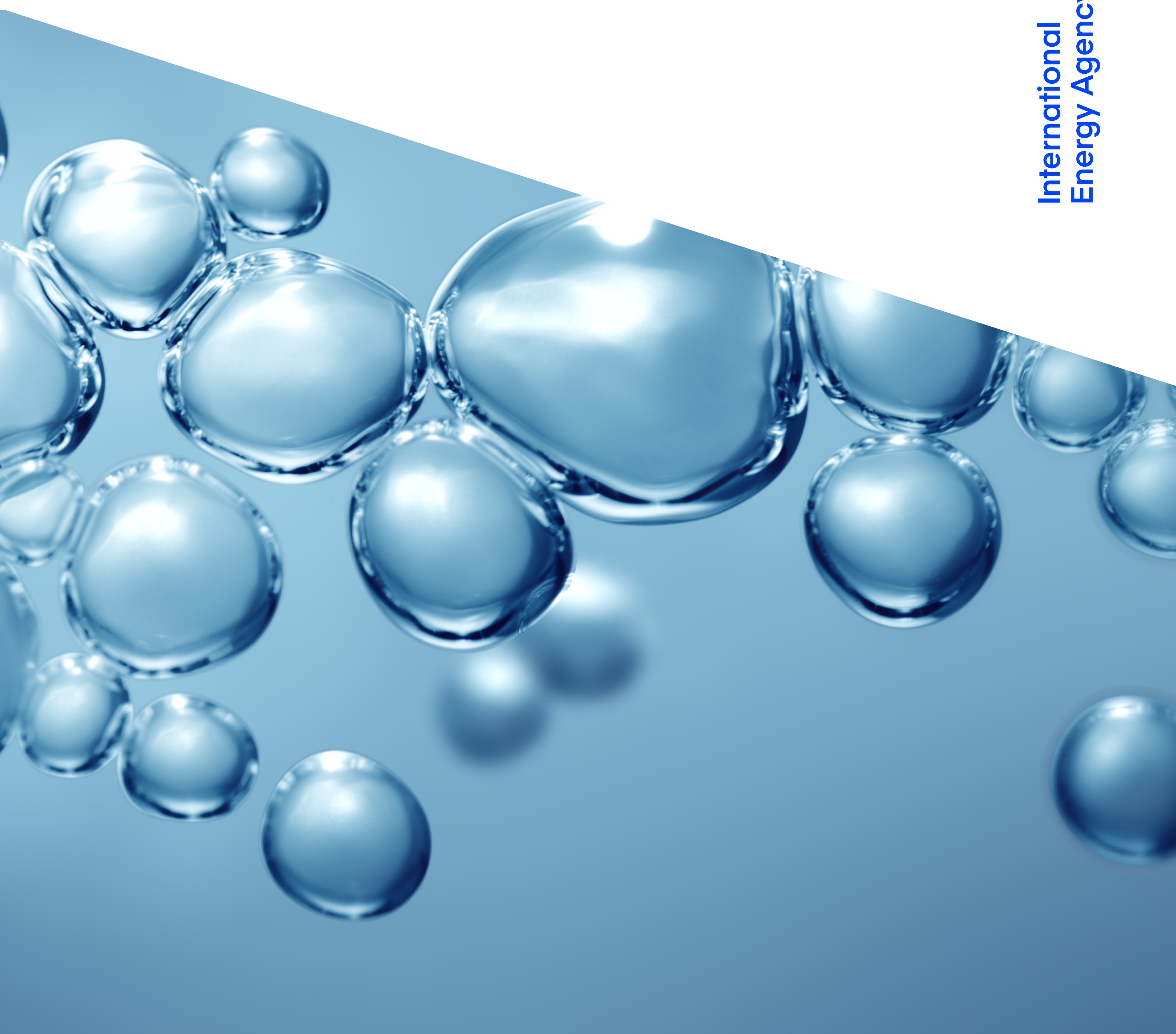
Towards hydrogen definitions based on their emissions intensity

International Energy Agency



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Abstract

Towards hydrogen definitions based on their emissions intensity is a new report by the International Energy Agency, designed to inform policy makers, hydrogen producers, investors and the research community in advance of the G7 Climate, Energy and Environmental Ministerial meeting in April 2023. The report builds on the analysis from the IEA's *Net Zero by 2050: A Roadmap for the Global Energy Sector* and continues the series of reports that the IEA has prepared for the G7 on the sectoral details of the roadmap, including the *Achieving Net Zero Electricity Sectors in G7 Members, Achieving Net Zero Heavy Industry Sectors in G7 Members* and *Emissions Measurement and Data Collection for a Net Zero Steel Industry* reports.

This report assesses the greenhouse gas emissions intensity of the different hydrogen production routes and reviews ways to use the emissions intensity of hydrogen production in the development of regulation and certification schemes. An internationally agreed emissions accounting framework is a way to move away from the use of terminologies based on colours or other terms that have proved impractical for the contracts that underpin investment. The adoption of such a framework can bring much-needed transparency, as well as facilitating interoperability and limiting market fragmentation, thus becoming a useful enabler of investments for the development of international hydrogen supply chains.

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Executive summary

A clear understanding of the emissions associated with hydrogen production can help enable investment and boost scale-up

Most large-scale projects for the production of low-emission hydrogen are facing important bottlenecks. Only 4% of projects that have been thus far announced are under construction or have taken a final investment decision. Uncertainty about future demand, the lack of infrastructure available to deliver hydrogen to end users and the lack of clarity in regulatory frameworks and certification schemes are preventing project developers from taking firm decisions on investment.

Transparency on the emissions intensity of hydrogen production can bring much-needed clarity and facilitate investment. Using colours to refer to different production routes, or terms such as “sustainable”, “low-carbon” or “clean” hydrogen, obscures many different levels of potential emissions. This terminology has proved impractical as a basis for contracting decisions, deterring potential investors. By agreeing to use the emissions intensity of hydrogen production in the definition of national regulations about hydrogen, governments can facilitate market and regulatory interoperability. This report aims to assist governments in doing so by assessing the emissions intensity of individual hydrogen production routes, for governments to then decide which level aligns with their own circumstances.

The production and use of hydrogen, ammonia and hydrogen-based fuels needs to scale up

The G7 is a cornerstone of efforts to accelerate the scale-up of the production and use of low-emission hydrogen, ammonia and hydrogen-based fuels. G7 members – Canada, France, Germany, Italy, Japan, the United Kingdom, the United States and the European Union – account for around one-quarter of today’s global hydrogen production and demand. At the same time, G7 members are frontrunners in decarbonising hydrogen production and technology development for new hydrogen applications in end-use sectors. The G7 can use its technological leadership and economic power to enable a greater increase in the production and use of low-emission hydrogen. However, G7 members cannot undertake this challenge alone. The development of an international hydrogen market will require the involvement of a wide range of other stakeholders, including among emerging economies.

Hydrogen, ammonia and hydrogen-based fuels have an important role to play in the clean energy transition. Global hydrogen demand reached 94 million tonnes in 2021, concentrated mainly in its use as a feedstock in refining and industry. Meeting government climate ambitions requires a step-change in demand creation for low-emission hydrogen, particularly in new applications in sectors where emissions are hard to abate, such as heavy industry and long-distance transport. At the same time, hydrogen production needs to be decarbonised; today, low-emission hydrogen represents less than 1% of global production.

The development of international supply chains can help to meet the needs of countries and regions with large demand and limited potential to produce low-emission hydrogen. Regional cost differences and growing demand in regions with less potential to produce low-emission hydrogen, ammonia and hydrogen-based fuels could underpin the development of an international hydrogen market to trade these fuels, despite the additional costs arising from conversion and transport. The global energy crisis has further strengthened interest in low-emission hydrogen as a way to reduce dependency on fossil fuels and enhance energy security, becoming a new driver for global trade in hydrogen.

Hydrogen definitions based on emissions intensity can form the basis for robust regulation

The emissions intensity of hydrogen production varies widely depending on the production route. Today, hydrogen production is dominated by unabated fossil fuels; emissions need to decrease significantly to meet climate ambitions. The fuel and technology used, the rate at which CO_2 capture and storage is applied, and the level of upstream and midstream emissions all strongly influence the emissions intensity of hydrogen production. For example, production based on unabated fossil fuels can result in emissions of up to 27 kg CO_2-eq/kg H_2, depending on the level of upstream and midstream emissions. Conversely, producing hydrogen from biomass with CO_2 capture and storage can result in negative emissions, as a result of removing the captured biogenic carbon from the natural carbon cycle. The average emissions intensity of global hydrogen production in 2021 was in the range of 12-13 kg CO_2-eq/kg H_2. In the IEA Net Zero by 2050 Scenario, this average fleet emissions intensity reaches 6-7 kg CO_2-eq/kg H_2 by 2030 and falls below 1 kg CO_2-eq/kg H_2 by 2050.

The emissions intensity of hydrogen produced with electrolysis is determined by the emissions from the electricity that is used. Using the methodology developed by the International Partnership for Hydrogen and Fuel

Cells in the Economy (IPHE)[1], renewable electricity[2] generation has no associated emissions, resulting in 0 kg CO_2-eq/kg H_2. In the case of grid electricity, the emissions intensity varies greatly between peak load and baseload hours, depending on which technology is used to meet additional demand for the electrolysers. To reduce emissions, it is therefore important to ensure that grid-connected electrolysers do not lead to an increase in fossil-based electricity generation.

Carbon capture and storage technologies can reduce direct emissions from fossil-based hydrogen production but measures to mitigate upstream and midstream emissions are needed. Hydrogen production from unabated natural gas results in an emissions intensity in the range of 10-14 kg CO_2-eq/kg H_2, with upstream and midstream emissions of methane and CO_2 in natural gas production being responsible for 1-5 kg CO_2-eq/kg H_2. Retrofitting existing assets with capture of CO_2 from the feedstock-related use of natural gas (capture rate around 60%) can bring the emissions intensity down to 5-8 kg CO_2-eq/kg H_2. Higher capture rates (above 90%) can be achieved with advanced technologies, reducing emissions intensity to 0.8-6 kg CO_2-eq/kg H_2, although no plants using these technologies are in operation yet. At high capture rates, the emissions intensity of hydrogen production is dominated by upstream and midstream emissions, which account for 0.7-5 kg CO_2-eq/kg H_2, underscoring the importance of cutting methane emissions from natural gas operations.

Governments should define roadmaps to decarbonise hydrogen production, both domestic and imported, in accordance with their national circumstances. This report therefore does not provide a generic acceptable upper threshold for the emissions intensity of hydrogen production. However, governments should take into account factors such as emissions intensity, supply volumes and affordability to inform decision-making to scale up production and use of low--emission hydrogen. The higher production cost of low--emission hydrogen and the relatively young age of existing unabated fossil fuel-based hydrogen production assets in the chemical sector are barriers to the uptake of low-emission hydrogen. Retrofitting existing production assets with CO_2 capture and storage can be a cost-effective near-term option to partially decarbonise production. In regions with abundant renewable resources, the use of renewable electricity to produce hydrogen is set to be the most cost-effective option, even before 2030.

[1] The IPHE has developed a methodology for calculating the greenhouse gas emissions intensity of hydrogen production and conditioning, and is due to complete the methodology for hydrogen transport. The IPHE methodology will serve as the basis for the first international standard on this topic and can serve as a first step for the adoption of emissions intensity of hydrogen production in regulations.
[2] IPHE methodology assigns zero emissions to solar PV, wind, hydro- and geothermal power.

Reference to the emissions intensity of hydrogen production in regulations can enable interoperability and limit market fragmentation

Several certification systems or regulatory frameworks defining the sustainability attributes of hydrogen are currently being developed, but there is a risk that lack of alignment may lead to market fragmentation. Existing efforts have some commonalities in scope, system boundaries, production pathways, models for chain of custody and emissions intensity levels. But inconsistencies in approaches risk becoming a barrier for the development of international hydrogen trade. Referring to the emissions intensity of hydrogen production, based on a joint understanding of the applied methodology used for regulation and certification, can be an important enabler of market development, facilitating a minimum level of interoperatibility and enabling mutual recognition rather than replacing or duplicating ongoing efforts.

Regulation and certification that uses the emissions intensity of hydrogen production should also be able to accommodate additional sustainability criteria. Governments and companies may wish to consider other potential sustainability requirements when making decisions about the use of hydrogen as a clean fuel and feedstock. Criteria related to the origin of the energy source, land or water use, and socio-economic aspects such as working conditions are already incorporated into some regulations and certification schemes. The use of emissions intensity is a first step to enable interoperability, but should not preclude governments and companies incorporating additional criteria. The use of “product passports” can help to bring all these criteria together, as well as to standardise processes, minimise costs and maximise transparency.

Introduction

Towards hydrogen definitions based on their emissions intensity is a new report by the International Energy Agency, designed to inform policy makers, hydrogen producers, investors and the research community in advance of the G7 Climate and Energy Ministerial in April 2023. The report builds on the analysis from the IEA's Net Zero by 2050: A Roadmap for the Global Energy Sector and continues the series of reports that the IEA has prepared for the G7 on the sectoral details of the roadmap, including Achieving Net Zero Electricity Sectors in G7 Members, Achieving Net Zero Heavy Industry Sectors in G7 Members and Emissions Measurement and Data Collection for a Net Zero Steel Industry.

Achieving net zero emissions by 2050 requires large-scale deployment of clean energy technologies at an unprecedented speed. Low-emission hydrogen, ammonia and hydrogen-based fuels have an important role to play in the decarbonisation of sectors with hard-to-abate emissions, such as heavy industry and long-distance transport. However, the availability of these low-emission fuels is today limited, and efforts are needed in the short term to scale up their production and use. This would help to bring production costs down and to develop international supply chains that can support the decarbonisation roadmap of regions with limited potential to produce these fuels domestically to meet their growing demand.

Momentum around hydrogen, ammonia and hydrogen-based fuels has been growing over the past years. They are now widely recognised as an important tool to support government climate ambitions and net zero greenhouse gas emissions commitments announced in recent years. The global energy crisis sparked by Russian Federation (hereafter, "Russia")'s invasion of Ukraine has further strengthened interest in low-emission hydrogen in particular, as a way to reduce dependency on fossil fuels and enhance energy security.

Industry has responded to this call for action, and announcements of new projects to produce low-emission hydrogen, ammonia and hydrogen-based fuels are growing at a very impressive speed. However, only a small fraction of these projects have secured the investment required to begin construction. The lack of clarity in regulatory frameworks and uncertainty around certification are important factors contributing to the slow progress in real-world implementation.

The use of terminologies that are based on colours to describe different production technologies (e.g. "grey" hydrogen for production based on unabated fossil fuels, "blue" hydrogen for production based on fossil fuels with carbon capture and storage, or "green" hydrogen produced through use of renewable electricity in electrolysers), or on terms such as “sustainable”, “low-carbon” or “clean” hydrogen as a means to distinguish it from unabated fossil fuel-based production has proved impractical for use in contracts that underpin investment. There is currently no international agreement on the use of these terms, which generates uncertainty among the different players involved in the nascent hydrogen, ammonia and hydrogen-based fuels markets.

The uncertainty created by the lack of regulatory clarity is hindering the investment required to scale up production and develop supply chains. Clarity on regulations and certification processes needed to demonstrate regulatory compliance can reassure different market players, especially first movers. Defining hydrogen based on the greenhouse gas (GHG) emissions intensity of its production can help to provide clarity to project developers and investors on the emissions intensity of their product and its compliance with regulatory and market requirements. In addition, it can enable a certain level of interoperability of regulations across different countries and allow mutual recognition of certification schemes, which can minimise market fragmentation.

This report reviews ways for putting emissions intensity at the centre of regulation and certification. It applies the methodology developed by the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) to assess the GHG emissions of hydrogen production in order to illustrate the range of emissions associated with different hydrogen production routes. The report sets out a route to implement an emissions accounting framework that can help governments to facilitate interoperability and minimise market fragmentation in order to unlock investment and speed up deployment.

The G7 brings together some of the world’s largest advanced economies, collectively accounting for about 40% of global GDP and roughly one-quarter of global hydrogen production and demand. Moreover, G7 members are among the leading countries in the implementation of policies to support the scale-up of production of low-emission hydrogen, ammonia and hydrogen-based fuels and the development of international supply chains. The G7 is also home to more than half of the most advanced projects currently under development for the production of low-emission hydrogen, ammonia and hydrogen-based fuels. The common use of hydrogen production emissions intensity in regulations and certifications of G7 members would provide the necessary regulatory and certification clarity to help developers and investors to move forward with their projects. This would help unlock the level of deployment and scale-up required to set in motion the development of an international market for low-emission hydrogen, ammonia and hydrogen-based fuels in the G7.

Hydrogen and its derivatives in a net zero energy system

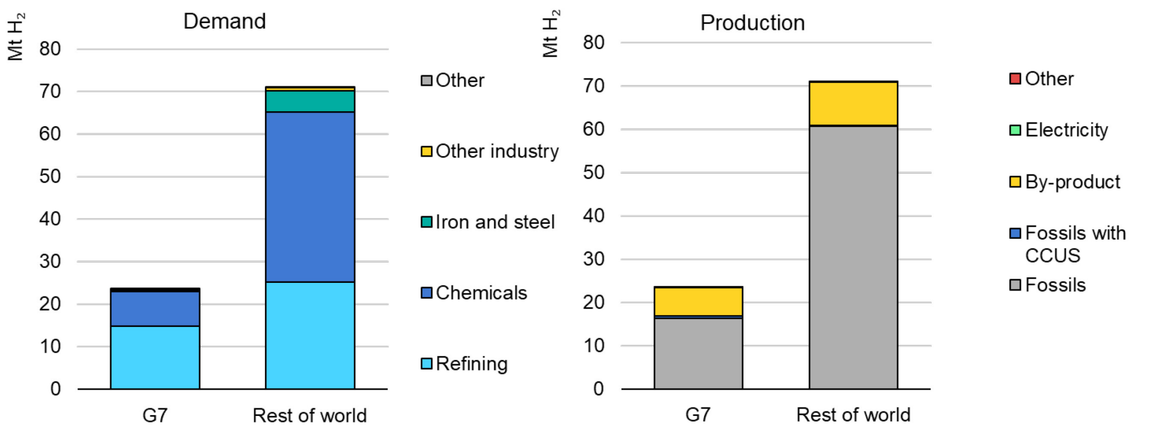
Highlights

- Hydrogen is an important part of today's energy sector, with 94 Mt of demand in 2021 concentrated in refining and industrial applications. The G7 accounts for around one-quarter of global demand. Demand in new applications that could be key to fully decarbonising the entire energy system remained limited to around 40 000 t in 2021.
- Hydrogen, ammonia and hydrogen-based fuels can support the decarbonisation of the global energy system, particularly in heavy industry and long-distance transport. This will require a step-change in demand creation, particularly in new applications; in the IEA's Net Zero Emissions by 2050 Scenario (NZE Scenario), global demand from such applications reaches more than 300 Mt by 2050.
- The production of hydrogen today is based predominantly on unabated fossil fuels. Low-emission hydrogen production is more costly, but scale-up and technology innovation can make low-emission hydrogen competitive in the short term in regions with abundant renewable resources or access to cheap fossil fuels and geological CO_2 storage.
- Regional cost differences and growing demand in regions with less potential to produce low-emission hydrogen, including some G7 members, and the need to diversify fuel supply in the wake of the global energy crisis, could require the development of an international hydrogen market to trade hydrogen, ammonia and hydrogen-based fuels, despite the additional costs arising from conversion and transport processes.
- The deployment of large-scale projects for the production of low-emission hydrogen, ammonia and hydrogen-based fuels is facing important bottlenecks. Only 4% of announced projects (with a total production capacity of almost 1 Mt of hydrogen) are under construction or have taken a final investment decision. Lack of clarity in regulation and certification, lack of infrastructure to deliver hydrogen to end users, and uncertainty about future demand are important impediments.
- G7 members have a critical role to play in scaling up production and use of low-emission hydrogen, ammonia and hydrogen-based fuels globally, and in the development of international supply chains, given their economic power, climate goals and leadership in technology innovation. Nonetheless, the successful development of a global hydrogen market will require an inclusive dialogue with other stakeholders, including producer and emerging economies.

Hydrogen today

Hydrogen is an important element of today's energy sector. Global hydrogen demand reached more than 94 Mt of hydrogen (H_2) in 2021[3] (Figure 1.1), recovering to above pre-pandemic levels, when it had reached its previous maximum at 91 Mt H_2. Hydrogen demand is almost completely concentrated in industrial applications (mainly in the chemical sector and in iron and steel production) and refining, where it is used mainly as a feedstock. Beyond these traditional industrial uses, hydrogen can be used as a fuel in other applications where it can contribute to the decarbonisation ambitions of governments and industry, such as in long-distance transport, the production of hydrogen-based fuels (such as ammonia and synthetic hydrocarbons), high temperature heat in heavy industry and for power generation. However, demand in these applications was limited to around 40 kt H_2 in 2021 (about 0.04% of global hydrogen demand).

Figure 1.1 Global and G7 members' hydrogen demand by sector and production by technology, 2021



Note: Mt H_2 = million tonnes of hydrogen. CCUS = carbon capture, utilisation and storage. In the left figure, *Other industry* includes small demands in industrial applications such as electronics or glassmaking; *Other* includes transport, buildings, power generation sectors and production of hydrogen-based fuels and hydrogen blending. In the right figure, *Other* includes hydrogen production from bioenergy.

Hydrogen demand today is met almost entirely by hydrogen production from unabated fossil fuels and by-product hydrogen from industrial processes that also use fossil fuels as feedstock, resulting in more than 900 Mt of direct CO_2 emissions

[3] This excludes around 30 Mt H_2 present in residual gases from industrial processes used for heat and electricity generation. As this use is linked to the inherent presence of hydrogen in these residual streams, rather than to any hydrogen requirement, these gases are not considered here as hydrogen demand.

in 2021[4]. The production of low-emission hydrogen[5] was less than 1 Mt, almost all from fossil fuels with carbon capture, utilisation and storage (CCUS)[6], with only 35 kt H_2 from electricity via water electrolysis.

The G7 plays a significant role in the hydrogen sector today. Together, G7 members account for around one-quarter of global hydrogen demand, which is lower than their share of global GDP (around 40%) but similar to their shares of global energy demand (around 30%) and energy-related CO_2 emissions (25%). However, the distribution of demand is slightly different to the rest of the world. Although the main applications are the same, within the G7 a larger share of demand is concentrated in refining (around 60% compared with 40% globally); demand in industrial applications (chemicals and steel) is more concentrated in China and the Middle East. New applications accounted for around 0.04% of demand in the G7 in 2021, largely concentrated in road transport.

Unabated fossil fuels dominate hydrogen production in the G7, but the share of low-emission hydrogen production is higher than at the global level, at more than 2% in 2021. The G7 accounts for more than 80% of global low-emission hydrogen production, demonstrating the leadership of G7 members in decarbonising hydrogen production. The share is higher in the production of low-emission hydrogen from fossil fuels with CCUS (nearly 90% of global production), with the United States and Canada spearheading developments. In the case of electrolysis, the G7 accounted for about 40% of global production, with China responsible for about 30% of global production.

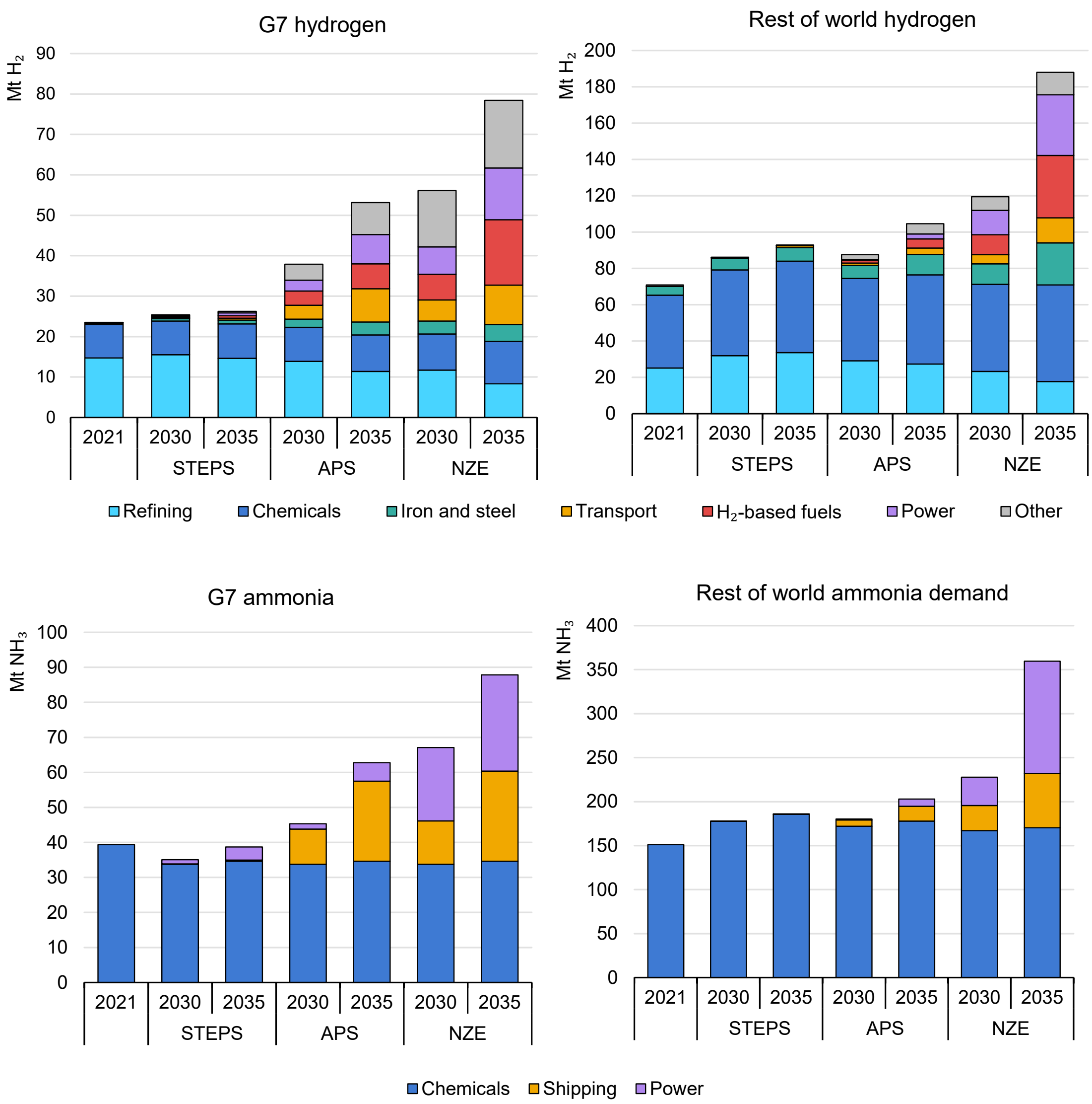
The role of hydrogen, ammonia and hydrogen-based fuels in the transition to net zero

Achieving net zero emissions globally by 2050 will require an unprecedented transformation of the energy system. Hydrogen, ammonia, and hydrogen-based fuels can play an important role in this transformation, particularly in decarbonising sectors where emissions are hard to abate, such as heavy industry and long-distance transport. These fuels can also facilitate integration of renewables and grid balancing.

[4] This includes 275 Mt CO_2 emitted through the use of hydrogen-based products (e.g. urea and methanol) that capture carbon only temporarily.
[5] The term "low-emission hydrogen" used in this report includes both renewable and low-carbon hydrogen as defined in the 2022 G7 Leaders' Communiqué. The definition used by the IEA for analytical purposes in its reports is described in the 2021 edition of the Global Hydrogen Review.
[6] In this report, CCUS includes carbon dioxide captured for use (CCU) as well as for storage (CCS), including CO_2 that is both used and stored, e.g. for enhanced oil recovery or building materials, if some or all of the CO_2 is permanently stored.

In the IEA's Stated Policies Scenario (STEPS), which shows how the energy system evolves under current policy settings, global demand for hydrogen grows slowly in the short and medium term, reaching 110 Mt by 2030 and 120 Mt by 2035 (Figure 1.2). Demand remains highly concentrated in sectors that are already using hydrogen today, with limited uptake in new applications (around 2.5% of global hydrogen demand by 2035). The uptake of hydrogen-based fuels is very small and limited to the use of ammonia in power generation in projects in Japan.

Figure 1.2 Hydrogen and ammonia demand in the G7 and the rest of world by sector and by scenario



Note: Mt H_2 = million tonnes of hydrogen; Mt NH_3 = million tonnes of ammonia; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario. STEPS = Stated Policies Scenario. *Other* includes generation of high temperature heat in industry, small demands in industrial applications such as electronics or glassmaking, other industries and use in buildings. *H_2-based fuels* includes ammonia used as a fuel and synthetic hydrocarbons.

In the IEA's Net Zero Emissions by 2050 (NZE) Scenario, global hydrogen demand reaches 470 Mt by 2050. Getting on track with the NZE Scenario would require a step-change in ambitions and policy implementation for demand creation in the short term, particularly in new applications. Hydrogen demand nearly doubles between 2021 and 2030, and triples by 2035, with new applications responsible for most of the growth in demand, particularly in electricity generation, heavy industry, long-distance transport and the production of hydrogen-based fuels. The production of hydrogen-based fuels alone accounts for 18% of global hydrogen demand in 2035, the majority of which comes from the production of ammonia for use as a fuel in power generation and shipping. The use of ammonia as fuel can play an important role in the transition to a net zero emissions system[7]. In the NZE Scenario, the demand for ammonia grows from 190 Mt NH_3 in 2021, all of it used as a chemical feedstock, to almost 450 Mt NH_3 by 2035, 35% of which is used as fuel for electricity generation and 20% for shipping.

Table 1.1 Net zero targets and hydrogen strategies in G7 members and other major economies

Government	Net zero target		Hydrogen strategy	
	Year	In law	Adopted	Announced
Brazil	2050	No	-	-
Canada	**2050**	**Canadian Net-Zero Emissions Accountability Act**	**2020**	
China	2060	No	2022	
European Commission	**2050**	**European Climate Law**	**2021**	
France	**2050**	**Energy-Climate Act**	**2020**	
Germany	**2045**	**Federal Climate Protection Act**	**2020***	
Italy	**2050**	**No**		**2020****
India	2070	No	2023	
Indonesia	2060	No	-	-
Iran	-	-	-	-
Japan	**2050**	**Act on Promotion of Global Warming Countermeasures**	**2017**	
Saudi Arabia	2060	No	-	-
Korea	2050	Carbon Neutrality Act (Framework Act on Carbon Neutrality and GreenGrowth)	2019	-
United Kingdom	**2050**	**Climate Change Act**	**2020**	
United States	**2050**	**No**		**2022*****

Note: G7 countries highlighted in bold.
* The German National Hydrogen Strategy is under revision and an update is expected in 2023.
** Italy published a draft hydrogen strategy in 2020 for public consultation but its final version has not yet been adopted by the government.
*** A draft of the United States Department of Energy National Clean Hydrogen Strategy and Roadmap was released for public consultation and an updated version will be released later in 2023

[7] The use of ammonia in combustion systems can lead to the production of nitrogen oxides (NO_x), indirect greenhouse gases, and nitrous oxide (N_2O), a greenhouse gas. However, there are technologies available that can limit the emissions of these gases in gas turbines and remove them from the exhaust gases in combustion engines, limiting their environmental impact.

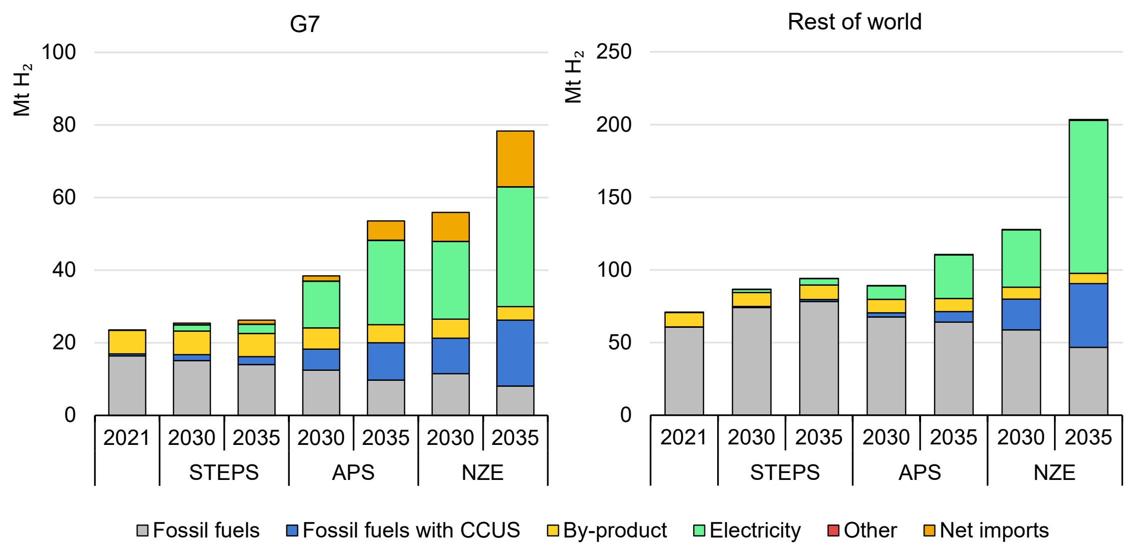
The G7 has a critical role in scaling up the production and use of low-emission hydrogen, ammonia and hydrogen-based fuels within member countries and stimulating developments in the rest of the world. In the NZE Scenario, hydrogen demand in the G7 grows more quickly than in the rest of the world, more than doubling by 2030 and more than tripling by 2035. In addition, the uptake of hydrogen as a fuel in new sectors is particularly strong, accounting for around half of global demand in new hydrogen applications by 2030, compensating for the decline in hydrogen demand in oil refining. In the IEA's Announced Pledges Scenario (APS), which takes into account all announced government climate targets and assumes that they are met on time and in full, the role of the G7 in scaling up global hydrogen demand is even larger than in the NZE Scenario. This is because all G7 members have net zero targets, most of which have already been adopted in national laws, and have adopted hydrogen strategies with ambitious targets to boost production and demand (Table 1.1). The uptake of hydrogen in new sectors to meet long-term net zero targets means that, in the APS, the G7 is responsible for nearly 80% of global hydrogen demand in new applications by 2030, and nearly 70% by 2035.

The accelerated adoption of hydrogen in new applications in both the APS and NZE Scenario is due to the technological leadership of the G7. Today, the United States and Europe account for the majority of projects under development for the use of hydrogen (either pure or blended with natural gas) in gas turbines. EU member states account for more than 90% of projects aiming to use pure hydrogen in direct reduction of iron. Japanese companies have spearheaded efforts to develop ammonia turbines and co-firing ammonia and coal for electricity generation, and Canadian and European companies are at the forefront of technology development for the use of hydrogen, ammonia and methanol in shipping.

Demand creation is only one piece of the puzzle: the other is cleaner production. In the STEPS, global hydrogen production remains dominated by unabated fossil fuels, with a slow adoption of low-emission hydrogen production technologies, which account for only 6% of global hydrogen production by 2030 and 9% by 2035 (Figure 1.3). Faster deployment is hindered by lack of clarity around future demand for low-emission hydrogen, as well as other factors that currently hinder investment decisions. As in the case of demand generation, for hydrogen, ammonia and hydrogen-based fuels to play a role in the energy transition, there is an urgent need for more ambitious action on policy implementation to enable a rapid transformation in the way hydrogen is produced today.

In the NZE Scenario, such hurdles are overcome and there is fast adoption of low-emission hydrogen production technologies. By 2030, more than half of global hydrogen is produced through electrolysis powered by low-emission electricity or by fossil fuels with CCUS, growing from less than 1 Mt in 2021 to more than 90 Mt H_2 by 2030 and reaching 200 Mt H_2 by 2035.

Figure 1.3 Global and G7 members' hydrogen production by technology by scenario



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Note: APS = Announced Pledges Scenario; STEPS = Stated Policies Scenario; NZE = Net Zero Emissions by 2050 Scenario; CCUS = carbon capture, utilisation and storage. *Other* includes hydrogen production from bioenergy.

G7 members continue to be leading actors in the deployment of low-emission hydrogen production technologies in the NZE Scenario. By 2030, the G7 is responsible for around one-third of global low-emission hydrogen production in the NZE Scenario. Low-emission hydrogen production in the G7 grows from less than 1 Mt H_2 today to more than 30 Mt H_2 by 2030 and more than 50 Mt H_2 by 2035, requiring a step-change in the speed of deployment of these technologies. In the NZE Scenario, some G7 members become importers of hydrogen, ammonia and hydrogen-based fuels due to their limited access to abundant renewable resources or cheap fossil fuels and geological CO_2 storage. Others become exporters thanks to their much larger resources for low-emission hydrogen production (see section Trade of hydrogen, ammonia and hydrogen-based fuels). However, imports outstrip exports, with the G7 needing to import around 8 Mt H_2-equivalent (eq) net by 2030 and 15 Mt H_2-eq by 2035 to meet its demand.[8] Most of the hydrogen, ammonia and other derivatives imported are produced using low-emission technologies, meaning that the G7 is a significant driver of the deployment of low-emission hydrogen production capacities overseas.

[8] The quantities of hydrogen, ammonia and hydrogen-based fuels traded are given in hydrogen equivalent terms, i.e. the mass of hydrogen consumed to produce the hydrogen carrier. For example,180 kg of hydrogen are consumed to produce 1 000 kg of ammonia.

In the case of the APS, the deployment of low-emission hydrogen production capacities is slower, both at the global level and in the G7. However, the G7 accounts for a larger share of global low-emission hydrogen production compared to the NZE Scenario (60% by 2030 and nearly 50% by 2035) due to the 2030 and net zero emissions targets adopted by its members.

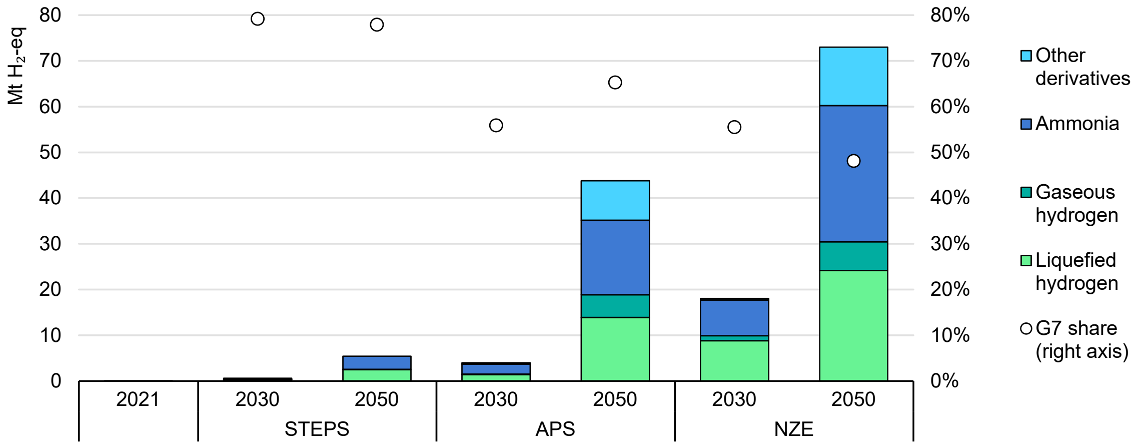
Trade of hydrogen, ammonia and hydrogen-based fuels

The level of hydrogen trade is very low today and limited to sporadic shipments in demonstration projects. However, in the future, countries that have limited opportunities to produce low-emission hydrogen domestically, either due to lack of abundant renewable resources or limited access to cheap fossil fuels and geological CO_2 storage potential, may have to rely on imports from other regions with more favourable conditions for low-emission hydrogen production to meet their hydrogen needs. In addition, the global energy crisis sparked by Russia's invasion of Ukraine in February 2022 has increased attention to the energy security benefits that could be achieved through the development of a global hydrogen market. Trade in hydrogen, ammonia and hydrogen-based fuels has technical and cost challenges, but can help countries with insufficient domestic resources to reach their climate pledges, and can simultaneously contribute to enhance energy security by diversifying the energy mix and the portfolio of suppliers. Hydrogen trade can also create export opportunities and revenues for countries with abundant renewable potentials or access to low-cost fossil fuels and CO_2 storage.

Japan has led the development of international supply chains for hydrogen, ammonia and hydrogen-based fuels. Japan has completed three demonstration shipments of liquefied hydrogen (from Australia, in 2022), ammonia (from Saudi Arabia, in 2020) and liquid organic hydrogen carriers (from Brunei, in 2020). Other countries have also started to increase efforts for the development of international trade of hydrogen, ammonia and hydrogen-based fuels, notably in Europe, as a way to reduce dependency on fossil fuels. Australia, Canada, and several countries in South America, the Middle East and Africa are positioning themselves as potential exporters – in readiness for the possible development of an international hydrogen market – by signing co-operation agreements with potential future importers.

The existing strong industrial base in G7 members is set to require hydrogen imports to meet demand; this, and the efforts to develop export capacity in others, could make the trade of hydrogen, ammonia and hydrogen-based fuels an increasingly important feature of the energy system over the next decades. However, this is unlikely to occur in the near term with current policy settings. In the STEPS, international trade of hydrogen, ammonia and other derivatives remains limited to 0.6 Mt H_2-eq by 2030 and only reaches slightly more than 6 Mt H_2-eq by 2050 (Figure 1.4). In energy terms, this is equivalent to less than 5% of liquefied natural gas (LNG) traded globally in 2021.

Figure 1.4 Global trade of hydrogen, ammonia and hydrogen-based fuels and share of global imports in the G7 by scenario



Notes: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario. *Hydrogen* includes both liquified hydrogen shipping and gaseous hydrogen trade via pipeline. The energy content is based on the lower heating value (LHV) of each carrier.

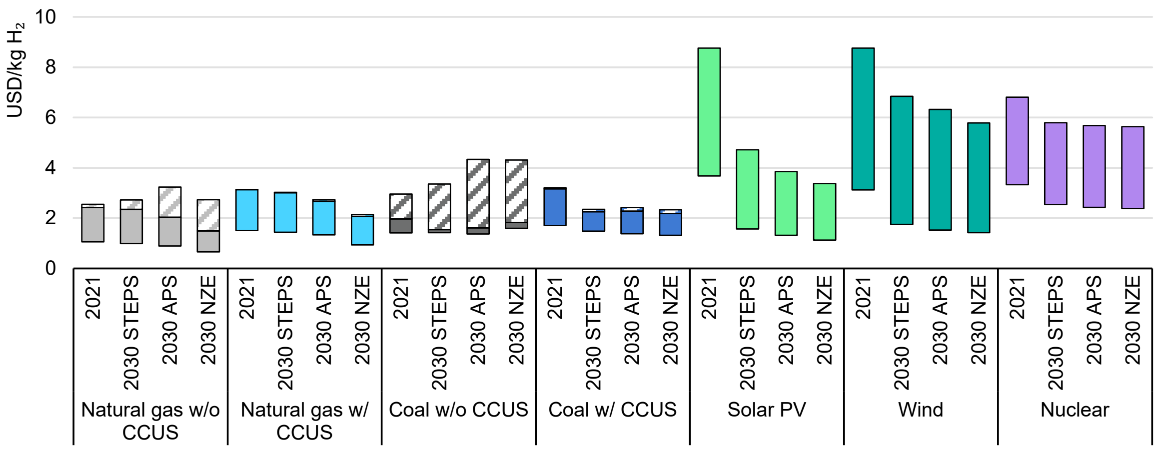
Meeting decarbonisation objectives for the energy system is set to enable a much quicker scale-up of international trade of hydrogen, ammonia and hydrogen-based fuels, and the creation of the respective global market. In both the APS and the NZE Scenario, the international trade of hydrogen, ammonia and hydrogen-based fuels grows to almost 45 Mt H_2-eq and more than 70 Mt H_2-eq respectively by 2050. In energy terms, this would be equivalent to almost 30% and 45% of LNG traded globally in 2021. G7 members are key players in the development and scale-up of international trade of hydrogen, ammonia and hydrogen-based fuels, accounting for more than half of the global trade of these fuels by 2030 in the APS and the NZE Scenario.

Imports of hydrogen, ammonia and hydrogen-based fuels represent an important share of the demand for these fuels in the G7. In the NZE Scenario, imports of hydrogen, ammonia and hydrogen-based fuels in the G7 reach 10 Mt H_2-eq by 2030, meeting nearly one-fifth of their demand. By 2050, G7 imports grow up to 35 Mt H_2-eq, meeting one-third of demand. In the APS, imports of hydrogen and ammonia develop more slowly in the G7, reaching only around 2 Mt H_2-eq or 5% of demand by 2030. However, by 2050, the situation in the APS is quite similar to the NZE Scenario, with close to 30 Mt H_2-eq of hydrogen, ammonia and hydrogen-based fuels being imported to meet more than one-quarter of demand.

The cost of hydrogen supply

The cost of hydrogen production depends on the technology and cost of the energy source used, which usually has significant regional differences. Prior to the global energy crisis sparked by Russia's invasion of Ukraine, the levelised cost of hydrogen production from unabated fossil-based sources was in the range of USD 1.0-3.0/kg H_2 (Figure 1.5). In 2021, these production routes offered the cheapest option to produce hydrogen, compared to the use of fossil fuels with CCUS (USD 1.5-3.2/kg H_2) or the use of electrolysis with low-emission electricity (USD 3.1-9.0/kg H_2).

Figure 1.5 Levelised cost of hydrogen production by technology and by scenario, 2021 and 2030



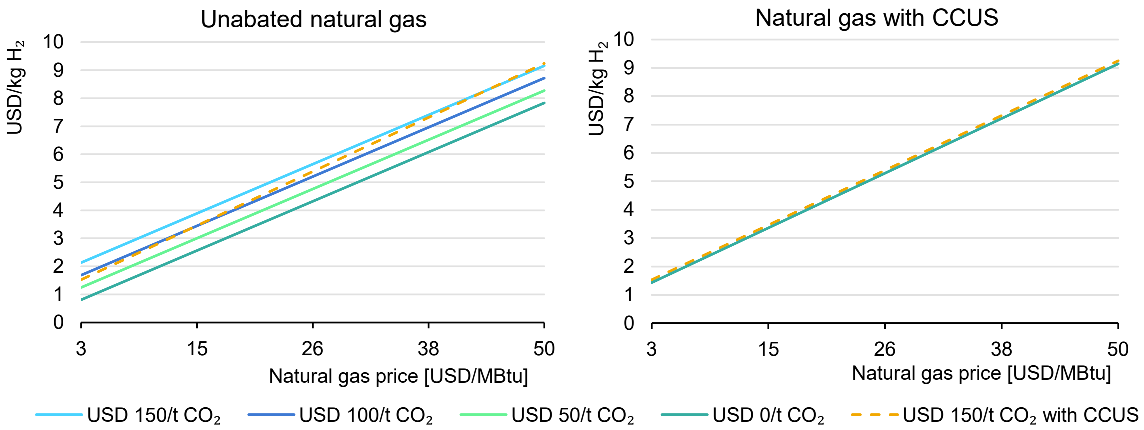
Note: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario; CCUS = carbon capture, utilisation and storage. Solar PV, wind and nuclear refer to the electricity supply to power the electrolysis process. Wind includes both offshore and onshore wind. The capital cost is USD 780/kW H_2 for the unabated natural gas reforming system and USD 1470/kW H_2 for the one equipped with CCUS; USD 1960/kW H_2 for unabated coal gasification and USD 2040/kW H_2 for the one equipped with CCUS; USD 1240-1500/kWe for electrolyser in 2021, USD 460-570/kWe in STEPS 2030, USD 340-390/kWe in APS 2030, USD 270-320/kWe in NZE Scenario by 2030. The dashed area represents the CO_2 price impact, based on USD 0-90/t CO_2 for STEPS, USD 0-135/t CO_2 for APS and USD 15-140/t CO_2 for NZE Scenario.

The large increase in fossil fuel prices observed during 2022, particularly for natural gas, has significantly increased the cost of producing gas-based hydrogen in certain regions. For example, at prices of USD 25-45 per million British thermal units (MBtu), such as those observed during June 2022 in gas markets in Europe, the cost of producing hydrogen from unabated natural gas is USD 4.8-7.8/kg H_2, with natural gas alone being responsible for at least 80% of this cost. This is up to three times the cost prior to the energy crisis. In the case of the production of hydrogen from natural gas with CCUS, the levelised cost of hydrogen production is USD 5.3-8.6/kg H_2, of which more than 75% is attributable to natural gas prices.

At such natural gas prices, the cheapest option for producing hydrogen today in many regions would be from electrolysis using renewable electricity, if production capacity was available.

The record highs in gas prices have started to recede after the turmoil of last year. With the gas prices observed in Europe the first quarter of 2023 (USD 15-20/MBtu), the cost of hydrogen production from unabated natural gas is around USD 2.9-4.2/kg H_2, and from natural gas with CCUS, in the range of USD 3.3-4.7/kg H_2. Moreover, not all markets have been as strongly affected as Europe and see more affordable production of gas-based hydrogen. For example, at gas prices typically observed for the Middle East (USD 1.5-4/MBtu), hydrogen production from unabated natural gas costs around USD 0.6-1.0/kg H_2, and from natural gas with CCUS USD 1.0-1.4/kg H_2. In the case of the United States (gas prices around USD 3/MBtu in the first quarter of 2023), where an operative network for CO_2 transport and storage is already in place, hydrogen production from unabated natural gas costs around USD 0.8/kg H_2, and from natural gas with CCUS USD 1.3/kg H_2.

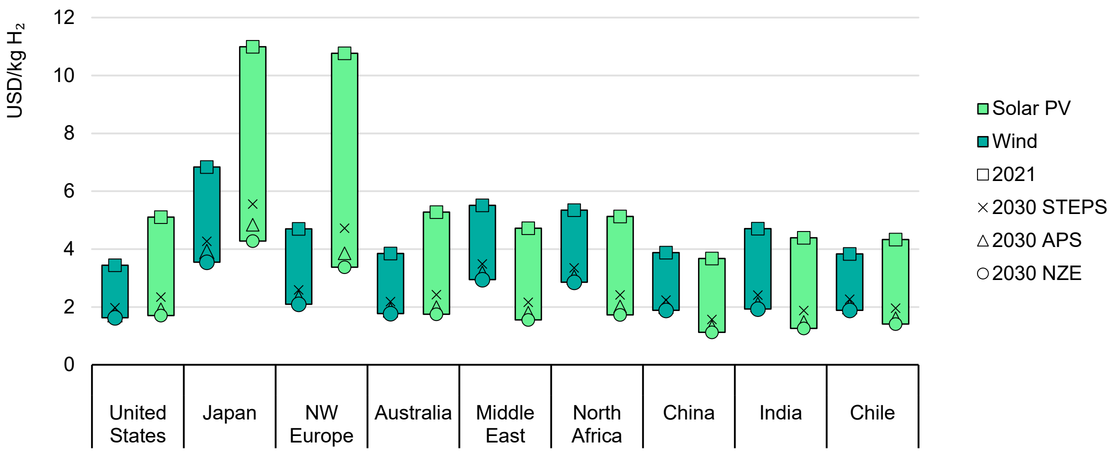
Figure 1.6 Impact of natural gas and CO_2 prices on the levelised cost of hydrogen production from natural gas



Note: CCUS = carbon capture, utilisation and storage. The capital cost of the unabated natural gas reforming system is USD 780/kW H_2 and USD 1470/kW H_2 for the one equipped with CCUS; the cost of CO_2 transport and storage is USD 30/t CO_2 and the capture rate is 93%.

The cost of producing hydrogen from unabated fossil fuels will remain highly influenced by the cost of the fossil fuels, but also by the potential adoption of policies such as carbon pricing (Figure 1.6). For example, a carbon price of USD 100/t CO_2, i.e. slightly above the carbon prices observed in the EU and UK Emissions Trading Systems since the end of 2021, would result in an additional cost of USD 1/kg H_2 in the production of hydrogen from unabated natural gas and USD 2/kg H_2 for unabated coal. In the case of the use of fossil fuels with CCUS, the impact of CO_2 prices would be very limited (less than USD 0.1/kg H_2 for natural gas at a carbon price of USD 100/t CO_2). Moreover, as for renewable electrolysis, the competitiveness of producing hydrogen from fossil fuels with CCUS can improve with higher deployment, as shown in the APS and NZE Scenario. Deployment in STEPS is very limited, and so, therefore, is the cost reduction. The additional capital cost to enable CCUS is expected to decrease as a result of scale-up and technology development, meaning the cost of producing hydrogen from fossil fuels with CCUS could become cheaper than from unabated fossil fuels, depending on fossil fuel and CO_2 prices.

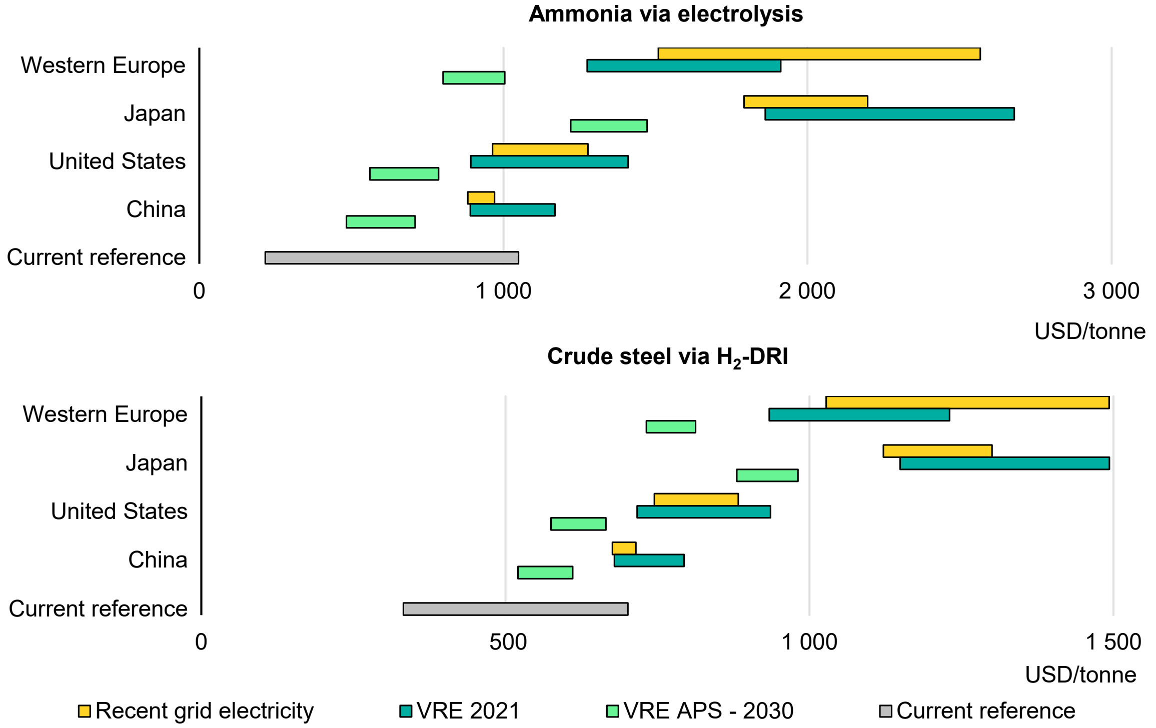
Figure 1.7 Levelised cost of hydrogen produced from renewable electricity by region and by scenario, 2021 and 2030



Note: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario; NW Europe = North-West Europe. Wind includes both offshore and onshore wind. The capital cost for an installed electrolyser system is assumed at USD 1240-1500/kWe for electrolyser in 2021, USD 460-570/kWe in STEPS 2030, USD 340-390/kWe in APS 2030, USD 270-320/kWe in NZE Scenario by 2030.

The cost of hydrogen produced using electrolysis is driven by the capital cost of electrolysers and the cost of the electricity used to power the electrolyser. The capital costs of electrolysers are set to decrease strongly in the short term thanks to economies of scale and further technology innovation. The cost of renewable electricity has already decreased sharply in the last decade (80% reduction in the cost of solar modules between 2010 and 2020), and is expected to continue to decline thanks to widespread deployment of renewables, which are projected to become the largest source of global electricity generation by early 2025. The recent increases in commodity prices may slow down further cost declines in the near term but are unlikely to stop them altogether over the longer term. As the capital cost of electrolysers goes down, the share of the cost of renewable electricity in the cost of producing hydrogen from renewable resources becomes more important. The cost of producing hydrogen from renewable electricity therefore strongly depends on the location of production, resulting in a very wide range of costs at a global level (Figure 1.7). If large-scale deployment takes place (as projected in all three IEA scenarios), the levelised cost of hydrogen could drop below USD 2/kg H_2 by 2030 in countries and regions with excellent solar irradiation, such as Africa, Australia, Chile, China and the Middle East. While solar PV-based electrolysis could become the cheapest way to produce hydrogen by the end of the decade, locations with excellent wind resources (offshore or onshore) could also see a significant drop in the levelised cost of hydrogen, reaching values under USD 3/kg H_2 in the North-West European region and under USD 2/kg H_2 in the United States. With these costs, the production of hydrogen using electrolysis powered with renewable electricity can become competitive with fossil-based routes (both unabated and with CCUS). This is especially the case in locations with access to cheap solar PV electricity.

Figure 1.8 Indicative production costs for hydrogen-based commodities produced via electrolysis in the Announced Pledges Scenario, 2021 and 2030



Notes: VRE = variable renewable energy; APS = Announced Pledges Scenario; H_2-DRI = hydrogen-based direct reduced iron. The VRE cost range represents electrolysis powered by solar PV, offshore wind or onshore wind. An additional hydrogen storage cost to guarantee a minimum load of 80% is considered. 'Current reference' values show production costs using the dominant incumbent means of production today with unabated fossil fuels. The cost of capital is assumed at 5%, while the other techno-economic assumptions are sourced from the references below. Incentives from support schemes such as the Inflation Reduction Act (IRA) have not been taken into account.
Source: IEA (2023), Energy Technology Perspectives 2023.

The considerable cross-region variations in the production costs of hydrogen can also have an important effect on the production costs of certain end-products, such as ammonia or steel, thereby affecting the competitiveness of the production of these products across differerent regions. Based on recent grid electricity prices, producing ammonia and steel with hydrogen using grid-connected electrolysers would cost around 50-170% more in Western Europe and Japan than in China, and 40-100% more than in the United States (Figure 1.8). Western Europe becomes much more competitive if the production costs that could be achieved using low-cost variable renewable energy are considered, although cost still remains higher than in China and the United States.

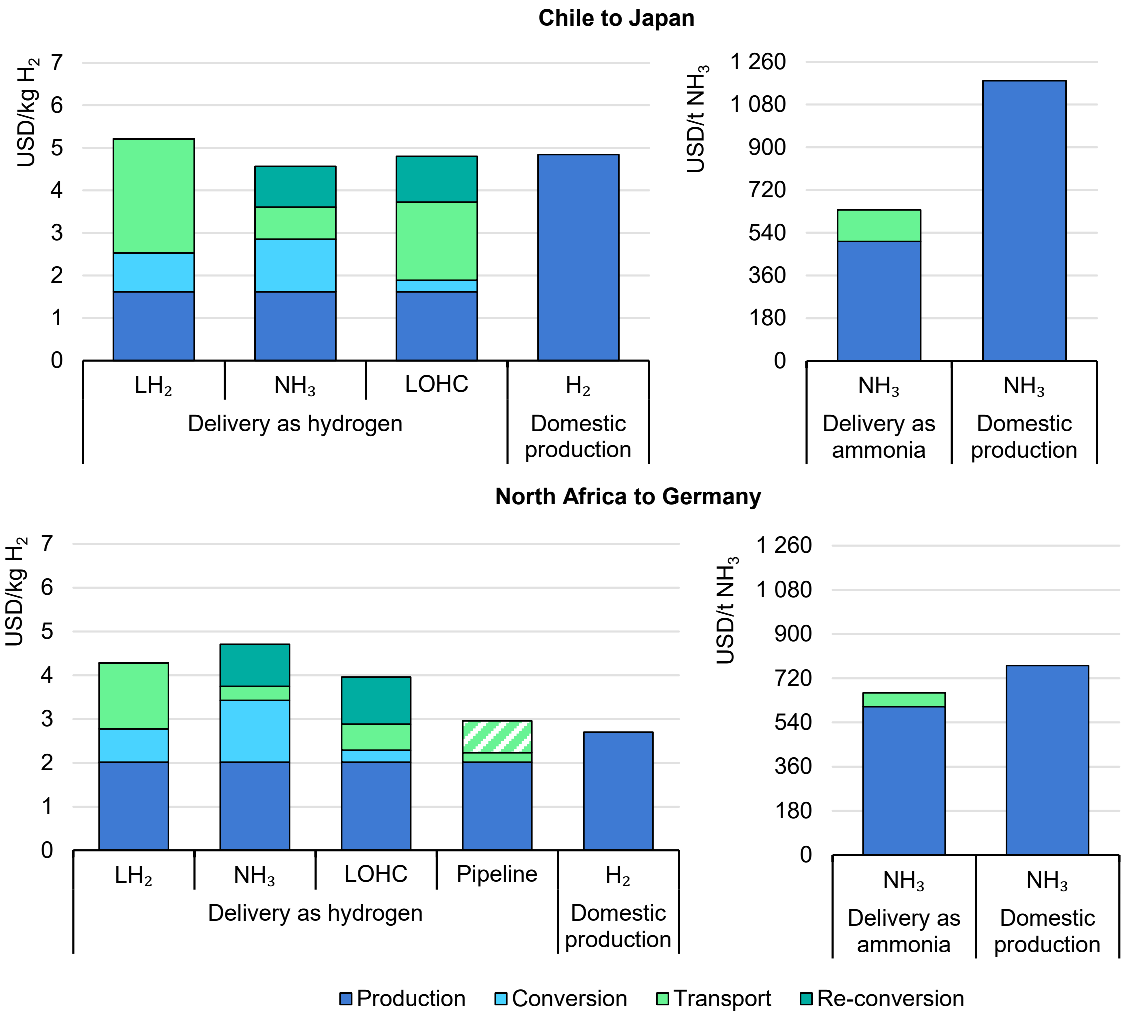
Substantially lower costs can be envisaged if countries are successful in implementing their announced pledges and scaling up the deployment of renewables and low-emission hydrogen production. Moreover, although cost differences will persist, these differences would be less marked. In the APS, using variable renewable energy to produce ammonia leads to costs in the range of USD 480-1 500/t, and USD 520-980/t for crude steel in 2030. Competitiveness is a key consideration for governments in designing their industrial strategies and assessing those of their key suppliers. This can lead to different priorities in the development international supply chains of hydrogen, ammonia and other derivatives.

The cost of transport and conversion processes

The production cost of hydrogen is only part of the final cost that consumers will need to pay. Today, most hydrogen production is captive, meaning that hydrogen production and consumption are integrated processes for large centralised industrial users. In this case, the production cost is the same as the cost faced by the final user. However, the adoption of hydrogen, ammonia and hydrogen-based fuels in new applications which are more distributed (such as in the transport sector) will require the creation of domestic hydrogen transport and distribution infrastructure. Moreover, significant regional differences in production costs and an increasing focus on diversifying supplies may lead to the creation of international markets. In such markets, countries with limited potential to develop low-emission hydrogen production capacities will rely on imports of hydrogen, ammonia and hydrogen-based fuels from regions with abundant renewable resources or with access to cheap fossil fuels and CO_2 storage potential.

The need for domestic and international trade infrastructure for hydrogen, including for conversion into other hydrogen carriers and potential reconversion into hydrogen, are further cost elements in addition to production costs. In certain cases, conversion and reconversion costs – if needed – as well as transport costs, can be greater than the production costs. When shipped as liquefied hydrogen over long distances, the shipping cost represents the main cost component of the delivered hydrogen. For example, the cost of transporting liquefied hydrogen from Chile to Japan can account for 50% of the final delivered cost of hydrogen (Figure 1.9). Shipping liquified hydrogen is a very expensive option for shipping hydrogen and will remain so in the near future, but this cost can be expected to decrease significantly with scale-up. If ammonia is chosen as the transport carrier, the transport costs decrease, but the cost of converting hydrogen into ammonia and the subsequent cost of cracking it back to hydrogen significantly affects the delivered cost of hydrogen. However, in cases where ammonia can be directly used without being reconverted to hydrogen, the reconversion costs can be avoided. In the case of hydrogen shipping using liquid organic hydrogen carriers, shipping costs are also expected to be lower than using liquified hydrogen, due to the possibility of using existing tankers, although the energy required in the conversion and reconversion processes strongly affects the final cost of delivery.

Figure 1.9 Near-term levelised cost of delivered hydrogen and ammonia from solar PV, by transport option, in selected trade routes



Note: LH_2 = liquified hydrogen. NH_3 = ammonia. Transport includes the cost associated with investment and operation of storage tanks at import and export shipping terminals assuming 20 annual shipments and shipping cost; in the case of pipeline, it includes the cost related to the construction and operation of hydrogen pipelines. For liquified hydrogen shipping, the tanker size assumed is 160 000 m^3; for ammonia shipping it is 76 000 m^3. For pipeline, the dashed area represents the cost variation in the case of a new or repurposed 48-inch pipeline operating between 25% and 75% of its design capacity during 5 000 full load hours. For ammonia, an additional hydrogen storage cost is considered, to guarantee a minimum load of the Haber-Bosch process of 80%. The levelised cost of hydrogen production from solar PV is assumed to be USD 1.6/kg H_2 in Chile and USD 2/kg H_2 in North Africa; and the levelised cost of ammonia production from solar PV is assumed to be USD 500/t of ammonia in Chile and USD 600/t of ammonia in North Africa.

In the case of shorter distances between the sites of production and demand (up to around 3 000 km), transporting compressed gaseous hydrogen via pipeline may be the cheapest option. For example, compressing and transporting hydrogen between North Africa and Germany using newly built pipelines could add around USD 0.5-0.9/kg H_2 to the production cost, if a new pipeline is built. This cost could fall to only USD 0.2/kg H_2 if an existing natural gas pipeline is repurposed to transport hydrogen, although this option presents some technical challenges that may limit its applicability.

Accelerating deployment to meet ambitions

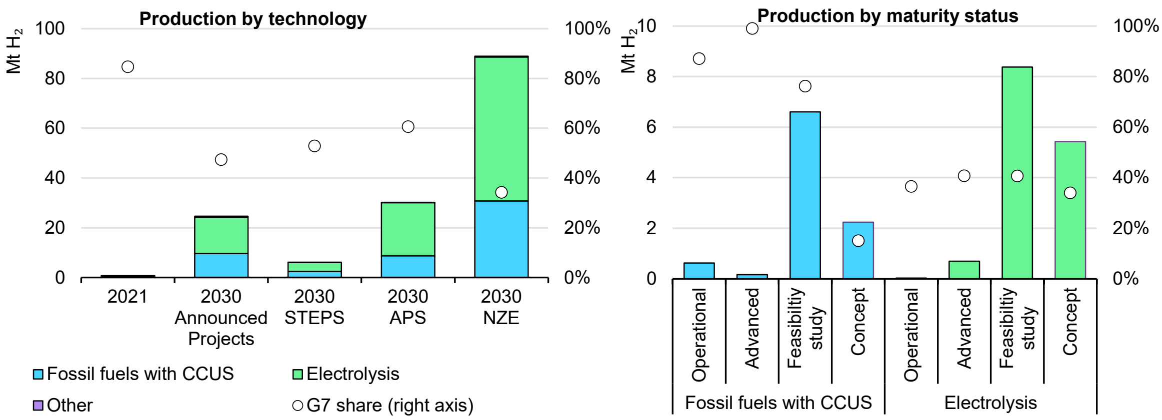
There is a very large gap between the production of low-emission hydrogen today and what is needed to put the world on track with the APS and the NZE Scenario. However, a sizeable number of projects have been announced, aiming to develop large capacities for the production of low-emission hydrogen. If all announced projects are realised, the annual production of low-emission hydrogen could reach 24 Mt by 2030 (Figure 1.10). These projects are spread across the globe, although G7 members account for roughly half of the potential production that could be achieved from all the projects under development.

The production of low-emission hydrogen from announced projects would be enough to meet 80% of the APS requirements but only around one-quarter of the needs of the Net Zero Emissions by 2050 Scenario. How many of the announced projects will become operational by 2030 is uncertain. With current policy settings, most of these projects will not be realised due to barriers to deployment being encountered by project developers today, including lack of demand, uncertainty on regulation and certification, and lack of infrastructure to deliver hydrogen to end users. In addition, emerging economies (which account for around one-quarter of the potential production from announced projects) face other important barriers, such as difficulties in accessing finance and the need to develop a skilled workforce. Without policy action to overcome these barriers, deployment will remain limited to 6 Mt, as projected in the STEPS.

The maturity of the projects under development can provide a good indication of the feasibility of reaching their full production potential by 2030. Currently, only 4% of the projects (in terms of their production output in 2030) are at advanced stages of development, i.e. are under construction or have reached a final investment decision (FID). About one-third of the potential production of low-emission hydrogen corresponds to projects at the concept stage, meaning that they are at very early stages of development (e.g. only a co-operation agreement among stakeholders has been announced), while the remaining portion consists of projects undergoing feasibility and engineering studies.

Around 2% of the CCUS projects are at advanced stages of development, representing 0.2 Mt of low-emission hydrogen production by 2030. In the case of electrolysis projects, only 5% are at advanced stages of development (representing around 0.7 Mt of low-emission hydrogen production), with the bulk of potential production coming from projects undergoing feasibility and engineering studies (58% of potential production) or at concept stage (37% of potential production). This means that the vast majority of the projects are still far from being realised. The construction and commissioning of hydrogen projects can take from around two years (for electrolysis projects smaller than 100 MW) to around a decade (in the case of large CCUS projects).

Figure 1.10 Global low-emission hydrogen production and G7 share based on announced projects and by scenario, 2021 and 2030



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Notes: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario; CCUS = carbon capture, utilisation and storage. *Other* includes hydrogen production from biomass, with and without CCUS.
Source: IEA (2022), Hydrogen Projects Database (March 2023).

In 2021, G7 members produced more than 80% of all hydrogen coming from operational projects using fossil fuels with CCUS, and 40% from operational electrolysis projects. Moreover, almost half of the announced projects that are currently under construction or have taken an FID and therefore could become operational by 2030 are located in G7 members, representing nearly 0.5 Mt of potential low-emission hydrogen production. In addition, projects with a potential production of 8.5 Mt of low-emission hydrogen by 2030 are undergoing feasibility and engineering studies in G7 countries. This is 55% of all the projects in the world at this development stage, highlighting the important role that the G7 can play in scaling up low-emission hydrogen production in the short term.

Clear hydrogen definitions to address deployment barriers

Despite the strong momentum behind hydrogen and the growing interest shown by both governments and industry, progress in project implementation is still slow and far from what would be needed for hydrogen to play its role in meeting climate ambitions. This highlights the need to rapidly address several barriers contributing to the slow pace of project deployment:

- The potential scale of demand for low-emission hydrogen in the near term is uncertain, and it is unclear how much of this demand will be specifically for low-emission hydrogen. Many governments have identified potential mechanisms to create this demand, such as such as auctions, mandates, quotas and requirements in public procurement. However, the majority of these polices have not yet been implemented. In the case of hydrogen produced using renewables more specifically, uncertainty around the long-term development of energy prices prevents FIDs being taken, despite the current competitiveness of renewable-based hydrogen in certain markets.
- There is a need to develop the infrastructure required to deliver hydrogen from the production side to the end users. This is particularly necessary in the case of distributed applications, or where large demand is situated far from locations that are attractive for producing low-emission hydrogen at low cost. Today there is almost no available infrastructure, and if developed it faces the risk of underutilisation due to the uncertain evolution of demand.
- There is a lack of clarity in regulatory frameworks and certification schemes. The scale-up of low-emission hydrogen production requires clear policy frameworks, including agreed standards for environmental criteria and policies to incentivise end users to commit to long-term purchases and manage offtake risk. Standards and certification for guaranteeing that hydrogen-based commodities meet environmental criteria, either voluntary, set by regulatory obligations or linked to government and market incentives, have become a priority for project developers to gain investors' confidence. Achieving a certain level of compatibility among these policy frameworks across borders will also be needed in order to facilitate international trade.

Governments have an important role in implementing measures to lower all of these barriers and facilitate deployment, and regulation is an area in which government action can have a large and immediate impact. Market players, and particularly first movers, require clarity on regulations and the certification processes needed to demonstrate regulatory compliance. This is particularly the case for aspects related to hydrogen sustainability attributes.

International co-operation to facilitate deployment

Governments need to enhance international co-operation in order to address various barriers to the scale-up of hydrogen production and use, particularly for aspects related to defining standards and certification systems for hydrogen. Finding avenues for mutual recognition of regulations and certification schemes can facilitate interoperability and minimise market fragmentation. This can help hydrogen producers to reach offtake agreements with multiple potential clients in different markets, without the need to certify their product individually for each client, region and regulatory authority. The G7 is an ideal forum to explore these potential avenues, drawing on the sizeable economic power and technological leadership of its members. The G7 is already taking action to enhance collaboration in addressing some of the barriers that are preventing hydrogen scale-up. In 2021, the UK G7 Presidency and the United States initiated the G7 Industrial Decarbonisation Agenda to work on regulation, standards, investment, procurement and joint research related to industrial decarbonisation, which can indirectly trigger hydrogen demand in the industrial sector. In 2022 the G7 members launched the Hydrogen Action Pact, with the objective of joining forces to accelerate the adoption of hydrogen and hydrogen-based fuels (especially ammonia), and streamlining the implementation of existing multilateral initiatives.

G7 members can benefit from being first movers and facilitating interoperability among their regulatory frameworks in order to scale up both domestic production and demand for hydrogen, ammonia and other derivatives, as well as facilitating international trade. This would support the development of international hydrogen trade in the near term. However, G7 members cannot undertake this challenge in isolation. The development of an international hydrogen market requires the involvement of as many stakeholders as possible, including producer and emerging economies. These countries have strong potential to produce affordable low-emission hydrogen and want to benefit from the development of a global hydrogen market in the form of economic growth, the creation of a skilled workforce or avoided environmental harm and negative impacts in their local and indigenous communities. The G7 needs to foster an inclusive dialogue, ensuring that the voices of all these potential partners are heard and their challenges are recognised. The success of the development of a global hydrogen market will, to a large extent, depend on its inclusivity and the fair distribution of its benefits.

Defining hydrogen according to its emissions intensity

Highlights

- Clear regulations and certification systems based on the emissions intensity of hydrogen production can bring much-needed transparency and be a useful enabler of investments in production and demand applications as well as infrastructure for hydrogen trade. The colour scheme often used for hydrogen, such as “green” or “blue” hydrogen, suggests a characterisation of the production route, but does not provide any quantification of its effect on emissions.
- Several voluntary certification systems and regulations to define hydrogen using the emissions intensity as key indicator already exist or are under development. Many of them share common elements, such as emissions intensity as a key indicator, or a focus on hydrogen production, but they differ in aspects such as system boundaries or the emissions intensity levels imposed. A consistent methodology to define hydrogen based on its emissions intensity will be critical to ensure interoperability between regulatory frameworks and certification systems. The analysis in this report is based on the methodology developed by the International Partnership on Hydrogen and Fuel Cells in the Economy.
- Emissions intensities vary widely among hydrogen production routes, from 10-13 kg CO_2-eq/kg H_2 from the use of unabated natural gas, to 0.8-4.6 kg CO_2-eq/kg H_2 for partial oxidation of natural gas with carbon capture and storage (CCS) (with the ranges depending on the upstream and midstream emissions of natural gas supply). For fossil-fuel based routes, in addition to increasing the CO_2 capture rate, minimising upstream and midstream emissions of fossil fuel operations, in particular methane emissions, will be critical to achieve low intensities.
- While hydrogen production from renewable electricity via electrolysis is assumed to lead to zero emissions, achieving low emission levels using grid electricity depends on the emissions intensity of the grid. For example, a grid electricity intensity of 40 g CO_2-eq/kWh yields hydrogen with an emissions intensity of 2 kg CO_2-eq/kg H_2.
- Global hydrogen production is today almost completely based on the use of unabated fossil fuels, resulting in an emissions intensity of 12-13 kg CO_2-eq/kg H_2. In the Announced Pledges Scenario (APS), the global average emissions intensity falls below 3 kg CO_2-eq/kg H_2 by 2050, while in the Net Zero by 2050 Scenario the intensity reaches levels of under 1 kg CO_2-eq/kg H_2 by 2050.

Introduction

Various terms are currently used to describe the environmental attributes of hydrogen. These either use colours to refer to different production routes (e.g. “green” for hydrogen from renewable-powered electrolysis and “blue” for production from natural gas with carbon capture, utilisation and storage (CCUS)) or terms such as “sustainable”, “low-carbon” or “clean” hydrogen to distinguish it from unabated fossil-based production. However, there is no international agreement on the use of these terms, and their existing definitions are generally considered insufficient to be used as a reference in regulations or supply contracts. For example, much existing electrolysis currently runs on grid electricity, for which a colour has not been proposed. The terms “grey” and “blue” provide no information about important factors such as upstream and midstream methane emissions and carbon capture rate.

Clear definitions based on the greenhouse gas (GHG) emissions intensity[9] of hydrogen production can bring much-needed transparency and be a useful enabler of investments in hydrogen production, hydrogen demand applications, infrastructure and trade in hydrogen. Without such clarity on definitions, contracting parties lack criteria needed to comply with divergent regulations and certification schemes around the world (Box 2.1). This could hinder the development of projects due to risks of non-compliance in the future, as well as time and costs associated with multiple certification processes.

Developing definitions based on a common methodology or agreed standard to determine the GHG intensity of hydrogen can simplify the certification process. A common definition would allow for comparison of the emissions intensities between different production pathways and producers, while still leaving governments the possibility to define acceptable emissions intensity levels, taking into account local circumstances and opportunities. Countries may set different thresholds, but use of a common methodology to determine emissions intensity would ensure interoperability between different countries.

This chapter starts with an overview of existing and proposed certification systems and regulations for hydrogen and their attributes and criteria. This is followed by an analysis of the emissions intensity of different hydrogen production routes. The analysis is based on the methodology developed by the International Partnership on Hydrogen and Fuel Cells in the Economy (IPHE), using IEA data for the

[9] Greenhouse gas (GHG) emissions refer here to the emissions of CO_2, methane (CH_4) and nitrous oxide (N_2O). For the supply of natural gas and coal and in hydrogen production processes, N_2O emissions are relatively small and levels uncertain, so N_2O emissions are only include in the emissions of grid electricity, but not in the emissions of upstream natural gas and coal supply. Hydrogen itself is an indirect GHG, but has been not considered in the analysis here, as research on its global warming potential is still ongoing.

production technologies and upstream and midstream emissions. This analysis is then used as the basis of a proposal for defining hydrogen according to its emissions intensity.

Box 2.1 Certification systems

A certification system provides evidence that methodologies and analytical frameworks are applied according to a specified standard or set of requirements. Certifications can help to provide credibility and transparency by demonstrating to consumers that a product or service meets certain expectations. Issued by independent bodies, certifications cover both the test methods to assess a certain product or process and the criteria that the product or process must meet. They undergo the necessary inspections and reviews to guarantee an objective evaluation.

These systems can be either mandatory or voluntary. Mandatory certification systems verify that market participants are adhering to specific criteria outlined in policies, regulations or contractual obligations. In contrast, voluntary certification systems can be used for reporting and disclosure purposes.

Mutually recognised certifications enable the global interoperability of products and devices. For example, WiFi certifications based on internationally recognised standards guarantee that a variety of devices will be able to connect to wireless networks around the world.

Certifications are found across all economic sectors, such as electronics, telecommunications, and pharmaceuticals. In general, the main elements of a successful certification system include:

- **Governance**: to establish the roles and responsibilities of the standards and certification bodies.
- **Application**: of the standard on which the product or process is being tested, and any additional criteria.
- **Evaluation**: of whether the product or process meets the standard or qualification criteria, and the need for more information or a second review.
- **Enforcement and verification**: that the product or process in the marketplace continues to meet the qualification criteria, and of the steps to audit and verify compliance.

Elements of regulations and certification systems for hydrogen

No internationally agreed framework or standard on how to define the GHG intensity of hydrogen production currently exists, though efforts are underway. The IPHE has developed a methodology to calculate the GHG emissions for different hydrogen production routes. This methodology is being used to establish an International Organization for Standardization (ISO) standard.[10]

Attributes and criteria of certification systems

Despite the nascent nature of hydrogen markets, several certification systems or regulatory frameworks defining the emissions intensity of hydrogen have been developed or are under development (Table 3.1). They can be characterised by different attributes and criteria:

- **Purpose**: Certification systems can be **voluntary** and used by market participants for reporting and disclosure purposes, such as the Green Hydrogen Standard at an international level, CertifHy in the European Union or TÜV SÜD CMS 70 in Germany. Certification can also be required for **regulatory** reasons to prove compliance with specific legislative criteria in a country, or to benefit from government incentives, such as California's Low-Carbon Fuel Standard or the hydrogen production tax credit of the Inflation Reduction Act in the United States. **Funding programmes, tenders or auctions** can also require that certain emissions intensity levels are met, such as the tenders for hydrogen purchase agreements of H2Global.
- **System boundaries**: Certification systems can be differentiated by the hydrogen supply chain steps that they cover (Figure 2.1). **Well-to-gate** system boundaries target the supply of the fuels used in the production process, while **well-to-point of delivery** or **well-to-tank** boundaries also include the transport and possible conversion and reconversion of hydrogen into other carriers (e.g. ammonia). **Well-to-wheel** system boundaries also include emissions associated with the use of hydrogen. CertifHy is based on a well-to-gate system boundary, while H2Global follows a well-to-point of delivery approach by taking into the account the transport emissions to specified delivery points in Europe.[11] A well-to-wheel system boundary is used for the definition of renewable hydrogen in the Renewable Energy Directive II of the European Union.
- **Scope**: Almost all existing and proposed certification systems cover direct emissions (Scope 1) and indirect emissions associated with the generation of electricity, heating/cooling, or steam purchased for own consumption (Scope 2). Most frameworks also include indirect emissions, such as in the case of hydrogen

[10] The development of an ISO standard takes several years. To provide a reference in the interim, the ISO is developing a Draft Technical Specification to measure the emissions intensity of hydrogen production, aiming for publication in 2024.
[11] The impact of transport emissions is illustrated in Box 2.3.

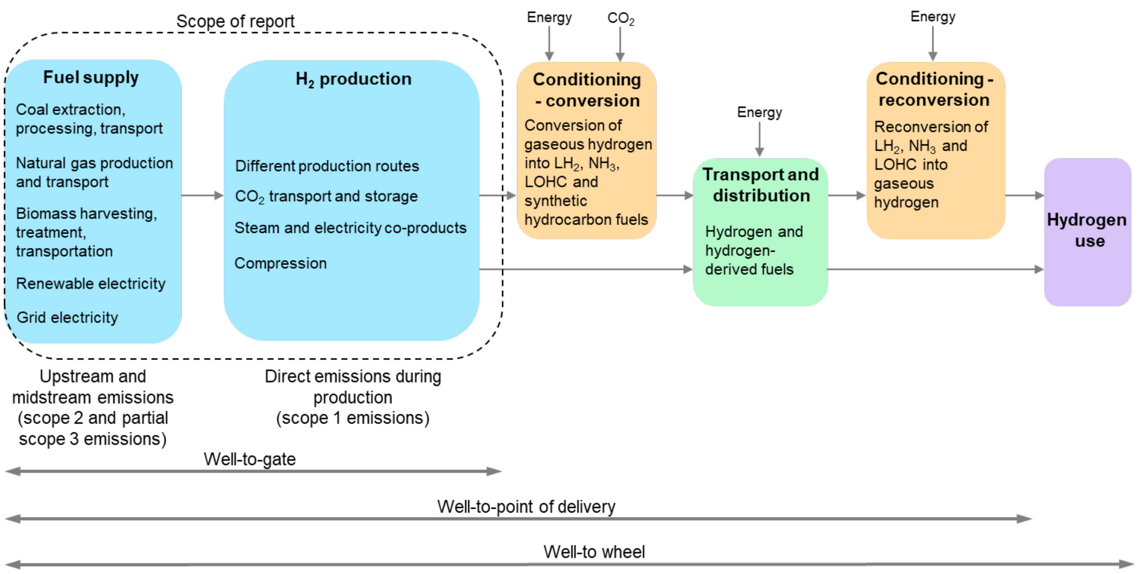
production from natural gas, the upstream methane and CO_2 emissions from gas production, and midstream emissions from transporting and storing the natural gas. The systems that cover the use of fossil fuels for hydrogen production also generally include the emissions associated with transporting and storing the captured CO_2 (e.g. indirect emissions from electricity use). Emissions from the manufacture of machinery and equipment are typically not included (partial Scope 3), which is also reflected in the IPHE methodology. While these embedded emissions can affect the emissions intensity of hydrogen production, particularly in the near term, indirect emissions from material production processes, such as aluminium, cement, copper or steel, are expected to decline in the medium and long term with increasing efforts to decarbonise the energy system. As a result, the emissions impact of electricity generation from wind, solar photovoltaic, hydropower and geothermal energy in the emissions intensity of hydrogen production is assumed to be zero.

- **Production pathways**: Certification systems or regulatory frameworks may limit the eligible technology and fuel options for hydrogen production. The Green Hydrogen Standard, for example, requires electrolysis using renewable electricity, while the UK Low Carbon Hydrogen Standard lists electrolysis, natural gas with CCUS and production from biomass and waste as production options. The French certification scheme currently under development does not include constraints on technology choice.
- **Hydrogen products**: Most certification systems to date consider only the production of hydrogen (i.e. in form of H_2). A few systems and regulations, such as the EU Taxonomy or RED II, also include hydrogen-based fuels.
- **Demand sectors**: In some cases, certification is linked to sector-specific regulation. The Low Carbon Fuel Standard in California and the UK Renewable Transport Fuel Obligation are limited to the transport sector. Most of the existing and proposed systems, however, are not tied to a specific demand sector.
- **Chain of custody model**: This determines the requirements for tracking and tracing product attributes along the supply chain. There are two types of chain of custody models commonly used in certification systems. In a *book-and-claim model*, the producer delivers a product meeting certain environmental criteria to the market, e.g. hydrogen below a certain emissions intensity threshold, and at the same time, books an equivalent amount in a certificate platform. Buyers of the product can acquire a certificate and thus claim that an equivalent amount of the product purchased meets the environmental requirements. This model allows certificates to be traded separately from the physical product, thus providing flexibility, but does not ensure any physical tracking of the product. Examples are CertifHy and the Low Carbon Fuel Standard in California. The *mass balancing model* links the certificate to the respective physical delivery of the product. The mass of the product is accounted for by tracking the mass at the input and output sides of the delivery steps involved, which provides some traceability of the physical product. Compliant and non-compliant products can be mixed, but operators are required to monitor and record the inputs of compliant and non-

compliant inputs into their operation, so that equivalent parts of the outputs can be regarded as compliant products. RED II refers to mass balancing as a tracking model.

- **Emissions intensity levels**: Most certification systems require the emissions intensity level, i.e. the specific GHG emissions per unit of hydrogen, to fall below certain levels to qualify for a label or to meet the requirements of a regulation. Other schemes, such as the planned Guarantee of Origin certificate scheme, certify the emissions intensity without any threshold levels.
- **Additional sustainability criteria considered**: Certification systems can also include further sustainability criteria, such as other environmental or social aspects. The EU Taxonomy, for example, lists water impact, air pollution and biodiversity as additional criteria.

Figure 2.1 Scope and system boundaries for emissions accounting schemes



Notes: LH_2 = liquefied hydrogen; NH_3 = ammonia; LOHC = liquid organic hydrogen carrier.

The emissions intensity of hydrogen production routes

A common and robust methodology for determining the emissions intensity of hydrogen, including common system boundaries and scope of emissions, is critical to ensure comparability between intensity levels in different certification systems and regulatory frameworks. The analysis and discussion in this report applies the IPHE methodology (Scope 1, 2 and partial Scope 3 emissions) and focuses on the production of hydrogen by using a well-to-gate system boundary. Other hydrogen supply chain steps, such as the conversion of hydrogen into other hydrogen carriers, the transport of hydrogen and hydrogen carriers (as in the case of international trade), and the reconversion of hydrogen carriers back into hydrogen are important steps that should be included to fully assess the GHG impact of hydrogen supply chains. The analysis that follows focuses on production to support the definition of a proposed international emissions accounting system for the production of hydrogen. The IPHE has already developed a methodology to assess the emission impact of hydrogen conditioning, i.e. conversion and reconversion. The methodology for assessing the emission impact of transporting hydrogen and hydrogen carriers is still under development by the IPHE. Some information on the emission impact of ammonia production is provided in Box 2.3, while Box 2.4 illustrates the potential impact of transporting hydrogen, ammonia and hydrogen-based fuels by ship or pipeline. In the following text, the IPHE methodology is used to illustrate the emissions intensity of different hydrogen production routes today and for 2030.

Overview of different hydrogen production routes

The emissions associated with the production of hydrogen can vary significantly between production routes, depending on the fuel, technology and the rate at which CCS[12] is applied (Figure 2.2). In addition to direct emissions occurring in the production of hydrogen, indirect emissions from the production, conversion and transport of the required input fuels, such as natural gas or electricity, can affect the overall emissions associated with the production of hydrogen.

Natural gas is today the main source of hydrogen production globally, accounting for 62% of production. The direct emissions of hydrogen production from natural gas without CCS using steam methane reforming (SMR) are around 9 kg CO_2-eq/kg H_2. Further emissions occur in the production, processing and transport of natural gas, either in the form of methane emissions[13] from venting or leakages, or as CO_2 emissions from flaring methane at gas fields or linked to the energy being used to produce and transport natural gas (e.g. emissions linked to the electricity for compressing natural gas).

Upstream and midstream emissions for natural gas can vary widely between natural gas basins and countries, reflecting different production practices and emission mitigation efforts. The application of best practices to avoid emissions from natural gas production, such as in Norway, limits the combined methane and CO_2 emissions to 4.5 kilogramme CO_2 equivalent per gigajoule of produced natural gas (kg CO_2-eq/GJ_{NG}), of which 0.8 kg CO_2-eq/GJ_{NG} are methane emissions and 3.7 kg CO_2-eq/GJ_{NG} CO_2 emissions, mainly from energy use during gas production and transport. These upstream and midstream emissions are in

[12] For the analysis in this chapter, only carbon capture and storage (CCS) has been considered. The IPHE methodology does not consider carbon capture and utilisation due to lack of consensus between government and industry whether the CO_2 emissions for the CO_2 used should be allocated to the producer of hydrogen or transferred to the end user.

[13] One tonne of methane is considered to be equivalent to 25 tonnes of CO_2 based on the 100-year global warming potential from the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report.

addition to the direct CO_2 emissions of 56 kg CO_2-eq/GJ_{NG}, created when burning the natural gas without CCS. Upstream and midstream emissions from natural gas supply can be much higher in other gas production regions in the world, reaching for example 27 kg CO_2-eq/GJ_{NG} in the Caspian region (around half of the direct emissions of the unabated use of natural gas). More than three-quarters of these upstream and midstream emissions are methane emissions from venting and leakages during gas production and transport. The global median upstream and midstream emissions from gas production today are around 15 kg CO_2-eq/GJ_{NG}. Using this median value for the upstream and midstream emissions results in additional emissions of 2.4 kg CO_2-eq/kg H_2, and in total emissions of 11 kg CO_2-eq/kg H_2 for the SMR production route from natural gas without CCS. Applying CCS to the various direct CO_2 sources at the SMR hydrogen plant can reduce the direct emissions to 0.7 kg CO_2-eq/kg H_2 (capture rate 93%); total emissions increase to 1.5-6.2 kg CO_2-eq/kg H_2 when including the upper and lower end of global upstream and midstream emissions for natural gas supply today.

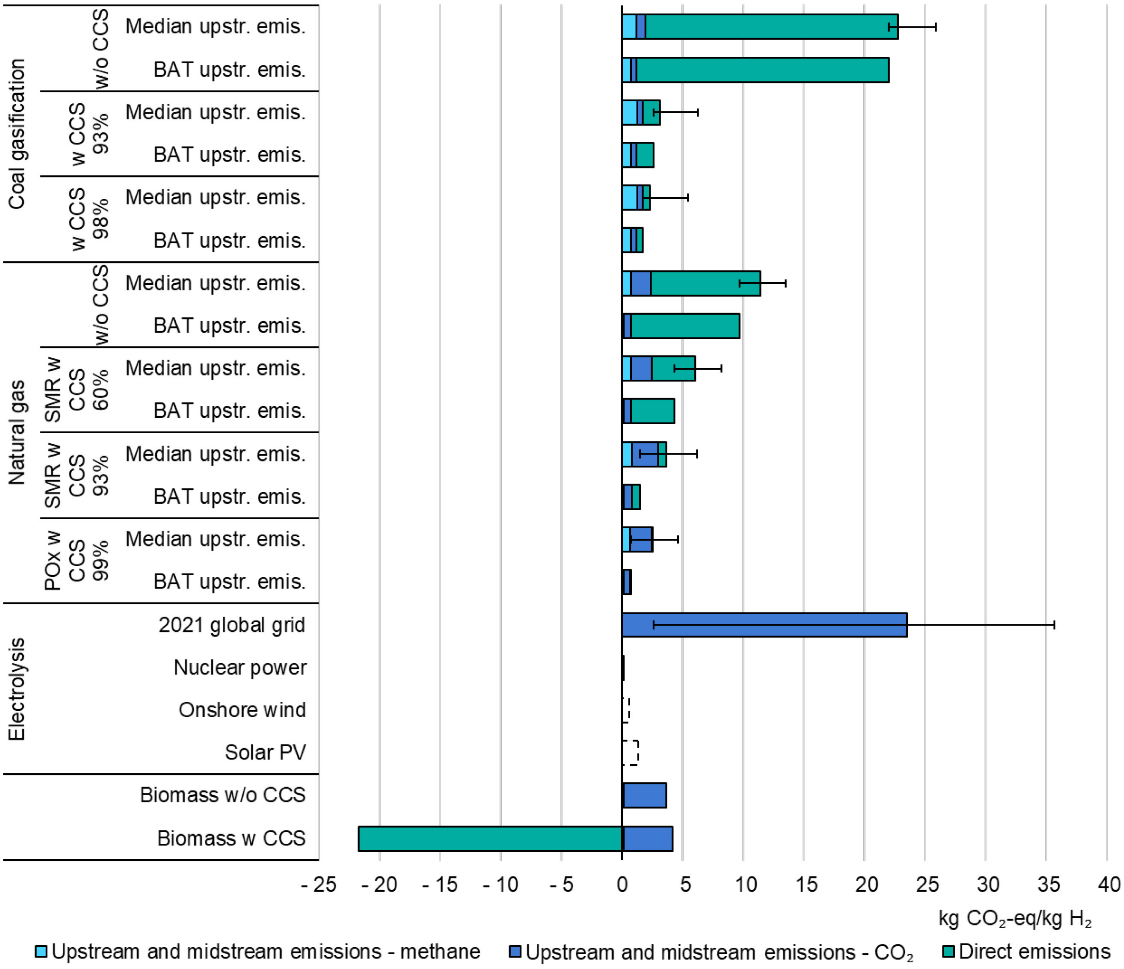
Coal accounts for around a fifth of global hydrogen production today, mainly based in China. Hydrogen production from coal gasification without CCS results in total emissions of 22-26 kg CO_2-eq/kg H_2, depending on the upstream and midstream emissions for coal mining, processing and transport, which range between 6-23 kg CO_2-eq/GJ_{coal} with a median of 8 kg CO_2-eq/GJ_{coal}. More than 80% of the emissions intensity of hydrogen production from coal is from direct emissions at the production plant and less than 20% is linked to coal mining, processing and transport. Applying CCS with a total capture rate of 93% reduces the emissions intensity of the coal pathway to 2.6-6.3 kg CO_2-eq/kg H_2, a range similar to that of natural gas SMR with CCS.

The emissions from water electrolysis are determined by the upstream and midstream emissions of electricity generation. Using the current average global CO_2 intensity of 460 g CO_2-eq/kWh results in an emissions intensity for hydrogen of 24 kg CO_2-eq/kg H_2, similar to the emissions for hydrogen from unabated coal, but can be as low as 0.5 kg CO_2-eq/kg H_2 in a country such as Sweden, which has one of the lowest emission factors for grid electricity production in the world today (10 g CO_2-eq/kWh).

Nuclear electricity can be another source for hydrogen production. Although the direct emissions of a nuclear power plant are zero, the nuclear fuel cycle of uranium mining, conversion, enrichment and fuel fabrication results in emissions of 2.4-6.8 g CO_2-eq/kWh. Taking into account these emissions, the emissions intensity of hydrogen production from nuclear electricity is in the range of 0.1-0.3 kg CO_2-eq/kg H_2.

Following the IPHE methodology, renewable electricity from wind, solar PV, hydropower and geothermal energy has zero upstream and direct emissions, so the resulting emissions for water electrolysers using these forms of renewable electricity is also zero (Box 2.2).

Figure 2.2 Comparison of the emissions intensity of different hydrogen production routes, 2021



Notes: BAT = best available technology; CCS = carbon capture and storage; SMR = steam methane reforming; POx = partial oxidation; Median upstr. emis. = global median value of upstream and midstream emissions in 2021; 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 upstream and midstream emissions today on 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 95% percentile of the world range (28 kg CO_2-eq/GJ). For coal, the lower bound corresponds to the 5% percentile (6 kg CO_2-eq/GJ) and the upper bound to the 95% percentile (23 kg CO_2-eq/GJ) of global upstream and midstream emissions of coal supply. The 2021 world grid average is based on a generation-weighted global average of the grid electricity intensity, with the error bars representing the 10% percentile (50 g CO_2-eq/kWh) and 90% percentile (700 g CO_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. Dashed lines refer to the embedded emissions occurring during the production of onshore wind turbines (12 g CO_2-eq/kWh) and solar PV systems (27 g CO_2-eq/kWh). These embedded 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 overall electricity demand of 50 kWh/kg H_2, including compression to 30 bar.

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, and on 49 kWh/kg H_2 for natural gas and 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 is 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%.

Box 2.2 Including lifecycle analysis in emissions intensity accounting

Most existing or proposed regulations and certification systems do not take into account the emissions associated with the manufacturing of the technologies involved in hydrogen production (e.g. the emissions for manufacturing the electrolyser and the solar PV system in the case of electrolytic hydrogen produced from solar PV electricity). The only exception is the French ordinance on hydrogen from February 2021 (Ordinance No. 2021-167), which includes lifecycle emissions gathered in the French Agency for Ecological Transition (ADEME)'s greenhouse gas database.

Nonetheless, emissions can arise from the manufacturing of renewable electricity and hydrogen production technologies. Based on lifecycle analysis, the production of solar PV modules, for example, is currently associated with emissions of 18-50 g CO_2-eq/kWh*, which would result in an emissions intensity of hydrogen production of 0.9-2.5 kg CO_2-eq/kg H_2. In the case of onshore wind, embedded emissions of 8-16 g CO_2-eq/kWh would translate into an emissions intensity of 0.4-0.8 kg CO_2-eq/kg H_2. A full coverage of all emissions linked to the manufacturing of technologies is not only limited to electricity generation technologies, but should also include technologies such as electrolysers or steam methane reformers. For electrolysers, lifecycle analysis studies indicated that the impact is rather small, for example 0.13 kg CO_2-eq/kg H_2 for a proton exchange membrane electrolyser running 3 000 hours in a year.

A comprehensive lifecycle analysis scope is desirable in principle, but the need to ensure that the methodology can be applied in practice may favour a pragmatic approach, in particular when introducing certification systems and regulatory frameworks in today's still nascent hydrogen markets. In addition, lifecycle inventory data reflecting the actual emissions along the full technology supply chain – from mining of minerals and material production, to processing and technology manufacturing – are not always easily available. This is especially the case as technologies such as electrolysers, solar PV modules or wind turbine components are traded between countries, making the analysis of the lifecycle emissions more complex.

It is also important to note that emissions from material production and technology manufacturing are likely to be lower in the future than today. The emissions data in lifecycle inventories for the production of materials (e.g. steel, aluminium) and for the manufacturing processes are often based on today's energy system. Notably, this implies the use of today's emission intensity of electricity generation, which is set to decline according to IEA scenarios, meaning that in the future the impact of the indirect emissions from the materials and manufacturing processes needed for the technologies involved in hydrogen production could be much lower and less relevant than today.

*The emission range has been derived from an emission intensity of 42 g CO2-eq/kWh for the production of crystalline silicon solar PV systems with an annual electricity generation of 975 kWh/kWp. The range is based on an annual electricity generation of 810 kWh/kWp to 2 300 kWh/kWp, while the central value of 27 g CO2-eq/kWh used in Figure 2.2 is based on annual generation of 1 500 kWh/kWp.

For hydrogen production from bioenergy, the direct emissions are also considered to be zero. Emissions can, however, occur upstream in the bioenergy supply chains. In the case of using wood chips, these emissions may be 4-18 kg CO_2-eq/GJ, resulting in total emissions of 1.0-4.7 kg CO_2-eq/kg H_2 for hydrogen from biomass gasification. Combining such a gasification plant with CCS and a capture rate of 95% then results in negative emissions of -16 to -21 kg CO_2-eq/kg H_2 by removing the captured biogenic carbon in the biomass from the natural carbon cycle.

Similar methods to calculate the emission intensity of hydrogen production can also be developed for and applied to the production of hydrogen-based fuels such as ammonia (Box 2.2). The IPHE has developed a methodology for hydrogen conditioning, i.e. the conversion of hydrogen into hydrogen carriers and reconversion back into hydrogen.

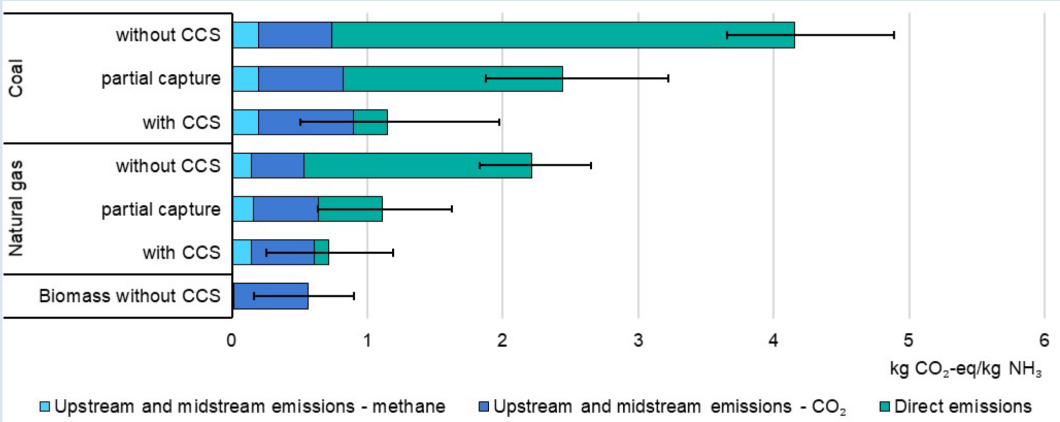
Box 2.3 Emissions intensity of ammonia production

Almost all ammonia produced today is used as a feedstock for industrial uses. Around 70% of global ammonia demand is for the production of mineral nitrogen fertilisers, while the remaining 30% is spread over a range of industrial applications, including explosives, synthetic fibres and specialty materials. Ammonia is produced from nitrogen and hydrogen. The nitrogen is sourced from the air, while the hydrogen is sourced from the feedstocks. Producing one tonne of ammonia requires around 180 kg of hydrogen, such that global total production of ammonia of 190 Mt in 2021 represented approximately 34 Mt of hydrogen demand.

Today virtually all ammonia is produced from unabated fossil fuels. Worldwide, about 70% of ammonia is produced from natural gas, and most of the remaining 30% from coal, the latter mainly in China. The production of ammonia from natural gas without CCS results in emissions of 10-15 kg CO_2-eq/kg H_2-eq[14], while the emissions intensity from coal is 20-27 kg CO_2-eq/kg H_2-eq, almost twice as high. The ranges reflect upstream and midstream emissions of 4.5-28 kg CO_2-eq/GJ for natural gas and 6-23 kg CO_2-eq/GJ for coal as well as of 50-700 g CO_2-eq/kWh for grid electricity).

[14] For comparability with hydrogen, the emission intensity for ammonia is expressed here per kg of hydrogen equivalent (kg H_2-eq), which corresponds to the hydrogen content of ammonia taking into account conversion losses, i.e. 1 kg NH_3 contains 0.18 kg H_2.

Emissions intensities of different ammonia production routes, 2021



Notes: CCS = carbon capture and storage. Ammonia production from coal is based on coal gasification, while the natural gas route uses steam methane reforming (SMR). Coal with partial capture corresponds to a CO_2 capture rate of 52%, while full results in a 93% capture rate. For natural gas, partial capture corresponds to 75% capture rate and full capture to 94%. Error bars reflect range of upstream and midstream emissions for natural gas, coal and biomass supply.

As for hydrogen production, substantial emissions intensity reductions for ammonia can be achieved via electrolysis and the use of natural gas with CCS. In the electrolytic production pathway, hydrogen produced from electrolysis and nitrogen are inputs to the Haber-Bosch synthesis process to produce ammonia. If all the energy inputs for the hydrogen and nitrogen production, as well as in the ammonia synthesis, are from renewable electricity, the overall emissions intensity is zero (excluding potential direct emissions from the operation of some renewable energy technologies as well as their embodied emissions).

Ammonia production from natural gas includes similar process steps to hydrogen production from natural gas. Steam methane reformers and a water gas shift reactor are used to produce a syngas consisting of hydrogen, nitrogen and CO_2. After separating the feedstock CO_2, the remaining syngas is used in a Haber-Bosch synthesis process to produce ammonia. Capturing the feedstock CO_2 results in emissions intensities for ammonia production from natural gas with CCS of 3.5-9.0 kg CO_2-eq/kg H_2-eq, which corresponds to a capture rate of 75%. Capturing in addition the CO_2 from the natural gas-fired steam boilers reduces the emissions intensity to 1.4-6.6 kg CO_2-eq/kg H_2-eq and results in an overall capture rate of 94%.

Coal gasification with CCS can be another production route for ammonia. Here the air separation unit provides both the oxygen for the coal gasification process and the nitrogen for the Haber-Bosch synthesis. The emissions intensity of ammonia production from coal with CCS is in the range of 3-11 kg CO_2-eq/kg H_2-eq (depending again on the upstream and midstream emissions for coal and electricity supply).

In addition to hydrogen production and conditioning, transport is a further supply chain step that can impact the emission intensity of the delivered hydrogen. While the focus of this report is on the emission intensity of hydrogen production, Box 2.4 illustrates the emissions of long-distance transport of hydrogen.

Box 2.4 Emissions from transporting hydrogen

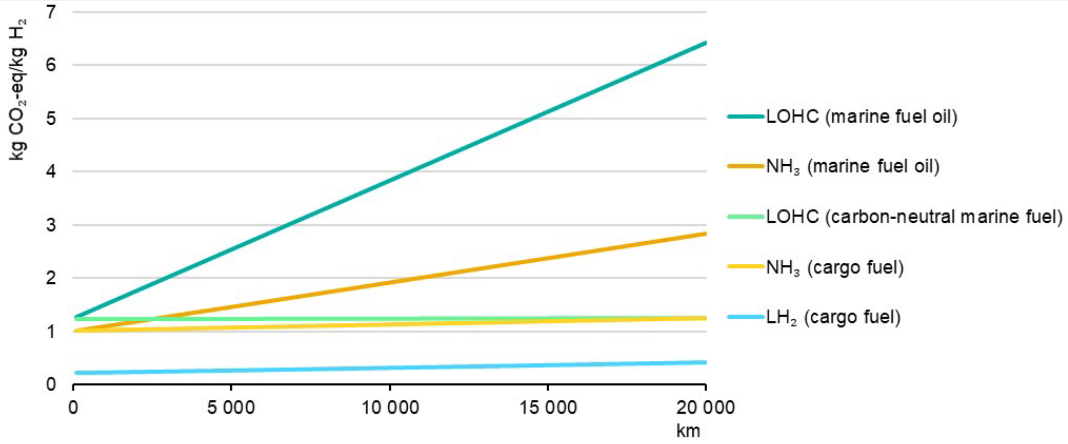
The transport and distribution of hydrogen is an important step in the hydrogen supply chain and affects the overall greenhouse gas footprint of hydrogen. The emissions from hydrogen transport are largely linked to the fuel used for transporting hydrogen and its associated direct and indirect emissions, such as heavy fuel oil for tankers or electricity for pipeline compressors.

The emissions impact of hydrogen transport by pipeline depends on the emissions intensity of the electricity used for compression. Transporting hydrogen through a 48-inch pipeline over a distance of 10 000 km requires 3.6 kWh/kg H_2 of electricity for compression, which results in emissions of 0.7 kg CO_2-eq/kg H_2 when electricity with an electricity intensity of 200 g CO_2-eq/kWh is used.

Hydrogen can also be transported by tanker in the form of liquefied hydrogen (LH_2), by converting hydrogen into ammonia or by storing hydrogen in a liquid organic hydrogen carrier (LOHC). The transport emissions by tanker will depend on the shipping fuel, but also on the energy needs and related emissions for the conversion of hydrogen into a carrier at the export port and the reconversion back into hydrogen at the import port. For LH_2, the emissions for liquefaction can be relatively low, assuming that in case of hydrogen production from renewable electricity, the renewable electricity can be also used for the liquefaction plant. The boil-off gas from the LH_2 storage cargo tanks can be used as a shipping fuel, meaning that the shipping emissions will depend on the emissions intensity of the transported hydrogen. For an emissions intensity of 1 kg CO_2-eq/kg H_2, liquefaction and transport of LH_2 over a distance of 10 000 km would result in emission of 0.3 kg CO_2-eq/kg H_2. Shipping hydrogen as ammonia or LOHC and using marine fuel oil for the tanker would, for a shipping distance of 10 000 km, result in emissions of 1.9 kg CO_2-eq/kg H_2 or 3.8 kg CO_2-eq/kg H_2 respectively, including conversion and reconversion. For marine fuel oil, only the direct CO_2 emissions from combusting the oil are considered here. If upstream and midstream emissions for oil production and refining are included, the emissions could be around 20% higher. In the case that part of the transported ammonia is used as a shipping fuel, the emissions intensity could fall to 1.1 kg CO_2-eq/kg H_2. For LOHC, the emissions intensity could be 1.2 kg CO_2-eq/kg H_2, if a low-emission shipping fuel with zero direct GHG emissions, such as biofuel, is used.

These examples illustrate that in addition to hydrogen production, the conditioning and transport of hydrogen can have a significant impact on the overall emissions intensity of hydrogen at the delivery point.

Illustrative analysis on emissions of hydrogen transport by tanker including conversion and reconversion of hydrogen



Note: LH_2 = liquefied hydrogen; NH_3 = ammonia; LOHC = liquid organic hydrogen carrier. Cargo fuel refers to using the shipped cargo as fuel in the case of LH_2 and ammonia. Carbon-neutral marine fuel represents a shipping fuel with zero direct greenhouse gas emissions. For the use of marine fuel oil, the direct emissions are included, but not any upstream and midstream emissions related to oil production and refining. Emissions include conditioning, i.e. the conversion of hydrogen into other carriers at the export port and the reconversion back into hydrogen at the import port, but emissions from hydrogen production are not included. The illustrative analysis is based on an emission intensity of hydrogen production of 1 kg CO_2-eq/kg H_2, an emission intensity of electricity of 20 g CO_2-eq/kWh at the export port and of 200 g CO_2-eq/kWh at the import port.

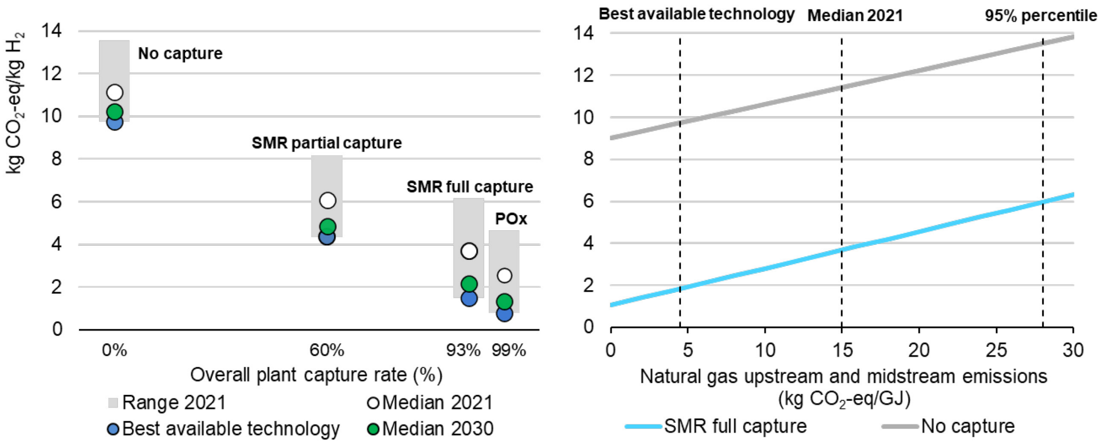
Emissions of hydrogen from natural gas with CCS

SMR is the dominant technology route for producing hydrogen from natural gas. Further technology routes are autothermal reforming (ATR) and, though less widely deployed and at a lower technology readiness level, partial oxidation (POx) and methane pyrolysis.

In SMR, natural gas is used both as a fuel to provide steam for the reforming process and as a feedstock for the hydrogen molecules. Overall, an SMR process requires around 45 kWh of natural gas per kilogramme of hydrogen being produced (kWh/kg H_2). Capturing the CO_2 from the feedstock-related use of natural gas is possible at relatively low capture costs, since separating the feedstock CO_2 from the hydrogen is part of the SMR process. This partial capture of the overall CO_2 emissions results in an overall capture rate of 60% and in emissions of slightly above 6 kg CO_2-eq/kg H_2 (using median upstream and midstream emissions for natural gas supply, Figure 2.3). For reference, the emission factor of natural gas excluding upstream emissions is 56 kg CO_2/GJ, which corresponds to 7 kg CO_2-eq/kg H_2. In other words, burning the same energy amount of natural gas directly in a boiler or turbine would generate slightly more emissions than burning hydrogen being generated from natural gas via SMR with partial CO_2 capture, assuming the same conversion efficiency for burning hydrogen and natural gas. In the near term, such technologies that allow a partial reduction of the emissions footprint of existing unabated fossil hydrogen production with less than 7 kg CO_2-eq/kg H_2 can therefore provide emissions benefits, contributing to CO_2 emission reduction.

At an SMR plant, it is also possible to capture the CO_2 resulting from the use of natural gas as fuel for steam production. The capture costs are higher compared with capturing the feedstock-related CO_2, as the flue gas stream from using natural gas as a fuel is more diluted. Capturing both sources of CO_2 results in capture rates of 93% for SMR and emissions of 1.5-6.2 kg CO_2-eq/kg H_2 (with the range again depending on the upstream and midstream emissions of natural gas supply).

Figure 2.3 Impact of capture rate and upstream and midstream emissions on the emissions intensity of hydrogen production from natural gas with carbon capture and storage



Notes: SMR partial capture = steam methane reforming with a 60% capture rate; SMR full capture = steam methane reforming with a 93% capture rate; POx = partial oxidation with a 99% capture rate; “Median 2021” = global median upstream and midstream emissions for natural gas in 2021; “Range 2021” = global range of global upstream and midstream emissions for natural gas in 2021; “Best available technology” = lowest level of upstream and midstream emissions being achieved today; “Median 2030” = global median upstream and midstream emissions for natural gas in 2030, which are 50% lower than today by combining a 75% reduction in methane emissions with further mitigation efforts in upstream and midstream CO_2 emissions.See notes of Figure 2.2 for further assumptions.

Autothermal reforming (ATR) is an alternative technology in which the required heat is produced in the reformer itself. This means that all the CO_2 is produced inside the reactor. ATR uses oxygen instead of steam, which requires electricity (rather than steam) as its fuel input. In combination with CO_2 capture, ATR requires 47 kWh/kg H_2 of natural gas and 3.7 kWh/kg H_2 of electricity and can achieve capture rates of 93-94%. ATR technology without CO_2 capture is already used today in the chemical industry, but no ATR plant with CCS is in operation yet, though several projects are planned.

The POx technology has traditionally been deployed where it is possible to use low-value waste products or heavy feedstocks to produce hydrogen or syngas (e.g. in refineries). The technology is available at commercial scale but has been modified only recently with the express aim of producing hydrogen from natural gas with CCS. Several CCS projects based on POx are under development. The relatively high CO_2 concentration allows for capture of the CO_2 from the synthesis gas stream. The achieved capture rates can be up to 99%, higher than SMR, where part of the CO_2 is captured from more diluted flue gas streams. The POx process requires around 41 kWh/kg H_2 of natural gas and 0.6 kWh/kg H_2 of electricity, which results in an emissions intensity of 0.8-4.6 kg CO_2-eq/kg H_2. Given the 99% capture rate, the bulk of emissions is linked to upstream and midstream emissions of natural gas supply.

Methane pyrolysis is the process of converting methane into gaseous hydrogen and solid carbon (e.g. carbon black, graphite), without creating any direct CO_2 emissions. The reaction requires relatively high temperatures (>600°C), which can be achieved through conventional means (e.g. electrical heaters) or using plasma. Per unit of hydrogen produced, methane pyrolysis uses around three times less electricity than electrolysis; however, it requires more natural gas than SMR. Depending on the technology variant, methane pyrolysis using plasma requires 62 kWh/kg H_2 of natural gas and 14 kWh/kg H_2 of electricity. This results in emissions of around 2-16 kg CO_2-eq/kg H_2 (depending on the upstream and midstream emissions for natural gas and electricity supply).

At high capture rates, the upstream and midstream emissions from natural gas production, processing and transport become the dominant component of the remaining GHG emissions from hydrogen production from natural gas with CCS. Assuming the global median upstream and midstream emissions intensity of 15 kg CO_2-eq/GJ_{NG} and a capture rate of 93% corresponds to an emissions intensity of hydrogen production from natural gas with CCS of 3.7 kg CO_2-eq/kg H_2, of which more than 70% is linked to the upstream and midstream emissions of natural gas supply. The relatively low emissions of natural gas production achieved in some countries today can serve as an example of how much upstream and midstream emissions can be reduced using best available technology (Figure 2.3). Combining such low upstream and midstream emissions (4.5 kg CO_2-eq/GJ_{NG}) with high capture rates results in emissions of 1.5 kg CO_2-eq/kg H_2, less than half the level when assuming current mean global upstream and midstream emissions, and even 75% below the level when assuming the higher range of upstream and midstream emissions today (28 kg CO_2-eq/GJ_{NG}).

Technologies and measures to reduce methane emissions from gas operations are already available and have been deployed in multiple locations around the world. Key examples include leak detection and repair campaigns, installing emissions control devices, and replacing components that emit methane in their normal operations. Many of the measures are already cost effective today, because the costs of deployment are less than the market value of the methane that is captured and can be sold. IEA analysis suggests that at the average gas prices seen from 2017 to 2021, around 40% of the methane emissions from oil and gas operations could be reduced at no net cost using existing technologies.

Reducing methane emissions is a widely recognised climate priority that is supported by more than 150 countries under the Global Methane Pledge announced at the United Nations Climate Change Conference (COP26) in 2021. The Pledge aims to reduce global anthropogenic methane emissions by at least 30% from 2020 levels by 2030. Reducing methane emissions from fossil fuel operations by 75%, as envisioned in the IEA's NZE Scenario, can meet a significant part of the Global Methane Pledge. Combining the 75% reduction in methane emissions with further mitigation efforts in upstream and midstream CO_2 emissions results in a 50% overall reduction in the global upstream and midstream emissions compared to today. Based on these reductions, the emissions intensity of hydrogen production from SMR with a 93% capture rate could be reduced by more than 40% compared to the median today, resulting in 2.2 kg CO_2-eq/kg H_2.

Emissions of hydrogen from water electrolysis

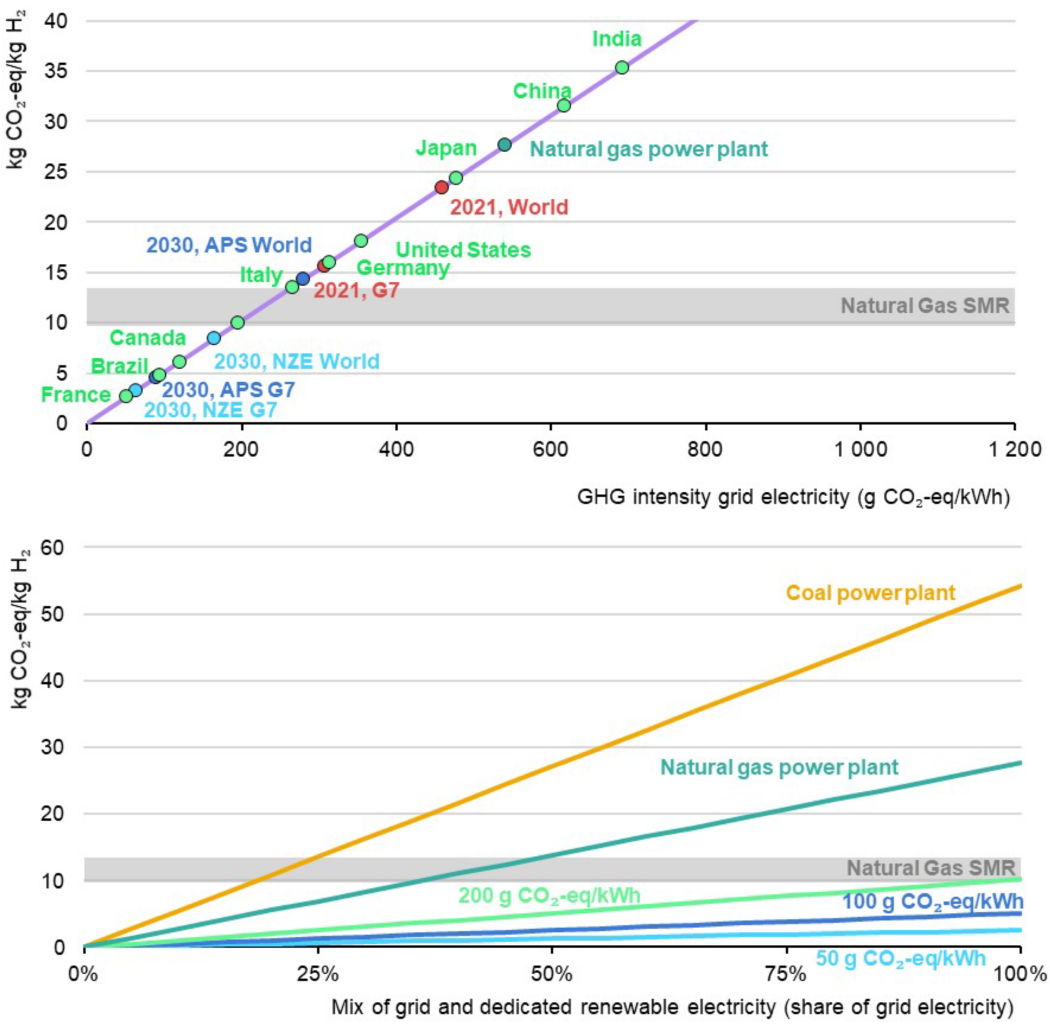
A large number of water electrolyser projects has been announced so far, potentially resulting – if all projects are realised – in a globally installed capacity of up to 240 GW by 2030. This is a very similar level of deployment as that required to meet countries' climate ambitions in the APS. Some of these projects are directly connected to renewable electricity sources, others are connected to the electricity grid or use a mixture of electricity from dedicated renewable electricity plants and the grid.

In the case of using electricity from directly connected renewable plants, the emissions are assumed to be zero, while the emission impact of using electricity from the grid depends on the technology and fuel mix in the electricity system and its operation (Figure 2.4).[15] If solely grid electricity is being used, reaching low

[15] In addition, the efficiency of the electrolyser influences the overall emission impact when using grid electricity. Alkaline and proton exchange membrane electrolyser are the two main commercially available electrolyser technologies today. The electricity consumption of the two electrolyser technologies is quite similar today, at around 52 kWh/kg H_2. Additional electricity is required to supply and purify the necessary water. These electricity needs are, however, very small, with up to 0.6 kWh/kg H_2 in the case of using seawater desalination and pumping the water over a 500 km distance. Solid oxide electrolysis is a third technology (which is however less mature and at demonstration stage) which operates at higher temperatures than alkaline or proton exchange membrane electrolysers using steam as water input. As a consequence, the electricity requirements are lower, with 40 kWh/kg H_2, but additional energy in the form of steam of 10 kWh/kg H_2 is required.

emissions intensities for hydrogen also requires a low emissions intensity of the electricity grid. Limiting, for example, the emissions of hydrogen production to 2 kg CO_2-eq/kg H_2 requires the emissions intensity of grid electricity to be 40 g CO_2-eq/kWh or lower. Within the European Union, for example, only Sweden currently has such a low emissions intensity of its electricity grid, with 10 g CO_2-eq/kWh. For 1 kg CO_2-eq/kg H_2, the threshold falls to 20 g CO_2-eq/kWh, not reached by any of the G7 members (if not taking into account Sweden as part of the European Union).

Figure 2.4 Impact of the emissions intensity of grid electricity and of the mix of grid and dedicated renewable electricity on the emissions intensity of hydrogen



Notes: APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario; SMR = steam methane reforming. Based on electricity consumption for the electrolyser of 50 kWh/kg H_2 or 67% conversion efficiency in lower heating value terms. Intensities for individual countries refer to the year 2020.

Using grid electricity during peak load hours could mean that the additional electricity demand for hydrogen production is covered by natural gas-fired power plants, resulting in emissions of 24-32 kg CO_2-eq/kg H_2 (depending on the upstream and midstream emissions of natural gas supply), more than twice as high as the emissions from direct hydrogen production from natural gas without CCS. If the electricity demand for water electrolysis is covered during baseload hours, it could come from generation plants – depending on the design of the electricity system – with almost zero direct emissions, such as hydro or nuclear power, but also from plants with significant emissions, such as coal-fired power plants with resulting emissions of 50-57 kg CO_2-eq/kg H_2. If electricity is used at times when there is a surplus supply of electricity from solar PV or wind, the use of this otherwise curtailed electricity will result in zero direct emissions.

Given the very different outcomes of using grid electricity, many certification systems and regulations include provisions to ensure that additional electricity demand for hydrogen production does not lead to an increase in fossil-based electricity generation or weaken the operation of the electricity system. This can be achieved by additionality requirements, as well as imposing conditions related to temporal and geographic correlation as part of the chain of custody:

- Additionality refers to the requirement that the electricity used for hydrogen production must come from new generation capacity, rather than relying on renewable electricity from existing plants that is already being used to decarbonise electricity consumption in other sectors. Power purchasing agreements can link electricity demand for hydrogen production to new renewable (or nuclear) electricity generation.
- Temporal correlation or synchronisation between electricity use for hydrogen production and renewable (or nuclear) electricity generation can be achieved by imposing further constraints to balance demand and generation over specified time periods (e.g. hourly, monthly, quarters of a year).
- Geographic correlation should avoid the creation of potential bottlenecks in the electricity grid between supply and demand locations. For example, in the case of pre-existing grid congestion, the renewable electricity unit and the hydrogen production plant should be located on the same side of potential bottlenecks.

In the amendments to the Renewable Energy Directive II as part of the Fit for 55 package, the European Union has detailed in a delegated act[16] requirements for additionality, temporal and geographic correlation for electricity used in the production of hydrogen and derived fuels. Other certification systems and regulations also include requirements for additionality, temporal or geographic correlation (e.g. H2Global, UK Low Carbon Hydrogen Standard, Climate Bonds Standard & Certification Scheme, GH2 Green Hydrogen Standard, TÜV SÜD Standard CMS 70).

[16] As of April 2023, the delegated act still needs to be approved by the European Parliament and the Council of the European Union to enter into force.

Emissions intensity and costs of hydrogen production in IEA scenarios

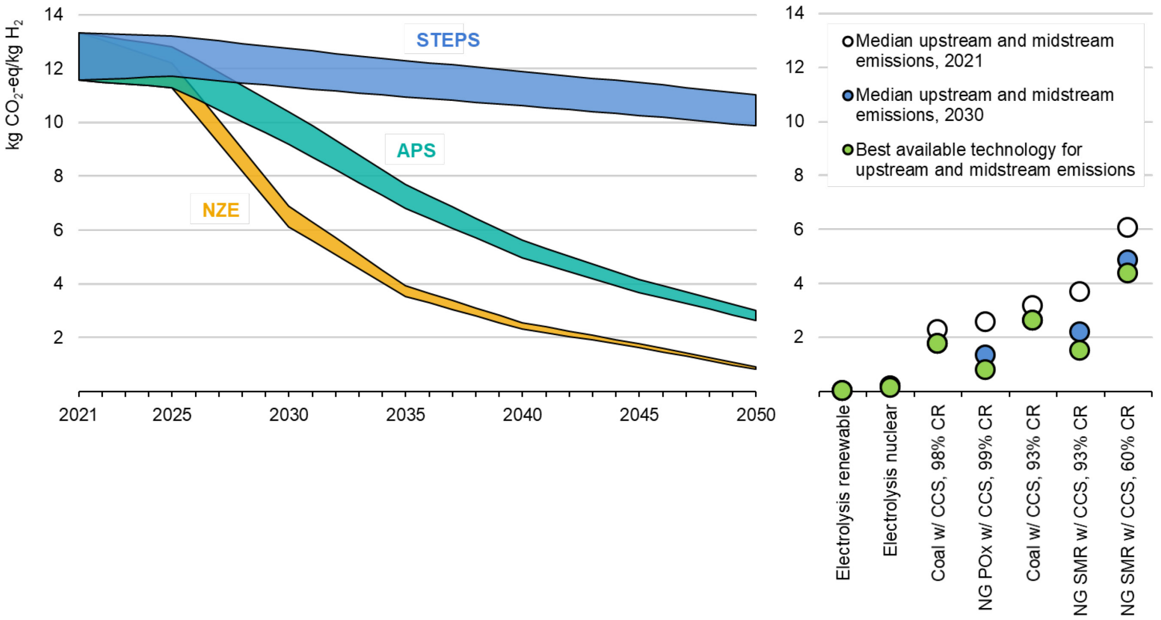
Hydrogen today is almost entirely produced from unabated fossil fuels, resulting in direct CO_2 emissions of more than 900 Mt CO_2. Hydrogen production from electrolysers using renewable electricity and from fossil fuels in combination with CCS covers less than 1% of global production. The higher costs of low-emission hydrogen production today compared to the production from unabated fossil fuels is a key factor in this limited share of global production. With countries making efforts to reach their climate pledges, however, this situation can change in the future, leading to wider deployment of low-emission hydrogen production technologies and a reduction in the emissions intensity of hydrogen. Policy measures to support the uptake of low-emission hydrogen will also lead to further cost reductions for low-emission hydrogen, driven, for example, by cost reductions for electrolysers and renewable electricity. The following sections illustrate these potential developments of emission intensity and costs using the IEA scenarios.

Emissions intensity of hydrogen production

The average emissions intensity of global hydrogen production today is 12-13 kg CO_2-eq/kg H_2, with the range reflecting different allocation methods for by-product hydrogen production in refineries (see Box 2.5). In the STEPS, the global average emissions intensity of hydrogen production declines slightly to 11-13 kg CO_2-eq/kg H_2 by 2030 and to 10-11 kg CO_2-eq/kg H_2 by 2050, thanks to reductions in upstream and midstream emissions of natural gas supply and the deployment of low-emission hydrogen technologies (Figure 2.5).

In the APS, the global average emissions intensity falls by 2030 to around 9-10 kg CO_2-eq/kg H_2. By 2050, the emissions intensity falls to 2.7-3.0 kg CO_2-eq/kg H_2. In the NZE Scenario, the global average intensity reaches 6-7 kg CO_2-eq/kg H_2 by 2030 and 0.8-0.9 kg CO_2-eq/kg H_2 by 2050. In all cases, these values are to be understood as average intensities of different hydrogen production routes. The average of 0.8-0.9 kg CO_2-eq/kg H_2 by 2050 in the NZE Scenario, for example, reflects the production-weighted average, which is largely influenced by hydrogen being produced from electrolysis (which has a zero emissions intensity in 2050), and the production of hydrogen from natural gas with CCS with an average intensity of 1.8 kg CO_2-eq/kg H_2.

Figure 2.5 Emissions intensity for hydrogen production by scenario, 2021-2050



Notes: NZE = Net Zero Emissions by 2050 Scenario; APS = Announced Pledges Scenario; STEPS = Stated Policies Scenario, NG = natural gas; CCS = carbon capture and storage; SMR = steam methane reforming; POx = partial oxidation; CR = capture rate. Ranges for scenario intensities reflect different emission allocation of by-product hydrogen production in refineries (Box 2.5).

Box 2.5 Greenhouse gas emissions of by-product hydrogen

Most hydrogen demand today is met by dedicated hydrogen production, meaning that production processes are designed specifically to produce hydrogen as a main product to meet certain demand. However, around 18% of global hydrogen use today is hydrogen that is produced as a by-product from industrial and refinery processes, such as naphtha reforming, steam crackers and chlor-alkali electrolysis.

Hydrogen is one of many outputs obtained in these processes. Therefore, there is a need to allocate emissions between hydrogen and the other co-products obtained. Several methodologies have been proposed to calculate the emissions intensity of hydrogen generated as a by-product from industrial processes:

- **Allocation based on the physical constants** of the co-products, such as energy content, mass or molar fractions. Allocation based on the energy content of the products (normally their lower heating value) can be suitable for processes where all or most of the co-products contain energy, like in steam crackers, but can be problematic for processes in which the other co-products do not contain energy (like chlorine and oxygen in the chlor-alkali process).

Allocation based on mass or molar fraction distributions can be less suitable for hydrogen since it has a very high energy to mass ratio compared to the other co-products, resulting in a very extreme emissions intensity (too low for mass allocation and too high for molar fraction allocation).

- **Allocation based on system expansion** to include functions related to other co-products. In this system, co-products are considered alternatives to other products on the market and can be assigned the same environmental burden as the products they replace. The application of this system requires a good understanding of the market for the co-products and the products that they replace, as well as the effects of this substitution in the industries affected. This system can be easily applied if the co-products replace a limited number of products, but can result in high variability if the co-products can replace a large number of products.
- **Allocation based on the economic value of the products:** this type of allocation is commonly based on the revenue that can be obtained for each of the co-products. An advantage of this methodology is that it can reflect the intention of operating a process and allocate varied amounts for the outputs obtained based on their economic value. However, market prices tend to vary over time and between regions. Moreover, in the case of hydrogen, there are currently no open markets, resulting in a lack of high-quality information about its market price that could be used to apply this methodology.

Results of various emission allocation methods for hydrogen as by-product from the chlor-alkali industry

Allocation method	Chlor-alkali (kg CO_2-eq/kg H_2)	Steam cracking (kg CO_2-eq/kg H_2)
Energy-based (physical constants)	33.8	2.6
Mass-based (physical constants)	1.4	1.0-3.0
Molar-based (physical constants)	16.1	-
Substitution (system expansion)	6.8-16.1	8.5-10.0
Market-value based (economic value)	4.1-7.1	1.0-3.0

The IPHE, in its methodology for determining the GHG emissions associated with the production of hydrogen, provided a series of values for the emissions intensity of by-product hydrogen in the chlor-alkali process and steam crackers based on all these allocation methods and examples from different national markets.

Costs of hydrogen production

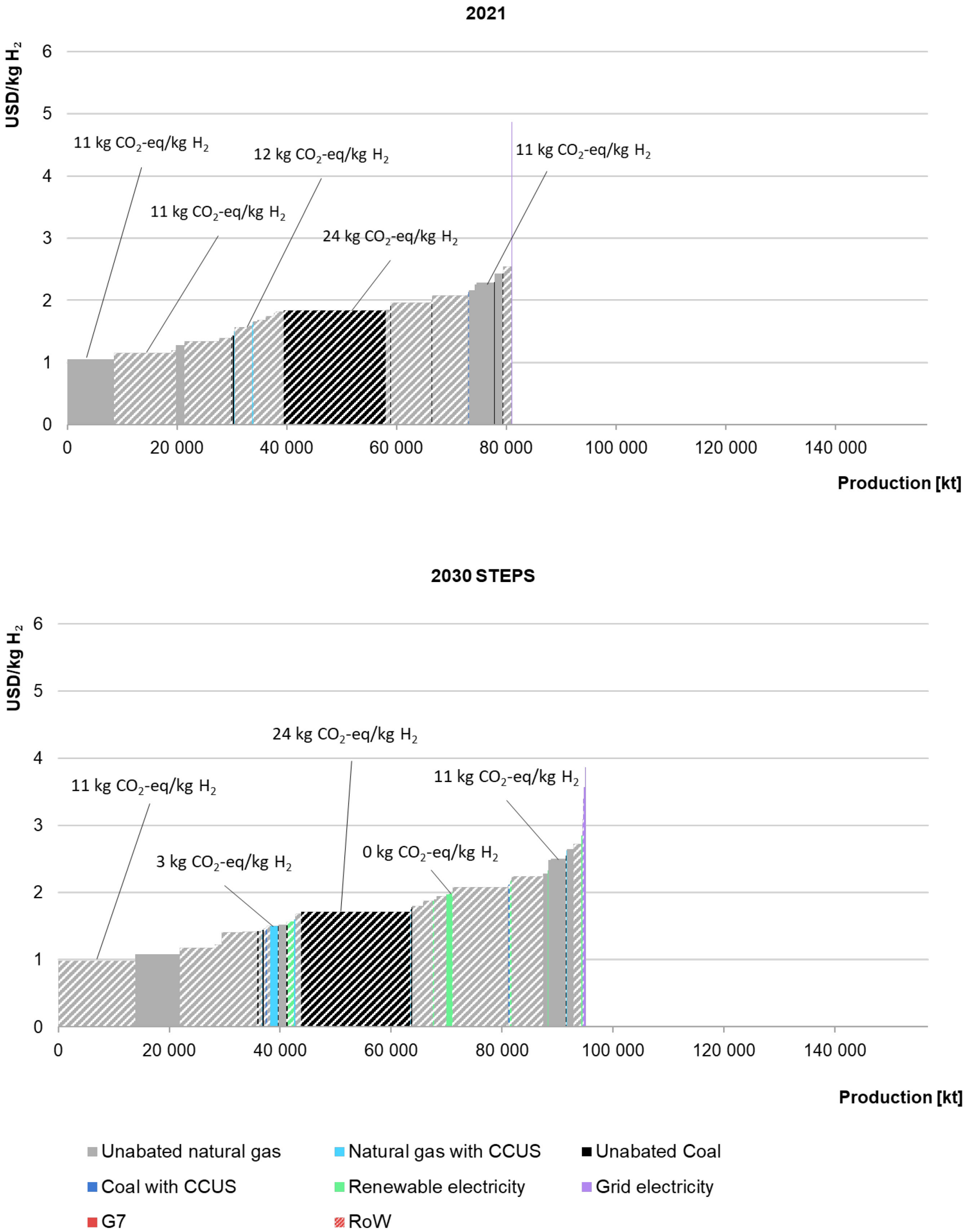
Today low-emission hydrogen production is still more expensive than from unabated natural gas and coal (see chapter *Hydrogen and its derivatives in a net zero energy system*). For example, producing hydrogen from natural gas without CCS costs around USD 1-2.5/kg H_2 (depending on the natural gas price), while costs for hydrogen production from renewable electricity at sites with good solar PV or onshore wind resources are in the range of USD 3-4/kg H_2. These higher costs are a barrier for the uptake of low-emission hydrogen. The relatively young age of existing hydrogen production plants in the chemical sector today, at around 10-15 years compared with a technical lifetime of 30 years, may further slow down the uptake of low-emission hydrogen production technologies. However, retrofitting existing SMR plants with CCS can be a near-term option. Even if these retrofits focus only on the high-concentration, process-related CO_2 stream of an SMR plant for cost reasons, they can reduce emissions by around 50% compared to an unabated plant, while only increasing production costs by around 18%. This partial capture of CO_2 emissions still results in emissions of 6 kg CO_2-eq/kg H_2, but would allow for continued use of some of the younger existing plants in the transition to a clean energy system.

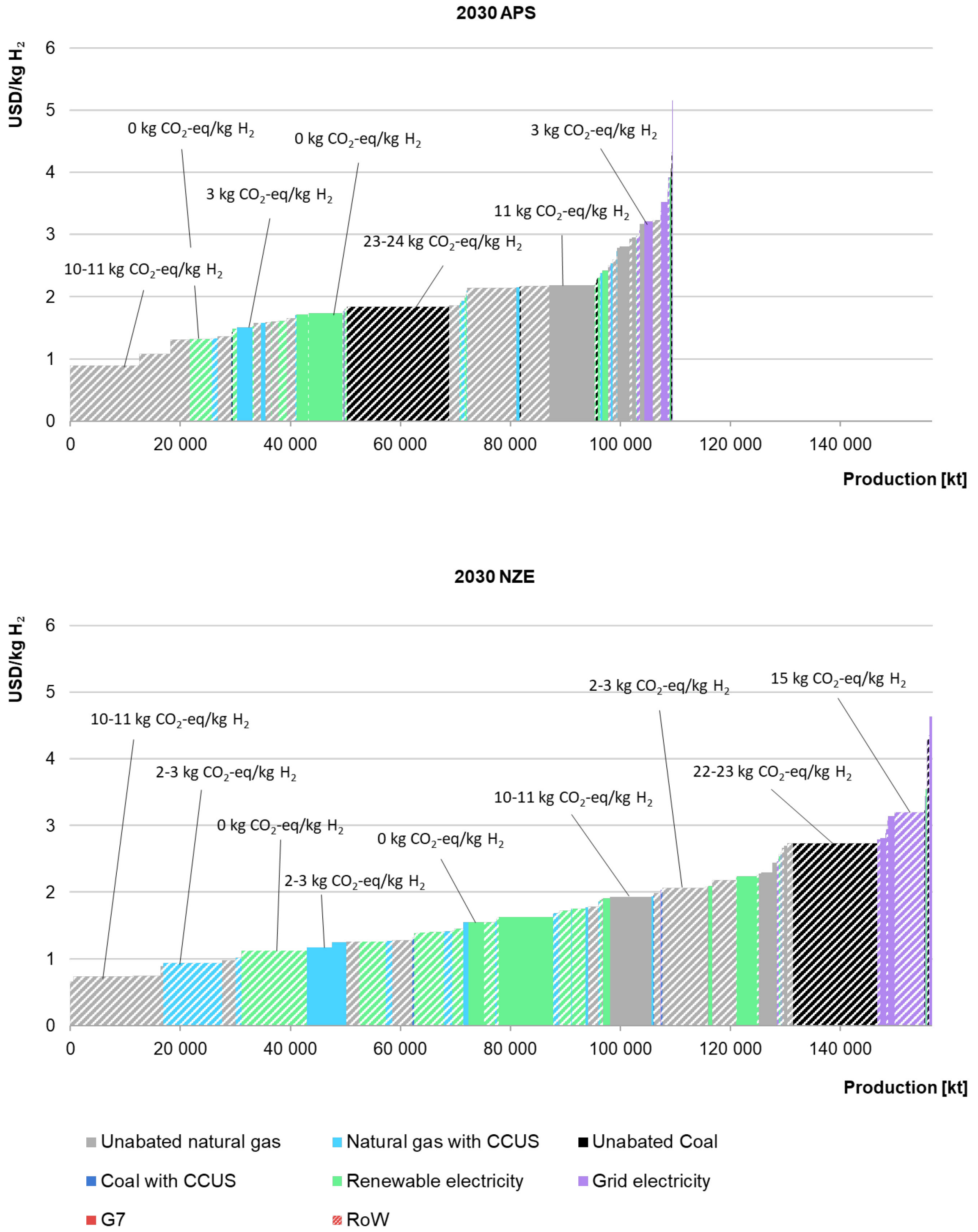
By 2030, compared to hydrogen and ammonia produced from fossil fuels with CCUS, steep declines in the cost of hydrogen and ammonia produced from renewables are expected due to further cost reductions in renewable electricity, as well as technology and cost improvements for electrolysers. However, the costs of producing hydrogen and ammonia using renewable electricity will vary between different regions and countries, depending on local renewable resource characteristics and potential. The low-emission production and supply option for hydrogen and ammonia will depend on local circumstances and opportunities, taking into account factors such as emissions intensity, supply volumes and affordability.

The production of hydrogen with low-emission technologies can become competitive with unabated routes in the short term in locations with abundant low-cost renewable electricity resources, or in regions with access to cheap fossil fuels and CO_2 storage to produce hydrogen from fossil fuels in combination with CCS. In the IEA's Stated Policies Scenario (STEPS), which reflects the policies that have been adopted or announced to date, global hydrogen demand by 2030 is still largely covered by production from unabated fossil fuels (Figure 2.6). The uptake of low-emission hydrogen production technologies remains limited, and where they are deployed, they mainly replace existing unabated production in the refining sector and the chemical industry.

In the APS, which assumes that all of the climate pledges announced by each country are met on time and in full, hydrogen demand from existing applications initially continues to be met by unabated fossil fuel-based production, which can achieve the lowest production costs in many regions (mostly outside of G7 members). Over time, however, the production of hydrogen with low-emission technologies becomes cheaper than unabated fossil fuel-based production in some regions, as the cost of low-emission production falls, resulting in the replacement of some emission-intensive production assets. In addition, low-emission hydrogen and ammonia satisfies rising demand in new uses, such as in steel production or long-distance transport. The uptake is even larger in the NZE Scenario, driven by faster cost reductions in renewables and electrolysers and policies such as CO_2 pricing. In the APS and NZE scenarios, hydrogen demand in new applications is almost exclusively met by hydrogen produced with low-emission technologies, driven by decarbonisation goals. Small fractions of hydrogen demand are met with hydrogen produced via electrolysis powered with grid electricity, which is used to complement the electricity supply from dedicated renewable electricity generation and to increase the operating hours and load factors of electrolysers.

Figure 2.6 Global and G7 hydrogen production cost profile to meet hydrogen demand by scenario, 2021 and 2030





Notes: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario; RoW = Rest of World; CCUS = carbon capture, utilisation and storage. The figure excludes by-product hydrogen produced in refineries and petrochemical plants and used in oil refining. The x-axis refers to the production volumes in the scenarios. The labels above the supply cost curves indicate the emissions intensity of hydrogen production in kg CO_2-eq/kg H_2.

Towards an international emissions accounting framework to define hydrogen

There is currently no globally agreed framework or standard to define hydrogen based on the emissions associated with its production. An internationally agreed emissions accounting framework that provides common definitions for hydrogen production can bring much-needed transparency to facilitate adoption and scale-up. A common framework can enable investment and trade by facilitating market and regulatory interoperability. Without such a framework, producers and consumers face challenges in assessing the technical criteria that allow their products to meet regulatory requirements, which can increase investment risks and lead to a fragmented market.

In this report, the IEA uses the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) methodology for calculating the greenhouse gas (GHG) emissions intensity of different hydrogen production routes. This state-of-the-art methodology will serve as the basis for the first international standard to calculate the GHG emissions of hydrogen supply. This is currently under development by the International Organization for Standardization (ISO), although the methodology still needs to be finalised to incorporate elements related to hydrogen transport, and other methodological issues are likely to be considered in future updates.

There are two major benefits of using an internationally agreed methodology for calculating emissions intensity. Firstly, terminologies that use colours or qualifiers (such as “sustainable”, “low-carbon” etc.) often mask a wide range of different emissions intensities, depending, for example, on the source of electricity, the CO_2 capture rate or the emissions associated with upstream fossil fuel production. Numerical values that reflect emissions intensities and that can be calculated directly for a specific production route are more transparent and allow project developers to assess regulatory compliance efficiently. Secondly, the use of one common methodology to calculate emissions intensities directly enables a certain level of interoperability of different regulations. Countries may have differing priorities in terms of production routes or other additional criteria, but the use of one common methodology can bring transparency to the GHG emission requirements for different countries.

Regulatory efforts to establish the expected emissions intensity of hydrogen are already underway or established in many countries. Their scope and the methodologies used differ, which can create barriers for investors in understanding their interoperability. This chapter reviews the opportunity that would be created by establishing a common international accounting framework and explores the elements that would need to be addressed to enable smooth implementation in regulatory frameworks and certification schemes.

Considerations for an international accounting framework

Similarities and differences in existing certification systems and regulations

Several certification systems and regulatory frameworks for hydrogen exist already or are under development (Table 3.1). They have some commonalities, but also significant divergences. The majority of the regulations and certification systems focus on the production of hydrogen (i.e. hydrogen in the form of H_2 and not ammonia and hydrogen-based fuels) and emissions within well-to-gate system boundaries. Systems and regulations that include the transport of hydrogen (well-to-point of delivery or well-to-wheel, such as H2Global or the Renewable Energy Directive II) often also consider hydrogen-based fuels, which are particularly attractive for long-distance transport and trade of hydrogen.

In most cases, direct and indirect emissions of electricity and heat generation, as well as upstream and midstream emissions for fuel production and transport (e.g. for coal, natural gas and biomass) are included, while indirect emissions associated with the manufacturing of technologies and their embedded materials are excluded (Scope 1, 2 and partial Scope 3). This emission scope is consistent with that of the IPHE methodology. The only exception is the French ordinance on hydrogen from February 2021, which includes the emissions gathered in ADEME's carbon database.

A comprehensive lifecycle analysis scope is desirable in principle, but the need to ensure that the methodology can be applied in practice may favour a pragmatic approach, in particular when introducing certification systems and regulatory frameworks in today's still nascent hydrogen markets. Some certification systems and regulations require hydrogen produced from renewable electricity, but some, such as the UK Low Carbon Hydrogen Standard or the US Clean Hydrogen Production Tax Credit, allow a broader portfolio of fuels and technologies for producing hydrogen. The imposed emissions intensity levels for well-to-gate system boundaries vary widely between certification systems and regulations, reflecting different regional circumstances. For systems with a well-to-gate boundary, the range goes from 0.45 kilogramme of CO_2 equivalent per kilogramme of hydrogen (kg CO_2-equivalent (eq)/kg H_2) in the US Clean Hydrogen Production Tax Credit to 14.5 kg CO_2-eq/kg H_2 in China Hydrogen Alliance's standard.[17]

This variability in criteria, scope and methodologies increases regulatory and certification barriers faced by project developers, who need to undertake ad-hoc certification process for each country where they want to access the domestic market, increasing transaction costs. This is likely to limit trade to that covered by bilateral agreements, thereby hampering the development of an international market.

Governments should co-operate to enable a certain level of interoperability among their regulatory frameworks. Governments that have not yet developed a regulation on hydrogen sustainability attributes can work with those that have already introduced regulations in order to avoid larger divergences. Governments with existing regulations will need to find avenues for mutual recognition. Bilateral agreements, in which the government with less stringent criteria recognises certificates issued in compliance with the regulation of the government with more stringent criteria, can be a first step. However, a larger group of governments agreeing to accommodate in their regulations a common emissions accounting framework can benefit from pooling a larger share of the potential global hydrogen market, which would create more opportunities for project developers.

The IPHE methodology offers a robust point of departure for the establishment of such an accounting framework. The methodology still needs to incorporate elements related to hydrogen transport (currently under development) and there are some additional methodological aspects that should be addressed, such as the allocation of emissions among co-products in plants producing hydrogen and carbon-containing derivatives or temporal and geographical correlation of low-emission electricity. All these aspects can be considered by the IPHE Hydrogen Production Analysis Task Force in the near future to improve the methodology, which could then be incorporated in future updated versions of the standard developed by ISO.

[17] The China Hydrogen Alliance's standard reflects the circumstance that most of the hydrogen today in China is produced from unabated coal, with the 14.5 kg CO_2-eq/kg H_2 intensity level still representing almost 50% reduction in the emissions intensity to the unabated production from coal (21-27 kg CO_2-eq/kg H_2).

Table 3.1 Overview of existing and planned certification systems and regulatory frameworks for hydrogen, ammonia and other hydrogen-based fuels

Purpose	Name	Market / jurisdiction	System boundary	Product	Demand sector	Status	Chain of custody	Production pathways	Emissions intensity level (kg CO_2-eq/kg H_2)
Regulatory	UK Low Carbon Hydrogen Standard; UK Low Carbon Hydrogen Certification Scheme	United Kingdom	Well-to-gate	Hydrogen		Operational (certification scheme under development)		Electrolysis, natural gas with CCUS, biomass and waste	2.4
Regulatory	Renewable Transport Fuel Obligation	United Kingdom	Well-to-point of delivery	Hydrogen	Transport	Operational	Mass balancing	Renewable energy excluding bioenergy	4.0
Regulatory	EU Taxonomy	European Union	Well-to-gate	Hydrogen		Operational		All	3.0
				Hydrogen-based synthetic fuels					3.4
Regulatory	Renewable Energy Directive II	European Union	Well-to-wheel	Hydrogen, hydrogen-based synthetic fuels		Under development	Mass balancing	Renewable electricity; low-carbon electricity (< 65 g CO_2-eq/kWh)	3.4

Purpose	Name	Market / jurisdiction	System boundary	Product	Demand sector	Status	Chain of custody	Production pathways	Emissions intensity level (kg CO_2-eq/kg H_2)
Regulatory	Low-carbon fuel standard (LCFS)	California (United States)	Well-to-wheel	Hydrogen	Transport	Operational	Book-and-claim	Compressed H_2 from SMR w/o CCUS using natural gas	14.1
								Liquefied H_2 from SMR w/o CCUS using natural gas	18.1
								Compressed H_2 from SMR w/o CCUS using biomethane	11.9
								Liquefied H_2 from SMR w/o CCUS using biomethane	15.5
								Compressed H_2 from electrolysis using grid electricity	19.8
								Compressed H_2 from electrolysis using solar or wind electricity	1.3
Regulatory	Clean Hydrogen Production Tax Credit	United States	Well-to-gate	Hydrogen		Under development		All	2.5-4 2.5-1.5 1.5-0.45 <0.45
Regulatory	Clean Hydrogen Investment Tax Credit	Canada	Well-to-gate	Hydrogen		Under development		Electrolysis, natural gas with CCUS	2-4 0.75-2 < 0.75
				Ammonia					<4

Purpose	Name	Market / jurisdiction	System boundary	Product	Demand sector	Status	Chain of custody	Production pathways	Emissions intensity level (kg CO_2-eq/kg H_2)
Regulatory	France Ordinance No. 2021-167	France	Well-to-gate including manufacturing of technologies	Hydrogen	All sectors	Under development	Book-and-claim and mass balancing	All	High-carbon hydrogen: > 3 H_2 regardless of energy source Low-carbon hydrogen: ≤ 3.38 H_2, regardless of energy source Renewable hydrogen: ≤ 3.38 H_2, from renewable sources
Funding programme	H2Global	International	Well-to-point of delivery	Ammonia, methanol, synthetic kerosene		Operational	Mass balancing	Renewable electricity	3.0
Voluntary	Zero Carbon Certification Scheme (Smart Energy Council)	Australia	Well-to-gate	Hydrogen, ammonia, steel		Operational	Mass balancing	Renewable electricity	-
Voluntary	Guarantee of Origin certificate scheme (Australian Government)	Australia	Well-to-gate	Hydrogen, hydrogen carriers		Under development	Mass balancing	Renewable electricity	-

Purpose	Name	Market / jurisdiction	System boundary	Product	Demand sector	Status	Chain of custody	Production pathways	Emissions intensity level (kg CO_2-eq/kg H_2)
Voluntary	Standard and Evaluation of Low-Carbon Hydrogen, Clean Hydrogen and Renewable Hydrogen (China Hydrogen Alliance)	China	Well-to-gate	Hydrogen		Operational	Not specified	All	Low-carbon hydrogen: 14.5 Renewable hydrogen, clean hydrogen: 4.9
Voluntary	CertifHy	European Union	Well-to-gate	Hydrogen		Operational	Book-and-claim	Renewable electricity	Green hydrogen: 4.4
								Nuclear electricity, fossil fuels with CCUS	Low-carbon hydrogen: 4.4
Voluntary	Low-carbon hydrogen certification system (Aichi Prefecture)	Japan	Well-to-gate	Hydrogen		Operational	Book-and-claim	Renewable electricity, biogas	-
Voluntary	Green Hydrogen Standard (Green Hydrogen Organisation)	International	Well-to-gate	Hydrogen		Operational	Not specified	Renewable electricity	1
				Ammonia		Under development			0.3 kg CO_2-eq/kg NH_3
Voluntary	Climate Bonds Standard & Certification Scheme	International	Well-to-gate	Hydrogen		Operational		Electrolysis, natural gas and waste biomass	2022: 3.0 2030: 1.5 2040: 0.6 2050: 0.0

Purpose	Name	Market / jurisdiction	System boundary	Product	Demand sector	Status	Chain of custody	Production pathways	Emissions intensity level (kg CO_2-eq/kg H_2)
Voluntary	TÜV SÜD CMS 70	European Union	Well-to-gate	Hydrogen	Transport	Operational	Book-and-claim	Renewable electricity	1.1
								Biomethane, glycerine	2.3-3.4
					Outside transport			Renewable electricity	1.1
								Biomethane, glycerine	2.1-3.2
			Well-to-point of delivery		Transport		Mass balancing	Renewable electricity	2.8
								Biomethane, glycerine	4.5-5.6
					Outside transpor			Renewable electricity	2.7
								Biomethane, glycerine	4.3-5.4
Voluntary	World Business Council of Sustainable Development	International	Well-to-gate	Hydrogen		Proposal	Not specified	All	Reduced-carbon hydrogen: 6 Low-carbon hydrogen: 3 Ultra-low-carbon hydrogen: 1
Voluntary	Ammonia Energy Association	International	Well-to-gate	Ammonia	All sectors	Under development	Not specified	All	

Notes: CCUS = carbon capture, utilisation and storage; SMR = steam methane reforming; H_2 = hydrogen. The "Demand sector" column indicates whether the certification system or regulation is limited to using the hydrogen in a specific sector.

Who would benefit from an international emissions accounting framework?

An international emissions accounting framework can facilitate the deployment of hydrogen by creating clarity about its emissions intensity, thus helping to reduce risks for 'first movers'. Such a framework will be of value to a variety of key stakeholder groups:

- **Producers**: project developers require clarity and consistency to be able to comply with regulations and incentives, report on environmental performance and attract investment. For example, a project developer producing ammonia from renewable electricity for export may plan to benefit from low-emission tax credits in the country of production and need to demonstrate regulatory compliance to access the market in the destination country. A recognised international accounting framework for hydrogen production avoids the need to conduct two separate certifications to comply with different regulatory requirements.
- **Consumers**: hydrogen users need assurance that the product they are purchasing is consistent with regulatory and/or environmental criteria. They require sufficient detail to make informed comparisons of different offerings from producers located in different countries or operating under different regulatory requirements or certification systems within the same country. Scale-up of low-emission hydrogen will be hampered and the market will fragment if, for example, a buyer wishing to import ammonia finds that the destination country requires a different standard to the one used by the seller in the country of production, for example to qualify for a tax credit.
- **Governments**: regulators are grappling with how to ensure that hydrogen production and use result in environmental benefits. A common framework, agreed between governments, simplifies the rule-making process. It provides a recognised means to quickly establish criteria for new support programmes. In addition, a robust accounting framework for traded hydrogen can increase trust between governments and avoid duplication in regulating all steps of the value chain.
- **Traders**: As the international hydrogen market scales up, prices can be expected to fall if hydrogen-based products are interchangeable, i.e. supply and demand can be readily balanced across regions. An international emissions accounting framework is likely to be necessary to move from purely bilateral trade agreements to a liquid marketplace where risks can be spread more evenly, creating efficiency opportunities for traders.
- **Investors**: Uncertainty about how different projects compare, and whether they will be compatible with regulations, government incentives or buyers' preferences is a major risk facing investors. This slows down the pace of project construction and increases the costs of hydrogen products. An international emissions

accounting framework would allow investors to easily compare projects against a common benchmark and reduce the need for in-house or third-party assessment.

- **Certification bodies**: An international emissions accounting framework will create incentives for independent certifiers to offer high-quality, competitively priced services to win market share and operate across borders. For small certification bodies, for example in smaller economies, the barriers to entry should be lower when private certificate schemes cannot become de facto monopolies.
- **General public**: Technical claims and counter-claims about the sustainability attributes of different hydrogen production pathways can make it difficult for the general public to understand what is being proposed by firms and governments. A common system for presenting emissions intensity can help demystify the emissions attributes of different hydrogen sources.

Some of these groups, such as investors, some final consumers of hydrogen-based products and the general public could also find value in a simple presentation of this accounting framework, such as the system of emissions intensity levels presented in Box 3.1.

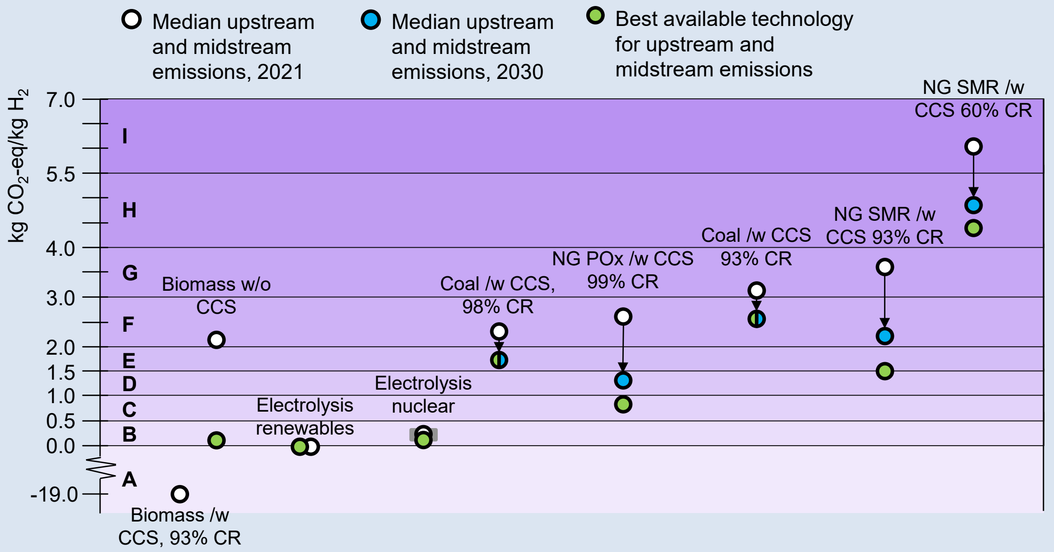
Box 3.1 Grouping emissions intensity into a series of levels for non-expert users

Transparency about the precise emissions intensity of traded hydrogen is appropriate for governments, regulatory authorities, certification bodies and market participants. But it is unlikely to be intuitive for all stakeholders. In particular, investors, financial institutions, final consumers of hydrogen-based products or the general public may struggle to interpret technical details or be able to immediately assess the relative scale of emissions. The importance of communicating in simple terms is already well evidenced by the extent to which the terms “blue” and “green” hydrogen have gained traction in expert and non-expert discussions alike.

When shifting from hydrogen colours to a more accurate measure of emissions intensity it is not necessary to entirely do away with the simplicity of distinguishing between a small set of hydrogen archetypes. A system that groups the emissions intensity into a smaller set of distinct levels could be a valuable complement, as a powerful means of communicating to non-expert stakeholders who wish to understand the emissions implications.

A possible avenue could be a set of nine distinct, technology-neutral levels, ranging from emissions intensities below zero (level “A”) to an upper value of 7 kg CO_2-eq/kg H_2 (level “I”) (see chapter *Defining hydrogen according to its emissions intensity*). The proposed levels reflect known hydrogen production routes that can achieve lower emissions than unabated fossil-based routes, while also considering potential for future improvement in the production technologies and fuel supply chains, such as reductions in upstream and midstream methane emissions in natural gas supply. Other potential systems could include a higher upper limit, at 23 kg CO_2-eq/kg H_2 to also include unabated fossil-based routes, or lower levels (in the range of 3-4 kg CO_2-eq/kg H_2) to reflect the ambitions by governments that have already set regulations in this respect.

Example of a potential quantitative system for emissions intensity levels of hydrogen production



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Some stakeholders, such as the investment community and general public, may appreciate the simplicity of quoting the aggregated "level" of emissions intensity. For example, hydrogen on sale at refuelling stations could be presented by its level to inform consumers of their environmental choices in a manner equivalent to energy efficiency labelling of appliances and buildings. Other non-greenhouse gas sustainability criteria (see The importance of compatibility with other sustainability requirements) could, of course, also be shared. Investors would also benefit from simple terminology for communicating what they are willing to finance (for example, "hydrogen with a level no higher than level D") and how it will vary over time, including in IEA scenarios.

Avenues for implementation

Implementation of a common framework would not require the creation of an entirely new system for standardisation and certification. Rather, it would use the existing global system of trust and recognition within standards bodies and certification schemes. This would provide familiarity, simplify the process for governments forming legislation, and empower companies with the language needed to meet reporting requirements and attract investment. Ensuring that the implementation process is robust and easy to understand will help facilitate uptake.

Implementation will need to be flexible to accommodate different reporting criteria from governments and companies. As the scope covers only hydrogen production emissions there needs to be flexibility to allow for the inclusion of emissions associated with the delivery and conversion of hydrogen. In addition, a growing number of governments are beginning to include non-emissions criteria in their energy policies, such as human and labour rights, as well as land use and water requirements.

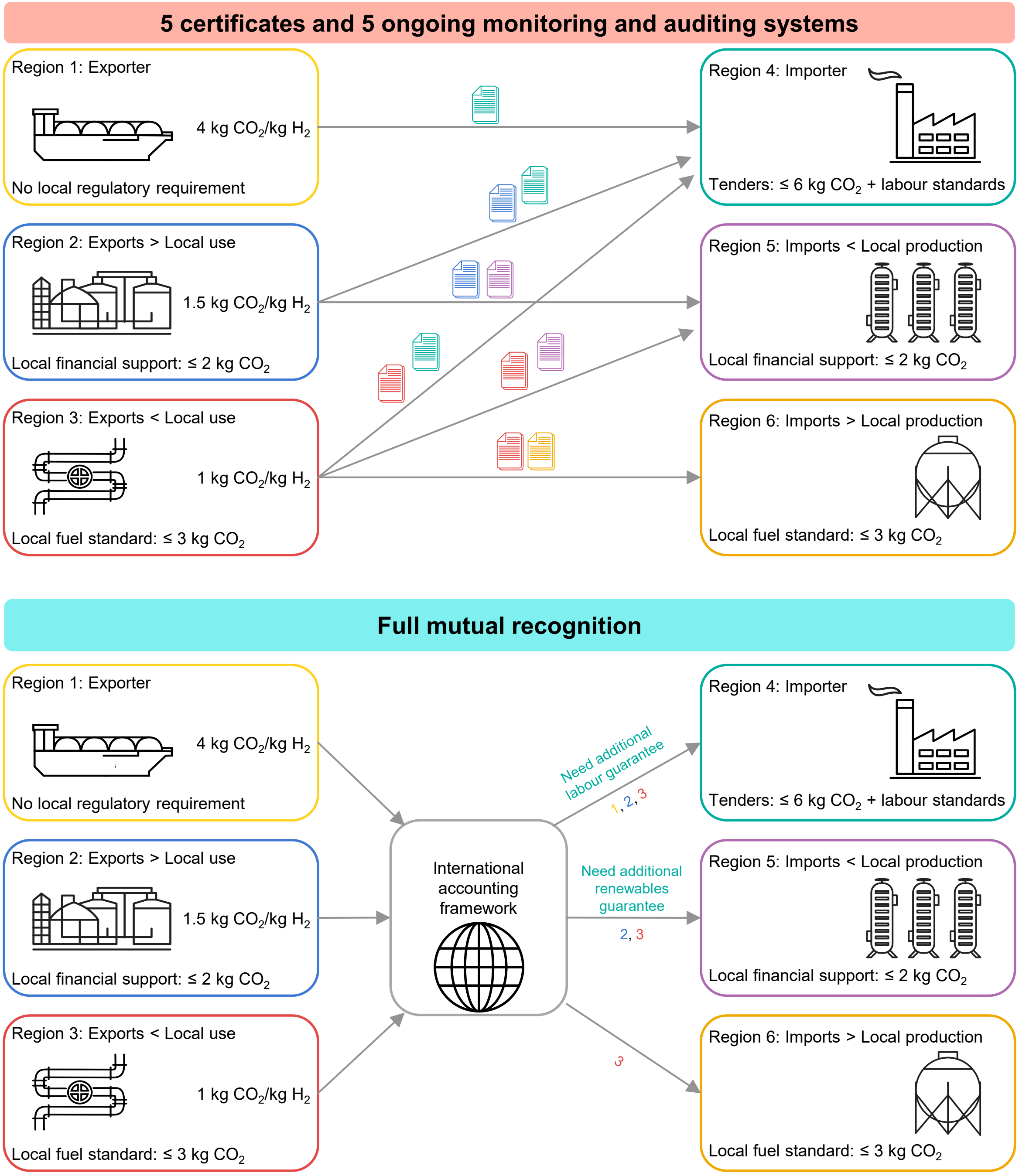
Adding value to an evolving international landscape of standardisation efforts and regulatory frameworks

There are several existing initiatives to create a market for hydrogen and facilitate trade and compliance (Table 3.1). An accounting framework would not replace or duplicate ongoing efforts, but rather support existing schemes by enabling mutual recognition and facilitating interoperability (Figure 3.1).

To successfully implement an international emissions accounting framework for hydrogen production, there must first be an agreement on the underlying methodology for determining the emissions intensity of hydrogen production, including common system boundaries and scope of emissions. The IPHE methodology offers one way to facilitate a common language with a technology-neutral approach, and can allow governments and companies to select the emissions intensities that best fit their decarbonisation objectives.

Implementation of a common framework may differ depending on the scheme. For instance, in mandatory schemes used for government compliance, regulations could require specific emissions intensity ratings to meet their own requirements and support net zero commitments. In voluntary schemes, companies may opt to use a labelling system that groups emissions intensity ratings into a smaller set of distinct levels to provide clarity for disclosure and communication purposes (see Box 3.1).

Figure 3.1 Use of an internationally agreed emissions accounting framework for hydrogen production to facilitate market interoperability



Expanding an accounting framework to address all emissions associated with hydrogen supply chains

For simplicity and to smooth the initial stages of implementation, an accounting framework could start with a “well-to-gate” scope, meaning that direct emissions from hydrogen production and indirect upstream and midstream emissions related to the supply of the fuels and other inputs (e.g. heat, water, steam) for the production process are included. However, hydrogen production is only one part of the supply chain. In the case of captive hydrogen production in industrial and refining applications, a “well-to-gate” scope is enough to evaluate the emissions related to the use of hydrogen. However, in the case of distributed uses or the creation of an international market to facilitate hydrogen trade, conversion into hydrogen carriers, transport and reconversion back to hydrogen (when the carrier cannot be used directly) can have a significant impact on the total emissions of the hydrogen delivered to end users. These emissions should be considered to enhance comparability of the different products delivered to final users.

The expansion of an accounting framework should be based on agreed methodologies, as should be the case for hydrogen production. These methodologies should be rapidly available to avoid delays that could compromise the development of international supply chains in the near term. The IPHE, in the second version of its guideline, has already developed methodologies to assess the GHG emissions associated with the conversion of hydrogen into carriers and reconversion to hydrogen, and is developing methodologies for hydrogen transport.

The importance of compatibility with other sustainability requirements

The sustainability attributes of hydrogen and the potential impacts of the development of hydrogen supply chains are not limited to GHG emissions. There are several other potential sustainability requirements (Table 3.2) that governments can take into account when making decisions about the use of hydrogen as a clean fuel and feedstock, and its contribution to their long-term sustainability targets. Companies may also want to voluntarily certify their products with additional sustainability criteria to highlight the sustainability attributes of their product and inform consumer choices.

Some governments and certification schemes have already taken a first step in the adoption of sustainability criteria other than GHG emissions. Environmental criteria related to the renewable origin of the energy source used for the production of hydrogen and land or water use and socio-economic criteria related to working conditions, living standards or food security are already incorporated in some regulations and certification schemes (Table 3.3). In addition, governments such as Canada, Chile and Colombia are studying the possibility of adopting additional socio-economic sustainability criteria related to their particular situations with regards to indigenous communities or water access rights.

Table 3.2 Selected sustainability criteria applicable to hydrogen supply

Criteria			Within the scope of this report	Available methodology	Available standard
Environmental criteria	GHG emissions	Production	Yes	IPHE	Under development*
		Conversion	No	IPHE	Under development*
		Transport	No	Under development**	Under development*
	Water use		No	Methodologies and standards for the evaluation of some of these environmental criteria exist, such as ISO 14001:2015 for Environmental management systems, ISO 46001:2019 for Water efficiency management systems and ISO 45001 for occupational health and safety, but they are not specific to hydrogen	
	Land use		No		
	Renewable origin		No		
	Air impacts		No		
	Waste management		No		
Socio-economic criteria	Human and labour rights		No		
	Water use rights		No		
	Health and safety		No		
	Food security		No		
	Local and social development		No		

* The ISO Technical Committee (TC) 197/SC1 aims to develop a Technical Specification by the end of 2023 (with publication in 2024) and an International Standard by the end of 2024 (with publication in 2025).
** The IPHE methodology to determine GHG emissions for hydrogen transport technologies is expected in April 2023.

As the market matures, it can be expected that a wide range of additional sustainability criteria arises and gets established under different regulations, government incentives and certification schemes. Having such criteria is ultimately important but the typically staggered approach to implementation can be a problem for nascent markets. Lack of foresight on potentially increasingly stringent environmental and socio-economic criteria, for example, can hinder investment by first movers and slow down deployment. In addition, not all potential sustainability criteria have standards or methodologies in place for their evaluation.

Starting with an internationally agreed emissions accounting framework for hydrogen production that can provide regulatory and certification clarity to market players can help unlock investment, enable scale-up and allow the market to mature. The experience gained as this happens can help with the subsequent incorporation of additional sustainability elements. An internationally agreed accounting framework is a first step focused exclusively on GHG emissions, but it does not prevent the adoption of additional sustainability criteria in the future.

Table 3.3 Selected regulations and certification schemes incorporating sustainability criteria other than greenhouse gas emissions

Regulation	Purpose	Environmental criteria	Socio-economic criteria
European Commission Delegated Act of the Renewable Energy Directive*	Define rules for hydrogen production to count towards the EU's renewable energy target	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	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 Organisation 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

* This Delegated Act still needs to be approved 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.

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

Box 3.2 A hydrogen passport to integrate multiple criteria

A "product passport" for a cargo of hydrogen or hydrogen-based fuels could be established in the form of a unique ID connected to a data repository accessible to trading partners and end users. The accessible data could include the emissions intensity rating, a simplified emissions intensity level such as the one proposed in Box 3.1, 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 included.

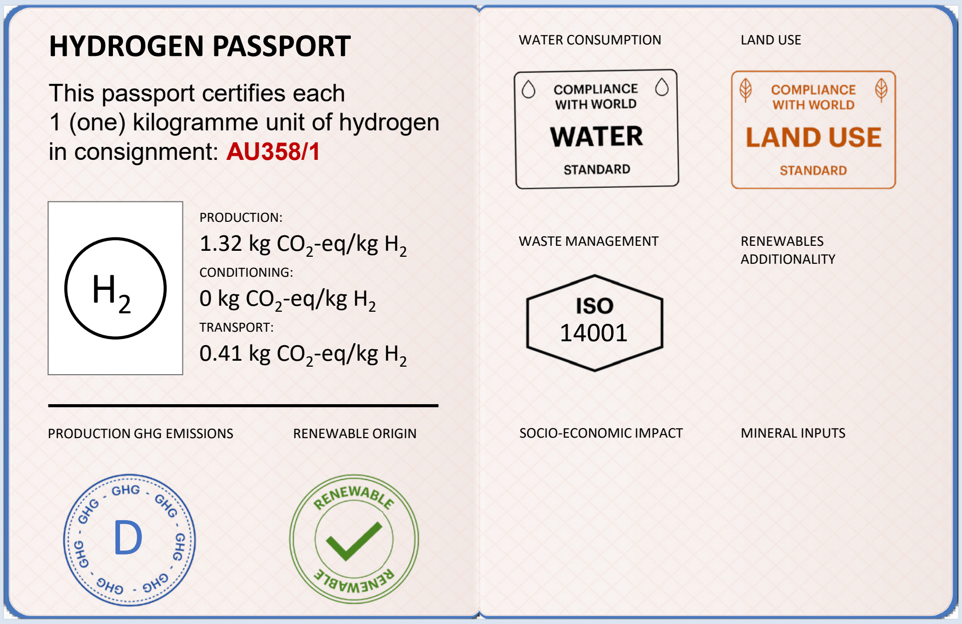
Product passports are not a new idea. Since 2000, as data and digital technology (including blockchain) have improved dramatically, they have been suggested for a variety of applications. The European Commission has advocated the transferral of product passports between owners of a traded good to document 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. Building Renovation Passports have been developed in the form of "logbooks" of successive renovations.

One of the most well-developed and global examples is the battery passport, proposed by the Global Battery Alliance. The proposal is for a "digital twin" of an electric vehicle's physical battery components. By enabling transparent access to key information about the origins of components, manufacturing history and sustainability, the Global Battery Alliance expects to raise consumer confidence and enable industry-wide benchmarking. The intention is to start with voluntary information about compliance with existing standards and legislation, but some jurisdictions are exploring how 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 may contain hydrogen from multiple sources and, by the time it reaches an end-consumer, be split into numerous smaller volumes, each needing a unique ID. As each delivery of hydrogen is used, it may be incorporated into different hydrogen-based fuels or other tertiary products whose buyers may, in turn, need the passport's values. This issue is by no means insurmountable, and systems have been developed for food and drink, and natural gas, by certifying all the output from a production facility or supply chain for a set period. Allocation of emissions intensity to sub-units has been codified for the transport sector.

For an intermediate energy product like hydrogen, any passport system should be developed in a manner that is compatible with products upstream and downstream in the supply chain. As energy transitions unfold, it is likely that end users and regulators will wish to distinguish between many different energy products based on their origin and credentials. This could include the renewable content of electricity, or the bioenergy, hydrogen or natural gas shares 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 general direction of policy and trade is towards ever more differentiation between physically indistinguishable and interrelated goods in the energy system.

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



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Practical considerations for effective implementation

There are a number of prerequisites for a common framework to become widely adopted and add value. Above all, recognition of the system by governments as compliant with regulations is fundamentally important. There are also critical roles for other stakeholders, including standardisation and certification bodies, and key design considerations that must be taken into account to be robust in a changing technical landscape.

Roles and responsibilities for key participants

The successful adoption of an international emissions accounting framework in such a complex, technical and commercial arena relies on the active participation of many different and interconnected stakeholders. This includes building upon the existing competences and activities of expert bodies (Table 3.4).

Governments will need to take the lead in supporting the initial adoption of an accounting framework and ensuring that it is integrated into national and regional regulatory frameworks. Unless this is the case, there remains a risk that any framework creates an additional burden for suppliers without reducing any existing ones.

Table 3.4 Roles and responsibilities for key participants to facilitate adoption of an international emissions accounting framework

Stakeholder	Role	Description
Governments	Recognise in legislation	For hydrogen certified under one standard to be eligible under that of another jurisdiction, an internationally agreed emissions accounting framework would need to be codified in official documentation relating to investment support; tax exemptions; obligation systems or portfolio standards; tenders and auctions; or prohibitions of hydrogen with certain characteristics.
	Champion the framework	The most likely route to wide adoption is via a core group of committed governments that represent a significant share of production, consumption or funding of traded low-emission hydrogen products, as is the case of the G7.
	Agree methodologies	Lifecycle boundaries, process descriptions, allocation methods, default values, measurement protocols, conversion constants (such as for converting methane emissions into CO_2 equivalents), unit of certification (assets, fleets or cargoes), and time horizons over which certified emissions intensities are averaged must all be harmonised, as described by IPHE.
	Agree accounting principles	Different jurisdictions may wish to take different approaches to “chains of custody” – on a book-and-claim or mass balance basis – depending on whether they implement a compliance market with tradeable certificates. Making these approaches interoperable will take careful consideration if it is necessary.
	Establish accreditation for certifiers	Governments will be responsible for establishing who can legally certify hydrogen cargoes. This could include giving a mandate to a dedicated public institution, maintaining a list of authorised bodies, or allowing certification by any party that complies with the rules. An international framework would require mutual recognition of these certifiers.
Standardisation organisations (national and international)	Prioritise standard development	Standardisation follows defined timelines, usually including reviews and updates every five years. The ISO Technical Committee 197 Sub Committee 1 has quickly responded to the IPHE guidelines and aims to expand them into standards by 2025. While it is ambitious, this should be considered the minimum allowable timeframe.
	Agree methodologies	International and national bodies should adopt the same underlying methodologies for their standards, as per the Vienna Agreement on technical co-operation to facilitate the recognition of ISO standards in European countries.

Stakeholder	Role	Description
Certification bodies	Adopt equivalent methodologies and accounting principles	There is a precedent for the mutual recognition of certificates, with six voluntary systems to certify sustainable biofuels that encompass mutual recognition of processes. All six are recognised by the European Union under REDII.
	Facilitate data availability	In addition to meeting the highest regulatory requirements for transparency and data access, certification bodies operating within an international framework may need to use interoperable data systems to ensure information is available and can be accumulated throughout the value chain.
	Consolidate the number of standards	Simplicity should be a core goal of an international emissions accounting framework, and it will be enhanced by competition based on excellence of certification rather than competition between standards offering conflicting criteria.
Producers, traders and buyers of hydrogen, and hydrogen-based products	Co-operate with early adopters	Market participants' incentives are broadly aligned with governments: successful deployment depends on clarity on standards and definitions for the duration of prospective investments, in addition to common approaches between regions without duplication of certification. To accelerate progress, first movers can work together to begin adopting the IPHE methodology even before regulatory processes are fully concluded.
	Champion transparency	Given the likelihood that various commercial and political interests will continue to contest the environmental credentials of hydrogen, it is in the interest of all actors to reduce the risk that the framework – and thus hydrogen – becomes devalued by secrecy, uncertainty and counter-claims.

Reporting, verification and auditing

The successful translation of an accounting framework into national and regional frameworks requires that hydrogen production pathways are performing as expected and reported emissions intensities continue to be accurate. Reporting of key data, verification of that data, and the auditing of reported results is critical to providing assurance.

Required information

Certification schemes may require detailed information to be reported to the regulator for assessment and validation before physical production, to track compliance. There are two main types of data required:

- Profile data, which is submitted when registering supply chain steps and which describes the key attributes of each step, including emissions sources and how they have been determined.
- Batch data, which is specific to a certificate creation batch and is submitted at the point of certification creation. It provides information on the specifics of a particular certificate creation batch.

It is important to use existing adjacent schemes, wherever possible, to bridge data gaps. For instance, if certification schemes require a specific source of electricity used in part of the hydrogen production process, or proof of upstream and midstream methane emissions for gas cargoes, utilising existing schemes to demonstrate this information (such as through Guarantees of Origin or methane certifications) helps to increase the ease of implementation and reduce regulatory burdens.

Frequency

Regulatory frameworks also need to establish the frequency of data reporting (e.g. real-time, every 6 months, 12 months, 18 months, etc.). For instance, Australia is currently considering that data be reported over a 12-month period, stating that this timeframe is typical for data collection for lifecycle assessments. However, data reporting and certification creation may need to operate on different timeframes to provide flexibility for producers.

Verification and auditing

Verification and auditing mechanisms should be in place to ensure that hydrogen or its derived products continue to be consistent with what is reported. A scheme should outline the verification process and timeline and consider if any auditing requirements should be put in place to ensure that the claimed emissions intensity continues to meet the certified level. Consideration should be given to the auditing process itself and who performs it (e.g. self-auditing, independent third parties, digital mechanisms, etc.).

As an example, a producer could have been selling hydrogen at an emissions intensity of 1.5 kg CO_2-eq/kg H_2 for several years, as certified by a certification body and verified by an independent organisation. However, changes to the upstream and midstream fuel supplier have increased the emissions intensity of the hydrogen to 2.5 kg CO_2-eq/kg H_2. Depending on the frequency of the reporting requirements and the auditing process, the producer may have inadvertently sold its hydrogen at a different emissions intensity from originally thought. Further complexity is added if that hydrogen is used for regulatory compliance or public subsidy purposes.

Regulatory frameworks may need to consider mechanisms to “claw-back” any subsidy linked to the produced hydrogen if the product is found to be at a different emissions intensity than recorded previously. There is precedent for this in other sectors: under the 45Q tax credit for CCUS in the United States, a claw-back mechanism embedded in the regulation requires the company claiming the tax credit to report any CO_2 leakage into the atmosphere that has occurred from CO_2 that was thought to have been previously contained underground. If the amount of leakage exceeds the amount of stored CO_2 for that given tax year, the company must pay the difference to the tax authority.

Resiliency in an evolving data and regulatory landscape

The IPHE’s methodology for assessing emissions from hydrogen production, conversion into carriers, and transport, is now being used by ISO to develop a three-part standard covering production, conditioning and transport. This process can take several years, although given the urgency for the development of regulatory frameworks, the aim is to develop a Technical Specification by the end of 2023 and an International Standard by the end of 2024. The long lead time to develop standards can delay the scale-up of a hydrogen market. Governments and certification bodies should therefore not delay existing efforts due to a lack of an international standard, but rather should take a dynamic approach and allow for the future incorporation of standards when they are ready (Box 3.3).

Box 3.3 Incorporating future standards into rule-making

In the United States, the 45Q tax credit incentivises the deployment of CCUS technologies by providing a credit for entities that capture and store CO_2. In order to claim the credit, companies must follow a methodology developed by the

Environmental Protection Agency (EPA) or use the methodology outlined in a relevant international standard. Although companies currently enjoy the choice between the two options, this has not always been the case.

When the tax credit was introduced in 2008, there was no international standard for CO_2 storage or its use in enhanced oil recovery, prompting the EPA to develop its own methodology. Then, in 2019, the ISO finalised ISO 27916 for CO_2 storage using enhanced oil recovery. Yet in order to claim the 45Q tax credit, companies at the time still had to use the EPA's methodology to demonstrate compliance.

Following the finalisation of the ISO standard, in 2021 the United States updated its regulatory guidance to include the use of ISO 27916 as a potential compliance pathway. It determined that the ISO 27916 and EPA methodology were similar: both used a mass balance approach and required assessment and monitoring.

Using the 45Q tax credit as an example, it is possible to see how rule-making can incorporate future international standards.

As the hydrogen sector grows, there will be learning experiences resulting in updates and improvements to current methodologies and standards, and regulations should be able to accommodate these changes. There could be new sources of emissions that are not initially considered in methodologies and standards, or for which there is not enough evidence on their impact. For example, there is growing scientific evidence of the potential climate impacts of hydrogen as an indirect greenhouse gas. However, there is still uncertainty around its global warming potential, a lack of information about hydrogen leakage rates, and limited data about downstream emissions. In some cases, available information is limited to a handful of demonstration projects. As projects are deployed, more data and evidence will be collected, helping to develop and improve the methodologies and standards.

Adopting a full lifecycle analysis approach

In the future there may be a need to include sustainability criteria across the full hydrogen lifecycle. Currently, the IPHE's methodology retains commonly used system boundaries, including Scope 1, Scope 2, and partial Scope 3 emissions.[18] The emissions from the construction, manufacturing, and decommissioning of the hydrogen production device, business travel, employee commuting, and upstream and midstream leased assets are not considered.

[18] Partial Scope 3 emissions include associated impacts from the raw material acquisition phase, raw material transportation phase, hydrogen production and manufacture.

To fully reflect the GHG intensity of hydrogen, the IPHE methodology could be extended to include a complete lifecycle assessment. In that case, this approach should also be applied to other energy products (including electricity and biofuels), and not restricted only to hydrogen and hydrogen-based fuels, to ensure a level playing field.

Data quality and assurance

The availability of high-quality data is essential. The robustness of the methodology used to calculate emissions is critical, but the most robust methodology may lead to misleading results if poor quality data is used. Using incomplete or inaccurate data to calculate the emissions associated with a hydrogen production project can result in significant deviations from the actual emissions of a project. For example, the contribution of upstream and midstream methane emissions to the total emissions associated with the production of hydrogen with natural gas and CCS can vary significantly depending on which, if any, methane abatement technology is used. If no data is available on the upstream and midstream emissions associated with the natural gas supply of this project, it could affect whether or not the project is compliant with regulations and support schemes.

Data availability does not always ensure high-quality data. Quality data should be complete, timely, consistent and accurate to produce reliable results. For example, an error of just 20 g CO_2-eq/kWh in the reported electricity emissions intensity of an electrolyser connected to the electric grid can lead to a deviation of more than 1 kg CO_2-eq/kg H_2 in the final emissions intensity.

Such a difference between the real emissions of the project and the emissions reported due to unavailable or bad quality data is misleading and can grant compliance with regulations and support schemes where the project is actually not compliant. If this occurs, it could discredit any internationally agreed emissions accounting framework and create strong reputational damage. Stakeholders along the hydrogen supply chain must commit to ensure that best practices and the highest level of transparency are adopted to ensure credibility in the system. The creation of open data repositories managed by credible independent bodies and verified by third parties could help to provide the necessary transparency to build such confidence. This is particularly important for hydrogen and hydrogen-based fuels, for which there is limited statistical information available today.

Considerations for the G7

Each G7 member will adopt policies based on its social and political priorities and constraints. But there are areas in which stronger co-operation between members of the group can help establish the basis for the development of a functional global market. Such co-operation should not be limited to G7 countries, as the development of a global hydrogen market will require the participation of stakeholders beyond the G7, particularly from emerging economies that could also benefit from the development of a global market for hydrogen, ammonia and hydrogen-based fuels.

The final section of this report presents recommendations for the G7 to spearhead action on agreeing and implementing an international emissions accounting framework for hydrogen and hydrogen-based fuels (Table 3.5).

Table 3.5 Near-term priorities for collective G7 action

Priority	Near-term steps
Set clear, unified expectations	• Commit to work towards an international emissions accounting framework for hydrogen and hydrogen-based fuels. • Communicate a timeline for putting a workable system in place, including milestones such as agreements on methodologies and accounting principles.
Co-operate on the details	• Foster dialogue in the IPHE Hydrogen Production Analysis Task Force to address any outstanding methodological or accounting issues that are not resolved by the current IPHE guidance, for example emissions allocation among co-products in hybrid plants or temporal and geographical correlation of renewables. • Develop interim measures for the implementation of a framework to minimise the risk that near-term actions are incompatible or create friction with future systems. • Aim to harmonise approaches (such as common default values) for calculating complete estimates of emissions intensities in situations where there is incomplete asset-level data.
Work with partners	• Open a dialogue with other relevant countries, including but not limited to major potential exporters and importers of hydrogen and hydrogen-based fuels. For example, countries planning to meet large future demand for hydrogen via domestic sources will nonetheless be key to developing global standards and benchmarks. • Seek to have as many countries and country groupings as possible sign up to a set of principles for a pathway to phase out emissions associated with traded hydrogen products.

Priority	Near-term steps
Clarify governance	• Outline institutional requirements for an effective international emissions accounting framework, such as responsibilities for convening dialogue, publishing documentation, promoting its use and managing updates. • If individual countries enshrine a common approach in their local rules, the need for a new governance body may be minimal. A custodian of the framework could be housed within an existing institution, such as the Hydrogen Trade Working Group of the Clean Energy Ministerial Hydrogen Initiative (H2I)* or the Hydrogen Trade Rules Task Force of the IPHE.

*The Hydrogen Initiative is a voluntary multi-governmental initiative that aims to advance policies, programmes and projects that accelerate the commercialisation and deployment of hydrogen and fuel cell technologies across all areas of the economy. The IEA serves as the H2I co-ordinator to support member governments as they develop activities aligned with the initiative.

In addition to collective action, individual countries and regions can take a number of steps that will strengthen investor confidence and set in motion the development of an efficient commodity market for low-emission hydrogen. Some governments are already advanced with some of these steps, and are well-placed to drive forward harmonisation (Table 3.6).

Table 3.6 Near-term priorities for policy action

Priority	Near-term steps
Set expectations for how hydrogen from different sources will be differentiated	• Enshrine emissions intensity in national and regional rules and add additional criteria where necessary. • Take a unified approach to rules across measures including investment support, tax exemptions, obligation systems or portfolio standards, tenders and auctions, or prohibitions of hydrogen with certain characteristics. • Issue guidelines for how regulations or eligibility for public support will evolve over time to ensure consistency with net zero emissions by 2050. • Clarify how first mover investors will not be disadvantaged by possible future changes in rules or standards, for example via time-limited grandfathering of eligibility. • Work to define the preferred type of accounting framework (e.g. book-and-claim) and how it can be internationally interoperable.
Act to adopt and accelerate international standards and processes	• Establish institutional competencies to co-operate swiftly with international partners (in the G7 and beyond) to develop the details of an international emissions accounting framework. • Empower standardisation development organisations to meet their timelines for developing international and national standards for harmonised emissions intensity assessments. • Develop interim measures to minimise the risk that near-term actions are incompatible or create friction with future systems.

Priority	Near-term steps
Elaborate nationally and regionally specific elements to ensure interoperability and resilience	• Define which entities will be accredited to certify cargoes of hydrogen and hydrogen-based fuels, and their monitoring and auditing responsibilities. • Confirm that methodologies will evolve to include additional sources of lifecycle emissions that are consistent with policies for net zero emissions and with policies governing adjacent parts of the energy system, to avoid double-counting and perverse incentives. • Define how any remaining differences between methodologies can be resolved to allow mutual recognition, for example by assigning default values to add or subtract emissions values when converting between systems.

Annex

Abbreviations and acronyms

ADEME	The French Agency for Ecological Transition
APS	Announced Pledges Scenario
ATR	autothermal reforming
BAT	best available technology
CCS	carbon capture and storage
CCU	carbon capture and utilisation
CCUS	carbon capture, utilisation and storage
CH_4	methane
CO_2	carbon dioxide
CO_2-eq	carbon dioxide equivalent
CR	capture rate
EPA	Environmental Protection Agency
EU	European Union
FID	final investment decision
GDP	gross domestic product
GHG	greenhouse gas
GH2	Green Hydrogen Standard
H_2	hydrogen
H_2-eq	hydrogen equivalent
H_2-DRI	hydrogen-based direct reduced iron
H2I	Clean Energy Ministerial Hydrogen Initiative
ID	Identifier
IPCC	Intergovernmental Panel on Climate Change
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRA	Inflation Reduction Act
ISO	International Organization for Standardization
LCFS	Low-carbon fuel standard
LH_2	liquified hydrogen
LHV	lower heating value
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
NG	natural gas
NO_x	nitrogen oxides
N_2O	nitrous oxide
NH_3	ammonia
NZE	Net Zero Emissions by 2050 Scenario
POx	partial oxidation
PV	photovoltaic

QR	quick response
RED	Renewable Energy Directive
RoW	rest of world
SMR	steam methane reforming
STEPS	Stated Policies Scenario (IEA)
TC	Technical Committee
USD	United States dollar
VRE	variable renewable energy

Units of measure

bar	bar
g	gramme
GJ	gigajoule
GW	gigawatt
kg	kilogramme
km	kilometre
kt	kilotonne
kW	kilowatt
kWe	kilowatt electric
kWh	kilowatt-hour
kWp	kilowatt peak
MBtu	million British thermal unit
Mt	million tonnes
MW	megawatt
m^3	cubic metres
t	tonne

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