Greenwheel

Greenwheel Insights

Clearing the air on hydrogen production & supply

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Executive Summary

- **Hydrogen produces no emissions when used and** is essential for achieving the IEA's Net Zero by 2050 (IEA NZE) roadmap. Expanding its use across sectors that do not currently use it is crucial.

- For hydrogen production to decarbonise, **there needs to be a shift from 'grey' hydrogen**, which has high lifecycle CO_2 emissions.

- There are **two main options**: **'blue' hydrogen** produced from natural gas with CO_2 emissions captured and stored, and **'green' hydrogen**, produced from water using electrolysis powered by renewables.

- The **EU is leading policy support for green hydrogen,** with stringent regulations, ambitious targets and financing mechanisms. Thus, **EU policy is likely to drive the global hydrogen market in the near- to medium-term**.

- Similarly, the USA also has strong production targets, covering green and blue hydrogen, with **subsidies available under the Inflation Reduction Act.**

- Although **green hydrogen costs are expected to outcompete grey and blue hydrogen by 2030 in more advanced markets**, there is, globally, minimal policy **on driving hydrogen demand**.

- Where feasible, **transporting hydrogen by pipeline is usually the cheapest and least CO_2-intensive option – particularly if using repurposed natural gas infrastructure**.

- **Announced green hydrogen production** outside Europe **is likely destined for export as ammonia**. However, **very little of this production capacity is committed due to uncertain demand**, **driven by the lack of demand-side policy support**.

- Announcements may firm up as policy frameworks crystalise, but **some currently promoted sources of significant hydrogen demand may fall away** due to competition with other decarbonisation options (e.g., electrification).

How is hydrogen currently produced?

Hydrogen is a crucial feedstock in some sectors. **Petrochemical refining uses half of all hydrogen** currently produced. **A third is used to produce ammonia**, most of which is **used to produce fertilisers**. **Most of the rest is used to produce methanol**, a precursor to a range of commodity chemicals.[1]

Almost all this hydrogen is extracted from fossil fuels, producing 3% of annual global CO_2 emissions. **Two-thirds is extracted from natural gas**, using a chemical process - steam methane reformation (SMR) – **to produce 'grey' hydrogen** (see Figure 1). **Around a fifth is produced from coal** via gasification, **producing 'brown' or 'black' hydrogen**, depending on the grade of coal used. Most of the rest is produced as by-product from key refinery and petrochemical processes, where it is reused in other processes within the industry.[1]

China accounts for a third of global hydrogen production, including most of the coal-based processes. The USA, Middle East, India and Russia together account for around 40%. Most hydrogen is used domestically.[1]

Why does hydrogen production need to change?

In sectors that currently use hydrogen, few if any substitutes are available. **Because it produces no emissions when used, hydrogen – or its derivatives – are a key piece of the decarbonisation puzzle for some other sectors**, including iron and steel production, aviation and shipping, and energy storage.

Under the IEA's Net Zero by 2050 (IEA NZE) scenario, hydrogen demand grows 50% by 2030, and 450% by 2050,[2] **driven by these new uses**. However, hydrogen production must also decarbonise. Figure 1 illustrates the key characteristics of the **two most promising** approaches to low carbon hydrogen production – **'blue' and 'green' hydrogen** – alongside conventional hydrogen production. **Low-carbon hydrogen accounts for <1% of current hydrogen production**.

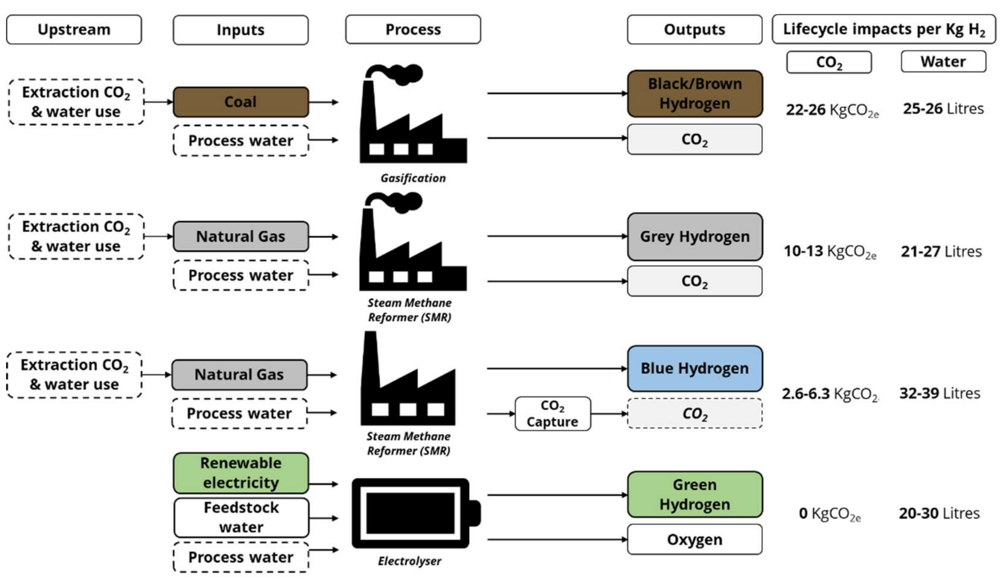

Figure 1 – Characteristics of key hydrogen production processes. CO_2 from IEA (2023); water from RMI (2023). Lifecycle impacts are 'well-to-gate"; includes direct and upstream emissions and water use; excludes downstream (i.e. transport/conversion and use of produced hydrogen). Graphic created by Greenwheel.

Other hydrogen production processes are possible, including low-carbon processes. However, due to their relative immaturity or other adverse characteristics, they are not explored in this briefing.

What is 'green' hydrogen?

Green hydrogen is hydrogen extracted from water through electrolysis, powered by renewable electricity. It produces very low to zero lifecycle CO_2 emissions (Figure 1), and only oxygen as a by-product.

We believe the EU is most advanced in its regulatory definition of green (or 'renewable') hydrogen (Figure 2), which **applies equally to domestic production and imports**. The size of the EU market means that **this definition is likely to shape regulatory definitions internationally**.

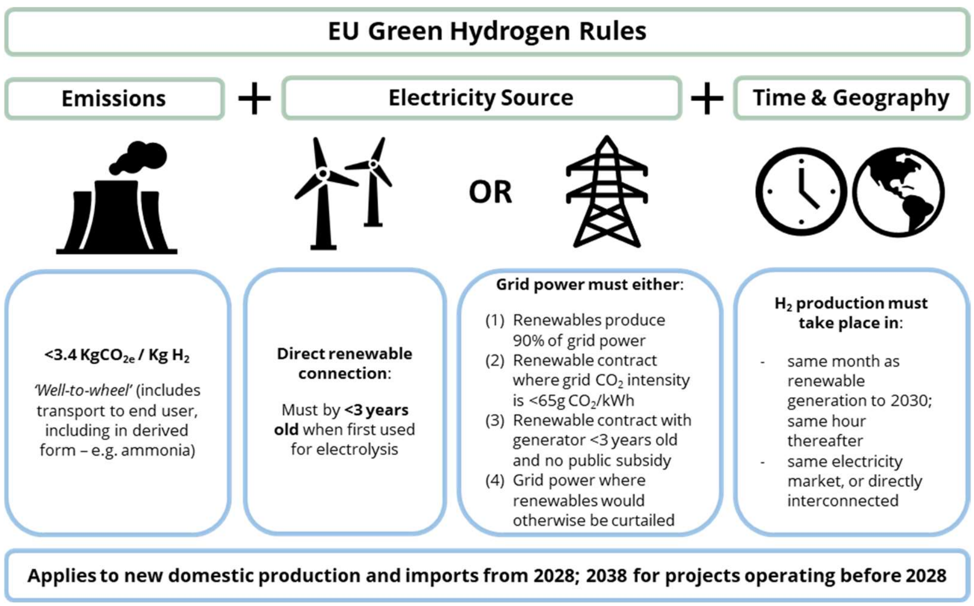

Figure 2 – EU Green (renewable) hydrogen definition. Graphic created by Greenwheel.

The EU **emissions limit reflects *'well-to-wheel'* lifecycle emissions** (i.e. including upstream, direct and downstream transport emissions). The **renewable electricity used must be 'additional' to existing capacity** to prevent diverting it from other purposes – except where the grid is already very low carbon, or generation from existing renewables is in surplus. It **must also be generated near in time and geography to the hydrogen production**. Hydrogen produced by nuclear power would not qualify as green hydrogen. Further emissions limits apply to the conversion of hydrogen into other products, such as synthetic fuels.

To qualify as 'clean' hydrogen in the USA, and thus for regulatory assistance, ***well-to-tank* emissions must be <4 $KgCO_2/kgh_2$** (i.e. upstream and direct emissions, but excluding downstream transport). **There are no separate definitions for green and blue hydrogen based on emissions**. Other requirements are not likely to be concluded until 2024, but they are likely to broadly align with EU requirements.

Several other countries are developing regulatory definitions for low-carbon hydrogen, with different requirements and stringency, however **4 $KgCO_2/Kgh_2$ is a common well-to-gate**

threshold.[1] An exception is China, where the regulatory limit for renewable (green) and clean (blue) hydrogen is 4.9 $KgCO_2/Kgh_2$.[3]

The **industry-led Green Hydrogen Organisation (GH2) has established a global Green Hydrogen Standard, under which producers may become certified**. The standard limits well-to-gate CO_2 emissions to 1 $kgCO_2/Kgh_2$, using <95% renewables.[4] Any additional or more stringent local regulatory requirements must also be met. A new version of the Standard is expected to launch in December 2023, which will expand CO_2 limits to a well-to-wheel basis, but with the threshold currently undefined. **The Standard is also likely to be accepted as sufficient to demonstrate compliance with both EU and upcoming US rules**.

Green hydrogen is the only process to use water as a feedstock. Water is also needed for feedstock purification and process cooling. The higher the purity of the water feedstock, the less purification is required. Assuming average purity, **if green hydrogen demand in 2050 under the IEA NZE scenario is met, it would require just half of the global lifecycle freshwater currently used by thermal electricity generation**.

However, water is also used in other hydrogen production processes, and for fossil fuel feedstock extraction. As such, despite its water feedstock requirements, **the lifecycle water footprint for green hydrogen is comparable to black, brown, and grey, and significantly less than blue hydrogen** (see Figure 1).[5]

Regardless, care is needed to prevent increasing freshwater stress in areas that experience it. Pressure on freshwater can be reduced through the using desalinated or industrial or municipal wastewater, which may be purified using commercially mature technologies.[5] If an electrolyser is co-located with a source of hydrogen demand, such as an iron and steel plant, the pure water produced when the hydrogen is used can be directly recycled to produce hydrogen again.

Land requirements for electrolysers are minimal. If global capacity were to match IEA NZE requirements, electrolysers would need land equivalent to two Manhattans in 2030, and less than half the area of golf courses in the UK by 2050.[6] However, the **area required for renewable electricity capacity would be several times larger**. **To match IEA NZE, we expect that the equivalent of 30% of all current global renewable generation would be required by 2030, and nearly double current renewable generation by 2050**.

There are four main electrolyser technologies: Alkaline, Proton Membrane Exchange (PEM), Solid Oxide and Anion Exchange Membrane. Their relative (dis)advantages are illustrated in Figure 3.

Due to their maturity and low cost, **alkaline electrolysers account for 60% of installed capacity to date, with PEM units accounting for most of the rest**. Around half of global capacity is in China, with most of the remainder in Europe and the USA.

Total installed **electrolyser capacity could increase from 2.2 GW today, to 420 GW by 2030 if all announced additions are installed** – **around 70% of capacity required by the IEA NZE pathway**.[1] Europe accounts for a third of this, with Australia, New Zealand, Africa and Latin America accounting for half.

This capacity would produce around half the green hydrogen required by 2030 under the IEA NZE. However, **less than 4% of this production capacity is currently committed**, **with more than half only at early stages of development** (see Figure 4). It is likely that capacity announcements will continue to grow rapidly, with the share taken by the USA and China increasing as policy frameworks evolve.

Annual electrolyser manufacturing capacity is currently less than 20GW, with half in China, and most of the rest in Europe and the USA. **Announced annual manufacturing capacity for 2030 is nearly 170GW – around the manufacturing capacity required under the IEA NZE pathway.**[7] China accounts for a quarter of this announced capacity, with Europe and the USA each accounting for a fifth. However, again, less than 10% of these announcements are committed.[8] More than three quarters of this announced capacity is for alkaline and PEM electrolysers. **It is not clear which, if any electrolyser type will come to dominate in the medium- to long-term.**

Electolyser Type	Advantages & Opportunities	Disadvantages & Challenges
Alkaline	- Mature & commercially available - Low cost - Rapid start-up; compatible with intermittent renewables - Long lifetime - No reliance on critical/rare materials	- High purity water input needed - Hydrogen may need further purification - Hydrogen needs further compression for transport
Proton Membrane Exchange (PEM)	- Commercially available - Rapid start-up; compatible with intermittent renewables - Long lifetime - H2 needs to further purification or compression - Low physical footprint	- High purity water input needed - Relies on critical/rare materials - Medium cost
Solid Oxide (SO)	- Very high efficiency, particularly if using waste heat input - Accepts low water purity - High purity hydrogen output	- Still under development - High cost - Slow start up; not compatible with intermittency - Low lifetime - Hydrogen needs further compression for transport - Relies on critical/rare materials
Anion Exchange Membrane (AEM)	- Potentially low cost - Accepts low water purity - No reliance on critical/rare materials	- Still under development - Slow start up; not compatible with intermittency - Low lifetime - Low efficiency

Figure 3 – Key characteristics of different electrolysers (Sources: IRENA, 2020; Scottish Government, 2022; Kumar & Lim, 2022). Graphic created by Greenwheel.

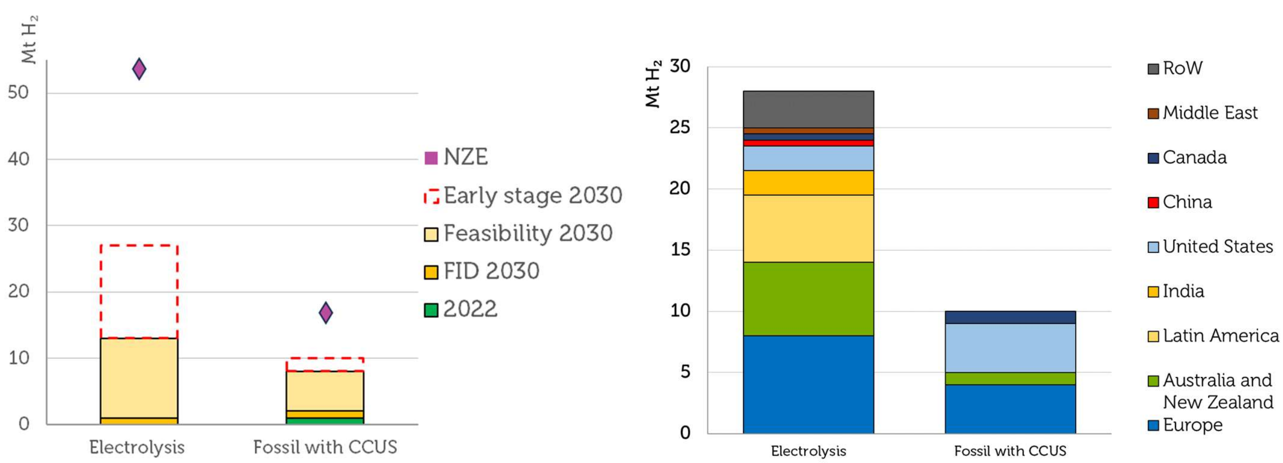

Figure 4 – Low-carbon hydrogen production in 2030 based on announced projects (Source: IEA, 2023). FID = Final Investment Decision. NZE = IEA Net Zero by 2050 Scenario. Graphic recreated by Greenwheel.

What is 'blue' hydrogen?

Blue hydrogen operates in the same way as grey, black or brown hydrogen, with the addition of carbon capture, utilisation and storage (CCUS) technology. **It can have low lifecycle emissions, but not zero**. This is because **emissions from upstream production and delivery of fossil fuels remain, and carbon capture rates are not 100%**.

To date, 16 hydrogen facilities have been retrofitted with CCUS technology, mostly in North America, with captured CO_2 used for enhanced oil recovery. However, capture rates are currently 40-60%. **Capture rates of up to 98 and 99% are technically possible** for natural gas SMR and coal gasification respectively, **but this has not been demonstrated in practice**.[1]

The **EU will set out specific requirements for blue ('low-carbon') hydrogen** by the end of 2024, but it **must meet the same well-to-wheel lifecycle emissions limit of 3.4 $KgCO_2/kgh_2$**. This is an **extremely challenging benchmark for blue hydrogen** - even excluding downstream emissions.[9] **It remains challenging even in countries with less stringent CO_2 requirements**, such as the USA and China.

If all announced blue hydrogen projects are realised, production by 2030 could grow to around 55% of that required by the IEA NZE scenario. Almost all this production would use SMR with natural gas. The USA and Europe would hold most of this capacity (see Figure 4). However, **as with green hydrogen projects, only a low single-digit proportion are committed.**

Blue hydrogen facilities largely use mass-manufactured equipment, and so excluding the technical feasibility of high carbon capture rates, face few supply chain constraints. Instead, excluding demand dynamics, **growth constraints surround access to sufficient natural gas supplies or CO_2 storage, and the ability to construct CO_2 transport infrastructure**.

How can hydrogen be transported?

Transporting and storing hydrogen is more technically challenging than for fossil fuels**. Over long distances hydrogen can either be transported as a compressed gas via pipeline, or in liquid or alternative form via ship. Each option has a set of benefits and limitations**, as summarised in Figure 5**.**

An alternative to transporting hydrogen produced by electrolysers co-located with renewable generation **is to instead transmit electricity to an electrolyser sited by hydrogen demand**, using high voltage (HVDC) transmission lines. Although not feasible over very long distances, this is a potential alternative to pipelines. I**n most cases, new HVDC lines are likely to be more expensive** than pipelines, particularly for high volumes of hydrogen production and transport. **However, at lower volumes, or where HVDC lines already exist, this may be an attractive alternative**.[10]

Around 5,000km of hydrogen pipelines are in operation, mostly in the USA and Europe, connecting refineries and chemicals complexes. **Under the IEA NZE scenario around 20,000km of hydrogen pipelines are needed by 2030, rising to well above 200,000km by 2050**. **Announced pipeline lengths exceed IEA NZE 2030 needs by 50**%. **Almost all of this is in Europe. Around two-thirds**

are new pipelines, with one-third repurposed natural gas pipelines.[11] The European Hydrogen Backbone initiative envisions a 53,000 km pan-European hydrogen pipeline network by 2040, aiming for around 70% repurposed natural gas pipelines.[12]

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Figure 5 – Key characteristics of different hydrogen transport options (Source: IRENA, 2022). Graphic created by Greenwheel.

Repurposing existing natural gas pipelines can reduce cost, environmental impact, lead times and the potential for public or political resistance. It can also reduce the risk of stranded assets as the use of natural gas declines. **However, technical challenges remain**. For example, chemical residues can reduce hydrogen purity, steel pipelines may quickly degrade, and natural gas compressors can't currently be retrofitted to compress pure hydrogen, meaning less efficient technology must replace them.[13]

Hydrogen can be blended in small amounts with natural gas in existing pipelines without modification. This is limited to 2% in the EU, but a 24% hydrogen blend has been demonstrated. However, technology to 'de-blend' the gas for separate use is not yet available at scale.[1]

Very few of these announced pipelines – new or repurposed - are yet committed due to uncertainties around hydrogen supply, demand and regulation. Large networks that cross multiple jurisdictions are also likely to face permitting delays and uncertain public and political support. The USA and China have just 400km of announced pipeline each, at concept stage.[11]

At high capacities, **transporting compressed hydrogen by pipeline is likely to be the cheapest option for distances up to 2,500km**[1]**, and at significantly larger distances if natural gas pipelines can be successfully repurposed**.[14] However, pipelines are either not feasible or very expensive for transport across oceans.

Tanker ships able to transport compressed or liquid hydrogen are under development and expected to be operational by 2030.[1] However, the hydrogen liquefaction process is energy-intensive, and neither hydrogen liquefaction or gasification infrastructure is yet available at scale. **Liquid or compressed hydrogen shipping may become viable for small-scale niche distribution.**[14]

Hydrogen may also be shipped as ammonia, which has a high energy density, can be easily liquified, and is already widely shipped using existing tankers between ports equipped to safely handle it. **For long distances, or where pipelines are not possible, shipping hydrogen as liquid ammonia by tanker is likely to be the cheapest option**.[14]

Announced long-distance international hydrogen trade flows by 2030 are heavily dominated by ammonia. This trade accounts for around 40% of all planned low carbon hydrogen production, although around half of this has no identified customers, **with very little fully committed**.[1]

Ammonia is already produced on a large scale, primarily for fertilisers, using grey hydrogen through the Haber Bosch process. **Although ammonia cannot be produced using low-carbon hydrogen from existing production facilities, this is not likely to present a significant barrier to growth**.

However, ammonia production, and **'cracking' the ammonia to release the hydrogen once shipped is also energy intensive**, together demanding energy equivalent to half that contained in the hydrogen itself. The **cracked hydrogen may also require purification and compression.** However, **if the ammonia is to be used directly, most of this energy use and associated cost is avoided**.

Two key technical challenges remain. Despite several large-scale project announcements in Europe, **ammonia cracking is not yet a commercial technology**, but innovation is expected to rapidly advance.[1] There is also **uncertainty around the ability of integrated hydrogen and ammonia production facilities to operate flexibility with variable renewables**.[14]

Announced ammonia trade volumes for 2030 would require a significant increase in the number of capable ships. **Bottlenecks in ship construction may become a constraint by the end of the decade**. Although around 150 ports and terminals can handle ammonia, **a trebling in overall port capacity would be needed**. **This includes infrastructure in countries that may have previously played no role in global ammonia trade**, requiring ammonia storage facilities, and deepwater ports and berthing facilities.[1] Around **50 new hydrogen import and export terminals have been announced**, mostly focused on Ammonia, and largely focused in Australia (export) and Europe (import), but **none are yet committed**.[11]

A final transport option is the use of 'liquid organic hydrogen carriers' (LOHCs), where hydrogen is 'loaded' to a liquid hydrocarbon (e.g. methanol) and then separated once it reaches its destination ('unloaded'). **LOHCs are easy to transport and can use existing trading and storage infrastructure**.

However, **LOHCs face several challenges**. Most potential carriers are expensive speciality chemicals, with small production capacities. Although carriers can be reused many times, for each cycle a small volume is lost, with environmental and cost implications. The 'unloading' process is also energy intensive.

How carbon-intensive are different transport options?

Figure 6 illustrates the range of CO_2 intensities for different transport options, and the well-to-wheel lifecycle emission limit for green hydrogen produced in or imported to the EU.

With a zero-carbon electricity supply, pipeline transport is effectively emissions-free. The EU's current grid CO_2 intensity would place it in the middle of the Figure 6 range. **Transporting liquid hydrogen has a very low carbon footprint if this hydrogen is also used to power the ship**.

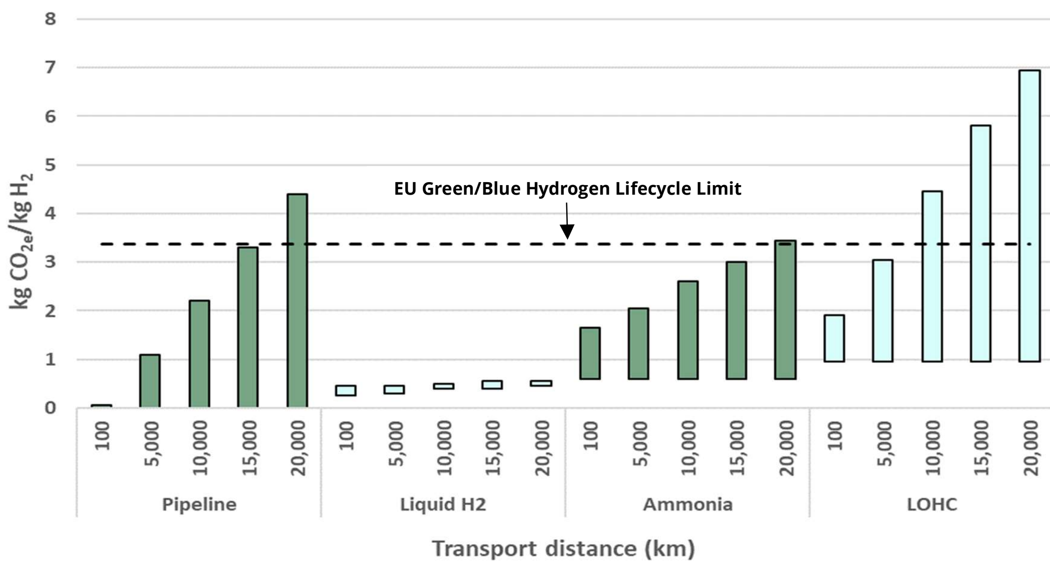

Figure 6 – Range of CO_2 intensities for different hydrogen transport options (Data source: [IEA, 2023](IEA, 2023)). Graphic recreated by Greenwheel.

The CO_2 implications of shipping ammonia is similar to liquid hydrogen if the ammonia is used directly by the importer or converted to hydrogen using carbon-free electricity, and is used to power the ship. If the ship is powered using conventional fuel, CO_2 emissions more than double above 10,000km. They increase further if ammonia is converted to hydrogen at the other end using non-zero carbon electricity.

Transporting hydrogen via LOHCs has the highest base CO_2 intensity, but remains low if hydrogen is extracted to power the ship, and 'unloaded' by the importer using zero-carbon electricity. However, **emissions increase more rapidly than for ammonia if the ship is powered using conventional fuel**.

Very long-distance shipping of hydrogen in any form would require the tanker to use some of the cargo it transports to achieve EU CO_2 limits that enter force from 2028. Alternatively fuelled ships are in their infancy but are developing rapidly.

Transport modes, and their CO_2 footprints, may stack. For example, hydrogen shipped to Europe may then be transported by pipeline to their final destinations.

How is policy supporting low-carbon hydrogen production and supply?

More than 40 governments have hydrogen strategies in place, but **policy support is most significant in the EU and USA**. While **the EU explicitly focused on green hydrogen, the USA – and other countries – are more colour-agnostic**. Key elements of the policy framework in the EU and USA are illustrated below.

European Union

- Targets **10mt 'green' h_2 production and imports** (20mt total); **40GW of electrolyser capacity** installed, **by 2030**
- A new **'European Hydrogen Bank'** will allow green h_2 producers to **bid for fixed support premiums,** with a **€3bn budget.**
- Potential introduction of **Carbon Contracts for Difference (CCfDs) for green hydrogen** use in steel and basic chemicals, to **top up carbon price set by the EU ETS**
- Electrolyser and H_2 pipelines can qualify as **Projects of Common Interest (PCIs)**; streamlining permitting and financial support of several €bn
- **Investment in international green h_2 production** capacities via the **European Investment Bank (EIB)** for export to EU, with **focus on Africa**
- **Member States encouraged to integrate green h_2 support** measures. **Germany** and the **Netherlands** have introduced **significant support**.

United States

- Targets **10mt of 'clean' h_2 production by 2030** with **production cost of $1/kg**; **50mt by 2050**.
- The **Inflation Reduction Act (IRA)** provides **tax credits for h_2 production** based on CO_2 intensity, with specific access rules to be confirmed:

CO_2 intensity (kgCO_2/kg h_2; *well-to-gate*)	Max Production Tax Credit ($/kg h_2)
4 – 2.5	$0.60
2.5 – 1.5	$0.75
1.5 – 0.45	$1.00
<0.45	$3.00

- IRA also provides: **30% tax credit for electrolyser** manufacture; tax credits for **renewable electricity** which ***can be stacked***; Increased tax credit for **CCUS**, which ***cannot be stacked***
- $7bn for 7 **'hydrogen hubs'** to connect and support clean h_2 production and use

Source: Key elements of EU & USA hydrogen policy. Created by Greenwheel. The information shown above is for illustrative purposes only and is not intended to be, and should not be interpreted as recommendations of advice.

Policy measures to support hydrogen production and supply are advancing elsewhere. Countries such as **Australia, Saudi Arabia, India, Canada Egypt and Japan have all introduced significant financial support for low-carbon hydrogen production** in various forms. China is the largest producer and user of hydrogen, **but its low-carbon hydrogen policy framework is weak**. It has a target to produce just 1-2mt of green hydrogen by 2025 – significantly below 2030 targets in the EU and USA. However, China is providing indirect support though, for example, supporting electrolyser manufacture and regulating electricity prices. A more comprehensive strategy in expected in the coming years.

Multilateral development banks (MDBs) have rapidly increased their funding for hydrogen production projects in emerging markets, rising from nothing in 2021 to nearly $5bn in 2023. Support is mostly focused on India, Namibia, Chile and Türkiye.[1]

Outside the EU, policy to support low-carbon hydrogen demand is limited. Japan and Korea have set high ambitions for the use of hydrogen in various sectors, and particularly road transport, but specific policies have either not yet been introduced or have underperformed. Competition in some sectors with other decarbonisation options, particularly electrification, will also likely make achieving these ambitions difficult.[1]

How much does low-carbon hydrogen cost to produce and supply?

Figure 7 illustrates the range of hydrogen production costs from each key process in 2022, and projected costs if IEA NZE production levels by 2030 are reached.

Black and grey hydrogen production costs are driven by coal and natural gas prices, which vary significantly across time and geography – particularly for natural gas. **High gas prices in Europe in 2022 meant grey production costs averaged $6/kg and peaked at over $11/kg**.[1] **Much lower gas prices were maintained in the USA, with production costs barely rising**

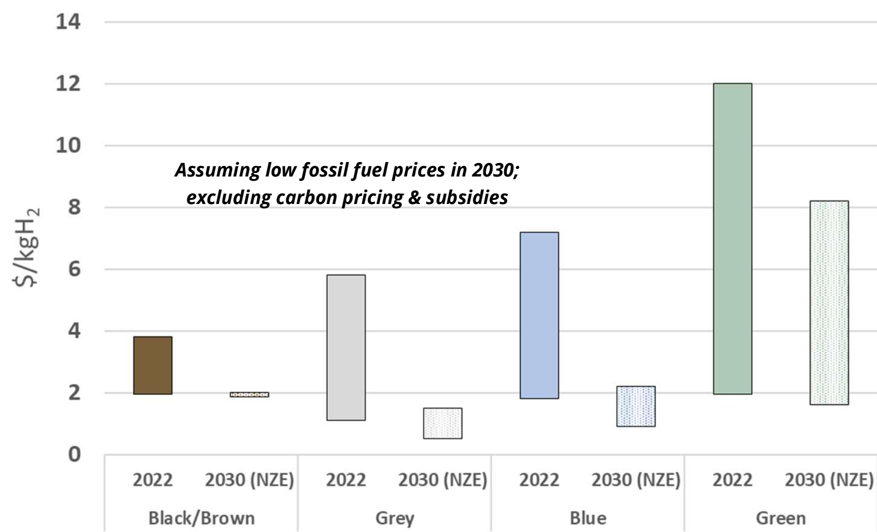

Figure 7 – Hydrogen production costs ranges in 2022 and 2030 under the IEA NZE scenario (Source: IEA, 2023). Graphic recreated by Greenwheel.

above $2/kg. Natural gas prices reduced in 2023, with hydrogen costs of around $1.2/kg in the USA and $3/kg in Europe. **Coal and gas prices under the IEA NZE scenario are significantly below current ranges by 2030**, reducing projected costs further.

The **cost of producing blue hydrogen is also pegged to natural gas prices, with CCUS costs a relatively small cost driver**, but sufficient for a continued premium over grey hydrogen.

The cost of producing green hydrogen is largely pegged to the cost of renewable electricity. Renewable electricity costs have reduced dramatically in recent years, but **geographic differences are stark**, driven by the strength of renewable resources (wind or solar) and financing costs. **Although capital and financing costs have recently increased with inflation, cost declines are likely to continue in the medium-term**.

Capital costs are more important to green hydrogen than any other hydrogen production process, both for renewable electricity capacity (particularly with the 'additionality' principle), and **for the electrolyser**.

Electrolyser costs have increased recently due to material, labour and financing costs. Costs are cheapest in China, largely driven by lower technical standards and other manufacturing conditions. Chinese electrolysers for the export market may need adjustments to match more stringent technical standards. Should announced manufacturing capacity and output come to fruition, **economies of scale coupled with further innovation and declining inflation are likely to reduce costs significantly by 2030**.[1]

Together, **reducing renewable electricity and electrolyser costs would significantly reduce the range of green hydrogen production costs by 2030**. **However, costs will vary widely by geography, dictated mainly by strength of renewable energy resources.**

BloombergNEF (BNEF) conclude that **new green hydrogen installations would outcompete new grey hydrogen installations in 90% of markets by 2030, and existing grey hydrogen installations by 2035 in Brazil, China, Sweden, Spain and India** – excluding subsidies.[15] **This would also mean green hydrogen would outcompete blue hydrogen by these dates, or earlier**.

High fossil fuel prices, and different forms of carbon price or subsidy would accelerate the point at which green hydrogen becomes competitive. For example, 'stacking' the maximum subsidies available under **the IRA would likely reduce average lifetime production costs for a new installation today to below $1.4/kg for green hydrogen**, in regions with strong renewable resources.[1] However, **because access rules for these subsidies are yet to be fully defined, blue hydrogen announcements have been more prominent in the USA to date**, as they may use an existing but extended subsidy for CCUS**.**

Whether and when green hydrogen becomes competitive in new applications is less clear. **To approach competitiveness with direct use of natural gas**, **hydrogen costs must be less than $1/kg**. This would requires electricity costs of <$15/MWh and large electrolyser cost reductions.[1] This may only be **realistic in the medium-term in regions with very strong renewable resources such as Australia the Middle East, North Africa and Latin America**, with low cost or concessionary finance.

However, **transport costs must also be added**. Figure 8 illustrates the projected range of costs for different transport options by 2050. Assuming the same volume of trade near-term cost ranges are similar, except for ammonia, where current costs are around $2.5/kgh$_2$ (including cracking).[1]

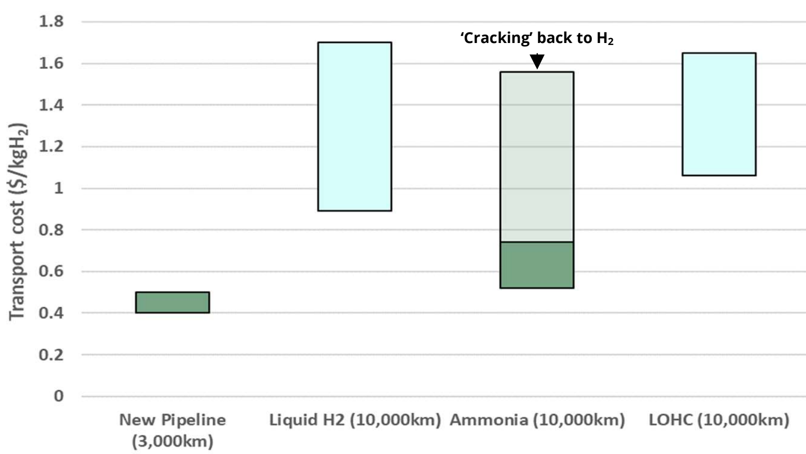

Figure 8 – Transport cost range projections for 2050, for 1 mt h$_2$/yr (Data sources: IRENA, 2022; IEA, 2023). Graphic created by Greenwheel.

Hydrogen pipelines are considered to be the simplest and cheapest option over short to medium distances where feasible, and if used at high capacity. **This is particularly the case if converted pipelines are used**. Liquid hydrogen costs are driven by the cost of liquification and cryogenic ships. LOHC costs are also driven by ship costs, including onboard extraction of hydrogen for propulsion, but around half the costs are from the electricity required to extract the hydrogen by the importer.

Transport costs via ammonia are driven by the hydrogen to ammonia conversion process. **Hydrogen via ammonia is by far the cheapest long-distance transport option, if the ammonia is used directly**. **However, if the hydrogen is 'cracked' from the ammonia, costs could double**. In this case, there is currently no stand-out long-term winner under current cost projections, for single transport modes over these distances. If transport modes are sequential (e.g., tanker then pipeline), costs would be cumulative.

Key Information

No investment strategy or risk management technique can guarantee returns or eliminate risks in any market environment. Past performance is not a guide to future results. The prices of investments and income from them may fall as well as rise and an investor's investment is subject to potential loss, in whole or in part. Forecasts and estimates are based upon subjective assumptions about circumstances and events that may not yet have taken place and may never do so. The statements and opinions expressed in this article are those of the author as of the date of publication, and do not necessarily represent the view of Redwheel. This article does not constitute investment advice and the information shown is for illustrative purposes only. Whilst updated figures are not available for all sources, we have performed further analysis and believe that this data has not significantly changed and is reflective for 2024.

Endnotes

[1] IEA (2023a)
[2] IEA (2023b)
[3] Li et al (2022)
[4] GH2 (2023)
[5] RMI (2023)
[6] Assuming 0.17km2 per 1GW electrolyser capacity (Source: IRENA, 2020)
[7] IEA (2022)
[8] IEA (2023)
[9] Riemer & Duscha (2023)
[10] Patonia et al (2023)
[11] IEA (2023)
[12] EHB (2022)
[13] ACER (2021)
[14] IRENA (2022)
[15] BNEF (2023)

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