Finding the sea of green

The opportunity and options for shipping green H_2

Edison themes

28 July 2021

This thematic report is designed to accompany our initiation of Global Energy Ventures (GEV). Using data from the Hydrogen Council (among other sources), we look at the potential demand for green hydrogen (H_2) in South Korea and Japan and the economics of shipping it to these markets from Australia, a low-cost 'renewable superpower'. We then evaluate the advantages and disadvantages of various shipping technologies using data from GEV's scoping study.

Green hydrogen is an essential component of most national 'net zero' strategies (see The hydrogen economy: Decarbonising the final 20%). Both Japan and South Korea have pledged to reduce emissions to net zero by 2050 and will require significant volumes to meet these commitments. However, due to modest renewable resources and spatial constraints on deployment, domestic supply will be relatively expensive and limited. Imports are likely to be needed to fill the shortfall.

The Hydrogen Council estimates that green hydrogen production costs in Australia and Japan/South Korea will be \$1.7/kg and \$2.6/kg respectively by 2030. With shipping costs of \$2–3/kg, imported green hydrogen sourced from Australia is likely to be more expensive than domestic supply. Nevertheless, given the domestic renewable energy supply constraints in Japan and South Korea, we still see a significant opportunity; an efficient, zero-emission shipping solution will be crucial to keeping costs down. GEV's compressed hydrogen technology looks to be cost effective compared to liquefaction, ammonia or other Liquid Organic Hydrogen Carriers (LOHCs) over this distance (4,000 nautical miles, or nm) and is particularly cost effective over shorter distances (2,000nm and below).

From the street

'The cost is definitely the biggest obstacle [to] this huge adoption [of green hydrogen]. But once it gets adopted, it will have huge implications, because it will be competitive with natural gas…on a global level, 18 countries which account for roughly 70% of global GDP, already have hydrogen deployment strategies.'

Ingrid Kukuljan, head of impact at Federated Hermes.

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Companies named in this report

AGL

BP

Engie

Fortescue Metals Group

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Hydrogen fundamentals: Net zero needs green H_2

The policy response to climate change has strengthened considerably over the last year. More than 110 countries (65% of global CO_2 emissions and 70% of GDP) have now made some form of net zero commitment. Eight countries including the UK have already enshrined a net zero objective into law and the European Union passed its Climate Law in June 2021.

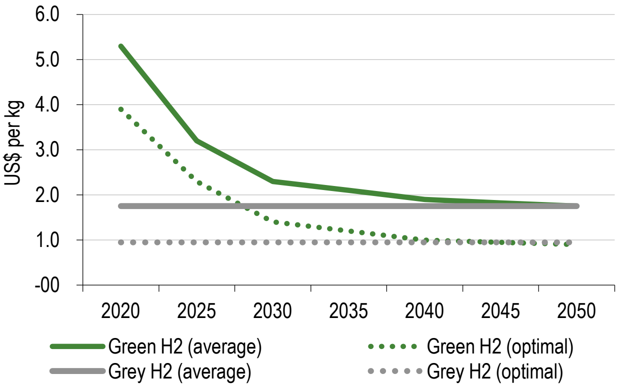
As highlighted in The hydrogen economy: Decarbonising the final 20%, in our view these targets cannot be achieved without hydrogen (H_2), and more specifically, green hydrogen. Hydrogen's unique properties – it releases no pollutants or carbon dioxide when combusted and has an exceptionally high energy to mass ratio – make it a suitable fuel for 'hard-to-abate' sectors such as heavy industry and long-distance freight transport, which cannot use renewable electricity directly.

Currently, the vast majority of c 70 million tonnes (mt) of hydrogen manufactured annually is used in the chemical industry and extracted from hydrocarbons (coal, natural gas and lignite) in a process that releases CO_2 (often described as black, grey or brown hydrogen respectively). Green hydrogen uses renewable electricity to split water (H_2O) into its constituent elements, and therefore its manufacture and use emits no CO_2.

Understanding the role of green hydrogen: Good in niches

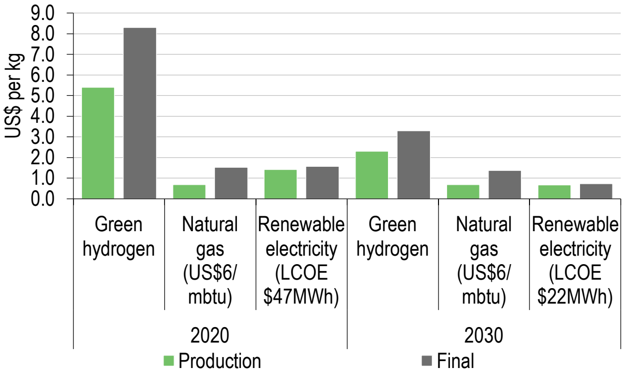
The main challenge with green hydrogen currently is its cost. The Hydrogen Council estimates that, on average, green hydrogen currently costs more than $5.3/kg to produce, nearly four times more than the $1.4/kg cost of natural gas-based production (grey hydrogen). While the costs are expected to fall 57% between 2020 and 2030 (8% per year) due to cheaper renewable electricity and electrolysers, the projected average cost (c $2.3/kg) by 2030 is likely to be a 30% premium to grey hydrogen (Exhibit 1) assuming no carbon tax on grey hydrogen.

Exhibit 1: Green hydrogen costs are expected to decline by 57% between 2020 and 2030*



Source: Hydrogen Insights Report, 2021 (Hydrogen Council and McKinsey). Note: Assumes renewable average levelised cost of electricity (LCOE) falls to US$7–25/MWh by 2050 and a gas price US$2.6–6.8/mmbtu. *A carbon tax of c US$100/tonne makes green hydrogen cheaper than grey hydrogen in 2030.

Exhibit 2: Green hydrogen remains expensive vs cost of other final energy sources (despite cost reductions)



Source: Edison Investment Research. Note: Converted on an energy equivalent basis assuming 1kg of hydrogen = 120MJ /33KWh/0.114mbtu. Losses in conversion to final electricity 35% for hydrogen in 2020, 10% for electricity, 55% for natural gas.

At the heart of this cost issue are the conversion losses incurred during its production. Between 19% and 43% of energy contained in the electricity used to make green hydrogen is lost on conversion. Further losses are incurred if it is either transported (discussed in more detail below) or converted back to electricity for final use (as it is with fuel cell vehicles for example). These 'round trip' losses substantially reduce the useful energy it delivers, effectively making it always more expensive than the energy in its original form (ie renewable electricity). The Hydrogen Council's projected average green hydrogen production cost of $2.3/kg in 2030 is still over three times the projected average levelised cost of electricity (LCOE) and natural gas. Even accounting for a more efficient conversion to electricity than natural gas, electricity derived from green hydrogen is expected to be more than twice the cost of electricity derived from natural gas (Exhibit 2).

In our view, these characteristics are likely to shape how the green hydrogen market will evolve in two key ways:

1. Green hydrogen is likely to require policy support, particularly in the near term, to stimulate end-demand and bridge the cost gap. Key policy tools are likely to include subsidies, deployment targets, carbon taxes and co-ordinated infrastructure development.
2. Adoption is likely to focus on applications where its unique properties enable it to provide 'system value', advantages in range or functionality that cannot be provided by other low-carbon alternatives. The inherent losses and high cost make its widespread use a relatively inefficient and expensive way to supply energy in general.

In The hydrogen economy: Decarbonising the final 20%, we identified seven end-use applications where we see green hydrogen playing a role: steelmaking, residential heating, long-distance heavy road freight, buses/coaches, aviation, shipping and other industrial applications. Each of these applications has very different dynamics and green hydrogen is likely to be part of the answer, rather than the complete solution. These caveats aside, we see demand for green hydrogen growing rapidly over multiple decades. Analysis from the EU, BNEF and the IEA expects green hydrogen's share of total global energy consumption to grow from essentially zero today to 13–24% by 2050.

Shipping green H_2: Matching demand with low-cost supply

The fundamental properties of hydrogen, the decarbonisation imperative, the need for policy and the economics of green hydrogen, relative to both other forms of hydrogen and other fuels, all have direct relevance to the market for shipping hydrogen. To encourage adoption within its target applications, green hydrogen needs to be cheap and round-trip losses minimised.

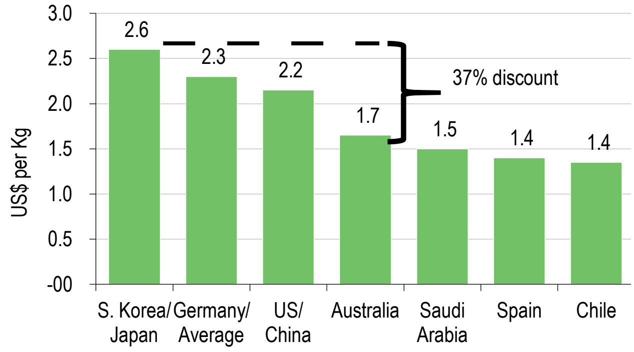
Matching demand in Japan and South Korea…

Japan and South Korea have been enthusiastic supporters of the long-term role of hydrogen. Motivated by the need to ensure energy security (both have limited domestic fossil fuel resources) and the potential to establish leadership positions in a growth market, they were among the first countries to set out hydrogen strategies (Japan 2017, South Korea 2019) and have been proponents of fuel cell vehicles. Adoption targets have been set in certain sectors backed by subsidies and infrastructure investment including port facilities and pipelines (for more detailed reviews of these strategies see The Strategic Road Map for Hydrogen and Fuel Cells and South Korea's Hydrogen Strategy and Industrial Perspectives). South Korea is aiming to quadruple current demand for hydrogen to 2mt by 2030 and grow this to 5mt by 2040. Japan is aiming to consume 3mt by 2030, rising to 20mt by 2050.

Until recently, both countries appeared relatively agnostic about how they produce hydrogen (either using fossil fuels or via green electricity). However, in 2020 both pledged to reach net zero emissions by 2050, suggesting that the focus will shift towards green hydrogen in time. South Korea was already aiming for 40% of its hydrogen to come from renewable sources by 2040 (ie 2mt); this figure may rise.

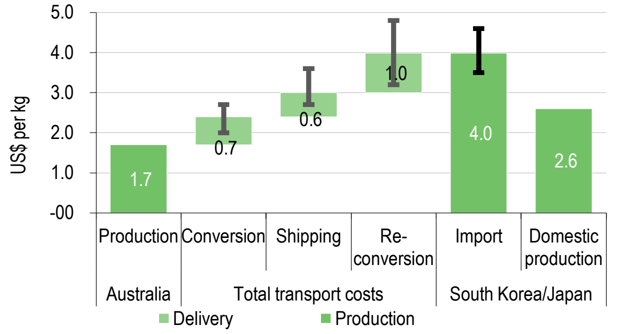
However, both nations will struggle to produce this amount of green hydrogen domestically. Neither is blessed with plentiful cheap renewable resources: solar radiation levels are relatively low, particularly in northern Japan and terrestrial deployment of both solar and wind is constrained by gh population density and limited land availability. Both countries are intending to expand their offshore wind capacity, but deep offshore water poses technical and cost challenges. As part of its net zero commitment, Japan recently announced its intention to double its current renewable electricity production to 37% by 2030, up from its previous 23% target. Given renewable resource constraints, it is more efficient for both countries to focus their deployments on domestic electricity production. The Hydrogen Council estimates that by 2030 production costs of green hydrogen in Japan and South Korea will fall to US$2.6 per kg, c 15% above the global average (see Exhibit 3).

Exhibit 3: Estimated green hydrogen production costs in 2030 by country



Source: Hydrogen Insights Report, 2021 (Hydrogen Council and McKinsey)

Exhibit 4: The cost of imported green hydrogen versus domestic production in South Korea/Japan in 2030



Source: IEA and Exhibit 16 of Hydrogen Insights Report, 2021 (Hydrogen Council and McKinsey)

…with low-cost supply in Australia

In contrast, Australia, with its combination of plentiful solar and wind resources, is one of the cheapest sources of renewable energy globally and often described as a 'renewable superpower'. By 2030, the Hydrogen Council estimates the cost of green hydrogen production in Australia will fall to $1.7/kg, 37% below the expected cost in Japan and South Korea (Exhibit 3). With only modest domestic demand for this energy (given its low population density), converting this renewable energy into green hydrogen to be shipped overseas presents a significant export opportunity. Analysis for ARENA estimated the size of the Australian export market for hydrogen by 2025 (in a medium scenario) at 0.13mt annually, rising to 0.50mt by 2030, with Japan and South Korea accounting for about 90% of the market. Based on a US$4,000/t landing cost (see Exhibit 4 and discussed below), this equates to a US$1.8bn market by 2030.

In this context, Australia published a National Hydrogen Strategy in November 2019. A key focus of that strategy is the creation of hydrogen hubs – clusters of large-scale demand at ports or industrial areas – that would make the development of infrastructure more cost effective and promote synergies. Players from many industries have announced plans to invest in the market including Engie, Fortescue Metals Group (FMG), BP, Origin and Sumitomo (for a full review see HyResource: A Short Report on Hydrogen Industry Policy Initiatives and the Status of Hydrogen Projects in Australia, May 2021).

One consortium, the Hydrogen Energy Supply Chain (HESC), which includes Kawasaki, AGL and Iwatani and has the support of both the Japanese and Australian governments, is aiming to kick start this market with a US$388m pilot project using coal from southern Australia to produce 'brown hydrogen'. This pilot phase is expected to produce and ship 3mt of liquified hydrogen annually, and has built the world's first liquified hydrogen ship. Production is expected to scale up to 0.23mt eventually and use carbon capture and storage (CCS) to reduce emissions.

H_2 transport economics: Comparing imported and domestic production

In 2019, the IEA's Future of Hydrogen report estimated that the cost of producing green hydrogen in 2030 in Japan would be $6/kg compared to $3.8/kg in Australia. With transport costs at $2–3/kg (depending on technology – see below), imported H_2 would broadly cost the same as domestic production.

However, green hydrogen production cost forecasts appear to be falling fast. The Hydrogen Council's 2021 average global production cost estimate for 2030 is down 10% on its 2020 estimate and its forecasts for production costs in Australia and Japan/South Korea ($1.7/kg and $2.6/kg respectively) are less than half the IEA figures.

Expectations of steep falls in production costs are good news for green hydrogen demand overall. However, this does reduce the absolute difference between low- and high-cost regions: the IEA forecast implies that the spread between Australian and Japanese production costs would be $2.2/kg in 2030, whereas the Hydrogen Council forecasts it as just $0.9/kg. With forecast transport costs appearing to be relatively static, the lower overall forecasts mean imported green hydrogen is likely to be at a premium to domestic production. Assuming an average $2.3/kg transport cost (based on the midpoint of three methods assessed by the Hydrogen Council) implies that imported Australian production will be at least a $1.4/kg (54%) premium to domestic production (Exhibit 4) in 2030.

While it is unlikely that, given the expected fall in production costs, importing green hydrogen from Australia will be cheaper than domestic production, that does not mean there will not be a market for it. Net zero will require both countries to decarbonise hard-to-abate heavy industry and transport sectors and that will require green hydrogen. Given the significant domestic renewable energy supply constraints (as detailed above), this will require imports. Australia is likely to represent the lowest cost source.

Transport options: Compressed green H_2 a cheaper option

To capitalise on the export opportunity requires a cost-effective method of transporting green hydrogen the 3,500–4,500nm from northern Australia to Japan and South Korea. This is not straightforward: hydrogen has a low volumetric energy density, so transporting it efficiently requires it to be compressed, liquified or combined with other elements. Exhibit 5 shows five potential solutions, each with its unique advantages and disadvantages.

Exhibit 5: The advantages and disadvantages of different hydrogen transport options from Australia to Japan and South Korea

Method	Description	Advantages	Disadvantages	Status
Pipeline	Continuous volumes of hydrogen can be transported over short and medium distances using adapted existing gas pipelines or new pipelines	Capable of transporting high volumes cheaply over distances of less than 940nm. Low operational costs	Existing gas infrastructure likely to require further investment to carry hydrogen. High capital costs of new pipeline, particularly over long distances and undersea	Unsuitable given distance between Australia and South Korea and Japan
Shipping: ammonia	By combining hydrogen with nitrogen to create ammonia (NH_3) and then liquifying (-33°C), density can be significantly increased	High density means low cost to ship. If ammonia can be used directly, conversion losses are only 7–18%. Some transmission infrastructure already established	Round trip conversion losses if a pure form of hydrogen is required (such as for fuel cell vehicles) are 14–36%. Toxic	Potentially suitable, particularly over longer distances and where re-conversion is not needed.
Shipping: other LOHCs	Hydrogen density can be significantly increased by combining with a 'carrier' molecule such as toluene	Can be transported as liquids without any cooling and therefore very low shipping costs. Could use adapted existing oil tankers	High conversion losses currently (35–40%). Potentially toxic. Multiple solutions still being trialled	Potentially suitable but technology still in its early stages
Shipping: liquid hydrogen	Hydrogen liquifies at -253°C, increasing its density by 800 times	Liquefaction significantly reduces transport costs/unit. Could use a similar technology to existing LNG vessels. Delivers pure hydrogen	Liquefaction and maintaining a low temperature consume significant amounts of energy (25–35%) & a certain proportion is lost as boil-off	Potentially suitable but highly capital intensive. First liquid hydrogen ships expected in 2022
Shipping: compressed hydrogen	Compressing hydrogen to 250 bar significantly increases the volume of hydrogen that can be stored	No conversion losses and only modest technical challenges to store compressed hydrogen. Delivers pure hydrogen	Relatively high shipping costs per unit reduces cost efficiency with distance	Potentially suitable. Type approval in principle from the American Bureau of Shipping. Construction of pilot ship expected to begin shortly

Source: Edison Investment Research, GEV, IEA and Hydrogen Insights Report, 2021 (Hydrogen Council and McKinsey)

Each of the four potentially suitable shipping technologies is likely to play a role in different circumstances and at different times. Transporting hydrogen as ammonia looks to be the most cost-effective solution over very long distances, particularly if the hydrogen is not needed in its pure form. The development of other LOHCs, particularly if they can utilise existing, adapted, spare tanker capacity, are potentially interesting but are still in the early stages. According to GEV, liquefaction is cheaper than ammonia, particularly at distances of 2,000nm (Exhibit 7). However, the process consumes significant energy and the first liquified hydrogen ships are not expected to be available in the near term (Hyundai and Kawasaki both recently received type approval for liquid hydrogen ships capable of transporting 20,000m^3 and 40,000m^3 respectively).

As it has neither the losses associated with conversion to ammonia nor the energy penalty of liquefaction, the compressed hydrogen solution that GEV is proposing can transport 85% of the supplied hydrogen at a distance of 2,000nm. As a result, it is up to 38% cheaper on a levelised cost of hydrogen (LCOH) basis. GEV does not disclose its forecast cost expectations directly, but conservatively assuming a $2.50/kg cost for existing technologies over this distance in 2030 suggests its transport costs could be US$1.6/kg.

Exhibit 6: Compressed H_2 substantially more efficient transportation method for distances of 2,000nm…

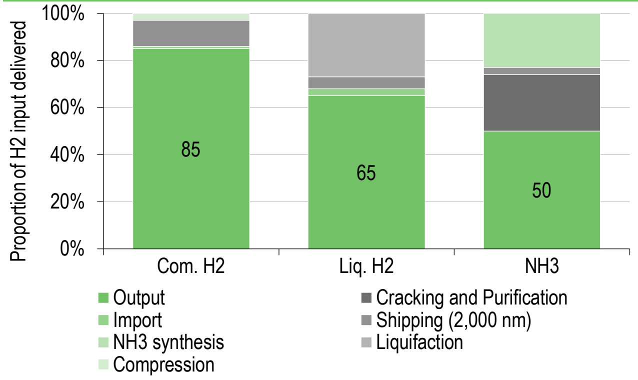
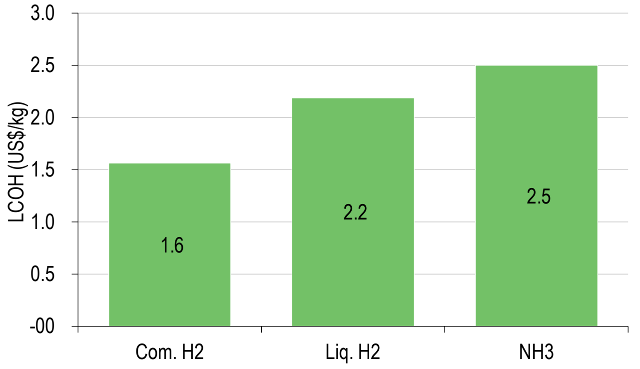


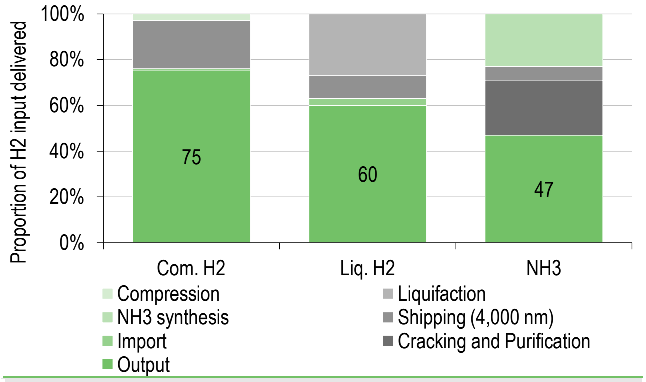
Exhibit 7: …and therefore up to 38% cheaper than alternative H_2 shipping methods*



Source: GEV and Edison Investment Research. Note: *Estimates of relative cost based on GEV's scoping study, which assumes 0.2mt shipments pa. This relative cost is applied to an Edison estimate of the absolute cost for liquified H_2 or NH_3 based on a variety of sources including the IEA, BNEF and Hydrogen Council.

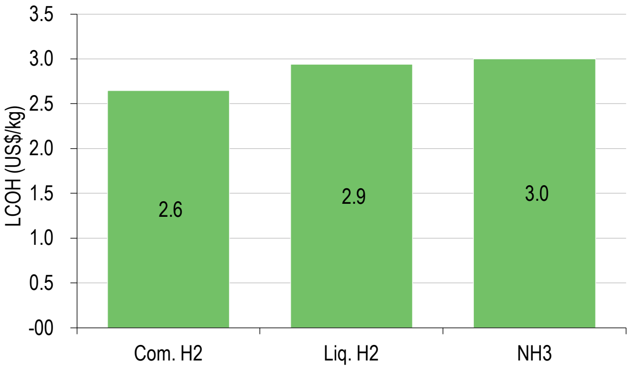
For 4,000nm – about the distance between northern Australia and Japan/South Korea – the cost advantage of the compressed solution is less clear. The relatively high transport costs over the longer distance mean that only 75% of the fuel is transported. Conservatively assuming a $3/kg transport cost for this distance for existing technologies (consistent with the Hydrogen Council's $2–3/kg range and the IEA data) suggests an LCOH for compressed hydrogen of US$2.6/kg. While the cost is higher and the advantage over competing technologies not as clear, compressed hydrogen remains the most cost-effective solution, and has the advantages of transporting pure hydrogen (with no need for reconversion) and being a relatively simple solution technically.

Exhibit 8: Efficiency of compressed H_2 falls more rapidly as distances rise to 4,000nm…



Source: GEV and Edison Investment Research

Exhibit 9: …and therefore cost advantage versus alternative H_2 shipping methods falls to just 12%*



Source: GEV and Edison Investment Research. Note: *Estimates of relative cost based on GEV's scoping study, which assumes 0.2mt shipments pa. This relative cost is applied to an Edison estimate of the absolute cost for liquified H_2 or NH_3 based on Hydrogen Council analysis ($2–3/kg range) and consistent with IEA and BNEF estimates.

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