

The inclusion of hydrogen in the EU CBAM



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1. Introduction

On 13 December 2022, the European Parliament and the Council reached a political agreement to introduce a European Union (EU) Carbon Border Adjustment Mechanism (CBAM). Although not part of the initial European Commission proposal, the CBAM will also apply to hydrogen, together with cement, iron and steel, aluminium, fertilisers, and electricity. The inclusion of hydrogen in the EU CBAM was a result of the interinstitutional negotiations or trilogues, between the European Commission, the European Parliament, and the Council.

This report presents the conclusions of an assessment of the rationale and implications of including hydrogen in the EU CBAM. The assessment builds on the methodology used by the European Roundtable on Climate Change and Sustainable Transition (ERCST) to analyse other sectors¹ and on the discussions held during ERCST public meetings on 1 February 2023 and 7 March 2023.

This report is divided into two main parts. Section 2 includes a summary of various hydrogen sector-related considerations (i.e. market, environmental and others) and hydrogen sector-related trade patterns. This lays the foundations for a better understanding of the analysis presented in Section 3, which includes an assessment of some potential implications of including hydrogen in the EU CBAM.²

¹ ERCST (2021) *Border Carbon Adjustments in the EU: Sectoral Deep Dive*. Available at: <https://ercst.org/border-carbon-adjustments-in-the-eu-sectoral-deep-dive/> (Accessed 9 March 2023).

² As some aspects of the CBAM regulation are still to be complemented, amended, or revised, Annex I present a summary of the secondary legislation (implementing and delegated acts) that could, if adopted, be relevant for hydrogen importers or exporters, and Annex II presents a summary of Art. 30 (reviewing and reporting by the European Commission).

2. Hydrogen sector-related considerations

2.1. Market considerations

Hydrogen (CN 28041000) is called on to play an important role in achieving climate neutrality in the EU by 2050.³ Hydrogen can be used as feedstock, a fuel, an energy carrier, or as a storage solution across different applications in a wide range of sectors.⁴

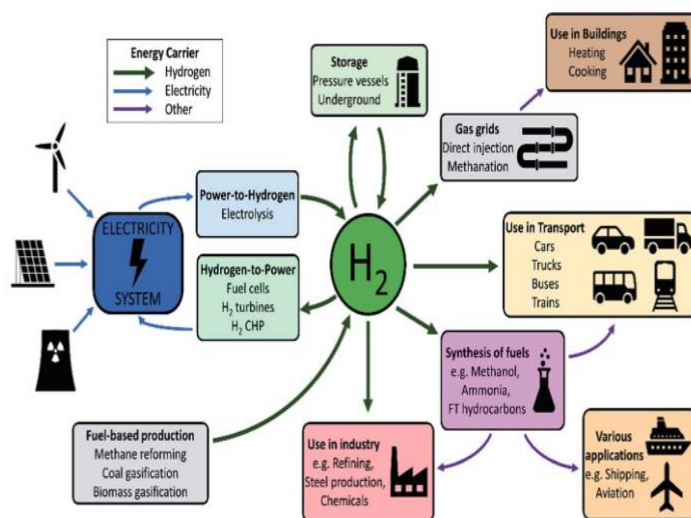


Figure 1 Overview of key hydrogen production and usage pathways
Source: The Royal Society of Chemistry

Demand

By the end of 2020, hydrogen demand in the EU 27 was approximately 8 Mt per year,⁵ with about 50% of hydrogen used in refineries and about 40% in ammonia production.⁶ Other end uses in the EU include the production of chemical products, methanol, energy, and others activities.⁷ It should be clarified that in some processes in the chemical and refineries sectors, hydrogen is a by-product of the main production process. For illustration purposes, when refineries produce hydrogen as a by-product, this supply meets only a fraction of their hydrogen needs.

EU hydrogen consumption EU 2020 in Kt of hydrogen

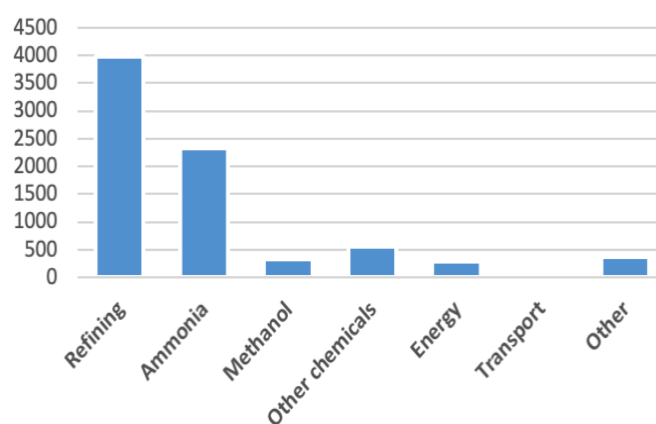


Figure 2. EU 27 hydrogen consumption in the EU in 2020 measured in Kt of hydrogen by sector

³ European Commission (2020) *Impact Assessment on Stepping up Europe's 2030 climate ambition Investing in a climate-neutral future for the benefit of our people*, p. 56. Available at: https://eur-lex.europa.eu/resource.html?uri=cellar:749e04bb-f8c5-11ea-991b-01aa75ed71a1.0001.02/DOC_1&format=PDF (Accessed 9 March 2023).

⁴ The Royal Society of Chemistry (2020) 'The curious case of the conflicting roles of hydrogen in global energy scenarios', *Sustainable Energy Fuels*, 4, pp. 80-95.

⁵ Fuel Cells and Hydrogen Observatory (2023) *Hydrogen Demand*. Available at: <https://www.fchobservatory.eu/observatory/technology-and-market/hydrogen-demand> (Accessed 9 March 2023).

⁶ A large proportion being produced by hydrocarbons.

⁷ Including the food industry, glass manufacturing, the automotive sector, cooling generators in the power sector, metal welding and cutting, electronics, research labs, and other small-scale applications.

Supply

Over 90% of current hydrogen production is obtained from hydrocarbons, primarily methane in a process known as steam methane reforming (SMR). Other conventional production processes include partial oxidation and autothermal reforming of fossil fuels, or catalytic reforming, where hydrogen is produced in refineries as a by-product. It is expected that other hydrogen production processes will play an increasingly important role in the coming years. These include the production of hydrogen through the electrolysis of water using decarbonized electricity, or through methane reforming with carbon capture and storage (CCS).⁸

Hydrogen production costs are a function of different factors, such as the production technology used, the price of inputs (i.e. electricity, coal, natural gas, biomass etc.), the geographical place of production, and the application of a carbon price.

In 2021, in most regions, the cost of fossil fuel-based hydrogen was cheaper than the production of low-emission hydrogen. Global average production costs varied between USD 1.0-2.5/kg H₂ from unabated natural gas; USD 1.5-3.0/kg H₂ from natural gas with carbon capture, utilisation and storage (CCUS); and USD 4.0-9.0/kg H₂ for production via electrolysis with renewable electricity.⁹

It is worth noting that since the beginning of 2022, energy prices in Europe have been subject to significant volatility. For some production processes in some regions, high energy prices have changed the economics of hydrogen production in the EU.¹⁰ This can impact the development of the EU hydrogen market and will play a role in two different ways: on the one hand, it can increase EU interest in importing hydrogen from areas where production costs are lower; on the other hand, for EU industries that use hydrogen as a precursor, it may contribute to their relocation to areas with access to cheaper hydrogen or cheaper hydrogen inputs in order to remain competitive in their respective global markets.

It should be clarified that high hydrogen prices will affect the competitiveness of sectors using hydrogen in different ways. These are characterized by the inherent differences of business models in different sectors. While for industrial users, high hydrogen prices may imply relocation or closure due to a loss of competitiveness in the global market, for the transport sector (where relocation of services is more difficult), high prices may imply a possible substitution of hydrogen by a cheaper energy carrier.

⁸ Other production processes include pyrolysis of methane or pyrolysis of biomass.

⁹ International Energy Agency (2022) *Global Hydrogen Review 2022*, p. 93. Available at: <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (Accessed 9 March 2023).

¹⁰ ERCST (2023) *Hydrogen: The imports dimension of REPowerEU*, p. 6. Available at: <https://ercst.org/hydrogen-the-imports-dimension-of-repowereu/> (Accessed 9 March). Includes data from the IEA (International Energy Agency).

Hydrogen market (present and future)

At present, there is no liquid hydrogen commodity market in the EU. Captive hydrogen production, which provides a constant hydrogen supply, represents the most common method of hydrogen supply, with about 90% of the total hydrogen production capacity being self-produced or recovered (as a by-product) by industrial consumers themselves. So-called 'merchant hydrogen', which is produced and sold by third parties based on long-term contracts, represents only about 10% of total hydrogen production capacity.¹¹ In this case, hydrogen is sold as a speciality chemical for industry and, in some cases, as an energy carrier for transport.

In the future, the EU hydrogen market is expected to become a largely liquid commodity market, using Guarantees of Origin as certificates.

To transition to a decarbonised hydrogen market in the EU, the European Commission aims to reach 10 Mt¹² of renewable hydrogen production in the EU by 2030, along with an additional 6 Mt of imported renewable hydrogen and 4 Mt of imported renewable hydrogen in the form of ammonia and other derivatives, including e-methanol, e-kerosene, and e-diesel).¹³

This policy ambition has been underpinned by the introduction of incentives and targets¹⁴ on both the demand and supply sides. These are enshrined in different pieces of legislation, most of them proposed as part of the 'Fit for 55' package of policies and legislation.

This view of the development of the EU hydrogen market contrasts with other more conservative demand-driven forecasts,¹⁵ which predict that hydrogen demand by 2030 will be significantly lower and that reliance on imports will therefore be reduced. As an example,

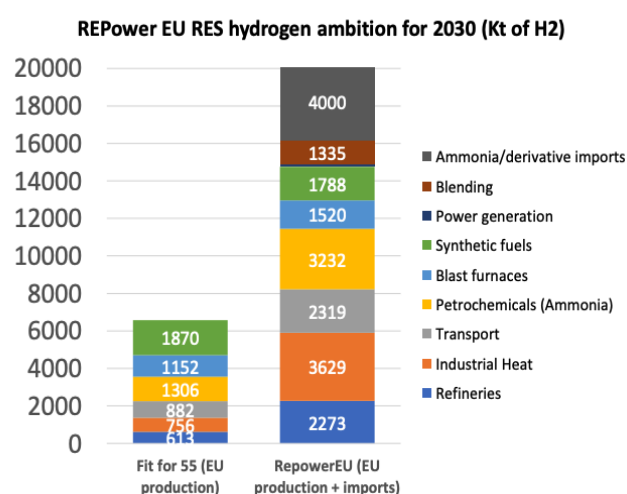


Figure 3. Hydrogen use by sector by 2030

Source: REPower EU Communication, further adapted by ERCST

¹¹ Hydrogen Europe (2022) *Clean Hydrogen Monitor 2022*, p. 16. Available at: https://hydrogeneurope.eu/wp-content/uploads/2022/10/Clean_Hydrogen_Monitor_10-2022_DIGITAL.pdf (Accessed 9 March 2023).

¹² Including the use of e-fuels derived from hydrogen.

¹³ European Commission (2020) *Implementing the REPowerEU Action Plan*, p. 27. Available at: <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022SC0230&from=EN> (Accessed 9 March 2023).

¹⁴ The European Commission Renewable Energy Directive (RED) proposal from July 2021 sets a binding 50% target for renewable fuels of non-biological origin (RFNBOs) for industry and a 2.6% RFNBOs binding target for the transport sector by 2030. This aspect is currently under negotiations in the RED trilogue process.

¹⁵ AgoraEnergie (2021) *No-regret hydrogen*, p. 10. Available at: https://static.agora-energiawende.de/fileadmin/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf (Accessed 9 March 2023).

the EU hydrogen strategy from July 2020 refers to 10 Mt of renewable hydrogen by 2030, which represents half of the REPowerEU ambition.

2.2. Environmental considerations

The average greenhouse gas (GHG) emissions intensity of all hydrogen installations covered by the EU Emissions Trading System (EU ETS) for the years 2016/2017 was 10.78 tonnes of CO₂ equivalent per tonne of hydrogen produced. The average GHG emissions intensity of the 10% most efficient installations for the years 2016/2017 was 4.09 tonnes of CO₂ equivalent per tonne of hydrogen.^{16,17}

It is important to clarify that the main source of emissions for current hydrogen production under the EU ETS Directive are direct emissions, and that the scope of the EU ETS Directive only includes processes based on fossil inputs, namely steam methane reforming and partial oxidation (grey hydrogen).¹⁸

Under the current EU ETS Directive, only fossil fuel-based hydrogen is entitled to free allowances, for which production capacity has to exceed 25 tonnes per day.¹⁹ As a result of the ongoing EU ETS Directive reform, the scope of the Directive – and subsequently the scope for free allowances – will be expanded to cover all hydrogen production methods, de facto including electrolytic hydrogen. Moreover, the production capacity threshold has been lowered from 25 to 5 tonnes per day, allowing smaller installations to also benefit.

For electrolytic hydrogen, the main source of emissions is related to the production of the electricity used to produce the hydrogen. In other words, the carbon footprint of electrolytic hydrogen will be as high as its indirect embedded emissions. Given its high energy intensity, hydrogen has been included as an eligible sector for indirect cost compensation as part of the revised EU ETS State aid Guidelines beyond 2021.

Electrolytic hydrogen can be produced in different ways, depending on the origin of the electricity used (e.g. renewable or non-renewable), and the way it is dispatched (e.g. direct connection, or grid connection²⁰ with or without a power purchase agreement (PPA)). This results in different GHG emission intensities.

¹⁶ European Commission (2021) *Update of benchmark values for the years 2021 – 2025 of phase 4 of the EU ETS*, p.57. Available at: https://climate.ec.europa.eu/system/files/2021-10/policy_ets_allowances_bm_curve_factsheets_en.pdf (Accessed 9 March 2023).

¹⁷ The current EU ETS emission benchmark values for 2021/2025 were established using data from 2016/2017.

¹⁸ Directive (EU) 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC (Text with EEA relevance) (2003) *Official Journal L 275*, Annex I. Available at: <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32003L0087> (Accessed 9 March 2023).

¹⁹ Production of hydrogen and synthesis gas by reforming or partial oxidation with a production capacity exceeding 25 tonnes per day.

²⁰ Average grid carbon intensities vary considerably between European countries. For example, the carbon footprint of an electrolyser connected to the Swedish electricity grid would be close to 0 while the same electrolyser connected to the Polish grid would produce about 35.5 kgCO₂/kgH₂. Using the EU-27 average electricity mix in 2020 for hydrogen production would have led to emissions of 11.5 kgCO₂/kgH₂, which is higher than the average fossil-fuel based production. Source: Hydrogen Europe (2022) *Clean Hydrogen Monitor*.

A set of rules defining the conditions and requirements under which hydrogen can be considered renewable was published in two Delegated Acts on 13 February 2023.²¹ These rules will also apply to imports of renewable hydrogen. A certification scheme relying on so-called ‘voluntary schemes’ will be introduced, and the European Commission will be in charge of validating the schemes. Although the intention to apply EU requirements to renewable hydrogen imports has been set in the legislation, from a practical point of view, it is still unclear how these requirements will be applied and enforced in third countries.

A definition for low-carbon hydrogen is also expected, in this case in the framework of the Hydrogen and Gas Directive, which is currently under negotiation. Besides the definitions for renewable and low-carbon hydrogen, other initiatives at the EU level have been put forward, each of them serving different purposes,²² as outlined in Table 1 below.

Table 1. Initiatives to define properties, attributes, and/or conditions of hydrogen in the EU
Source: Own elaboration by ERCST

Initiative / legislative text and type of hydrogen	GHG threshold	Methodology	Aim/purpose	Status
RED (renewable hydrogen)	3.384 tCO ₂ e/tH ₂ (70% of a fossil fuel comparator of 94 gCO ₂ e/MJ)	RED Delegated Acts adopted on 13 February 2023. These include additional criteria to qualify electricity as renewable, i.e. additionality, temporal and geographical correlation, or absence of state aid.	Provide a definition for renewable hydrogen at the EU level to assess compliance with regulatory incentives and mandates. ²³	The Delegated Acts have been submitted to the Parliament and the Council for approval. They both have two months to accept or reject the Commission's proposal. The Parliament has requested to extend the scrutiny period by additional two months.
Hydrogen and Gas Directive, ITRE position (low-carbon hydrogen)	3.384 tCO ₂ e/tH ₂ (70% of a fossil fuel comparator of 94 gCO ₂ e/MJ)	Delegated Acts to be adopted after the adoption of the Directive.	Provide a definition for low-carbon hydrogen at the EU level to assess compliance with	The Hydrogen and Gas Directive is still under negotiation. The Council has not yet adopted its position. It is still unclear when the

²¹ After the adoption of the Delegated Acts, the Parliament and Council have two months to accept or reject the Commission Proposal. Amendments are not possible. The Parliament has requested to extend the scrutiny period by additional two months.

²² As an example, the definition of hydrogen under the EU taxonomy aims to drive investments towards what is defined as ‘sustainable hydrogen’ while the definition of hydrogen in the Renewable Energy Directive aims to prove compliance with regulatory incentives in the legislation.

²³ The European Commission Renewable Energy Directive (RED) proposal from July 2021 sets a 50% RFNBOs binding target for industry and a 2.6% RFNBOs binding target for the transport sector by 2030. This aspect is currently under negotiation in the RED trilogue process.

			regulatory incentives. ²⁴	Delegated Acts complementing the definition of low-carbon hydrogen with a methodology to assess its GHG footprint will be published.
EU taxonomy (sustainable hydrogen)	3 tCO ₂ e/tH ₂ (73.4% of a fossil fuel comparator of 94g CO ₂ e/MJ and 70% for hydrogen-based synthetic fuels)	RED Delegated Acts or, alternatively, ISO 14067:2018 or ISO 14064-1:2018.	Drive investments towards 'sustainable' hydrogen.	Already in place
CertifiHy (low-carbon hydrogen)	4.36 tCO ₂ e/tH ₂ (60% fossil fuel comparator 91 gCO ₂ e/MJ)	CertifiHy methodology – ISO-compliant voluntary scheme.	First EU attempt to certify low-carbon hydrogen. ²⁵	Voluntary schemes
CBAM	No threshold applicable	In progress	Avoid carbon leakage	In progress

2.3. Trade patterns and other considerations

At present, imports and exports of hydrogen to and from the EU are very low.²⁶ By 2030, the European Commission forecasts that imports of renewable hydrogen will increase to cover the expected demand and to reduce dependency on natural gas.

In terms of the types of hydrogen that will be imported in the coming years, it seems reasonable to expect that hydrogen imports will evolve in parallel to EU regulatory requirements, incentives, and mandates. Several regulatory incentives have been introduced at the EU level for renewable hydrogen on both the demand and supply sides, as well as for low-carbon hydrogen primarily on the supply side.²⁷ Of these, the incentive that has the most

²⁴ Low-carbon hydrogen could also benefit from some incentives in EU legislation, such as state aid, free allowances under the EU ETS, accountability towards the quotas in the Fuel EU Maritime Regulation, Innovation Fund financial support etc. The revision of the RED is still under negotiation and some Member States support that low-carbon hydrogen should be, in some form counted towards the RFNBO mandates in the RED.

²⁵ Some observers prefer to use a colour code to refer to the different hydrogen production types. Based on the proposed EU regulatory framework, a brief explanation of the equivalence between EU definitions and the different colours is presented below:

Renewable Fuels of Non-Biological Origin (RFNBO): green. Hydrogen produced from biomass sources will not fall under the definition of RFNBO but will fall in the scope of the Renewable Energy Directive and will count towards RED targets if it meets the relevant standards.

Low-carbon hydrogen: blue, pink or turquoise. Hydrogen is considered low-carbon if it meets the relevant requirements and standards to be defined in the Hydrogen and Gas Directive and accompanying Delegated Acts.

Other types of hydrogen: grey, brown, black.

²⁶ According to WITS World Bank, imports of hydrogen into the EU in 2019 were about 50 tonnes. Source: WITS World Bank (2019) *European Union Hydrogen imports by country in 2019*. Available at: <https://wits.worldbank.org/trade/comtrade/en/country/EUN/year/2019/tradeflow/Imports/partner/ALL/product/280410> (Accessed 9 March 2023).

²⁷ Incentives for renewable and low-carbon hydrogen include: the introduction of binding targets in different sectors, setting standards, the possibility for Member States to grant state aid, scope enlargement for free allocation under the EU ETS, etc.

potential to shape market behaviour is the introduction of demand side binding mandates in the proposed revision of the Renewable Energy Directive (RED) from July 2021.

The RED revision proposal, which is currently under negotiation, introduced binding mandates for the use of RFNBOs²⁸ in industry (50% share of all hydrogen consumed by 2030) and in the transport sector (2.6% share of all fuels by 2030). According to this, it is expected that imports of renewable hydrogen and derivatives will surpass low-carbon and grey hydrogen imports in the coming years. It is important to mention that the revision of the RED is still under negotiation and that some Member States support allowing low-carbon hydrogen to count towards the RED's RFNBO targets in some form. The Hydrogen and Decarbonised Gas Market Package, which is also under negotiation, may also include some kind of demand-side incentive for low-carbon hydrogen. If this turns out to be the case, an increase in low-carbon hydrogen imports can also be expected.

There are different ways in which hydrogen can be transported. The most cost-effective manner to transport and deliver hydrogen depends on different variables, including distance, amount, final use, state, availability of transport infrastructure etc.²⁹ For short distances, hydrogen pipelines, where hydrogen is transported in compressed gaseous form, offer lower costs than chemical carriers.

In contrast, chemical carriers such as Liquid Organic Hydrogen Carriers (LOHC) or ammonia become more competitive for longer distances. Moreover, hydrogen imports are also expected in the form of other hydrogen derivatives and carriers, such as methanol, synthetic gases and e-fuels (i.e. e-kerosene, e-diesel or e-methane). In the future, hydrogen will also be embedded in final products such as green fertilisers or green steel.

Other considerations and factors may further increase or decrease the EU's appetite for hydrogen imports. In this regard, energy prices are a crucial element. Inputs to hydrogen production, such as natural gas or electricity, represent a considerable share of total hydrogen production costs.³⁰ Energy prices in the EU have been peaking in 2022,³¹ while remaining stable in other regions.³² If this trend continues, imported hydrogen, which would compete with EU domestic production of hydrogen, could become more attractive. In light of high energy prices in the EU, industry may opt to relocate to regions where hydrogen is cheaper.

²⁸ RFNBOs consist of pure hydrogen derived from water and renewable energy (except biomass sources), and also liquid fuels such as ammonia, methanol or e-fuels when produced from renewable hydrogen.

²⁹ European Commission Joint Research Centre (2021) *Assessment of Hydrogen Delivery Options*. Available at: https://joint-research-centre.ec.europa.eu/system/files/2021-06/jrc124206_assessment_of_hydrogen_delivery_options.pdf (Accessed 9/ March 2023).

³⁰ Using average prices in the EU for natural gas and CO₂ allowances in 2021, natural gas prices would represent about 70% of total natural gas-based hydrogen production costs per kg of hydrogen, while the carbon price would account for about 20% of total costs. Source: Hydrogen Europe (2022) *Clean Hydrogen Monitor*, p. 35. Available at: https://hydrogeneurope.eu/wp-content/uploads/2022/10/Clean_Hydrogen_Monitor_10-2022_DIGITAL.pdf (Accessed 9 March 2023).

³¹ At natural gas prices of about EUR 150/MWh, hydrogen produced with natural gas and CCS (also called blue hydrogen) may exceed EUR 8 kg/H₂.

³² As an example, gas prices in the US have remained relatively stable during 2022, ranging from EUR 10 to EUR 30 per MWh. Source: Energy Information Administration (2022) *Henry Hub Natural Gas Spot Price*. Available at: <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm> (Accessed 9 March 2023).

CBAM could be considered as part of the toolkit to address this problem. However, CBAM is a mechanism that protects against carbon leakage by equalising the cost of carbon between imported and EU-produced products, rather than a tool to address the volatility of steep energy prices in the EU. The combination of CBAM with other support instruments such as Carbon Contracts for Difference (CCfDs), Contracts for Difference (CfDs) or premiums should be viewed positively.

Finally, the introduction of financial or fiscal incentives in other jurisdictions could also make imports of hydrogen more attractive when compared with EU domestic production. As an example, the United States' Inflation Reduction Act (IRA) has proposed the introduction of a tax credit for clean hydrogen production. Under the Act, producers can receive a tax credit of up to USD 3 per kg of hydrogen depending on the GHG footprint of the hydrogen produced and further conditions, guaranteed for a 10-year period.

3. Implications of CBAM coverage

3.1. Free allocation phase-out for hydrogen accelerated due to CBAM

The EU ETS Directive establishes that the 10% best CO₂ performers in a product benchmark receive 100% of their required allowances allocated for free. From Phase 3 (2013-2020) of the EU ETS onwards, benchmark values have been used to determine the amount of free allocation of CO₂ certificates. CO₂ emitters covered by the EU ETS can use these allowances to cover their CO₂ surrender obligations.

According to the recently adopted revision of the EU ETS Directive, benchmark values would decrease by a maximum of 2.5% per year starting in 2026. On top of that, CBAM is set to gradually diminish free allowances for various goods, including hydrogen. The reduction of free allowances under CBAM will be implemented progressively³³ between 2026 and 2033. From 2034 onwards, free allocations will have been phased out completely for CBAM sectors.

This means that the inclusion of hydrogen in the CBAM will translate into a faster phase-out of free allowances compared to applying only the maximum benchmark annual reduction rates (maximum of 2.5%) if hydrogen were not covered by the CBAM.

If, as indicated in the previous section, hydrogen produced in the EU faces higher costs than competing foreign production, the loss of free allowances could result in imports being favoured over domestic production. At this point, it is difficult to anticipate whether – amid all the other supply - and demand- side measures that are being introduced in the EU – the loss of free allowances will be a decisive factor in determining the competitiveness of domestic renewable or low-carbon hydrogen production.

³³ 97.5% in 2026, 95% in 2027, 90% in 2028, 77.5% in 2029, 51.5% in 2030, 39% in 2031, 26.5% in 2032 and 14% in 2033. From 2034, no CBAM factor should apply.

3.2. Circumvention, relocation and resource shuffling

As previously mentioned, when hydrogen needs to be transported over longer distances, this is likely to be in the form of hydrogen derivatives and carriers to overcome some of the inherent limitations in transporting gaseous and liquid hydrogen. Of relevance to the hydrogen supply chain, Annex I of the CBAM Regulation only lists products with the Combined Nomenclature (CN) code 28041000 (hydrogen) and 2814 (ammonia, anhydrous or in aqueous solution) as being covered by CBAM. Other derivatives and carriers, such as LOHCs,³⁴ methanol, and synthetic gases and e-fuels, including e-kerosene, e-diesel, or e-methane, are not included in the scope of the Regulation.

A significant share of hydrogen imported into the EU market may thus not be subject to the CBAM, raising concerns about the potential for circumvention: producers looking to sell hydrogen on the EU market could thus be incentivised to focus their production on derivatives and carriers not covered by the CBAM, with any conversion to liquid or gaseous hydrogen only occurring after entry into the EU.

It is also possible that CBAM could act as an incentive to producers of e-fuels and synthetic fuels to relocate production outside the EU and export the final fuel to the EU market. This substitution effect could also extend to other products for which H₂ is a precursor.

Where foreign producers can deliver both products covered by the CBAM – hydrogen and ammonia – as well as derivatives or carriers that do not fall within the scope of the CBAM, they could avoid incurring CBAM charges by modifying trade flows so as to only export the latter to the EU. This would lead to a form of circumvention known as resource shuffling.³⁵

If such practices become widely used, the inclusion of hydrogen in the CBAM risks becoming irrelevant in practice. It is too early to anticipate whether, and to what extent, the exclusion of carriers and derivatives other than ammonia from Annex I of the CBAM Regulation will create a regulatory loophole. However, it is equally clear that the provision it contains to address circumvention – Article 27 – is largely limited to reviewing trade patterns and flows, deferring any actual solutions to future delegated acts.

3.3. Indirect emissions of hydrogen are not covered by CBAM – implications i.e. for treatment of renewable vs. carbon intensive electrolytic hydrogen

The scope of coverage for hydrogen in the CBAM will, at least initially, involve only direct emissions. This means that, like most products covered by the CBAM, hydrogen importers will

³⁴ It should be noted that LOHC differ from other hydrogen carriers, as it has no use on its own, and therefore the assessment of circumvention through LOHC deserves a more technical assessment. LOHC are organic compounds that can absorb and release hydrogen through chemical reactions. This means that LOHC may be seen as a means of hydrogen transportation that could be reused several times rather than a product itself. LOHC could be also separated from its hydrogen content before customs clearance, which would not prevent the hydrogen content going through customs clearance independently.

³⁵ ERCST (2022) *Indirect Emissions in the EU CBAM*. Available at: <https://ercst.org/indirect-emissions-in-the-eu-cbam-2022> (Accessed 10 March 2023).

pay only for direct embedded GHG emissions, and not for what the EU is calling indirect emissions, i.e. emissions embodied in the generation of the electricity used in production.

Electricity is covered under the ETS, and so EU hydrogen producers would be at risk of leakage and loss of competitiveness without some sort of protection. Unlike most of their foreign competitors, EU producers pay high electricity costs because they are paying for the cost of ETS allowances purchased by electricity producers. Costs are also high because electricity is priced at the cost of the marginal producer in the EU (unlike in most other jurisdictions), and the marginal producer is usually burning coal or gas.

Therefore, like other sectors in similar situations, instead of having indirect emissions covered under the CBAM, hydrogen producers are eligible for indirect cost compensation. Such compensation, covering up to 75% of a hypothetical cost of emissions, is granted by the Member States at their discretion, and approved under special EU State aid rules. There is also a 'supercap' provision that allows compensation limited to 1.5% of the installation's gross value added, if that amount is greater.

These protections are mostly relevant to EU producers of renewable hydrogen, since the production of hydrogen via SMR, by contrast, has few indirect emissions. The compensation means that EU renewable hydrogen production is protected against leakage to non-EU renewable hydrogen producers for whom electricity does not have the same indirect carbon costs.

It is not clear whether protection is needed from non-EU producers of SMR-derived hydrogen. Those producers have significant direct emissions for which they would pay under CBAM. On the other hand, they would not have to pay for high-cost electricity, since SMR does not use much electricity. It also seems likely that imports of SMR-based hydrogen (at least the unabated variety) will ultimately be reduced by the regulatory initiatives described in Table 1.

One advantage of indirect cost compensation over including indirect emissions in the scope of the CBAM is that the former does not involve the risk of resource shuffling. Resource shuffling gets increasingly hard to define as we get deeper into its specifics,³⁶ but at a high level, it involves global trade flows in covered goods simply being rearranged so that goods produced using clean electricity flow to the EU, where they would have an advantage under a CBAM that covered indirect emissions, and those produced using high-emissions electricity would flow elsewhere. In this scenario, nothing has changed regarding the amount of emissions produced, but EU producers now face lower-cost competition.

Indirect cost compensation also has its drawbacks. Firstly, such compensation is not necessarily tied to actual carbon costs, and risks over-compensating or under-compensating covered firms. Secondly, it is applied at the discretion of the Member States, and of the 27 Member States of the European Union, less than half currently provide compensation for indirect costs. Thirdly, it provides no incentive for foreign producers to reduce indirect

³⁶ Ibid.

emissions in electricity-based hydrogen production. Finally, its costs will increase significantly as more renewable hydrogen is produced in the EU.

3.4. Disparate definitions and methodologies across relevant regimes

As mentioned in Table 1, the EU is in the process of introducing several supply- and demand-side measures to promote the commercialisation and use of hydrogen, in particular, renewable hydrogen. Each of the relevant regimes – including the Renewable Energy Directive and its Delegated Acts, the Hydrogen and Decarbonised Gas Market Package, and the Sustainable Finance Taxonomy – contains definitions, criteria, methodologies, and procedures, and these may differ from operational rules adopted under the CBAM Regulation as delegated and implementing acts.

With these various legislative or regulatory measures currently in different stages of elaboration and adoption, it is still too early to assess whether, and to what extent, the process and methodology for determining embedded carbon in hydrogen under the CBAM will align with the definitions and criteria of the other relevant regimes. Where multiple different approaches lead to inconsistencies or outright conflicts, however, there is a risk of regulatory uncertainty, increased transaction costs, and a higher administrative burden.³⁷

It is therefore critical that the various legislative and regulatory measures currently being elaborated under the aegis of different legislative committees and administrative units of the European institutions ensure mutual coordination and alignment concerning the treatment of hydrogen. It is also imperative that legislative or regulatory outcomes, once finalised, are carefully evaluated with regard to potential inconsistencies or conflicts in their practical application. In this context, the creation of a ‘green pass’ or ‘low-carbon pass’ through which EU-compliant RED, or Hydrogen and Gas Directive certified hydrogen would be exempted from the administrative burden that CBAM could entail, could be considered as part of the solution.

3.5. CBAM could hamper access to hydrogen at affordable prices and in sufficient quantities during the transition

As explained in section 6, the scope of coverage for hydrogen in the CBAM will, at least initially, involve only direct emissions. This means that under CBAM, renewable hydrogen will be considered as having zero emissions and therefore, imports of this type will not incur CBAM charges.

However, CBAM may represent an administrative burden for renewable hydrogen importers. These will have to comply with the procedures and formalities established in the Regulation, which may act as a de facto non-tariff barrier (size unknown) to trade. This is also true for low-carbon hydrogen imports, with the caveat that low-carbon hydrogen will embed a certain level of direct emissions and therefore may be subject to CBAM charges.

Although still too early to draw conclusions, considering that renewable and low-carbon hydrogen may be scarce and expensive in the EU during the transition, adding an additional layer of difficulty or an additional cost to the importation of decarbonised hydrogen could be detrimental to EU industries that need access to decarbonised and affordable hydrogen in sufficient quantities to remain competitive.

The impact of CBAM on EU industrial competitiveness leads us to an important discussion about the very nature of this instrument. While some argue that CBAM should be regarded as a purely climate tool and therefore its ultimate objective is to avoid carbon leakage, there are others that argue that CBAM, in some form, also serves as a protection mechanism by ensuring the competitiveness of EU Industry.

When assessing the impact of CBAM on the development of the EU hydrogen market, it is also important to differentiate between the short term and the long term. In the short term, all hydrogen types will compete for market share in the EU, and for this reason, a mechanism to level the playing field for grey hydrogen imports may be needed. Nevertheless, by 2030 for instance, renewable hydrogen will have seen its cost competitiveness improved, and the RED mandates and other incentives will have driven imports towards renewable hydrogen, reducing the need for adjustment at the border.

4. Annexes

Annex I – List of Delegated and Implementing Acts yet to be published, and that could impact H₂ imports/exports

Art. no.	Applies from	Type of Act	How does it affect H₂ imports/exports?
2(2)	1 January 2026	Implementing Act	<i>This act concerns geographical circumvention through artificial islands, fixed or floating installations, etc.</i>
2(11)	1 October 2023	Delegated Act	<i>This act refers to the possibility of amending the list of countries in Annex II, i.e. countries and territories outside the scope of the Regulation.</i>
5 (6)		Implementing Act	<i>This act refers to the standard format of the application and the procedures to submit applications through the CBAM registry.</i>
6 (6)		Implementing Act	<i>This act refers to the format and some elements of the CBAM declaration.</i>
7(6)	1 January 2026	Implementing Act	<i>This act refers to the elements for the methods for calculating embedded emissions (Annex III), including determining system boundaries of production processes and relevant precursor materials, emission factors, installation-specific values, etc.</i>
7(6)		Implementing Act	<i>This act refers to Annex III point 4.3 (determination of default values for embedded emissions) and the possibility that default values can be adapted to areas, regions or countries.</i>
8(3)	1 January 2026	Implementing Act	<i>This act refers to the process of verification of embedded emissions.</i>
9(4)	1 January 2026	Implementing Act	<i>This act concerns how to make the conversion of the average yearly carbon price in a third country and the corresponding reduction of CBAM certificates.</i>
17(11)		Implementing Act	<i>This act refers to the conditions for applying for the status of authorised CBAM declarant.</i>
18 (1)		Implementing Act	<i>This act concerns the accreditation of verifiers.</i>
20 (3)		Delegated Act	<i>This act concerns the sale of CBAM certificates and the further definition of timing, administration, and other aspects of the sale and re-purchase of CBAM certificates.</i>
21(3)	1 January 2026	Implementing Act	<i>This act concerns the calculation of the price of CBAM certificates.</i>
25(5)	1 January 2026	Implementing Act	<i>This act concerns the periodicity, timing and means for communication of specific information about exported goods, such as the EORI number, etc.</i>
27(6)	1 January 2026	Delegated Act	<i>This act concerns circumvention through slightly modified goods to make those goods fall outside Annex I of the CBAM Regulation.</i>
31(2)	1 January 2026	Implementing Act	<i>This act refers to the calculation of the adjustment that reflects the extent to which EU ETS free allowances are allocated free of charge.</i>
35(6)	1 January 2026	Implementing Act	<i>This act refers to the information to be reported as part of the reporting obligation for importers.</i>

Annex II – Summary overview of Art. 30 (Reviewing and Reporting by the European Commission)

When?	How?	What?
Before the end of the transition period	Report to the Parliament and the Council	An assessment of: a) the possibility of extending the scope to: 1. embedded indirect emissions to the sectors listed in Annex Ia; 2. embedded emissions in the transport of goods listed in Annex I and transportation services; 3. goods at risk of carbon leakage other than those listed in Annex I, and specifically, organic chemicals and polymers; and 4. other precursor materials for the goods listed in Annex I. (b) the criteria to be used to identify the goods to be included in Annex I I; (c) the technical requirements for calculating embedded emissions for other goods to be included in Annex I; (d) the progress made in international discussions regarding climate action; (e) the governance system, including the administrative costs; (f) the impact of this Regulation on goods listed in Annex I imported from developing countries, with special attention given to the least developed countries and on the effects of the technical assistance given; and (g) the methodology for the calculation of indirect emissions pursuant to Article 7(6) and Annex III point 4.3. <i>* This report should, if appropriate, be accompanied by a legislative proposal by the end of the transition period, including a detailed impact assessment, in particular with a view to extending the scope of this Regulation on the basis of the conclusions drawn in those reports.</i>
At least one year before the end of the transition period	Report	• Identification of products that are further down the value chain of the goods listed in Annex I and that are recommended to be considered for inclusion in the scope of application of this Regulation. • To that end, the Commission shall develop, on time, a methodology that should be based on the relevance in terms of cumulated GHG emissions and risk of carbon leakage. <i>* This report should, if appropriate, be accompanied by a legislative proposal by the end of the transition period, including a detailed impact assessment, in particular with a view to extending the scope of this Regulation on the basis of the conclusions drawn in those reports.</i>
Every two years from the end of the transition period	Annual report to the Parliament and the Council	• The Commission shall assess the effectiveness of the CBAM in addressing the carbon leakage risk for goods produced in the EU for export to third countries that do not apply the EU ETS or a similar carbon pricing mechanism. • The report shall, in particular, assess the development of EU exports in CBAM sectors and the developments as regards trade

		<i>flows and the embedded emissions of those goods on the global market.</i> • <i>Where the report concludes that there is a carbon leakage risk for goods produced in the EU for export to third countries that do not apply the EU ETS or a similar carbon pricing mechanism, the Commission shall, where appropriate, present a legislative proposal to address that carbon leakage risk in a manner that is compliant with WTO rules and takes into account the decarbonisation of installations in the EU.</i>
<i>Before 1 January 2028, and every two years thereafter</i>	<i>Report to the Parliament and the Council</i>	<i>a) An assessment of the impact of the CBAM on:</i> <i>1. carbon leakage, including in relation to exports,</i> <i>2. the sectors covered;</i> <i>3. internal market, economic and territorial impact throughout the EU;</i> <i>4. inflation and the price of commodities;</i> <i>5. the effect on industries using goods in Annex I;</i> <i>6. international trade, including resource shuffling; and</i> <i>7. on least developed countries.</i> <i>b) An assessment of:</i> <i>1. the governance system, including an assessment of the implementation;</i> <i>2. and administration of the authorisation of CBAM declarants by</i> <i>3. different Member States;</i> <i>4. the scope of the Regulation;</i> <i>5. circumvention practices; and</i> <i>6. the application of penalties in Member States.</i> <i>c) Results of investigations and penalties applied.</i> <i>d) Aggregated information on the emissions intensity per country of origin for the different products listed in Annex I.</i>