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Blue hydrogen emerging as a long-term enabler of green hydrogen

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Executive Summary

Carbon-free or green hydrogen has seen considerable investment and an even larger project pipeline in recent years. It remains seen as a core part of the Energy Transition given its expected role as a fuel that can help decarbonize some hard-to-abate sectors such as green steel and fertilizers, and is also seen as a potential energy storage solution for the power sector. However, recent years have seen a slowing in the energy transition, questioning green hydrogen's future. And an increasing number of projects envision hydrogen as an end-point, but in the near term will use more tangible fuels such as natural gas or blue hydrogen (hydrogen from natural gas with carbon capture). This raises questions about the future of green hydrogen. Furthermore, the new global trade environment, with increased tariffs and other protectionist measures, has raised questions about how green hydrogen, ammonia, and methanol will be impacted. We address these issues in this paper.

- ✔ **Use of blue hydrogen and natural gas is positive for the development of green hydrogen in the long-term.** Some projects will initially use gas or blue hydrogen, opening up the question about whether they will ever progress to green hydrogen. But we see these projects as a positive for green hydrogen development. They allow projects to be built and either create hydrogen supply that can later be replaced with green hydrogen supply, or demand that can later be replaced with green hydrogen demand. Most importantly, the current certainty around supply of natural gas and hydrogen has allowed these projects to go ahead today, where it would be much more challenging for many purely green hydrogen projects to go ahead given high green hydrogen costs.

- ✔ **The project pipeline for hydrogen projects remains strong.** While some projects will start out as blue hydrogen- or gas-fueled, with green hydrogen to come later, the project pipeline remains strong. And this is true across many industries. Green steel development is strongest in Europe, the Middle East, and North Africa but activity is certainly present elsewhere including the United States and China. And the pipeline for both green methanol and ammonia projects – including those initially utilizing blue hydrogen – is also strong. We have not seen meaningful changes to the pipeline in terms of cancellations, though a large pre-FID project list could prove to be more challenged than 2-3 years ago.

- ✔ **Tariffs are unlikely to substantially impact green hydrogen development.** The current tariff/trade war environment is highly uncertain, and we expect tariffs to ease over time. Even if they did persist into the longer term, it is unlikely that there would be major impacts on the prospects for green hydrogen. Green steel projects in the United States will mostly be for domestic consumption so are unlikely to be impacted by tariffs. The US is a net exporter of methanol so would only be at risk of counter-tariffs. Of course, if tariffs and the current trade war cause a global recession then all commodities are vulnerable, and this would slow green hydrogen development.

- ✔ **The long-term time-frame for green hydrogen is unclear, but the development of hydrogen as a globally traded market is likely.** Projects that utilize blue hydrogen, or utilize natural gas en route to green hydrogen will help to create global demand and supply for hydrogen. Then as green hydrogen becomes cheaper – and there are clear pathways regarding how this will happen – it will be able to step in and replace other hydrogen supply.

Chapter 1: Introduction

Hydrogen produced in carbon-free ways (which has many names, including "carbon-free hydrogen" and "green hydrogen"), along with its related commodities green ammonia and green methanol, are envisioned as fuels that can be used to decarbonize many sectors that have traditionally been viewed as "hard-to-abate", including steel, fertilizers, and marine transportation, while also being seen as an energy storage solution – something potentially highly useful given questions around availability of the raw materials for utility scale batteries and electric vehicles, not to mention likely challenges in the future of copper availability.

However, the past two years have seen a deceleration in the decarbonization agenda and a slowing of the energy transition. This is most notable in the United States, but has also been a feature globally as countries wrestle with challenges around electric reliability and high power prices for consumers and industry. With green hydrogen still expensive, questions are being asked about how quickly it will deploy, and if it even has a chance of a widespread future.

Furthermore, there has been an increase in projects that envision green hydrogen in their future, but for now are using higher carbon intensity products such as blue hydrogen – hydrogen produced from natural gas with carbon capture – or natural gas itself. We are sometimes asked if these plans to ultimately move to green hydrogen are real, or if they are a way to greenwash projects that may simply remain gas or blue hydrogen fueled.

Given these questions, we have put together this to address some of the challenges facing hydrogen in its various industries. It is a follow-up to our 2024 paper "*Dispelling the myths around hydrogen*". We conclude that while hydrogen certainly has meaningful issues, activity and investment remain strong and have considerable momentum. Pathways to cheaper hydrogen remain clear, and it remains the most viable path to decarbonization in many sectors.

An overview of the hydrogen sector and its recent challenges

The global energy system has consistently evolved over time, as new fuels enter the market replacing existing incumbents. This has typically been due to advancements in technology, efficiency, ease of deployment, or reduction of byproducts (such as carbon). It generally requires either favorable economics or policy support. An example of this is growth of renewable energy sources since the early 1990s to become an integral part of the world's energy supply.

After decades of policy support, renewables are now mature enough to compete with fossil fuels on cost competitiveness, ease of deployment, and in many cases are preferred for new energy capacity and power generation. In the same way, we see clear pathways for green hydrogen costs to fall significantly, such as through much larger electrolyzers and a transition to lower cost raw materials. For full details, see our 2024 hydrogen whitepaper.

This trend is illustrated in the International Energy Agency's (IEA) latest global energy review which states that for 2024, 80% of the growth in global electricity generation was provided by renewables and nuclear power.[1] Also regarding actual power generated, renewables alone accounted for 32% of global electricity. It was also the 22nd consecutive year that renewable installations hit record levels. This was also reflected in the United States, where electricity generated from utility-scale solar and wind increased by 32% and 7.7% from 2023 levels, respectively.[2]

Accordingly, with climate concerns coming to the fore, there has been a concerted effort over the last few years to extend the climate benefits of renewables into other economic sectors. Hydrogen is at the core of this process. It is envisioned as an energy carrier and storage solution, and also as having chemical uses such as a reductant in iron steelmaking. As such it has the potential to decarbonize a variety of sectors including refining, fertilizers, chemicals, power generation, and steel.

However, in contrast to solar and wind that have had decades to develop and mature, hydrogen has entered a market with relatively near-term carbon goals, carbon pricing in some markets, and pressure to help rapid decarbonization. Consequently, the reality is setting in that the scale of change required for hydrogen adoption – particularly hydrogen from renewables – may not be feasible in the desired timeline. To illustrate this, producing 10 million tonnes of renewable-based hydrogen (which is the EU target for 2030) is estimated to require around 550 terawatt hours of dedicated electricity, which corresponds to more than three quarters of the electricity produced by solar and wind in 2023 in the EU.[3,4] And this is before consideration of the transmission/distribution infrastructure and regulatory permitting required. Such levels of scale and the investments required would in turn likely result in high product prices that could threaten overall growth and adoption.

Furthermore, 2025 has begun with uncertainty regarding the levels of political support for renewable energy projects, notably in the United States where the future of government funding from prior climate laws remains to be determined. This has included pauses in the disbursements of funds by the Environmental Protection Agency (EPA),[5] as well as a stop work order issued to Norwegian energy giant, Equinor, regarding its 810 MW "Empire Wind 1" offshore wind project in New York which was expected to begin operations in 2027. Also, it is to be seen what (if any) effects would result from the tariffs announced by announced by the administration, or reciprocal tariffs announced by trade partners of the US.

And aside from these challenges, hydrogen has had a lingering problem for a number of years: suppliers want demand certainty in the form of long-term offtake agreements before committing to projects, while the demand side wants long-term supply certainty.

1 "Global Energy Review 2025", International Energy Agency (IEA), 2025.

2 "2024 State of the Markets", Federal Energy Regulatory Commission (FERC). 2025.

3 "European hydrogen markets: 2024 Market Monitoring Report", EU Agency for the Cooperation of Energy Regulators (ACER). November 2024

4 Electricity produced from wind and solar in 2023 was 469 TWh and 200 TWh, respectively

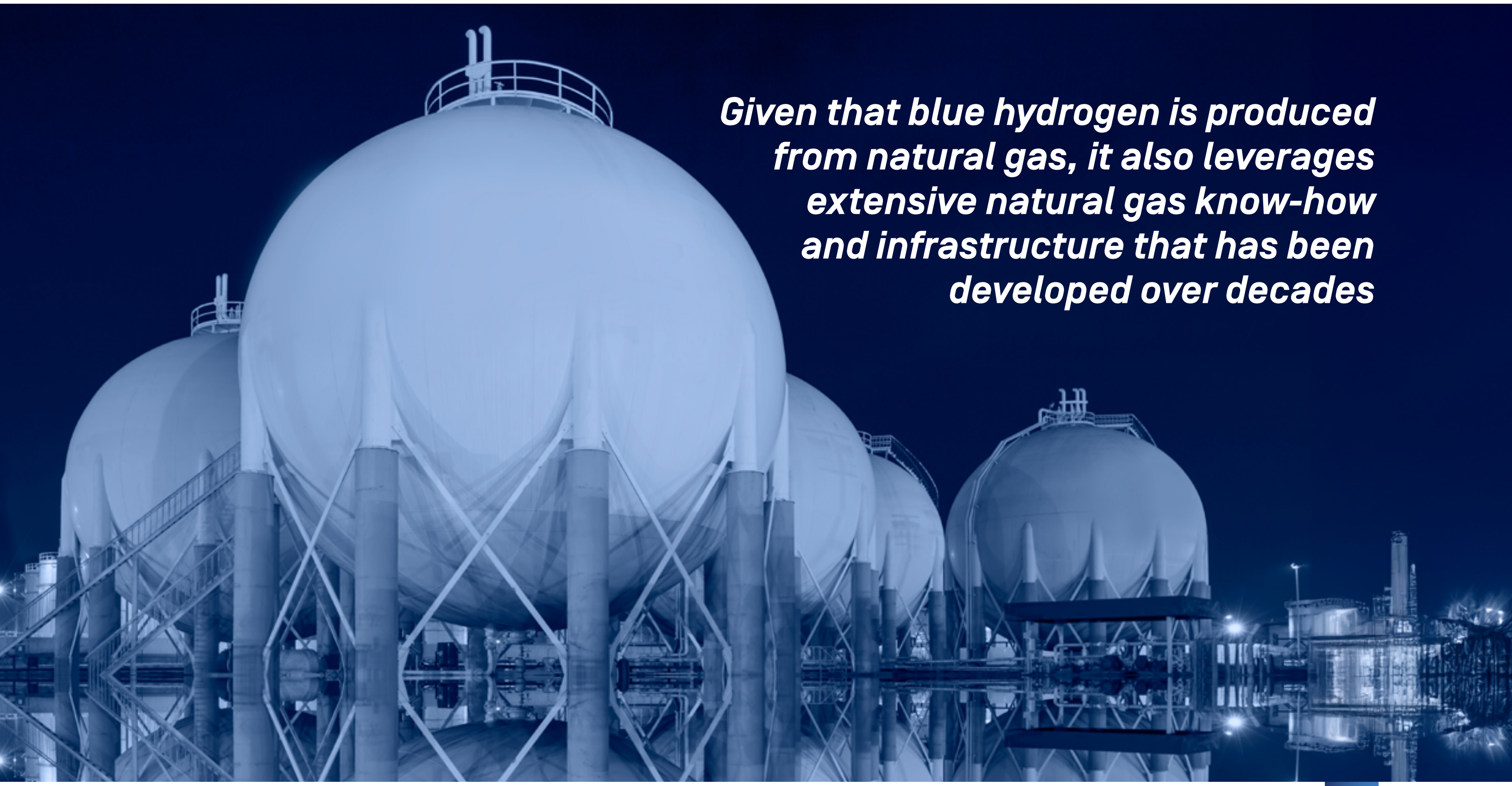
5 "Biden Climate Funds Create Legal Storm for Trump Administration", The Wall Street Journal. 2025.

This chicken-and-egg situation has challenged new hydrogen demand and supply.

Nevertheless, despite these challenges, the hydrogen sector is still growing – albeit through an unexpected route: fossil gas-derived hydrogen with carbon capture, commonly termed "blue hydrogen", which primarily comes from natural gas. Blue hydrogen is proving to be the bridge from the present to the desired future state. With advancements in carbon capture technologies, blue hydrogen is showing the potential to contribute to significant carbon emission reductions, while providing the cost competitiveness needed to set up long-term certainty required to stimulate investments in demand-side sectors.

Given that blue hydrogen is produced from natural gas, it also leverages extensive natural gas know-how and infrastructure that has been developed over decades, such as the operation at scale of natural gas reformers (vs electrolyzers), subsurface geology and well operations for carbon sequestration, and the repurposing of existing gas pipelines and storage infrastructure. Outside of technological reasons, blue hydrogen provides commercial advantages to reduce uncertainty and de-risk investments needed to develop hydrogen demand, which includes providing arbitrage opportunities for producers and market players, as well as substantially reducing the risk of creating stranded assets.

In this paper, we closely examine the evolution of the hydrogen system to the current state, headwinds and opportunities present in the market, and we highlight how the journey to green hydrogen is increasingly being enabled through blue hydrogen. In addition to hydrogen use itself, other hydrogen-enabled sectors of green steel, ammonia and methanol are also discussed.



Chapter 2: Hydrogen

Hydrogen momentum over the last few years

The last few years have seen significant build-up in momentum for hydrogen to be a staple of the global energy system. This was evidenced by the countries putting forth their visions in official national hydrogen strategies, and the introduction of supportive policy and legislation that included binding national and sectoral targets, infrastructure support, research and development investments, dedicated financing entities and price support mechanisms such as grants, subsidies, tax incentives, contract-for-difference systems etc. All of this was aimed at incentivizing both demand and supply, as well as incentivizing the value-chain components necessary for the required scale-up of the sector.

Accordingly, this momentum was reflected in the European Union and in the United States, which made significant steps, albeit via different paths, to incentivize a hydrogen future. In Europe, this primarily took the form of revised legislative targets to increase the share of renewable energy and low-carbon hydrogen consumed in the Union, alongside targeted policy and financial support for projects of designated importance.

This was established in Revised Renewable Energy Directive (commonly called RED III), regulations that define “clean hydrogen” (so-called renewable fuels of non-biological origin or RFNBO) and specify its calculation methodology, and regulations on gas operators and market availability for hydrogen. Thus, providing a comprehensive legal framework for the establishment of the hydrogen sector.

> “*The United States, on the other hand, focused on financial incentives to encourage private sector investment in hydrogen development.*

The United States, on the other hand, focused on financial incentives to encourage private sector investment in hydrogen development. The 2022 Inflation Reduction Act (IRA) was a key part of this, establishing several tax credits that aim to promote renewable and clean energy technologies. With respect to hydrogen, these are primarily the Section 45V Clean Hydrogen Tax Credit and the Section 45Q Carbon Sequestration Tax Credit.

Furthermore, in 2023, the Department of Energy launched the Regional Clean Hydrogen Hubs initiative, which sought to create 7 industrial hydrogen hubs across the US - integrated networks of infrastructure to support hydrogen production, storage, delivery and end-use. The initiative, allocated $7 billion from the 2021 Infrastructure Investment and Jobs Act (IIJA), aimed to catalyse $50 billion in private investment, had an annual production target of 3 million metric tons (MMT) of hydrogen (one-third of US’ 10 MMT 2030 hydrogen production target)[6].

6 For details on the US Regional Clean Hydrogen Hubs initiative, see our OPIS whitepaper Dispelling Myths around Hydrogen (2024)

Figure 1: US Clean Hydrogen Regional Hubs

Source: US Department of Energy (US DOE) Office of Clean Energy Demonstrations

Evolving headwinds in the US: uncertainty in hydrogen credits and funding

The year 2025 began with policy measures that have introduced varying levels of uncertainty in the future of the hydrogen development landscape. Most notably, the January 2025 Executive Order, "Unleashing American Energy", mandated all federal agencies to pause "the disbursement of funds appropriated through the IRA or the IIJA". The order specifies that the pause is for a period of 90 days and that any subsequent disbursement of funds shall be in accordance with the new policy position of the United States; this position, specified in Section 2 of the Executive Order, contains several instructions, such as the encouragement of fossil-fuel exploration, amongst others.

It should be noted that the IRA and IIJA laws contain fund appropriations for a plethora of industrial sectors beyond hydrogen, such as credits for solar and wind electricity generation, credits for manufacturing value chains (for certain clean technology), electric vehicle purchase credits, carbon sequestration and direct air capture, and several clean fuels that include sustainable aviation fuels, bio and renewable diesel, hydrogen etc. Nonetheless, while the pause is not "hydrogen-specific", the hydrogen sector is likely to be affected by the potential futures of the IRA and IIJA.

Accordingly, there is much anticipation about the state of the hydrogen tax credits and the regional hydrogen hubs. Regarding the status of money that has already been spent or allocated, Republican Senator Shelley Moore Capito stated her belief (regarding the West Virginia-related hydrogen hub) that the executive order would not affect "money that has been already obligated".[7] Additionally, there are concerns about the potential for repeals by Congress, and on the issuance of new rules by the Internal Revenue Service on the interpretation of the tax credits, which have had a lot of debate on the "three pillars" of additionality, time matching and geographic correlation (needed to claim highest credit amounts).[8]

Nevertheless, while uncertain congressional outcomes and legal interpretations (such as arguing the difference between "appropriated" vs "obligated" vs "conditional" funds) will most likely cause a period of slowdown for hydrogen development, it must be noted that hydrogen (among other energy technologies) has seen bipartisan political support across the United States. Over 15 Republican Representatives have twice in the last 6 months expressed their support for IRA energy tax credits, referencing that the credits had "spurred innovation, investment and good jobs in their districts", and urging the prioritization of "business and market certainty" as investments and project development have already begun.[9,10]

Likewise, a bipartisan group of California lawmakers have called on the administration to preserve funds for California's Alliance for Renewable Clean Hydrogen Energy Systems ("ARCHES"), the state's prospective regional hydrogen hub, with a letter signed by 47 of the 52 state representatives, including 4 Republicans. This hub has been awarded $1.2 billion in federal funds;[11] projects reported to be at risk include California Resources Corps'. $2 billion carbon capture and sequestration project, Hydrostor Inc.'s $1.5 billion Willow Rock Energy Storage Center, National Cement Co. of California's $1 billion Lebec Net Zero Project and Pacific Steel Group's $600 million Mojave Micro Mill.

Evolving headwinds in Europe and growing prominence of blue H2

The European Union has set ambitious targets for hydrogen to become a mainstay of its future energy system. As established in the 2022 RePowerEU strategy, the union targets 20 million tonnes of renewable hydrogen in its energy mix by 2030, involving the production of 10 million tonnes and the importing of the other 10 million tonnes. Several legislative & policy pieces have been released to guide hydrogen adoption. Most notably, the 2023 Delegated Acts define "renewable hydrogen" as being produced with renewable electricity, have a carbon intensity below a certain threshold, and satisfying conditions of additionality, time matching and geographical correlation. In this way they qualify as renewable fuels of non-biological origin (RFNBOs).

7 "After presidential orders, Capito is confident that federal support for W.Va. projects will be stable", Metro News – The Voice of West Virginia. January 2025.

8 Final rules for the Clean Hydrogen Production Credit were issued by the Internal Revenue Service (IRS), during the Biden administration on January 03, 2025, and can be found here

9 "21 House Republicans oppose cutting clean energy credits to pay for tax cuts", Utility Dive. March 2025

10 "Future of IRA, shape of permitting reform hinge on upcoming election, experts say", Utility Dive. October 2024

11 "LA Times: California lawmakers urge Trump to spare state's hydrogen energy project". April 2025.

To complement the targets and ambition, and incentivize uptake and demand-sides, mandates were introduced in RED III that specify amounts of hydrogen that must be utilized in the energy system; the largest being in the industrial sector, for which 42% of all hydrogen utilized by 2030, must be RFNBO hydrogen.[12] Other sector targets include an ambition that 1.2% of maritime fuel is from hydrogen, as well as a goal for hydrogen-derived sustainable aviation fuel (SAF) – 1.2% of all SAF by 2030. Together with adjacent measures such as increasing the efficacy of the EU Emissions Trading Scheme (EU ETS) and funding schemes, these mandates were expected to provide the regulatory certainty required for business investment in the sector.

However, while the RFNBO targets and ambition are widely supported, the reality has become clear that there are several headwinds. These challenges primarily concern the potential for low-cost production, on the supply-side, which would provide the necessary signals and certainty for investment and long-term offtake by demand sectors. Contributing factors to this have included high energy prices in the union, global macroeconomic trends that have raised inflation and cost of capital, long manufacturing lead-times and anticipated reductions in equipment and capital costs (e.g., electrolyzers) that have not materialized.

There are additional challenges for the nascent renewable hydrogen sector such as establishing the required infrastructure necessary to enable offtake at scale. This includes transmission and distribution pipelines for transport from production to demand centres, and given the importance of imports, the need for infrastructure at ports for loading/offloading, storage and cracking facilities needed for reconversion of hydrogen derivatives (e.g., ammonia); incremental to all these are timelines for permitting and approvals.

Because of this, there is a risk that adoption of renewable hydrogen poses not only risks to the scale-up of the sector, but could also lead to loss of industrial competitiveness to foreign suppliers – especially for those in countries with less stringent mandates for hydrogen production. The need to keep the European Union's industry competitive has been stressed by key industry stakeholders in the steel,[13] chemicals[14] and fertilizer industrial sectors,[15] which are especially strategic industries for food security and regional autonomy.

12 Article 12 of Article 1 "Amendments to Directive (EU) 2018/2001", EU Directive 2023/2413

13 "Implementation of RFNBOs targets in industry: EUROFER policy recommendations to national governments", The European Steel Association (Eurofer). March 2024

14 "Cefic position on the Commission proposal amending the Renewable Energies Directive (RED III)", European Chemical Industry Council (Cefic). October 2021

15 "Yara's recommendations for the 2024-2029 European mandate: Ensuring success by moving from ambition to action", Yara. 2024

Could blue – and even grey – hydrogen be an enabler of green hydrogen development?

Regulatory developments in Europe

The prior section highlights many of the challenges facing green hydrogen. In this section we highlight how "blue hydrogen" is emerging as a solution to ameliorate those headwinds and is increasingly being seen as complementary to enabling the long-term scale up of RFNBOs. This is especially true in the short-to-medium-term where it can help enable competitive delivery of large hydrogen volumes and provide structure to upstream and downstream value chain components. This is due to the fact that blue hydrogen has lower production costs and can leverage existing infrastructure (facilities, pipelines, storage etc.). This in turn helps provide certainty for uptake at scale, while allowing time for renewable hydrogen infrastructure to develop and ensuring that when it does there will be a readily accessible market.

Let's put this in context: EU hydrogen demand was ~7.3 million tonnes (MT) in 2023,[16] which compared to the 2030 target of 20MT, would indicate the need for substantial growth. However, several analyses show that RED III and related policies are only likely to drive total 2030 hydrogen demand growth in the range of ~1.5-4 MT.[17] This includes estimates of 1.6 MT by the IEA,[18] of 2-4 MT by ACER[19] and 1.85 MT by Hydrogen Europe.[20] While it should be noted that the analyses differ in boundaries/sectors and hydrogen classifications considered, the message is clear that achieving the desired scale up will require contributions from non-RFNBO hydrogen.

Official recognition for blue hydrogen's role in the EU was provided in July 2024 within the Hydrogen and Gas Market Directive, which sets forth a legal framework for the adoption of blue hydrogen (now officially termed "low-carbon hydrogen"). Directive 2024/1788 notes that "renewable hydrogen production is not likely to be scaled up fast enough to meet the expected growth in demand for hydrogen in the Union" and that "low-carbon hydrogen may play a role in the energy transition in line with the Union's climate targets, particularly in the short and medium-term". The European Commission is working to provide a Delegated Regulation to formally define what qualifies as "low-carbon hydrogen", and also its carbon intensity calculation procedure (as was done for RFNBOs). Public consultation took place in October 2024 and the EU Commission is required to adopt the final policy position by August 2025. EU countries have until August 2026 to transpose the new rules into national law.

16 European Hydrogen Observatory, Hydrogen Demand. April 2025

17 "Challenges and Opportunities Posed by the EU's 42 Percent Renewable Hydrogen Target by 2030", Oxford Institute for Energy Studies. March 2025

18 "Northwest European Hydrogen Monitor 2024", International Energy Agency (IEA). April 2024

19 "European hydrogen markets: 2024 Market Monitoring Report", EU Agency for the Cooperation of Energy Regulators (ACER). November 2024

20 "Clean Hydrogen Monitor 2024", Hydrogen Europe. November 2024

Outside of the European Union level, corroborative developments are being seen at the national level as well, with blue hydrogen (and natural gas) becoming entrenched in national policy. This perspective comes through in the April 2025 agreement put forth by Germany's new coalition government (Christian Democratic Union and Social Democratic Party); which while maintaining climate goals of climate neutrality by 2045 and phasing out coal-fired power generation by 2038, also presents a strategic shift towards affordability, cost efficiency and security of supply.

Thus, in addition to renewable energy, the coalition agreement also emphasizes gas-fired power plants, hydrogen from various sources and carbon capture, all underpinned by a market-driven approach and transparent and predictable policies. The importance of pipeline infrastructure, the Hydrogen Core Network is also highlighted – the network is mandated to connect industrial centres throughout Germany. Also, a legislative package for carbon storage and use is to be enacted promptly and their construction is to be of paramount public interest.

Project developments in the United States

Despite the headwinds facing the sector, there continues to be impressive progress being made for new blue hydrogen projects. Most recently, in April 2025, CF Industries announced a positive final investment decisions (FID) on a $4 billion blue ammonia facility to be constructed at CF Industries' Blue Point Complex in Ascension Parish, Louisiana, which would be one of the largest facilities globally given its nameplate production capacity of 1.4 million tonnes per year. This shows that even with the seeming slowdown in projects moving through the announcement-to-FID pipeline, investments can be made once market conditions are favorable. This blue ammonia project was first announced in 2022 and at the time, FID was expected to be taken by 2023.

This CF Industries project highlights the impact of governments' demand-side support for the hydrogen sector. The project is an export-opportunity, including sending ammonia to the Japanese market, and the Japanese government's 15-year contract-for-difference (CfD) price support mechanism, which enables cost competitiveness and long-term certainty needed for investment, would no doubt have been a significant factor driving the positive decision. The project offtaker, Japanese utility JERA, is expected to use the blue ammonia product for co-firing with coal, for power generation.

Concurrently, the project's carbon capture and sequestration (CCS) will be provided by 1PointFive – Occidental Petroleum's carbon capture firm – on a 25-year agreement, and it has been stated that the project is expected to benefit from the IRA's Section 45Q Carbon Sequestration Tax Credit. And the project is a joint venture of both supply and demand-side players, being owned by CF Industries (40%), JERA (35%), and Japan's largest ammonia importer, Mitsui (25%). Low-carbon ammonia production is expected to begin in 2029.

Carbon capture in turn is enabling Blue Hydrogen

The Blue Point project is an example of a broader theme, where CCS is enabling Blue Hydrogen, and is also seeing rapid development. Regardless of the source of carbon emissions, as capture technologies improve and as CO_2 pipeline and injection infrastructure get deployed, CCS costs will fall and make its overall adoption easier – including for blue hydrogen facilities. Notably, a lot of the CCS projects are being advanced by conventional fossil companies such as Exxon Mobil and Occidental Petroleum.

Some noteworthy recent progress includes:

- ✔ Occidental (through subsidiary 1PointFive) in April 2025, securing the first-ever Class VI permits issued by the U.S. Environmental Protection Agency for sequestering CO_2 from direct air capture (DAC), for its Stratos DAC facility in Texas. The project, with a capacity of 500,000 tonnes CO_2 per year is reportedly 70% complete and is expected online in 2025.21
- ✔ Occidental, in 2023, announced plans to invest in 3 CO_2 sequestration hubs and 70 DAC facilities that would be online by 2025 and 2035, respectively.
- ✔ Exxon Mobil in April 2025 announced an agreement with Calpine Corporation (the nation's largest producer of electricity from natural gas) to transport and sequester up to 2 million tonnes of CO_2 per year from Calpine's Baytown Energy Center, a cogeneration facility near Houston. This agreement reportedly brings Exxon Mobil's total CO_2 under contract to 16 million tonnes per year.[22]

Project developments in Europe

Similarly in Europe, concrete steps are being made for the deployment of blue hydrogen (and natural gas) to support climate and affordability targets. In Germany, developments are being seen in the power generation sector (where the new government's coalition agreement aims to expand gas-fired power capacity by 20 GW by 2030).

Recently, in April 2025, energy company EnBW commissioned one of the first hydrogen-capable gas-fired power plants in Germany. However, while the long-term goal is to use green hydrogen, this is not expected until the 2030s when it is expected that green hydrogen would be more readily available. In the meantime, the plant will utilize natural gas for power generation. EnBW is utilizing this approach in their strategy to phase out existing coal generation. There are 3 such projects currently underway, with a planned capacity of 1.5 GW and an expected cost of 1.6 billion euros.

Significant strides are also being made in European CCS deployments. As is the case in the US, there is the same trend that supportive government policies and incentives are helping to make the case for investments by the private sector. Denmark and Norway have over the last 5 years, particularly through the Danish CCS Fund and the Norwegian Longship Initiative, advanced the business case for carbon sequestration in the North Sea. Consequently, this has led to several recent positive FIDs in the Nordics and the United Kingdom.

21 "Stratos, Occidental's First DAC Plant Is 70% Complete", Carbon Herald/ March 2024

22 "Calpine, ExxonMobil Sign CO_2 Transportation and Storage Agreement for Power Generation Project", Business Wire. April 2025.

The Northern Lights CCS Project (a joint venture between Equinor, Shell & Total), announced in April 2025 a positive FID for phase 2 of the project. This will expand the CO_2 storage and transport capacity from 1.5 to 5 million tonnes per year. Phase 1 takes carbon emissions from cement and power plants in Norway and Denmark, and is expected to begin in 2025, while phase 2 is scheduled for 2028. Phase 2 is expected to include carbon emissions from Yara's ammonia plant in the Netherlands and Stockholm Exergi's biomass power plant in Sweden.

Across the North Sea, December 2024 saw 2 positive FID announcements for the United Kingdom's first ever CCS projects: the Northern Endurance Partnership (NEP) and Net Zero Teesside Power (NZT Power). NEP is a joint venture between Equinor (45%), BP (45%) and Total Energies (10%), while NZT is a JV between BP (75%) and Equinor (25%). Both projects feature gathering networks for carbon emissions from adjacent industries, with common injection and sequestration in the North Sea (Figure 2).

Figure 2: Northern Endurance Partnership (NEP) and Net Zero Teesside Power (NZT Power) projects

Source: Equinor

The Humber project (NEP) illustrates the potential for clusters of low-carbon industries. It consists of existing industries in the area, and alongside these would be Equinor's blue hydrogen H2H Saltend facility, and a 1.2 GW gas power plant providing power and steam for its neighbors. The Teesside project would include a new 740 MW gas power plant. Construction is expected to begin in 2025, with start-up targeted for 2028; collectively, up to 4 million tonnes of carbon emissions are expected to be sequestered annually.

Infrastructure developments in Europe

Within Europe, development of hydrogen infrastructure is seen as a highly important policy driver, with the aim of transporting hydrogen from supply centers (both ports and local production) to demand centers within and across the various member states. On the continental level, this is reflected by the European Hydrogen Backbone (EHB), which is an initiative consisting of 33 transmission system operators who are jointly committed to the development of an integrated, European hydrogen network. A key component of this initiative is repurposing existing gas pipelines to transport hydrogen; collectively, EHB projects aim to repurpose over 31,000 kilometers of pipelines by 2030.

In Germany, progress is being made on the Hydrogen Core Network – the national plan to connect production, import, storage and consumption sites around the country (Figure 3). A core component is the "Flow – making hydrogen happen" program, which is repurposing 400 kilometres of gas pipelines and is scheduled for completion by the end of 2025. To avoid delays with sourcing green hydrogen, German gas grid operator, Gascade, is using conventional fossil-derived grey hydrogen to fill the first section of the pipeline network under construction. However, in the longer term it wants to transport 100% green hydrogen. Per the company, "we as a network operator are providing the necessary infrastructure in advance, but we are also creating planning security for the other stages of the value chain for their market launch".

Figure 3: Germany's Hydrogen Core Network, highlighting the "Flow - making hydrogen happen" pipeline infrastructure

Source: Gascade

To support market operational certainty, Germany has put forth an annual network fee of 25 euros per kilowatt-hour per hour to be applied to all entry and exit points of the Hydrogen Core Network. In addition, to help network operators recover the upfront investment costs, the government has set up an “amortization account”, which will make up the difference between the investment costs and the expected low initial pipeline revenues.

To Germany’s west, Belgium’s transmission system operator, Fluxys, has announced the start of construction on the nation’s hydrogen grid. The first stage will link the port areas of Antwerp and Ghent, and it is expected to be ready for market operations in 2026.

Progress in green hydrogen development: chugging along against the headwinds

Despite the headwinds and growing role of blue hydrogen and natural gas, it is critical to highlight that significant progress is still being made in green hydrogen development, albeit at a slower rate than had been initially expected. This is reflected by continuing government support for high-maturity projects and growing private investments and offtake agreements.

Across Europe, state funding continues a trend of supporting projects. Germany, in March 2025, obtained EU state aid approval for 5 billion euros for its carbon contract-for-difference (C-CfD) scheme; in 2024, it obtained approval for 4 billion euros and over 1 billion went to 5 companies’ hydrogen initiatives. The UK in April 2025 announced a shortlist of 27 projects, at a combined 765MW, for the second round of its Hydrogen Allocation Round (HAR 2).[23] HAR is a CfD scheme that guarantees green hydrogen price, relative to the fossil-derived (grey hydrogen) equivalent. The first round (HAR 1) had 11 successful projects (125 MW total), that are expected to begin operations in 2026; the 11 projects had an average strike price of £241 per MWh (£175 per MWh in 2012 prices). Due south, the Spanish government, in April 2025, published a list of seven award winners as part of the H2 Valleys program; estimated at 1.2 billion euros, the awarded projects represent a significant capacity of over 2.2 GW of green hydrogen capacity.

On the project front, there have been encouraging announcements for green hydrogen in the first half of 2025. This includes commissioning and operations for the 2 largest new green hydrogen facilities in Europe. BASF commissioned a 54 MW electrolyzer to produce 8,000 tonnes of green hydrogen, which would be utilized for ammonia and methanol in Germany. Also, European Energy commissioned a 52.5 MW power-to-X facility in Denmark with a design capacity of 42,000 tonnes per year of e-methanol (green methanol). The product is expected to supply aviation and shipping fuel needs in the EU.

Sentiment around green hydrogen demand and long-term offtake recently got a major boost when TotalEnergies and Germany utility RWE announced a legally binding agreement for a 30,000 tonne per year green hydrogen facility in March 2025. This is the largest green hydrogen quantity contracted in Germany, and TotalEnergies plans to use

23 “Hydrogen Allocation Round 2 (HAR2): shortlisted projects”, Department for Energy Security & Net Zero (DESNZ) UK Gov. April 2025.

it at its Leuna refinery. The agreement is for 15 years and will run from 2030 to 2044. The hydrogen will be produced 600 kilometres away in the town of Lingen and transported to the refinery via repurposed gas pipelines within Germany's Hydrogen Core Network. Transmission system operator, Nowega GmbH, already began filling the pipeline with hydrogen, and first transports are to begin in 2025.

Other green hydrogen initiatives are also progressing around the world. In the United States, Plug Power stated that it expects to begin construction of a $850 million liquid green hydrogen facility in Texas, which would produce 16,000 tonnes per year; this project is reportedly highly dependent on prior funding agreements with the US DOE.

There is also a growth in the international collaborations being announced, especially between regions poised to be core global hydrogen supply areas and primarily hydrogen consumption regions. Two such recent announcements include a cooperation agreement signed by Egypt and France to develop, finance and construct a comprehensive green hydrogen facility in Egypt. The main parties involved are France's EDF Renewables and Egyptian firm Zero Waste. The plant is envisioned to export 1 million tonnes of green ammonia by 2029. At the same time, Oman and the Netherlands announced their intention to create a liquefied hydrogen transport corridor that will serve as a direct export route for liquefied RFNBO-compliant hydrogen from the Port of Duqm in Oman, to the Port of Amsterdam.

Chapter 3: Green Steel

Hydrogen in steelmaking: a critical link in the decarbonization chain

Given that 7-9% of global CO_2 emissions come from the steel sector, hydrogen-based technologies are central to the steel decarbonisation agenda as they allow near-zero emissions steel production. This is particularly important where companies are subject to legal requirements to become net-zero producers, as in the EU, or must follow government guidelines on emissions, as in China. In addition, there is also growing enthusiasm for hydrogen that is based on the specifics of the steel production process and prospective challenges with global availability of raw steel materials.

The most prevalent (over 71%) and cost-efficient steelmaking process is the blast furnace - basic oxygen furnace (BF-BOF) route. BFs use coke produced from metallurgical (coking) coal as a reducing agent to produce pig iron from iron ore (emitting CO_2), while BOFs use oxygen to remove carbon and impurities from the pig iron (also emitting CO_2) to produce steel of the required chemical composition. The abundance of iron ore and coking coal have led to BF-BOF being the dominant production route; the process is also particularly suited for quality-demanding flat steel production. However, the BF-BOF is highly carbon intensive, with average emissions intensity of 2.33 tonnes of CO_2 per tonne of steel (tCO_2/ts).

The second most common steel production method is production of recycled steel using the electric arc furnaces (EAFs) route. This is the cleanest production method, with an average emissions intensity of 0.68 tCO_2/ts, and if the furnace is powered by renewable electricity, it drops to 0.2-0.4 tCO_2/ts. Unlike the BF-BOF route, EAFs rely on scrap steel rather than iron ore; however, currently there is only approximately 20% scrap available worldwide relative to global steel production needs. Impurities limit its use primarily to construction steel products, though quality issues relative to BF-BOF steel are steadily resolving over time. Because of feedstock availability, EAF expansion will be limited unless it reduces its reliance on steel scrap. And herein lies a strategic role for hydrogen in steel making.

Hydrogen can be used to produce direct reduced iron (DRI) and its compacted and transportable variant, hot briquetted iron (HBI), which is usually used to produce steel by melting it in an EAF. In the traditional DRI production process, iron oxide is reduced to iron in a shaft furnace using either coal gas or natural gas or coke oven gas. Where coal is used (mostly in India) CO_2 emissions are similar or even higher than for the BF-BOF process. Where natural gas or coke oven gas is used, however, the process is more environmentally friendly than BF-BOF steel production, with emissions below 1.4 tCO_2/ts.

However, gas in the DRI process can be replaced with hydrogen, either pure or mixed with other gases, and in doing so CO_2 emissions can be reduced close to zero, with water produced as a byproduct instead of CO_2. Emissions intensity from the various steel production routes is shown in Figure 4.

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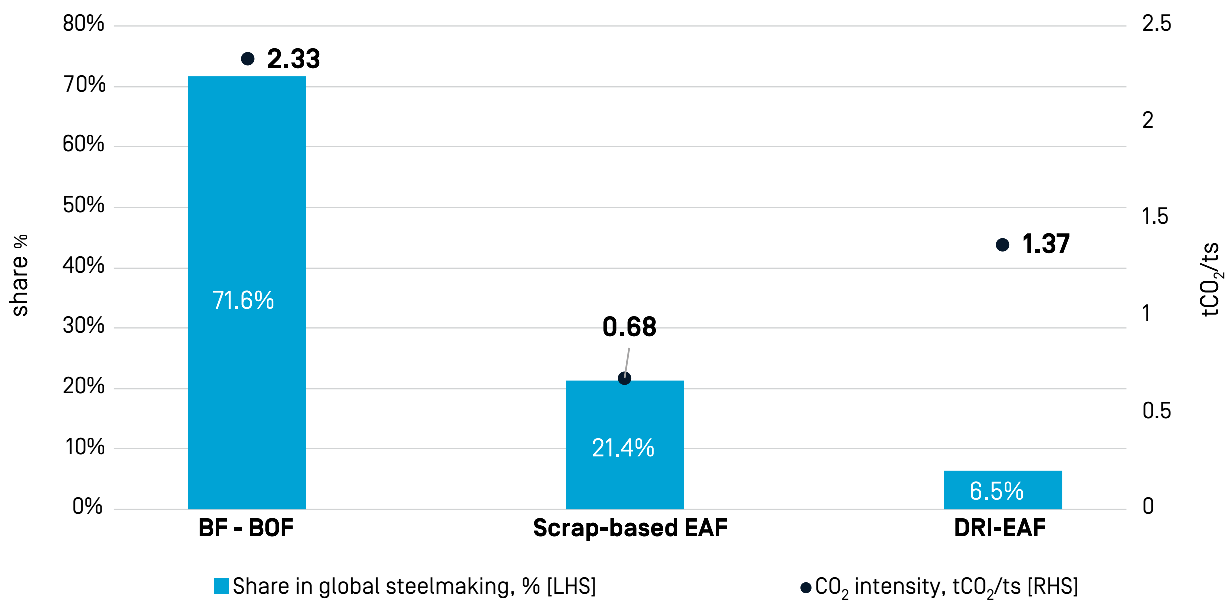
Figure 4: Main steelmaking technology routes



Source: Worldsteel, McCloskey by OPIS, A Dow Jones Company

But using hydrogen to decarbonize steel is not limited to just the DRI-EAF process. Another use is further downstream, with replacement of natural gas in rolling mill preheating furnaces. Three such projects have been identified in Europe. And one has just come online, with Ovako Hofors, a Swedish long steel and tubes producer, inaugurated a 20 MW hydrogen electrolyzer in September 2023. It generates 4,000 m^3 of fossil-free hydrogen and 2,000 m^3 of oxygen, with hydrogen now used instead of LPG for reheating steel prior to rolling.

Another way to use hydrogen is to inject it into BFs as a replacement for pulverized coal injection (PCI). Some Chinese producers, such as Sinogiant Group and Zenith Steel Group, are installing new BFs that use gases enriched with hydrogen and CO, which reduce CO_2 emissions by 5-10% compared to conventional BFs, however, this technology has the potential to achieve even greater emission cuts.

Nippon Steel, Japan's largest steel producer, has been working since 2008 on emissions reduction technologies. These focus on injecting hydrogen into BFs as a PCI replacement coupled with CO_2 capture. Demonstration tests showed a 22-43% reduction in emissions, and the company plans to launch hydrogen injections into a 4 million tonne per annum (mtpa) blast furnace at the Kimitsu site in fiscal year 2026. Ultimately, Nippon Steel aims to reduce its emissions by more than 50% through this method. According to company estimates, it would need several million tonnes of hydrogen per year for carbon-neutral steelmaking processes. This would include three facets: using hydrogen to replace PCI in BFs, hydrogen-based DRI production, and decarbonisation of on-site power generation.

Natural gas: a challenger for hydrogen, or a step towards a hydrogen steelmaking future?

What is interesting about the DRI process, is that it can be done with either natural gas, or with hydrogen, with relatively little adaptation required to switch.[24] Steelmakers have recognized this, and increasingly we are seeing projects that envision using natural gas in the near term, before switching to hydrogen later. This achieves emission reductions relative to traditional BF-BOF steel production (assuming that the gas logistics don't have heavy emissions of their own). But more importantly, it circumvents the usual concerns about hydrogen use: that it may not become cheap enough to be economically viable, and may not develop into a global market if production becomes localized to demand. By starting with natural gas, a project can switch to hydrogen if it becomes a viable fuel, or stick with natural gas if not.

To assess the role of natural gas in future green steel projects, OPIS recently examined 149 green steel projects of major steel and mining companies in Europe, Middle East and Northern Africa, Asia, and Oceania, as shown in Table 1. And it becomes apparent that while hydrogen is tracking to play a dominant role, its initial adoption is shaped by geographical factors.

24 The main difference is that using natural gas as a reductant is exothermic, with that heat used elsewhere in the process. Using hydrogen is endothermic, which means that another heat source will generally be required.

Table 1: Numbers of Hydrogen in green steel projects, by region

	ALL	EUROPE	MENA	AUSTRALIA	CHINA	INDIA	JAPAN, S. KOREA
Hydrogen production source							
On-site	23	11	2	1	6	3	0
Outsource	29	2	9	2	9	1	6
Both	2	1	1	0	0	0	0
Hydrogen colour							
Green	32	14	9	3	3	3	0
Blue	2	0	0	0	2	0	0
Brown	1	0	0	0	1	0	0
Not specified	19	0	3	0	9	1	6
Hydrogen use by technology							
DRI	40	10	12	3	9	1	5
BF and DRI	3	0	0	0	2	1	0
BF	6	0	0	0	4	1	1
Re-heating furnaces	3	3	0	0	0	0	0
Sell	1	1	0	0	0	0	0
Other	1	0	0	0	0	0	0
Likelihood of hydrogen use in the early stage of the project							
High	33	12	2	1	12	3	3
Medium	10	2	1	0	3	1	3
Low	11	0	9	2	0	0	0
Greenfield project or not							
Greenfield project	17	6	7	3	1	0	0
Brownfield project	37	8	5	0	14	4	6

More than a third, or 54, of recently examined 149 green steel projects plan to use hydrogen immediately or switch to it in the future, and 43 of these 54 projects will use hydrogen to produce DRI or HBI. However, the likelihood of hydrogen use in the early stages of DRI projects varies depending on regional specifics. In Europe, green hydrogen, often produced onsite, is planned to be used in 12 out of 14 cases. In contrast, in the Middle East and Northen Africa (MENA) region, natural gas is prioritized, and hydrogen is considered a possible option for the future.

Take Stegra's greenfield project in Boden, northern Sweden, as an example. The country benefits from a surplus of non-fossil energy sources, such as nuclear and wind power, particularly in the north. Initially, Stegra plans to build a 700 MW green hydrogen electrolyzer powered by renewable electricity, a 2.1 mtpa DRI/HBI plant, and a 2.5 mtpa EAF steel mill specializing in the production of various high-value flat steel products, with sales planned for 2026-2027. The project is now in the active construction phase and began installing electrolysis equipment in May 2025.

But when the hydrogen infrastructure or renewable electricity generation capacity is not in place, European steelmakers are considering starting DRI production with natural gas first. For example, German Thyssenkrupp plans to gradually replace one of its four BFs with a hydrogen-based DRI plant and two submerged arc furnace (SAF) smelters. Projected 2.5 mtpa DRI production, starting in 2027, will require an annual supply of around 143,000 tonnes of hydrogen, but the company recently suspended a tender for hydrogen due to high prices and is expected to launch the project running on natural gas initially.

In the oil and gas-rich MENA region, which is poised to become an HBI supply hub for European steelmakers, the initial focus for new DRI/HBI production is natural gas, with hydrogen as a future consideration but without a defined timeline. Of the 48.2 mtpa of new DRI/HBI capacity announced by MENA companies for 2027 and onwards, 39 mtpa will be hydrogen-compatible but will initially run on natural gas, 5 mtpa has no hydrogen in the announced specifications, and 4.2 mtpa hinges on a pilot project that could lead to the transition to hydrogen.

Vulcan Green Steel in Oman is a typical DRI-EAF project of the region that relies on natural gas in its initial phase. The $3-billion enterprise of India's Jindal Steel Group plans to build a green steel complex consisting of a DRI unit running on natural gas and an EAF powered by 100% renewable electricity. In its initial phase, from 2027, the plant's carbon intensity will be 0.5-0.7 tCO_2/ts, with a reduction to 0.35-0.50 tCO_2/ts when the DRI units switch to green hydrogen.

Will sufficient, affordable hydrogen become available for green steelmaking?

One view – perhaps cynical, perhaps pragmatic – is that companies embarking on hydrogen-DRI projects that start out as gas-DRI may not be genuine in their aim of ultimately moving to hydrogen. But even if this is the case, the optionality of switching to hydrogen will remain. And that switch will happen when hydrogen becomes both available, and affordable.

The Indian Ministry of Steel has sought to determine if hydrogen is affordable and available, and their conclusion is: "not yet". India has a unique challenge where it aims to achieve net-zero emissions by 2070, while its steel industry, dominated by BF-BOF and coal gas-based DRI-BOF, is expected to grow significantly in the coming years.

The Indian government plans to facilitate the green transition through green steel procurement, encouraging the use of renewable energy (solar power plants), and supporting hydrogen-based DRI and hydrogen injection in BF pilot projects. However, green hydrogen will play a limited role over the next five to six years because of its unavailability and high cost.

According to the "Greening the Steel Sector in India Roadmap and Action Plan", released by the Indian Ministry of Steel in 2024, the country's steel sector can theoretically consume up to 3.5 mtpa of green hydrogen by 2030-2031, but this may be unrealistic. The report analysed correlations between hydrogen, coking coal and natural gas prices, and **established an affordable hydrogen breakeven price of $0.48-0.88/kg** with a coking coal price in the range of $180-260/tonne for BF injections, and $0.75-2.02/kg with a natural gas price of $8-18/MMBtu for DRI production in shaft furnaces. The report concludes that when green hydrogen reaches $1/kg and natural gas is $9.5/MMBtu, the Indian steel industry could potentially consume up to 1.1 mtpa of green hydrogen, which is theoretically equivalent to around 22-23 mt of steel. However, green hydrogen is currently up to four to six times more expensive and is not available in the required volume, so these projections may appear optimistic.

Australia is another promising market for hydrogen adoption. The continent has over 58 billion tonnes of iron ore reserves, about 31% of the world's share, and is by far the leading global iron ore exporter. Additionally, unlike many other countries, it has large reserves of magnetite which can be beneficiated to high iron contents and low impurity levels needed in DRI process. And like the Middle East - Northwest Australia has abundant sunshine, allowing for high efficiency solar generation for powering electrolyzers.

Western Australia's Green Steel Opportunity report, prepared by the Minerals Research Institute of Western Australia in 2023, identified several pathways in the regional decarbonization journey:

- ✔ Green iron-ore mining using renewable energy
- ✔ Pellet production using green hydrogen
- ✔ HBI production from green pellets using natural gas or hydrogen
- ✔ Establishment of green steel production chain with renewable energy-powered EAFs

These pathways converge into two main scenarios: green HBI for export or a complete green steel production chain. Both scenarios favour the use of magnetite, and both **assume that the use of hydrogen would be viable at around $2/kg**. At this price point, the scale of the projects could be substantial.

This is illustrated by Australian mining giant Fortescue, whose over 400 mtpa Christmas Creek mine, in Pilbara region of Western Australia, is trialing green iron production. The company expects production of 1,500 tonnes of green iron in 2025 using a combination of green hydrogen DRI and an electric smelting furnace (ESF). Green hydrogen will be produced on site by two 700 kW electrolyzers (530 kg of hydrogen per day), which, together with the future ESF, will run partially on green electricity.

Looking ahead, Fortescue is considering a feasibility study in 2025 to assess the possibility of producing 1 mtpa of green iron in the Pilbara region and ultimately aims to produce 100 mtpa of green DRI/HBI in partnership with China, which would require 8 mtpa of green hydrogen, according to the company's estimates.

Tariff headwinds facing green steel adoption

A significant challenge for steelmakers is the current market uncertainty stemming from broad US tariffs and escalating global trade tensions. These tariffs are generally inflationary and therefore pose immediate risks to the green steel agenda and, by extension, the adoption of hydrogen – both of which require lower costs. OPIS also expects that the projected economic slowdown due to tariffs will reduce global steel demand, intensify competition in seaborne trade as demand contracts and protectionism rises. It will also ultimately lower global steel prices, squeezing mill margins.

In this environment, steelmakers will likely adopt a highly cautious approach towards projects requiring substantial capital and operational expenditure. This certainly does not mean a halt to the industry's transformation, and ongoing new plant construction will proceed. But projects still in planning or pilot phases are highly vulnerable to delays or temporary halts.

"Adding policy uncertainty to an industry already navigating complex climate-related regulations will hinder long-term investment decisions and slow the adoption of hydrogen.

Financing also presents a hurdle. Steelmakers have been counting on premiums for green steel relative to other equivalent steels ("green steel premiums") to partially or wholly offset the high costs of both greenfield plants and transformation of existing operations. Early adopters of these premiums included the automotive industry, which itself faces targeted US tariffs. Particularly in Europe, Japan, and South Korea, where steel mills are actively investing in hydrogen-based projects, a reduction in offtake from a key customer like the automotive sector could delay the commissioning of new green steelmaking facilities. Some help can come from governments and regulators, who can introduce and expand procurement targets for low-emission products, boosting green steel demand, but it won't fully compensate for lost demand from other sectors. And the impetus for green activities has slowed somewhat, particularly in the United States under the current administration.

Adding policy uncertainty to an industry already navigating complex climate-related regulations will hinder long-term investment decisions and slow the adoption of hydrogen. However, given the legal net zero targets in many jurisdictions, hydrogen-based technologies remain the leading solution for decarbonizing the steel sector. As long as serious decarbonization efforts remain an agenda item, hydrogen-DRI and other green steel technologies will have to come; the primary question is timing.

More than a third of green steel projects rely on the use of hydrogen, although often as future rather than immediate option. Demand is growing, and once hydrogen is available at scale and at a breakeven price, it will revolutionize the steel industry.

Chapter 4: Ammonia & Methanol

Given the increased prominence of hydrogen, there is growing momentum to couple clean hydrogen to ammonia and methanol markets; although both require hydrogen in their production, this has conventionally been through natural gas in most instances. Consequently, hydrogen is increasingly seen as a way to decarbonize ammonia and methanol, and by extension, their associated industrial sectors – primarily fertilizer and chemical production. Additionally, there are new cases emerging for ammonia and methanol as fuels (such as for power generation and transportation) and as hydrogen carriers. Likewise, ammonia and methanol are taking on new nomenclature such as "green" (from hydrogen produced with renewable electricity), "blue" (from hydrogen produced with natural gas and carbon capture) and "bio" (from biomass feedstock).

Similar to hydrogen, there are various pieces of legislation around the world that are supportive of low-carbon ammonia and methanol production and demand. In the European Union/European Economic Area (EEA), these include the EU Emission Trading System (ETS) and Carbon Border Adjustment Mechanism (CBAM), which together, add an increasing cost burden on conventional, carbon intensive ammonia and methanol, whether produced within, or exported to the EU/EEA. In the United States, the Inflation Reduction Act provides tax credits specific to clean fuels, as well as for carbon capture and hydrogen, which are financial boosts to producers of clean ammonia and methanol.

Ammonia and methanol in transportation

An area that has garnered a lot of interest in the last few years is in transportation – specifically, the use of ammonia/methanol as a fuel in maritime transport. To this end, the European Union's ETS maritime extension 2024, is supportive of low-carbon alternative fuels, as is FuelEU Maritime, which came into force this year. Both pieces of legislation, which are independent of each other, add a cost burden to conventional, CO_2-emitting fuels.

In further momentum for maritime/shipping decarbonization, in December 2024 the International Maritime Organization (IMO) approved interim guidelines, which set international safety procedures for the use of ammonia as a marine fuel. The IMO has also agreed specifications for three grades of methanol as a marine fuel: Marine Methanol Grades A, B, and C (MMA, MMB, and MMC). It uses the International Methanol Producers and Consumers Association (IMPCA) specifications as a starting point, with some properties less critical for marine and other fuel-related aspects not covered. Grade MMC allows for wider tolerances in certain characteristics compared to MMB, while MMA includes additional requirements for lubricity and cleanliness.

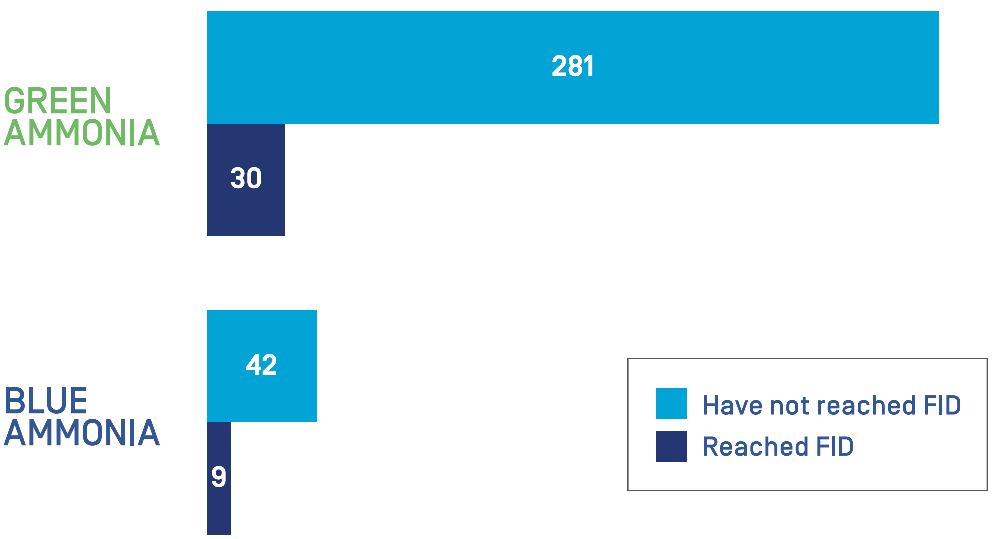
Subsequently, in April 2025, the IMO created its Net-zero Framework – a mandatory global fuel standard to phase out carbon intensive fuels and a global pricing mechanism for greenhouse gas emissions from vessels. It is expected to come into force in 2027, subject to formal IMO adoption and approvals. In terms of its development as a marine fuel, methanol is significantly ahead of ammonia, with around 100 methanol-powered ships already on the water, and off-the-shelf methanol marine engines available in both 2-stroke and 4-stroke models, manufactured by companies such as MAN, Wartsila and Rolls-Royce. In addition, over 160 ammonia dual-fuel orders and almost 500 methanol-ready vessels are currently being tracked in Chemical Market Analytics' extensive databases for delivery by 2030.

Challenges and evolving role of blue ammonia and methanol

Challenges facing renewable-based ammonia and methanol (green or e-ammonia and methanol) are similar to those associated with green hydrogen; this includes cost competitiveness with fossil fuel incumbents, and difficulties with establishing the infrastructure, value chains and markets required to support adoption at scale. However, the landscape is evolving to reflect the role of blue ammonia as the first step towards wider decarbonisation and the ammonia project landscape has evolved to reflect this.

In our analysis of the ammonia project pipeline - from project announcements to final investment decisions (FID) – it is observed that a greater percentage of blue ammonia/hydrogen projects are progressing to FID than green (Figure 5). Lower capital costs and financial risk, shorter development timescales and availability of enabling technologies at scale, are among the reasons for the difference in progress between blue vs green. That said, the number of projects progressing to FID remains low overall.

Figure 5: Low-Carbon Ammonia Projects' Status Overview



Source: Chemical Market Analytics by OPIS; Ammonia Energy Association; International Fertilizer Association; DNV; IEA.

Although more than 200 low-carbon methanol projects have been announced, very few have reached the FID stage. Reasons for this include a significantly higher production cost than for world-scale grey methanol projects; uncertainty around future carbon/fuels legislation; and a consumer unwillingness to commit to firm offtake agreements.

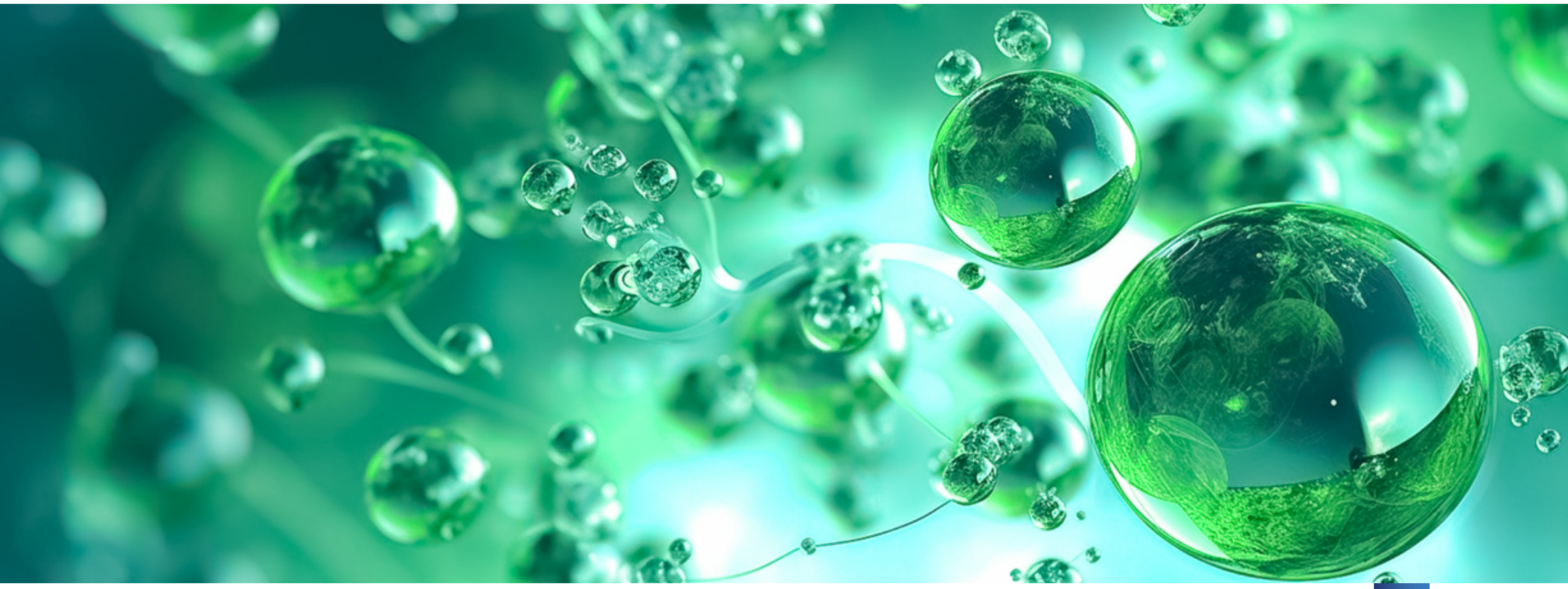
In addition to the slowdown in projects moving through the development pipeline, there has also been an overall slowdown in project announcements during the past year, while at the same time, several green projects have recently been shelved or stalled. These include Australian power generator Origin Energy pulling out of its Hunter Valley Hydrogen Hub project in New South Wales, due to financial risks and market uncertainty. The project targeted 4,700 metric tons per year (mt/yr) of green ammonia.

Concurrently, other companies have refocused low-carbon production efforts away from green, towards blue ammonia. Norwegian fertilizer major and leading ammonia trader Yara abandoned some green ammonia investment projects including HEGRA in Porsgrunn, Norway, and Haddock in Sluiskil, the Netherlands. Instead, Yara is increasing blue ammonia production in more cost-effective regions such as the United States, which it will then likely transport to the EU and other markets. Its blue projects include 1.4 million mt/yr YaREN in Texas, with Canadian energy firm Enbridge (50/50 partnership), and another 1.4 million mt/yr unit in the US Gulf with BASF; both are targeting final investment decisions (FIDs) in 2026.

Other challenges include recent cancellations such as the 50 thousand tonnes per annum (Kta) Flagship One e-methanol unit in Sweden and the 8 Kta power-to-methanol e-methanol unit in Belgium. Furthermore, development of the partially constructed 100 Kta Varennes Carbon Recycling renewable and bio-methanol plant in Quebec, Canada was halted in February 2025. This illustrates the challenge of commercializing a low-carbon methanol unit as part of a larger facility incorporating hydrogen production that carries a significant and uncertain Capex burden.

Outlook for blue and green ammonia development

Today’s juncture highlights a more considered approach to the low-carbon ammonia and methanol sectors. Geopolitical uncertainty and the refocus on fossil fuel production is seeing fewer low-carbon projects announced overall. Those ammonia projects that are progressing are more likely to be blue than green. That is not to say green ammonia



supply and demand will not emerge. Green ammonia will become the product of choice for many at a later date, as carbon penalties steadily build, costs for renewable energy and related renewable infrastructure fall and supply becomes more prevalent. Several green projects have already reached FID, including AM Green's 1 million mt/yr (first phase) Kakinada project in India and the 1.2 million t/yr Neom green ammonia project under construction in Saudi Arabia.

> ***"One critical challenge facing ammonia and methanol is that sizeable markets that are willing to pay a price premium for low-carbon ammonia and methanol are yet to be firmly established, despite the building momentum.***

Moreover, there have also been some recent challenges around blue ammonia, with LSB Industries pausing its 1.1 million mt per year JV Houston Ship Channel project because of geopolitical uncertainty, US tariff-related price rises, and slower-than-expected low-carbon ammonia demand uptake.

There is a chicken-and-egg situation in the methanol market; on the demand side, a growing number of methanol-ready ships to be delivered by 2030, yet on the supply side, very few low-carbon methanol projects are reaching FID. The market needs some of these low-carbon projects to be delivered, in order for proof of concept to be achieved, and to give confidence that sufficient volumes of low-carbon methanol can ultimately be made available for chemical consumers, as well as for fuel purchasers.

Spotlight on the importance of demand to market adoption

One critical challenge facing ammonia and methanol is that sizeable markets that are willing to pay a price premium for low-carbon ammonia and methanol are yet to be firmly established, despite the building momentum. Japan and South Korea are expected to be early adopters of low-carbon ammonia, predominantly for use in power generation. Various policies are in place to support, including a contract for difference funding scheme in Japan and a clean hydrogen power bidding market in South Korea. The first South Korean auction concluded in late Q4 2024, with the price cap set by the Korea Power Exchange considered to be unrealistic as it resulted in just one successful bid representing only 11.5% of the total target. In addition, lower cost blue ammonia, rather than green, will be co-fired under this bid.

The shortfall in this first auction highlights the challenges of pricing alternative power fuels and the lack of demand at scale for low-carbon ammonia/clean hydrogen that many suppliers had expected by now in East Asia, given that the first shipment of low-carbon ammonia to the region was five years ago from the Middle East. This was echoed by Saudi Aramco's CEO Amin Nasser in March when the firm's blue ammonia production target was revised downward from 11 million mt to 2.5 million mt by 2030. And Aramco stated that even this new lower target is dependent on an offtake agreement being reached at commercially attractive levels.[25]

25 MOTIE and the Ammonia Energy Association

Although many chemical companies have stated sustainability targets and are interested in purchasing bio-methanol or e-methanol, the most logical home for low-carbon methanol is into fuels applications, particularly into the shipping industry, driven partly by company sustainability aims, but primarily by legislation. It is for this reason that many “hypothetical” low-carbon plants in Chemical Market Analytics’ medium and long-term supply-demand balances are located near major bunkering hubs.

But the major challenge preventing consumers of low-carbon methanol, including shipping companies, is that it is currently around five times the cost of conventional grey methanol. A.P. Moller Holding and A.P. Moller-Maersk have attempted to solve this problem by setting up a subsidiary, C2X, to participate in low-carbon methanol projects in various parts of the world, not just as an offtaker but as an equity stakeholder too. As the cost of carbon and the penalties for conventional fossil fuels increase, the price gap between grey and low-carbon methanol will close, but ultimately the cost of methanol will need to come down too so it can survive without regulatory support.

Potential impact of tariffs on the sector

The United States is both an importer (around 2 million t/yr) of ammonia as well as an exporter (around 1 million t/yr). On imports, supply from Trinidad and Tobago is expected to continue flowing into the US because of intercompany relationships across US and Trinidadian industries. However, if a US duty is in place, a proportion of the volumes traditionally earmarked for the US may be redirected to other markets, such as Europe and parts of Latin America. Canadian product remains duty free into the US under USMCA.

On exports, some US ammonia does move to the EU and UK, so any reciprocal, additional tariffs may deter this and see more brought into these countries from duty-free origins such as North Africa as well as Trinidad and Tobago.

The US became a net exporter of methanol in 2021. For this reason, tariffs are more likely to impact downstream products than methanol itself. We are likely to see a restructuring of trade flows, with lower US imports from Trinidad, as volumes from this production centre are diverted to other markets such as Europe and Northeast Asian markets such as South Korea, Japan and Taiwan, China; and more methanol remaining in the US. With the Jones Act making it very expensive to move product from the US Gulf to the US East coast ports, the lower import volumes into the US seem most likely to threaten supply to consumers in the US northeast. In addition, economic uncertainty caused by tariffs could result in reduced global demand and crude oil prices falling, which in turn, is likely to move freight rates down.

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Dominic leads analysis and hydrogen thought leadership content with a focus on production dynamics, costs, and demand and supply perspectives in North America amid the broader global context. Dominic possesses bachelor's and master's degrees in Chemical Engineering and has worked across sectors of conventional oil and gas, power and utilities, and environmental and clean energy consulting - most recently at Deloitte. He leverages his comprehensive energy background with core consulting skills of critical thinking and concise communication to generate insights and shape industry intelligence (analysis & commentary, opportunity areas, outlooks, trends) on hydrogen and its relationship across the complex global energy landscape.

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Dr. James Stevenson's expertise includes supply, demand, and price dynamics of global coal, iron ore, steel, and ferrous scrap. He also has extensive experience in trading, M&A, and business development. Prior to his current role, Dr. Stevenson worked in commodity trading, most recently at Mercuria Energy Trading, and before then at Louis Dreyfus Highbridge Energy (now Castleton Commodities). Dr. Stevenson holds undergraduate and master's degrees from the University of Sydney, and a PhD from Yale University.

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Matias is an experienced Research Analyst with a strong background in the energy sector, specializing in gas, electricity, and renewable energy, particularly hydrogen. With a demonstrated expertise in Policy Analysis, Political Economy, and Quantitative Comparative Analysis within the energy landscape, Matias is focused on enhancing hydrogen use in the European landscape and creating new insights into the broad H2 market.

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Carl Roache joined the company in 2024 and leads analysis and pricing globally from London, UK. Prior to joining CMA, Mr. Roache was EuroChem's global business development manager for NPK fertilizers, based in Dubai, UAE. From here he coordinated global sales for the company's 1.2mn t/yr Antwerp plant. Before this, he was EuroChem's Asia NPK business development lead, based in Singapore. Mr Roache is an NCTJ/NCE qualified newspaper journalist, starting his career with Northcliffe Media group in the UK.

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Marina Maliushkina is the steel research lead at McCloskey and the editor of the Steel Market Briefing publication, which provides analysis of global steel market trends and steel price forecasts. Prior to joining McCloskey, Marina worked as a senior research analyst at Fastmarkets and S&P Global Platts. Marina holds bachelor's degrees in history from the Belarusian State University and Financial Management from the University of Sunderland.

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Mike Nash works with a global team of regional consultants and overlays their analyses with a global perspective. His responsibilities include the World Methanol Report and World Methanol Analysis, as well as the Global Acetyls Market Reports and the related World Analyses for methanol, acetyls and formaldehyde. Mr. Nash also worked for BP's petrochemicals division for 19 years before a two-year stint in Total's UK fuels business. Mr. Nash holds a Master of Arts in English language and literature from Edinburgh University and an MBA from Kingston University, both in the United Kingdom

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