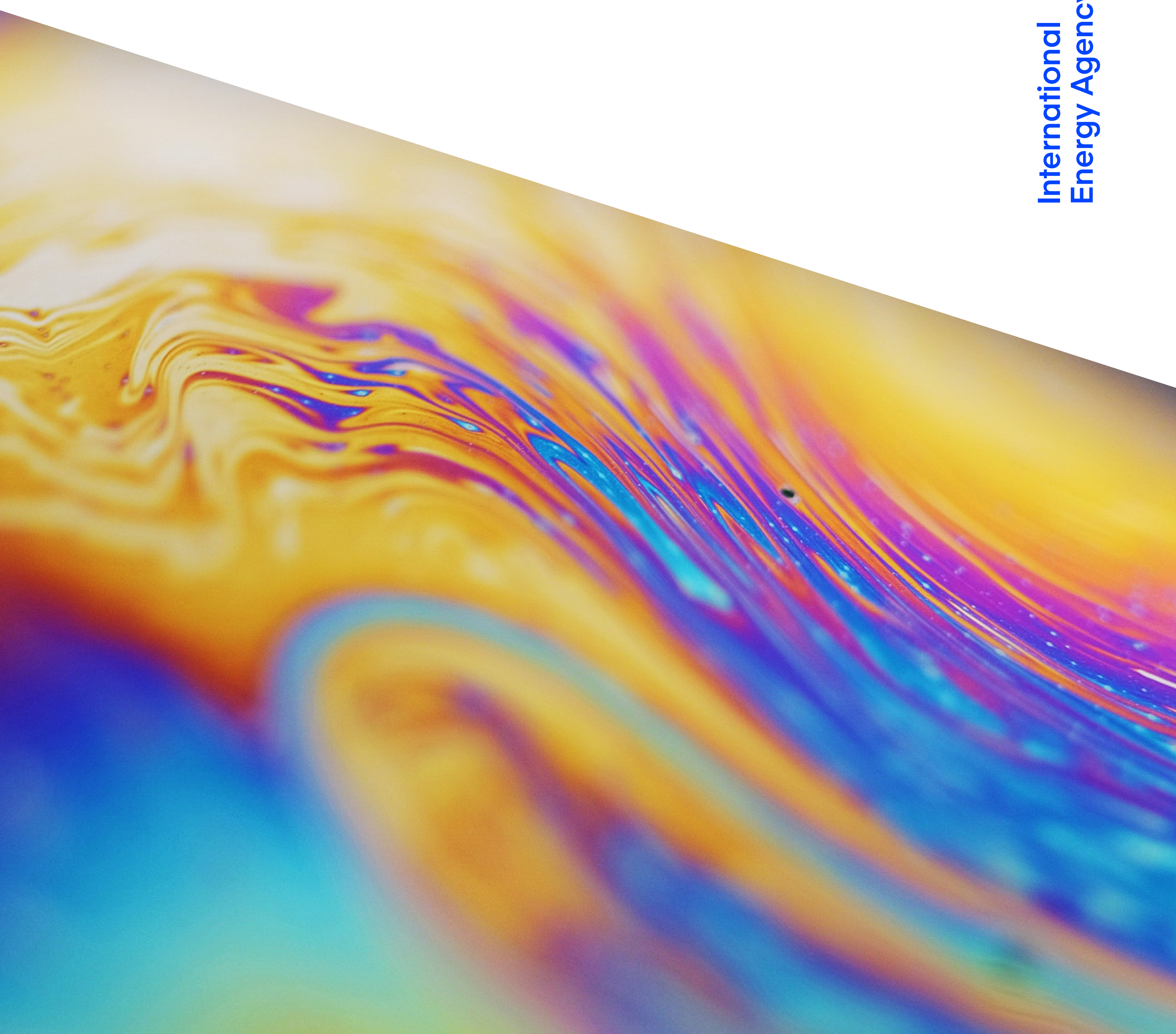
G20 BRASIL 2024
BUILDING A JUST WORLD AND A SUSTAINABLE PLANET

# Towards Common Criteria for Sustainable Fuels

International Energy Agency



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# Abstract

Sustainable fuels play a crucial role in clean energy transitions. They complement direct electrification and energy efficiency measures in decarbonising sectors for which emissions are hard to abate, while contributing to energy diversification and security. Under the IEA's Net Zero Emissions by 2050 (NZE) Scenario, the demand for low-emission fuels such as liquid biofuels, biogases, hydrogen and hydrogen-based fuels would need to double from current levels by 2030 and double again by 2050. Despite their importance, none of the main sustainable fuel options are on track for a net zero pathway.

Accelerated deployment of sustainable fuels depends in part on achieving a common understanding of what makes a fuel "sustainable". Numerous frameworks and certification schemes for sustainable fuels have been established worldwide. Terms such as "green," "blue," or "advanced" are frequently used to describe the sustainability features of fuels and to differentiate them from their unabated fossil counterparts. However, there is no international consensus on the meaning of these terms. Their definitions are inconsistent and, critically, they do not usually provide quantitative information about greenhouse gas emissions.

This report – produced in support of Brazil's G20 Presidency – explores the feasibility and implications of setting up common criteria to enable fair comparisons of sustainable fuels. It maps commonalities and differences among the standards, regulations and certifications used for sustainable fuels across different regions and markets. It reviews typical carbon intensities and the improvement potential of various fuel production pathways and sets out policy considerations for governments that wish to work toward common criteria for sustainable fuels.

# Acknowledgements, contributors and credits

This report was prepared jointly by the Renewable Energy Division and the Energy Technology Policy Division of the International Energy Agency. The study was designed and directed by Paolo Frankl, Head of the Renewable Energy Division.

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The report builds upon and expands on analysis presented in the reports Carbon Accounting for Sustainable Biofuels (IEA, 2024) and Towards hydrogen definitions based on their emissions intensity (IEA, 2023), as well as the Global Hydrogen Review 2024 (IEA, forthcoming).

Valuable comments and feedback were provided by senior management and colleagues within the IEA, including Keisuke Sadamori, Timur Gül, and Uwe Remme.

The Communications and Digital Office provided production support. Particular thanks go to Jethro Mullen and his team: Astrid Dumond, Liv Gaunt, Clara Vallois, Lorenzo Squillace and Poeli Bojorquez. Nicola Clark edited the report.

Many experts from outside of the IEA provided valuable input, commented and reviewed this report. They include:

Countries

Brazil (Mariana de Assis Espécie, Director of Energy Transition at the Brazilian Ministry of Mines and Energy and Laís de Souza Garcia, Head of the Renewable Energy Division – Ministry of External Relations); Germany (Federal Ministry for Economic Affairs and Climate Action); Japan (Mr Takashi Hasegawa, Fuel Supply Infrastructure Policy Division, Ministry of Economy, Trade and Industry); United Kingdom (HM Treasury, Department for Energy Security and Net Zero).

Organisations

Catavento (Clarissa Lins, Bruna Mascotte and Tamara Fain), H2Global (Florian Geyer), Hydrogen Council (Daria Nochevnik and Andrei Tchouvelev), IPHE (Laurent Antoni and Noé van Hulst), Polytechnic University of Turin (David Chiaramonti and Matteo Prussi), Raízen (Simone Pereira de Souza).

# Executive summary

## Sustainable fuels play a crucial role in clean energy transitions

**Sustainable fuels complement direct electrification and energy efficiency measures in decarbonising sectors for which emissions are hard to abate.** Under the IEA's Net Zero Emissions by 2050 (NZE) Scenario, the demand for low-emission fuels such as liquid biofuels, biogases, hydrogen and hydrogen-based fuels would need to double from current levels by 2030 and double again by 2050. They facilitate decarbonisation across a range of end-use sectors, especially parts of transport and industry, while contributing to energy diversification and security.

**None of the main sustainable fuel options are on track for a net zero pathway.** There are potentially hundreds of pathways available for producing fuels. Biofuels are currently the most developed and cost-effective alternative to fossil fuels. However, substantial efforts are needed to expand and diversify sustainable biomass feedstock supplies, commercialise new processing technologies and harmonise sustainability frameworks to address concerns related to large-scale deployment. Hydrogen has significant industrial demand today, but supply of low-emission hydrogen is very limited so far. In addition to scaling up low-emission production and reducing cost, significant investments in distribution infrastructure and end-use equipment are needed. Hydrogen-based low-emission fuels typically offer some benefits in terms of lower infrastructure requirements compared to pure hydrogen, but they are more expensive to produce, and their scale-up is further limited by access to low-cost, low-emission sources of $CO_2$ feedstock (except for ammonia which is carbon-free).

**Accelerated deployment of sustainable fuels depends in part on achieving a common understanding of what makes a fuel "sustainable".** Numerous frameworks and certification schemes for sustainable fuels have been established worldwide. Terms such as "green," "blue," or "advanced" are frequently used to describe the sustainability features of fuels and to differentiate them from their unabated fossil counterparts. However, there is no international consensus on the meaning of these terms. Their definitions are inconsistent and, critically, they do not usually provide quantitative information about GHG emissions.

**This report – produced in support of Brazil's G20 Presidency – explores the feasibility and implications of setting up common criteria to enable fair comparisons of sustainable fuels.** It maps commonalities and differences among the standards, regulations and certifications used for sustainable fuels across different regions and markets. It reviews typical carbon intensities and the improvement potential of various fuel production pathways and sets out policy considerations for governments that wish to work toward common criteria for sustainable fuels. The report builds upon and expands on analysis presented in the reports Carbon Accounting for Sustainable Biofuels (IEA, 2024) and Towards hydrogen definitions based on their emissions intensity (IEA, 2023), as well as the Global Hydrogen Review 2024 (IEA, forthcoming).

## Supply chain GHG intensity provides a robust basis for a fair and transparent comparison

**Many standards, regulations and certifications are in use today for sustainable fuels with some commonalities, but there are also important differences.** Generally, GHG accounting is handled similarly across the main biofuel policy frameworks, with the notable exception of land-use change. The GHG intensities can vary widely among similar biofuel production pathways, but methodologies for their assessment are robust, and causes for differences are well understood. They typically relate to regional differences, methodological choices, and data input quality and representativeness. In contrast, impacts of land-use change are a major source of disagreement across different biofuel policy frameworks. For hydrogen and/or hydrogen derivatives, there are currently 34 certification schemes. More than half of these schemes require a GHG intensity of less than 33 $gCO_2$-eq/MJ (4 $kgCO_2$-eq/$kgH_2$), around two-thirds lower than emissions of production from unabated natural gas, the most common production pathway today. However, most schemes consider only emissions from production and do not include transport and distribution of the final fuel in their scope.

**For a consistent comparison across fuels, supply chain GHG intensity should be calculated at the point of delivery and include complete oxidation of the fuel.** GHG intensity (expressed in $gCO_2$-eq/MJ) should consider not only production, but also emissions related to transport and distribution to the point of delivery, since these steps can add significantly to supply chain emissions for certain fuels (e.g. hydrogen). GHG intensity calculations should also assume complete oxidation of the fuel to account for any fossil carbon inputs that are used during the production process – e.g. for fuels such as synthetic methanol or kerosene. In the case of fuels produced via electrolysis, embodied GHG emissions from the manufacture of captive power plants (e.g. renewable or nuclear) should also be included within the system boundary. For biofuels, direct land-use change emissions should be included in the GHG metrics, as they are measurable and verifiable over time. Indirect land-use change should be treated separately (see below).

**Minimum requirements for emissions reduction compared to unabated fossil fuels can be set by establishing a GHG intensity threshold**. Such a threshold should be set low enough to trigger ambitious emission reductions. At the same time, it should also be able to ensure that a broad range of technologies and emerging pathways with lower emissions than unabated fossil fuels can play a role in the early phases of the transition, attract investment and benefit from learning at relevant scales. This is especially relevant in countries that cannot afford to go directly to near-zero-emission fuels. As much of the sustainable fuel sector is still nascent, setting extremely low thresholds at the outset can hinder technological development, increase costs and ultimately slow progress in reducing global average fuel emissions. In many cases, a phased approach towards ambitious thresholds can be desirable.

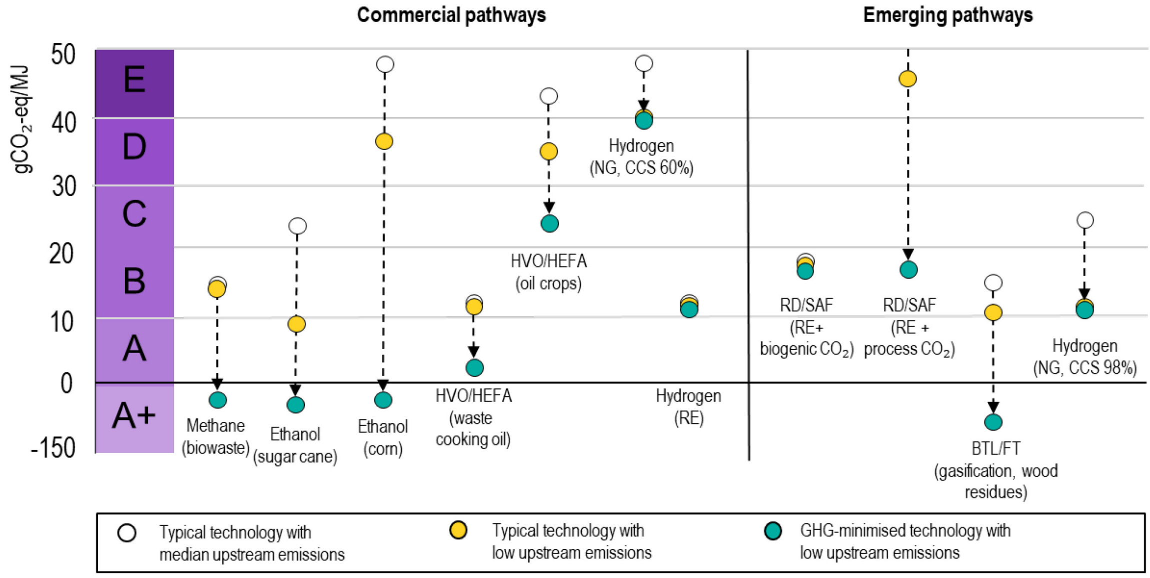
**GHG intensity should be complemented by a broader portfolio of policies covering non-GHG impacts of fuels.** Lifecycle GHG emissions are just one of many sustainability factors to consider when expanding the production and use of low-emission fuels. A growing number of policies are also addressing issues like food and water security, biodiversity and other socioeconomic factors, such as ensuring a secure and affordable energy supply and supporting a just transition.

## Policies should reward better GHG performance and drive continuous improvement over time

**Several measures can be applied to improve GHG performance of fuels, but incentives are required to cover extra costs.** Fuel pathways show a wide range of GHG intensities, but measures like adopting sustainable farming practices, using carbon capture utilisation and storage (CCUS), switching to renewable energy for processing, and powering electrolysers with dedicated low-emission energy, can lead to significant improvements already today. All fuel pathways can achieve low GHG intensities over time, but measures to reduce emissions are likely to increase costs, requiring market and policy frameworks that incentivise fuel pathways with superior GHG performance, supported by measurable and verifiable lifecycle data.

**A tiered GHG labelling system for fuels allows to define a minimum requirement, identify and reward better performance, and drive continuous improvement.** A labelling system that groups supply chain GHG intensities ($gCO_2$-eq/MJ) into a small set of distinct levels offers a robust and transparent way of communicating the sustainability of fuels to investors, policymakers and end-users. Based on consistent methodologies it helps the mutual recognition of existing schemes and fosters regulatory interoperability. It enables policies to identify and reward better performance, both today and over time, while still allowing a portfolio of lower-GHG fuels to contribute to decarbonisation in the early phase of the transition. Technologies tend to improve as they scale up and compete in the markets, making it important to focus on potential future GHG intensity levels rather than current ones (see arrows in the figure below). The threshold and tiers could be revised at certain intervals (e.g. every 5 years) to become more stringent, in line with the gradual transition of the global energy system towards net zero emissions by 2050.

**Example of a quantitative GHG intensity labelling system for selected sustainable fuel pathways**






Note: For assumptions and definitions, see Figure 4.1.

## Common policies and international collaboration are key to attract investment

**The absence of unified policy approaches to account for pathway-specific factors can deter investment and, ultimately, slow down the energy transition.** Certain emission drivers and sustainability attributes are unique to specific fuel pathways and cannot be solved within lifecycle assessment (LCA) and integrated in the proposed GHG labelling scheme. Examples of such pathway-specific sustainability aspects include indirect land-use change for biofuels, additional requirements for the electricity used for hydrogen produced from renewables, and the source of $CO_2$ and allocation of benefits for hydrogen-based fuels. Pragmatic policy solutions are needed to prevent them from becoming an obstacle for the deployment of sustainable fuels.

**Indirect land-use change (iLUC) concerns should be addressed by adopting risk-based approaches in the near term and striving to develop global land-use policies over time.** Although potential iLUC impacts can be significant, they cannot be directly measured or verified, only modelled. Rather than trying to calculate indirect emissions in terms of $gCO_2$-eq/MJ for a given biofuel pathway, alternative methods should be applied. In the short term, qualitative risk-based approaches that ensure compliance with low-iLUC-risk requirements can address potential impacts and encourage improvements. Over the long term, policies should shift from modelling impacts to enforcing direct land-use regulations globally and promoting better agricultural land management practices. In emergencies, such as economic crises, geopolitical events or extreme weather conditions, governments should consider temporary measures to address food security concerns. Biofuel policies should be designed to be flexible during periods of tightness in global agricultural markets to avoid amplifying or prolonging price spikes.

**Extra requirements for electricity used to produce electrolytic hydrogen, such as additionality, temporal and spatial correlation, should be applied thoughtfully.** To address potential indirect system impacts, some jurisdictions are placing extra requirements beyond the GHG intensity of the power grid mix, such as additionality and temporal and spatial correlation for the renewable electricity used for hydrogen production. However, power systems are decarbonising rapidly worldwide, independent of hydrogen deployment. Setting very strict criteria during the early stages of technology scale-up risks delaying investments, impeding the development of supply chains and infrastructure, and hindering potential benefits in terms of creating new electricity demand and new flexibility resources for integrating variable renewables. In the long term, possible indirect system impacts will fade as the role of fossil fuels in power systems diminishes. Under the NZE Scenario, power systems would be fully decarbonised globally before 2045.

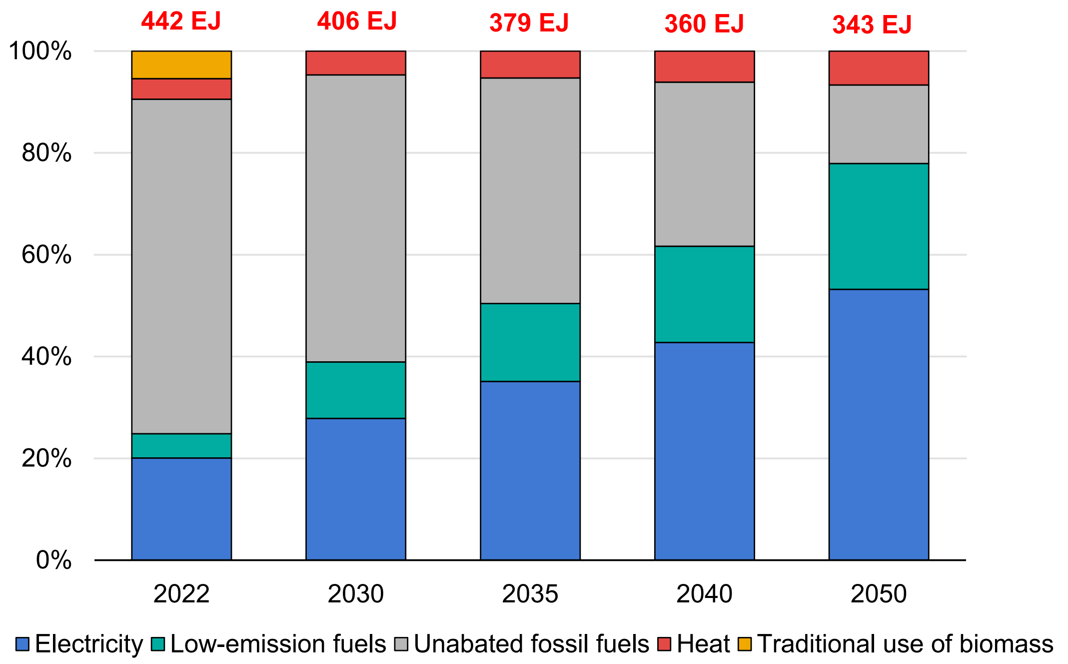
**The capture and use of fossil $CO_2$ from existing industrial sources could temporarily facilitate production of lower emission hydrogen-based fuels, as $CO_2$ supply from biogenic sources and direct air capture grows over time.** The $CO_2$ that is used to produce hydrogen-based fuels is ultimately released back into the atmosphere, and therefore it is important to consider the source of $CO_2$ feedstock. The biogenic or direct air-captured $CO_2$ component is carbon-neutral when the fuel is burned. In contrast, if fossil $CO_2$ captured from existing industrial processes is used as feedstock, system-level emissions are only partially reduced. The opportunity lies in the possibility to help jumpstart this new industry and relevant supply chains, while achieving initial emission reductions. However, robust, transparent and mutually agreed emissions allocation methods need to be in place to avoid double counting of emission reductions and correctly assess the GHG intensity of the synthetic fuel. This cannot be solved by LCA methodology, therefore requiring policy and commercial agreements. For instance, emission benefits could be split between the original $CO_2$ emitter and the fuel producer, at a mutually agreed share, possibly in proportion to relevant investments. In the long term, no use of fossil $CO_2$ feedstock would be compatible with the NZE Scenario.

**Enhanced stakeholder engagement and international cooperation is key for increasing consensus on common criteria for sustainable biofuels.** This includes further strengthening collaboration among international organisations, fostering cooperation with other end-use sectors, and encouraging consistent and transparent regulations for carbon accounting in Article 6 of the Paris Agreement, as well as in voluntary carbon markets. The G20 could also establish a voluntary expert group to develop and test a tiered labelling system for sustainable fuels in selected countries.

# Chapter 1. Introduction

At the 28th United Nations Climate Change Conference (COP28) in Dubai, governments acknowledged the necessity for emissions in the energy sector to reach net zero by 2050. The interim goals for 2030 include tripling global renewable energy capacity and doubling the rate of energy efficiency improvements. Other goals involve transitioning away from fossil fuels in a just, orderly and equitable manner; accelerating the use of emerging technologies like low-carbon hydrogen and carbon capture; as well as a focus on reducing emissions from road transport through infrastructure development and the rapid deployment of zero and low-emission vehicles.

**Figure 1.1 Global final energy consumption in the Net Zero Emissions by 2050 Scenario**

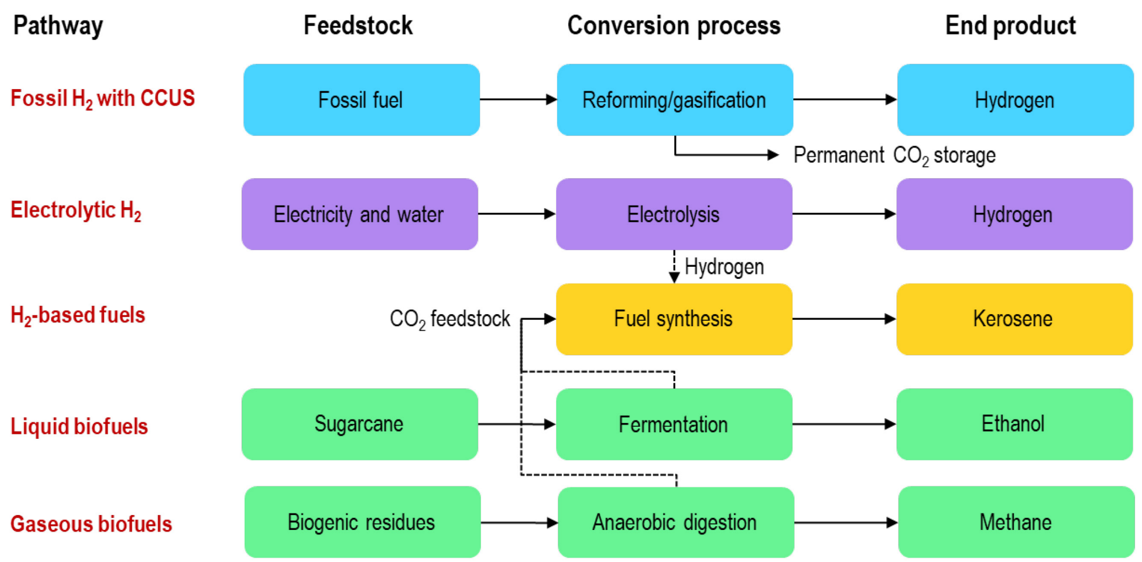





Notes: EJ = Exajoules

Under the IEA's Net Zero Emissions by 2050 (NZE) Scenario, demand for low-emission fuels such as liquid biofuels, biogases, hydrogen and hydrogen-based fuels would need to double from current levels by 2030 and double again by 2050. Despite their higher cost and availability barriers, low-emission fuels play a significant role in clean energy transitions, serving as critical complements to energy efficiency and direct electrification, and contributing to energy diversification and security. They facilitate decarbonisation across a range of end-use sectors, including transport, industry and power generation, while also providing seasonal energy storage and ancillary support to power grids.

**Figure 1.2 Examples of production pathways and technologies for sustainable fuels and potential synergies**





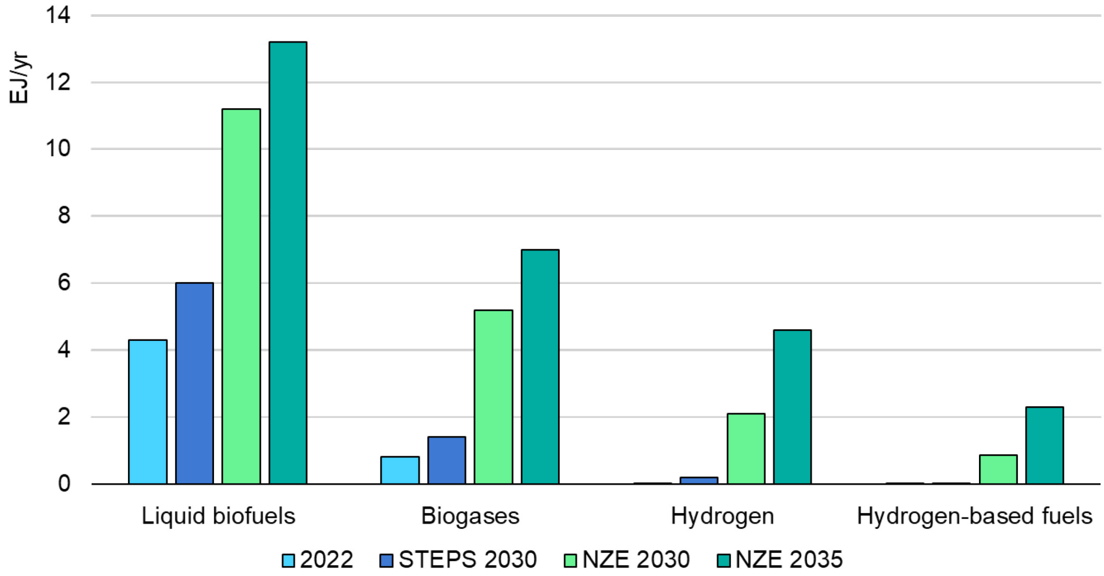

Numerous low-emission fuel options exist, ranging from alcohols (e.g. methanol, ethanol) to gaseous fuels (e.g. biogases, ammonia) and to liquid hydrocarbons (e.g. renewable diesel, sustainable aviation fuels). Same types of low-emission fuel can be produced through several pathways. Low-emission hydrogen, for example, can be produced either from biomass, from water with the help of electricity (electrolysis) or from fossil fuels through carbon capture utilisation and storage (CCUS). Some synergies also exist between different pathways. (See Fig 1.2) For example, converting low-emission hydrogen to synthetic kerosene requires also $CO_2$ feedstock, which could be obtained from a biofuel pathway that produces large quantities of $CO_2$ as a coproduct.

At present, none of the main sustainable fuel options are on track for a net zero pathway (Fig 1.3). They also vary widely in terms of costs, infrastructure needs, availability, level of deployment and technological maturity.

Biofuels are currently the most developed and cost-effective alternative to fossil fuels. However, substantial efforts are needed to expand and diversify biomass feedstock supplies, commercialise new processing technologies and harmonise sustainability frameworks to address concerns related to large-scale deployment.

Interest in low-emission hydrogen is driven in large part by its potential as a substitute for unabated fossil hydrogen in industry and by growing demand for new hydrogen applications. Falling renewable energy prices and the ability to retrofit existing fossil hydrogen plants with CCUS also contribute to its appeal. However, low-emission hydrogen is hindered by insufficient demand-side policies and a significant need to invest in infrastructure for its transport, distribution and storage.

**Figure 1.3 Total final consumption of liquid and gaseous low-emission fuels in 2022 and in the Stated Policies Scenario and the Net Zero Scenario**






Notes: STEPS = Stated Policies Scenario. NZE = Net Zero Emissions by 2050 Scenario. Fuel use for electricity generation or as a feedstock are excluded.

Hydrogen-based fuels such as ammonia, methanol and synthetic hydrocarbons add to the diversity of fuel decarbonisation options. Although hydrogen-based fuels typically require less investment in new distribution infrastructure than hydrogen, they are more expensive to produce. Their scalability is also constrained by limited access to low-cost, low-emission $CO_2$ feedstock (except for ammonia, which is a carbon-free molecule). Hydrogen-based fuels also compete with emerging non-fuel uses for hydrogen, such as the production of direct reduced iron (DRI).

There are potentially hundreds of pathways available for producing fuels, with a wide range of greenhouse gas (GHG) emissions today. However, a majority of pathways can achieve better and eventually very low emissions. Numerous frameworks and certification schemes for sustainable fuels have been established worldwide, creating confusion among investors, regulators and fuel producers. At the same time, most countries still lack GHG regulations for fuels.

This report – produced in support of Brazil's G20 Presidency – explores the implications of setting up common criteria to enable fair comparisons of sustainable fuels across different regions and markets. It maps the commonalities and differences among current standards, regulations and certifications used for low-emission fuels. It reviews typical carbon intensities and improvement potential of various fuel production pathways and lays out policy considerations for governments that wish to work towards common criteria for sustainable fuels. The report builds upon and expands on analysis presented in Carbon Accounting for Sustainable Biofuels (IEA, 2024), Towards hydrogen definitions based on their emissions intensity (IEA, 2023), and the Global Hydrogen Review 2024 (IEA, forthcoming).

# Chapter 2. Carbon accounting: Standards, regulations and certification systems

Standards, regulations and certification systems exist to assess, validate and incentivise the deployment of low-emissions fuels based on the intensity of their greenhouse gas (GHG) emissions. As low-emission fuels have gradually entered markets, it has become necessary to create frameworks to account for these emissions, and to verify and certify them. Biofuels were the first alternative fuels to be developed – in Brazil in the 1970s and in the United States and Europe in the early 2000s. Because of their higher cost compared to fossil fuels, growth was driven by energy security concerns, national targets and mandates. In certain regions, certification schemes were developed to help producers demonstrate compliance with legal requirements.

With the evolution of carbon markets, carbon pricing instruments and voluntary private sector commitments, biofuels have attracted new demand from non-regulated customers. For instance, some gas utilities supply biomethane to assist their customers in meeting voluntary decarbonisation targets. In such cases, certificates and guarantees of origin are required to verify the sustainability attributes of the energy used (to justify the price premium) and to prevent double counting of emission reductions.

Low-emission hydrogen and hydrogen-based fuels are beginning to gain traction in the sustainable fuels market. While policy frameworks for them are still being finalised, several certification schemes have already been established to comply with regulations and to support emissions reporting.

## System boundary for fuel supply chains

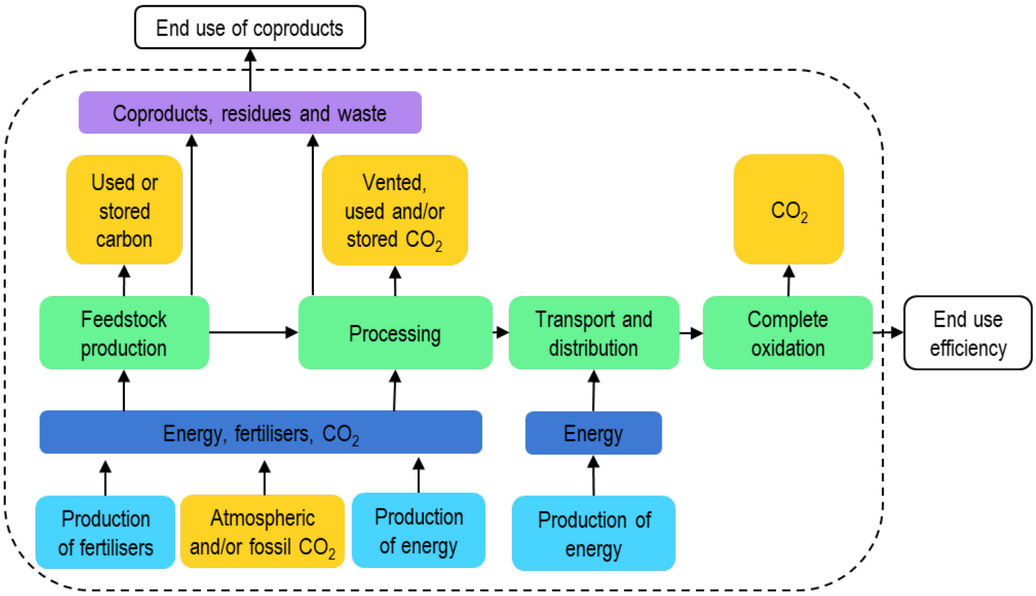
With the emergence of regulations and certification systems for sustainable fuels, the ability to calculate the GHG intensity for fuels in a transparent and comparable way has become important. Any robust calculation a fuel's GHG intensity (usually expressed as grams of $CO_2$ equivalent per megajoule of fuel, or $gCO_2$-eq/MJ) starts with the definition of a system boundary that describes all elements in the fuel supply chain that are considered relevant for the assessment (see Fig 2.1).

Fuel regulations are in most cases based on the widely recognised lifecycle assessment (LCA) methodology. The ISO standard (in particular ISO 14040, ISO

14044 and ISO 14067) states that LCAs should evaluate "environmental aspects and potential impacts throughout a product's life cycle (i.e. cradle-to-grave) from raw materials acquisition through production, use and disposal."

In the case of sustainable fuel regulations such as biofuels, the assessment takes only GHG emissions into consideration, with other sustainability criteria being covered by other additional requirements. Emissions associated with fuel delivery can also be significant, especially for hydrogen that is transported over long distances by ship.

**Figure 2.1 System boundary for comparing the supply chain GHG intensity of fuels**






Note: In the case of hydrogen carriers, transport and distribution also includes possible conversion and reconversion of hydrogen.

Emissions from construction and manufacturing of assets (usually called embodied emissions, or capital goods emissions) are usually excluded from the lifecycle assessment, as they are deemed to be low and therefore below the typical cut-off criteria. However, in the case of fuels produced via electrolysis, GHG emissions from the manufacture of captive power plants (e.g. renewable or nuclear) should be included within the system boundary, as their contribution may be non-negligible.

The final oxidation of the fuel should be considered in the GHG intensity calculation to account for the release of any fossil $CO_2$ possibly used in fuel production. $CO_2$ emissions from biofuels are considered balanced by the amount of $CO_2$ captured by the biomass feedstock during its growth. Similarly, $CO_2$ emissions resulting from the oxidation of fuels that were made using air-captured $CO_2$ feedstock are considered balanced by the amount that was originally captured, therefore not affecting the overall atmospheric balance of $CO_2$. If the scope of the GHG comparison is extended beyond fuels to the final product or service, end-use efficiency should also be included (see Box 2.1).

All major biofuel policy frameworks apply a similar system boundary to the one described above, encompassing emissions from feedstock and fuel production as well as fuel transport, distribution and complete oxidation. In contrast, almost 80% of hydrogen certification schemes today do not cover transport and distribution of the final fuel. At COP28, the International Organization for Standardisation (ISO) introduced Technical Specification 19870, based on ISO 14067. This technical specification provides a framework for determining emissions associated with the production, conditioning and transport of hydrogen and will be used as input for a series of ISO standards in 2025/2026, which are expected serve as common voluntary technical standards for subsequent hydrogen certification schemes.

### Box 2.1 Impact of energy end uses on overall GHG emissions

In GHG accounting, the term “well-to-production gate” (WTG) typically refers to a system boundary that encompasses GHG emissions associated with feedstock production (“well”), its transport to the conversion plant, and the conversion of feedstocks into finished fuels and possible coproducts (“gate”). A “well-to-tank” (WTT) system boundary extends the scope to include distribution of the fuel to the point of use (“tank”). A “well-to-wheels” (WTW) system boundary expands the scope further to include the powertrain efficiency associated with a fuel’s end use.

Biofuel policy frameworks – such as the EU RED, California’s LCFS (using the GREET model) or CORSIA for aviation – use an approach equivalent to a well-to-tank scope, plus emissions that result from the fuel’s complete oxidation. This approach ensures that all relevant elements contributing to GHG emissions are included. It also enables comparison between different biofuels and vis-a-vis fossil fuels.

However, when comparing fuels that are used in vastly different powertrains or applications, the well-to-wheels (WTW) method is recommended. The GHG intensity can then be expressed in units of use or service, such as $gCO_2eq/100$ km (in the case of transport) or $gCO_2$-eq/MJ heat (in the case of process industry). For example, hydrogen can be used either in an internal combustion engine (operating at 20% to 30% efficiency) or in a fuel cell (operating at 40% to 60% efficiency). This means that in transport, fuel cells can reduce fuel consumption and emissions per kilometre by as much as 50% compared to internal combustion engines, even when they use the same fuel.

Electrification of energy demand is another critical technology pathway for lowering emissions again showing the importance of considering end-use efficiencies in certain contexts. For example, in some industrial applications, heat pumps are far more efficient than combustion-based systems, delivering three to four units of heat for each unit of electricity consumed. In transport, battery-electric powertrains operate at over 80% efficiency, resulting in significantly lower GHG emissions per kilometre compared to internal combustion engines, even though the GHG intensities of the input fuel and electricity would be identical.

There are several studies that provide information on the WTW approach for fuels (for example, the JEC series published for the European context, with separated values for well-to-tank and tank-to-wheels emissions). The GREET model has also additional modules, with the GREET1 series covering well-to-wheels emissions and GREET2 focusing on a vehicle-cycle emissions, including manufacturing and material recycling. These aspects become relevant when considering other powertrains such as electric vehicles (EVs).

While it is crucial to recognise differences in end-use efficiency, it is equally important to be able to compare energy inputs on a consistent basis. This is common practice with electricity, where different generation pathways are compared based on grams of $CO_2$-equivalent per kilowatt-hour ($gCO_2$-eq/kWh). Once common criteria for comparing fuel sustainability are established, end-use efficiency can be incorporated to arrive at a more holistic approach that aligns with other objectives.

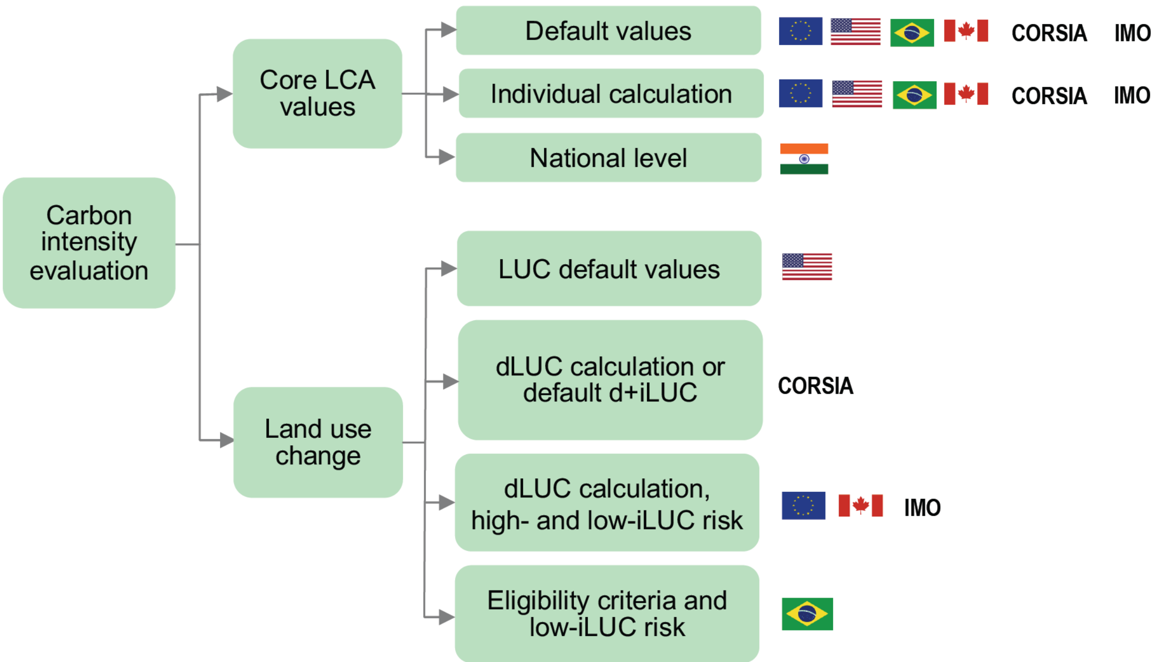
# Overview of existing frameworks and schemes

## Biofuels

The main biofuel policy frameworks provide specific guidance on calculating GHG emissions from biofuels and how compliance with GHG reduction requirements should be verified. These are based on widely recognised LCA methodology, including the ISO's 14000 series of environmental management standards.

Approaches to carbon accounting for biofuels vary across countries, markets and end-use sectors (Figure 2.2). Variations in GHG intensity results are due to different regional conditions, the sector's level of development and reliance on specific feedstocks. Emissions associated with biofuel production and usage (excluding the impact of land-use changes) are referred to as "core LCA values" under the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) framework and the California Low Carbon Fuel Standard (LCFS). Several frameworks, such as those of the United States and Brazil, permit the use of default values for total or partial emissions, or the calculation of individualised pathways with specific standardised calculation tools such as GREET (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) in the United States, CA-GREET and other GREET-based calculators in California, and RenovaCalc in Brazil. In the European Union, biofuel producers can use default values that correspond to upper-bound (not average) emissions or can calculate their own actual GHG emission values to demonstrate superior performance, based on a methodology defined in the Renewable Energy Directive (RED) allowing for the use of different calculators. Values are then verified through a certification system involving a third-party audit by an independent certification body.

**Figure 2.2 Carbon accounting approaches in the main biofuel policy frameworks**






Notes: LCA = lifecycle assessment; dLUC/iLUC = direct/indirect land-use change. In core LCA values, Brazil's RenovaBio presents default values for the agricultural phase only.
Source: IEA (2024), Carbon Accounting for Sustainable Biofuels.

The main biofuel policy frameworks also differ in how emissions from direct and indirect land-use change are considered. Direct land-use change (dLUC) refers to the direct conversion of land from one use to another to produce biofuels, while indirect land-use change (iLUC) occurs when biofuel production indirectly causes changes in land-use elsewhere. Due to the indirect nature of iLUC, it cannot be measured or verified, only estimated using economic models.

Frameworks such as the California LCFS, the US Environmental Protection Agency's (EPA) Renewable Fuel Standard (RFS) and CORSIA use customised models to estimate potential emissions from overall land-use change for biofuel pathways and include them in regulations.

Meanwhile, biofuel producers selling their products in the European Union under RED III must individually calculate emissions from direct land-use change based on a harmonised methodology whenever a relevant land-use change event is identified in their production processes. Emissions from indirect land-use change are not quantified at the biofuel producer level. However, member states report iLUC emissions resulting from government policies to the European Commission using standardised default values for iLUC emissions across the European Union. Furthermore, the EU RED III includes detailed instruments to make biofuels with low iLUC-risk feedstocks eligible, while in some sectors biofuels with high iLUC risk are either subject to progressive quota limitations or excluded completely. Other regulations, such as CORSIA, IMO and RenovaBio, also consider low-iLUC-risk feedstock categories. (See IEA report on biofuel carbon accounting for more information.)

## Hydrogen and hydrogen-based fuels

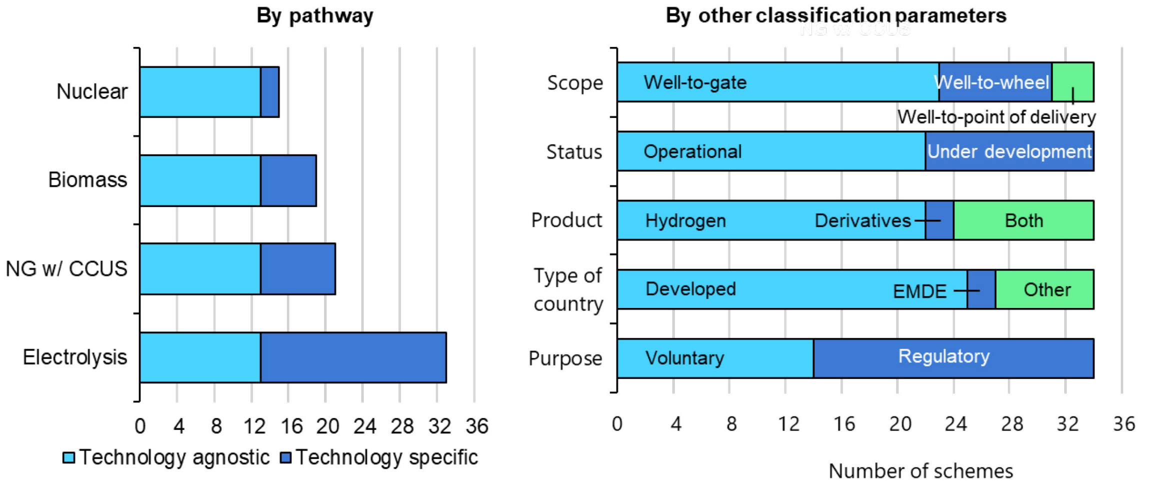
There are currently 34 certification schemes[1] (Figure 2.3) for hydrogen and/or hydrogen derivatives.[2] Thirteen schemes are technology-open, setting only GHG intensity thresholds that must be met for hydrogen or its derivatives to be considered low-emission and comply with regulations. With one exception, all the schemes include electrolysis in their production routes. Eight schemes explicitly cover natural gas reforming with CCUS, while six address production from biomass. Most of the schemes were established in advanced economies, while only two (Brazil and India) were designed in emerging market and developing economies (EMDEs). Around one-third of the schemes are still under development, which provides an opportunity to use international guidelines – such as the Technical Specification from the International Organization for Standardization (ISO) – as a voluntary technical standard.

Only 20% of the schemes include transport and end-use emissions in their scope. The scope of the schemes is relevant given that multiple countries are targeting trade as part of their hydrogen strategies and the global project pipeline of trade projects adds up to almost 17 Mt $H_2$eq by 2030 (about 20% of current hydrogen demand).

[1] This section discusses all the "certification schemes" together to ease understanding. Some refer to legislation linked to mandatory requirements or incentives introducing criteria that would need a recognised certification scheme to demonstrate compliance, while others are voluntary schemes. Refer to Box 2.2 for clarifications of the terminology.

[2] Derivatives include a wide range of products, ranging from ammonia to other hydrogen-based fuels and non-fuel commodities like steel.

**Figure 2.3 Certification schemes for hydrogen and/or derivatives**






Note: EMDE = Emerging market and developing economies. NG = natural gas. CCUS = carbon capture utilisation and storage. Total sample of 34 certification schemes. Some certification schemes are technology-open, bioenergy is explicitly mentioned by six schemes, while nuclear is explicitly mentioned by only one. Hydrogen derivatives include ammonia, methanol, methane and jet fuel (kerosene). Under type of country, "Other" combines schemes that are international with one for China. Three entries with a scope of "well-to-point of delivery" have been simplified as "well-to-gate" for illustration purposes.

Certification schemes apply various emission thresholds based on the underlying regulatory frameworks and legislation (Figure 2.4). More than half of the schemes require a GHG intensity of less than 33 $gCO_2$-eq/MJ (4 $kgCO_2eq/kgH_2$), which is 60% to 70% lower than emissions of production from unabated natural gas – the most common production pathway today.

Among the schemes that allow higher thresholds, six are targeted to reduce $CO_2$ emissions from road transport. They consider that hydrogen is used more efficiently in fuel cells compared to fossil fuels in internal combustion engines, justifying the use of higher thresholds. Higher thresholds are also permitted in China, where nearly 60% of hydrogen is produced from unabated coal (which can have more than double the emissions from unabated natural gas) and therefore reference emissions are higher. Brazil recently passed legislation with an emissions threshold of 7 $kgCO_2$-eq/$kgH_2$ (58 $gCO_2$-eq/MJ), which is more than double the threshold in the European Union, and 3.5 times the threshold set by India. At the lower end, Australia has proposed a threshold equivalent to just 5% of the unabated natural gas route for its Hydrogen Production Tax Incentive (HPTI). The goal is to promote the development of renewable hydrogen.

In addition to fixed limits, several countries use tiered systems that define multiple emissions thresholds, rewarding fuels from lower emissions.

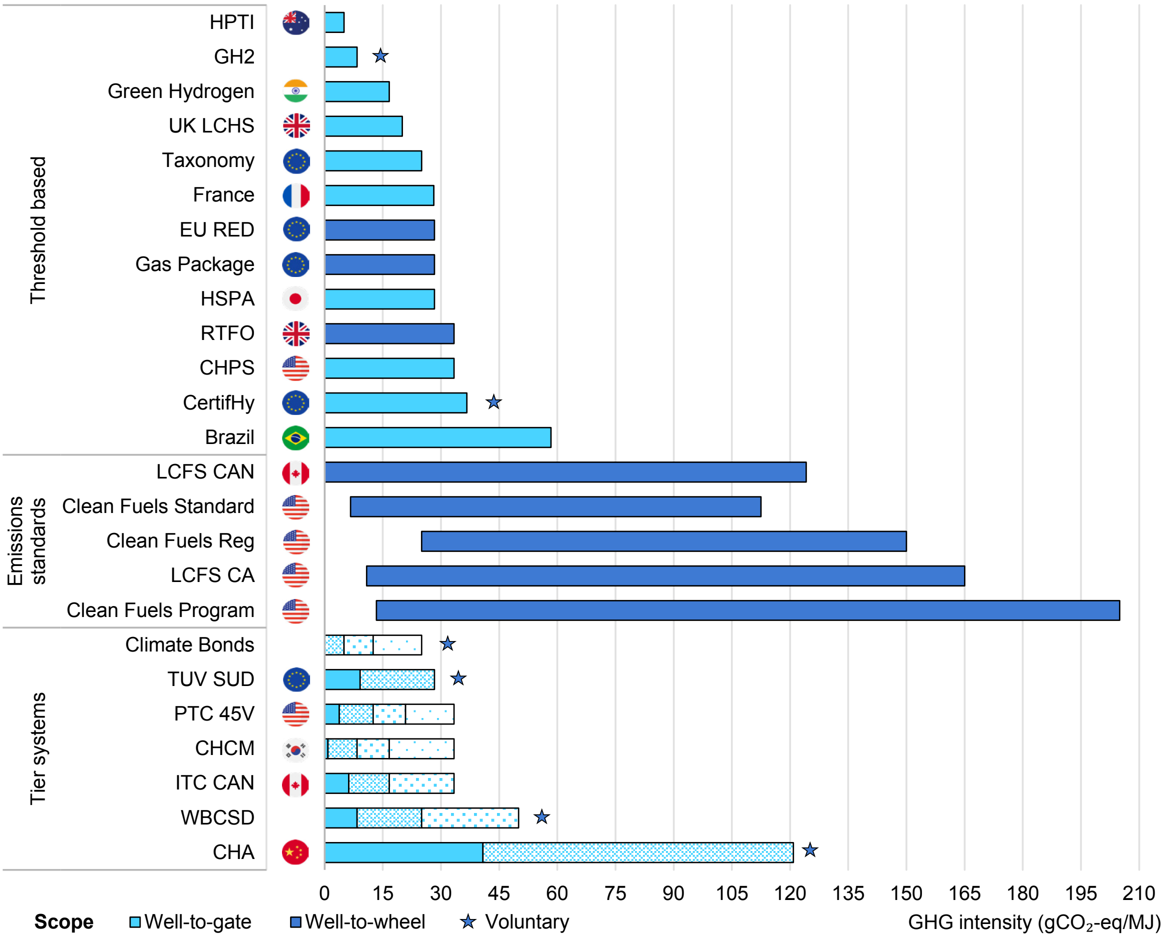
Except for the European Union, the UK Renewable Transport Fuel Obligation and H2Global, all the schemes with a threshold below 33 $gCO_2$-eq/MJ (4 kg-$CO_2$eq/kg

$H_2$) exclude emissions from transport and distribution of hydrogen from their scope. Hydrogen that is traded globally will necessarily have higher GHG intensity due to transport and conversion. This means that schemes that consider transport and are also subject to the same thresholds as schemes that only consider production emissions must set more stringent compliance requirements for hydrogen producers.

Only two schemes cover hydrogen-based fuels exclusively. One is from H2Global, which has a well-to-point of delivery scope. The other is a voluntary scheme by the Ammonia Energy Association, which was originally proposed in 2021 and currently under development.

Most schemes that do not define a threshold are voluntary. One exception is the EU Carbon Border Adjustment Mechanism (CBAM). Instead of a dedicated certification scheme for hydrogen, the European Union relies on accredited verifiers to assess the emissions from imported goods, which are then used to create CBAM certificates (equivalent to their estimated emissions). The products covered include hydrogen and fertilisers (including ammonia), while other fuels like synthetic methanol, methane and kerosene are excluded. The scope of the emissions assessment includes electricity consumption but excludes transport of the goods and upstream and midstream emissions.

**Figure 2.4 GHG intensity level of certification schemes and regulations for hydrogen and/or derivatives, by scope and type of scheme**






Notes: HPTI = Hydrogen Production Tax Incentive; GH2 = Green Hydrogen Standard; UK LCHS = United Kingdom Low-Carbon Hydrogen Standard; RED = Renewable Energy Directive; HSPA = Hydrogen Society Promotion Act; RTFO = Renewable Transport Fuel Obligation; CHPS = Clean Hydrogen Production Standard; LCFS = Low-Carbon Fuel Standard; Reg = Regulation; CA = California; PTC 45V = Production Tax Credit under section 45V of the US Inflation Reduction Act; CHCM = Clean Hydrogen Certification Mechanism; CAN = Canada; ITC = Investment Tax Credit; WBSCD = World Business Council of Sustainable Development; CHA = China Hydrogen Alliance. Emissions standards are credit-based systems for road transport with progressive emissions-reduction targets for the entire sector. Values reflected for these standards are the default certified pathways. Pattern-filled bars refer to schemes that use a tier system. Total sample of 25 certification schemes excluding 9 out of 34 that do not assign thresholds. For regions that do not start from zero, these are carbon-crediting schemes with default carbon intensities for defined pathways, which are the ones reflected in the figure.

Source: Global Hydrogen Review 2024 (IEA, forthcoming).

In total, ten schemes[3] (of which five are regulatory and five voluntary) cover both hydrogen and its derivatives. Seven (three regulatory) of these are already operational. European schemes do not have a specific pathway defined, but they only specify a GHG threshold and the methodology that any hydrogen (or derivative) should achieve. Ammonia is the most common pathway among

[3] European Union Taxonomy, Renewable Energy Directive, Clean Hydrogen Investment Credit, Zero Carbon Certification Scheme, Guarantee of Origin (Australia), Hydrogen Society Promotion Act, GH2 Green Hydrogen Standard, ISSC EU, I-REC, International Maritime Organisation.

schemes that explicitly mention hydrogen carriers. Steel is exclusively mentioned in the (voluntary) Zero Carbon Certification Scheme.

Most of the discussed schemes have emerged in the last five years. They have different aims – such as boosting the share of renewable energy in a sector, accelerating hydrogen deployment, providing policy incentives, etc – resulting in a variety of designs and giving rise to four key challenges:

- Data gaps exist for certification across schemes. If an importer's jurisdiction covers ammonia, but the exporter does not collect data associated with ammonia production (as it is outside the scope of their country's scheme), the importer might miss certain data for estimating emissions associated with the imported product.
- Schemes could be subject to different governance structures, operational procedures or IT systems that hinder interoperability.
- Assessment scopes vary among different schemes (e.g. well-to-gate versus well-to-tank). Two countries can therefore claim the same GHG intensity for a given pathway, yet still reference different actual emissions due to variations in scope.
- Several voluntary schemes do not fall under the purview of a specific government. Governments can either approve or reject the use of these schemes but have no control over their design or criteria. This can lead to parallel markets for regulated and voluntary schemes, increasing the administrative burden for project developers.

There are various solutions to the challenges mentioned above. Data gaps can be addressed, for example, by using standard templates for data collection. Adopting ISO standards – which also account for hydrogen (re)conversion and transport – could provide a common foundation for all schemes. Countries would be free to apply additional criteria as they see fit, but a shared minimum standard would apply to everyone. This unified approach would also avoid the risk of misinterpreting parameters involved in commodity production. Potential solutions to the differing scopes of the schemes would be either mutual recognition with equivalence conversions, or adopting a common standard, as suggested above. While this might work for future schemes or those under development, it could still result in inconsistencies with those already in operation. However, there is also a trend toward harmonisation. At COP28, 37 governments pledged to work toward aligning design principles for certification by collaborating within the framework of the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) and the Hydrogen Technology Cooperation Programme (Hydrogen TCP). In Latin America, 14 countries launched "CertHiLAC", backed by multilateral development banks, to reach a similar objective.

### Box 2.2 Certification terminology

In this report, various terms related to certification are defined as follows:

**Certification** refers to the process of determining whether a product complies with a given set of criteria. These may be **mandatory** requirements to demonstrate **compliance** with legislation (e.g. the Low Carbon Fuel Standard in the United States) and/or eligibility for incentives (e.g. Green Hydrogen Standard in India). Alternatively, they can be **voluntary**, such as **reporting** progress toward defined targets (e.g. Climate Bonds Initiative) following **disclosure** guidelines.

**Certificates** can carry information about the origin of the energy used for production, time and location, as well as evidence of its sustainability attributes including GHG emissions footprint. This is usually intended to enhance transparency. Information disclosed may be limited to the origin of the energy (in which case, the certificate is called a "**guarantee of origin**") or broader environmental attributes such as land or water use (in which case it is called a "**sustainability certificate**"). An example is the Renewable Energy Directive (RED) in the European Union, which mandates disclosure of energy origin (Article 19) and broader environmental impact aspects (Articles 29 and 30), resulting in the development of schemes to verify compliance with these requirements.

**Chain of custody** refers to the process of transferring ownership of the certificates and ensuring the certificate corresponds with the certified product. In a **book and claim** model, the certificate is entirely separate from the product and both can be traded independently. In a **mass-balancing** model, the two remain linked.

A **certification scheme** encompasses the governance, application, evaluation, enforcement and verification of certificates. This includes stakeholders (e.g. issuing body) and their roles, registry and processes. In some cases, legislation comes first, followed by the establishment of certification schemes to enable project developers to access incentives associated with the legislation. For example, the production tax credit in the United States has set GHG thresholds that projects must comply with to access tax incentives. But there is currently no certification scheme to verify compliance, and final guidelines are still being defined. In contrast, the International Sustainability and Carbon Certification (ISCC) scheme for synthetic fuels was in place before the EU RED legislation became final, and the issuing body is now seeking recognition for the scheme from the European Commission to demonstrate compliance toward RED targets (as are the bodies behind other schemes).

A **labelling scheme** can be used to document that a product or production route has satisfied a defined set of criteria established by the certification process, such as labels that communicate the emissions intensity of hydrogen production. For example, the “green” hydrogen standard in India is a label that can be applied to hydrogen meeting a threshold of 17 $gCO_2$-eq/MJ (2 $kgCO_2eq/kgH_2$).

A technical **standard** defines a formalised and shared methodology to be used to assess certain criteria defined by the certification scheme. This can include boundaries, product specifications and GHG accounting rules, among others. The ISO Technical Specification is one example.

To facilitate understanding, the term “certification” may be used elsewhere in this report to encompass several of the above aspects.

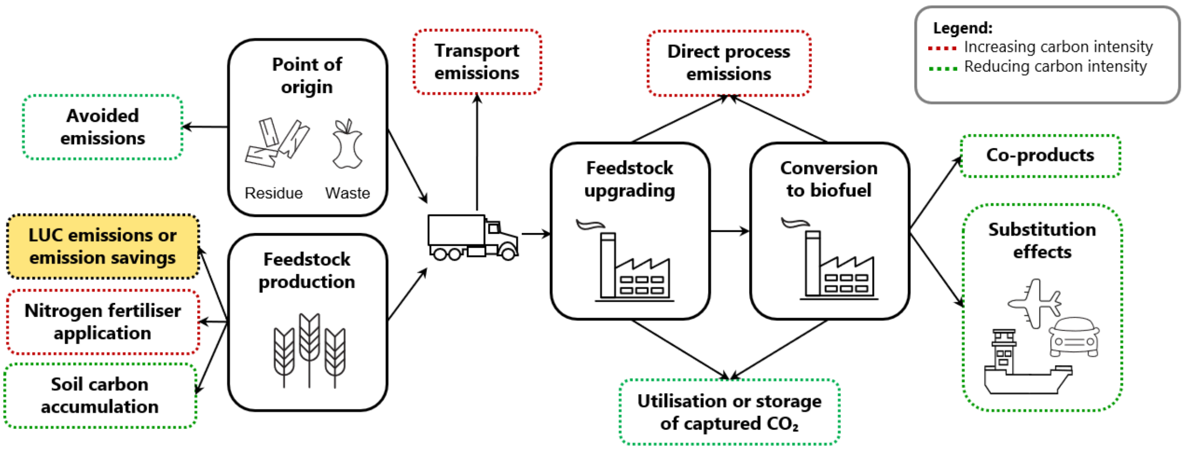
# Chapter 3. GHG emission drivers and improvement potential

## Emission drivers of biofuels

Main attributes impacting the lifecycle emissions of biofuel supply chains relate to production of the feedstock, conversion of the feedstock to biofuel, handling of biogenic $CO_2$ and allocation of emissions to possible coproducts (see Fig 3.1)

When biofuels are produced from crop feedstocks, emissions from nitrogen fertilisers and from changes in soil carbon stocks need to be considered. Traditional nitrogen fertilisers are made from fossil fuels, and they also emit nitrous oxide ($N_2O$) – a powerful greenhouse gas – when applied to a field. Certain agricultural practices, such as using organic soil amendments (e.g. biochar, compost, digestate), can enhance organic soil carbon and thus help reduce overall supply chain GHG emissions.

**Figure 3.1 Key factors for calculating GHG intensity for a typical biofuel supply chain**




IEA. CC BY 4.0.

Notes: LUC = land-use change.
Source: IEA (2024), Carbon accounting for sustainable biofuels.

Changes in land use can have a further impact on emissions, either directly or indirectly. Direct land-use change (dLUC) happens when biofuel feedstock cultivation replaces another land-use. It is relatively well understood and can be measured and monitored over time. Indirect land-use change (iLUC) occurs when biofuel crops replace food or feed crops and consequently displace food or feed cultivation elsewhere. Unlike with direct emissions, iLUC emissions cannot be measured or verified, only estimated based on global economic models. Land-use change can either increase biofuel supply chain emissions (e.g. through the transformation of grassland to agricultural land) or reduce it (e.g. through reconversion of marginal or degraded land into agricultural land).

Using biogenic wastes and residues as feedstock for biofuels avoids land-use change. It can also reduce overall emissions by avoiding those emissions that would result from alternative (non-biofuel) waste treatment methods.

Emissions occur also at the processing plants where feedstocks are converted to biofuel. If fossil fuels are used to meet process energy demand – common for many pathways today – direct process emission can be significant. However, they can be mitigated by switching to low-emission energy sources, such as biogas or electric heating. For pathways where a significant amount of biogenic $CO_2$ is released as a coproduct (e.g. fermentation, anaerobic digestion and gasification), carbon capture followed by permanent storage can result in significant negative emissions.

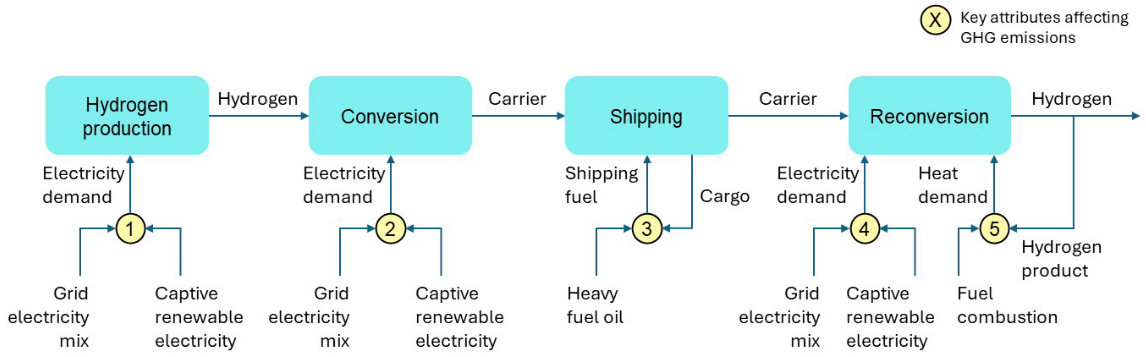
Some biofuel pathways can produce substantial amounts of coproducts, such as corn oil or distiller's dried grains with solubles (DDGS) from corn ethanol plants, electricity from bagasse (from sugarcane mills), or biochar (from pyrolysis or gasification). How emissions are allocated to coproducts can significantly affect overall biofuel emissions.

# Emission drivers of hydrogen and hydrogen-based fuels

When hydrogen is produced from fossil fuels with carbon capture utilisation and storage (CCUS), the main drivers for emissions are the $CO_2$ capture rate (the share of direct $CO_2$ emissions that are captured and permanently stored), and upstream and midstream emissions associated with the fossil fuel. When hydrogen is produced from water with electrolysis, electricity use is the main driver for emissions.

Supply chain emissions of hydrogen can be much higher than those associated with its production, due to the multiple conversion losses that occur along the supply chain (Figure 3.2). This is especially true for the marine transport of hydrogen, as it may need to be converted into another chemical compound, such as ammonia, for shipment and then converted back to hydrogen at the delivery point. The share of total emissions from fuel transport and reconversion can vary significantly depending on the sources of electricity used for conversion, the fuel used for shipping and the energy required for reconversion. In the case of ammonia, these emissions can represent anywhere between 10% and 85% of a fuel's supply chain emissions.[4]

**Figure 3.2 Key factors for calculating GHG intensity for a typical electrolytic hydrogen supply chain with marine transport**




IEA. CC BY 4.0.

Fossil fuels are not necessarily required for shipping hydrogen, as the vessel can also be powered using low-emission fuels or the transported fuel (cargo) itself. However, using the cargo as a fuel reduces the amount that can ultimately be delivered, resulting in higher emissions per MJ (as production emission are allocated to a smaller amount of product). Finally, conversion of the carrier substance back to hydrogen at the receiving port is energy-intensive for both ammonia and Liquid Organic Hydrogen Carriers (LOHC). If fossil fuels are used for this energy, it results in higher emissions.

For hydrogen-based fuels the main emission drivers are same as for hydrogen. However, because of additional efficiency losses caused by conversion of hydrogen to another fuel (e.g. ammonia or methanol), these fuels are more sensitive to the GHG intensity of their energy inputs. Additionally, when $CO_2$ feedstock is used to produce hydrogen-based fuels, emissions related to this $CO_2$ must also be considered.

# GHG intensities and improvement potential

## Biofuels

While biofuel pathways are as diverse as their feedstocks, a large share of biofuels is produced using either fermentation or hydrotreatment. In fermentation, sugars

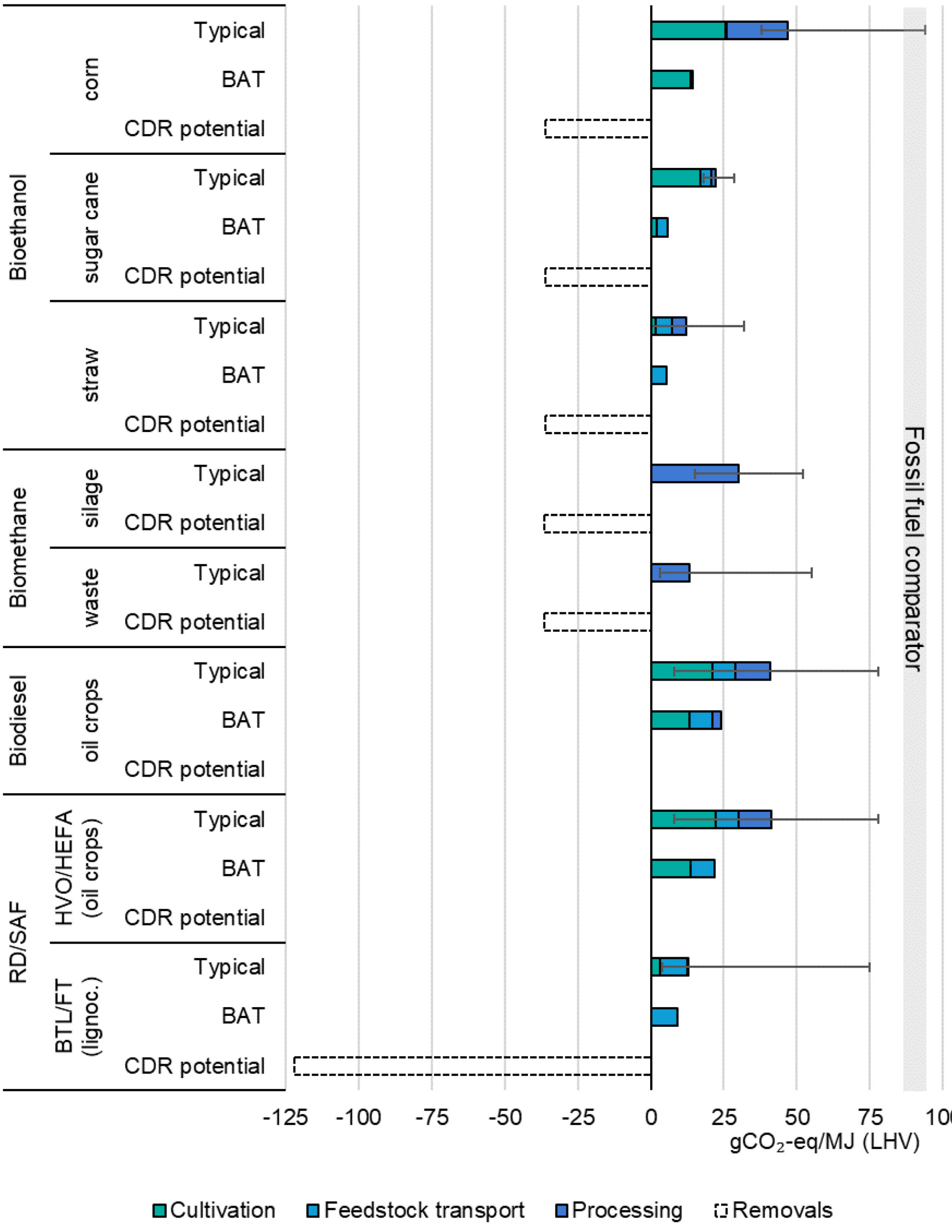
[4] The lower bound assumes that conversion to ammonia is powered by grid electricity (460 gCO2/kWh) and heat for the reconversion is delivered by the hydrogen itself. The upper bound reflects a system where both the conversion and reconversion are based on renewable electricity and heat. In both cases ammonia cargo is used as fuel for shipping.

are extracted from the feedstocks and converted to ethanol by applying water and enzymes at low temperature. This is followed by purification of the ethanol via distillation. Most process energy needs are for heat and are usually supplied by natural gas. However, when the feedstock is sugarcane, energy needs can also be met by burning bagasse residues. Additional low-emission energy options would be biogas or electric heating. A corn ethanol pathway based on fossil fertilisers and fossil energy inputs has a typical GHG intensity of 45 $gCO_2$-eq/MJ – roughly half the emissions from fossil gasoline.[5] A switch to low-emission energy sources at the ethanol plant would cut emissions by 40%, leaving only emissions related to cultivation. Using low-emission energy sources and fertilisers in cultivation could further reduce emissions (caused by $N_2O$ emissions from fertilisers) to around 20% of gasoline emissions. Fermentation also generates a significant amount of biogenic $CO_2$, which is released as a concentrated, nearly 100% pure stream. The capture and permanent underground sequestration of this $CO_2$ stream could potentially result in negative emissions, pushing total ethanol emissions to -20 $gCO_2$-eq/MJ. Once ethanol is produced, it can be blended with fossil gasoline, or further processed into liquid hydrocarbon fuels such as kerosene, using alcohol-to-jet technologies.

In hydrotreatment, vegetable oils, animal fats and waste oils are broken down at elevated temperature and converted to hydrocarbons like renewable diesel or sustainable aviation fuels (SAF), in the presence of hydrogen. A pathway based on crop feedstocks and fossil hydrogen has a typical GHG intensity of between 33 and 55 $gCO_2$-eq/MJ, or between 35% and 60% of fossil diesel emissions. Using low-emission energy sources and fertilisers in cultivation could reduce emissions to as low as 15% to 20% of those from fossil diesel, leaving only soil $N_2O$ emissions. For waste oils – such as used cooking oil – cultivation emissions are zero. The hydrogen needed for the hydrotreatment process is typically derived from natural gas, contributing to 10 $gCO_2$-eq/MJ of emissions for the conversion step. This could be minimised by switching to low-emission hydrogen in the production process. Hydrotreatment does not produce a significant $CO_2$ coproduct stream, leaving fewer opportunities for negative emissions through integration with CCS.

[5] Typical GHG emissions for biofuel pathways discussed in this section are from IEA analysis based on Edwards et al. (2019), Definition of input data to assess GHG default emissions from biofuels in EU legislation.

**Figure 3.3 GHG intensity of selected biofuel production routes under typical conditions, with best available technologies, and potential for $CO_2$ removal**






Notes: RD/SAF = renewable diesel/sustainable aviation fuel; HVO/HEFA = hydrotreated vegetable oils/hydro processed esters and fatty acids; BTL/FT = biomass-to-liquids/Fischer-Tropsch; CDR = carbon dioxide removal; BAT = best available technology to minimise GHG emissions from cultivation and processing using low-emission energy and fertilisers, but assuming no change in emissions from feedstock transport. CDR potential refers to the amount of negative emissions that could be obtained by permanently sequestering coproduct $CO_2$ (only capture and storage as $CO_2$ is considered, additional CDR could be achieved via soil carbon accumulation through the application of biochar). Impact of possible sustainable land-use practices or land-use changes are not included.

Source: IEA analysis based on GHG emissions values (typical) from EU RED II Annex V (2018).

Hydrocarbon fuels or alcohols can be produced also from solid lignocellulosic feedstocks, although such technologies are not yet fully commercialised. An example process involves gasification of biomass at elevated temperatures, followed by purification of the produced gas and catalytic synthesis to form the desired fuel molecules. Typical emissions for this pathway would be less than 10% compared to fossil fuels. Conversion emissions are close to zero, as the process is self-sufficient in terms of heat. For this reason, emissions are largely driven by cultivation. A large, concentrated stream of biogenic $CO_2$ would be produced as a coproduct of the process. If captured and permanently stored underground, this could lead to deeply negative emissions of around -120 g$CO_2$-eq/MJ.

**Box 3.1 Carbon neutrality of biofuels and hydrogen-based fuels**

During the growth of biomass feedstocks, plants absorb carbon dioxide from the atmosphere through the process of photosynthesis. When biofuels are burned for energy, the $CO_2$ released into the atmosphere is essentially the same carbon that was previously absorbed, and therefore $CO_2$ emissions from the use of biofuels are typically assumed to be carbon neutral (0 g$CO_2$-eq/MJ).

Not all the carbon contained by biomass ends up in a biofuel as some is released when biomass feedstocks are converted to biofuel. This release of $CO_2$ is also considered carbon neutral as it is not affecting the overall atmospheric balance of $CO_2$. However, if the $CO_2$ were captured and permanently stored underground, it would result in a net removal of $CO_2$ from the atmosphere, potentially giving the biofuel a negative GHG intensity.

Instead of storage, biogenic $CO_2$ can also be used as a feedstock for making hydrogen-based fuels. An alternative source would be $CO_2$ that has been acquired directly from the ambient air using a process called direct air capture (DAC). When hydrogen-based fuel is burned for energy, the released $CO_2$ is essentially the same carbon that was previously removed from the atmosphere, either through plant growth or a DAC process. As a result, these emissions can also be considered carbon neutral.

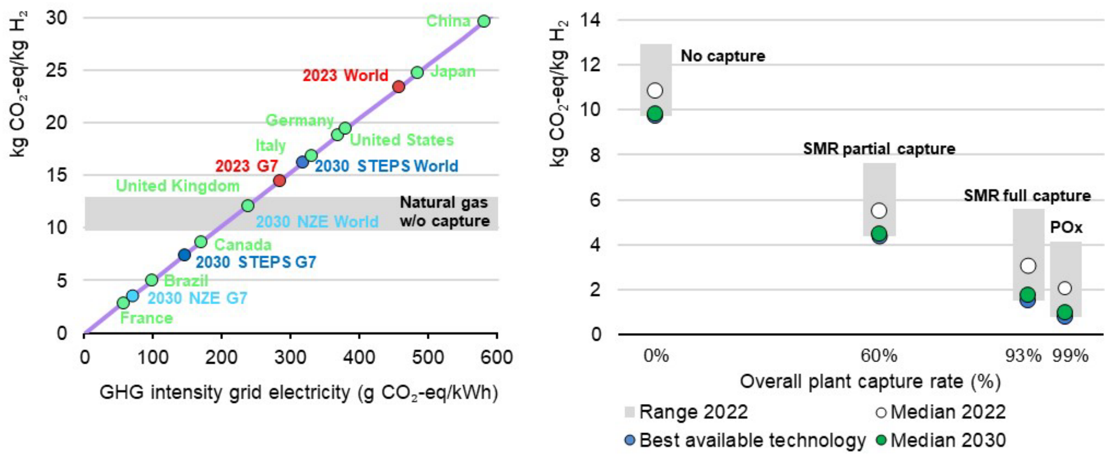
## Hydrogen

In 2023, global production of hydrogen resulted in emissions of nearly 920 Mt$CO_2$, equivalent to the annual energy-related emissions of the Indonesia and France combined. More than 60% of the production came from unabated natural gas, roughly 20% from unabated coal, and most of the remainder was a byproduct of industrial processes and in refineries. Low-emissions hydrogen production was less than 1% of the total.

Producing hydrogen from fossil fuels with very low emissions requires both the use of carbon capture and mitigation of the upstream and midstream emissions. In 2022, the global average upstream and midstream emissions for natural gas accounted for 20% of the $CO_2$ produced when it was burned. For coal, the impact of upstream and midstream emissions can be even more substantial. Even with a $CO_2$ capture rate of 98%, the high end of upstream and midstream emissions can still equate to almost 50% of emissions from the unabated natural gas route.

While direct emissions of hydrogen from electrolysis are zero, indirect emissions linked to the electricity supply can be significant. For example, 20 $gCO_2$-eq/kWh of electricity emissions lead roughly to 1 kg of $CO_2$ per 1 kg of hydrogen produced through electrolysis. To break even with emissions from the unabated natural gas route, electricity input emissions must be lower than 200-240 $gCO_2$-eq/kWh.[6] This is comparable to the emissions intensity of the European Union's electricity mix, or about half of the global average in 2023. That said, power grids are decarbonising rapidly around the world, independent of hydrogen deployment.

**Figure 3.4 GHG intensity of hydrogen based on emissions from electricity (electrolytic pathway, left) and $CO_2$ capture rate (fossil fuels with CCUS pathway, right)**

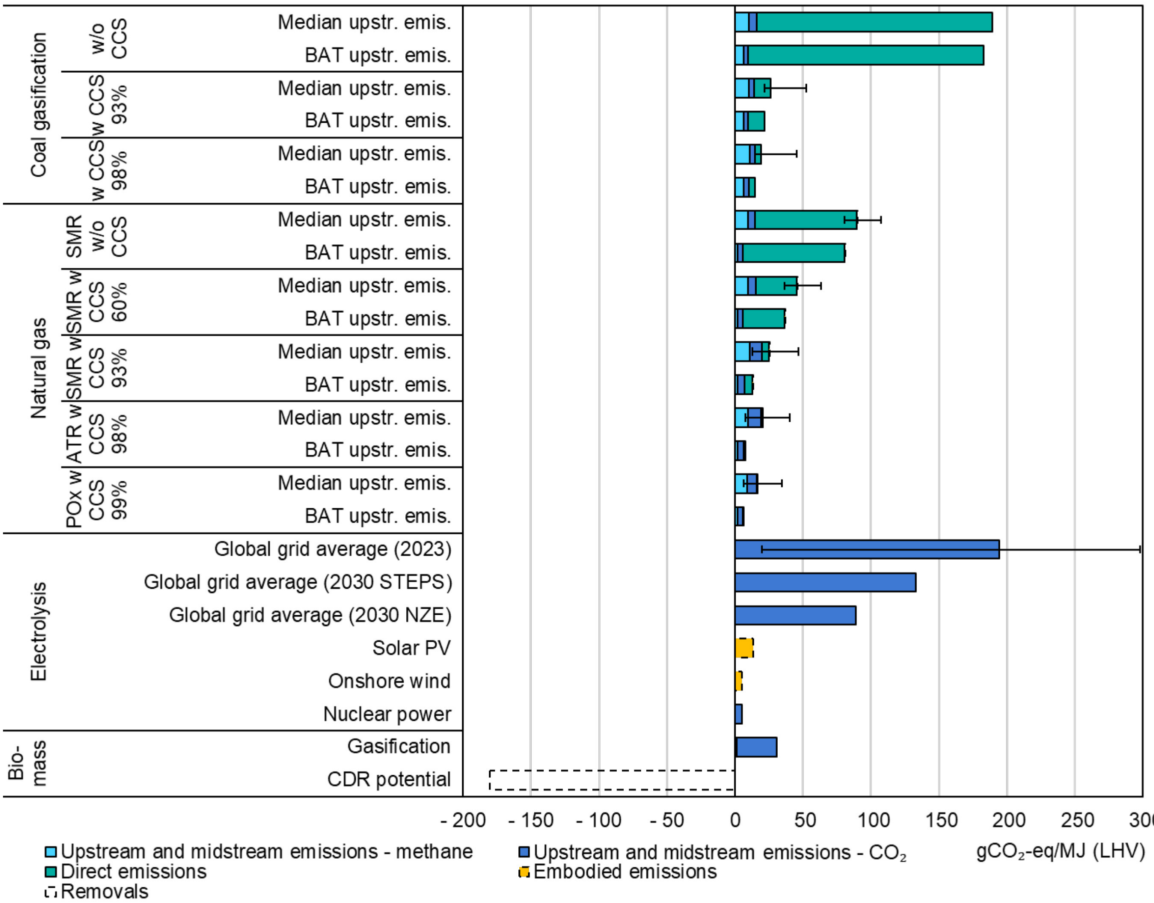



Notes: Hydrogen production from natural gas via SMR is based on 44.5 kWh/kg $H_2$ for natural gas in the case of no $CO_2$ capture; on 45.0 kWh/kg $H_2$ for natural gas in the case of 60% capture rate; on 49 kWh/kg $H_2$ for natural gas and on 0.8 kWh/kg $H_2$ for electricity in the case of a 93% capture rate. Hydrogen production from natural gas via POx is based on demands of 41 kWh/kg $H_2$ for natural gas and 0.6 kWh/kg $H_2$ for electricity in the case of a 99% capture rate. Hydrogen production from coal based on gasification, with demands for coal of 57 kWh/kg $H_2$ and for electricity of 0.7 kWh/kg $H_2$ in the case of no $CO_2$ capture; demands for coal of 59 kWh/kg $H_2$ for a $CO_2$ capture rate of 93% and demands for coal of 60 kWh/kg $H_2$ for a $CO_2$ capture rate of 98%.

[6] Assuming an efficiency of 66% on a lower heating value basis.

An alternative to using grid electricity is to use captive power (e.g. renewable or nuclear power) that allows hydrogen to be produced with very low emissions (below 8 $gCO_2$-eq/MJ, or 1 kg $CO_2$eq/kg$H_2$) even including embodied emissions from manufacturing of power plants.

**Figure 3.5 Comparison of the GHG intensities of different hydrogen production routes, 2022**






Notes: BAT = best available technology; CCS = carbon capture and storage; SMR = steam methane reforming; POx = partial oxidation; CDR = carbon dioxide removal; Median upstr. emis. = global median value of upstream and midstream emissions in 2022; BAT upstr. emis. = best available technology today to address upstream and midstream emissions. Upstream and midstream emissions include $CO_2$ and methane emissions occurring during the extraction, processing, and supply of fuels (coal, natural gas) or production, processing and transport of biomass. Error bars for natural gas and coal represent the impact of the observed range of emissions intensities. For natural gas, the lower bound corresponds to best available technology today (4.5 kg $CO_2$-eq/GJ), and the upper bound to the 95th percentile of the world range (14.4 kg $CO_2$-eq/GJ). For coal, the lower bound corresponds to the 5th percentile (6 kg $CO_2$eq/GJ) and the upper bound to the 95th percentile (23 kg $CO_2$-eq/GJ) of global upstream and midstream emissions of coal supply. Methane emissions are converted to $CO_2$-eq with a global warming potential over a time horizon of 100 years. The 2023 world grid average is based on a generation-weighted global average of the grid electricity intensity, with the error bars representing the 10th percentile (100 $gCO_2$-eq/kWh) and 90th percentile (680 $gCO_2$-eq/kWh) across countries. The grid electricity intensities include direct $CO_2$, $CH_4$ and $N_2O$ emissions at the power plants, but not upstream and midstream emissions for the fuels used in the power plants. The 2030 world grid average is 320 $gCO_2$-eq/kWh in STEPS and 215 g $CO_2$/kWh in NZE. Dashed lines refer to the embodied emissions occurring during the production of onshore wind turbines (12 $gCO_2$-eq/kWh) and solar PV systems (27 $gCO_2$eq/kWh). These embodied emissions are not included in the IPHE methodology and shown here only for illustrative purposes. Electrolysis refers to low-temperature water electrolysis with an assumed efficiency of 66% (Lower heating value, LHV).

Source: IEA (forthcoming), Global Hydrogen Review 2024.

Hydrogen can be produced also from biomass via gasification. Although not used today, it could be a potential future route. Combining a gasification plant with a $CO_2$ capture rate of 95% could result in strongly negative emissions by effectively removing almost all biogenic carbon from the natural carbon cycle. Another emerging option for producing hydrogen is methane pyrolysis. This technology is not yet proven at commercial scale,[7] but it offers the advantage of converting the carbon in methane to solid form (instead of $CO_2$). With a biomethane feedstock, emissions for this pathway would be potentially negative.

Emissions from construction and manufacturing of all assets and infrastructure (commonly called embodied emissions) are excluded from most schemes today. However, these emissions are part of the mandatory information to be reported in the ISO Technical Specification. For renewables, they could represent up to a quarter of the emissions of the unabated natural gas route.[8] This value would increase further by factoring in global trade. The efficiency losses involved could more than triple if calculated based on the product at the import site. However, embodied emissions are expected to decline as technological learning leads to improved efficiency, increased capacity factors and reduced materials intensity. At the same time, energy used for manufacturing continues to be decarbonised.

Hydrogen can also be converted to different materials, and technologies it replaces will vary – as will the efficiency gains for the value chain. These two factors result in a different emissions intensity threshold for the electricity input to the electrolyser. For example, when hydrogen is used for steel production, the emissions intensity of the electricity input required to match the fossil equivalent can be nearly twice as high as that for matching hydrogen production alone.

## Hydrogen-based fuels

Hydrogen can be further converted to different fuel types. However, such conversion leads to losses and the GHG intensity of hydrogen-based fuels is therefore higher on a per-megajoule (MJ) basis compared with the hydrogen used in their production.

Except for ammonia, hydrogen-based fuels require $CO_2$ as a carbon source for production, and this carbon will be released back to the atmosphere when the fuel is used. This makes the origin of that $CO_2$ relevant for determining lifecycle emissions.

[7] There are four main technologies. One (plasma thermal decomposition) has a technology readiness level (TRL) of 8, while two of the technologies have TRL rates between 3 and 4.

[8] This refers to the upper bound, represented by the 95th percentile of emissions for solar PV (95 $gCO_2$ /kWh) based on a review of almost 40 studies. Using the median value instead would reduce this value by half. Emissions from onshore wind are much smaller, and the median from 50 studies is one-third of the median for solar PV.

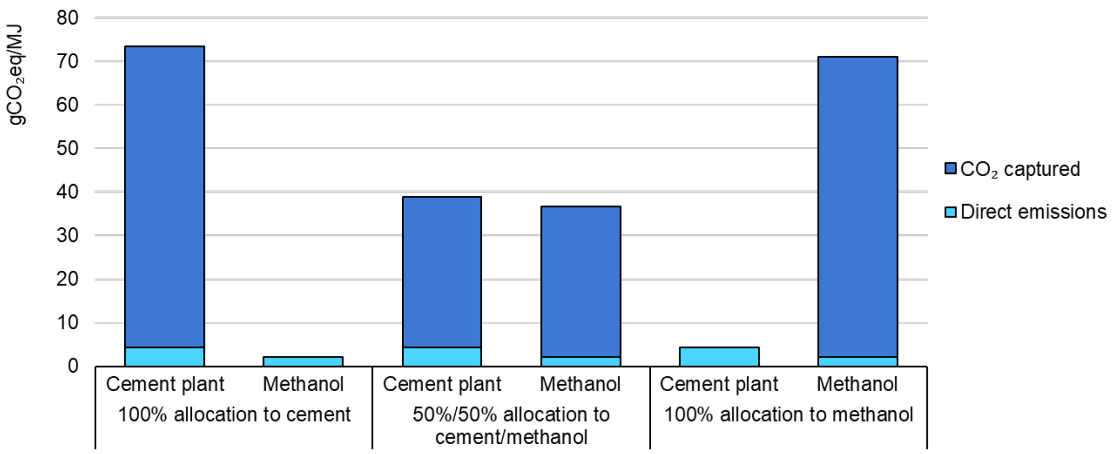
High-concentration sources, such as fermentation processes, provide $CO_2$ in a nearly 100% pure stream that needs only drying and compression before it can be used. Under current policies, around 90 Mt of concentrated $CO_2$ could be available globally from bioethanol plants in 2030. In addition, 30 Mt would be available from plants that upgrade biogas to biomethane, increasing the potential availability of low-cost biogenic $CO_2$ feedstock to 120 Mt by 2030. These high-concentration point sources could be complemented by kraft pulp mills, which release significant amounts of biogenic $CO_2$ from the combustion of black liquor and bark.

In addition to biomass-based sources, there is a virtually endless supply of $CO_2$ available from the atmosphere – though at significantly higher cost. Direct air capture (DAC) is still in the early stages of development, with only 27 DAC plants currently in operation. These plants are also very small, with the largest having a nominal capture capacity of just 4 000 t of $CO_2$ per year. Today's global capture capacity amounts to around 0.01 $MtCO_2$ annually.

Based on project announcements, there are plans for approximately 25 large-scale capture projects on industrial facilities, each targeting at least 100 000 t of $CO_2$ per year. These projects focus on using process emissions for producing hydrogen-based fuels.

From a carbon accounting perspective, one of the key decisions involves determining how $CO_2$ emissions released during combustion are allocated across the supply chain. This allocation is crucial because it impacts the overall GHG intensity of the different entities involved. The decision is often complex and requires careful consideration of factors such as the lifecycle of the product, the point of combustion and the boundaries set for emissions accounting (Figure 3.6).

**Figure 3.6 Impact of different $CO_2$ emission allocations between cement plant and methanol**




IEA. CC BY 4.0.

Using non-biogenic $CO_2$ from industrial sources could serve as a transitional strategy to kickstart hydrogen-based fuel production, to supplement supply from biogenic sources, and as direct air capture scales up over time. To enhance the competitiveness of hydrogen-based fuels relative to their fossil counterparts, projects will likely need policy support. While fossil-based $CO_2$ feedstock sources could initially benefit from some support to foster early market development and reduce technology risks, supportive policies should also consider overall lifecycle emissions. Robust, transparent and mutually agreed emissions accounting methods need to be in place to quantify emissions allocation and reduction and prevent double counting of emission reductions. This requires that consistent regulations be incorporated into certification schemes to ensure compliance – particularly for hydrogen-based fuels that are traded internationally.

# Non-GHG impacts

While the primary purpose of sustainable fuels is to reduce greenhouse gas emissions, it is also important to consider their non-GHG impacts. These include a range of environmental, social and economic factors that are essential to determining their overall sustainability.

All main biofuel policy frameworks regulate land use to varying degrees, mainly to prevent deforestation and safeguard high-biodiversity areas. The European Union's Renewable Energy Directive (RED) and the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) use specific criteria to discourage conversion of land for biofuel production in a way that leads to increased GHG emissions, while RenovaBio in Brazil and the US renewable fuel standard (RFS) include provisions that indirectly protect biodiversity by restricting potentially harmful land-use change. Regulation of the effects on water and soil is less direct, but such impacts are considered in broader sustainability requirements. Certification plays a crucial role – particularly in EU RED, CORSIA and RenovaBio – in ensuring compliance with sustainability criteria that include non-GHG impacts, such as land, air and water. In the United States, the RFS and California's Low-Carbon Fuel Standard rely primarily on lifecycle assessments and indirect regulation to address these concerns.

For hydrogen, governments can consider various additional sustainability requirements when deciding on the use of low-emission fuels and feedstocks, as well as their contribution to long-term sustainability targets. Companies might also choose to voluntarily certify their products to highlight various sustainability attributes and inform consumer choices. Some governments and certification schemes have already adopted hydrogen sustainability criteria beyond GHG emissions (see Table 3.1).

**Table 3.1 Selected regulations and certification schemes for hydrogen featuring non-GHG and system-related sustainability criteria**

| Regulation | Purpose | Environmental criteria | Socio-economic criteria |
|---|---|---|---|
| European Commission Delegated Act of the Renewable Energy Directive* | Define rules for hydrogen production to count toward renewable energy targets | Renewable origin; Additionality of electricity source; Temporal correlation with electricity source | |
| US Clean Hydrogen Production Tax Credit | Provide incentives for producers of clean hydrogen** | | Wage and labour requirements |
| **Certification scheme** | **Purpose** | **Environmental criteria** | **Socio-economic criteria** |
| TÜV Süd CMS 70 standard (Germany) | Voluntary certification of biomass-based hydrogen production | Indirect land-use change in line with the EU Renewable Energy Directive | |
| Climate Bonds standard and certification scheme | | Provisions related to biomass sustainability, which cover indirect land-use change | Food security |
| Green hydrogen standard | Voluntary certification of hydrogen production | Renewable origin; Water use and quality; Waste, noise and air quality; Biodiversity | Requirements on living standards, resettlement, Indigenous communities, labour and working conditions |
| **Other** | **Purpose** | **Environmental criteria** | **Socio-economic criteria** |
| H2Global | Double-auction mechanism to close the gap between production cost and willingness to pay by end users | Protection of arid regions, sustainable land use, conservation of biodiversity | Local value creation, equal opportunities and gender, protection from forced resettlement |

* This Delegated Act is still awaiting approval by the European Parliament and Council.
** The Act defines qualified clean hydrogen as hydrogen that is produced through a process that results in a lifecycle greenhouse gas emissions rate no greater than 4 kg $CO_2$.eq/Kg $H_2$ (33 g$CO_2$-eq/MJ).

Buyers and regulators of sustainable fuels can ensure that their own combinations of sustainability and other criteria are met. In some cases, a buyer will need to secure guarantees from multiple producers and traders. In other cases, a single producer may be required to provide different combinations of guarantees to different buyers or regulators. So-called "product passports" can standardise this process, minimise costs and maximise transparency (Box 3.2).

### Box 3.2 A hydrogen passport to integrate multiple criteria

For an intermediate energy product like hydrogen, a "product passport" could be created for a shipment of hydrogen or hydrogen-based fuels. This would involve assigning a unique ID linked to a data repository that trading partners and end users can access. The data could include the GHG intensity rating and a simplified GHG intensity level, as well as other certificates, assessments or information on environmental and socio-economic considerations. In each case, the associated standard, regulation, institution or methodology would be provided.

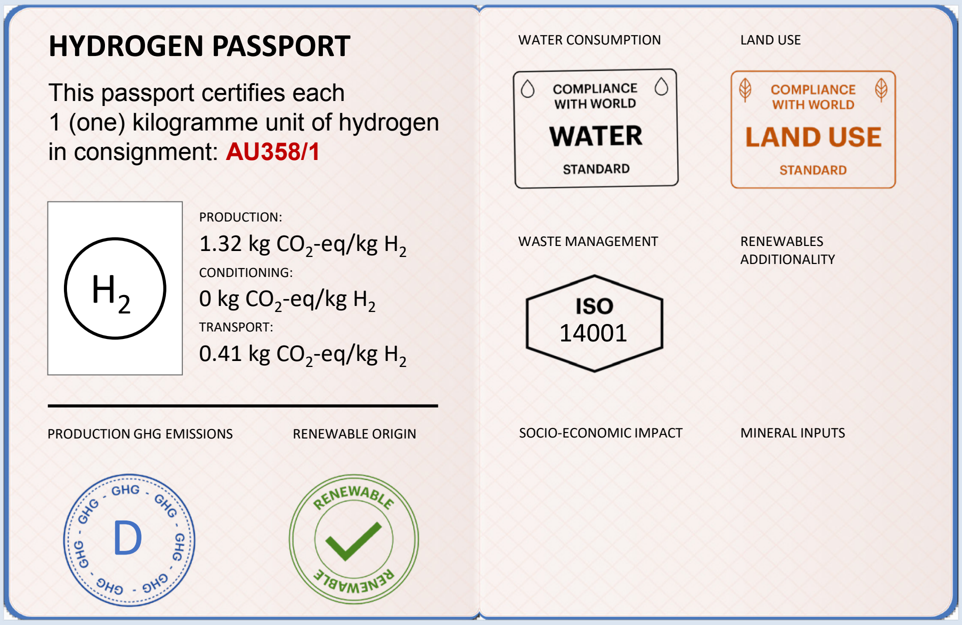
Product passports are not a new idea. Since 2000, as data and digital technology (including blockchain) have improved dramatically, they have been suggested for a variety of applications. The European Commission has advocated the transfer of product passports between owners of a traded good to document the resources used in its production. Information in Digital Product Passports could be accessible from a chip, or by scanning a watermark or quick response (QR) code. In the construction sector, Building Renovation Passports have been developed in the form of "logbooks" for tracking successive renovations.

One of the most well-developed and global examples is the battery passport, proposed by the Global Battery Alliance. This involves creating a "digital twin" of an electric vehicle's physical battery components. By enabling transparent access to key information about the origins of battery components, manufacturing history and sustainability, the Global Battery Alliance expects to raise consumer confidence and enable industry-wide benchmarking. The aim is to begin with voluntary disclosure of compliance with current standards and legislation. However, some jurisdictions are exploring ways to make battery passports a legal requirement, accompanied by agreed methodologies for calculating lifecycle data.

Hydrogen passports could face additional challenges compared to those for discrete physical products. Gaseous and liquid fuels are traded in many different volumes and vessels. A single, large seaborne cargo can contain hydrogen from multiple sources, and by the time it reaches the consumer, it may be split into multiple smaller units, each needing a unique ID. The delivered hydrogen may be subsequently integrated into other hydrogen-based fuels or tertiary products whose buyers may, in turn, require the information contained in the passport. This challenge is by no means insurmountable, and solutions have been developed for food and drink products, as well as natural gas, that certify all outputs from a given production facility or supply chain for a specific period. The allocation of GHG intensity to sub-units has already been codified for the transport sector.

Any passport system should be designed to be compatible with products both upstream and downstream in the supply chain. As energy transitions progress, it is likely that end users and regulators will want to differentiate between energy products based on their origin and sustainability credentials. This could encompass the renewable content of electricity or the bioenergy, hydrogen or natural gas composition of pipeline gas, as well as the upstream and midstream methane emissions associated with the natural gas content. It may even extend to information about the inputs and equipment used in the bioenergy and electricity supply chains. The overall trend in policy and trade is toward increasing differentiation among physically indistinguishable and interrelated goods within the energy system.

**Visual representation of the possible content of a product passport for a traded hydrogen cargo**




Source: IEA (2023), Towards hydrogen definitions based on their emissions intensity.

# Chapter 4. Conclusions and policy considerations

Replacing unabated fossil fuels with low-emission counterparts is critical for the clean energy transition, particularly in hard-to-abate sectors, where they are an essential complement to direct electrification and improved energy efficiency and contribute to energy diversification and security.

Considering the varied costs, availability and regulatory challenges facing different fuels, the focus for 2030 should be on promoting a broad range of sustainable fuel pathways, while accounting for their distinct characteristics. This calls for a coordinated global effort to develop and commercialise technologies, build production plants, support innovation, establish fair trade rules and ensure fair competition through transparent sustainability assessments.

## Towards common criteria

Fuel sustainability is becoming an increasingly important consideration for regulators, but criteria of what makes a fuel "sustainable" vary across assessment frameworks. Terms such as "green," "blue," or "advanced" are frequently used today to describe the sustainability features of fuels and to differentiate them from their unabated fossil counterparts. However, there is no international consensus on the meaning of these terms. Their definitions are inconsistent and, critically, they do not usually provide quantitative information about GHG emissions.

Sustainability assessments generally consist of two main elements. The first sets either a minimum target for reducing greenhouse gas emissions compared to unabated fossil fuels, or a cap on total emissions across the supply chain. The second looks at non-GHG factors (e.g. the impact on biodiversity for biofuels) or conditions linked to the background system, such as ensuring that renewable electricity supply aligns with demand for electrolytic hydrogen.

While existing frameworks share some commonalities in scope, system boundaries and production pathways, they often differ in thresholds and methodologies, which can lead to market fragmentation. It can also be difficult to verify and document compliance with sustainability requirements in a way that satisfies investors. To enhance transparency, attract investments and ensure a baseline level of market and regulatory interoperability, it is critical to have clear definitions based on widely accepted and standardised methodologies.

# Policy principles

While detailed policy descriptions and roadmaps for implementation are beyond the scope of this study, a list of key policy priorities is given below.

**Use GHG intensity ($gCO_2$-eq/MJ) at the point of delivery as the basis for common sustainability criteria.** Supply chain GHG intensity can be defined for all fuel types, making it a universal, technology-open metric for comparing the sustainability of different fuels, provided that a common and consistent approach is adopted for methodological aspects, such as system boundaries, allocation of $CO_2$ and/or handling of coproducts.

GHG intensity should consider not only production, but also emissions related to transport and distribution to the point of delivery, since these steps can add significantly to supply chain emissions for certain fuels (e.g. hydrogen). In this context, developing and using common global standards, such as those being elaborated by the ISO, is critical for ensuring the transparency and consistency of emissions assessments.

GHG intensity calculations should also assume complete oxidation of the fuel to account for any fossil carbon inputs that are used during the production process (e.g. for fuels such as synthetic methanol or kerosene). In the case of fuels produced via electrolysis, embodied GHG emissions from the manufacture of captive power plants (e.g. renewable or nuclear) should also be included within the system boundary, as their contribution can be non-negligible. For biofuels, direct land-use change emissions should be included in the GHG metrics, as they are measurable and verifiable over time. Indirect land-use change should be treated separately (see below).

**Establish a GHG intensity threshold for sustainable fuels to set minimum requirements for emission reductions compared to unabated fossil fuels**. A GHG intensity threshold should be set low enough to trigger ambitious emission reductions. However, it should also be high enough to ensure that a broad range of technologies and emerging pathways with lower emissions than unabated fossil fuels can play a role in the transition, attract investment and benefit from learning at relevant scales. This is especially relevant in countries that cannot afford to go directly to near-zero-emission fuels. Setting overly ambitious thresholds at the outset can limit technological diversity, increase costs and ultimately slow progress in reducing global average fuel emissions.

**Reward fuels that surpass minimum requirements.** Fuel pathways show a wide range of GHG intensities, but measures like adopting sustainable farming practices, using carbon capture utilisation and storage (CCUS), switching to renewable energy for processing and powering electrolysers with dedicated low-emission energy can lead to significant improvements already today. These interventions are likely to increase costs and therefore require market and policy frameworks that incentivise fuel pathways with superior GHG performance, supported by measurable and verifiable lifecycle data.

**Drive better GHG performance over time.** Given that technologies tend to improve with more experience, it is important to focus on future GHG intensity levels rather than current ones. Introducing a tiered system with several thresholds that enable to identify and reward improvements creates a policy environment that not only minimises barriers to market entry but also maximises GHG benefits over time.

**Separate GHG intensity from indirect system impacts such as iLUC for certain biofuels and additionality of renewable electricity supply for hydrogen plants.** While these fuel-specific impacts can be important, they should be managed through separate policies and not lumped together with GHG intensity considerations. Additional system-related requirements should be applied cautiously, to avoid placing the full burden of transitioning energy systems on those who are investing in clean technologies.

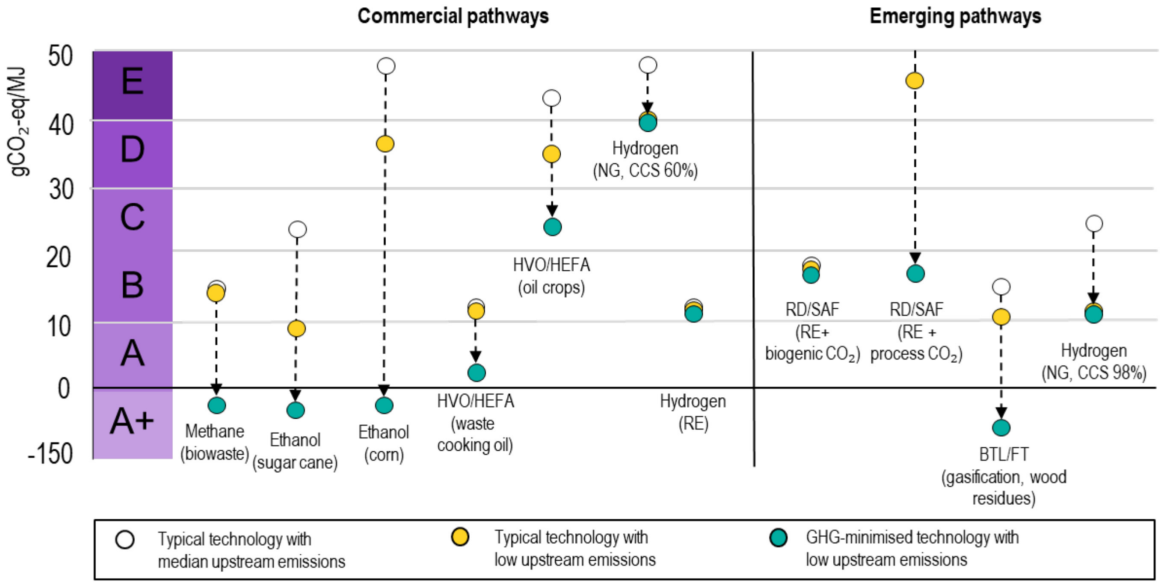
**Complement GHG intensity with a broader portfolio of policies covering non-GHG impacts of fuels.** Lifecycle GHG emissions are just one of many sustainability factors to consider when expanding the production and use of low-emission fuels. A growing number of policies are also addressing issues like food and water security, biodiversity and other socio-economic factors, such as ensuring a secure and affordable energy supply and supporting a just transition.

# Developing a common GHG intensity label

While common criteria and methodologies for GHG emissions enable the comparison of different fuel production pathways, it still leaves governments the flexibility to define acceptable emission intensity levels based on local circumstances and opportunities. Countries are naturally free to establish their own GHG intensity thresholds, but they should use standardised methodologies to ensure compatibility and to facilitate international trade.

One approach is to use a set of five technology-open levels, or tiers, for GHG intensity, ranging from zero (level "A") to an upper value of 50 $gCO_2$-eq/MJ (level "E"), in increments of 10 $gCO_2$-eq/MJ. Additionally, negative carbon intensity values due to carbon removal could be classified as level A+ (see Fig 4.1). Setting the threshold at 50 g $CO_2$-eq/MJ includes main production pathways for sustainable fuels having lower emissions than any unabated fossil fuel. The labels allow to assess and identify the performance of selected pathways, some of which can be achieved already today by reducing upstream emissions (e.g. using low-emission fertilisers or preventing fugitive methane emissions – from white to yellow dots in Fig 4.1). The levels also help to identify future technological improvements and supply chain advancements (green dots). Several examples of GHG-minimised technologies with low upstream emissions are indicated in Figure 4.1, which also distinguishes between commercially available and emerging pathways.

**Figure 4.1 Example of a quantitative GHG intensity labelling system for selected sustainable fuel pathways**






Notes: For biofuel pathways, median upstream emissions refer to using fossil fuels and fertilisers in cultivation, while low upstream emissions refer to use of low-emission fuels and fertilisers in cultivation. GHG-minimised technology involves low-emission energy inputs in processing and CCS where feasible, but does not include removals through soil carbon accumulation. No change in feedstock transport emissions assumed in the figure, although could be influenced with a switch to low-emission energy sources. RE = captive renewable electricity for powering electrolysis; RD/SAF (RE + process $CO_2$) = median upstream emissions for this pathway refer to 30/70 allocation of $CO_2$ emission benefits between industry ($CO_2$ source) and produced fuel, while low upstream emissions refer to 100% allocation of benefits to fuel. Embodied emissions of renewable power are included (assuming 50/50 hybrid PV/wind power plant) which differs from the current ISO methodology where these emissions are not included in the GHG intensity but are reported separately. Assumptions: All efficiencies are given for lower heating value. Electrolyser efficiency 66% (typical), 69% (GHG-minimised); $H_2$-to-syncrude 57%, transport fuel mass yield from FT jet fuel refinery 85%. Emissions from transport and distribution of final fuel to end user are 2 $gCO_2$-eq/MJ for liquid fuels and pipeline transport of methane, and 4 $gCO_2$-eq/MJ for pipeline transport of hydrogen. Biofuel GHG emissions based on EU RED II Annex V (2018).

A tiered labelling system applied to an intermediate product such a sustainable fuel has the advantage of providing transparent and quantitative information to a wide range of possible end users. Certain stakeholders – such as investors and the general public – would likely appreciate the simplicity of referring to an aggregated "level" of GHG intensity. For example, investors would benefit from clear terminology for describing the types of fuels they are willing to finance (for example, "kerosene with a GHG intensity no higher than level D"). Moreover, fuel available at service stations could be labelled to help consumers make informed environmental choices, similar to energy efficiency labels on appliances and buildings.

While GHG emissions should be the primary focus, it is also important for policies to recognise and address other critical sustainability criteria and support the development of common methodologies for assessing them. Additional criteria, such as land use, water consumption, air quality, biodiversity impacts and social equity are vital for evaluating the overall sustainability of fuel options. These criteria could be included alongside GHG intensity labels (see Box 3.2 on hydrogen passport).

## Addressing fuel pathway-specific factors in the early phase of the transition

**The absence of unified policy approaches to account for pathway-specific factors can deter investment and, ultimately, slow down the energy transition.** Certain emission drivers and sustainability attributes are unique to specific fuel pathways. These factors cannot be typically solved within lifecycle assessments – adding to the uncertainty about their net impact. Examples of such pathway-specific sustainability aspects include indirect land-use change for biofuels, additional requirements for electricity used to produce hydrogen from renewable power, and the source of $CO_2$ and allocation of benefits for hydrogen-based fuels. A list of pragmatic approaches to address these factors is given below.

**Indirect land-use change (iLUC) concerns should be addressed by adopting risk-based approaches in the near term and striving to develop global land-use policies over time.** Although potential iLUC impacts can be significant, they cannot be directly measured or verified, only modelled. When addressing these potential impacts, policy makers should consider alternatives such as risk-based approaches and direct measurement, which are both effective and widely applicable for global iLUC analysis. Rather than try to quantify indirect emissions in terms of $gCO_2$-eq/MJ for a given biofuel pathway, these alternative methods may offer more practical solutions.

In the short term, qualitative risk-based approaches that ensure compliance with low-iLUC-risk requirements are effective for addressing potential impacts and encouraging improvements. Over the long term, policies should shift from modelling impacts to enforcing direct land-use regulations globally and promoting better agricultural land management practices. In emergencies – such as economic crises, geopolitical events or extreme weather conditions – governments should consider temporary measures to address food security concerns. Biofuel policies should be designed to be flexible during periods of tightness in global agricultural markets to avoid amplifying or prolonging agricultural price spikes.

**Extra requirements for electricity used to produce electrolytic hydrogen, such as additionality, temporal and spatial correlation, should be applied cautiously.** To address potential indirect system impacts, some jurisdictions are placing extra requirements beyond the GHG intensity of the grid mix. Such requirements can include:

- **Additionality**: Hydrogen must be produced using electricity from new low-emission projects rather than from existing facilities.
- **Temporal correlation**: Producers may need to demonstrate that their electrolysers are powered by renewable electricity at specific intervals (hourly, weekly, monthly or annually).
- **Grid proximity:** Hydrogen production may need to occur in the same control area as the low-emission electricity source.

However, power grids are decarbonising rapidly worldwide, independent of hydrogen deployment. Setting very strict criteria during the early stages of technology scale-up risks delaying investments, impeding the development of supply chains and infrastructure, and hindering potential benefits in terms of creating new electricity demand and new flexibility resources for integrating variable renewables. In the long term, possible indirect system impacts will fade as the role of fossil fuels in energy grids diminishes. Under the IEA's Net Zero Emissions by 2050 (NZE) scenario, power systems would be fully decarbonised globally before 2045.

Additional requirements like those described above should be applied cautiously, to avoid placing the full burden of transitioning energy systems on those who are investing in clean technologies.

**The capture and use of fossil $CO_2$ from existing industrial sources could temporarily facilitate production of lower emission hydrogen-based fuels, as $CO_2$ supply from biogenic sources and direct air capture grows over time.** The $CO_2$ that is used to produce hydrogen-based fuels is ultimately released back into the atmosphere, and therefore it is important to consider the source of $CO_2$ feedstock. The biogenic or direct air-captured $CO_2$ component is carbon neutral when the fuel is burned. In contrast, if fossil $CO_2$ captured from existing industrial processes is used as feedstock, system-level emissions are only partially reduced. The opportunity lies in the possibility to help jumpstart this new industry and relevant supply chains, while achieving initial emission reductions. Robust, transparent and mutually agreed emissions allocation methods need to be in place to avoid double counting of emission reductions and correctly assess the GHG intensity of the synthetic fuel. This cannot be solved by LCA methodology, therefore requiring policy and commercial agreements. For instance, emission benefits could be split between the original $CO_2$ emitter and the fuel producer, at a mutually agreed share, possibly in proportion to relevant investments. In the long term, no use of fossil $CO_2$ feedstock would be compatible with a NZE scenario.

# Possible next steps

**Enhanced stakeholder engagement and international cooperation is key for increasing consensus on common criteria for sustainable biofuels.** This includes further strengthening the collaboration among international organisations such as the International Civil Aviation Organization (ICAO) and the International Maritime Organization (IMO), fostering cooperation with other end-use sectors such as steel and fertilisers, and encouraging consistent protocols and regulations for carbon accounting in Article 6 of the Paris Agreement as well as in voluntary carbon markets. The G20 could also consider establishing a voluntary expert group to further develop and test a tiered labelling system for sustainable fuels in selected countries.

# Annex

## Abbreviations and acronyms

| | |
|---|---|
| ASU | air separation unit |
| ATR | autothermal reforming |
| BAT | best available technology |
| BTL/FT | biomass-to-liquids/Fischer-Tropsch |
| CDR | carbon dioxide removals |
| CHA | China Hydrogen Alliance |
| CHCM | Clean Hydrogen Certification Mechanism |
| CHPS | Clean Hydrogen Production Standard |
| $CO_2$ | carbon dioxide |
| CCS | carbon capture and storage |
| CCUS | carbon capture utilisation and storage |
| DAC | direct air capture |
| dLUC/iLUC | direct/indirect land-use change |
| EMDE | emerging market and developing economies |
| GH2 | Green Hydrogen Standard |
| HPTI | Hydrogen Production Tax Incentive |
| HSPA | Hydrogen Society Promotion Act |
| HVO/HEFA | hydrotreated vegetable oils/hydroprocessed esters and fatty acids |
| ITC | Investment Tax Credit |
| LCA | lifecycle assessment |
| LCFS | Low-Carbon Fuel Standard |
| POx | partial oxidation |
| PTC 45V | Production Tax Credit under Section 45V of the Inflation Reduction Act |
| RED | Renewable Energy Directive |
| RTFO | Renewable Transport Fuel Obligation |
| SMR | steam methane reforming |
| WBSCD | World Business Council of Sustainable Development |

## Glossary

| | |
|---|---|
| bbl | barrel |
| bbl/d | barrels per day |
| bcm | billion cubic metres |
| bcm/yr | billion cubic metres per year |
| cm/s | centimetres per second |
| $gCO_2$ | gram of carbon dioxide |
| $gCO_2$/kWh | grams of carbon dioxide per kilowatt-hour |
| $gCO_2$-eq/MJ | grams of carbon dioxide equivalent per megajoule |

| | |
|---|---|
| GJ | gigajoule |
| Gt/yr | gigatonnes per year |
| $GtCO_2$ | gigatonne of carbon dioxide |
| $GtCO_2$/yr | gigatonnes of carbon dioxide per year |
| GW | gigawatt |
| GWh | gigawatt hour |
| LHV | lower heating value |

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