa before transportation and therefore is assumed to still be at 50Mpa when delivered, whereas hydrogen produced onsite can be available immediately at 3MPa.

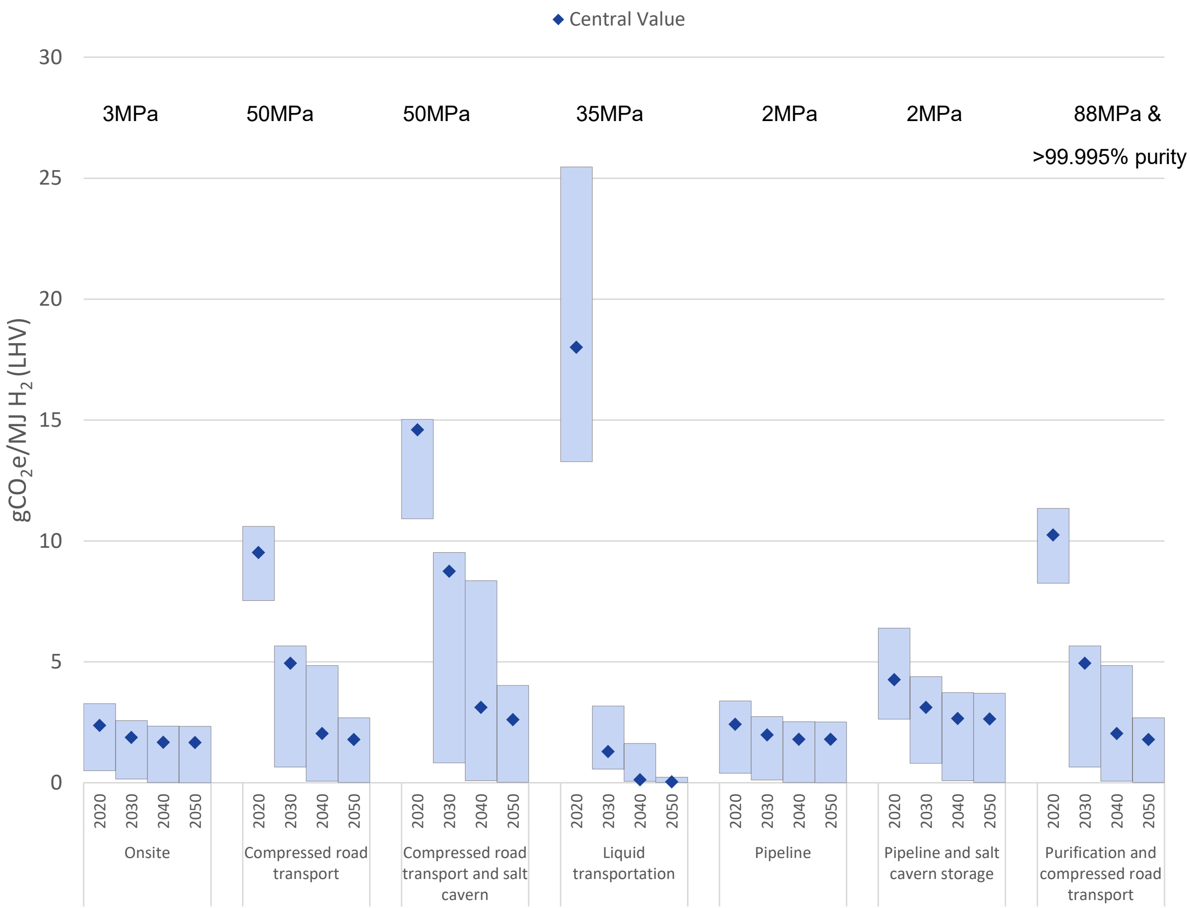


Figure 12: Downstream distribution emissions (scenario ranges, 2020 to 2050, delivered pressures shown, 99.9% purity unless specified)

Figure 13 below shows a sensitivity, with all chains now including compression to 88 MPa (to allow for dispensing to 70MPa for road transport vehicles). As all these chains deliver hydrogen at the same pressure (88MPa), results for these different downstream chains can be more easily compared against each other.

Broadly, the same conclusions presented in Figure 12 hold, although emissions are generally higher in earlier years due to the additional 88MPa compression electricity required. These increases in GHG emissions are most pronounced for the onsite and pipeline chains, given they experience the greatest increase in pressure (from 2-3 MPa previously up to 88MPa). This means that these chains also have a slightly sharper decrease in GHG emissions between 2020 and 2030 due to grid decarbonisation compared to Figure 12.

Similarly, by 2030, for almost all chains the central value is at or below 5 gCO_2e/MJ delivered hydrogen, again except for compressed road transport with salt cavern storage.

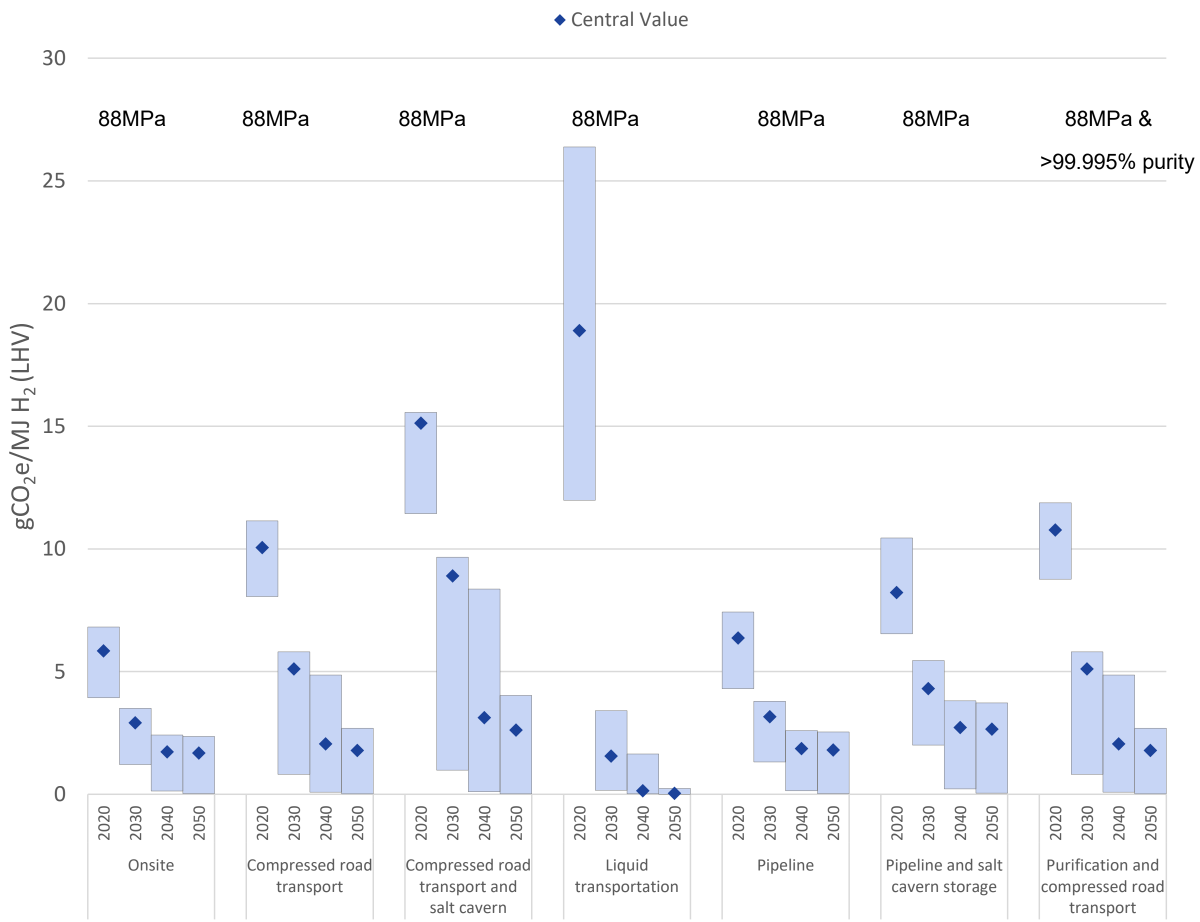


Figure 13: Downstream distribution emissions (scenario ranges, 2020 to 2050, with final compression to 88MPa, 99.9% purity unless specified)

Figure 14 illustrates the yearly decreases between 2020 and 2050 for each downstream chain, for Scenario 1 only (for the chain choices with different end use pressures). As mentioned previously, the rapid decarbonisation of the grid between 2020 and 2030 and HGV decarbonisation by 2040 results in a sharp decrease in GHG impacts for downstream chains, particularly those with compression requirements prior to trucking (e.g. compressed road transport). By 2050, the majority of GHG emissions are fugitive hydrogen emissions from leakages.

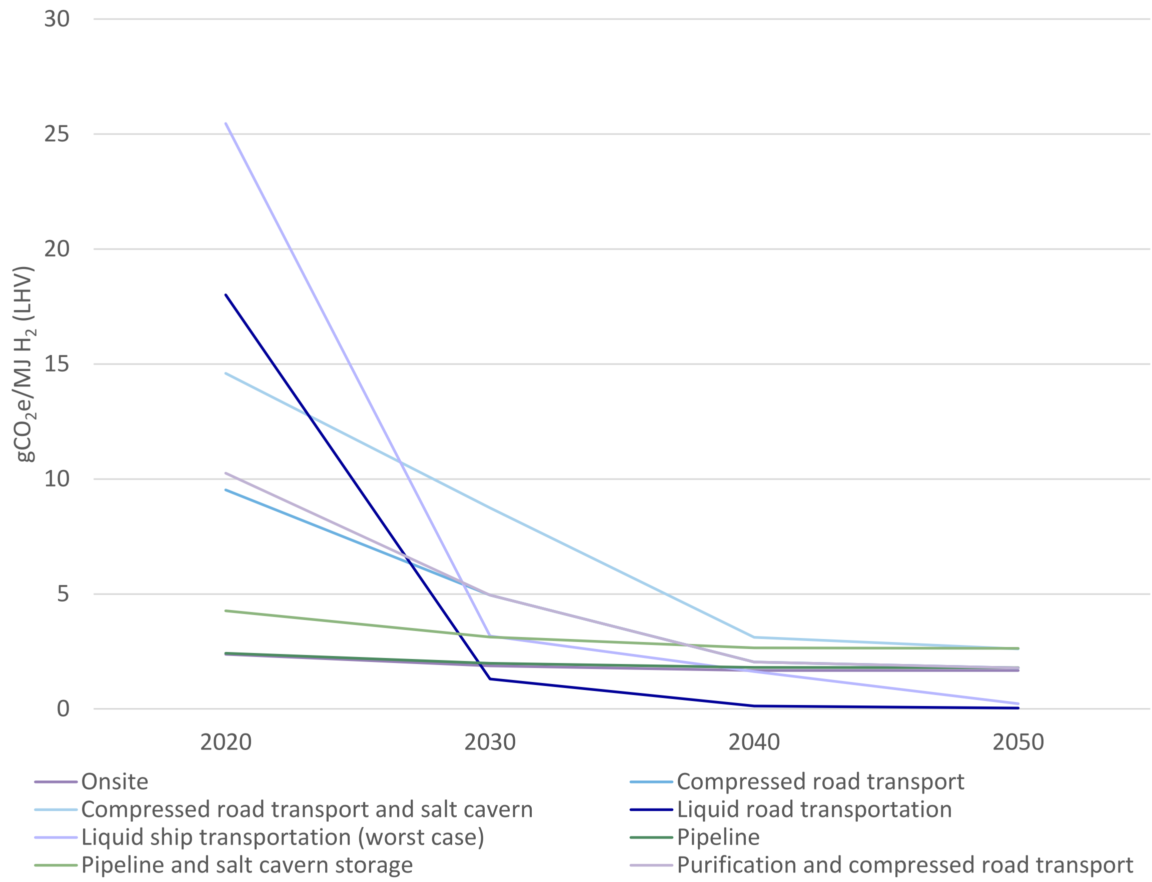


Figure 14: Downstream distribution emissions (Scenario 1, 2020 to 2050)

Figure 15 separates the downstream impacts by step for Scenario 1 in 2020 (for the chain choices with different end use pressures) – i.e. initial compression/liquefaction, transportation, salt cavern storage and final compression, storage and dispensing at final consumer. The split out for compression/liquefaction only relates to additional compression/liquefaction at the start of the chains, e.g. compression or liquefaction required for initial transportation. For the liquid transportation chain, the greatest impact in 2020 arises from the liquefaction of the hydrogen (requiring ~0.30 MJ of electricity per MJ of hydrogen).

Similarly, some data is aggregated, i.e. storage emissions depend on the received pressure at the salt cavern storage site. For example, in the “pipeline and salt cavern storage” chain, hydrogen is received at the salt cavern site at 2MPa, so needs compression to inject into storage – this compression is included within the storage block. Whereas for “compressed road transport and salt cavern”, the hydrogen is received at the salt cavern site at 50MPa, and does not need further compression before injection. However, compression on exit from the salt cavern back into a truck is still counted within the storage step. For pipeline transportation, there are minimal transport emissions, linked to the assumed hydrogen losses in the pipeline (0.15%).

The impacts from road transport in the compressed scenarios make up over a third of the 2020 impacts for the purification and compressed road transport scenarios. However, for the scenario where hydrogen is transported by compressed road truck to salt caverns, transportation accounts for over 40% of the downstream chains impact, due to the doubled trucking distance (to and from storage).

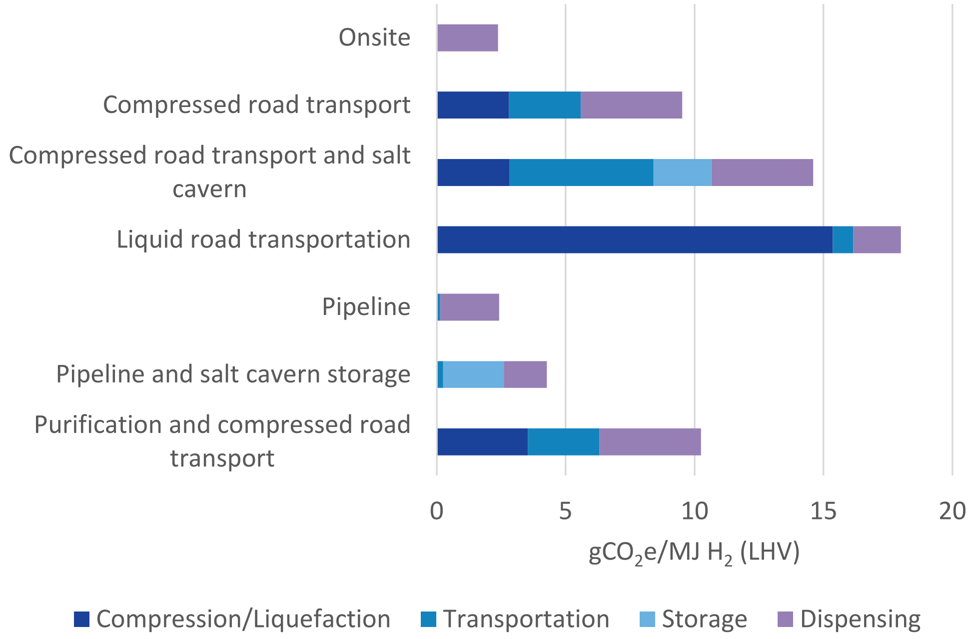


Figure 15: Downstream distribution emissions by step (Scenario 1, 2020)

5.3.3 Combined well-to-point-of-use chain results

This section presents combined results where hydrogen production pathways are paired with downstream distribution chains. The results provide illustrative well-to-point-of-use results. Any efficiency losses/leakage in the downstream distribution are accounted for and fed back through the chains – effectively producing more hydrogen to account for the losses. The results are presented for 2030 only, but other years can be assessed within the LCA tool. Furthermore, the results only illustrate some of the possible combinations between production and downstream chains. The LCA tool allows the user to select any hydrogen production pathway and match it to any downstream distribution chain. Note that comparison between chains with different downstream distribution options is limited, as the dispensed hydrogen can have different pressures (as described in Section 5.3.2).

Figure 16 illustrates the range of GHG emissions when hydrogen produced from renewable electrolysis and from fossil gas ATR with CCS are paired with all the modelled downstream distribution options. The downstream distribution chains have effectively added between 1.5 and 9 $gCO_2e/MJ\ H_2$ to the hydrogen production pathways in 2030.

Hydrogen produced from renewable electrolysis generally has a well-to-user impact of under 5 $gCO_2e/MJ\ H_2$ (central values), with the exception of chains using compressed road transport. However, this figure, as with all other figures produced in this study, is excluding embodied emissions. The addition of embodied emissions for wind power and electrolysers could increase these renewable electrolysis results by ~4gCO_2e/MJ LHV, as shown by the dotted boxes added to the scenario 3 results in Figure 16.[37]

For hydrogen produced from fossil gas ATR with CCS, the total combined GHG impacts in the central scenario range between 13 and 21 gCO_2e/MJ H_2. The addition of embodied emissions would be likely to increase ATR+CCS results by ~1gCO_2e/MJ LHV.[37]

Figure 16 shows that there may be some limited overlap between a few of renewable electrolysis and ATR+CCS chain results in 2030 if embodied emissions are included, although renewable electrolysis chain results remain below ATR+CCS results within each of the Best, Worst and Central scenarios.

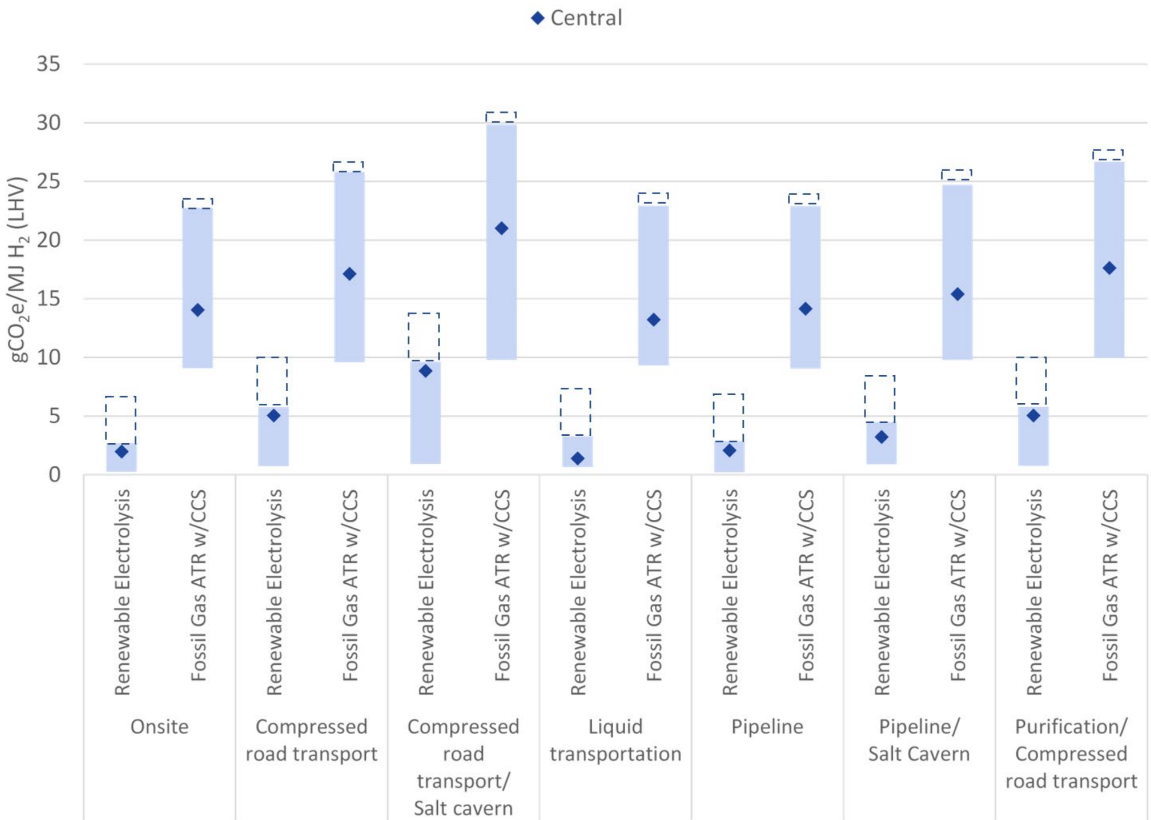


Figure 16: Well-to-point-of-use emissions for renewable electrolysis and fossil gas ATR+CCS, paired with different downstream chains (scenario ranges, 2030, dotted boxes indicating additional embodied emissions)

Figure 17 provides the well-to-point-of-use GHG impacts in 2030 of the different hydrogen production pathways all paired with onsite storage & dispensing. Adding this onsite downstream chain adds between 0.5 and 3.5 gCO_2e/MJ H_2 for each chain, with the exception of wood gasification chain. For the wood gasification chain, adding the downstream distribution very slightly decreases the overall GHG emissions. This is because the losses related to downstream distribution chain (2% in dispensing) results in a

[37] Hydrogen Council (2021) Hydrogen decarbonisation pathways: A life-cycle assessment. Available at: https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf

greater amount of biogenic CO_2 being captured and sequestered per MJ of delivered H_2, which cancels out the additional GHG impacts from downstream distribution (e.g. the impact from fugitive hydrogen emissions). Other biogenic production pathways with carbon capture have a similar effect with downstream losses boosting the per MJ capture of CO_2, but not to the same extent (as waste gasification is only 49% biogenic, and the biomethane chains in scenarios 1 and 3 do not have CO_2 capture during biogas upgrading). This highlights how less efficient downstream chains could end up producing more negative GHG intensity hydrogen for some biohydrogen+CCS routes, i.e. why negative GHG intensities need to be treated with considerable care. Further discussion of negative emissions is provided at the end of this chapter.

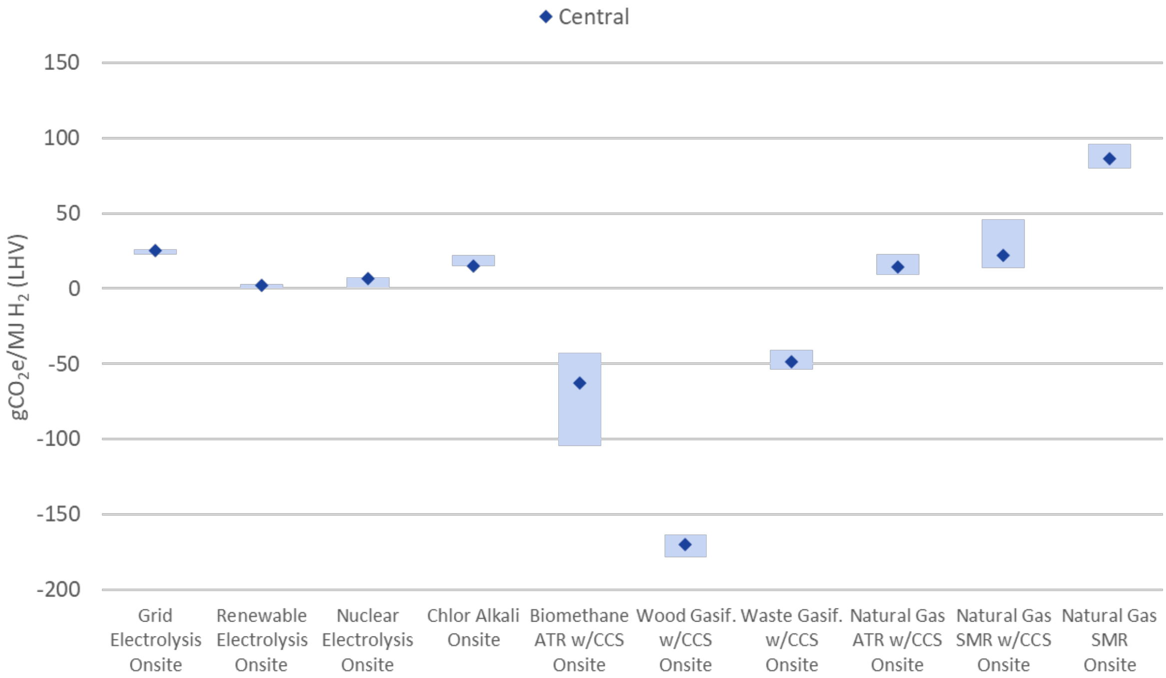


Figure 17: Well-to-point-of-use emissions of hydrogen production pathways, all paired with onsite compression, storage & dispensing (scenario ranges, 2030)

Figure 18 provides indicative well-to-user GHG impacts for hydrogen production methods paired with downstream distribution scenarios for 2030 (combinations listed on the x-axis). These scenarios are shown as examples, chosen through consultation with BEIS and Hydrogen Advisory Council Standards & Regulations Working Group stakeholders, as well as internal discussions. However, as mentioned previously, the LCA tool allows for any combination of production pathways and downstream chains to be selected, in any scenario and any year, given that any of these combinations could potentially be presented for assessment under a new standard. On average, the selected downstream distribution emissions adds around 2.5 gCO_2e/MJ delivered H_2 (range of -2.9[38] to 7.1 gCO_2e/MJ delivered H_2) to the hydrogen production emissions in 2030 across all scenarios.

[38] As mentioned previously, adding downstream distribution impacts on to some negative emission production pathways can decrease the emissions of the overall chain on a $gCO_2e/MJ_{\text{delivered } H2}$ basis, due to the reduced efficiency of the overall chain resulting in more biogenic CO_2 being captured upstream in production per MJ of H_2 delivered (the drop in H_2 delivered can outweigh the additional GHG impacts from the downstream distribution chain).

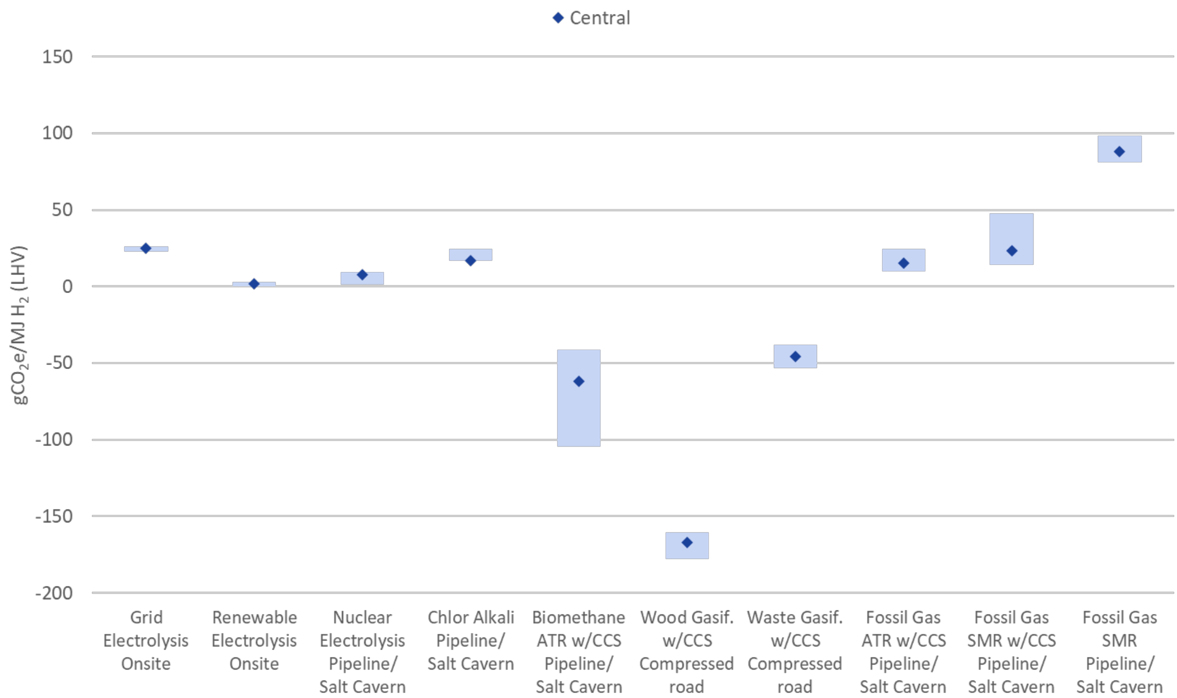


Figure 18: Well-to-point-of-use emissions of hydrogen production paired with indicative downstream chains (scenario ranges, 2030)

5.4 Sensitivity analysis

Starting from the Central foreground data and Baseline background data, a number of single parameter sensitivities were run, to assess the impact of either changing feedstock, emission factor, efficiency, capture rate or allocation assumptions. A list of the sensitivities run is given in Table 5.

Table 5: List of the sensitivities that were performed

Sensitivity	Description
Biogas feedstock	Changed the input feedstock for the biomethane ATR with CCS chain: **Baseline**: food waste; **Sensitivity**: maize
Composition of municipal solid waste (MSW)	Changed the input feedstock for the waste gasification with CCS chain: **Baseline**: 49% biogenic and 51% fossil; **Sensitivities**: (1) 100% fossil and (2) 100% biogenic
Biomass feedstock	Changed the input feedstock for the wood gasification with CCS chain: **Baseline**: forest residues; **Sensitivity**: miscanthus bales

Electricity emissions factor	Changed the grid electricity emissions factor for all upstream chains to highlight impact of different accounting choices: **Baseline**: UKTM "Core" run; **Sensitivities**: (1) UKTM "CCS Delay" (high impact), (2) UKTM "high CCS" (low impact) and (3) a different accounting decision is made to include negative emission power generation within the UK grid intensity, so that it goes negative overall by 2030 in the National Grid Future Energy Scenarios "Leading the way" scenario
Natural gas upstream emissions factor	Changed the natural gas emissions factor for all upstream chains: **Baseline**: weighted average intensity of different gas production methods based on data from the OGA to represent current UK mix; **Sensitivities**: (1) LNG, (2) pipeline and (3) CCC high scenario
Technology efficiencies	Changed the technology efficiencies of the production steps of all upstream chains, except chlor-alkali electrolysis: **Baseline**: central; **Sensitivities**: (1) worst and (2) best
Carbon capture and sequestration rates	Changed the capture rates for all upstream chains with CCS: **Baseline**: 95% capture and sequestration for ATR and gasification chains and 85% for SMR chains (producer only takes liability for uncaptured CO_2); **Sensitivities**: (1) 0% capture to reflect either no capture or CO_2 utilisation with the producer taking full liability for all the produced CO_2, (2) 50% capture and sequestration, or CO_2 utilisation with a shared liability between producer and user, (3) 90% capture and sequestration for ATR chains and 80% for gasification and SMR chains (producer only takes liability for uncaptured CO_2), and (4) 98% capture and sequestration for ATR chains and 95% for gasification and SMR chains (producer only takes liability for uncaptured CO_2)
Oxygen allocation	An economic value allocation for the oxygen was applied for the grid electrolysis chain (no allocation occurs in the baseline scenario)
Hydrogen GWP	Changed the GWP of hydrogen for all downstream chains: **Baseline**: 10 tCO_2e/tH_2; **Sensitivities**: (1) 0 tCO_2e/tH2 and (2) 14 tCO_2e/tH_2
Transport distances	Changed the transport distances for all relevant downstream chains: **Baseline**: 150 km; **Sensitivities**: (1) 0 km, (2) 50 km and (3) 350 km For food waste ATR, wood and waste gasification upstream chains: **Baseline**: 20 km (food waste and waste) and 250 km (wood); **Sensitivity**: 200 km

Downstream compression	Added downstream compression & dispensing: **Baseline**: pressure of hydrogen is maintained at the same pressure it arrives from the final transportation step, or from production in the case of on-site, with the exception of the "purification and road transport" chain which is compressed to 88 MPa. **Sensitivities**: (1) 88 MPa for all downstream chains (see Section 5.3.2, Figure 13) and (2) 8.5 MPa for pipeline chains instead of 2MPa
Downstream efficiency	Reduced downstream efficiency to account for increased dispensing (or other chain) losses of hydrogen: **Baseline**: 2% leakage for gaseous chains, 0% for liquid chains; **Sensitivities**: (1) 5% and (2) 10% for all chains
GWP scenario	Changed the GWP scenario for all upstream chains: **Baseline**: AR5 with climate feedbacks; **Sensitivities**: (1) AR4 and (2) AR5 without climate feedbacks

Full results arising from the sensitivity analysis are given in Appendix B. The chains for which the sensitivities are most significant are summarised in Table 6 and Table 7. These largest impacts are all seen in the production pathways (Table 6), with smaller changes seen in the downstream chains (Table 7). Note that there may be other factors, not modelled here, to which each chain is sensitive, and so these tables should not be taken as representing the main factors which could affect each chain individually.

Note that this sensitivity analysis is simplistic, in that the results reflect the change in a single parameter from the central case, and some of the knock-on impacts are not accounted for. For example, when removing CO_2 capture, there would be some benefits from the reduction in processing plant power demands, but the sensitivity analysis does not include this level of technical sophistication.

Table 6: Key sensitivities for production pathway emissions

all units are in $gCO_{2e}/MJ_{LHV\ produced}\ H_2$					
Sensitivity: Maize as biogas feedstock					
		2020	**2030**	**2040**	**2050**
Biomethane ATR with CCS	Baseline	-56.3	-63.3	-66.9	-67.1
	After Sensitivity	-30.9	-37.6	-40.9	-41.1
Sensitivity: MSW fraction 100% fossil					
		2020	**2030**	**2040**	**2050**
	Baseline	-37.9	-49.7	-54.7	-54.9

Waste Gasification with CCS	After Sensitivity	25.1	13.3	8.3	8.0
Sensitivity: MSW fraction 100% biogenic					
		2020	**2030**	**2040**	**2050**
Waste Gasification with CCS	Baseline	-37.9	-49.7	-54.7	-54.9
	After Sensitivity	-102.5	-114.3	-119.4	-119.6
Sensitivity: Miscanthus bales feedstock					
		2020	**2030**	**2040**	**2050**
Wood Gasification with CCS	Baseline	-168.7	-168.4	-168.5	-165.6
	After Sensitivity	-167.2	-166.8	-167.0	-164.2
Sensitivity: High impact grid electricity emissions factor					
		2020	**2030**	**2040**	**2050**
Grid Electrolysis	Baseline	78.4	22.7	1.3	0.3
	After Sensitivity	80.2	20.3	1.4	0.5
Chlor-alkali	Baseline	38.2	13.2	3.1	2.6
	After Sensitivity	38.9	12.0	3.2	2.7
Sensitivity: Low impact grid electricity emissions factor					
		2020	**2030**	**2040**	**2050**
Grid Electrolysis	Baseline	78.4	22.7	1.3	0.3
	After Sensitivity	77.7	23.1	2.6	0.6
Chlor-alkali	Baseline	38.2	13.2	3.1	2.6
	After Sensitivity	37.8	13.3	3.7	2.8
Sensitivity: Negative grid electricity emissions factor					
		2020	**2030**	**2040**	**2050**
Grid Electrolysis	Baseline	78.4	22.7	1.3	0.3
	After Sensitivity	62.7	-2.3	-37.5	-40.8
Chlor-alkali	Baseline	38.2	13.2	3.1	2.6
	After Sensitivity	31.0	1.4	-15.4	-17.3
Sensitivity: High impact natural gas emissions factor					
		2020	**2030**	**2040**	**2050**

Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	23.0	19.0	17.4	17.3
Natural Gas SMR (no CCS)	Baseline	83.6	82.5	82.0	82.0
	After Sensitivity	90.9	89.8	89.3	89.3
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	29.0	27.4	26.8	26.8
Sensitivity: Low impact natural gas emissions factor					
		2020	**2030**	**2040**	**2050**
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	13.5	9.5	7.9	7.8
Natural Gas SMR (no CCS)	Baseline	83.6	82.5	82.0	82.0
	After Sensitivity	81.1	80.0	79.5	79.5
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	18.8	17.3	16.7	16.6
Sensitivity: Very high impact natural gas emissions factor					
		2020	**2030**	**2040**	**2050**
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	36.9	32.9	31.3	31.2
Natural Gas SMR (no CCS)	Baseline	83.6	82.5	82.0	82.0
	After Sensitivity	105.2	104.0	103.6	103.6
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	43.8	42.2	41.6	41.6
Sensitivity: Worst technology efficiency					
		2020	**2030**	**2040**	**2050**
Grid Electrolysis	Baseline	78.4	22.7	1.3	0.3
	After Sensitivity	98.4	25.6	1.4	0.3
Sensitivity: Best technology efficiency					
		2020	**2030**	**2040**	**2050**
Grid Electrolysis	Baseline	78.4	22.7	1.3	0.3

	After Sensitivity	75.4	21.9	1.2	0.3
Sensitivity: No carbon capture					
		2020	**2030**	**2040**	**2050**
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	83.4	80.5	79.3	79.2
Biomethane ATR with CCS	Baseline	-56.3	-63.3	-66.9	-67.1
	After Sensitivity	9.3	3.4	0.3	0.1
Wood Gasification with CCS	Baseline	-168.7	-168.4	-168.5	-165.6
	After Sensitivity	6.8	6.5	4.3	4.0
Waste Gasification with CCS	Baseline	-37.9	-49.7	-54.7	-54.9
	After Sensitivity	80.8	70.8	66.5	66.3
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	85.9	85.3	85.1	85.1
Sensitivity: 50% carbon capture					
		2020	**2030**	**2040**	**2050**
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	47.9	44.4	43.0	42.9
Biomethane ATR with CCS	Baseline	-56.3	-63.3	-66.9	-67.1
	After Sensitivity	-25.2	-31.7	-35.1	-35.3
Wood Gasification with CCS	Baseline	-168.7	-168.4	-168.5	-165.6
	After Sensitivity	-85.6	-85.5	-86.6	-85.3
Waste Gasification with CCS	Baseline	-37.9	-49.7	-54.7	-54.9
	After Sensitivity	18.4	7.4	2.7	2.5
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	48.0	46.8	46.4	46.3
Sensitivity: 90% carbon capture for ATR, 80% for gasification and SMR chains					
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	19.5	15.5	13.9	13.9
	Baseline	-56.3	-63.3	-66.9	-67.1

Biomethane ATR with CCS	After Sensitivity	-52.9	-59.8	-63.3	-63.5
Wood Gasification with CCS	Baseline	-168.7	-168.4	-168.5	-165.6
	After Sensitivity	-141.0	-140.8	-141.2	-138.9
Waste Gasification with CCS	Baseline	-37.9	-49.7	-54.7	-54.9
	After Sensitivity	-19.1	-30.6	-35.6	-35.8
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	25.2	23.7	23.1	23.1
Sensitivity: 98% carbon capture for ATR and gasification chains, 95% for SMR chains					
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	13.8	9.8	8.1	8.1
Biomethane ATR with CCS	Baseline	-56.3	-63.3	-66.9	-67.1
	After Sensitivity	-58.4	-65.4	-69.0	-69.2
Wood Gasification with CCS	Baseline	-168.7	-168.4	-168.5	-165.6
	After Sensitivity	-174.3	-173.9	-173.9	-171.0
Waste Gasification with CCS	Baseline	-37.9	-49.7	-54.7	-54.9
	After Sensitivity	-41.6	-53.5	-58.5	-58.8
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	13.8	12.2	11.5	11.5
Sensitivity: economic allocation of emissions to oxygen					
		2020	**2030**	**2040**	**2050**
Grid Electrolysis	Baseline	78.4	22.7	1.3	0.3
	After Sensitivity	57.2	16.6	0.9	0.2
Sensitivity: Upstream transport distance changed to 200 km (from 20 km)					
		2020	**2030**	**2040**	**2050**
Biomethane ATR with CCS	Baseline	-56.3	-63.3	-66.9	-67.1
	After Sensitivity	-47.9	-55.4	-65.8	-66.7
Waste Gasification with CCS	Baseline	-37.9	-49.7	-54.7	-54.9
	After Sensitivity	-34.6	-46.6	-54.3	-54.8
Sensitivity: GWP scenario changed to AR4					

		2020	2030	2040	2050
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	14.8	10.7	9.1	9.1
Natural Gas SMR (no CCS)	Baseline	83.6	82.5	82.0	82.0
	After Sensitivity	82.2	81.1	80.7	80.7
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	20.0	18.5	17.8	17.8
Sensitivity: GWP scenario changed to AR5 without feedback					
		2020	**2030**	**2040**	**2050**
Natural Gas ATR with CCS	Baseline	16.0	11.9	10.3	10.2
	After Sensitivity	15.2	11.1	9.5	9.4
Natural Gas SMR (no CCS)	Baseline	83.6	82.5	82.0	82.0
	After Sensitivity	82.7	81.6	81.1	81.1
Natural Gas SMR with CCS	Baseline	21.4	19.9	19.2	19.2
	After Sensitivity	20.5	18.9	18.3	18.3

Table 7: Key sensitivities for downstream chain emissions

all units are in $gCO_{2e}/MJ_{LHV\ delivered}\ H_2$					
Sensitivity: GWP of H2 = 0 $tCO_2e/tH2$ (from 10 tCO2e/tH2)					
		2020	**2030**	**2040**	**2050**
Compressed road transport + salt cavern	Baseline	14.6	8.7	3.1	2.6
	After Sensitivity	12.2	6.4	0.7	0.2
Pipeline + salt cavern storage	Baseline	4.3	3.1	2.7	2.6
	After Sensitivity	1.6	0.5	0.0	0.0
Sensitivity: GWP of H2 = 14 $tCO_2e/tH2$ (from 10 $tCO_2e/tH2$)					
		2020	**2030**	**2040**	**2050**
Compressed road transport + salt cavern	Baseline	14.6	8.7	3.1	2.6
	After Sensitivity	15.6	9.7	4.1	3.6
Pipeline + salt cavern storage	Baseline	4.3	3.1	2.7	2.6
	After Sensitivity	5.3	4.2	3.7	3.7

Sensitivity: Downstream transport distance removed					
		2020	2030	2040	2050
Compressed road transport + salt cavern	Baseline	14.6	8.7	3.1	2.6
	After Sensitivity	11.8	6.1	2.8	2.5
Sensitivity: Downstream transport distance reduced to 50 km (from 150 km)					
		2020	2030	2040	2050
Compressed road transport + salt cavern	Baseline	14.6	8.7	3.1	2.6
	After Sensitivity	12.7	7.0	2.9	2.5
Sensitivity: Downstream transport distance increase to 350 km (from 150 km)					
		2020	2030	2040	2050
Compressed road transport + salt cavern	Baseline	14.6	8.7	3.1	2.6
	After Sensitivity	18.3	12.2	3.6	2.8
Sensitivity: Downstream compression to 88 MPa added					
		2020	2030	2040	2050
Onsite	Baseline	2.4	1.9	1.7	1.7
	After Sensitivity	5.8	2.9	1.7	1.7
Pipeline	Baseline	2.4	2.0	1.8	1.8
	After Sensitivity	6.4	3.2	1.9	1.8
Pipeline + salt cavern storage	Baseline	4.3	3.1	2.7	2.6
	After Sensitivity	8.2	4.3	2.7	2.7
Sensitivity: Downstream compression to 8.5 MPa added for pipeline chains					
		2020	2030	2040	2050
Pipeline	Baseline	2.4	2.0	1.8	1.8
	After Sensitivity	3.8	2.4	1.8	1.8
Pipeline + salt cavern storage	Baseline	4.3	3.1	2.7	2.6
	After Sensitivity	5.7	3.5	2.7	2.6
Sensitivity: Downstream leaks increased to 5% (from 0% for liquid and 2% for all other chains)					
		2020	2030	2040	2050
	Baseline	9.5	4.9	2.0	1.8

Compressed road transport	After Sensitivity	12.2	7.5	4.6	4.3
Compressed road transport + salt cavern	Baseline	14.6	8.7	3.1	2.6
	After Sensitivity	17.4	11.4	5.7	5.1
Liquid transportation	Baseline	18.8	2.0	0.2	0.1
	After Sensitivity	23.8	6.2	4.4	4.2
Purification + compressed road transport	Baseline	10.3	4.9	2.0	1.8
	After Sensitivity	13.0	7.5	4.6	4.3
Sensitivity: Downstream leaks increased to 10% (from 0% for liquid and 2% for all other chains)					
		2020	**2030**	**2040**	**2050**
Compressed road transport	Baseline	9.5	4.9	2.0	1.8
	After Sensitivity	16.7	11.8	8.7	8.5
Compressed road transport + salt cavern	Baseline	14.6	8.7	3.1	2.6
	After Sensitivity	22.2	16.0	9.9	9.4
Liquid transportation	Baseline	18.8	2.0	0.2	0.1
	After Sensitivity	28.9	10.5	8.6	8.4
Purification + compressed road transport	Baseline	10.3	4.9	2.0	1.8
	After Sensitivity	17.5	11.8	8.7	8.5

Removing carbon capture from the CCS chains results in the greatest increase in GHG emissions. The impact of removing carbon capture from the ATR and SMR chains was similar to the impact of changing the composition of the MSW used in the residual waste gasification with CCS chain to being 100% fossil. The grid electrolysis chain was the only chain that produced a relatively high impact when changing the technology efficiency to the worst case, however, this impact reduced rapidly over the timescale. Rapid grid decarbonisation means that the increased electricity requirement of the electrolyser in e.g. the worst case scenario in 2050 has much less of a GHG impact than it does in 2020, when the grid is more carbon intensive. Compression to 88 MPa was added as a sensitivity to the downstream chains (based on the added power emissions), although the impact is relatively modest and decreasing over time (noting that any potential impacts on the downstream efficiency and additional fugitive emissions of H_2 were not accounted for with this added compression sensitivity).

The large majority of UK hydrogen is currently produced via SMR without CCS. Some biogenic routes, particularly in the near-term before CCS is widely available, may be developed initially without CCS. It is therefore instructive to look at chain results without

CCS benefits included. The impact of removing carbon capture from the modelled CCS chains is shown in Figure 19.

The greatest increase in emissions is observed for the wood and waste gasification chains. Biomethane chains have a more modest rise, due to a significant share of the biogenic carbon in the feedstock already being vented as CO_2 during biogas upgrading (in scenarios 1 and 3), prior to the ATR with CCS plant. However, both wood gasification without CCS and biomethane ATR chains without CCS still have low overall production GHG emissions (they just are no longer negative). Without CCS, the waste gasification and fossil gas ATR chains both have very high GHG emissions, close to unabated fossil SMR emissions.

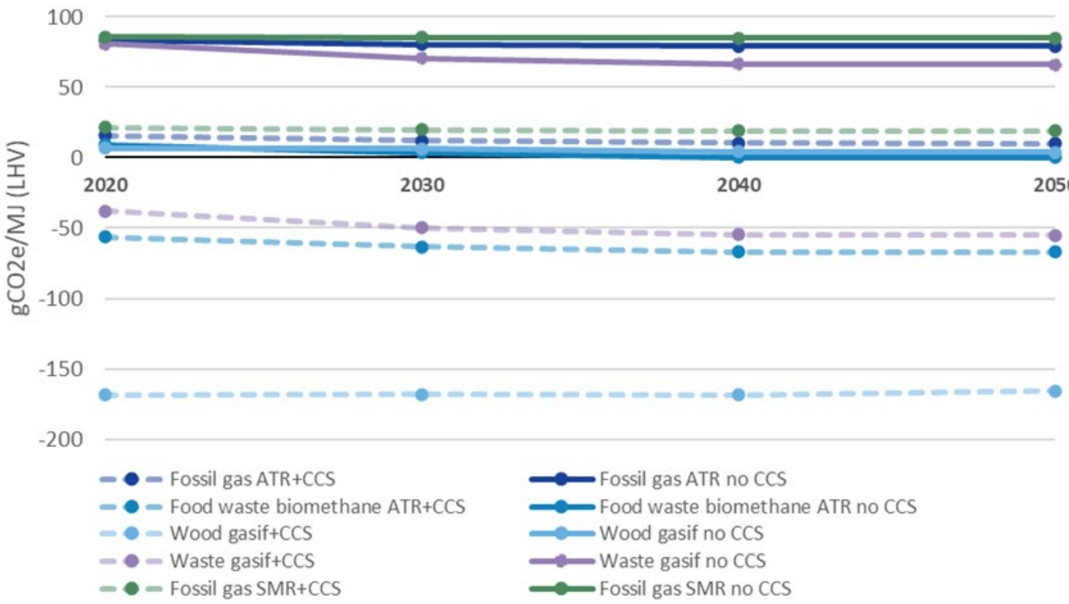


Figure 19: Impacts from the different hydrogen production pathways between 2020 and 2050 with and without carbon capture

5.5 GHG thresholds

If choosing to set a single GHG threshold based only on well-to-gate emissions (up to point of production), and covering all technology pathways, then Figure 20 (red line) shows the potential impacts of an example single GHG threshold of around 15-20 gCO_2e/MJ_{LHV} of produced H_2. This example threshold is flat over time, but alternative thresholds could be set slightly higher initially, but falling over time to 2050.

This example threshold of 15-20 gCO_2e/MJ_{LHV} of produced H_2 would already allow in a number of low and negative emissions chains, such as renewable and nuclear electrolysis, and all the biomethane, biomass and waste gasification pathways involving CCS, as well as some of the better biomethane and biomass gasification pathways without CCS. It would also allow fossil gas pathways that show sufficiently high efficiency and capture rates combined with sufficiently low upstream emissions, such as the majority of ATR with CCS chains, as well as the better end of the SMR with CCS chains (presuming that CCS retrofits of SMR plants at high CO_2 capture rates are possible). This example threshold would likely exclude:

- Chlor-alkali until around 2030 and grid electrolysis until shortly after 2030, if using grid average intensities, as this will be when the grid has sufficiently decarbonised;
- Maize biomethane ATR/SMR without CCS and waste gasification without CCS; and
- Most fossil gas pathways where CO_2 capture rates are below ~85% or those relying on LNG.

An alternative approach would be to set one looser threshold at around 20-25 gCO_2e/MJ_{LHV} of produced H_2 (which would let in a slightly wider range of fossil gas pathways), with a second tighter threshold at around 10 gCO_2e/MJ_{LHV} of produced H_2 (which would only initially include renewable or nuclear electrolysis, biogenic+CCS or lower carbon biogenic pathways without CCS, and the very best of the fossil ATR+CCS pathways – but when the grid fully decarbonises closer to 2040, grid electrolysis and chlor-alkali could also qualify for this second threshold).

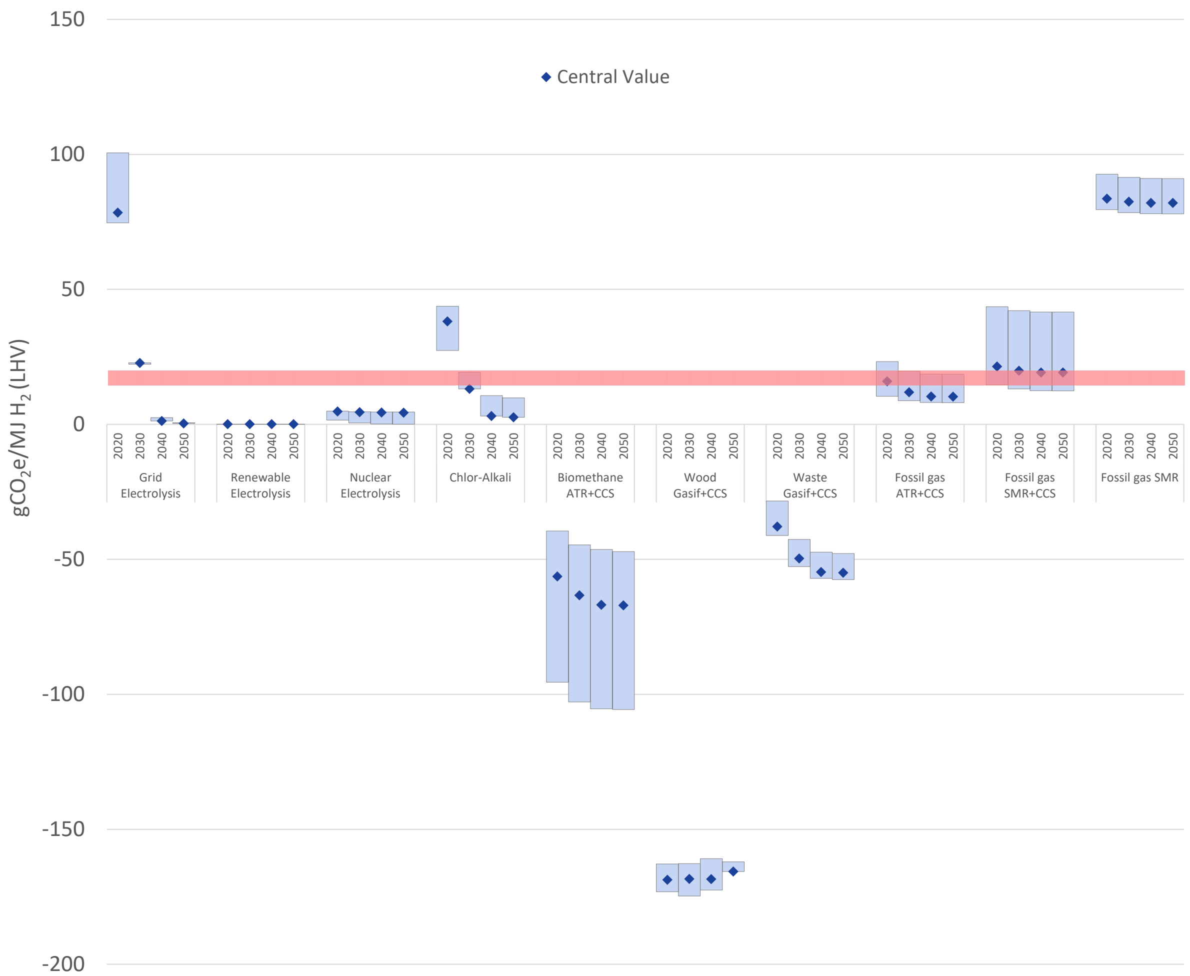


Figure 20: Hydrogen production emissions (scenario ranges, 2020 to 2050, red bar as an example threshold range)

Changes to the GHG methodology or system boundary employed in this WP2 analysis would impact some of these potential inclusions/exclusions (e.g. whether waste gasification without CCS is able to use a system expansion approach to only account for displaced incineration power generation rather than accounting for the direct fossil CO_2 emissions).

Looking at the downstream distribution chains, there is more uncertainty, and there may need to be different choices assumed for different end users. Any separate threshold specifically for downstream chains may also not be required, if a combined GHG threshold is chosen that covers the whole well-to-point-of-use instead.

However, there is still value in discussing what additional downstream emissions might be acceptable, with an example range of 5-10 gCO_2e/MJ_{LHV} of delivered H_2 shown in Figure 21. Only a few chains would be excluded in 2020 if a threshold were set towards the upper end of this range (compressed road transport with salt cavern storage, and liquified transport chains). But by 2030, most chains have emissions below 5gCO_2e/MJ_{LHV} of delivered H_2, except those with long compressed road transport distances, suggesting that lower thresholds could be possible over time.

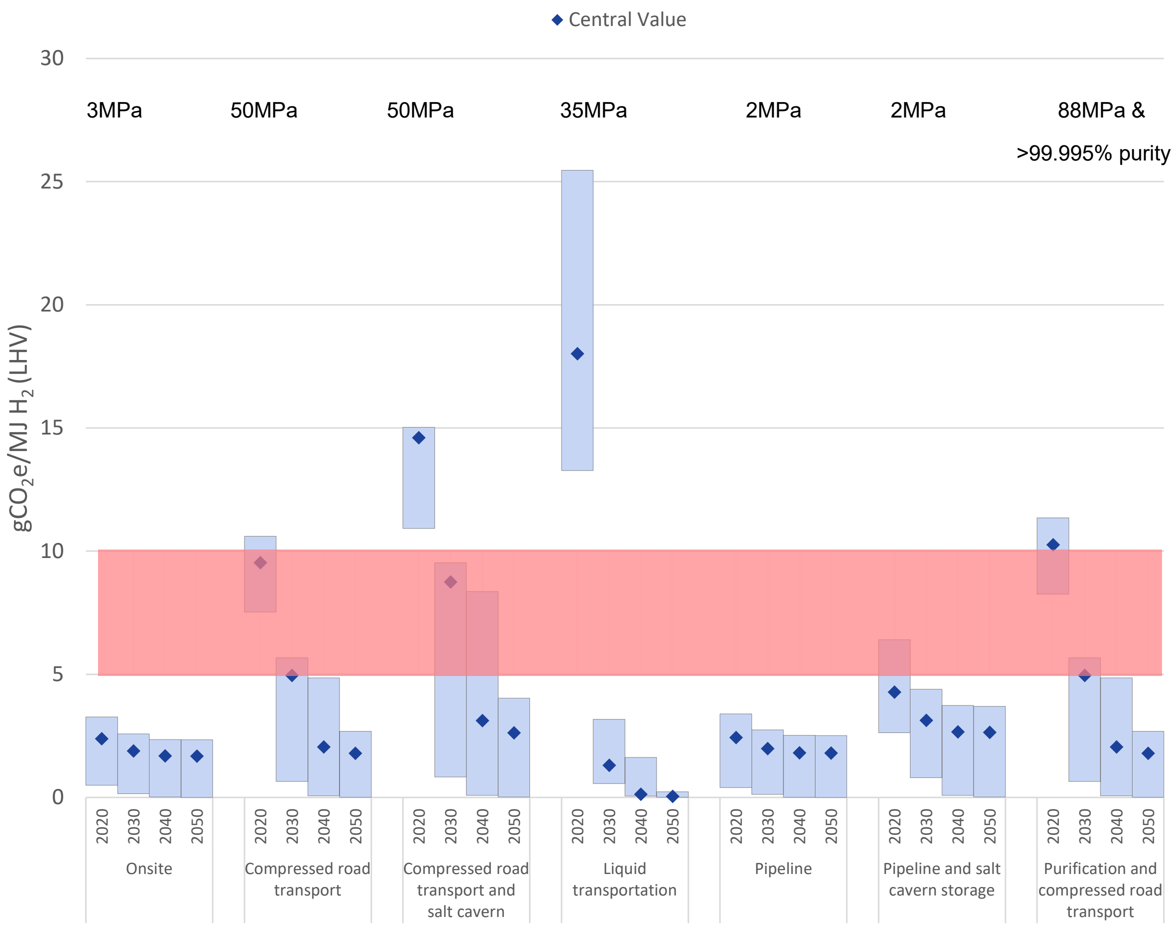


Figure 21: Downstream distribution emissions (scenario ranges, 2020 to 2050, delivered pressures as shown, 99.9% purity unless specified, red bar as an example threshold range)

Note that these discussed downstream threshold values should not be added directly to the production threshold values discussed, as the downstream efficiency losses/leakages also need to be taken into account when deriving whole chain emissions results (effectively the units are different, with gCO_2e/MJ of produced H_2 vs. gCO_2e/MJ of delivered H_2). However, given these leakages/losses are relatively small, their sum will be close to the combined chain result.

If considering a combined GHG threshold from well-to-point-of-use, this will need to take into account the various potential combinations of production pathways and downstream distribution chains. Figure 26 indicates the potential impacts of setting an example combined GHG threshold of around 20-25 gCO_2e/MJ of delivered H_2 in 2030. This example level would include/exclude a similar set of production routes as discussed above, as by 2030, the emissions of the downstream options are not a major differentiator between whole routes. A combined GHG threshold would allow actors to optimise emissions across the different parts of the supply chain, allowing e.g. greater distribution distances for near-zero emission production technologies (e.g. helping renewable electrolysis in more remote locations get product to market), or incentivising fossil routes to develop and utilise lower-GHG intensity distribution channels.

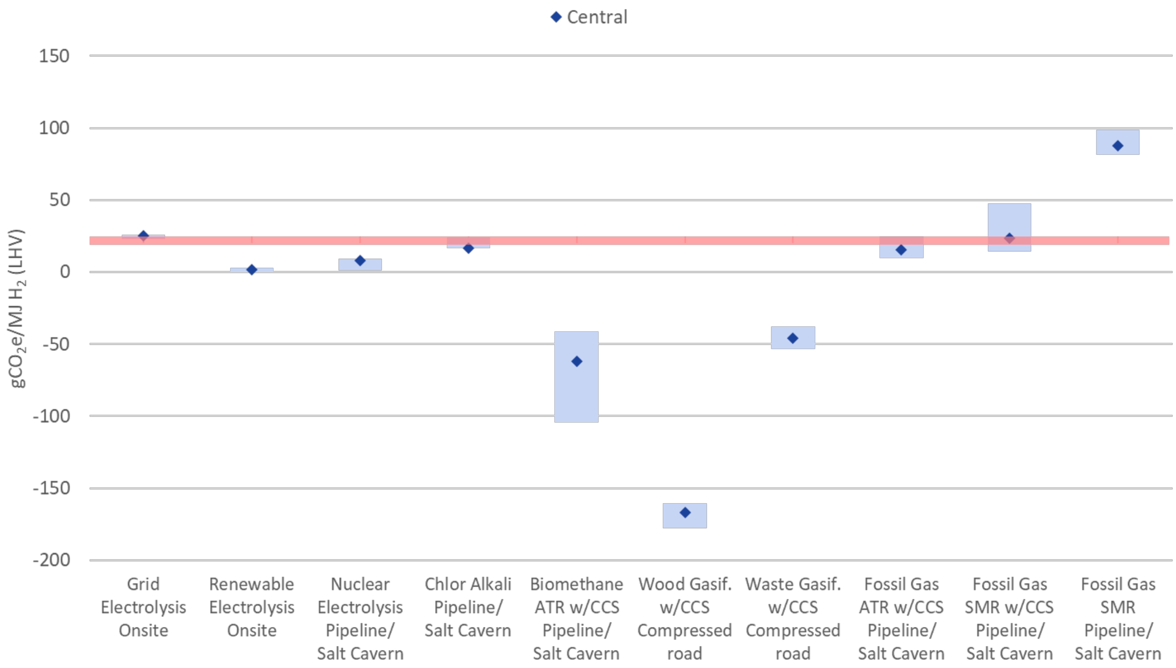


Figure 22: Well-to-user emissions of hydrogen production paired with indicative downstream chains (scenario ranges, 2030 only, red bar as an example threshold range)

It is worth noting that this example threshold level of 20-25 gCO_2e/MJ of delivered H_2 is well below most of the existing thresholds in other standards globally, as outlined in Figure 2, although several of these existing thresholds will be tightened once REDII is finalised.

If looking to compare these potential options for GHG threshold against a UK specific fossil comparator, then UK average natural gas used in unabated SMR results in 84 gCO_2e/MJ_{LHV} of produced H_2 in 2020. Combined with an indicative downstream pipeline and salt cavern storage before compression and dispensing, this rises to 90 gCO_2e/MJ_{LHV} of delivered H_2 in 2020. This is only a suggested fossil comparator, based on current merchant hydrogen production – other comparators may be more appropriate as the low-carbon hydrogen market grows and different end uses develop (e.g. the comparator may be fossil natural gas directly if hydrogen is displacing natural gas in heating applications).

A point-of-production threshold of 15-20 gCO_2e/MJ_{LHV} of produced H_2 would therefore equate to a 76-82% GHG saving vs. a UK SMR benchmark. A point-of-use threshold of 20-25 gCO_2e/MJ_{LHV} of delivered H_2 would equate to a 72-78% GHG saving vs. an indicative whole chain UK SMR benchmark.

Negative emissions

Significant care needs to be taken when dealing with negative GHG emissions intensities (either as input vectors/materials or as final fuels). Given the same annual tonnage of CO_2 capture in processing, less efficient chains will actually produce hydrogen with a more negative GHG intensity (a lower value in terms of $gCO_2e/MJ\ H_2$). This is because a plant using more biomass feedstock to generate a tonne of hydrogen will generate more CO_2, and therefore more CO_2 will be stored, leading to a more negative result. If any GHG thresholds under a standard were to ever be set as a negative value (for example, a new super-low banding were being considered as a support mechanism for bioenergy with CCS chains), additional safeguards or requirements would likely be needed to ensure that certain minimum process efficiencies are achieved for processing plants, to prevent perverse outcomes whereby only inefficient plants are able to achieve the new negative threshold.

When GHG thresholds are low and positive and inputs all have positive intensities, this already incentivises a minimum level of efficiency to be achieved. However, if process inputs have negative GHG intensities (e.g. due to a different accounting choice allowing UK grid electricity to include the negative emissions from biomass power with CCS plants), this similarly could lead to some unwanted outcomes, where greater power consumption leads to lower GHG intensity hydrogen.

Coordination will be required across government departments as to whether energy vectors/fuels ought to be able to report negative GHG intensities at all, or should separate out any biogenic CO_2 capture from the fuel GHG intensity calculations. The RTFO and LCFS already allows some biofuels to report negative GHG intensities.

6 Options and recommendations for a standard

Summary

This chapter discusses options for the methodological choices used within a low carbon hydrogen standard, giving advantages and disadvantages of these options, and drawing conclusions intended to help in development of a standard, together with further work from BEIS and the outcomes of stakeholder consultation. For many of the factors related to the system definition and GHG calculation requirements, the analysis shows that one approach is strongly preferred. These include using units of $gCO2_e$/MJ LHV, defining a threshold on an absolute basis, and using a hybrid approach to the data used to calculate GHG emissions.

However, there are some decisions that are not clear, either because the option chosen depends heavily on how the standard is intended to be used, or because of uncertainties related to the options. Several of these decisions also depend on each other, with the choice made for one factor reducing the options available for another. The key decisions to be made on these more complex, interacting factors include whether the standard is applied at the point of hydrogen production, or at the point of use (the 'system boundary'), and how this interacts with the approach used for the chain of custody, requirements for hydrogen purity and pressure, and the geographical boundary of the scheme – whether it covers UK production and use only or also hydrogen imports and/or exports. Overall, two main types of approach could be taken - albeit with intermediate approaches possible:

- A point of production system boundary, with requirements for purity and pressure requirements/adjustments and with a book & claim chain of custody, analogous to a CertifHy Guarantee of Origin type approach.

- A point of use system boundary with mass balance chain of custody, with no purity and pressure requirements, analogous to the RTFO approach.

For several other factors, alignment with other schemes are important:

- Allocation of emissions to non-energy co-products – the outcomes of decision made at IPHE should be taken into account when making this decision.

- Use of low carbon electricity – we recommend allowing low carbon electricity based on traded activities such as power purchase agreements with cancellation of guarantees of origin or equivalent. However, additional criteria to mitigate potential risks are in development at UK and EU level, and so need to be reviewed once agreed.

- Treatment of mixed inputs – should be reviewed after decisions in RED II and the RTFO.

In many cases the decision depends on the intended scheme in which the standard is used, or on decisions made in other UK policy mechanisms such as the RTFO. These include the number and form of GHG thresholds, requirements to show additionality of renewable electricity use, treatment of ILUC emissions for biomass, treatment of waste fossil feedstocks, the choice of global warming potentials used and the approach to use of low carbon gas.

6.1 Introduction

This chapter discusses options for the methodological choices used within a low carbon hydrogen standard. For most choices, several options are identified, and the advantages and disadvantages of each are compared, with conclusions drawn on the most suitable options. For others, where the choice is clearer (for example, as a result of the need for alignment with other standards), a recommendation is made. This is intended to inform the development of a standard, together with further work from BEIS and the outcomes of a forthcoming consultation.

A low carbon hydrogen standard needs to include several elements which ensure that credibility, transparency, ease of use and other criteria defined in WP1 are met. The key elements of a low carbon hydrogen standard are:

1. System definition – boundaries, scope
2. GHG calculation requirements – units, reference flows, allocation, inputs, thresholds
3. Chain of custody
4. Assurance
5. Communication and claims
6. Governance

Decisions related to topics 1-3 have a significant effect on the options possible for topics 4-6. Topics 4-6 also depend heavily on the way in which the standard is used, for example whether it is used to support a one-off assessment (such as eligibility for a capital grant) or used to support an ongoing certification scheme or policy mechanism. Note that we have referred to these varying uses of the standard (policy mechanisms, certification schemes etc) collectively as ‘schemes’ as a shorthand. This chapter covers options within topics 1-3, with conclusions drawn on the most suitable options/sets of options, whilst the following chapter sets out at a high level the choices needed within topics 4-6.

Note that there are other policies in place that will affect GHG emissions from hydrogen pathways, such as fossil emissions from production plants being covered (and therefore disincentivised) by the UK ETS, and policies to decarbonise various supply chain steps such as road transport.

6.2 Boundaries

6.2.1 Upstream system boundary

The system should include all upstream emissions, back to the point where emissions contributions are no longer material to the analysis. This is recommended so that the results reflect as far as possible all emission incurred in the supply chain, and to give operators a driver to reduce upstream emissions, for example by choosing lower GHG intensity upstream options. In many cases these emissions will not be under the control of those applying the standard, however this could be the case for several areas in which data is needed, and has not proved to be a barrier to the approach in other schemes. This decision has a significant impact on the choice of threshold value. It is independent of the type of scheme in which the standard might be used.

This means that GHG intensity data used for all inputs should include upstream emissions, for example through use of data from LCA databases. Note that in some cases, commonly used data does not include all upstream emissions that provide a material contribution: for example, the UK grid GHG intensity used in this project from BEIS modelling includes only combustion emissions for natural gas power generation but not the upstream fossil fuel extraction emissions. The GHG methodology for the standard should require that upstream emissions be included, and these should be included in any default data allowed/required by the administrator.

6.2.2 Downstream system boundary

Setting the point in the supply chain at which a low carbon hydrogen standard applies (the calculation point) is probably the single most important decision to make when designing a standard, as it has several knock-on impacts in terms of choices for other options, including the GHG threshold level. Once hydrogen has been produced, the main options for establishing the extent of the system boundary are:

- **At the point of production**. This is calculating the GHG emissions of the hydrogen produced at the exit of the production plant. Compression or purification may or may not be included (see later options).
- **At the point of use**. The GHG emissions of delivered hydrogen include production emissions as well as the emissions from downstream distribution to the end user. Compression or purification may or may not be included (see later options). However, any emissions from the final use of the hydrogen are excluded.
- **At the point of use + in use emissions.** The GHG emissions calculation includes production emissions, distribution emissions, and emissions arising from the use of hydrogen (e.g. any H_2 'slip' as fugitive emissions during the use phase, or high-temperature combustion N_2O emissions, or other CO_2 & CH_4 emissions given the H_2 will not be 100% pure). However, this is not calculating the GHG emissions of the service provided (generated heat, power, transport mobility, etc.) by taking into

account use efficiencies – the emissions calculated is still per unit of hydrogen consumed.

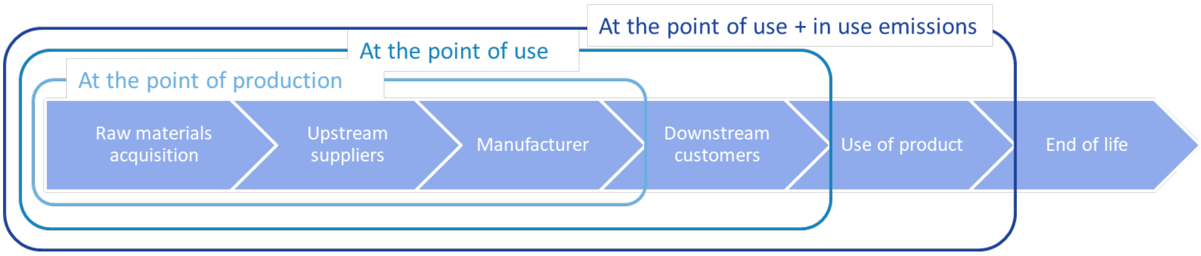


Figure 23: Schematic of the downstream system boundary options

We have not considered the option of the downstream system boundary being the service provided e.g. gCO_2/km for vehicles, gCO_2/kWh_{th} for heat, as this would involve setting different reference flows for each end use. A UK low carbon hydrogen standard is expected to cover multiple current and potential end uses of hydrogen, meaning that a wide and evolving range of services would need to be considered. For some of these, there would be many users, who would be very unlikely to be reporting under any scheme in which the standard was used e.g. individual drivers and households. As such, the entity reporting under the standard would need to make assumptions over the end use efficiency across these end users, which would be difficult. Also, if a service level approach was used, the same approach would need to be adopted for other technologies providing the same service, so that the standard would actually be e.g. a heat standard and a vehicle standard, rather than a hydrogen standard.

The options are compared with the criteria to be met by a UK low carbon hydrogen standard (see Chapter 0), in Table 8 below. Green cell shading in the following tables indicates that the option aligns with the criteria (or has no impact on the criteria), red cell shading indicates that the option does not align with the criteria, and amber cell shading indicates partial alignment.

Table 8: Options for the downstream system boundary

Option	**Option A** **Point of production**	**Option B** **Point of use**	**Option C** **Point of use + in use**
Inclusive	**Amber:** Open to all routes, including H_2 exports and imports. Does not necessarily take into account the ability of different production technologies to produce at different scales and locations.	**Green:** Open to all routes, including H_2 imports. H_2 exports would be unlikely to be assessed by the UK standard, as the point of use is abroad. Takes into account different end user requirements. May be slightly less able to deal with new complex routes (e.g. if new data not yet available)	**Green:** Open to all routes, including H_2 imports. H_2 exports be unlikely to be assessed by the UK standard, as point of use is abroad. Takes into account different end user requirements, and end user circumstances (e.g. leakage rates). May be less able to deal with new complex routes (e.g. if new data not yet available).
Accessible	**Green:** Simplest and cheapest. The organisation	**Amber:** More complex and costly to include distribution	**Amber:** More complex and costly to include distribution

	reporting emissions would be the hydrogen producer.	chains, though could also be done using default values for different uses (if defaults available). The organisation reporting emissions could be the hydrogen producer (with default downstream data) or the vendor to the end user.	chains, though could also use default values for different uses (if defaults available). The organisation reporting emissions could be the hydrogen producer (with default downstream data) or the vendor to the end user, or the end user.
Transparent	**Green:** No impact on transparency, although noting there will be fewer stakeholders	**Green:** No impact on transparency, although noting there will be more stakeholders	**Green:** No impact on transparency, although noting there will be many stakeholders
Compatible	**Green:** Boundary compatible with CertifHy, TÜV SÜD and IPHE	**Amber:** Boundary compatible with TÜV SÜD, and RTFO (where use emissions set as nil, e.g. biofuels & RFNBOs)	**Amber:** Boundary compatible with LCFS and RTFO (and REDII fuels)
Ambitious	**Red:** Does not guarantee that H_2 used will still be low carbon after distribution. Does not take into account emissions from imports (unless add default import factor). Does not incentivise distribution and end use innovation	**Amber:** Relatively ambitious, as ensures H_2 is low carbon at user (emissions in use are likely very small), and encourages innovation in distribution chains	**Green:** Most ambitious, as covers whole lifecycle, supporting distribution and end use innovation
Accurate	**Green:** Accurate, relatively low uncertainties in GHGs and categorisation	**Amber:** Likely less accurate, as more uncertain GHG datasets and categorisation	**Amber:** Likely less accurate, as more uncertain GHG datasets and categorisation
Robust	**Green:** Easiest to audit, least potential for fraud	**Amber:** More potential for fraud and mis-use, as harder to audit	**Amber:** More potential for fraud and mis-use, as harder to audit
Predictable	**Green:** Most predictable, as shortest supply chain	**Amber:** Marginally less predictable, as harder to assess compliance	**Amber:** Marginally less predictable, as harder to assess compliance

Conclusion: Any of the options above could be a viable approach, with the appropriate choice depending on the type of scheme with which the standard will be used. The main choice to be made is between point of production (option A) and point of use (options B or C, which are very similar).

The main disadvantage of the **point of production approach** is that it omits emissions from the system that could be large in the 2020-2030 timeframe until significant grid decarbonisation is achieved, principally related to electricity use in the downstream supply chain. These emissions are significant in the context of the threshold levels being discussed, with downstream supply adding around 6 to 19 $gCO_2e/MJ\ H_2$ (Scenario 1) in 2020. Omitting these emissions would mean relying on operators having an economic driver to reduce emissions (e.g. reducing transport distances or buying efficient equipment) or on these emissions being reduced through other policy mechanisms (e.g. vehicle decarbonisation policy) rather than incentivising reduction through this standard.

Note, however, that omitting emissions associated with imported hydrogen could have a much greater effect, for example emissions associated with hydrogen conversion to forms suitable for long distance transport (liquefaction, ammonia, liquid organic hydrogen carriers) and long distance transport itself. An example of this is shown by the high end of the liquid hydrogen downstream chain, whose emissions of 19 $gCO_2e/MJ\ H_2$ (Scenario 1) in 2020, include 15 $gCO_2e/MJ\ H_2$ from the liquefaction step. As a result, if a point of production approach was taken, we would recommend defining this as point of production within the UK OR point of entry into the UK. .

The main advantages of the point of production approach are that:

- it allows a book and claim chain of custody scheme to be used (see section 6.8), whose main advantage is to be able to incentivise low GHG hydrogen production without relying on a physical link to consumption. This means low GHG hydrogen could be produced where it is cheapest to do so, in particular outside the UK. However, if the system boundary was set at the point of import to the UK, with a book and claim approach, then a default factor would need to be added for transport emissions, which may be difficult to define fairly given the range of possible values for different distances and transport options;
- for UK chains, there is no requirement to measure or monitor emissions from the downstream steps, making compliance by the supply chain, verification and scheme administration simpler and cheaper, particularly where there are many different users from the same production plant;
- compatibility with other schemes using the same approach i.e. CertifHy, TÜV SÜD and IPHE.

The main advantage of the **point of use** approach is that it requires downstream emissions to be taken into account. This means that routes with very large downstream emissions will not meet the GHG threshold, and (assuming actual data is allowed) there can be a driver for supply chain players to measure and reduce the downstream emissions. The disadvantage of this option is that only the mass balance chain of custody option is possible (see section 6.8), and costs are higher (as above). In particular, if there are many downstream supply chains from the same producer, then there will be a greatly increased data requirement (including derivation of default data, if used) – for example, where hydrogen is injected into the gas grid. While mass balance systems are well understood in transport (with the RTFO and RED), in other uses, there is much less familiarity.

If it is used, the addition of “in-use” emissions would increase the accuracy of the GHG measurement with very little impact on cost and complexity, assuming default in-use emissions data is provided.

6.2.3 End uses

An individual scheme may only cover particular end uses: for example, use of hydrogen for energy, rather than other uses such as chemicals, or use for energy in particular sectors. Once this is agreed, there may be impacts on the other methodological choices considered here, such as the downstream system boundary, or threshold set. For example, use of hydrogen in a sector where the alternative options have a very high GHG intensity could lead to a higher threshold being acceptable if it enabled faster deployment of hydrogen. Nevertheless, the approach taken here, as agreed when setting the criteria, is to recommend options that allow for any end use.

6.2.4 Materiality

LCA analysis typically defines a "materiality" level: if emissions from an input or process are estimated to be below a small percentage of the final result, typically 1%, they can be excluded. For example, in PAS2050, a product carbon footprinting standard, the cut-off is 1%, provided that 95% of total emissions are included. A materiality threshold should be included, with the level set to match that required in other GHG reporting required under UK government schemes.

Note that a materiality threshold for data quality is also possible, and is used in other hydrogen standards e.g. up to 5% of the input energy can be conservatively estimated without the need for exact measurements. This reduces the effort of measuring energy consumption that is quantitatively minor (e.g. auxiliary systems such as pumps, ventilation, etc.). This does not imply that 5% of the energy will not be accounted for, but rather that 5% of the energy consumption data are estimated rather than measured in detail.[39] TÜV SÜD applies a materiality threshold of 5%. CertifHy specifies for production batch audits: "Regarding the 'Level of Assurance' and 'Materiality' the audits shall be performed in accordance with ISO 14064-3 as well as the EU Directive 2003/87/EC. The Auditor will perform the audit with all due means to verify accuracy and completeness of the Production Batch registration."[40,41] An earlier CertifHy report mentions a materiality level for data quality of 5%.[39]

6.2.5 Embodied emissions

There are additional emissions associated with the raw materials and processes used to manufacture, construct, maintain and decommission capital equipment used in hydrogen production, as well as equipment used in energy generation, transport vehicles, hydrogen storage etc. Calculating these embodied emissions would involve estimating material usage in the capital equipment, the location of production and relevant emissions factors, and then determining a method of dividing up these capital emissions (typically incurred in

[39] CertifHy (26 October 2015) "Technical Report on the Definition of 'CertifHy Green' Hydrogen", Deliverable No. D2.4, https://www.certifhy.eu/publications-and-deliverables.html

[40] CertifHy Scheme Subsidiary Document Procedure 1.1 "GO Issuing", 11 March 2019, https://www.certifhy.eu/publications-and-deliverables.html

[41] ISO 14064-3 provides specification with guidance on materiality and level of assurance in the verification and validation of greenhouse gas statements.

the years before hydrogen production starts) across the operational lifetime of production emissions, along with a method for reallocating these capital emissions if operations cease earlier than expected or production is consistently lower than expected.

This decision will have some impact on the choice of threshold value. Available estimates of these embodied emissions are discussed in Section 5.1.9, and suggest that they would be relatively modest in most cases (adding a few gCO_2e/MJ of H_2 for the most relevant UK pathways[42]), and will fall over time as global energy and manufacturing decarbonise.

There are therefore three potential options we have considered:

- **Excluded**. None of the existing hydrogen standards, or low carbon fuels standards, or UK low carbon policies, or REDII, include embodied emissions within scope.
- **Included for H_2 production technology only**. This intermediate option includes only equipment procured by the project owner, for which it may be easier to request data from manufacturers.
- **Included for all supply chain equipment**. This would cover energy generation sources, hydrogen production technology, transport vehicles, storage vessels etc.

Table 9: Options for embodied emissions

Option	Option A Excluded	Option B Include for H2 production	Option C Included throughout
Inclusive	**Green:** Open to all routes	**Amber:** Open to all routes. Slightly less able to deal with new complex routes (e.g. if robust plant data not yet available)	**Red:** Open to all routes. But less able to deal with new complex routes (e.g. if data not yet available or not recorded)
Accessible	**Green:** No added costs or complexity	**Amber:** Complex and costly to include	**Red:** Extremely complex and very costly, as requiring data throughout supply chain for equipment emissions
Transparent	**Green:** No direct impact on transparency, no additional stakeholders	**Green:** No direct impact on transparency, although noting will mean more stakeholders involved	**Green:** No direct impact on transparency, although noting will add many more stakeholders
Compatible	**Green:** Compatible with all existing schemes	**Red:** Not compatible with any existing schemes	**Red:** Not compatible with any existing schemes
Ambitious	**Amber:** Not ambitious (could be missing 1-8 gCO_2e/MJ of embodied emissions), and not incentivising innovation in equipment manufacturing, but still can be consistent	**Amber:** Slightly more ambitious, as ensures some innovation in H_2 production equipment manufacturing, but only likely accounts for up	**Green:** Most ambitious, as covers whole chain, supporting innovation. Effectively goes beyond Net Zero commitments to closer to a consumption emissions

[42] CCC generally have much more onshore and offshore wind production in their UK grid scenarios to 2050 than solar PV, so the upper end of these embodied emissions (5.0-8.3 gCO_2e/MJ H_2 LHV for solar PV + electrolysis) may not be as common as the 4.2 $gCO2e/MJ$ H_2 LHV for wind + electrolysis given by Hydrogen Council (2021) Hydrogen decarbonisation pathways: A life-cycle assessment: https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf.

Option	Option A Excluded	Option B Include for H2 production	Option C Included throughout
	with Net Zero pathways (based on UK production emissions accounting)	to 1 gCO_2e/MJ of embodied emissions	accounting basis, accounting for additional 1-8 gCO_2e/MJ of embodied emissions
Accurate	**Green:** No impact on accuracy	**Amber:** Likely less accurate, as more uncertain GHG datasets, unless requesting project specific datasets	**Red:** Likely significantly less accurate, as highly uncertain GHG datasets
Robust	**Green:** No impact	**Amber:** Harder to audit and lifetime assumptions have to be made	**Red:** Extremely difficult to audit e.g. which vehicles were used and where they were manufactured, many lifetime assumptions have to be made
Predictable	**Green:** No impact	**Amber:** Less predictable, as harder to assess compliance, as asset closures could spike emissions, or due to embodied emissions accounting changes	**Red:** Significantly less predictable, as harder to assess compliance, as any asset closure could spike emissions, or due to embodied emissions accounting changes

Conclusion: We recommend that "exclusion" is selected for the UK's development of a low carbon hydrogen standard. This ensures compatibility with all other relevant schemes in the UK and globally, avoids large administrative burdens and high costs for scheme participants, and also avoids introduction of uncertainty and reliability issues in the calculations (and audit processes). Any inclusion is also likely to significantly delay the establishment of a UK low carbon hydrogen standard, given the lack of existing rules for these elements. This decision is also taken in light of the likely modest embodied emissions that will be associated with UK production pathways of 1-4 gCO_2e/MJ H_2 LHV for all routes except solar PV electrolysis.

This decision could be kept under review, particularly if countries begin to report their annual emissions on a consumption basis more systematically as the UK currently does (in addition to just reporting territorial production emissions as per UNFCCC current convention), and as embodied emissions data starts to become more readily available from any cross-border carbon adjustment mechanisms or tariffs that are introduced. For example, the EU's proposed carbon border adjustment mechanism will not enter into force for at least another two years at the earliest and will only cover a limited list of materials like steel and cement.

As a future step once the standard is established, hydrogen chains could be made to separately report on their embodied emissions, but not include these estimates within their chain GHG emissions calculations (similar to section 6.2.8 on indirect land use change). This would ensure compatibility with existing schemes, but would encourage actors to gather data and reduce these embodied emissions (as inclusion of these emissions could be a final step once robust enough data is available), and it could also encourage other schemes to also take embodied emissions into account.

Requiring an operator to provide embodied emissions data as part of a voluntary one-off UK capital grant scheme may be very difficult and costly, because the industry is not currently in a position to readily provide this data and would be unlikely to develop these capabilities for a single assessment. The industry would be more likely to develop these capabilities if required for an ongoing revenue support scheme.

If a single GHG threshold in section 6.7.1 is chosen, this would likely leave sufficient headroom for wind and solar PV routes and all other routes to include their embodied emissions at a future date and remain compliant. However, if multiple GHG thresholds are used, there is less headroom and a much higher chance that inclusion of these embodied emissions at a future date could push some renewable or nuclear electrolysis routes above the lower GHG threshold (e.g. if this lower threshold is set at ~10 $gCO_2e/MJ\ H_2$).

There may also have to be a policy decision to be taken whether these embodied emissions should be taken into account in the hydrogen production sector or the manufacturing sector (for embodied emissions across the energy system), in terms of national inventory accounting. A further decision may be required as to whether other decarbonisation options such as electrification, CCS and bioenergy also should account for these embodied emissions if hydrogen chains are doing so, to ensure comparability and a level playing field in UK policy.

6.2.6 Hydrogen purity and pressure

Different hydrogen production pathways produce hydrogen at different purities and pressures, and different hydrogen end uses have different purity and pressure requirements. If the downstream system boundary is the point of use, then this point of use will have a defined purity and pressure. However, if the downstream system boundary is the point of production, it may be necessary to define a reference purity and pressure to enable comparison between production pathways, and accept that downstream steps (e.g. gas grid, salt cavern storage) may introduce impurities. This reference purity and pressure would avoid the situation where a process producing very low quality or low pressure hydrogen appeared to meet the GHG threshold, despite significant additional emissions occurring outside the system boundary when it was purified and/or compressed. The choice made here will have some impact on the choice of GHG threshold value.

Note that work done under the Hy4Heat programme[43] recommended a minimum purity standard for domestic end use of 98-100%, which has been taken forward as the basis of the new hydrogen appliance design standard issued by BSI (PAS 4444), and is likely to be adopted by the IGEM Hydrogen Committee as the reference specification for hydrogen

[43] Hy4Heat (WP2) Hydrogen Purity 2019 https://static1.squarespace.com/static/5b8eae345cfd799896a803f4/t/5e58ebfc9df53f4eb31f7cf8/1582885917781/WP2+Report+final.pdf

within the GB distribution network. By contrast, for use in fuel cell vehicles, hydrogen purity of 99.999% will be required (ISO 14687:2019).

Options are:

- **Not specified** – in this case the GHG intensity of hydrogen would be considered “as is” at the calculation point, at its current purity and pressure level. This approach is taken in the RTFO and LCFS, where the calculation point is after end use, with end user requirements determining the purity and pressure.
- **Defined reference purity and pressure** – here purity and pressure levels would be specified as GHG calculation references. If hydrogen were sold at lower purity and/or pressure, default factors for the extra emissions associated with purification and/or compression to reach the reference purity and pressure would be added. This approach is taken by CertifHy for pressure only (i.e. hydrogen can be produced at lower pressures, but CertifHy GHG calculations always have to assume at least 3MPa is achieved), whereas TÜV SÜD require compression to 3MPa unless hydrogen is fed into the natural gas network at low pressure. For purity, under TÜV SÜD the user estimates the emissions required to achieve the required purity (99.9%), which are verified by an auditor. Note that there are a wide range of possible impurities in hydrogen, which will vary by production technology, and therefore it will be relatively complex to derive default data for purification up to a reference level.
- **Minimum purity and pressure** - CertifHy require a hydrogen purity of at least 99.9%vol, i.e. only hydrogen at this purity or above is permitted to be certified under the scheme, although this may change in the future, with an alternative more flexible option being allowed.

If the system boundary were set at the point of use:

Table 10: Options for hydrogen purity – system boundary at point of use

Option	Option A Not specified	Option B Defined reference purity and pressure	Option C Minimum purity and pressure
Inclusive	**Green:** Open to all routes	**Red:** Open to all routes. Adds emissions to pathways to cover purification where none/a lower level is used	**Red:** Excludes routes that do not require this purity and pressure or requires unnecessary costs
Accessible	**Green:** Simple	**Amber:** More complex – purification emissions will depend on what impurities exist, and on scale and inputs to purification	**Red:** Requires potentially unnecessary supply chain steps
Transparent	**Green:** Transparent	**Green:** Transparent	**Green:** Transparent

Option	Option A Not specified	Option B Defined reference purity and pressure	Option C Minimum purity and pressure
Compatible	**Amber:** Not compatible with CertifHy.	**Amber:** Compatible with CertifHy for pressure.	**Amber:** Compatible with CertifHy for purity.
Ambitious	**Green:** No impact	**Green:** No impact	**Amber:** Could reduce GHG savings by introducing unnecessary steps, or reduce uptake of the scheme
Accurate	**Green:** Accurate	**Red:** Not accurate – adds emissions that are not being emitted, and relies on default data to do so	**Green:** Accurate
Robust	**Green:** No impact	**Green:** No impact	**Green:** No impact
Predictable	**Green:** Predictable	**Amber:** Less predictable – default factors could change	**Green:** Predictable

Conclusion: The main benefits to defined or required pressure and purity would be an ability to compare all pathways supplying hydrogen to the UK on the same basis. However this was not defined as an aim of this standard: the aim to treat all routes equally and take into account different end user requirements means that it is more important to assess the emissions that are taking place rather than to force comparability either physically (though a minimum purity and pressure) or through adding a default factor. As a result, we recommend not specifying a defined or required purity and pressure if the downstream system boundary is set at the point of use, rather than the point of production. However, the choice made here will depend on the sectoral scope of the policy instrument/scheme within which the standard is used. Note that any of the options is compatible with the RTFO, which does not set pressure or purity requirements, as these are set by the transport end user, and are likely to be the same as or higher than any defined/minimum requirement set here.

If the system boundary were set at the point of production:

Table 11: Options for hydrogen purity – system boundary at point of production

Option	Option A Not specified	Option B Defined reference purity and pressure	Option C Minimum purity and pressure
Inclusive	**Amber:** Open to all pathways. But does not recognise the benefits of higher pressure and purity of some production methods	**Green:** Open to all pathways. Able to deal with new pathways as long as appropriate default are developed	**Red:** Excludes pathways that do not require this purity and pressure or requires unnecessary costs

Option	Option A Not specified	Option B Defined reference purity and pressure	Option C Minimum purity and pressure
Accessible	**Green:** Simple	**Amber:** More complex – purification emissions will depend on what impurities exist, and on scale and inputs to purification	**Red:** Requires potentially unnecessary supply chain steps
Transparent	**Green:** Transparent	**Green:** Transparent	**Green:** Transparent
Compatible	**Amber:** Not compatible with CertifHy. Any option is compatible with RTFO as transport will have the highest requirements	**Amber:** Not compatible with CertifHy. Any option is compatible with RTFO as transport will have the highest requirements	**Amber:** Not compatible with CertifHy. Any option is compatible with RTFO as transport will have the highest requirements
Ambitious	**Red:** Combined with the system boundary choice, may omit significant emissions from the assessment in the near term (5-10gCO_2e/MJ) if downstream purification and compression is required	**Green:** Conservative approach that assumes that some compression and purification will be needed in most cases, so should be assumed to take place	**Amber:** Could reduce GHG savings by introducing unnecessary steps, or reduce uptake of the scheme
Accurate	**Green:** No impact on accuracy	**Red:** Not always accurate – adds emissions when it is not known whether they are being emitted, and relies on default data to do so	**Green:** Accurate
Robust	**Green:** No impact	**Green:** No impact	**Green:** No impact
Predictable	**Green:** Predictable	**Amber:** Less predictable – default factors could change	**Green:** Predictable

Conclusion: If the system boundary is set at the point of production, not taking into account pressure and purity would not treat production technologies equally, given that some require more downstream clean up and compression than others, which can give significant emissions impacts. A defined or minimum pressure and purity would also be needed to enable book and claim chain of custody (see section 6.8), otherwise there would be no way to book hydrogen volumes on a common basis. However, given that this may not always be required by the end user, adding a factor or a requirement to achieve fixed levels would disadvantage those with an end user satisfied with the hydrogen as produced. In this case, an option would be to exempt a producer from adding the purity/pressure factor if they could demonstrate that they had a user with lower requirements, and did not participate in any book and claim scheme.

6.2.7 Treatment of direct land-use change for biomass

Direct land use change is conversion of high carbon stock land to land used for biomass production, which can include deforestation, use of peatland, etc. The emissions associated with direct land use change are typically large. As a result, we recommend that emissions associated with direct land use change should be included in the GHG methodology, following the same approach as under the RTFO. The approach to do this defined in RTFO or RED is straightforward, using default data for the carbon stock in the previous and current land types based on IPCC data.

6.2.8 Treatment of ILUC emissions for biomass

Consideration of indirect land use change emissions for some biomass-derived hydrogen pathways could have a large influence on the lifecycle emissions. ILUC emission factors cannot be calculated by individual operators, as they are not specific to individual projects, but to feedstock types as a whole. They would need to be set by the administrator, based on analysis using global models, and provided as default data for each relevant feedstock type. Options for treatment of ILUC emissions are:

- **Do not consider** – as in CertifHy and TÜV SÜD
- **Report separately** from the rest of the GHG assessment to allow the administrator to monitor impacts - as in RTFO
- **Include in GHG assessment** – as in LCFS

Table 12: Options for treatment of ILUC emissions for biomass

Option	Option A Do not consider	Option B Report separately	Option C Include
Inclusive	**Green:** Technology neutral - indirect impacts of other pathways are not included No barrier to inclusion of new feedstocks	**Amber:** Technology neutral whilst still allowing impacts to be assessed Default data required for new feedstocks – although for main feedstocks may already be available from biofuels policy	**Red:** Not technology neutral - indirect impacts of other pathways are not included Default data required for new feedstocks – although for main feedstocks may already be available from biofuels policy
Accessible	**Green:** No cost or user impact	**Amber:** Cost to administrator to develop/choose/review values No cost to user	**Amber:** Cost to administrator to develop/choose/review values No cost to user
Transparent	**Green:** No impact	**Red:** Although information can be made freely available, ILUC models are highly complicated and not transparent to stakeholders	**Red:** Although information can be made freely available, ILUC models are highly complicated and not transparent to stakeholders

Option	Option A Do not consider	Option B Report separately	Option C Include
Compatible	**Green:** No impact – as emissions are reported separately under the RTFO	**Green:** Same approach as RTFO. As reportedly separately no international impact	**Red:** Potential international impact as not included in other schemes except LCFS
Ambitious	**Red:** Not conservative. Ignores potentially large GHG impacts. Does not drive a move away from high ILUC feedstocks	**Red:** Not conservative. Does not drive a move away from high ILUC feedstocks	**Green:** Conservative. Drives a move away from high ILUC feedstocks
Accurate	**Green:** Does not introduce inaccurate estimates	**Amber:** ILUC estimates are inherently very uncertain	**Amber:** ILUC estimates are inherently very uncertain
Robust	**Green:** No impact	**Green:** No impact	**Amber:** Small risk of feedstock type fraud
Predictable	**Green:** Highly predictable. However risk to the scheme's reputation and longevity if large impacts occur	**Green:** Highly predictable. However risk to the scheme's reputation and longevity if large impacts occur	**Amber:** Depends on the frequency of updating of ILUC factors. Factors themselves are highly unpredictable

Conclusion: Not considering ILUC emissions would ignore potentially large GHG impacts, and would not drive from higher to lower ILUC feedstocks (in practice, likely to be mainly from maize to wastes in anaerobic digestion). As a result we recommend either option B or C, with the choice depending on alignment with the approach taken by DfT.

6.2.9 Treatment of waste fossil feedstocks

There are several options for the treatment of waste fossil material used for hydrogen production, such as the non-biogenic fraction of municipal solid waste. These take into account the treatment of GHGs released during the processing of the material, and consideration of the impacts of diverting that waste stream from an alternative fate (counterfactual) on life-cycle emissions of hydrogen. In some cases, the counterfactual can store carbon for a long time (e.g. through the disposal of plastic to landfill, where it may not degrade for many years), or provide a service which would need to be replaced by an alternative process (such as use to generate electricity in an incinerator, which could be replaced by grid electricity).

Rules are yet to be defined for the treatment of fossil wastes in other schemes: Under RED II, the methodology for 'recycled carbon fuels' is currently being determined through preparation of a delegated act, and similarly under the RTFO the approach to be used for recycled carbon fuels is still under consideration. This has not yet been addressed in CertifHy.

Options considered here are:

- **Consider as fossil feedstock without counterfactuals**: Any GHG from feedstock processing released to the atmosphere is counted as a fossil emission of the hydrogen production pathway, i.e. the definition of the feedstock as a waste does not confer any benefit. This approach was used in the GHG assessment in WP2.
- **Consider as fossil feedstock with counterfactuals**: Any GHG from fossil feedstock processing released to the atmosphere is counted as a fossil emission of the hydrogen production pathway. In addition, avoided emissions from the displacement of counterfactual uses (e.g. combustion in an incinerator to generate electricity) are credited to the hydrogen production pathway, along with additional emissions generated to compensate for the avoided counterfactual use (e.g. producing an equivalent amount of grid electricity). For example, if non-biogenic MSW were diverted from an Energy from Waste (EfW) combustion plant for use instead in a gasification plant to produce hydrogen, the emissions would be taken as (emissions associated with generating an equivalent amount of energy via an alternative process) + (CO_2 emissions from hydrogen production – CO_2 emissions from EfW). Note that this approach was considered for MSW to transport fuels for DfT in 2019[44], showing that the counterfactual waste fate, as well as the grid GHG intensity to generate energy by an alternative process had a large impact on the emissions associated with using wastes for fuels.

Note that we have not considered the option to treat CO_2 emissions from fossil wastes as zero, as this does not represent reality in many cases: hydrogen production from solid wastes from which the CO_2 would not otherwise have been released will lead to an increase in emissions that would not otherwise have occurred.

Note also that as with all fossil emissions from hydrogen pathways, the emissions may also be covered (and therefore disincentivised) by the UK ETS.

Table 13: Options for treatment of fossil wastes

Option	Option A Consider as fossil - without counterfactual emissions	Option B Consider as fossil - with counterfactual emissions
Inclusive	**Green:** Inclusive - Open to all fossil waste feedstocks, flexible	**Amber:** Inclusive- Open to all fossil waste feedstocks, neutral, flexible. However counterfactual emissions are not considered for any other feedstocks or process inputs
Accessible	**Green:** Accessible – Simple to implement for any operator	**Amber:** Limited accessibility - Depending on the evidence required by the administrator, could entail significant extra work to demonstrate and verify the emissions of the counterfactual

[44] E4tech 2019 Work Package 1-743 Waste Disposal Outcomes and Diversion Impacts https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/826717/work-package-1-743-waste-disposal-outcomes-and-diversion-impacts.pdf

Option	Option A Consider as fossil - without counterfactual emissions	Option B Consider as fossil - with counterfactual emissions
Transparent	**Green:** Transparent – No extra modelling required.	**Amber:** Limited transparency - Counterfactuals used by each user add more modelling stages and may be kept confidential
Compatible	**Amber:** Not known – not yet decided in other schemes.	**Amber:** Not known – not yet decided in other schemes
Ambitious	**Amber:** Conservative - disincentivises any use of fossil wastes unless CCS is used. As such, could limit diversion of UK wastes from low efficiency EfW	**Green:** Ambitious - Disincentivises use of wastes whose counterfactual is no CO_2 release (e.g. landfill). Incentivises diversion from wastes where CO_2 is released in the counterfactual, and where the same service could be provided by a low carbon option (e.g. grid electricity)
Accurate	**Amber:** Limited accuracy - Does not recognise that for some wastes CO_2 would have been released anyway	**Amber:** Limited accuracy - Use of counterfactuals is inherently uncertain. Difficult to define default data, given likely geographical variation
Robust	**Green:** Robust - Simple to audit	**Amber:** Limited robustness - Need to audit what the counterfactual use is, which may be simple for a documented previous use but harder for a best available technology (BAT)
Predictable	**Green:** Predictable	**Amber:** Question of whether the counterfactual should remain the same over time: may be more appropriate to switch from the previous use to the BAT, which would be less predictable. Counterfactual emissions also vary as they are a function of other systems, e.g. changes in grid factors, heat networks etc.

Conclusion: The option taken depends heavily on the way the scheme is to be used. For a one-off assessment, for example to underpin a decision on capital support, Option B gives a more accurate estimate of the net GHG impact of the project on the UK energy system, and could allow waste diversion from less efficient uses, and therefore is likely to be worth the additional effort required. To support an ongoing scheme, a decision would need to be made on the balance between the additional reporting and verification effort for the system expansion approach in option B versus the projects that would be excluded from support by option A. Alignment with the approach agreed under the RTFO for recycled carbon fuels would be valuable. Note that it would be difficult to use default values in Option B: the same type of waste is unlikely to have the same counterfactual across all geographies. The impact of the decision on the ability of projects to meet the threshold will also depend on the decision made on treatment of mixed waste inputs (see 6.6.3)

Note that both options discourage diversion of fossil wastes from landfill to hydrogen production, on the grounds that diversion to hydrogen production will increase CO_2 emissions. This may not, however, fit with other policy goals of reducing waste disposal to landfill for other reasons, such as other environmental impacts. As a result, BEIS should discuss the approach taken with DEFRA and with DfT, who are considering the same question for treatment of recycled carbon fuels under the RTFO.

6.2.10 Treatment of waste biomass feedstocks

As a result of the recommendations above on treatment of waste fossil feedstocks, the same question may be asked of waste biomass feedstocks: should avoided emissions from their counterfactual fate be taken into account, such as avoided methane emissions from landfill? Some schemes, such as the LCFS, take the avoided emissions of certain counterfactual fates into account. Nevertheless, we recommend alignment with the approach taken under the RTFO and RED here (and other UK policy, such as the RO and RHI), which is to treat waste biomass feedstocks as having zero emissions at the point of collection.

6.2.11 Inclusion of CCS as an allowable benefit in GHG calculations

We recommend that pathways involving CCS are allowed to take this into account in GHG calculations, as long as evidence is provided that satisfies the administrator as to the permanence of the CO_2 storage method. Not allowing this would exclude many hydrogen pathways from the market.

6.2.12 Inclusion of CCU as an allowable benefit in GHG calculations

Carbon capture and utilisation (CCU) may be associated with a hydrogen production pathway, thus potentially resulting in additional GHG savings. The inclusion of CCU would, however, require clear and consistent rules for the calculation of GHG emissions and potential credits. It will also be necessary to consider the source of the carbon that is re-used in CCU: if biogenic or atmospheric, then a negative GHG pathway could be achieved, as for the CCS options modelled in Chapter 5.

- **Include CCU with proven displacement.** A credit can be given if operators demonstrate that CCU displaces an equivalent amount of CO_2 from fossil origin. Displacement needs to be modelled through an analysis of current CO_2 origin in the concerned sectors (e.g. carbonated drinks) and expected evolution in the CO_2 demand to demonstrate that the use of captured CO_2 effectively displaces fossil CO_2 and does not compete with other CCU. Given the volume of point source CO_2 available in the market, and the limited demand for this CO_2, increasing CCU without increasing the demand for CO_2 might only displace other CCU. Examples: RED II, RTFO.
- **Include CCU with proven permanence.** A credit can be given if operators demonstrate that the utilisation of captured carbon ensures that it will not return to the atmosphere over an agreed period of time (e.g. use in materials). The demonstration of permanence requires clear rules, which may vary according to the type of utilisation, e.g. minimum time before the carbon can return into the atmosphere. To overcome modelling constraints, a list of authorised utilisations could be established and maintained.

- **Do not include CCU.** No credit given to CCU. Example: LCFS.

Table 14: Options for CCU

Option	Option A Include + proven displacement	Option B Include + proven permanence	Option C Do not include
Inclusive	**Green:** Inclusive – gives more possibilities (in addition to CCS) to fossil hydrogen production pathways (e.g. SMR) to achieve compliance.	**Green:** Inclusive – gives more possibilities (in addition to CCS) to fossil hydrogen production pathways (e.g. SMR) to achieve compliance.	**Amber:** Limited inclusiveness –fossil H_2 production pathways (e.g. SMR) cannot achieve compliance without CCU or CCS. Although this is still perhaps treating all technologies equally according to GHGs.
Accessible	**Amber:** Limited accessibility - Demonstrating CCU conditions are met entails additional effort and costs for calculation and verification	**Amber:** Accessible if a list of authorised utilisations exists. Otherwise, demonstrating CCU conditions are met entails additional effort and costs for calculation and verification	**Green:** Accessible - No extra cost to the administrator
Transparent	**Green:** Transparent, as long as the rules for including CCU and demonstrating displacement are clear and compliance consistently verified.	**Green:** Transparent, as long as the rules for including CCU and demonstrating displacement are clear and compliance consistently verified.	**Green:** No impact on transparency.
Compatible	**Amber:** Limited compatibility – few schemes allow CCU but RTFO and RED II do.	**Amber:** Limited compatibility – few schemes allow CCU but RTFO and RED II do.	**Amber:** Compliant H_2 could enter any scheme, whether they allow CCU or not. However, H_2 from another scheme that includes CCU in GHG calculations could not enter this scheme.
Ambitious	**Green:** Relatively ambitious – allowing CCU can increase GHG savings and scheme impact, compared to not allowing CCU – provided purpose generated fossil CO_2 is displaced (CCS may give even greater benefits than CCU, but may not always be possible.)	**Green:** Most ambitious – allowing CCU can achieve greater GHG savings and larger impact for the scheme overall, compared to not allowing CCU, given the permanence of CCU. (CCS may give even greater benefits than CCU, but may not always be possible.)	**Amber:** Limited ambition – no possibility to further reduce GHG emissions through CCU.
Accurate	**Amber:** Limited accuracy – assessing displacement of hydrogen from fossil origin relies on economic modelling, which makes it complex to demonstrate with certainty.	**Amber:** Defining a list of authorised utilisation types can reduce uncertainty, but measurement of permanence still has some uncertainties	**Green:** No impact on accuracy

Option	Option A **Include + proven displacement**	Option B **Include + proven permanence**	Option C **Do not include**
Robust	**Amber:** Limited robustness – the complexity of demonstrating displacement makes such system more prone to fraud or errors.	**Amber:** Limited robustness – the complexity of demonstrating permanence in utilisation makes such system more prone to fraud or errors.	**Green:** No impact on robustness
Predictable	**Amber:** Limited predictability – compliance of certain pathways will be bound to the results of CCU modelling and calculations.	**Green:** Predictable as long as an unambiguous list of authorised utilisation types is maintained.	**Green:** No impact on predictability

Conclusion: The possibility of allowing CCU in GHG calculations would have the benefit of providing an opportunity for more pathways to demonstrate compliance with the scheme. CCU is, however, not widely used at present, and has complexity and uncertainty around the modelling of displaced fossil CO_2 or the length and permanence of CO_2 storage. These weaknesses could be mitigated by establishing and updating a list of permitted types of carbon utilisation, as long as these can be verified by assurance providers, making CCU with the condition to prove permanence (Option B) a balanced option. This should align with other approaches taken to permanence of CCS/CCU in other UK policy, such as support for greenhouse gas removal methods.

6.3 Scope

6.3.1 Geographical scope of hydrogen production and use

Any scheme using a standard will need to define the allowable geographical scope, in terms of the locations allowed for hydrogen production and end use. This decision is for the scheme to make, and is outside the scope of this project. The standard could be designed to accommodate any combination of options, including:

- Only UK production and use allowed
- UK production only, with use in the UK or export
- UK and imported production allowed, for use only in the UK

Depending on the choice made, all areas of the standard would need to be reviewed to ensure that the choices made did not present a risk to the accuracy of the result (for example through making a choice that was clear only in the UK context) or present an effective barrier to trade. In particular:

- Downstream system boundary (see 6.2.2): emissions associated with imported hydrogen could be significant, for example emissions associated with hydrogen conversion to forms suitable for long distance transport and the transport itself. As a result, either a point of import or point of use reference point would be appropriate.

- Treatment of waste fossil feedstocks (see 0): using an approach with counterfactuals would require appropriate counterfactuals for the country of production.
- Use of low carbon electricity (see 6.6.1) and low carbon electricity additionality (6.6.2): different options may be appropriate for UK only vs non-UK schemes.
- Chain of custody (see 6.8): a book and claim approach would increase the potential for import/export significantly, but would not take into account downstream emissions.
- Default vs actual data (see 0): if default data were used, a decision would be needed on the level at which they were set e.g. development of regional default data.

6.3.2 Allowable H_2 production pathways

The owner of a low carbon hydrogen scheme must decide whether the scheme is applicable to any existing and future H_2 production pathways or only to a specific list of pathways, which would be updated periodically or on request.

There are two potential options we have considered:

- **No List.** Any production pathway or technology can participate in the scheme, as long as compliance with the scheme's requirements is achieved. Examples: CertifHy, IPHE, RTFO in general.
- **List operated.** The standard owner maintains a list of pathways and technologies, which are allowed to use the standard, but would still need to demonstrate compliance. The list is regularly updated, or upon successful application for new pathways to be added. Examples: TÜV SÜD, LCFS, RTFO for development fuels and waste and residue feedstocks.

Table 15: Options for a list of allowable H_2 production pathways

Option	Option A No list	Option B List operated
Inclusive	**Green:** Inclusive – applicable to any production pathway.	**Amber:** Limited inclusiveness – pathways not yet included must submit an application and wait to obtain a validation.
Accessible	**Amber:** Operators may need to deploy extra efforts and costs to achieve compliance for pathways, which were not considered by the standard owner upon developing requirements and guidance.	**Amber:** More cost-effective for users, due to the fact all listed pathways/technologies would have pre-defined options (e.g. GHG default values). More effort needed for the standard owner to develop and maintain the list

Option	Option A No list	Option B List operated
Transparent	**Green:** No impact on transparency	**Green:** No impact on transparency, as long as the rules for inclusion on the list are clear, available and applied consistently.
Compatible	**Amber:** Limited compatibility if pathways allowed in the scheme are not allowed in other schemes or other countries.	**Amber:** Limited compatibility if pathways allowed in other schemes or other countries are not included in the list.
Ambitious	**Amber:** Lack of assessment of potential impacts of new pathways before they enter the market could increase the risk of undetected non-conformities, due to limited knowledge from assurance providers and possibly unforeseen weaknesses in assurance systems due to process specificities.	**Amber:** Some uncertainty for new technology developers that their pathway may not be included
Accurate	**Amber:** Limited accuracy – a risk exists that requirements and guidance are less adapted to novel technologies and pathways, thus leading to approximations or potential errors in GHG assessment.	**Green:** Accurate – the scheme's requirements are designed to cover all pathways in the list. The administrator can review each pathway to identify any risks or uncertainties
Robust	**Amber:** Limited robustness – a risk exists that the assurance system is less adapted to novel technologies and pathways, e.g. auditors' skills or proofs of compliance.	**Green:** Robust – the scheme's requirements are designed to cover all pathways in the list.
Predictable	**Amber:** Limited predictability – new pathways can enter easily which reduces predictability for others	**Green:** Predictable – only the pathways in the list can achieve compliance. The timing for updating the list should be transparent.

Conclusion: The main benefit of not operating a list (Option A) would be to achieve greater inclusiveness and limit the need for updates and related efforts/costs by the standard owner. Operating a list (Option B) would, however, ensure that the scheme is appropriate for all the pathways on the list, with regards to the GHG saving requirements, other sustainability risks, guidance (e.g. on GHG calculation methodologies), chain of custody and assurance. Operating a list would also allow the standard owner to identify unintended impacts of new pathways and act on them by adapting the requirements of the scheme or refusing to include the new pathways.

6.3.3 Non GHG impacts

The scope of this study was to consider options for a low GHG hydrogen standard, and as such we have not investigated potential interactions with other policy goals that may be achieved through a combined scheme such as promotion of renewable energy, innovation, safety, minimising impacts to air, water, land etc. Nevertheless, one important factor to take into account is the interaction with other sustainability rules for similar supply chains: principally the sustainability rules of the RTFO for biomass. We recommend that any schemes using the GHG methodology apply wider sustainability rules for biomass which are aligned with other UK policy support for biomass such as the RTFO, RHI and RO (noting that the requirements of these schemes differ, and so it will have to be decided with which it is most important to align).

6.4 Units and impacts

6.4.1 Unit

All schemes analysed use gCO_{2e}/MJ LHV, and so this is recommended for any UK scheme. Note that the hydrogen industry are also using LHV across Europe when reporting hydrogen energy supplied, although the gas industry historically use HHV when reporting on natural gas energy supplies. Conversion tables could be provided to HHV, kWh etc in any scheme documentation.

6.4.2 Choice of GWP

This is a much broader UK government decision that impacts all emissions reporting, and not just a low carbon hydrogen standard. This study used the latest IPCC AR5 with feedback GWP factors (which also aligns with CCC's Sixth Carbon Budget analysis), but the ultimate choice of GWP factors for a new standard will depend on current Government-wide policy in this area. These GWP factors will likely be updated over time, and the standard should be able to be updated (including, if necessary, the level of the GHG threshold).

6.4.3 Inclusion of GWP for hydrogen

In the analysis for this project, a GWP was used for hydrogen losses from the system. Including a GWP for hydrogen is more accurate than not doing so. The disadvantages to doing this are that:

- The science of calculating the GWP is uncertain, and so the figures used may change over time, causing uncertainty for the industry.
- This is not included in any other schemes, so reduces comparability
- Measuring hydrogen losses can be complex, as precision of hydrogen measurement is not high enough to estimate the rather low level of losses precisely enough

Conclusion: We recommend including hydrogen GWP as a result of improved accuracy, and because improving knowledge on fugitive losses will improve the accuracy over time. If this is found not to be possible (for example if uncertainty in the science is too high or measurement too onerous for some pathways), an alternative would be to require these emissions to be reported separately in the near term, while knowledge and experience is built up, with a view to incorporating them at a later stage (potentially with a change in GHG threshold level to accommodate this).

6.5 Allocation of emissions to co-products

Allocation methodologies define how to allocate upstream and process GHG emissions to products of a process if there is more than one product. This choice could have a significant impact on the GHG emissions of several pathways, and therefore the choice of level for the GHG threshold(s):

- **Energy based allocation** assigns upstream and process emissions to all products according to the proportion of output energy that they have. Where e.g. a process has two outputs such as heat (representing 67% of the total output energy) and electricity (representing 33% of the total output energy), 67% of the upstream and process emissions are allocated to the heat, and 33% are allocated to the electricity.
- **Mass-based allocation** assigns upstream and process emissions to all products according to the proportion of output mass that they have.
- **Market value based allocation** assigns GHG emissions to the products based on their market value.
- **System expansion**, expands the analysis to consider alternative (counterfactual) ways of generating all of the co-products of the process, and then subtracts these emissions from the emissions of the pathway in question. For example, if a process produces hydrogen with an electricity co-product, this approach considers how that electricity would otherwise be generated, and subtracts those emissions from the lifecycle emissions of the hydrogen pathway. Provided a clear counterfactual and robust data are available, this option is recommended in preference for LCA by the principal international LCA standard ISO 14044, on the basis that it best reflects the impacts of a process on the emissions of the economy as a whole. The other methods involving allocation are inherently arbitrary, as the mass, energy content or price of products do not determine their emissions impacts.

Energy-based allocation is generally used throughout all schemes, in particular those in the UK and Europe. As a result we recommend that energy-based allocation be used in general, to ensure compatibility with other schemes.

The reasons for using energy allocation in GHG assessment linked to policy mechanisms are typically that:

- mass-based allocation bears no relationship to the relative usefulness of products to society, and is not possible for electricity
- market value based allocation relies on use of market values, which change over time, and between locations
- system expansion, relies on defining the displaced product, which can also change over time, and between locations.

However, there remain decisions to be made over the approach used where energy allocation is not possible (significant non energy products) and where the RTFO does not use energy allocation, in line with the RED (this includes a system expansion approach for CHP units, and allocation of nil impacts to biogenic residues/wastes by only allocating emissions to products and co-products). There has been debate over the approach used, in particular with reference to the chlor-alkali process, but there will be other cases where energy allocation is not possible or difficult to apply, such as in the many complex reactions in refineries.

For non energy coproducts, some of the options are:

- **Market value allocation** – allocation of upstream emissions based on the relative market value of the products, for example as done in CertifHy using an average of the last 5 years price data from Eurostat, although a change to system expansion is planned once data is available.
- **Enthalpy allocation** – allocation of upstream emissions based on the relative enthalpy of the products, as allowed in the TÜV SÜD scheme.
- **System expansion** – consideration of the emissions saved by displacing the co-products in their market, through the best available technology. In the chlor-alkali case this means assessing the emissions that would result from producing chlorine by an alternative process (such as the ODC process offered by Thyssenkrupp) which does not have a hydrogen by-product. The emissions for hydrogen from the chlor-alkali process would then be considered as the whole emissions from the process *minus* the emissions for producing chlorine by the alternative process. This relies on a) there being an alternative process to produce the co-products and b) availability of robust data on the alternative process. As third-party verified data from commercial operations of the ODC process are not yet available, this approach is not yet used in CertifHy. It is allowed in the TÜV SÜD scheme, but only if data verified by an independent third party for that process is available, which is not yet the case. There is the option either for the scheme to define a benchmark process and robust data for it, or to allow operators to choose the appropriate expansion in their situation, and have this verified.

Table 16: Options for allocation of emissions to non-energy co-products

Option	Option A Market value allocation	Option B Enthalpy allocation	Option C System expansion
Inclusive	**Green:** Open to all pathways, technologies and highly flexible	**Green:** Open to all pathways, technologies and highly flexible	**Red:** Not possible where there is no commercialised alternative pathway to the co-product
Accessible	**Green:** Low cost	**Green:** Low cost	**Amber:** Effort required to get data required for the alternative process, unless defaults are provided ,which may not be straightforward in all cases

Option	Option A Market value allocation	Option B Enthalpy allocation	Option C System expansion
Transparent	**Green:** Transparent	**Amber:** Transparent, though enthalpy is not a commonly understood concept	**Amber:** Limited transparency - Counterfactuals used by each user adds more modelling stages and may be kept confidential, unless set as default data
Compatible	**Amber:** Compatible with CertifHy (currently)	**Amber:** Allowed in the TÜV SÜD scheme	**Amber:** Will be allowed in CertifHy and the TÜV SÜD scheme
Ambitious	**Amber:** Not recommended by ISO 14044 given arbitrary nature of allocation	**Amber:** Not recommended by ISO 14044 given arbitrary nature of allocation	**Green:** Best represents the emissions impacts of using co-product hydrogen
Accurate	**Green:** Low uncertainty of data required	**Green:** Lowest uncertainty	**Amber:** Limited accuracy - Use of counterfactuals is inherently uncertain. In some cases can be difficult to define default data, given likely geographical variation
Robust	**Green:** Harder to verify but commonly done	**Green:** Easy to verify	**Amber:** Need to audit what the counterfactual use is, which may be simple for a documented previous use but harder for a BAT
Predictable	**Amber:** Not predictable - relies on use of market values, which change over time	**Green:** Highly predictable	**Amber:** Counterfactual choice and related emissions can change over time

Conclusion: System expansion could be allowed or required where verified data is available, given that it gives a more accurate assessment of the impact on the economy overall of using co-product hydrogen. System expansion is preferred in the hierarchy of options for treatment of co-products under ISO 14044. Given that system expansion is not always possible, either market value allocation or enthalpy allocation is appropriate. ISO 14044 also recommends allocation based on physical attributes before market value allocation, which would imply enthalpy based allocation before market allocation. Although there is little experience with enthalpy allocation, its use would be straightforward and the results would not vary over time and geography.

6.6 Energy inputs

6.6.1 Use of low carbon electricity

It is necessary to define how an operator using low carbon electricity, such as renewable or nuclear electricity, should account for this, and the evidence that should be required. As described in Chapter 0, the approach used for this in other schemes and standards is currently under review: the RTFO currently requires physical links between the renewable power generator and the electrolyser, being either off-grid (the whole system is not connected to the grid), using curtailed renewables (the generator is connected to the grid but supplies the electrolyser when grid supply is not possible) or with evidence that grid electricity is not used (the generator supplies to the grid and to the electrolyser, but the electrolyser does not use electricity from the grid. Here an additionality requirement also applies (see below)). These rules may be changed to allow market-traded Power Purchase Agreements instead of a local connection. RED II currently states that grid mix electricity should be assumed unless there is a direct connection to a renewable energy installation provided that the installation is built after or at the same time as the electricity using plant, and that it is not connected to the grid or has not taken electricity from the grid. Rules for operators using renewable electricity via the grid, for example with a power purchase agreement, are being developed through a delegated act. The delegated act will ensure that there is a temporal and geographical correlation between the electricity production unit with which the producer has a bilateral renewables power purchase agreement and the fuel production, and also consider additionality (see later). Once this is agreed, CertifHy will use the RED II approach for its mass balance based option.

The options considered are below. Note that in this case these are not mutually exclusive – the question is how many of these options to allow.

- Allow use of the GHG intensity of the grid mix - note that this is an option typically included for when an operator cannot meet the requirements of the other options, but could also be used in countries with heavily decarbonised grids.
- Allow low carbon electricity use to be claimed based on physical links, such as:
    - Off grid - the whole system is not connected to the grid
    - Use of curtailed/constrained power - the generator is connected to the grid but supplies the electrolyser only when grid supply is not possible
    - No import from the grid - the generator supplies to the grid and to the electrolyser, but the electrolyser does not use electricity from the grid (with additionality requirements) .
- Allow low carbon electricity use to be claimed based on traded activities (as below) but with further conditions. This could include temporal correlation with generation (e.g. at hourly level in order to ensure that electrolysis supports grid stability and integration of large shares of fluctuating renewables) and geographical correlation (e.g. within a certain distance, or the user not being on the other side of grid

congestion that would prevent the renewable electricity being used, i.e. there is available transmission capacity). This could also include any additionality conditions (see later). RED II also sets conditions on use of GOs from outside the EU, allowing this only where the EU has an agreement with that country on mutual recognition of guarantees of origin, and only where there is direct import or export of energy[45]. The RTFO does not currently allow imports of renewable electricity to be used to make fuels – only UK renewable electricity.

- Allow low carbon electricity to be claimed based on traded activities alone, such as
  - Cancellation of guarantees of origin or equivalent – i.e. the user buys and cancels certificates associated with low carbon power production
  - Bilateral power purchase agreement with cancellation of guarantees of origin or equivalent – i.e. the user buys low carbon power and cancels certificates associated with it

Table 17: Options for use of low carbon electricity

Option	Grid mix	Physical links	Traded with conditions	Traded
Inclusive	**Red:** Does not deal with a range of circumstances	**Red:** Only applies to a small number of cases. Would excludes many point of use electrolysers e.g. grid connected ones at refuelling stations	**Green:** Allows wide range of participants	**Green:** Allows widest range of participants
Accessible	**Green:** Low cost	**Green:** Evidence required but low effort	**Amber:** More complex data required	**Green:** Evidence required but low effort
Transparent	**Green:** Clear	**Green:** Clear	**Amber:** Approach may be more complex	**Green:** Clear
Compatible	**Green:** Allowed in all schemes	**Green:** Allowed in all schemes	**Amber:** Not yet known	**Amber:** Not yet known
Ambitious	**Amber:** Conservative approach: restricts use of the scheme, but ensures electricity is only used when the grid is sufficiently decarbonised	**Amber:** Conservative approach: restricts use of the scheme, but ensures electricity is only used when there are physical links i.e. strong proof that renewable electricity has been used	**Green:** Broadens scheme access and so will lead to greater uptake and savings, with more guarantees of avoiding negative grid impacts	**Amber:** Broadens scheme access and so will lead to greater uptake and savings

[45] EU (2018) RED II Article 19 (11.): https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN

Option	Grid mix	Physical links	Traded with conditions	Traded
Accurate	**Green:** Low uncertainty	**Green:** Low uncertainty	**Amber:** Medium uncertainty: depends on conditions set	**Red:** Higher uncertainty: could lead to induced additional high GHG electricity generation if demand for hydrogen pathways does not match generation
Robust	**Green:** Very low risk	**Green:** Low risk	**Amber:** More difficult to audit but low risk	**Green:** Low risk
Predictable	**Red:** Not predictable: industry cannot predict grid mix	**Green:** Predictable: under industry control	**Amber:** Partly predictable: meeting additional conditions could be uncertain	**Green:** Predictable

Conclusion: Allowing use of grid mix electricity, and allowing use based on physical links, both have advantages for some users and at some times, in terms of simplicity and low risk of unintended impacts. However, if only these two options are allowed, there is the risk of very few electrolysis-based pathways being incentivised: electrolysis projects would either need to be sited with physical links to low carbon generation, such as on the same site, or be in countries with extremely low grid GHG intensity. Grid connected electrolysers sited close to the point of use, such as at urban refuelling stations with no potential for onsite renewables would be excluded (assuming the example threshold levels considered here) until sufficient grid decarbonisation is achieved, estimated in modelling here as from 2030, though depending heavily on the threshold value chosen. This would be likely to severely constrain roll out of hydrogen in many parts of the UK, through removing the option for onsite electrolysis, or lead to hydrogen being transported around the UK by road, rather than allowing production onsite.

As a result, allowing use of low carbon electricity based on traded activities is recommended. Within this, there is a potential risk that allowing users to claim low carbon power use based on retiring GOs alone has unintended consequences: in particular driving additional high carbon power generation. It would therefore be useful to review the rules on additionality (see next section) as well as temporal and other correlation developed within the RED II delegated act, and decide whether meeting these would reduce these risks at acceptable cost to users. Alignment with DfT on RTFO decisions on this topic, as well as the geographical origin of low carbon electricity would be beneficial.

6.6.2 Low carbon electricity additionality

Another key decision is how to define a requirement for **additionality**, to ensure that use of electricity for hydrogen production does not divert low carbon electricity from other users, with the increased demand met by higher carbon options, rather than incentivising new low carbon power generation.

The options for dealing with this are below, with it being possible to allow more than one option:

- **No requirement** - ensure additionality through other policy instruments, such as renewable electricity targets. This could also be used once grid mix in the UK or other country already has sufficiently high renewable share for the administrator to be confident that additional power demand will be met by renewables
- **New build requirement:** require that all or a percentage of power used has to come from new build renewable power facilities, which have not been supported by other schemes that are volume limited (e.g. by taking subsidy from a national fund of limited size)
- **Fund contribution:** require that all low carbon electricity use pays a fixed rate per kWhe amount that has to go into a separate fund for low carbon power development/deployment.

As described above, these options are under consideration for CertifHy. Under RTFO, the supplier must provide actual data to prove additionality where the project is not off grid or not using curtailed power, such as planning proposals for new sites that will be constructed at the same time or after the fuel production plant. The RED II delegated act is being prepared on the basis that "there should be an element of additionality, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy". TÜV SÜD requires additionality for renewable electricity, with three options for satisfying this requirement (at least >30% from new renewable energy sources, a €2/MWh_e payment into a development fund, or a specific technology mix that it can be assumed renewables are not being displaced or that the expansion of energy from renewable sources is promoted).

Table 18: Options for low carbon electricity additionality

Option	No requirement	New build	Fund
Inclusive	**Green:** Open to all pathways	**Red:** Requires electricity users to prove additionality but not other users of low GHG inputs – e.g. lower GHG intensity natural gas sources	**Red:** Requires electricity users to prove additionality but not other users of low GHG inputs– e.g. lower GHG intensity natural gas sources
Accessible	**Green:** No costs	**Red:** Large impact on capital requirements for electricity users	**Amber:** Likely lower cost impact on electricity users than new build option
Transparent	**Green:** No impact	**Green:** No impact	**Green:** No impact
Compatible	**Amber:** Not yet known	**Amber:** Not yet known	**Amber:** Not yet known

Option	No requirement	New build	Fund
Ambitious	**Red:** Relies on other policies to ensure growth in low carbon electricity supply	**Green:** Ensures additionality if the new build requirement is a high percentage of the electricity used	**Amber:** Depending on the fund level, could lead to some guaranteed additional supply
Accurate	**Green:** No impact	**Green:** No impact	**Green:** No impact
Robust	**Green:** No impact	**Green:** Straightforward to verify	**Green:** No impact
Predictable	**Green:** Predictable	**Amber:** Percentage may change	**Amber:** Fund level may change

Conclusion: This decision needs to be taken by BEIS in the context of the overall policy landscape for renewable electricity in the UK. Setting no additionality requirement, and relying on other policies to achieve this, is the most technology neutral way to treat hydrogen production pathways using electricity compared with other hydrogen pathways, but also compared with other uses of electricity that are supported by policy. If policy incentives are given for low carbon electricity use in other sectors, without additionality requirements, then adding these requirements for hydrogen production would be deprioritising this sector compared with other users. Nevertheless, if BEIS considers it likely that any support put in place would drive a significant increase in use of electricity for hydrogen production, without a likely similar level of increase in low carbon power generation under the market and policy conditions at that time, requiring new build or a fund contribution would ensure that additional low carbon power was built. This should be done including consideration of the approach taken in the RTFO and RED II. Note that this decision cannot be taken in a UK context alone: if the choice were made to include imported hydrogen, it would be important to ensure that the use of low carbon electricity in the country of origin was being matched either by growth in generation in that country, or to have new build requirements. To avoid this presenting a barrier to trade, criteria would need to be included to assess whether any additionality rule applied, which would be applied equally to the UK as to other countries. A fund-based approach could be more difficult to administer internationally.

We consider that it would be useful to define that pathways with total electricity input below a certain $MJ_e/MJ\ H_2$ value are excluded from any additionality requirements put in place.

6.6.3 Use of low carbon gas

All schemes allow use of guarantees of origin for biomethane transported via the gas grid, in some cases with a requirement for a feasible physical link (i.e. not book and claim between separate gas grids). No additionality or other requirements similar to those in discussion for electricity are included in other schemes. It is important to align the approach taken here with that used in the RTFO and Green Gas Support Scheme, given that there is a risk that biomethane injected into the gas grid is claimed in the sector with the highest price, leading to diversion from other sectors, and therefore no additional GHG savings, rather than new biogas production being stimulated (at least in the near term)

6.6.4 Treatment of mixed inputs

Where a process has mixed inputs, it is important to define whether the outputs should be treated as one consignment with an average GHG intensity, or whether it is allowable for the operator to separate this into multiple consignments each with its own GHG intensity. Also if multiple consignments are allowed, should each be required to meet the threshold, or would it be acceptable for some not to meet the threshold , and in what cases? For example, if an electrolyser has 40% low-carbon electricity, 60% high-carbon electricity inputs, can the operator claim 40% low-carbon H_2, 60% high-carbon H_2, or 100% average-carbon H_2? This question will also be important for use of natural gas and biogas in SMR/ATR, for gasification of MSW which has a biogenic and non-biogenic component, and any other process using mixed feedstocks. For this question, the link to the scheme in which the standard is being used is very important: would the scheme only support the project if the whole impacts of the project were beneficial in GHG terms, or would it be acceptable to provide support for only the portion of the output meeting the standard. The decision made here may also affect the choice of threshold value, given that it could affect many pathways, and therefore the supply of hydrogen likely to be available under a given threshold value.

Under the RTFO, fuels produced from mixed feedstocks need to report each consignment separately (note that currently non-renewable feedstocks are not eligible under RTFO, and so this is necessary so that only the renewable portion is counted). This means that in the example above, only 40% of the plant output would qualify. The approach to this in RED II for RFNBOs and biofuels co-processed with fossil fuels is to be defined in delegated acts, both for treatment of renewability and GHG emissions. In CertifHy, LCA is done separately for renewable input and non-renewable input. In relation to mixed residual wastes, TÜV SÜD only certifies the biogenic share (% share of input is equal to renewable share of output), and for electricity, only 100% renewable input is accepted.

The options considered are below:

- **Averaging** - All H_2 consignments have the same GHG intensity, with averaging over a specified time period. This average must meet the threshold. Note that under RTFO and RED II, averaging is generally only allowed over consignments that all meet the threshold individually, but the option being considered here is where only the average needs to meet the threshold. This is the approach taken by the Green Gas Support Scheme for biomethane injection.
- **Separate consignments or averaging** - Different H_2 consignments can be defined, based on splitting the major inputs into consignments with different GHG intensities, or an average can be used. If split into separate consignments, each of the consignments would be assessed separately against the standard, so that the low carbon ones could qualify whilst high carbon ones would not.

- **Separate consignments or averaging, with average meeting a benchmark** - Different H_2 consignments can be defined, based on splitting the major inputs into consignments with different GHG intensities, or an average can be used. If different consignments are used, the average emissions still need to meet a defined maximum value (not the threshold value, but a higher figure). In CertifHy, the average value needs to meet the 'benchmark' figure of 91 $gCO2_e$/MJ (based on SMR). In this case, the low carbon consignments would qualify as long as the average is below the benchmark. The benchmark does not have to be the same as the fossil comparator used in a policy scheme - the benchmark could be lower than the fossil comparator and potentially get tighter over time (but still remain above the GHG threshold).

Note that the reason for using the term major inputs would be that this is intended to cover examples given above, where the main energy inputs to the process are mixed. We consider that it would be useful to define that all energy inputs below a certain threshold (e.g. 5%) are excluded from the ability to generate separate consignments. Without this, it would be possible for a high GHG process (e.g. unabated SMR) being able to buy low carbon electricity for process requirements, and then claim small quantities of low carbon hydrogen. Note that under the RTFO and RED, a distinction is made between feedstock inputs (e.g. electricity used in an electrolyser) and process inputs (electricity used in compression). This is because it is necessary to determine what proportion of the product is renewable, which depends on the renewability of the feedstock energy. For process energy inputs, their GHG emissions contribute to the overall GHG emissions of the product, but their renewability does not affect the renewability of the product. However, under CertifHy, all inputs are treated in the same way. We recommend that here all energy inputs should be treated equally, as the notion of "feedstock" and "process energy" can be misleading.

Table 19: Options for treatment of mixed inputs

Option	**Option A** **Averaging**	**Option B** **Separate consignments or averaging**	**Option C** **Separate consignments or averaging, with average meeting a benchmark**
Inclusive	**Amber:** Treats all pathways equally, but means that for some pathways, alternative plant sizes/scale/configurations will be required e.g. smaller electrolysers, electrolysers sited near renewables (depending on approach taken to use of low carbon electricity), increased waste separation, SMR/ATR for only biomethane.	**Green:** Greatest flexibility for projects, and greatest flexibility on varying inputs over time	**Amber:** As in option A, but with increased flexibility on plant configurations.

Option	Option A Averaging	Option B Separate consignments or averaging	Option C Separate consignments or averaging, with average meeting a benchmark
Accessible	**Green:** No impact - in all cases reporting and verification of inputs needed	**Green:** No impact - in all cases reporting and verification of inputs needed	**Green:** No impact - in all cases reporting and verification of inputs needed
Transparent	**Green:** Transparent if plants are required to disclose inputs	**Green:** Transparent if plants are required to disclose inputs	**Green:** Transparent if plants are required to disclose inputs
Compatible	**Amber:** Not compatible with RTFO or CertifHy, not known for RED II	**Amber:** Compatible with RTFO, not CertifHy, not known for RED II	**Amber:** Compatible with CertifHy[46] approach, not with RTFO, not known for RED II
Ambitious	**Green:** Ensures that the whole impact of a project is taken into account when giving any type of policy support **Green:** Gives the highest incentive for projects to move to the lowest overall GHG emissions May lead to some additional emissions in some cases (e.g. additional waste separation, smaller less efficient plants)	**Red:** Risks that compliant consignments are sold into the scheme and non compliant consignments are sold elsewhere into non regulated markets e.g. chemicals, markets outside the UK.	**Amber:** Ensures that the scheme does not support hydrogen with very high GHG emissions being produced and sold outside the scheme
Accurate	**Green:** No impact	**Green:** No impact	**Green:** No impact
Robust	**Green:** No impact	**Green:** No impact	**Green:** No impact
Predictable	**Green:** No impact	**Green:** No impact	**Green:** No impact

Conclusion: Averaging over all inputs (Option A) is most ambitious, but may exclude many production facilities and/or operating concepts, notably electrolysers using mixed electricity inputs. Allowing for separate consignments (Option B) allows flexibility for projects, and varying inputs over time, but risks channelling compliant and non-compliant consignments into regulated and non-regulated markets, respectively, without necessarily driving additional low-carbon hydrogen replacing high-carbon. Allowing consignments whilst requiring the average emissions not to exceed a benchmark (Option C) has the same advantages as Option B while limiting the associated risk. The benchmark would need to be defined specifically for this option. As explained above, the choice here is also highly dependent on the scheme(s) in which the standard is to be used: if providing capital support to a project which will enable it to go ahead then the whole impacts can be assessed in detail and compared with counterfactual options in each market for the

[46] CertifHy differentiates between renewable and non-renewable, but does not allow for different consignments within these categories.

hydrogen, whilst in an ongoing certification scheme linked to a market based policy it might be necessary to allow support for low carbon consignments (with a cap on average emissions as above), as the inputs might vary over time.

6.7 GHG thresholds

Having calculated the GHG emissions of hydrogen, a GHG emissions threshold can be used to determine whether this hydrogen meets the requirements of a standard or not. Assuming other acceptance criteria are met (e.g. any sustainability or additionality rules), then hydrogen GHG emissions intensities below the threshold would be allowed under a standard, and emissions intensities above the threshold would be excluded.

Meeting the GHG emissions threshold can be accompanied by the assignment of a label or category (e.g. “low carbon” hydrogen), but might also be accompanied by assignment of other labels unrelated to GHG emissions, such as “renewable” or “green” or “advanced” or “development fuel”, depending on the characteristics of the hydrogen produced. These alternative labels/categories often mean a GHG threshold has been met as well as further characteristics being present.

6.7.1 Number of GHG thresholds

There are three main options for the number of GHG emissions thresholds to be defined in a standard:

- **No threshold**. In this option, there is no GHG threshold against which chains are assessed, and chains only report their GHG emissions. Standards can be established which follow this approach for simple reporting or disclosure purposes (as proposed in Australia), or might be tied to a wider policy driver to encourage use of lower carbon intensity fuels (e.g. the LCFS) but without setting threshold levels.
- **Single universal threshold for all chains**. A single universal GHG threshold is used across all chains, determining which chains are in or out of the standard, e.g. as in CertifHy (which uses a common GHG threshold for both “green” and “low carbon” hydrogen categories).
- **Different threshold for each chain**. One GHG threshold is used for each chain, but set at different levels depending on the chain characteristics or end use, e.g. TÜV SÜD has one GHG threshold level for each chain, which varies depending on the technology pathway, end use, plant age and system boundary.
- **Multiple thresholds**. In this option, chains have the possibility of meeting a specified GHG threshold for inclusion in one category of the standard, but also have the possibility of meeting another stricter GHG threshold (lower emissions level) for inclusion in a different category of the standard. China Hydrogen Alliance follow this approach, although the looser threshold set by this standard has very high emissions (120.9gCO_2e/MJ_{LHV}).

Table 20: Options for the number of GHG emission thresholds

Option	Option A No threshold	Option B Single universal threshold	Option C Different threshold for each chain	Option D Multiple thresholds
Inclusive	**Green:** Open and applicable to any pathway. No need for flexibility	**Green:** Open and applicable to any technology pathway. Less flexible, as only a single threshold to set.	**Red:** Open and the most flexible, but by definition would not be treating each technology equally. Could be appropriate in point of use schemes	**Amber:** Open and flexible. Setting ‘low’ and ‘very low’ thresholds, but avoiding negative thresholds (risky and only accessible by BECCS), would treat technologies equally.
Accessible	**Green:** No added cost	**Green:** Simple, cost of compliance depends on threshold level	**Amber:** Most complex, cost of compliance depends how each threshold level is set relative to each route	**Amber:** complex, costs of compliance depends on threshold levels (will generally be higher cost for tighter threshold levels)
Transparent	**Green:** No GHG threshold to assess compliance against, but still need to report emissions	**Green:** No impact on transparency, as long as threshold is clear and applied consistently.	**Amber:** Marginally less transparent, as thresholds need to be set for each route, and some may only impact one or two stakeholders	**Green:** No impact on transparency, as long as thresholds are clear and applied consistently.
Compatible	**Amber:** Scheme is not directly compatible with UK or EU schemes, but fits LCFS and Australian approach. However, UK H_2 may be compatible with CertifHy if UK GOs recognised by EU Member States.	**Green:** Compatible with RTFO and CertifHy	**Amber:** Compatible with TÜV SÜD and RED II	**Red:** Different approach from most schemes. UK H_2 may be compatible with CertifHy if UK GOs recognised by MSs (and vice versa), and GHG emissions info shared rather than categorisations.
Ambitious	**Red:** On its own, will not ensure low carbon investments or consistency with Net Zero. Would need to be combined with a reduction policy e.g. LCFS	**Amber:** Can be Net Zero consistent, but single threshold only drives innovation near the margin. If the threshold were tightened over time, would drive further innovation	**Green:** Can be Net Zero consistent, and different thresholds for each route can ensure innovation across all routes	**Green:** Can be Net Zero consistent, and multiple thresholds can support innovation throughout a range of emissions (provided the highest threshold is sufficiently ambitious)

Option	Option A No threshold	Option B Single universal threshold	Option C Different threshold for each chain	Option D Multiple thresholds
Accurate	**Green:** No uncertainty	**Green:** Threshold itself is accurate	**Green:** Thresholds themselves are accurate	**Green:** Thresholds themselves are accurate
Robust	**Green:** No risks or threshold compliance requirements	**Green:** Limited impact on robustness if single level	**Amber:** Marginally more risk if different levels for different routes	**Amber:** Limited impact on robustness, marginally more risk with the different threshold levels
Predictable	**Green:** No compliance to forecast	**Green:** Single level is reasonably predictable providing security	**Amber:** Different levels may be less predictable and provide slightly less security	**Amber:** Less predictable, as more routes will be marginal, and particularly if thresholds are close together (e.g. low and very low thresholds)

Conclusion: The approach of applying a single universal GHG threshold (Option B) is simple, transparent, predictable, fair across all technologies, and compatible with other key schemes. This is the recommended approach, unless there are strong policy reasons for wanting further differentiation and sophistication in the standard.

Setting multiple thresholds (Option D) can support greater innovation, but comes with some added costs and complexity. If the intention is to use the standard to underpin a UK capital grants scheme, then multiple thresholds only make sense if there are multiple funding pots, and projects have a higher likelihood of receiving funding support (or more funding) if their GHG savings are higher. If the intention is to use the standard to underpin an ongoing UK revenue support scheme (e.g. feed-in-tariff, contracts for difference, obligation etc), then multiple thresholds only makes sense if there are multiple funding streams (e.g. tiers, pots or sub-mandates), with more value attached to higher GHG savings. The design of these policy schemes therefore drives the number of thresholds required.

Setting different thresholds for different routes (Option C) provides greater innovation incentives, but adds complexity and risk, and removes some transparency and predictability. However, it could be appropriate if the downstream system boundary is defined as the point of use. In this case setting different thresholds for different end uses could be considered: for example, setting a higher threshold where high carbon alternatives are displaced (meaning a higher level of emissions from hydrogen may be acceptable), where hydrogen helps meet other policy goals (e.g. air quality benefits), or where the emissions associated with meeting the end user requirements are higher (e.g. compression and purification for fuel cell vehicles).

Establishing a low carbon hydrogen standard without specifying a GHG threshold (Option A) is not recommended, as this is not providing a definition of what is “low carbon”. This approach would only serve a use for disclosure reporting, or else requires a wider policy driver to incentivise lower GHG hydrogen routes over higher GHG routes. Like the current fuels under the LCFS, the majority of UK hydrogen today is high carbon. However, as low-carbon hydrogen supplies in the UK are expected to exceed current fossil hydrogen supplies by at least an order of magnitude, and be used in multiple applications (compared to the LCFS situation of lower carbon fuels slowly displacing high GHG fossil fuels only in Californian transport), using a declining overall GHG intensity target for UK hydrogen would quickly require this target to become a proxy low-carbon threshold for the hydrogen industry. Some high GHG intensity hydrogen could still be supplied, but would have to be compensated for by significantly more near-zero emissions hydrogen to still meet the overall target. Given the stated UK policy intention to focus on establishment of a new and widespread UK low-carbon hydrogen market across multiple applications, not specifying a GHG threshold is unlikely to be a suitable approach.

6.7.2 Form and timeframe for GHG threshold

A GHG threshold is typically specified as an absolute level of “X” gCO_2e per MJ_{LHV} of hydrogen. UK and EU schemes often describe this as a minimum % GHG saving compared to a high carbon benchmark, but the requirement is still to be below the absolute threshold level when reporting the hydrogen GHG emissions, rather than being above the required % GHG saving. The high carbon benchmark could be different for different end uses (e.g. as in TÜV SÜD), and benchmarks can be changed periodically (e.g. as the RTFO is currently doing, accompanied by a compensatory increase in the % GHG saving required so that there is minimal change in the absolute threshold value for RTFO compliance). We found no examples of decreasing absolute thresholds or decreasing benchmarks over time being announced in advance.[47]

Benchmarks are typically set based on the fossil fuels that are being displaced, e.g. 94 gCO_2e/MJ in EU road transport for fossil diesel/petrol. However, given low carbon hydrogen is expected to be used across multiple applications in the UK (road transport, heating, power, industry, shipping, aviation fuels, etc.), it is unlikely there is a single high carbon benchmark that would be appropriate. Low carbon hydrogen supplies are expected to out-supply high carbon hydrogen supplies by an order of magnitude, so an unabated SMR benchmark will also relatively quickly become obsolete (particularly if CCS is retrofitted).

The use of a % saving as a threshold instead of an absolute threshold value would theoretically be expected to have some benefits in terms of greater resilience to changes in accounting methodologies, but since the changes in accounting methodologies might only impact high carbon routes (e.g. updating methane GWP in IPCC AR6) and not impact many of the low carbon routes, this benefit is not guaranteed. Having to predict changes to

[47] Note that the LCFS benchmark, which does decrease over time according to a set trajectory to 2030, is the value that a fuel supplier must meet on average across all fuels sold, not a threshold for an individual pathway.

the benchmark as well as predicting changes to an operator's own chain when assessing future compliance also adds additional uncertainty. It is therefore recommended that for transparency reasons, any GHG threshold is set as an absolute value in gCO_2e/MJ. This could be revised if necessary due to significant accounting changes.

The need for a GHG threshold to provide certainty over time depends on the policy scheme in which it will be used. A GHG threshold may only be needed in one year, if the standard is only used for a single UK capital grants scheme. Whereas if the standard is used for a long running revenue support scheme, consideration could be given to how the GHG threshold might change over time. The GHG threshold chosen could stay fixed, or could decrease over time either via ad-hoc revisions, a pre-announced set of conditions for revisions ("will revise if X & Y occur"), a pre-announced periodic timetable for revisions ("will revise on these dates"), or with a pre-announced long-term decreasing trajectory (e.g. to the end of the latest Carbon Budget, or to 2050). A decrease over time could allow higher emissions in the early stages of hydrogen deployment, with a tightening in the future to drive improvement. This would be justified only where it could be demonstrated that hydrogen options saved emissions compared with the alternative means of supplying the same service, and where there was a valid argument for how emissions from the hydrogen option would decrease in the future, rather than locking the producer in to the higher emissions level with no chance of improvement. For example, in some pathways decarbonisation of the energy inputs, such as grid GHG intensity reduction, will bring rapid pathway GHG reductions over time, whereas in others, the emissions are largely fixed by the equipment initially installed, and are unlikely to decrease significantly or quickly.

It would also be possible to give some limited leeway on the thresholds to selected routes, for example some biofuels plants built before a certain date are given an additional 10% leeway in RTFO, RED and TÜV SÜD. This would be justifiable only where hydrogen supplied from those older plants continued to save significant emissions compared with the alternative means of supplying the same service, and those plants could provide a material contribution to UK hydrogen supply without preventing the introduction of newer, lower emission hydrogen pathways into the market. Consideration of leeway for existing/older plants would not be required for a new build UK capital grant scheme, but may be more relevant for ongoing hydrogen revenue support schemes. Assessing whether any limited leeway would be needed would require data on variation between plants and by plant age, and as such is beyond the scope of this project. However, given the early stage of the UK low-carbon hydrogen market and current lack of CCS, there may be little need for any leeway to be considered for existing UK low-carbon hydrogen production facilities.

6.7.3 Level of GHG threshold

The decision on the level of the threshold will need to be made once all of the other decisions are made on boundaries, scope, GWP, energy inputs and allocation. At this point, the GHG emissions of pathways can be assessed (for example through BEIS using the LCA tool provided by E4tech), and a level of threshold agreed. The level of the threshold should be set so as to maximise the GHG savings from the standard:

- Setting the threshold at a lower level would reduce the emissions from hydrogen compliant with the standard, but would reduce the number of pathways that were compliant, which could reduce the overall emissions saving of any scheme supporting only pathways that met the standard.
- Setting the threshold at a higher level could widen access and so have greater overall savings in the near term, but have the risk of supporting construction of projects today that lock in emissions at a higher level than would be acceptable to achieve net zero in the future.

For example, as discussed in WP2, based on the choices made in the GHG analysis done in this project, if a single GHG threshold were set at the point of production, a threshold of 15-20 gCO_2e/MJ_{LHV} of produced H_2 would already allow a number of low and negative emissions chains.

- This would include renewable and nuclear electrolysis, and all the biomethane, biomass and waste gasification pathways involving CCS, as well as some without CCS. It would also allow fossil gas pathways with high efficiency and capture rates combined with low upstream emissions, such as the majority of ATR with CCS chains, as well as the better end of the SMR with CCS chains.
- It would exclude grid electrolysis and chlor-alkali pathways using grid electricity (where an average grid factor is used) until around 2030 (when the grid has sufficiently decarbonised), as well as maize biomethane ATR and waste gasification without CCS, and most fossil gas pathways where CO_2 capture is below ~85% or those relying on LNG. Unless use of low carbon electricity via traded activities were allowed, this would exclude many electrolysis-based pathways until around 2030, apart from those with a physical link to renewable generation.

A point-of-production threshold of 15-20 gCO_2e/MJ_{LHV} of produced H_2 would equate to a 76-82% GHG saving versus a UK SMR benchmark.

If the downstream system boundary were set at the point of use, different thresholds could be set for different end uses, for example higher thresholds set where alternative methods of providing the end use have higher emissions (as discussed above in Section 6.7.1). In transport uses, a well-to-point-of-use GHG threshold of around 20-25 gCO_2e/MJ of delivered H_2 in 2030 would include/exclude a similar set of production routes as discussed above (although more chains would be excluded earlier where downstream emissions are much higher). Tighter thresholds could potentially be considered for non-transport uses.

6.8 Chain of Custody

Chain of custody (CoC) requirements define how compliant hydrogen passes through the value chains until it reaches the end-user. CoC requirements should ensure sufficient traceability and transparency across the supply chain, while not adding unnecessary administrative efforts or costs for the operators implementing the standard.

Four categories of chain-of-custody systems generally exist, which include varying levels of physical traceability of products:

- *Identity Preserved* systems are used to keep a batch of products from a specific origin fully separate from other batches from different origins across the entire supply chain, even if all batches are compliant. This system is the most rigorous, with regards to traceability of products, but entails significant costs due to the specific logistics requirements. Identity Preserved does not allow blending any batch of products (e.g. in a pipeline or a gas grid).
- *Segregation* systems do not allow the physical mixing of compliant products with non-compliant products at any step of the supply chain. Operators are, however, allowed to mix compliant products from different origins, or with different GHG savings, which is the main difference from an *Identity Preserved* system. Therefore, while remaining stringent in terms of traceability, a segregated system is more flexible and less costly to operate than an Identity Preserved system. Segregation does not allow blending of compliant and non-compliant hydrogen (e.g. in a pipeline or a gas grid).
- *Mass balance* systems allow the physical mixing of compliant and non-compliant products. Operators are required to monitor and keep records of the balance of compliant and non-compliant batches of inputs to their operation. They are then allowed to claim compliance on outgoing products in the same proportion as the entering inputs (taking into account process efficiencies, losses, etc.). Mass balance therefore ensures some physical traceability for compliant products but is less burdensome to operate than Identity Preserved or Segregation, which can be regarded as more stringent. Mass balance systems can also be used to keep track of hydrogen being produced through different technologies, e.g. biogenic vs non-biogenic hydrogen. Mass balance is currently used in TÜV SÜD and RTFO and is under development in CertifHy.
- *Book and claim (certificate trading)* systems are not based on physical tracking, but on transfer of environmental characteristics. Compliant operators deliver their products onto the market and “book” equivalent volumes of compliant products, via a dedicated certificate platform. At the other end of the chain, buyers may acquire compliance certificates and “claim” a contribution to the production of an equivalent volume of compliant products. Book and claim systems are more affordable than other CoC systems, but they do not guarantee any physical traceability and are therefore more vulnerable to accounting errors or fraud, and therefore seen as less reliable than other CoC systems. Book and claim is currently allowed in CertifHy, TÜV SÜD and LCFS.

Demonstrating compliance with CoC requirements is the responsibility of each economic operator involved in the supply chain for their respective operations. This includes:

- Verifying that incoming material and attached documentation includes all the characteristics required in the standard (operators may require missing documentation from suppliers or refuse material if it does not comply with documentation requirements);

- Ensuring that operations under their control comply with all relevant CoC requirements;
- Ensuring that outgoing material and attached documentation include all the characteristics required in the standard.

In identify preserved, segregation and mass balance systems, the chain of custody carries on until the last operator within the scope of the standard, with information being passed down the chain. In a book and claim system, the chain of custody goes up until the registry of the product with the certificate trading platform. The different CoC systems and their main characteristics are summarised in Table 21.

Table 21: Summary of CoC Systems and their characteristics (ISEAL[48])

	Identity preserved (IP)	Segregation	Mass balance overview			Certificate trading
			Batch level mass balance	Site level mass balance	Group level mass balance	
Ensure that volumes of certified material sold matches (or does not exceed) volumes of certified materials bought[1]	Yes	Yes	Yes	Yes	Yes	Yes[2]
Traceability linked to volume reconciliation over a set time period	No	No	No	Yes	Yes	Yes
Allows mixing of certified and non-certified content	No	No	Yes	Yes	Yes	Yes
Physical traceability	Yes	Yes	Yes	Yes, to point of blending	Depends	No[3]
Identify origin of a final product or product component in actual product	Yes	Yes, but 'origin' may not be as specific as IP depending on the supply chain (e.g. to country or region may be possible)	Depends (lost with physical blending)	Depends (lost with physical blending)	Depends (lost with physical blending)	No

[1] Accounting for conversion rates
[2] Refers to numbers of credits as they represent volumes, rather than the volumes themselves
[3] No physical traceability, but can sometimes be linked to location or region, i.e. volume of production per country

[48] ISEAL (2016) Guidance on Chain of Custody Models https://www.isealalliance.org/sites/default/files/resource/2017-11/ISEAL_Chain_of_Custody_Models_Guidance_September_2016.pdf

Table 22: Options for Chain of Custody

Option	Option A Identity Preservation	Option B Segregation	Option C Mass balance	Option D Book & claim
Inclusive	**Red:** Does not treat technologies and scales equally - IP requires strict logistics rules and equipment (storage, transport), which guarantee a full separation of batches. Not economically realistic for large scale production (e.g. SMR) or storage of batches from multiple origins. Would not be possible in gas grids.	**Red:** Treats technology equally as long as sufficient amounts of compliant hydrogen are produced to enable storage sites and logistics chains. If compliant H_2 represents a limited share of the market, large scale production /storage will not be economically feasible. Would not be possible in gas grids.	**Amber:** Treats technologies equally as long as mass balance accounting periods chosen are appropriate for each type of storage (e.g. the time period over which material is typically stored). Mass Balance allows for any production/storage scale.	**Green:** Treats technologies equally- Book & Claim is the most appropriate system to accommodate multiple production pathways and scales and allow for imports.
Accessible	**Red:** Expensive – IP requires stringent logistic rules and prevents any intermediary mixing, thus reducing opportunities to reduce costs through bulk trading. Extra cost passed onto end-user. Simple accounting and tracking.	**Red:** Expensive – Although, more options exist with regard to sourcing and trading than IP, logistic costs (esp transport and storage) remain high. Extra cost passed onto end-user. Simple accounting and tracking.	**Amber:** Moderately expensive. Complex mass balance accounting to be put in place. Extra cost passed onto end-user.	**Green:** Limited cost. B&C only relies on an online trading platform. No extra cost involved.
Transparent	**Green:** Highly transparent – stakeholders can trace 100% of the H2 back to production site. Robust guarantee that 100% of the physical product is compliant.	**Green:** Transparent – robust guarantee that 100% of the physical product is compliant, but exact production site of a given batch cannot be tracked.	**Amber:** Moderately transparent – some tracking of origin possible over compliant fraction, but cannot guarantee that physical product is compliant.	**Red:** Not transparent – full disconnect between physical products and low C certificate/claims. No possible tracking of origin and no guarantee that physical product is compliant. Public credibility is generally lower for B&C than other options.
Compatible	**Green:** Compatible with any CoC system but no more IP claim possible if transferred into a Segregation, MB or B&C system.	**Green:** Compatible with any CoC system (except IP) but no more Segregation claim possible if	**Amber:** Not compatible with IP/Segregated systems. Compatible with BC, but no more MB claim possible. Allowed by 3/5	**Amber:** Not compatible with any other CoC system. However, 3 of the studied schemes out of 5 allow B&C.

Option	Option A Identity Preservation	Option B Segregation	Option C Mass balance	Option D Book & claim
		transferred into a MB or B&C system)	of the studied schemes.	
Ambitious	**Amber:** Additional equipment and logistics will increase GHG emissions. However would incentivise local production.	**Amber:** Additional equipment and logistics will increase GHG emissions.	**Amber:** Impact on emissions of some pathways due to need to follow mass balance rules e.g. increased transport of consignments between different producers and users compared with B&C approach	**Green:** Highest GHG saving performance as allows greatest flexibility and avoids transport steps. Also enables greater scheme uptake if imported hydrogen is allowed
Accurate	**Green:** Accurate – reduces the risk of errors in GHG accounting due to mishandling of product documentation.	**Green:** Accurate – reduces the risk of errors in GHG accounting due to mishandling of product documentation.	**Amber:** Accurate as long as bookkeeping over mass balance of incoming/outgoing products is robust. Higher risk of errors in GHG accounting due to mishandling of product documentation than in IP / Seg.	**Amber:** Accurate from a systemic point of view, but higher risk of fraud over GHG savings than in other systems.
Robust	**Green:** Robust – strict tracking of physical product and documentation across all stages of the value chain. Low risk of fraud.	**Green:** Robust – strict tracking of physical product and documentation across all stages of the value chain. Low risk of fraud.	**Amber:** Moderately robust – limited tracking of physical product and documentation across all stages of the value chain. Moderate risk of fraud.	**Red:** Not robust – no tracking of physical product or documentation across all stages of the value chain. Higher risk of fraud.
Predictable	**Green:** No impact on predictability	**Green:** No impact on predictability.	**Green:** No impact on predictability.	**Amber:** Moderate impact on predictability, due to operators being able to change the emissions of their pathways quickly without changes in infrastructure.

Conclusion: The impossibility of using the existing gas grid with hydrogen in *Identity Preserved* and *Segregation* Chain of Custody models is a fundamental obstacle to the implementation of these options in the UK context. A *Book and Claim* system appears to be a flexible, fast to implement and less demanding model for operators, but it does not permit physical traceability of hydrogen and thus lacks transparency. However, Book & Claim could be an option for a standard with a downstream system boundary set at the point of production, to underpin schemes where the objective is solely to support low carbon hydrogen production. *Mass Balance* is a good compromise between transparency and flexibility, which could be a more appropriate option for a standard with a downstream system boundary set at the point of use. Currently based on REDII rules, Book & Claim systems typically support consumer disclosure, whereas Mass Balance systems typically support legal compliance, but there are exceptions where countries (e.g. Belgium) have used Book& Claim systems for legal requirements or funding schemes.

Note that an operator already using a mass balance approach (e.g. for RTFO compliance) would be able to use the same data to comply with a standard based on book & claim. However, it is less clear whether the reverse will be possible – under current REDII discussions, it is being debated whether an upstream guarantees of origin (book & claim) system could be combined with a downstream mass balance system, and what accompanying changes would be necessary in assurance systems.

Note that Mass Balance would normally apply to an identified production/storage site rather than, for example, the entire gas grid. Applying this to a wider system in this way could be considered as a hybrid book and claim system, with some degree of physical tracking. The approach to this at a European level is still under debate with revision of EN 16325[49], in terms of whether guarantees of origin for hydrogen should be cancelled upon injection into the gas grid, or on extraction. The approach taken to gas grids should be aligned with any approach used for the RTFO, for which guidance is currently being updated.

6.9 Default versus actual data

Assurance providers (e.g. auditors) would assess compliance of economic operators with the requirements included in a low carbon hydrogen standard by verifying a large number of pieces of data and evidence. The verification of the accuracy of GHG emissions of hydrogen is of high importance for the robustness and credibility of the standard. GHG emissions and savings could be demonstrated by using default values developed and approved by the standard owner, actual values calculated by economic operators, or a combination of both default and actual values. Default values can cover the entire scope of GHG emissions (e.g. from production to end-use) or specific steps (e.g. storage only). Options for treatment of GHG values are:

[49] Revision of CEN- EN 16325 and the development of a multi-energy carrier GO system https://www.regatrace.eu/revision-of-cen-en-16325-and-the-development-of-a-multi-energy-carrier-go-system/

- **Default values only** – this option was not reported in any of the case studies.
- **Actual values only** – as in CertifHy, and the aim of IPHE.
- **Default and actual values allowed** – as in TÜV SÜD (actual values for direct emissions; default values in upstream supply chain steps are accepted), LCFS (default values can be used if the operator can demonstrate sourcing for biomethane or zero-emissions electricity used in hydrogen production; otherwise, operators must provide actual values), RTFO (default values exist for hydrogen chains, but at the moment, only actual values are being reported to the RTFO) and RED II (use of default values, actual values or a combination of both are allowed).

Table 23: Options for default or actual GHG emissions values

Option	Option A Default values only	Option B Actual values only	Option C Default/Actual (Hybrid)
Inclusive	**Amber:** Treats technologies equally if the scheme is able to quickly develop and implement consistent and robust default values for new routes.	**Amber:** Treats technologies equally. Less inclusive than default values, as some operators may have limited means to conduct GHG assessments. Allows more flexibility to include alternative routes than with default values only. However, the GHG methodology used to calculate actual values needs to evolve fast to remain adapted to the new routes.	**Green:** A hybrid approach treats technologies equally and is inclusive, as it gives benefits from both approaches e.g. new entrants can provide actual data if defaults are not yet available (although to ensure fairness the same level of default data provision should ultimately be provided for all pathways)
Accessible	**Green:** Cost-effective and simple for users, incl. smaller operators. The use of default values significantly reduces compliance and audit costs.	**Red:** Less cost-effective and more complex – operators and auditors need to conduct/verify complex calculations and associated evidence.	**Green:** Cost effective, as it provides a cheaper option (default values) for operators with limited GHG assessment skills. Requirements for actual data can be limited to key data that the operator will definitely have anyway (e.g. energy use)
Transparent	**Green:** Transparent – the calculation of default values can be disclosed to ensure the methodology is consistently implemented.	**Amber:** Limited transparency - the detail of GHG assessments may not be included in public audit summary, due to the use of confidential data.	**Amber:** Reduced transparency if actual values are used.
Compatible	**Amber:** Compatibility is more related to the GHG methodology itself, but default values can enhance trust in the values across different schemes.	**Green:** No significant impact on compatibility, but the use of actual values may add an extra layer of verification in case of transfer into another scheme.	**Green:** Compatible – the possibility to use default or actual values may further enhance compatibility with other schemes.
Ambitious	**Amber:** Ambitious as long as default values are	**Green:** Supports improvement over time as users have to	**Green:** Ambitious if conservative (high) default

Option	Option A Default values only	Option B Actual values only	Option C Default/Actual (Hybrid)
	conservative. Does not encourage users to calculate actual values and so identify areas for improvement, i.e. no innovation driver	measure their performance. However could reduce the overall impact of the scheme through narrowing participation	values and/or a strict (low) threshold are applied.
Accurate	**Amber:** Moderately accurate – default values may under/overestimate GHG emissions for a given route.	**Green:** Accurate – actual values allow fine tuning of the calculation and reflect supply chain specificities	**Amber:** More accurate if actual values are used. Companies may use default values when their actual emissions are higher.
Robust	**Green:** Robust – it reduces the possibility for fraud or misreporting.	**Amber:** Robust as long as the verification system (assurance) is robust. More prone to fraud or misreporting.	**Amber:** Robust as long as the verification system (assurance) is robust. More prone to fraud or misreporting.
Predictable	**Green:** Predictable – using default values enhance the capacity for investors to anticipate compliant volumes of H_2, based on existing technologies. Limited likelihood of important variations in GHG emissions.	**Amber:** Less predictable than default values, due to higher probability of important variations in GHG emissions.	**Amber:** Less predictable than default values only, due to higher probability of important variations in GHG emissions.

Conclusion: A *hybrid* approach could be established on the model of the EU's RED II, whereby economic operators may:

- Use a default value for total life-cycle emissions or GHG savings;
- Calculate their life-cycle emissions and GHG savings based entirely on actual values;
- Calculate their life-cycle emissions and GHG savings based on a combination of actual values and disaggregated default values.

Such a hybrid approach would offer the highest level of flexibility for operators, as well as higher compatibility and cost effectiveness. It does not completely prevent the risk of misreporting or inaccuracy in GHG values, since operators may opt for default values if those provide higher GHG savings than actual values. This can be mitigated by setting default values at conservative levels. For example, if there is a concern that new demands from fossil gas reforming pathways would be likely to use imported LNG, then a default value for upstream fossil gas emissions could be set higher than the UK weighted average of fossil gas supply, and more in line with LNG emissions. This would incentivise use of lower emission gas sources and reporting of actual data. This conservative default value approach has been followed in RED and the RTFO for over a decade, whereby conservative default values (with a significant uplift applied to average production emissions) encourage biofuel pathways to report actual data.

6.10 Summary and conclusions

For many of the factors related to the system definition and GHG calculation requirements for a low carbon hydrogen standard, the choice of option is clear, or the analysis above has shown that one approach is strongly preferred. These are listed below.

Table 24: Factors where there is a clear recommended option

Factor	Option recommended
Upstream system boundary	Include all upstream emissions, back to the point where emissions contributions are no longer material to the analysis
Materiality	Include a materiality limit
Embodied emissions	Exclude embodied emissions, but review in the future
Treatment of direct land-use change for biomass	Include
Inclusion of CCS	Include
Inclusion of CCU	Include a list of permitted CCU options, based on evidence on their degree of permanence
Allowable H_2 production pathways	Standard owner maintains a list of allowed pathways
End use	Allow for any end use
Non GHG impacts	Not generally assessed here, however include biomass sustainability criteria as in the RTFO
Unit	use $gCO2_e$/MJ LHV
Inclusion of GWP for hydrogen	Include
Form of GHG threshold	Absolute value rather than % saving
Default vs actual data	Hybrid approach allowing both default and actual data

However, there are some decisions that are not clear, either because the option chosen depends heavily on the scheme(s) within which the standard is intended to be used, or because there are uncertainties related to the advantages and disadvantages of each option. Several of these factors also depend on each other, with the choice of one option for one factor reducing the options available for another. The key decisions to be made on these more **complex, interacting factors** are:

- The **choice of downstream system boundary, chain of custody approach, and geographical boundary** of the scheme. Here there is a trade-off between a lower cost of compliance and the ability to interact with guarantee of origin (book and claim) schemes if point of production is chosen, versus the risk of omitting potentially significant downstream distribution emissions from some hydrogen pathways (that point of use would include). If the scheme intends to support hydrogen imports or exports this issue is exacerbated: a book and claim chain of custody approach would significantly broaden access to the scheme, meaning a point of production reference point, but the emissions potentially omitted could be considerably larger.

- The choice of downstream system boundary also has significant impacts on the choice of **hydrogen purity and pressure** – if the downstream system boundary were set at the point of use, a defined or required pressure and purity would not be needed. If the downstream system boundary were set at the point of production, with book and claim chain of custody, a defined or required pressure and purity would be needed, though it may be possible to exempt a producer from adding the purity/pressure factors to their calculations if they could demonstrate that they had a user with lower requirements, and did not participate in any book and claim scheme.
- If the **geographical boundary** is set as UK only for the near term, with an intention to broaden it at a later point, it is important that the choices made on other factors apply in a global context, rather than relying on characteristics of the UK energy system, such as the UK grid mix.

Overall, two main generic types of approach could be taken with details to be defined, and intermediate approaches possible:

a) A point of production boundary, with purity and pressure requirements/adjustments and with book and claim chain of custody. This is analogous to a Guarantee of Origin type approach (as defined in RED II Art 19) or CertifHy.

b) A point of use system boundary with mass balance chain of custody, with no purity and pressure requirements. This is analogous to the RTFO approach.

Note that these groupings are not fixed: as described above some of these options can be varied within each approach, or intermediate or more differentiated approaches are possible.

For some factors, there is a need to review the decision based on ongoing work in other schemes internationally as well as on other UK policies:

- **Allocation** of emissions to co-products – whilst energy allocation is generally used in other standards for energy co-products, there is no consensus yet on whether and when system expansion is required for non energy co-products, and the approach that should be used where this is not possible. The outcomes of decision made at IPHE should be taken into account when making this decision.
- **Use of low carbon electricity** – we recommend allowing low carbon electricity based on traded activities such as power purchase agreements with cancellation of guarantees of origin or equivalent, which gives greater access to the scheme to routes with higher electricity use than other options. However, additional criteria for this option to mitigate potential risks are in development at UK and EU level, and so need to be reviewed once agreed to determine whether they are suitable for inclusion here.

- Treatment of **mixed inputs** – the option to have separate consignments or averaging, with average meeting a benchmark has a balance between flexibility and avoiding risk, however, this should be reviewed in the light of decisions made in RED II and the RTFO.

Other factors where the decision depends on the intended scheme in which the standard is used, or on decisions made in other UK policy mechanisms are:

- **Number of GHG thresholds** – setting multiple thresholds can support greater innovation, but comes with some added costs and complexity, so would only be recommended if UK policy schemes required the ability to support different levels of GHG savings through e.g. separated funding pots, tiers or (sub-)mandates.
- Low carbon electricity **additionality** - this decision needs to be taken by BEIS in the context of the overall policy landscape for renewable electricity in the UK, and based on the choices made on geographical scope, as options suitable for the UK alone may not be suitable or possible in other countries.
- **Treatment of ILUC emissions for biomass** – these should be included, but alignment is needed with DfT on reporting these separately (as in the RTFO) or including them.
- **Treatment of waste fossil feedstocks** – highly dependent on the scheme in which the standard is used, in terms of the trade off between reporting effort, accuracy and potential for change over time. Alignment with the approach agreed under the RTFO for recycled carbon fuels would be valuable.
- **Choice of GWP** – for gases other than hydrogen, this should be chosen based on current Government-wide policy in this area.
- **Use of low carbon gas** - it is important to align the approach taken here with that used in the RTFO and Green Gas Support Scheme, to ensure that additional biogas production is stimulated.
- **Details of the GHG threshold** – such as whether this should decrease over time, or leeway be given for certain older production plants. The approach to this will depend heavily on the intended scheme.

7 High-level delivery and administration

Summary

This section discusses at a high level the options and requirements for assurance, communication and claims, and governance. This is done at a high level because these aspects depend heavily on the way in which the standard is used, for example whether it is used to support a one-off assessment (such as eligibility for a capital grant) or used to support an ongoing certification scheme or policy mechanism. They also depend on the decisions made as a result of the information in Chapter 6.

The concept of assurance is introduced: demonstrable evidence that the requirements of the standard have been met. Assurance can have different levels of stringency, defined as reasonable or limited, which affect factors such as the type and frequency of verification (audits) and documentation for proof of compliance. There is a trade-off between the level of rigour and credibility versus the burden placed upon economic operators implementing the standard, and the number of participants. Options are discussed for the type and frequency of reporting and verification, and compared with the approach taken in other low carbon/renewable hydrogen standards. Lastly, options for governance of the standard are discussed: whether it would be delivered and administered by BEIS, as done for the RTFO by DfT, or by an independent industry-led or multi-stakeholder organisation.

7.1 Introduction

This section covers at a high level the options and requirements for assurance, communication and claims and governance. This is done at a high level because these aspects depend heavily on the way in which the standard is used, for example whether it is used to support a one-off assessment (such as eligibility for a capital grant) or used to support an ongoing certification scheme or policy mechanism. They also depend on the decisions made as a result of the information in Chapter 6.

It is important to note that a scheme supporting hydrogen may take into consideration attributes of hydrogen pathways other than their GHG emissions, such as renewability, use of advanced technology, or other attributes not considered in this study. If this is the case, a methodology for assessing these would need to be developed, and decisions made on assurance, communication and claims and governance would need to take into account the most appropriate approach for assessing whether a pathway met the other requirements, as well as those for the GHG methodology discussed above.

7.2 Assurance

7.2.1 Introduction

Assurance is a generic term used primarily in a standard/certification context to cover all the systems and procedures put in place to formally and accurately verify an entity's compliance with a given set of normative requirements. In its Assurance Code[50], the ISEAL Alliance defines assurance as:

"Demonstrable evidence that specified requirements relating to a product, process, system, person or body are fulfilled. (adapted from ISO 17000)."

The ISAE 3000 standard[51] defines two levels, which determine the stringency of assurance systems:

- "The objective of a reasonable assurance engagement is a reduction in assurance engagement risk[52] to an acceptably low level in the circumstances of the engagement as the basis for a positive form of expression of the practitioner's conclusion (i.e. evidence of compliance was found)."
- "The objective of a limited assurance engagement is a reduction in assurance engagement risk to a level that is acceptable in the circumstances of the engagement, but where that risk is greater than for a reasonable assurance engagement, as the basis for a negative form of expression of the practitioner's conclusion (i.e. no evidence of non-compliance were found)."

In the context of the Renewable Energy Directive recast (2018/2001), voluntary schemes seeking approval by the European Commission[53] are required to implement a limited assurance level, which 'implies a reduction in risk to an acceptable level as the basis for a negative form of expression by the auditor such as *"based on our assessment nothing has come to our attention to cause us to believe that there are errors in the evidence"*.

The decision to adopt a limited or a reasonable level of assurance has multiple implications on the standard's ability to remain aligned with the criteria defined in Section 0, which directly relate to:

- The type and frequency of verifications (audits). A reasonable assurance level would require more frequent audits, which are more resource intensive (e.g. number of auditors or experts in the audit team) and may evaluate compliance at a deeper level (e.g. type of evidence sought, sample sizes in case of group or multi-site certification, need for direct observations rather than self-declarations or desk-based verification) than in a limited assurance level. The type and frequency of verification are further explored in Section 7.2.2.

[50] ISEAL (2018) Assurance Code - https://www.isealalliance.org/sites/default/files/resource/2018-02/ISEAL_Assurance_Code_Version_2.0.pdf
[51] IFAC (2008) IFAE 3000 - https://www.ifac.org/system/files/downloads/2008_Auditing_Handbook_A270_ISAE_3000.pdf
[52] In this context, assurance engagement risk refers to the risk for assurance providers to come to erroneous conclusions.
[53] European Commission (2020) Assessment Protocol for Voluntary Schemes recognition - https://ec.europa.eu/energy/sites/default/files/assessment_protocol_template_redii_final.pdf

- Proofs of compliance used in reporting/verification of compliance:
  - Accepted documentation.
  - Period over which records are kept.
  - Transparency over procedures and audit reports (e.g. public summaries).
- Managing non-compliances and compliance decisions:
  - Definitions.
  - Consequences of non-compliance on the issuance of certificates (e.g. no effect, suspension, cancellation).
  - Modalities for corrective actions (time provided to address non-compliances, temporary certificate in the interim, etc.).
- The final decision over the overall compliance of an operator and, if relevant, delivery of a certificate, may be taken by the lead auditor or collectively by the audit team and the certification body management. Competence of assurance providers:
  - Minimum education/experience level required for lead auditors, auditors and experts.
  - Required accreditations at individual or organisational levels (e.g. IAF, ISO 17021/17065, ISAE 3000).
  - Ownership of development and implementation of training programs (standard owner vs assurance providers), content, frequency of standard-specific training, validation (e.g. exam, witness audit, etc.) and monitoring (e.g. yearly training).
  - Composition of verification teams (e.g. presence of a lead auditor, number of auditors, additional experts).
- Accreditation of assurance providers, i.e. formal process to deliver and maintain accreditation by an accreditation body vs assurance providers being designated and monitored directly by the standard owner.
- Grievance mechanisms. Assurance providers may implement a grievance mechanism whereby a third party may report potential non-compliance outside the verification process and/or provide additional evidence and documentation to the assurance provider. A resolution process for grievances should be developed and may escalate up to the standard owner under certain conditions.

Trade-offs exist between the level of rigour implemented in assurance systems and the burden placed upon the economic operators implementing the standard, especially compliance and certification costs, which could increase the price of compliant products. Assurance requirements perceived as being too loose will undermine the credibility of the standard, whereas assurance requirements perceived as being too stringent will limit the number of eligible participants and therefore reduce the overall impact of the standard. It is therefore important to find the right balance between an acceptable level of robustness and the attractiveness of the standard and its overall impact on GHG mitigation efforts.

The following sections further explore the different options for one of these topics - reporting/verification of compliance - based on the five case studies.

7.2.2 Type and frequency of reporting and verification

The verification of compliance with GHG calculations, chain-of-custody requirements, claims/labelling rules and other criteria covered in a hydrogen standard can apply to a specific operation site (e.g. production unit, storage facility, hydrogen refuelling station, etc.), to a company operating several sites (vertical integration) or to a project, which could include a combination of production site and one or more end users (horizontal integration). The following elements need to be discussed and decided upon by the standard owner:

- The **responsibility for verification of compliance** can be handled directly by the standard owner or via approved/accredited assurance providers, including certification bodies or independent auditors. Verifications lead to a decision from the standard owner or assurance provider to confirm compliance/certification (with or without corrective measures) of an operation site, a company or a project. Should the verification of compliance be delegated to an accredited assurance provider, the standard owner should not take part in the compliance decision process (unless a grievance process is triggered, in which case the assurance provider may escalate a decision to the standard owner) but may collect information and data directly from economic operators for monitoring or communication purposes.
- The **type of verification** may include self-reporting, whereby the operators assess compliance of their own operations and report accordingly to the standard owner or assurance provider, who may conduct their own verification if needed. The standard owner or assurance providers may also verify and establish compliance independently through a desk-based verification/audit (verification of documentation and records provided by the operator) and/or on-site verification/audit, in which the verification of documentation and records is complemented by direct observations and investigations (e.g. adequate implementation of procedures, nature of chemical stocks, interviews with staff, etc.). Finally, the operator and assurance provider may use existing evidence from other certification processes to establish compliance through a formal recognition or equivalence. For example, ISCC recognises certification of other EU-approved biofuel schemes when they fulfil specific conditions[54]. Batches of product certified to the recognised schemes can therefore integrate ISCC's chain-of-custody without additional verification.
- The **frequency of verification/audit** should be established to reach a balance between the targeted level of assurance (see section 7.2.1) and the avoidance of unnecessary effort and costs for the operators. An operation site, company or project may undergo an initial verification of compliance, based on planned data, which can be used to assess which projects could receive a certificate and/or specific support (e.g. funds); surveillance verifications/audits could then be organised on a regular basis (e.g. every year) to confirm or suspend certification, in case non-compliance are found. As an

[54] ISCC (2021) Acceptance of other schemes - https://www.iscc-system.org/process/acceptance-of-other-schemes/

alternative, ongoing reporting and auditing of the project can be conducted to enable monitoring over time of whether the threshold is met, compliance claims and the downstream transfer of product documentation for different consignments of hydrogen.

7.2.3 Reporting/verification options for a low carbon hydrogen standard

Case studies reveal different models for the reporting/verification of compliance, particularly around whether consignments of hydrogen are verified, or the project as a whole, and around who needs to verify the information provided:

- In CertifHy, an initial on-site audit is conducted of the production facility and its equipment, followed by surveillance audits every five years. In addition, “batches” (i.e. consignments) of hydrogen production must be defined (the exact size of a consignment is freely defined by the operator); every consignment must be reported by the operator and verified by an independent auditor approved by CertifHy at a frequency, which shall not exceed 12 months.
- In TÜV SÜD, audits are conducted annually by an independent certification body holding a valid accreditation from the European Union, to ISO 17065 or an equivalent standard.
- In RTFO, operators may enter the scheme, following a verification by DfT of compliance with the scheme’s requirements and, possibly, a site visit. Operators must self-report every consignment of product to RTFO, on frequency varying between a month and a year. Claims must be verified, but first-party audits (e.g. by the company’s accountant) are accepted. As an alternative, operators may use certificates issued by an EU-approved scheme as proof of compliance, in which case no further check is required by DfT.
- In order for CARB to allow an operator to generate LCFS credits, quarterly reports of fuel transactions and annual fuel pathways records must be submitted to CARB, following a verification and validation by a CARB-approved third-party verification body. CARB’s Executive Officer or his designees may review and audit the credits generated by operators upon reporting.

The above examples can be summarised as follows:

- **Option A (Self reporting):** the standard owner conducts verifications and makes decisions on compliance and issuance of certificates. Operators are required to self-report on each product consignment or quarterly and bear the cost for self-reporting. The standard owner may conduct, at its own cost ,desk-based or on-site verifications of operation sites, consignments of products or claims whenever required.
- **Option B (Annual third-party verification):** the standard owner delegates verification of compliance to accredited certification bodies, which take compliance and certification decisions. A systematic desk-based or on-site verification/audit of operation sites, consignments of products or claims are conducted on an annual basis, which are paid for by the economic operators. No self-reporting is required on consignments.

- **Option C (Annual third party verification + consignment reporting):** A verification/audit of the operation site(s) is conducted every year, but consignments of products must be reported and independently verified by an approved auditor at a defined frequency (depending on batch size), which must be at least once a year. All costs are covered by the economic operator.

In any of these cases, public support for compliance and verification could be provided, particularly for smaller operators. The following table summarises the possible approaches to the verification type and frequency against the criteria defined in Section 0.

Table 25: Options for verification types and frequency

Option	Option A Self reporting, including for consignments	Option B Annual third party verification	Option C Annual third party verification + consignment reporting
Inclusive	**Amber:** Limited inclusiveness – more demanding for technologies for which small consignments would require more frequent reporting.	**Green:** Inclusive – this type and frequency of verification apply to any existing or new technology.	**Amber:** Limited inclusiveness – more demanding for technologies for which small consignments would require more frequent reporting.
Accessible	**Green:** Accessible – self-reporting costs are lower than for independent audits.	**Amber:** Limited accessibility – cost of independent audits is significant.	**Amber:** Limited accessibility – cost of independent audits and verification of consignments is significant.
Transparent	**Green:** Transparent – the standard owner may disclose reports, within confidentiality limits.	**Amber:** Limited transparency, unless audit reports are published, within confidentiality limits.	**Amber:** Limited transparency, unless audit reports are published, within confidentiality limits.
Compatible	**Amber:** Limited compatibility – compatible with RTFO, but not with EU RED.	**Amber:** Limited compatibility – compatible with EU RED, but not with RTFO.	**Green:** Compatible with RTFO and with EU RED.
Ambitious	**Green:** No impact	**Green:** No impact	**Green:** No impact
Accurate	**Amber:** Limited accuracy due to the absence of systematic verification of GHG emissions by an independent verifier.	**Amber:** Limited accuracy due to the frequency of audits (annual).	**Green:** Accurate due to the combination of an independent verification of batches with a high frequency.
Robust	**Red:** Lack of robustness due to the acceptance of self-declaration and first-party audits.	**Green:** Robust – verification is conducted by an accredited and independent certification body.	**Green:** Robust – verification is conducted by an accredited and independent certification body.
Predictable	**Green:** No impact	**Green:** No impact	**Green:** No impact

Conclusion: An important trade-off exists between the accessibility (Option A) and robustness of a hydrogen standard (Option B or C). The use of systematic independent audits by approved or accredited assurance providers (e.g. certification bodies) is generally seen as a good practice to ensure the credibility and robustness of a standard (e.g. in ISEAL Assurance Code[55]), which would be further reinforced by a reporting obligation over consignments of products, which would also be verified independently, as in Option C. The definition of a consignment could, however, be more stringent than in CertifHy by setting a maximum size.

7.3 Communication and claims

Following the successful completion of a verification process by an official entity (e.g. a third party audit by an accredited certification body), compliant operators are allowed to communicate to their direct customers (B2B) and/or end-users (B2C), for example by using off-product and on-product claims. On-product claims may be accompanied by an official label owned by the standard owner. Claims are particularly important for the successful uptake of the standard, as they reward compliant economic operators with the ability to distinguish themselves to customers and end-users and obtain commercial benefits, which offset compliance costs. Consequently, strict rules must be applied and monitored as part of the assurance process for both on-product and off-product claims to ensure that only compliant operators benefit from these.

Communication and claims rules include:

- Allowed off-product claims, i.e. general communication by the organisation regarding its compliance with the low carbon hydrogen standard.
- The exact on-product claim allowed to be attached to the physical product (e.g. a consignment of low GHG hydrogen), including the type of chain-of-custody system used.
- The mechanism for verification of claims by assurance providers, for example by analysing samples of claims at a set frequency to detect possible misuse or unsubstantiated claims.
- The modalities whereby incorrect or unsubstantiated claims are addressed by the standard organisation and/or assurance providers, including through corrective actions by the operator and/or the potential suspension of certificates.
- The conditions of use of a label (if relevant) or labels, if the standard owner decides to use different labels to reflect the nature of consignments or their GHG emissions level.

[55] ISEAL (2018) Assurance Code - https://www.isealalliance.org/sites/default/files/resource/2018-02/ISEAL_Assurance_Code_Version_2.0.pdf

7.4 Governance

Governance relates to the development, maintenance and continuous improvement of a low carbon hydrogen standard. Defining proper rules for governance is important to ensure that the technical content of the standard remains up to date and in line with the state-of-the-art in GHG accounting and hydrogen supply chains. Clear governance rules are also required to ensure transparency and credibility of the standard. Such rules include, but are not limited to the following questions:

- **Who can deliver and administer the standard?** The standard may be delivered and administered by BEIS, which would ensure a higher level of coherence with other related policies, especially support schemes (e.g. subsidies); it could also ensure some balance between sustainability aspirations and economic stakes. As an alternative, the standard could be delivered and administered by an independent industry-led organisation. The main benefit would be for the standard to be implemented in a business-friendly manner and in line with the practical and economic constraints of the private sector, but with a risk to the credibility and neutrality of the standard. A third option would be for the standard to be delivered and administered by a multi-stakeholder entity to ensure a higher level of independence and neutrality, but with multi-stakeholder participation (see below) to ensure a balance of interests.
- **How would BEIS interact with an independent standard owner?** BEIS can approve or endorse a low carbon hydrogen delivered and administered by an independent organisation. Such approval or endorsement should be framed by clear and transparent rules so that BEIS keeps control over the policy scheme. In the context of biofuels and bioliquids under EU RED II, the European Commission delegates *de facto* the implementation of sustainability and traceability rules to independent organisations (voluntary schemes). Stringent rules are established, in addition to the content of RED II, before recognition is granted to a voluntary scheme. Once recognition is granted, voluntary schemes must report on activities every year and implement a grievance mechanism whereby the Commission has the possibility to flag any irregularity or potential non-compliance to the scheme and require them to act upon it. Whenever the legislation changes, either through the revision of the Directive or the enforcement of delegated acts, voluntary schemes are required to update their standards accordingly and implement these changes.
- **Who can participate in governance?** The development, maintenance and continuous improvement of the standard may be open to the participation of external stakeholders, e.g. private sector, civil society organisations, academics. Contributions from external stakeholders bring in more expertise and experience of practical implementation; they also enhance transparency and the legitimacy of the standard among potential users.
- **How can the standard be revised?** The frequency and mechanism to trigger new standard development or the revision of existing documents should be defined.

For reference, the RTFO is operated by DfT, whose team is allowed to proceed with minor modification of the guidance documents and to make decisions regarding the eligibility of a fuel route for RTFCs. Major decisions over the content of the standard include consultation with external stakeholders. In most “roundtable” standard setups (e.g. Forest Stewardship Council, Roundtable on Sustainable Biomaterials, Round Table for Responsible Soy, Better Cotton Initiative, etc.), important changes in sustainability or traceability requirements are decided by a general assembly of members, primarily through consensus. Modifications of other types of requirements (e.g. assurance, communication, etc.) generally follow a simplified and quicker procedure (e.g. through validation by a steering board), while minor modifications are made at the discretion of the executive body of the organisation.

8 Recommended next steps

Summary

This final section discusses the recommended next steps for BEIS following publication of this report. This includes BEIS leading a process to consult more widely with stakeholders, to finalise the low carbon hydrogen standard design, to revise the GHG emission estimates and set the final GHG threshold(s), before further work to operationalise the new scheme. In parallel, inter-department and international discussions should be held to ensure alignment between schemes where required, and further research supported to reduce uncertainties regarding hydrogen emissions estimates.

With the delivery of this report and accompanying Excel tool, BEIS may use the findings of this study to inform ongoing internal thinking on the design of low carbon hydrogen policies, plus the design of accompanying standards and assurance activities.

There are a set of recommended next steps for BEIS in order to finalise the low carbon hydrogen standard:

- The first step is publication of this study, to inform stakeholders of the various options for a UK low carbon hydrogen standard, their relative merits and potential impact on different hydrogen routes.
- As we have not consulted widely with the industry during this study, we recommend that BEIS consult with stakeholders on the key questions from this study.
- Confirmed UK policy designs to support low carbon hydrogen will inform the choices to be made regarding the accompanying low carbon hydrogen standard and assurance activities, as the confirmed policy designs may rule some options out or may make some options more suitable.
- BEIS will then be able to take a series of decisions to narrow down the remaining options to one choice for the design of the standard.
- Once the GHG methodology and system boundary choices have been decided for the standard, the GHG emissions calculations in this study should be revised to match the final methodology and system boundary. This is important, as there could be significant changes in the GHG emissions of some routes depending on the final choices made.
- The levels and distribution of resulting GHG emissions from the routes within this study, and any other routes that BEIS add to the analysis, can be used to set the GHG threshold(s) within the new low carbon hydrogen standard.
- Further development work would then commence to translate the final standard into an operational scheme within the chosen policy/policies, including derivation of any default values to be used, and setting up of the required assurance activities.

While this design finalisation process is ongoing, there are two further sets of activities recommended for BEIS:

- To continually engage with other UK policy teams (e.g. RTFO), as well as internationally (e.g. IPHE), to ensure alignment with other schemes where needed.
- To continue to support research focused on the reduction of uncertainties relating to hydrogen lifecycle GHG emissions. This could include further work on:
  - Embodied emissions, understanding their level and distribution in a UK context, and how these emissions can be mitigated or will fall with UK and global decarbonisation.
  - Improving estimates of upstream gas supply emissions and how these may change over time given shifting domestic and imported supply mixes.
  - Quantifying the impact of including upstream fuel supply emissions within UK grid electricity factors.
  - Updated indirect land use change estimates for biomass feedstocks.
  - Waste fossil feedstock counterfactual emissions and their likely change over time.
  - Improving estimates of hydrogen and other gas leakage rates from downstream infrastructure, including any transport, storage, purification, compression and dispensing steps.
  - Improving estimates of unused fugitive hydrogen released in different end use applications, plus other ‘in use’ emissions.
  - The global warming potential associated with fugitive hydrogen, and how this might be accounted for within UK policy and national inventories.

Appendix A – Data collection

Foreground data for production pathways

When building the foreground data set, three scenarios were defined for each production pathway: Central, Best and Worst. The scenarios are defined based on the choice of feedstocks, process efficiencies and CO_2 capture rates of the chains. Best represents a scenario with the highest process efficiency and capture rates and lowest impact feedstocks; worst represents a scenario with the lowest process efficiency, lowest capture rates and highest impact feedstocks; and central represents an in-between set of values. In some cases, no technological differences were modelled between the different scenarios, and therefore process efficiencies, as well as carbon rates and other inputs and outputs, remain the same.

Data availability and certainty varies across chains. Table 26 provides a high-level assessment of the data availability for each chain, with red highlighting the most uncertain data, green the most certain data, and amber highlighting some uncertainties.

Table 26: High-level data availability for each hydrogen production pathway

Production pathway	Feedstock	Production process
Grid Electrolysis	**Green:** Data provided by BEIS	**Green:** Data from Element Energy and Ecoinvent
Renewable Electrolysis	**Green:** No impact	**Green:** Data from Element Energy and Ecoinvent
Nuclear Electrolysis (high temperature)	**Green:** Modelled using JEC WTT V5	**Green:** Data from Element Energy and Ecoinvent
Chlor-alkali Electrolysis	**Green:** Data provided by BEIS	**Amber:** Three chlor-alkali chains modelled from Herrero et al. (2016)
Biomethane ATR with CCS	**Green:** Food waste and maize biogas to biomethane from JRC (2017)	**Amber:** Efficiency data, power inputs and carbon capture rates from Element Energy. Some assumptions required.
Forestry residues Gasification with CCS	**Green:** Data from JEC WTT v5	**Amber:** Data from ETI BCVM. Some assumptions required.
Residual waste Gasification with CCS	**Green:** DUKES data for biogenic/fossil fraction of residual waste	**Red:** Progressive Energy study only data found.
Natural Gas ATR with CCS	**Green:** Data from Oil & Gas Authority, split using Balcombe et al. (2017)	**Amber:** Efficiency data, power inputs and carbon capture rates from Element Energy. Some assumptions required.
Natural Gas SMR with CCS	**Green:** Data from Oil and Gas Authority, split using Balcombe et al. (2017)	**Green:** Data from JEC WTT v5
Natural Gas SMR (no CCS)	**Green:** Data from Oil and Gas Authority, split using Balcombe et al. (2017)	**Green:** Data from JEC WTT v5

Foreground data for each production pathway are discussed in greater detail in the sections that follow below, including any specific assumptions made in relation to the individual chains. It is assumed that the outlet hydrogen produced from all production pathways is at least 99.9% purity with a pressure of 3 MPa. Note that all inputs and efficiencies are given/calculated on an LHV basis, unless otherwise stated.

Production: Low temperature electrolysis

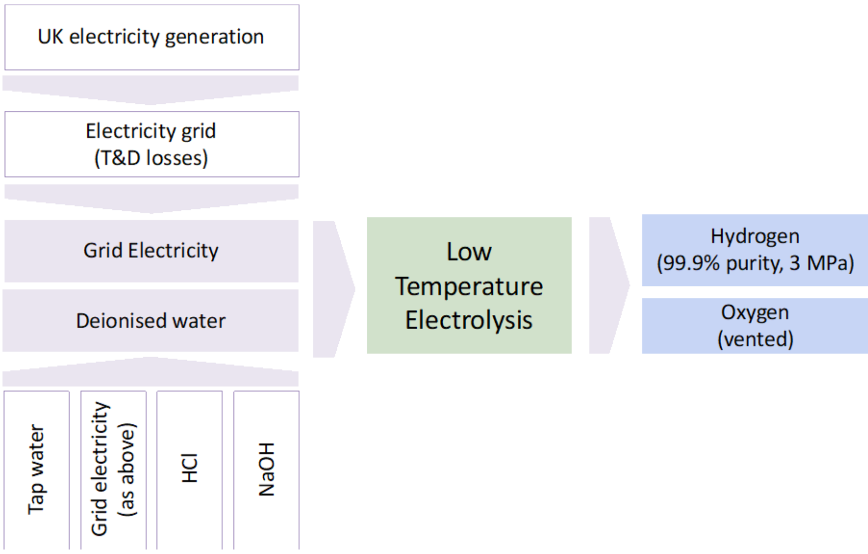


Figure 24: Low temperature electrolysis using grid electricity

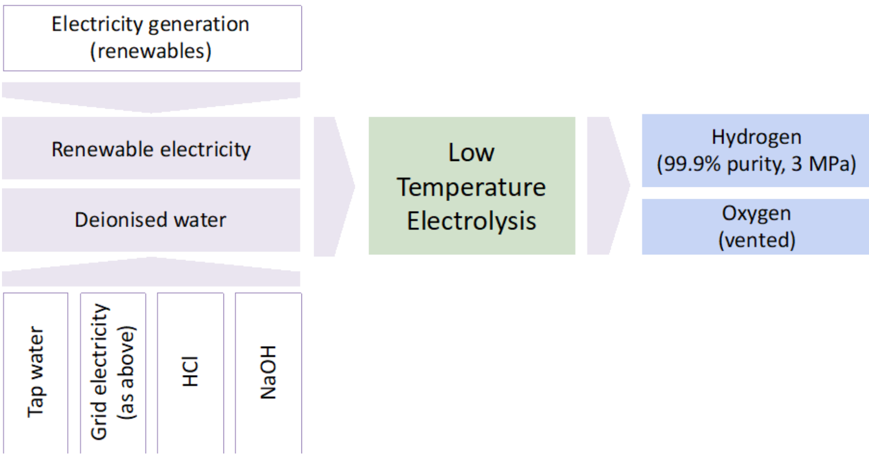


Figure 25: Low temperature electrolysis using renewable electricity

Low temperature electrolysis using both grid electricity and renewable electricity are modelled from the same datasets. The electrolyser efficiency data is from Element Energy (2018)[56], converted to LHV, with the following scenarios:

- **Central:** Alkaline 'Base' data, with an efficiency of 65% in 2020, increasing to 69% by 2050
- **Best:** PEM Lower, with an efficiency of 69% in 2020, increasing to 74% by 2050

[56] Element Energy (2018) Hydrogen supply chain evidence base. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

- **Worst:** PEM Upper, with an efficiency of 52% in 2020, increasing to 65% by 2050

It is worth noting that electrolyser efficiencies vary significantly with load, as does the relative parasitic load of running auxiliary systems onsite. The water input of 20 litres per kg of hydrogen required for electrolysis is based on Element Energy (2018).[56] However, this water needs to be deionised, and data from Ecoinvent v2[57] was used to estimate the inputs required. Tap water is assumed to be deionised. However, other water sources could be used, e.g. grey water, river water etc., but these would require greater treatment than those assumed for tap water deionisation.

Production: High temperature electrolysis

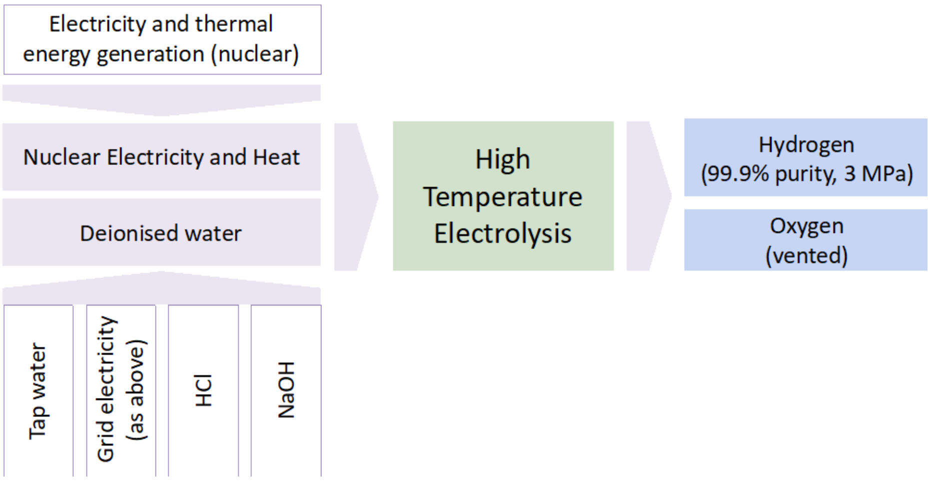


Figure 26: High temperature electrolysis using nuclear electricity & heat

High temperature electrolysis is modelled as being adjacent to a nuclear power plant, taking nuclear electricity as well as waste heat from the power plant. Solid oxide electrolyser efficiency data is from Element Energy (2018)[58], converted into LHV, using the following scenarios:

- **Central:** SOE Base, with an electrical efficiency of 85% in 2020 (combined heat and electrical efficiency 63%), increasing to 95% by 2050 (combined heat and electrical efficiency 72%)
- **Best:** SOE Lower, with an electrical efficiency of 90% in 2020 (combined heat and electrical efficiency 74%), increasing to 98% by 2050 (combined heat and electrical efficiency 81%)
- **Worst:** SOE Upper, with an electrical efficiency of 83% in 2020 (combined heat and electrical efficiency 60%), increasing to 90% by 2050 (combined heat and electrical efficiency 65%)

It is worth noting that electrolyser efficiencies vary significantly with load, as does the relative parasitic load of running auxiliary systems onsite. High temperature electrolysis systems also have much longer ramp-up/ramp-down response times than low temperature electrolysis

[57] Ecoinvent v2.0 (2007) Life Cycle Inventories of Chemicals. Available at: https://db.ecoinvent.org/reports/08_Chemicals.pdf
[58] Element Energy (2018) Hydrogen supply chain evidence base. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

systems, and are therefore generally not considered well suited to load-follow variable renewable power generation. Water inputs are assumed to be the same as for low-temperature electrolysis.

Production: Chlor-alkali

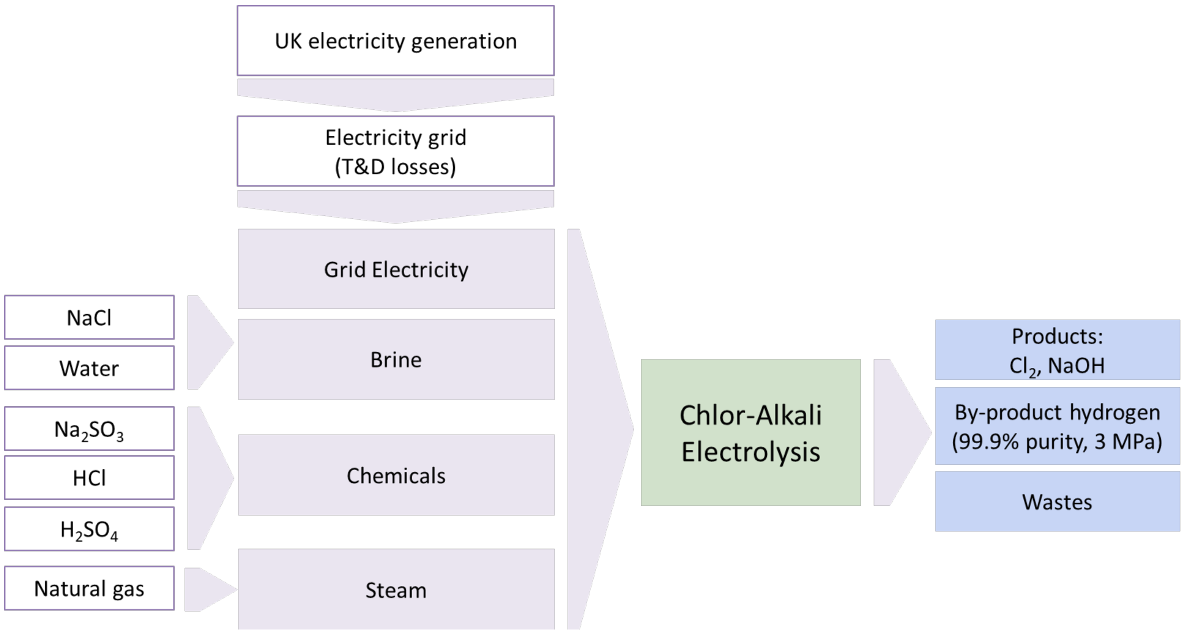


Figure 27: Chlor-alkali electrolysis using grid electricity, producing by-product hydrogen

The inputs and outputs required to model the chlor-alkali process are from Herrero et al. (2016[59]), who provide data on different chlor-alkali production processes. For the GHG assessment the following chlor-alkali production systems are modelled for each scenario:

- **Central**: Scenario 1 from Herrero et al. (2016), which represents a mercury based technology – currently the most common chlor-alkali production method.
- **Best**: Scenario 2 from Herrero et al. (2016), which models a membrane technology in a bipolar configuration. This was selected as the best scenario, as it has a lower steam demand than the worst scenario (and so lower natural gas demand), and of all the chains has the lowest electricity demand.
- **Worst**: Scenario 3 from Herrero et al. (2016), which models an asbestos-free diaphragm technology. This was selected as the worst scenario due to it having the highest steam demand (and so highest natural gas demands) of the three production methods from the study.

Herrero et al. (2016) do not provide a pressure for the outlet hydrogen that is produced. However, in GREET (2017)[60], they estimate that hydrogen from the chlor-alkali process has an outlet pressure of 0.131 MPa. Therefore using the equation also provided in GREET (2017), compression requirements to pressurise the hydrogen to 3 MPa were estimated. The data

[59] Herrero et al. (2017) Environmental challenges of the chlor-alkali production: Seeking answers from a life cycle approach. Available at: https://www.sciencedirect.com/science/article/abs/pii/S0048969716323932
[60] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.

provided by Herrero et al. (2016) indicates that the outlet hydrogen has a purity of at least 99.9%.

As discussed in Section 5.1.6, the chlor-alkali process produces sodium hydroxide and chlorine. An economic allocation was used to allocate production impacts between the different products. Table 27 provides the economic values assumed for each product in the different scenarios.

Table 27: Economic value of hydrogen, chlorine and sodium hydroxide

	Hydrogen €/kg	Chlorine €/kg	Sodium hydroxide €/kg	Reference
Central	1.63	0.16	0.34	Eurostat, EU 28 (2015-2019)[61]
Best	1.64	0.63	0.34	Eurostat, EU 27 (2015-2019)
Worst	1.69	0.16	0.22	Khasawneh et al. (2019)[62]

Production: Biomethane ATR with CCS

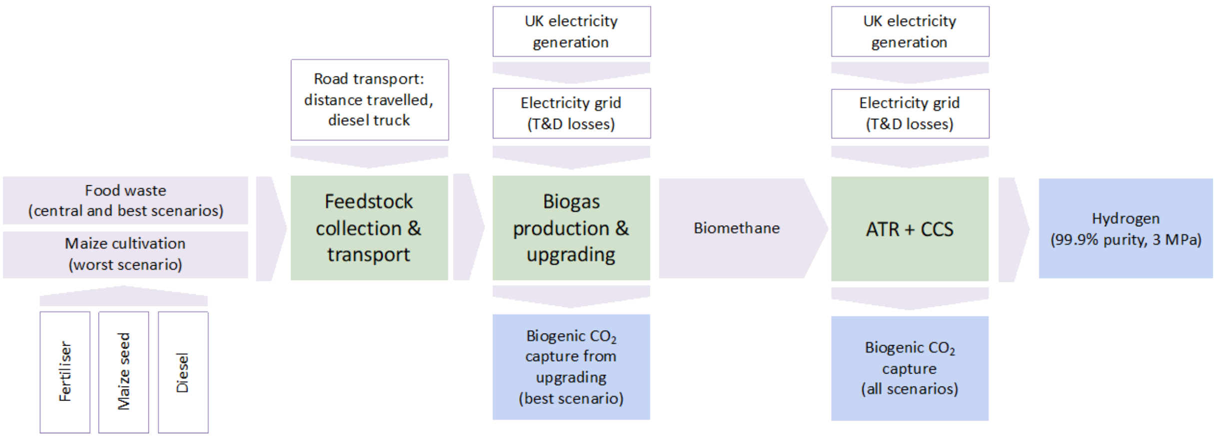


Figure 28: Biomethane ATR with CCS using food waste or maize biogas feedstocks (dependent on the scenario)

The feedstock for biogas production in the central and best scenarios is food waste, while it is whole maize crop for the worst case (requiring seed, fertiliser and diesel inputs for cultivation and harvesting activities). Data on feedstock collection and transportation for food waste and maize is from JEC (2020)[63]. Data on biogas production from the different feedstocks and upgrading to biomethane is from the JEC (2020).

[61] Eurostat (n.d.) Sold production, exports and imports by PRODCOM list (NACE Rev. 2) – annual data. Available at: https://ec.europa.eu/eurostat
[62] Khasawneh et al. (2019) Utilization of hydrogen as clean energy resource in chlor-alkali process. Available at: https://journals.sagepub.com/doi/pdf/10.1177/0144598719839767
[63] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

In the best case scenario only, the CO_2 released from upgrading is assumed to be captured and stored, with an assumed capture rate of 95%. Electricity requirements of 425 MJ_e/tCO_2 required for CO_2 compression, pipeline transportation and injection are estimated from Koornneef et al (2008)[64]. However, the volume of biogenic CO_2 emissions from biogas upgrading available for CO_2 capture is not reported in the JEC dataset (2020). Therefore, these are calculated by assuming a 60% CH_4:40% CO_2 biogas composition (by volume) and a biogas LHV of 17.75 MJ/kg.

The biomethane is assumed to be transported by pipeline to the ATR facility. It is assumed to be transported on the low pressure distribution network, and therefore needs to be compressed before being fed to the ATR. Compression requirements are provided in JEC (2020).

Data on the power requirements and efficiency of the ATR facility are from Element Energy (2018)[65], assuming the following for each scenario[66]:

- **Central:** ATR with external power input, with an energy efficiency of 78% held from 2020 to 2050
- **Best:** ATR and GHR with external power input, with an energy efficiency of 84% held from 2020 to 2050
- **Worst:** Self-sufficient ATR (generates own power, with efficiency impact), with an energy efficiency of 68% held from 2020 to 2050

The biogenic CO_2 generated is calculated based on the combustion emissions of biomethane, from BEIS (2020)[67], and the efficiency of the ATR. These are calculated directly in the LCA tool, and therefore any changes to process efficiency will change the biogenic CO_2 generated per MJ H_2 output. However, it should be noted that the impacts of changing the capture rate on e.g. process efficiency are not included within the model, as this involves more detailed process engineering, which is outside of the scope of this work.

In this chain, the biogenic CO_2 produced at the ATR plant is assumed to be captured in all scenarios, with capture rates of 95.0-95.7% based on Element Energy (2018)[68] – wider capture rate range sensitivities are explored in Section 5.4.

[64] Koomneef et al. (2008) Life cycle assessment of a pulverised coal power plant with post combustion capture, transport and storage of CO2. Available at: https://www.sciencedirect.com/science/article/abs/pii/S1750583608000571

[65] Element Energy (2018) Hydrogen supply chain evidence base. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/60479/H2_supply_chain_evidence_-_publication_version.pdf

[66] The ATR+CCS configuration with external power input has a significantly higher process efficiency (higher MJ H_2/MJ gas) than the configuration without external power input, because the self-sufficient plant has to burn some of the natural gas/process flows onsite to generate its own heat and power needs. The lower efficiency of the self-sufficient ATR plant means more upstream fossil gas emissions and therefore higher gCO_2e/MJ H_2 than the external power configuration (even once accounting for the grid power input in 2020, the highest grid intensity year). The Best/Central/Worst scenarios are chosen on the ordering of the resulting hydrogen emissions – they are not chosen based on the electricity consumption.

[67] BEIS (2020) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

[68] Element Energy (2018) Hydrogen supply chain evidence base. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/60479/H2_supply_chain_evidence_-_publication_version.pdf

Electricity requirements of 425 MJ_e/tCO_2 for CO_2 compression, pipeline transportation and injection into geological storage is estimated using data from Koornneef et al. (2008)[69]. This used for all chains which store CO_2 for consistency.

The outlet pressure of the hydrogen from the ATR is assumed to be 2 MPa, in line with the outlet pressure from an SMR plant. Therefore, electricity requirements for hydrogen compression to 3MPa are estimated from GREET (2017)[70].

Production: Wood gasification with CCS

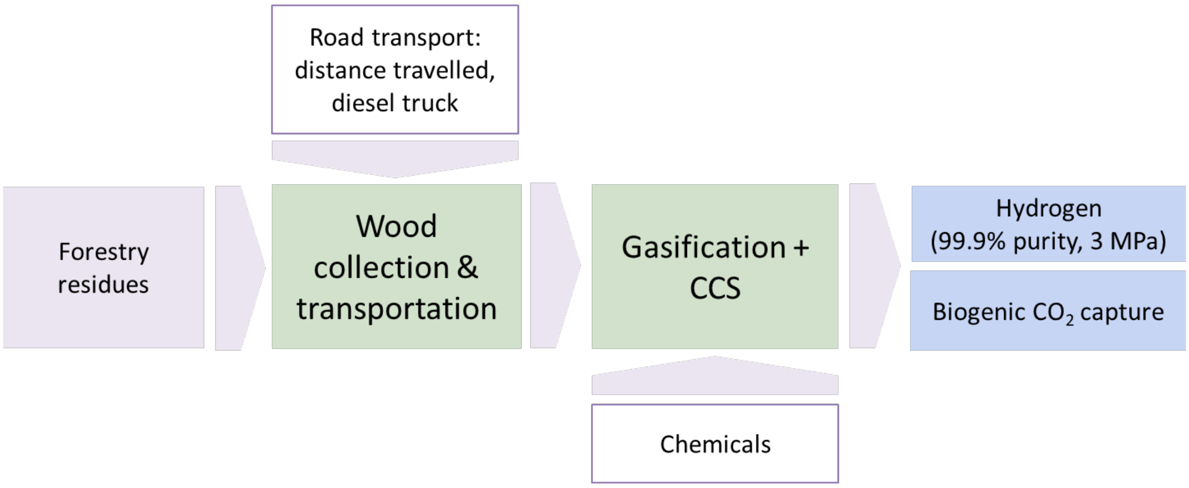


Figure 29: Forestry residue gasification with CCS

Data for forestry residue collection, seasoning and chipping is sourced from JEC WTT v5. The moisture content is assumed to be 30% once chipped. The wood is then transported 250 km (central scenario), 200 km (best) or 500 km (worst) by truck to the gasification plant – based on scenarios developed by the JRC (2017)[71]. Different transport range sensitivities are explored in Section 5.4.

The wood is then assumed to be gasified in a self-sufficient plant, which therefore does not require any electrical input or oxygen input. The efficiency of the gasification unit is based on data developed for the ETI's BCVM model as used in the ETI's ESME model[72], and is as follows for each scenario:

- **Central:** 52% energy efficiency in 2020, increasing to 54% by 2050
- **Best:** 52% energy efficiency in 2020, increasing to 57% by 2050
- **Worst:** 50% energy efficiency in 2020, increasing to 53% by 2050

[69] Koornneef et al. (2008) Life cycle assessment of a pulverised coal power plant with post combustion capture, transport and storage of CO2. Available at: https://www.sciencedirect.com/science/article/abs/pii/S1750583608000571
[70] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.
[71] JRC (2017) Definition of input data to assess GHG default emissions from biofuels in EU legislation: Version 1c – July 2017. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/definition-input-data-assess-ghg-default-emissions-biofuels-eu-legislation-version-1c-july
[72] ETI (2021) ESME, available dataset for download at: https://www.eti.co.uk/programmes/strategy/esme

Chemicals requirements are assumed to be the same as for the waste gasification plant (see next section). Biogenic CO_2 emissions are calculated based on the combustion emissions of woodchips from BEIS (2020)[73], and the efficiency of the gasification plant. These are calculated directly in the LCA tool, and therefore changes to process efficiency will change the total biogenic CO_2 emissions.

In this chain, the biogenic CO_2 is assumed to be captured. The capture rate is varied between the different scenarios, with the central scenario assuming an 95% capture rate, best 97% and worst 90%. The captured biogenic CO_2, as well as the remaining biogenic CO_2 emissions, are calculated directly in the LCA tool, allowing for the capture rate to be directly changed within the LCA tool. However, the impacts of changing the capture rate on e.g. process efficiency are not included within the model.

The impacts related with CO_2 capture and storage fall within the system boundary of this chain. Electricity requirements of 425 MJ_e/tCO_2 for CO_2 compression, pipeline transportation and injection into geological storage is estimated using data from Koornneef et al. (2008)[74].

Production: Waste gasification with CCS

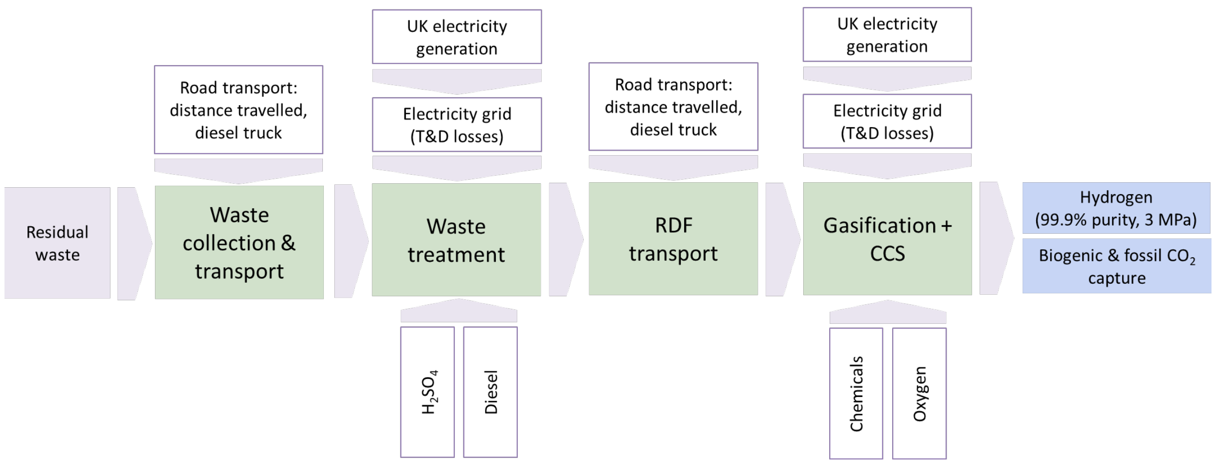


Figure 30: Residual waste gasification with CCS

Data on the LHV split of biogenic (49%) and fossil (51%) fractions of residual waste in the UK is from DUKES (2020)[75]. The moisture content of the residual waste is assumed to be 70% and needs to be dried to ~15%. The input requirements to dry the waste and produce a refuse derived fuel (RDF) are from the Biomass and Biogas Carbon Calculator (B2C2), with power use by far the largest input, accompanying by minor use of diesel in feedstock handling.[76] The central and best cases for waste treatment are based on aerobic digestion, whereas the worst case is based on bio-drying.

[73] BEIS (2020) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting
[74] Koornneef et al. (2008) Life cycle assessment of a pulverised coal power plant with post combustion capture, transport and storage of CO2. Available at: https://www.sciencedirect.com/science/article/abs/pii/S1750583608000571
[75] Digest of United Kingdom Energy Statistics (DUKE) (2020) Table 6.1 Renewable sources of energy commodity balances 2019. Available at: https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2020
[76] Biomass and Biogas Carbon Calculator (B2C2). Available at: https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator

The waste gasification process modelled is based on data from Progressive Energy (2017)[77]. The data source indicates the power requirement, oxygen requirement and CO_2 generated per MWh of hydrogen. It also provides the total GHG impact of chemicals per unit of hydrogen, which has also been included in the LCA tool. The study does not provide the moisture content of the RDF, but does also use the B2C2 calculator to estimate the impacts of producing the RDF.

In this chain, most of the generated CO_2 is assumed to be captured. The capture rate is varied between the different scenarios, with the central scenario assuming an 95% capture rate, the best 97% and the worst 90%. As the feedstock is mixed, the generated CO_2 is assumed to have the same fossil/biogenic split as the incoming feedstock. The captured fossil and biogenic CO_2, as well as the emitted biogenic and fossil CO_2, are calculated directly in the LCA tool, allowing for changes in capture rate and biogenic/fossil content to be made within the model.

The impacts related with CO_2 capture and storage fall within the system boundary of this chain. Electricity requirements of 425 MJ_e/tCO_2 for CO_2 compression, pipeline transportation and injection into geological storage is estimated using data from Koornneef et al. (2008)[78].

Production: Natural gas ATR with CCS

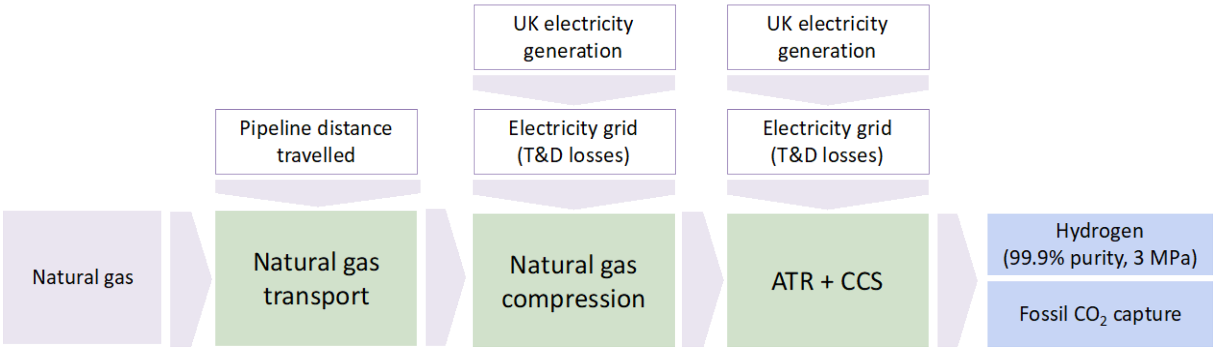


Figure 31: Natural gas ATR with CCS

The ATR + CCS process is the same as described in the Biomethane ATR with CCS section. The same efficiencies and capture rates are assumed. The only differences is the CO_2 is fossil as opposed to biogenic, and therefore CO_2 captured does not generate negative emissions and CO_2 released to atmosphere generates GHG impacts.

While the combustion emissions of natural gas are important, the upstream emissions related to natural gas extraction, processing and transportation can also be significant. These upstream emissions will vary by reserve type, technologies used for extraction and processing, transportation distances among other factors. Further, losses of natural gas during extraction, processing and transportation can result in significant GHG impacts, due to the higher GWP of

[77] Progressive Energy (2017) Biohydrogen : Production of hydrogen by gasification of waste.
[78] Koornneef et al. (2008) Life cycle assessment of a pulverised coal power plant with post combustion capture, transport and storage of CO2. Available at: https://www.sciencedirect.com/science/article/abs/pii/S1750583608000571

methane compared to CO_2. Figure 32 illustrates different upstream natural gas values from the Oil and Gas Authority (OGA)[79], the CCC[80] and Balcombe et al. (2017)[81].

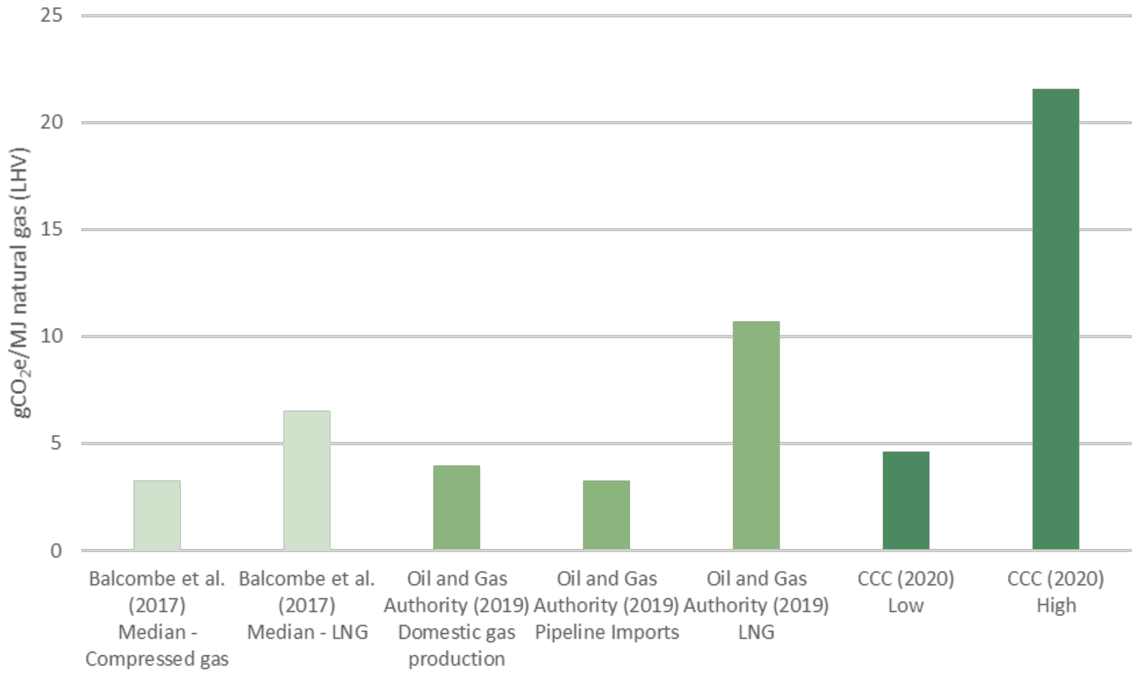


Figure 32: Impacts from upstream natural gas extraction, processing and transport

Data from the Oil and Gas Authority[82] was used, as it best reflects the UK context. The following natural gas upstream emissions were assumed by scenario:

- **Central**: weighted average of domestic natural gas production, imported natural gas by pipeline and LNG sources, based on their relative 2019 consumption in the UK.
- **Best**: imports of natural gas by pipeline.
- **Worst**: LNG. Note that this represents a weighted average of the LNG imported to the UK in 2019, taken from a much wider range (as shown, for example by the CCC (high) figure which represents LNG from countries with particularly high LNG emissions intensities). This range highlights the need to use as specific data as possible, as discussed in 0.

However, as mentioned above, any methane losses over the chain can have a significant impact on the final GHG emissions. Further, the net CO_2e impact of methane is dependent on the GWP scenario used. Therefore, as the GWP can be changed in the LCA tool, the CO_2e impacts derived from OGA have been split into CO_2 and CH_4 emissions, using indicative values from Balcombe et al. (2017):

- **Central:** 68% of CO_2e impact arising from CH_4

[79] Oil & Gas Authority (2019) Emissions Intensity Comparison of UKCS Gas Production and Imported LNG and Pipelined Gas. Available at: https://www.ogauthority.co.uk/the-move-to-net-zero/net-zero-benchmarking-and-analysis/natural-gas-carbon-footprint-analysis/
[80] CCC (2020) The Sixth Carbon Budget: Methodology Report. Available at: https://www.theccc.org.uk/publication/sixth-carbon-budget/
[81] Balcombe et al. (2017) The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions. Available at: https://pubs.acs.org/doi/abs/10.1021/acssuschemeng.6b00144
[82] Oil & Gas Authority (2019) Emissions Intensity Comparison of UKCS Gas Production and Imported LNG and Pipelined Gas. Available at: https://www.ogauthority.co.uk/the-move-to-net-zero/net-zero-benchmarking-and-analysis/natural-gas-carbon-footprint-analysis/

- **Best:** 56% of CO_2e impact arising from CH_4
- **Worst:** 22% of CO_2e impact arising from CH_4 (NB this case is based on LNG, which has greater electricity and transport fuel requirements compared to other natural gas chains)

In the model, CO_2 emissions and CH_4 emissions are entered in the foreground data for each scenario. Table 28 outlines the amount of each pollutant by scenario, and the calculated GHG impact, using a GWP of 34 for methane.

Table 28: CO_2, CH_4 and CO_2e emissions for upstream natural gas extraction, processing and transport

Scenario	gCO_2/MJ natural gas (LHV)	gCH_4/MJ natural gas (LHV)	gCO_2e/MJ natural gas (LHV)
Central	1.66	0.10	5.15
Best	1.44	0.05	3.26
Worst	8.30	0.07	10.69

Production: Natural gas SMR

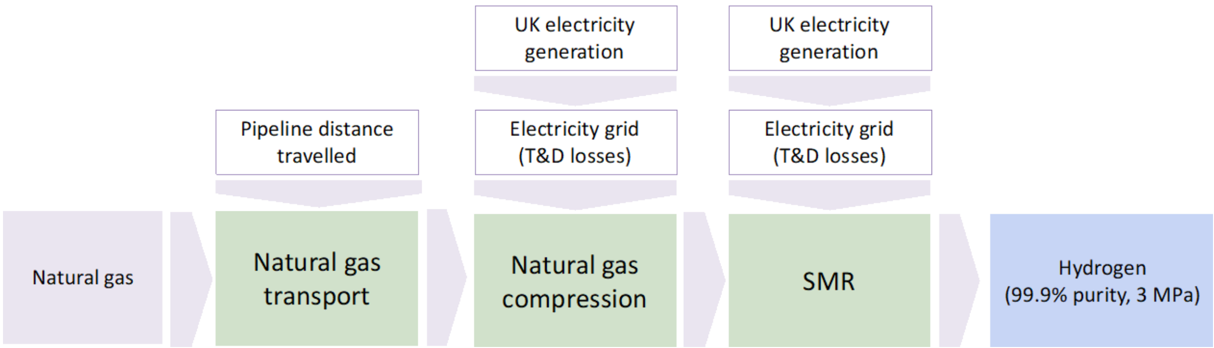


Figure 33: Fossil gas SMR (unabated)

The data used to calculate the upstream natural gas emissions are explained in the Natural gas ATR with CCS section above.

Data on steam methane reforming of natural gas to produce hydrogen is from the JEC (2020)[83]. Natural gas is assumed to reach the SMR plant at 0.5 MPa, as the plant is assumed to be connected to the low pressure distribution network in the JEC dataset. The natural gas is compressed, using electricity, to 1.6 MPa before going to the reformer. Data on the electricity requirement is provided by the JEC (2020).

Inputs and outputs from the SMR are provided in JEC (2020), where different efficiencies are provided for the reformer. The following efficiencies were used in each scenario in the GHG assessment:

[83] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

- **Central:** 76% energy efficiency held from 2020 to 2050
- **Best:** 78% energy efficiency held from 2020 to 2050
- **Worst**: 75% energy efficiency held from 2020 to 2050

While the JEC (2020) data set provides CH_4 emissions from the SMR process, it does not directly provide the CO_2 emissions. Fossil CO_2 emissions are calculated based on the combustion emissions of natural gas, from BEIS (2020)[84], and the efficiency of the SMR. These are calculated directly in the LCA tool, and therefore any changes to process efficiency will change the fossil CO_2 emissions.

The outlet pressure of the hydrogen from the SMR is 2MPa. Therefore, electricity requirements for hydrogen compression to 3MPa are estimated from GREET (2017)[85].

Production: Natural gas SMR with CCS

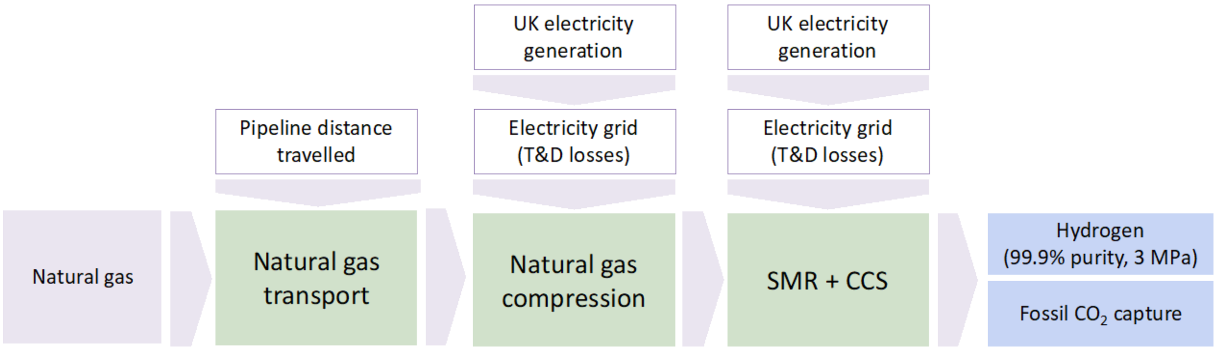


Figure 34: Fossil gas SMR with CCS

The data used to calculate the upstream natural gas emissions are explained in the Natural gas ATR with CCS section above.

Data on steam methane reforming of natural gas with CCS to produce hydrogen is from the JEC (2020)[86]. As above, natural gas arrives at the SMR plant at 0.5 MPa and is compressed to 1.6 MPa, using electricity. Electricity requirements are from JEC (2020).

Inputs and outputs from the SMR with CCS are provided in JEC (2020), where different efficiencies are provided for the reformer. The following efficiencies were used in each scenario in the GHG assessment:

- **Central:** 73% energy efficiency maintained for 2020 to 2050
- **Best:** 75% energy efficiency maintained for 2020 to 2050
- **Worst**: 72% energy efficiency maintained for 2020 to 2050

[84] BEIS (2020) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting
[85] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.
[86] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

While the JEC (2020) data set provides CH_4 emissions from the SMR process, it does not directly provide the CO_2 generated from the SMR process. Fossil CO_2 generated is calculated based on the combustion emissions of natural gas, from BEIS (2020)[87], and the efficiency of the SMR. These are calculated directly in the LCA tool, and therefore any changes to process efficiency will change the fossil CO_2 generated.

In this chain, the fossil CO_2 is assumed to be captured with a capture rate of 85%[88] in the central scenario, the best 90.1%[89] and the worst 66.9%[90]. Note that these rates are lower than for CCS with ATR, as ATR produces more of its CO_2 as a high pressure stream. Impacts of changing the capture rate on e.g. process efficiency are not included within the model, as this involves more detailed process engineering, which is outside of the scope of this work.

The impacts related with CO_2 capture and storage fall within the system boundary of this chain. Electricity requirements of 425 MJ_e/tCO_2 for CO_2 compression, pipeline transportation and injection into geological storage is estimated using data from Koornneef et al. (2008)[91].

The outlet pressure of the hydrogen from the SMR is 2MPa. Therefore, electricity requirements for hydrogen compression to 3MPa are estimated from GREET (2017)[92].

Foreground data for downstream distribution chains

When building the foreground data set, three scenarios were defined for each distribution chain: Central, Best and Worst. The scenarios are defined based on the compression efficiencies, transport distances and leakage rates of the chains. Best represents a scenario with the highest compression efficiency, shortest distances and lowest leakage; worst represents the opposite; and central represents an in-between set of values. In some cases, no differences were modelled between the different scenarios, and therefore parameters remain the same.

Data availability and certainty varies across chains. Table 29 provides a high-level assessment of the data availability for each distribution chain (with red showing high uncertainty data, amber medium and green low uncertainty data). As a reminder, it is assumed that each distribution chain starts at 99.9% purity with a pressure of 3 MPa. The final dispensing pressure is dependent on the downstream chain:

- For hydrogen produced onsite, the hydrogen is assumed to be delivered at 3MPa

[87] BEIS (2020) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting
[88] Calculated from JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5
[89] Wood (2018) Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology
[90] IEAGHG (2017) Techno-Economic Evaluation of SMR Based Standalone Hydrogen Plant with CCS (Case 1B)
[91] Koomneef et al. (2008) Life cycle assessment of a pulverised coal power plant with post combustion capture, transport and storage of CO2. Available at: https://www.sciencedirect.com/science/article/abs/pii/S1750583608000571
[92] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.

- For hydrogen transported by compressed road truck, the hydrogen is assumed to be delivered at 50MPa
- For hydrogen transported by liquid road truck, the hydrogen is assumed to be delivered at 35MPa
- For hydrogen transported by pipeline, the hydrogen is assumed to be delivered at 2 MPa
- For hydrogen transported by compressed road truck and delivered for the transport market, the hydrogen is assumed to be delivered at 88 MPa.

A higher pressure sensitivity for the downstream chains is investigated in Section 5.4., where hydrogen is assumed to be compressed to 88 MPa.

Table 29: High-level data availability for each downstream distribution chain

Downstream chain name	Downstream steps
Onsite compression & dispensing	**Green:** Data from JEC WTT v5
Compressed road transport	**Green:** Data from JEC WTT v5
Compressed road transport and salt cavern storage	**Amber:** Combined data from JEC WTT v5 and Element Energy (2018)
Liquid transport	**Amber:** Data from JEC WTT v5. Some assumptions required for long distance shipping in worst scenario.
Pipeline transport	**Green:** Data from JEC WTT v5
Pipeline transport and salt cavern storage	**Amber:** Combined data with JEC WTT v5 and Element Energy
Purification and compressed road transport	**Red:** Data on purification limited to electrolysers. Combined with data from JEC WTT v5

Distribution: Onsite use

Storage and dispensing is assumed to occur at the hydrogen production facility, with compression optional.

The electricity requirement to reach 88 MPa pressure for dispensing is from JEC (2020)[93], with the following requirement by scenario:

- **Central:** 0.079 $MJ_e/MJ\ H_2$
- **Best:** 0.075 $MJ_e/MJ\ H_2$
- **Worst:** 0.083 $MJ_e/MJ\ H_2$

However, it was decided that the final compression to 88 MPa would be removed from the main analysis, as few downstream users would require this pressure. Therefore, using GREET

[93] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

(2017)[94], the electricity requirement to go from 3 MPa (pressure of hydrogen after onsite production) to 88 MPa was removed, i.e. 0.066 MJe/MJ H_2 was removed from each of the above scenarios.

Hydrogen losses in dispensing are assumed to be 2%[95], resulting in 0.167 gH_2 emitted/MJ H_2.

Distribution: Compressed road transport

According to JEC (2020)[96], the hydrogen first needs to be compressed to 50 MPa to be transported by truck. The electricity requirement is also provided in the JEC (2020), with the following requirements by scenario:

- **Central:** 0.054 MJ_e/MJ H_2
- **Best:** 0.051 MJ_e/MJ H_2
- **Worst:** 0.057 MJ_e/MJ H_2

No losses are assumed for the on-site compression. The hydrogen is then assumed to travel 150 km by truck, with a payload of a 28 tonne tank per 0.955 tonne of hydrogen (JEC, 2020). Similarly, no hydrogen losses are assumed from transportation. See the "Road transport" sub-section in the Background data section further below in Appendix A for the HGV decarbonisation assumptions used in the study.

Final compression, storage and dispensing is assumed to occur at the final customer. As with onsite compression, JEC (2020) data includes electricity requirements for compression to 88 MPa, storage and dispensing, which are used in the different scenarios as follows:

- **Central:** 0.053 MJ_e/MJ H_2
- **Best:** 0.050 MJ_e/MJ H_2
- **Worst:** 0.055 MJ_e/MJ H_2

As with onsite compression, it was decided that the final compression to 88 MPa would be removed, as few downstream users would require this pressure. Therefore, using GREET (2017)[97], the electricity requirement to go from 50 MPa (pressure of hydrogen in the final transport step) to 88 MPa was removed, i.e. 0.01 MJe/MJ H_2 was removed from each of the above scenarios.

Hydrogen losses in dispensing are assumed to be 2%, resulting in 0.167 gH_2 emitted/MJ H_2.

[94] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.

[95] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

[96] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

[97] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.

Distribution: Compressed road transport and salt cavern storage

The compression and transportation of hydrogen is modelled the same as the Compressed Road Transport chain (see above). Once the hydrogen reaches the salt cavern, it is injected without requiring additional compression, as the hydrogen is already compressed to higher than the maximum working pressure of the salt caverns (11 MPa in the central scenario, 27 in the best and worst scenario[98]). The assumed working pressures of the salt caverns, as well as the electricity requirements required to inject the hydrogen into the cavern are from Element Energy (2018)[99].

Once the hydrogen is removed from the salt cavern, it needs to be compressed to 50 MPa. Electricity requirements are estimated using GREET (2017) and the difference between 50 MPa and the maximum working pressure of the salt cavern. It was assumed that the hydrogen retains the same purity (i.e. >99.9%) when it leaves the salt cavern as when it entered the cavern.

The hydrogen is then assumed to be transported 150 km to the final consumer. Requirements for final compression, storage and dispensing are in line with the Compressed Road Transport chain. Hydrogen losses in dispensing are maintained at 2%.

Distribution: Liquid transportation

Hydrogen is liquefied at the production facility. Electricity requirement is from JEC (2020)[100], with the following requirements by scenario:

- **Central:** 0.30 $MJ_e/MJ\ H_2$
- **Best:** 0.21 $MJ_e/MJ\ H_2$
- **Worst:** 0.39 $MJ_e/MJ\ H_2$

No hydrogen losses are assumed during liquefaction.

For the central and best case scenario, the hydrogen is assumed to be transported 150 km by liquid road transport to the final consumer. The payload of the truck is a 27.5 tonne tank per 3.5 tonnes of hydrogen transported[101].

In the worst scenario, an indicative imported hydrogen chain is modelled. This scenario is intended to reflect the potential additional GHG impacts with transporting hydrogen long distances in a scenario where hydrogen is imported. The hydrogen is first transported 150 km to a port (same payload as above). It is then transported by ship 5,500 nautical miles before being transported a final time 150 km by truck to final consumer. Electricity requirements for loading and unloading and fuel requirements for the ship are calculated using data from JEC

[98] Note that the Central scenario is based on storing hydrogen in the Chesire Basin, in the best scenario in East Yorkshire and in the worst in Wessex. Data from Element Energy (2018).

[99] Element Energy (2018) Hydrogen supply chain evidence base. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

[100] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

[101] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

(2020). Further, by 2040, shipping is assumed to be powered by hydrogen (instead of fossil fuels as in 2020 and 2030). Therefore, the efficiency of the process decreases in 2040 to account for the hydrogen losses to power the ship (2.72 MJ H_2/t.km), but without the GHG impacts of using heavy fuel oil. Note that within the LCA tool, hydrogen produced in different geographies is not calculated. Therefore, this worst case is simply to provide an indication on the magnitude of additional GHGs could arise from long distance hydrogen transportation.

For all scenarios, once the hydrogen is delivered to the final consumer, it is vaporised, compressed and dispensed. Using data from the JEC (2020), an electricity requirement of 0.051 MJ_e/MJ H_2 is quoted to reach 88 MPa. However, as with onsite compression, it was decided that the final compression to 88 MPa would be removed from the central cases, as not all downstream users would require this pressure. Therefore, using GREET (2017)[102], the electricity requirement of 0.02 MJe/MJ H_2 to go from 35 MPa (pressure of liquid hydrogen in the final transport step) to 88 MPa was removed, leading to only 0.035 MJe/MJ H_2 being required for each of the scenarios.

No hydrogen losses are assumed.

Distribution: Pipeline transportation

According to data from the JEC (2020)[103], the hydrogen from the production facility is at a high enough pressure to be injected into the distribution gas network, i.e. does not require compression. Further, JEC assumes no hydrogen losses in pipeline transport nor any hydrogen combustion required to generate electricity to operate pipeline compressors. However, based on data supplied by BEIS, the model assumes a hydrogen loss of 0.15% in the pipeline.

Once it reaches the final customer, the hydrogen at 2 MPa is compressed to 88 MPa and then stored and dispensed at the final customer site. The electricity requirements for this are provided by JEC (2020), and are assumed to be as follows by scenario:

- **Central:** 0.086 MJ_e/MJ H_2
- **Best:** 0.082 MJ_e/MJ H_2
- **Worst:** 0.091 MJ_e/MJ H_2

As with onsite compression, it was decided that the final compression to 88 MPa would be removed, as few downstream users would require this pressure. Therefore, using GREET (2017)[104], the electricity requirement to go from 2 MPa (pressure of hydrogen in the pipeline) to 88 MPa was removed, i.e. 0.07 MJe/MJ H_2 was removedfrom each of the above scenarios.

[102] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.

[103] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

[104] GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.

Hydrogen losses are assumed to be 2% in dispensing, resulting in 0.167 gH_2 emitted/MJ H_2.

Distribution: Pipeline transportation and salt cavern storage

As mentioned above, pipeline transportation is assumed to have hydrogen losses of 0.15%. The hydrogen is transported by pipeline to salt caverns, where it arrives at 2 MPa (JEC, 2020)[105]. At the salt cavern, the hydrogen is compressed to match the working pressure of the salt caverns. The assumed working pressures for each scenario are the same as the compressed road transport and salt cavern chain. Electricity requirements to compress the hydrogen is estimated using GREET (2017)[106]. Electricity requirements to operate the salt cavern are provided in Element Energy (2018).

Once the hydrogen is removed from the salt caverns, it can be directly injected into the pipelines, and does not require further compression (as the working pressure of the salt cavern in greater than the pressure required in the pipeline, which is 2 MPa according to JEC, 2020). It was assumed that the hydrogen remains at the same purity (>99.9%) when it leaves the salt cavern compared to when it entered the cavern. Again, hydrogen losses are assumed at 0.15% for pipeline transportation. The hydrogen is then compressed at the final consumer to 88 MPa, as it is in the Pipeline Transportation chain above. Hydrogen losses are maintained at 2% for final compression, storage and dispensing.

Distribution: Purification and compressed road transport

This chain is included to indicatively model the additional requirements associated with increasing hydrogen purity to >99.995%. As mentioned in 5.1.9, data could only be estimated for the additional electricity requirement to dry hydrogen produced from an electrolyser, as data to increase hydrogen purity from SMR, ATR and gasification chains is based on process design and engineering, which is outside the scope of this project. According to Machens (2004)[107], the following inputs are required to increase hydrogen purity from 99.9% to >99.995%:

- Hydrogen: 1.0418 MJ H_2/ MJ $H_{2\ (99.995\%)}$
- Electricity: 0.0139 MJ_e/MJ $H_{2\ (99.995\%)}$

From the data above, hydrogen losses are therefore calculated as 4.2% for this step. The rest of this chain uses the same data at the Compressed Road Transport chain, except that the electricity requirements are not reduced to avoid the final compression. In other words, this chain assumes the hydrogen is always compressed to 88 MPa. It is assumed that increasing the purity of the hydrogen does not affect the hydrogen pressure.

105 JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5
106 GREET (2017) Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants. Available at https://www.osti.gov/servlets/purl/1461466#:~:text=It%20was%20estimated%20that%20by,the%20conventional%20central%20SMR%20pathway.
107 Pers. Comm. to Weindorf, W. (LBST) on 12 October 2004

Background data

When building the background datasets, similarly to the foreground datasets, three scenarios were defined: Baseline impact, Low impact and High impact. Table 30 outlines the data sources for each impact factor for each process input/output. Note that some background factors were calculated in the LCA tool or were provided by BEIS, and will be explained in greater detail below.

Table 30: Background data sources for the global warming impacts of inputs and outputs used

Parameter	Baseline impact	Low Impact	High Impact
Tap water	BEIS (2020)[108]	Same as baseline	Same as baseline
Wastewater	BEIS (2020)	Same as baseline	Same as baseline
NaCl	JRC (2017)[109]	Same as baseline	Same as baseline
Na_2CO_3	JRC (2017)	Biograce v4[110]	Same as baseline
NaOH	JRC (2017)	Biograce v4	Same as baseline
HCl	JRC (2017)	Biograce v4	Same as baseline
H_2SO_4	JRC (2017)	Same as baseline	Same as baseline
Nitrogen fertiliser	JRC (2016)	Same as baseline	Same as baseline
Maize seed	JRC (2017)	Same as baseline	Same as baseline
Waste effluent	BEIS (2020)	Same as baseline	Same as baseline
Other waste	BEIS (2020)	Same as baseline	Same as baseline
Diesel (supply and use)	BEIS (2020)	Biograce v4	JRC (2017)
Emission of Hydrogen	BEIS (2018)[111] – central	BEIS (2018) – low	BEIS (2018) – high
Emission of Chlorine	No GHG impacts associated with chlorine emission to air		

[108] BEIS (2020) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020
[109] JRC (2017) Definition of input data to assess GHG default emissions from biofuels in EU legislation: Version 1C – July 2017. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/definition-input-data-assess-ghg-default-emissions-biofuels-eu-legislation-version-1c-july
[110] Biograce (n.d.) Biograce standard values – version 4 – Public. Available at: https://www.biograce.net/content/ghgcalculationtools/standardvalues
[111] BEIS (2018) Hydrogen for heating: atmospheric impacts – a literature review. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760538/Hydrogen_atmospheric_impact_report.pdf

Parameter	Baseline impact	Low Impact	High Impact
Emission of Mercury	No GHG impacts associated with mercury emission to air		
Emission of Oxygen	No GHG impacts associated with oxygen emission to air		

Some background impact factors needed to be modelled directly into LCA tool or were provided by BEIS directly, but require greater discussion. The following sections will discuss these in greater detail.

Grid electricity emissions intensity

A number of projections exist on the potential GHG intensity of the future UK electricity grid. Figure 35 outlines the different scenarios which were examined during this research. Data from UKTIMES run were provided directly from BEIS. National Grid's Future Energy Scenarios (FES)[112] were also investigated, and the graph illustrates the results from their most ambitious 'Leading the Way' scenario, which includes BECCS removals within the UK grid intensity factor. This scenario also starts at a lower 2020 value than the UKTM dataset, likely due to different assumptions being taken regarding COVID-19 impacts during 2020.

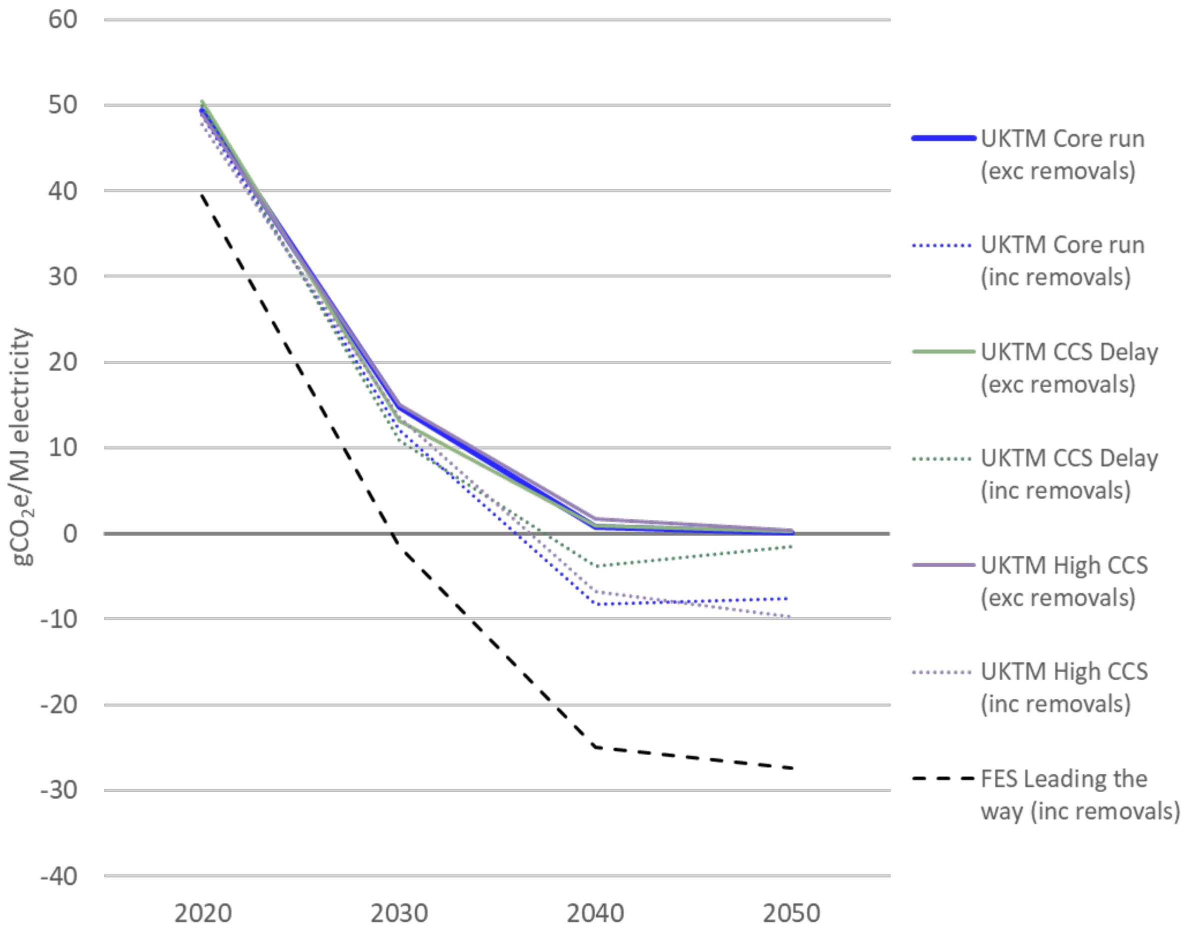


Figure 35: Projected GHG intensity of UK grid electricity generation

[112] National Grid (2020) Future Energy Scenarios. Available at: https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

For the GHG assessment, the following were selected for each scenario:

- **Baseline impact:** UKTM[113], "Core run - CB6 965 Mt - CCC trajectory", excluding the negative emissions from BECCS power plants and biomethane with CCS. This run is based on the core "central" assumptions of UKTM.
- **High Impact:** UKTM, "CCS Delay - CB6 965 Mt - CCC trajectory", excluding the negative emissions from BECCS power plants and biomethane with CCS. This run reflects downside technology uncertainty, with CCS availability starting in 2030 instead of 2025, and a 5 %-point decrease in CO_2 capture rates. Hydrogen imports (up to 70TWh) are also allowed to offset domestic delays in production at scale.
- **Low Impact:** UKTM, "High CCS - CB6 965 Mt - CCC trajectory, excluding the negative emissions from BECCS power plants and biomethane with CCS. This run reflects upside technology uncertainty, with a 4 %-point increase in CO_2 capture rates for nth of a kind technology (from 95% to 99% in most cases) and higher availability of Direct Air Carbon Capture and Storage at 25MtCO_2/year by 2050 compared with 13MtCO_2/year in other runs.

This data was provided directly by BEIS. These chains were selected as they are in line with the CCC's recommended level for the 6th Carbon Budget and with the target of Net Zero emissions in 2050. It was decided that negative GHG intensity electricity factors would not be used in the default settings of the LCA tool, as the biogenic CO_2 captured in power production is accounted for by BEIS and CCC in the "Removals" sector, rather than the "Power" sector. However, as this is simply an accounting choice, a sensitivity is explored on the impacts of using negative emission electricity (from National Grid FES 'Leading the way') in Section 5.4.

As these factors only represented generation figures, grid transmission & distribution losses were then applied to estimate the GHG impacts associated with consuming high voltage electricity, medium voltage electricity and low voltage electricity. Data on grid losses was collected from JEC (2020)[114], which estimates the losses between each step for the average European grid (i.e. loss from generation to transmission, to high voltage, to medium voltage, to low voltage). While BEIS did supply data on UK specific transmission & distribution losses, these were total losses from generation to low voltage, without the required granularity. Nevertheless, the datasets are similar, with BEIS data estimating total transmission & distribution losses of around 7.2% and JEC (2020) losses of around 6.9%.

It should also be noted that the figures from UKTM and National Grid FES only represent generation emissions and therefore do not include the upstream impacts of electricity generation (e.g. supply of natural gas to gas power stations). It is recommended that emission factors which include these upstream impacts be used in future work for the standard. However, BEIS was not able to provide electricity grid factors which included these upstream emissions within the timescale of this project.

[113] The UKTIMES model is a model of the UK energy system used by BEIS to model the cost-optimal decarbonisation pathways for a given set of assumptions and constraints.
[114] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

Nuclear electricity and heat

Nuclear electricity and heat is modelled as being used in a high temperature electrolyser. The waste heat from the nuclear process is assumed to have a zero GHG impact (any allocation to useful heat would only be allocating away from power, leading to the same input emissions to electrolysis overall, due to the scarcity of power and abundance of heat). Therefore for simplicity, all GHG impacts associated with nuclear energy production are allocated to the produced electricity.

In the Low impact scenario, nuclear electricity is modelled using foreground data from JEC (2020)[115] combined with background data (i.e. grid electricity factors) from the UK context. The system boundary covers uranium extraction to nuclear power generation, as well as transmission & distribution losses between different electricity voltages. This allows for nuclear electricity to decarbonise over time. For the Baseline impact and High Impact scenarios, the value modelled in JEC (2020) is maintained – 3.87 gCO_2e/MJ nuclear electricity (i.e. does not benefit from grid decarbonisation).

Steam production

Based on the data, a steam import is required for the chlor-alkali production. Steam is assumed to be produced from the combustion of gas taken from the gas grid (which decarbonises over time, see below). The efficiency of the boiler changes between scenarios with a 85% efficiency in the baseline impact scenario, 80% in the high impact scenario and 90% in the low impact scenario. The energy density (LHV) of steam was assumed at 3.996 MJ steam/kg steam, based on JRC (2017)[116]. Note that other processes may also require steam, but these are assumed to be produced on-site and therefore the inputs and outputs to the system capture this (e.g. increased natural gas input to produce steam).

Gas grid process input

For some chains, an input from the gas grid may be required[117]. The gas grid is projected to decarbonise, in part due to increasing biomethane injection into the gas grid. Three scenarios are modelled for biomethane mixing into the gas grid:

- Baseline impact based on UKTM "Core" run – CB6 965Mt – CCC trajectory, going from 2% biomethane mixed in 2020 up to 36% by 2050.
- Low impact based on UKTM "High CCS" – CB6 965Mt – CCC trajectory, going from 2% biomethane mixed in 2020 up to 53% by 2050.
- High impact based on UKTM "CCS Delay" – CB6 965 Mt – CCC trajectory, going from 2% biomethane mixed in 2020 up to 31% by 2050.

[115] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5

[116] JRC (2017) Definition of input data to assess GHG default emissions from biofuels in EU legislation: Version 1C – July 2017. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/definition-input-data-assess-ghg-default-emissions-biofuels-eu-legislation-version-1c-july

[117] NB this differs from when natural gas or biomethane is required as a production feedstock. This reflects gas which may be required for e.g. steam production.

These blend scenarios are then coupled with GHG impact factors for natural gas and biomethane. The impacts from natural gas supply and combustion and biomethane combustion are based on the data in BEIS Conversation Factors 2020 Full Set[118]. The impacts from biomethane production are from BEIS' Impact Assessment on the Future Support for Low Carbon Heat[119]. Based on this data, natural gas has combined emission factor of 64.16 gCO_2e/MJ LHV (includes supply and combustion), while biomethane has a combined emission factor of 25.05 gCO_2e/MJ LHV. These are then used to calculate a weighted average gas grid emissions factor based on the blend scenarios defined above.

Oxygen production

Oxygen required for waste gasification is modelled based on industry sources and the electricity grid factors defined in the LCA tool. Therefore, the impacts from oxygen decarbonise over time. In the baseline impact scenario, 1.08 MJ of electricity is required per kg of oxygen produced. This is 0.72 MJ/kg oxygen in the low impact scenario and is 2.40 MJ electricity/kg oxygen in the high impact scenario.

Road transport

Different decarbonisation scenarios were modelled for HGV road transport. By 2050, all these scenarios assume zero emission transport at point of combustion (i.e. zero tailpipe emissions). Table 31 provides details on each scenario modelled, as well as the calculated gCO_2e per t.km assumed. Data to calculate these emission factors were sourced from JRC wtt v5[120], GREET (2020)[121] and BEIS (2020)[122]. Further, this data is combined with other background datasets outlined above (e.g. diesel supply and use).

Table 31: Road transport decarbonisation scenarios

	2020	2030	2040	2050
Baseline impact	71.88 gCO_2e/t.km	67.31 gCO_2e/t.km	8.74 gCO_2e/t.km	2.91 gCO_2e/t.km
	Assumes current biofuel blend in ICE vehicle	12% biofuel blend (energy basis). This is the current RTFO target for 2030.	Hydrogen HGV – lifecycle emissions of 15gCO_2e/MJ of dispensed hydrogen	Hydrogen HGV – lifecycle emissions of 5gCO_2e/MJ of dispensed hydrogen
Low impact	71.88 gCO_2e/t.km	0 gCO_2e/t.km	0 gCO_2e/t.km	0 gCO_2e/t.km

[118] BEIS (2020) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020
[119] BEIS (2020) Consultation Stage IA: Future Support for Low Carbon Heat. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/881623/future-support-for-low-carbon-heat-impact-assessment.pdf
[120] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5
[121] GREET (2020) Argonne GREET model. Available for download at: https://greet.es.anl.gov/
[122] BEIS (2020) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020

	Assumes current biofuel blend in ICE vehicle		Assumes renewable electricity used in an electric HGV. No impacts associated with using renewable electricity.	
High impact	71.88 $gCO_2e/t.km$	69.45 $gCO_2e/t.km$	64.01 $gCO_2e/t.km$	8.74 $gCO_2e/t.km$
	Assumes current biofuel blend in ICE vehicle	12% biofuel blend (energy basis). This is the current RTFO target for 2030.	20% biofuel blend (energy basis).	Hydrogen HGV – lifecycle emissions of 15gCO_2e/MJ of dispensed hydrogen

Sea transport

For a single downstream scenario, liquid hydrogen is assumed to be transported by ship, using fossil heavy fuel oil for 2020 and 2030. For 2040 and 2050, the ship is assumed to use some of the liquid hydrogen being transported. Therefore to calculate the emission factors associated with sea transportation, GHG impacts are only calculated for 2020 and 2030, after which point the chain has a decrease in efficiency to account for the use of hydrogen by the ship. Data required to calculate the impacts of using heavy fuel oil in a ship come from JEC (2020)[123] and JRC (2017)[124]. Further, the amount of hydrogen required per tonne.km transported in a ship is calculated from data in JEC (2020).

[123] JEC (2020) JEC Well-to-Tank report v5. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5
[124] JRC (2017) Solid and gaseous bioenergy pathways: input values and GHG emissions. Available at: https://publications.jrc.ec.europa.eu/repository/bitstream/JRC104759/ld1a27215enn.pdf

Appendix B – Sensitivity analysis results

Sensitivity: Biogas feedstock

The feedstock used for the biomethane chain was originally food waste. A sensitivity was performed to note the impact of changing the feedstock to maize which required cultivation.

Table 32: Maize feedstock for biomethane ATR with CCS

Chain	Unit	Before sensitivity (feedstock: food waste)				After sensitivity (feedstock: maize)			
		2020	2030	2040	2050	2020	2030	2040	2050
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-30.9	-37.6	-40.9	-41.1

Sensitivity: Composition of MSW

The MSW content for the central scenario assumes 51% fossil fraction and 49% biogenic fraction in line with DUKES Table 6.1.

Table 33: MSW composition 100% fossil biogenic for waste gasification with CCS

Chain	Unit	Before sensitivity (feedstock: 51% fossil, 49% biogenic)				After sensitivity (feedstock: 100% fossil)			
		2020	2030	2040	2050	2020	2030	2040	2050
Residual waste gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	25.1	13.3	8.3	8.0

Table 34: MSW composition 100% biogenic for waste gasification with CCS

Chain	Unit	Before sensitivity (feedstock: 51% fossil, 49% biogenic)				After sensitivity (feedstock: 100% biogenic)			
		2020	2030	2040	2050	2020	2030	2040	2050
Residual waste gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-102.5	-114.3	-119.4	-119.6

Sensitivity: Biomass feedstock

The feedstock used for the wood gasification chain was originally forest residues. A sensitivity was performed to understand the impact from using an energy crop feedstock, Miscanthus, as the input feedstock. The changes in emissions are small, as the emissions associated with cultivation and harvesting of Miscanthus are larger than extraction of forestry residues, but still small overall.

Table 35: Miscanthus bales feedstock for wood gasification with CCS

Chain	Unit	Before sensitivity (feedstock: forestry residues)				After sensitivity (feedstock: miscanthus bales)			
		2020	2030	2040	2050	2020	2030	2040	2050
Forestry residues gasification with CCS	gCO2e/ MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-167.2	-166.8	-167.0	-164.2

Sensitivity: Electricity emissions factors

The electricity emissions factors were based on the Core run (baseline impact), CCS Delay (high impact) and High CCS (low impact) scenarios from UKTM trajectories. The negative grid emissions factor from the National Grid FES Leading the way scenario was also applied as an additional sensitivity. As the UKTM decarbonisation pathways are all similar, the impact of changing between the baseline, high and low factors is small. Grid electricity emissions make up a significant part of several chains' overall GHG emissions results, but these high and low sensitivities given below are constrained by the narrow range in the background dataset (UKTM). The sensitivity to the input grid factors can be more clearly seen by the use of a different dataset (e.g. National Grid FES) outside of the UKTM narrow range.

Table 36: High impact grid electricity emissions factor for all chains

Chain	Unit	Before sensitivity (baseline grid factor)				After sensitivity (high impact grid factor)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid Electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	80.2	20.3	1.4	0.5
Renewable Electrolysis	gCO2e/MJ (LHV)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Chain	Unit	Before sensitivity (baseline grid factor)				After sensitivity (high impact grid factor)			
		2020	2030	2040	2050	2020	2030	2040	2050
Nuclear Electrolysis (high temperature)	gCO2e/MJ (LHV)	4.8	4.5	4.4	4.3	4.8	4.5	4.4	4.3
Chlor-alkali Electrolysis	gCO2e/MJ (LHV)	38.2	13.2	3.1	2.6	38.9	12.0	3.2	2.7
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-56.1	-63.6	-66.8	-67.0
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-168.6	-168.5	-168.5	-165.6
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-37.5	-50.2	-54.7	-54.9
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	16.1	11.7	10.3	10.3
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	21.5	19.8	19.2	19.2
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	83.6	82.4	82.0	82.0

Table 37: Low impact grid electricity emissions factor for all chains

Chain	Unit	Before sensitivity (baseline grid factor)				After sensitivity (low impact grid factor)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid Electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	77.7	23.1	2.6	0.6
Renewable Electrolysis	gCO2e/MJ (LHV)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear Electrolysis (high temperature)	gCO2e/MJ (LHV)	4.8	4.5	4.4	4.3	4.8	4.5	4.4	4.3
Chlor-alkali Electrolysis	gCO2e/MJ (LHV)	38.2	13.2	3.1	2.6	37.8	13.3	3.7	2.8
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-56.4	-63.3	-66.7	-67.0
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-168.8	-168.4	-168.4	-165.6
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-38.0	-49.6	-54.4	-54.9
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	15.9	12.0	10.4	10.3
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	21.4	19.9	19.3	19.2
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	83.6	82.5	82.1	82.0

Table 38: Negative grid electricity emissions factor for all chains (FES leading the way scenario)

Chain	Unit	Before sensitivity (central grid factor)				After sensitivity (negative grid factor)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid Electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	62.7	-2.3	-37.5	-40.8
Renewable Electrolysis	gCO2e/MJ (LHV)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear Electrolysis (high temperature)	gCO2e/MJ (LHV)	4.8	4.5	4.4	4.3	4.8	4.5	4.4	4.3
Chlor-alkali Electrolysis	gCO2e/MJ (LHV)	38.2	13.2	3.1	2.6	31.0	1.4	-15.4	-17.3
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-58.3	-66.6	-72.0	-72.6
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-169.5	-169.6	-170.4	-167.7
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-41.2	-55.2	-63.4	-64.3
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	14.8	10.0	7.3	7.0
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	21.0	19.1	18.1	18.0
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	83.3	82.0	81.2	81.1

Sensitivity: Natural gas emissions factor

The central emissions factor uses the weighted average of the share of domestic gas, imported pipeline gas and LNG to reflect the UK supply (5.15 gCO2e/MJ LHV). The natural gas emissions factors for LNG and piped North sea gas were applied for the high impact (worst) and low impact (best) cases, respectively. The emissions factor for the CCC high LNG scenario was also applied as an additional sensitivity.

Table 39: Worst natural gas emissions factor for all chains (10.69 gCO_2e/MJ LHV, average LNG)

Chain	Unit	Before sensitivity (average emissions factor)				After sensitivity (worst emissions factor)			
		2020	2030	2040	2050	2020	2030	2040	2050
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	23.0	19.0	17.4	17.3
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	29.0	27.4	26.8	26.8
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	90.9	89.8	89.3	89.3

Table 40: Best natural gas emissions factor for all chains (3.26 gCO_2e/MJ LHV, North Sea piped)

Chain	Unit	Before sensitivity (average emissions factor)				After sensitivity (best emissions factor)			
		2020	2030	2040	2050	2020	2030	2040	2050
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	13.5	9.5	7.9	7.8
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	18.8	17.3	16.7	16.6
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	81.1	80.0	79.5	79.5

Table 41: Worst-worst natural gas emissions factor for all chains (21.55 gCO_2e/MJ LHV, CCC LNG)

Chain	Unit	Before sensitivity (average emissions factor)				After sensitivity (worst-worst emissions factor)			
		2020	2030	2040	2050	2020	2030	2040	2050
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	36.9	32.9	31.3	31.2
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	43.8	42.2	41.6	41.6
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	105.2	104.0	103.6	103.6

Sensitivity: Technology efficiency

The worst and best case efficiencies in the production steps of the production pathways was selected for this sensitivity. Chlor-alkali was excluded, as an energy efficiency does not represent the chain well, as it produces mainly non-energy products (sodium hydroxide and chlorine)[125]. Based on the data collected, it was not possible to estimate how changing the electricity input would affect hydrogen, sodium hydroxide and chlorine production, and therefore how emissions would be allocated between the three products.

The sensitivity to technology efficiency is significant in 2020 for grid electrolysis, due to the wide range of electrolyser efficiencies and the high grid intensity in 2020. These sensitivities decrease over time as the grid decarbonises, and as electrolyser efficiencies improve. By 2050, the impacts are generally small.

Table 42: Worst technology efficiencies for all chains, apart from chlor-alkali electrolysis

Chain	Unit	Before sensitivity (central efficiencies)				After sensitivity (worst efficiencies)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid Electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	98.4	25.6	1.4	0.3
Renewable Electrolysis	gCO2e/MJ (LHV)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

[125] Note: an energy efficiency value is included within the LCA tool, calculated on an electricity in over hydrogen out (central scenario: 12% energy efficiency, 18% in best and 14% in worst). However, the chlor-alkali production process is only modelled as one step in the GHG assessment, the assumed energy efficiency of the step does not affect other parts of the model (i.e. does not affect cumulative efficiency applied in previous steps, as it does not have previous steps).

Chain	Unit	Before sensitivity (central efficiencies)				After sensitivity (worst efficiencies)			
		2020	2030	2040	2050	2020	2030	2040	2050
Nuclear Electrolysis (high temperature)	gCO2e/MJ (LHV)	4.8	4.5	4.4	4.3	4.9	4.7	4.6	4.6
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-65.0	-72.5	-76.4	-76.6
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-175.5	-175.0	-175.0	-171.9
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-37.9	-49.7	-54.7	-54.9
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	17.6	13.5	11.8	11.7
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	21.8	20.2	19.6	19.6
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	85.2	84.1	83.6	83.6

Table 43: Best technology efficiencies for all chains, apart from chlor-alkali electrolysis

Chain	Unit	Before sensitivity (central efficiencies)				After sensitivity (best efficiencies)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid Electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	75.4	21.9	1.2	0.3
Renewable Electrolysis	gCO2e/MJ (LHV)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear Electrolysis (high temperature)	gCO2e/MJ (LHV)	4.8	4.5	4.4	4.3	4.6	4.3	4.2	4.2
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-52.2	-58.9	-62.3	-62.5
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-168.7	-168.4	-168.5	-159.8
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-37.9	-49.7	-54.7	-54.9
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	15.2	11.2	9.6	9.5
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	21.0	19.5	18.9	18.8
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	82.0	80.9	80.4	80.4

Sensitivity: Carbon capture rates

Four sensitivities were performed to change the capture rates of the CCS chains. The ATR and gasification chains had 95% capture rates before the sensitivities were applied, and the SMR CCS chain had an 85% capture rate before the sensitivities were applied.

Table 44: No carbon capture for CCS chains

Chain	Unit	Before sensitivity (with CCS)				After sensitivity (without CCS)			
		2020	2030	2040	2050	2020	2030	2040	2050
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	9.3	3.4	0.3	0.1
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	6.8	6.5	4.3	4.0
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	80.8	70.8	66.5	66.3
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	83.4	80.5	79.3	79.2
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	85.9	85.3	85.1	85.1

Table 45: 50% carbon capture for CCS chains

Chain	Unit	Before sensitivity (with CCS)				After sensitivity (50% CCS)			
		2020	2030	2040	2050	2020	2030	2040	2050
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-25.2	-31.7	-35.1	-35.3
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-85.6	-85.5	-86.6	-85.3

Chain	Unit	Before sensitivity (with CCS)				After sensitivity (50% CCS)			
		2020	2030	2040	2050	2020	2030	2040	2050
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	18.4	7.4	2.7	2.5
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	47.9	44.4	43.0	42.9
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	48.0	46.8	46.4	46.3

Table 46: 90% carbon capture for ATR chains and 80% capture for gasification and SMR chains

Chain	Unit	Before sensitivity (with CCS)				After sensitivity (90% ATR CCS and 80% gasification/SMR CCS)			
		2020	2030	2040	2050	2020	2030	2040	2050
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-52.9	-59.8	-63.3	-63.5
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-141.0	-140.8	-141.2	-138.9
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-19.1	-30.6	-35.6	-35.8
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	19.5	15.5	13.9	13.9
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	25.2	23.7	23.1	23.1

Table 47: 98% carbon capture for ATR and gasification chains and 95% capture for SMR chains

Chain	Unit	Before sensitivity (with CCS)				After sensitivity (98% ATR CCS and 95% gasification/SMR CCS)			
		2020	2030	2040	2050	2020	2030	2040	2050
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-58.4	-65.4	-69.0	-69.2
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-174.3	-173.9	-173.9	-171.0
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-41.6	-53.5	-58.5	-58.8
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	13.8	9.8	8.1	8.1
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	13.8	12.2	11.5	11.5

Sensitivity: Allocation of oxygen

An economic allocation of GHG emissions was assigned to the oxygen co-product produced in the grid electrolysis chain (other electrolysis chains were not investigated due to having much lower emissions). This allocation was based on the unit price of hydrogen reported as $4.20/kg and oxygen as $0.20/kg with a production volume ratio of 7.8 kg oxygen/kg hydrogen. Therefore, the GHG emissions allocation ratio was 73% hydrogen and 27% oxygen. (An exchange rate of 0.82 €/$ was used).

Table 48: Economic allocation to oxygen (27% for oxygen and 73% for hydrogen)

Chain	Unit	Before sensitivity (no economic allocation of oxygen)				After sensitivity (economic allocation of oxygen)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	57.2	16.6	0.9	0.2

Sensitivity: Hydrogen GWP

Table 49: Hydrogen GWP changed to 0 tCO_2e/tH_2 for all downstream chains

Chain	Unit	Before sensitivity (GWP 10 gCO2e/gCO2)				After sensitivity (GWP 0 gCO2e/gCO2)			
		2020	2030	2040	2050	2020	2030	2040	2050
Onsite	gCO2e/MJ (LHV)	2.4	1.9	1.7	1.7	0.7	0.2	0.0	0.0
Compressed road transport	gCO2e/MJ (LHV)	9.5	4.9	2.0	1.8	7.9	3.3	0.4	0.1
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	12.2	6.4	0.7	0.2
Liquid transportation	gCO2e/MJ (LHV)	18.8	2.0	0.2	0.1	18.8	2.0	0.2	0.1
Pipeline	gCO2e/MJ (LHV)	2.4	2.0	1.8	1.8	0.6	0.2	0.0	0.0
Pipeline and salt cavern storage	gCO2e/MJ (LHV)	4.3	3.1	2.7	2.6	1.6	0.5	0.0	0.0
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	4.9	2.0	1.8	8.6	3.3	0.4	0.1

Table 50: Hydrogen GWP changed to 14 tCO_2e/tH_2 for all downstream chains

Chain	Unit	Before sensitivity (GWP 10 gCO2e/gCO2)				After sensitivity (GWP 14 gCO2e/gCO2)			
		2020	2030	2040	2050	2020	2030	2040	2050
Onsite	gCO2e/MJ (LHV)	2.4	1.9	1.7	1.7	3.0	2.5	2.3	2.3
Compressed road transport	gCO2e/MJ (LHV)	9.5	4.9	2.0	1.8	10.2	5.6	2.7	2.5
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	15.6	9.7	4.1	3.6
Liquid transportation	gCO2e/MJ (LHV)	18.8	2.0	0.2	0.1	18.8	2.0	0.2	0.1
Pipeline	gCO2e/MJ (LHV)	2.4	2.0	1.8	1.8	3.1	2.7	2.5	2.5
Pipeline and salt cavern storage	gCO2e/MJ (LHV)	4.3	3.1	2.7	2.6	5.3	4.2	3.7	3.7
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	4.9	2.0	1.8	10.9	5.6	2.7	2.5

Sensitivity: Transport distances

Sensitivities were performed on the distances for downstream hydrogen distribution chains and upstream feedstock transport for the relevant production pathways.

Table 51: Transport distances removed for relevant downstream chains

Chain	Unit	Before sensitivity (150 km)				After sensitivity (0 km)			
		2020	2030	2040	2050	2020	2030	2040	2050
Compressed road transport	gCO2e/MJ (LHV)	9.5	7.5	10.6	4.7	6.7	7.5	10.6	1.9

Chain	Unit	Before sensitivity (150 km)				After sensitivity (0 km)			
		2020	2030	2040	2050	2020	2030	2040	2050
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	11.8	6.1	2.8	2.5
Liquid transportation	gCO2e/MJ (LHV)	18.0	13.3	25.5	1.0	17.2	13.3	25.5	0.2
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	8.3	11.3	4.7	7.5	8.3	11.3	1.9

Table 52: Transport distance reduced to 50 km for relevant downstream chains

Chain	Unit	Before sensitivity (150 km)				After sensitivity (50 km)			
		2020	2030	2040	2050	2020	2030	2040	2050
Compressed road transport	gCO2e/MJ (LHV)	9.5	7.5	10.6	4.7	7.7	7.5	10.6	2.8
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	12.7	7.0	2.9	2.5
Liquid transportation	gCO2e/MJ (LHV)	18.0	13.3	25.5	1.0	17.7	14.1	25.5	0.5
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	8.3	11.3	4.7	8.4	8.3	11.3	2.9

Table 53: Transport distance increased to 350 km for relevant downstream chains

Chain	Unit	Before sensitivity (150 km)				After sensitivity (350 km)			
		2020	2030	2040	2050	2020	2030	2040	2050
Compressed road transport	gCO2e/MJ (LHV)	9.5	7.5	10.6	4.7	13.2	7.5	10.6	8.4

Chain	Unit	Before sensitivity (150 km)				After sensitivity (350 km)			
		2020	2030	2040	2050	2020	2030	2040	2050
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	18.3	12.2	3.6	2.8
Liquid transportation	gCO2e/MJ (LHV)	18.0	13.3	25.5	1.0	20.9	14.1	25.5	2.1
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	8.3	11.3	4.7	14.0	8.3	11.3	8.4

Table 54: Transport distance changed to 200 km for relevant production pathways

Chain	Unit	Before sensitivity (20 km for biomethane and waste chains and 250 km for wood chain)				After sensitivity (200 km)			
		2020	2030	2040	2050	2020	2030	2040	2050
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-47.9	-55.4	-65.8	-66.7
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-169.3	-168.9	-168.5	-165.7
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-34.6	-46.6	-54.3	-54.8

Sensitivity: Downstream compression

A compression and dispensing step (to 88 MPa) was added for the downstream chains. An additional sensitivity was run for the pipeline downstream chains with compression and dispensing to 8.5 MPa.

Table 55: Downstream compression to 88 MPa added for all downstream chains

Chain	Unit	Before sensitivity (no downstream compression)				After sensitivity (downstream compression added)			
		2020	2030	2040	2050	2020	2030	2040	2050
Onsite	gCO2e/MJ (LHV)	2.4	1.9	1.7	1.7	5.8	2.9	1.7	1.7
Compressed road transport	gCO2e/MJ (LHV)	9.5	4.9	2.0	1.8	10.1	5.1	2.0	1.8
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	15.1	8.9	3.1	2.6
Liquid transportation	gCO2e/MJ (LHV)	18.8	2.0	0.2	0.1	18.9	1.6	0.1	0.0
Pipeline	gCO2e/MJ (LHV)	2.4	2.0	1.8	1.8	6.4	3.2	1.9	1.8
Pipeline and salt cavern storage	gCO2e/MJ (LHV)	4.3	3.1	2.7	2.6	8.2	4.3	2.7	2.7
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	4.9	2.0	1.8	10.8	5.1	2.0	1.8

Table 56: Downstream compression to 8.5 MPa added for pipeline downstream chains

Chain	Unit	Before sensitivity (no downstream compression)				After sensitivity (downstream compression to 8.5 MPa added)			
		2020	2030	2040	2050	2020	2030	2040	2050
Pipeline	gCO2e/MJ (LHV)	2.4	2.0	1.8	1.8	3.8	2.4	1.8	1.8
Pipeline and salt cavern storage	gCO2e/MJ (LHV)	4.3	3.1	2.7	2.6	5.7	3.5	2.7	2.6

Sensitivity: Downstream efficiency/losses

Sensitivities were performed on the dispensing losses for the downstream chains to evaluate the impact of the downstream efficiency. The central scenario included losses of 2% at the dispensing step prior to running the sensitivities. The only chain that did not previously include any losses was the liquid transportation chain.

Table 57: Downstream efficiency reduced to account for 5% dispensing losses for all downstream chains

Chain	Unit	Before sensitivity (no losses for liquid chain and 2% dispensing losses for remaining chains)				After sensitivity (5% dispensing losses for all chains)			
		2020	2030	2040	2050	2020	2030	2040	2050
Onsite	gCO2e/MJ (LHV)	2.4	1.9	1.7	1.7	4.9	4.4	4.2	4.2
Compressed road transport	gCO2e/MJ (LHV)	9.5	4.9	2.0	1.8	12.2	7.5	4.6	4.3
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	17.4	11.4	5.7	5.1
Liquid transportation	gCO2e/MJ (LHV)	18.8	2.0	0.2	0.1	23.8	6.2	4.4	4.2
Pipeline	gCO2e/MJ (LHV)	2.4	2.0	1.8	1.8	4.9	4.5	4.3	4.3
Pipeline and salt cavern storage	gCO2e/MJ (LHV)	4.3	3.1	2.7	2.6	6.8	5.7	5.2	5.2
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	4.9	2.0	1.8	13.0	7.5	4.6	4.3

Table 58: Downstream efficiency reduced to account for 10% dispensing losses for all downstream chains

Chain	Unit	Before sensitivity (no losses for liquid chain and 2% dispensing losses for remaining chains)				After sensitivity (10% dispensing losses for all chains)			
		2020	2030	2040	2050	2020	2030	2040	2050
Onsite	gCO2e/MJ (LHV)	2.4	1.9	1.7	1.7	9.0	8.5	8.3	8.3
Compressed road transport	gCO2e/MJ (LHV)	9.5	4.9	2.0	1.8	16.7	11.8	8.7	8.5
Compressed road transport and salt cavern	gCO2e/MJ (LHV)	14.6	8.7	3.1	2.6	22.2	16.0	9.9	9.4
Liquid transportation	gCO2e/MJ (LHV)	18.8	2.0	0.2	0.1	28.9	10.5	8.6	8.4
Pipeline	gCO2e/MJ (LHV)	2.4	2.0	1.8	1.8	9.1	8.7	8.5	8.5
Pipeline and salt cavern storage	gCO2e/MJ (LHV)	4.3	3.1	2.7	2.6	11.2	9.9	9.4	9.4
Purification and compressed road transport	gCO2e/MJ (LHV)	10.3	4.9	2.0	1.8	17.5	11.8	8.7	8.5

Sensitivity: GWP scenario

The original analysis used GWP values based on IPCC AR5 with climate feedback. A sensitivity was performed on the upstream chains to evaluate the impact of using the GWP data from IPCC AR4 and AR5 without climate feedback values. Note that these changes only impact those datasets where we have data available for the split of CO_2, CH_4 and N_2O – these changes will not impact those datasets where only CO2e values are available.

Table 59: GWP scenario changed to AR4 for all chains

Chain	Unit	Before sensitivity (GWP AR5 with feedback)				After sensitivity (GWP AR4)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid Electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	78.4	22.7	1.3	0.3
Renewable Electrolysis	gCO2e/MJ (LHV)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear Electrolysis (high temperature)	gCO2e/MJ (LHV)	4.8	4.5	4.4	4.3	4.8	4.5	4.4	4.3
Chlor-alkali Electrolysis	gCO2e/MJ (LHV)	38.2	13.2	3.1	2.6	38.2	13.2	3.1	2.6
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-56.3	-63.3	-66.9	-67.1
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-168.7	-168.4	-168.5	-165.6
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-37.9	-49.7	-54.7	-54.9
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	14.8	10.7	9.1	9.1
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	20.0	18.5	17.8	17.8
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	82.2	81.1	80.7	80.7

Table 60: GWP scenario changed to AR5 without climate feedback for all chains

Chain	Unit	Before sensitivity (GWP AR5 with feedback)				After sensitivity (GWP AR5 without feedback)			
		2020	2030	2040	2050	2020	2030	2040	2050
Grid Electrolysis	gCO2e/MJ (LHV)	78.4	22.7	1.3	0.3	78.4	22.7	1.3	0.3
Renewable Electrolysis	gCO2e/MJ (LHV)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear Electrolysis (high temperature)	gCO2e/MJ (LHV)	4.8	4.5	4.4	4.3	4.8	4.5	4.4	4.3
Chlor-alkali Electrolysis	gCO2e/MJ (LHV)	38.2	13.2	3.1	2.6	38.2	13.2	3.1	2.6
Biomethane ATR with CCS	gCO2e/MJ (LHV)	-56.3	-63.3	-66.9	-67.1	-56.3	-63.3	-66.9	-67.1
Forestry residues Gasification with CCS	gCO2e/MJ (LHV)	-168.7	-168.4	-168.5	-165.6	-168.7	-168.4	-168.5	-165.6
Residual waste Gasification with CCS	gCO2e/MJ (LHV)	-37.9	-49.7	-54.7	-54.9	-37.9	-49.7	-54.7	-54.9
Natural Gas ATR with CCS	gCO2e/MJ (LHV)	16.0	11.9	10.3	10.2	15.2	11.1	9.5	9.4
Natural Gas SMR with CCS	gCO2e/MJ (LHV)	21.4	19.9	19.2	19.2	20.5	18.9	18.3	18.3
Natural Gas SMR (no CCS)	gCO2e/MJ (LHV)	83.6	82.5	82.0	82.0	82.7	81.6	81.1	81.1

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