J.P.Morgan CAZENOVE

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EMEA Hydrogen

A revolution in need of realism; separating the opportunity from the optimism

We believe a Hydrogen Revolution is quickly gathering momentum to drive energy transition across several 'hard-to-abate' sectors. However, investors should also be wary of over-optimism given H_2 adoption for some end-uses appears more challenging and less economic vs other low CO_2 alternatives. Our proprietary policy and economic analysis shows green H_2 could be cost competitive across most regions by 2030E, but blue H_2 could be lower cost in North America. Investing in H_2 is also likely to remain challenging, in our view, both with major corporates & smaller H_2-focused companies. After the dramatic performance of H_2-focused stocks over 2020, we believe investors ought to take a more relative approach to the nascent H_2 subsector. In EMEA, we initiate coverage of ITM Power (ITM.L) at Overweight with a GBp700/sh PT (link) and Nel (NEL.OLS) at Neutral with a NOK28/sh PT (link). In the US, we are OW on Nikola, Neutral on Bloom & Plug Power, and UW on FCEL.

Alternative Energy - Hydrogen

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- **Why the H_2 revolution is real this time.** H_2 interest is now far wider than in past episodes of 'hydrogen hype'. National H_2 strategies now consider the whole H_2 value chain & corporate net zero emissions targets are driving H_2 investment to decarbonise 'hard-to-abate' sectors, which cannot simply switch to renewable power. Also, the critical barrier for water electrolysis ('green H_2') is renewable power costs and these, have already and will likely continue to decline, while the electrolyser industry quickly scales up.

- **Green H_2 costs rapidly falling, but regional differences will be critical; Blue H_2 could play a transitional role in the US.** Our proprietary green H_2 cost model indicates green H_2 costs could fall from $3.4-5.0/kg today to $1.7-2.8/kg by 2030, allowing green H_2 to compete in many regions. However, regional variances will be critical, with blue H_2 offering a potentially lower-cost transitional, option in North America, albeit non-technical barriers should not be underestimated. Turquoise H_2 could play a role post 2030 if the technology can be commercially developed. We expect pipeline transport costs will not be a major hurdle, but seaborne transport costs will be far higher. Nevertheless, this will likely be needed to move H_2 from where it is low cost to produce (MENA, Australia, Latam) to where demand is emerging without low-cost domestic production (i.e. Korea, Japan).

- **But H_2 adoption across some industries more challenging; refining, ammonia, steel, & heavy-duty vehicles could lead H_2 transition; but heating, power gen & cement production appear less certain.** We expect several sectors to lead the H_2 transition. Sectors where H_2 is used today (refining, ammonia) will likely move quickly, facing lower hurdles and costs to transition. H_2-derived steel is also quickly gathering pace with several EU producers setting hard volumes targets for H_2-steel by 2030. However, H_2 adoption will be more difficult in other sectors. We expect other energy storage options will remain lower cost than H_2 for grid-scale energy storage, while passenger FCEV costs still need to fall by ~45% to be competitive vs ICEs.

- **Investing for the H_2 revolution: confident in future H_2 volumes, harder to see H_2 value; initiate coverage of ITM at OW & Nel at Neutral.** Investing for an H_2 revolution presents a dilemma: H_2 exposure (especially green H_2) for major corporates is still relatively low, while many H_2 pure-plays are still EBITDA negative. We also believe electrolyser manufacturers could face stiff competition as more companies bring on new lower-cost capacity. We expect EMEA-listed H_2 electrolyser manufacturers ITM Power & Nel to benefit from rapidly growing global H_2 electrolyser demand, but after both stocks remarkable performance vs the market and persistent FCF burn, we now believe investors should be more focused on relative winners. We expect ITM to turn FCF positive by FY'25, but maintain a strong cash position. In contrast, Nel's greater FCF burn raises greater financing risks, in our view. We determine fair values for ITM & Nel using CY'30 multiples discounted back to CY'21 across three global electrolyser shipments scenarios. This reveals ~34% upside potential for ITM and ~5% for Nel. Therefore, we initiate on ITM at Overweight with a 700p/sh PT and Nel at Neutral with a NOK28/sh PT. In the US, we are OW on Nikola, Neutral on Bloom & Plug Power, and UW on FCEL.

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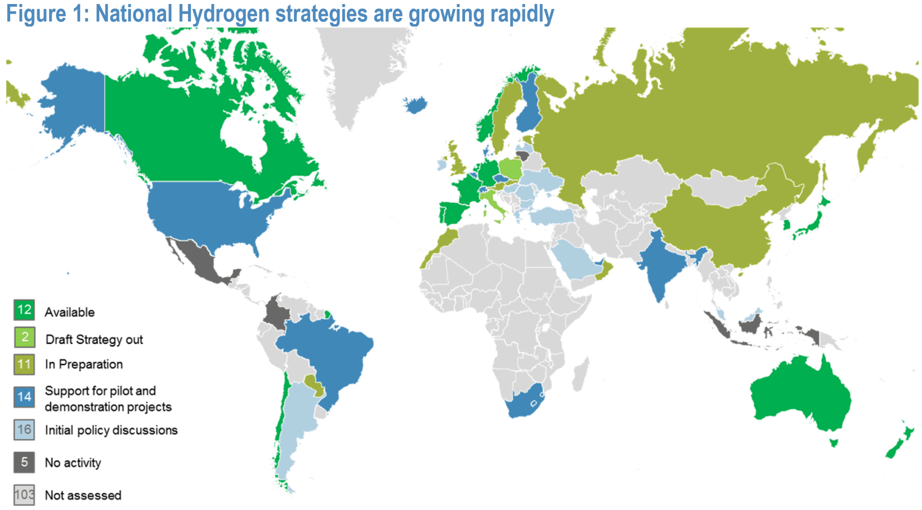
Executive Summary

The potential for a Hydrogen Revolution, as the next stage of addressing climate change, has garnered significant investor, corporate, and political interest over the past 12-18 months. National green H_2 capacity targets now conservatively amount to >100GW by 2030E and some long-term H_2 demand forecasts are now as high as ~700Mtpa, ~10x current global output. We expect Green H2 costs to fall dramatically over the next decade to $1.7-2.8/kg, leading to exponential growth in Green H_2 volumes and enabling several hard-to-abate sectors to decarbonise using H_2. However, we see several concerns and nuances for investors despite this positive momentum. Although we expect Green H_2 to be more competitive in Europe and China, blue H_2 could play a greater transitional role in the US given cost advantages there. Further policy support is still needed to maintain momentum and accelerate a virtuous cycle of scaling both supply and demand. Yet, some of the expected catalysts have started to materialize. Also, given rapidly increasing manufacturing capacity, H_2 electrolyser manufacturers could face greater competition and thus margin pressure. Thus, we initiate coverage of EMEA H_2 electrolyser manufacturers ITM Power at Overweight and Nel ASA at Neutral.

Another episode of 'Hydrogen hype'? H_2 revolution now appears credible with rapidly growth policy support & improving economics

Hydrogen's potential as a versatile, transportable, and storable energy carrier has spurred interest in decarbonising multiple sectors with H_2. Today, hydrogen interest is not focused on any one single end-use or sector (in contrast to past episodes of 'H_2 hype') nor is it focused on addressing a prohibitively high oil price. Now, the impetus is squarely on climate change and decarbonising multiple 'hard-to-abate' sectors. New country-specific strategies, many in a COVID-economic context, have brought H_2 to the top of agendas.

Figure 1: National Hydrogen strategies are growing rapidly



Source: J.P. Morgan based on BNEF & World Energy council

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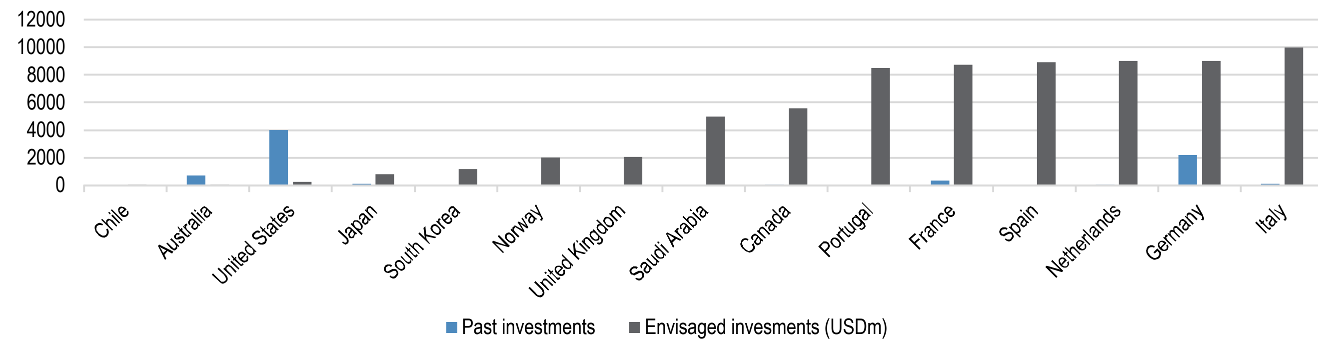
Policies & investments envisaged have changed in scale…

These announcements represent a major change in scale for investments Based on our estimates, 15 countries have announced envisaged investments (both public & private) for the years to come, for a total of $71bn, vs $8bn of historical investment. And we still believe this number could be conservative. Also, the breadth of envisioned H_2 end-uses has also increased, from a narrow focus on LD vehicles previously, to a wider range of 'hard-to-abate' sectors. To scale this up, we envisage significant efforts to ramp up green and low-carbon production and trigger a value-chain wide "virtuous circle" between supply and demand.

Figure 2: Investment pledges grew tenfold



Source: J.P. Morgan Estimates

The EU expects each EUR 1bn invested in H_2 to create 10,570 new jobs. Based on the EUR 180bn-470bn range of envisaged investments by 2050, this would represent ~2m-5m new jobs.

H_2 policy supported by COVID-19 "special" situation and the need to deliver a "fair transition"; not all policy 'lights' are green, but we see encouraging signals

We believe that this change in scale is helped by the specific macro-economic context (COVID-19 effect on unemployment, the low interest rates), meaning large fiscal policy initiatives are more politically acceptable. Moreover, scaling up a H_2 economy also represents a significant opportunity for job creation and supporting other strategic sectors (mentioned by several countries' H_2 strategies). The EU expects each EUR 1bn invested in H_2 to create 10,570 new jobs. Taking the EUR 180bn-470bn range of envisaged investments by 2050, this would represent ~2m-5m new jobs. Also, we believe the ESG concerns around H_2, namely electricity & water requirements, and safety appear addressable.

In this report, we discuss each of the policy catalysts that investors should keep an eye on to differentiate between the enthusiasm and the opportunity. While not all lights are green, we think several catalysts have already materialized and others are sending encouraging signals. In particular, we believe that catalysts have materialized related to the clarification of ambitious long-term decarbonisation targets. We are now seeing encouraging signals, with policies emerging to support both green and low-carbon H2 production and also to support demand from hard-to-abate sectors. We believe that concrete enactment of this policies into law would provide additional visibility and de-risk financing mechanisms.

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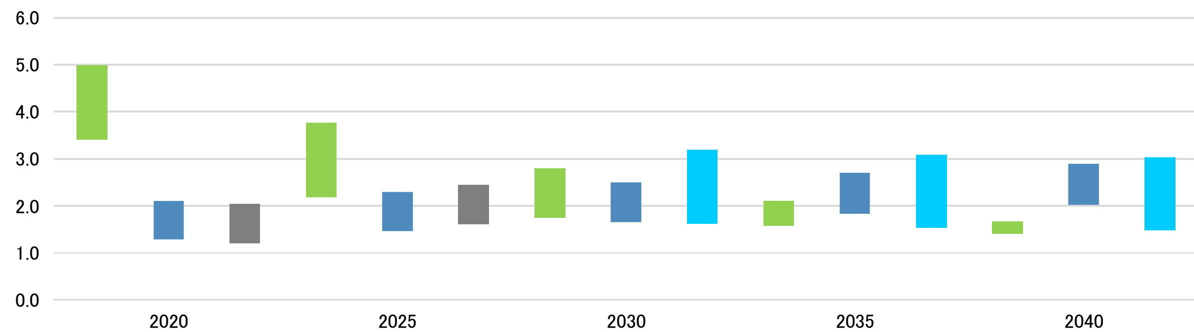
Green H_2 costs rapidly falling with declining renewable costs & electrolyser industry scaling up; but scope for blue H_2 to play a transitional role in the US

With power costs ~70% of the levelised cost of green H_2, further declines in wind & solar power costs should further reduce green H_2 costs. Also, the electrolyser manufacturing industry is rapidly scaling up, also helping lower system prices. We expect Green H_2 costs could fall **from \$3.4-5/kg today to \$1.7-2.8/kg by 2030E,** which will enable green H_2 to be a cost competitive alternative across a number of end uses and against Blue H_2. Nevertheless, we expect blue H_2 could remain cost competitive in the US at least until 2030 and could play a greater transition role in there if Carbon Capture policy is supportive.

Figure 3: How will H_2 costs progress?

Green, blue, grey, and turquoise levelised cost of H2 range over time, \$/kg



Source: J.P. Morgan estimates, Company data.

Time to be realistic where H_2 can compete for demand – steel, commercial vehicles achievable, but utility power generation, heating more challenging

Declining costs will enable transitioning with H_2 across a number of sectors, particularly for large scale industrial users who can better navigate the transition and where H_2 is already used today (ie refining, ammonia). Also, the EU steel industry is rapidly advancing H_2-derived steel projects with increasing scale. We expect Fuel Cell EVs (FCEV) to gather momentum, particularly among commercial vehicles and Asia, but we estimate the total cost of ownership for passenger FCEVs still needs to fall by ~45%. However, some potential end-uses for H_2 will be less likely to be widely adopted. We expect that H_2 power generation will likely remain more expensive than other energy storage alternatives. Also, H_2 for residential heating still appears higher cost than other low CO_2 alternatives, such as heat pumps.

Investing in H_2: plenty of H_2 volumes, harder to see H_2 value; increasing competition could drive margin pressure & valuations appear challenging

Nevertheless, finding opportunities to play the H_2 theme is still difficult, with H_2 exposure among major corporates still currently modest and H_2 pure-plays either relatively small or still not profitable. Although we expect at least 45% CAGR in global electrolyser installed capacity by 2030, increasing competition among OEMs will likely lead to several more years of cash burn for some manufacturers.

In EMEA, initiate on ITM at OW& Nel ASA at Neutral. In US, OW on Nikola, Neutral on Bloom & Plug Power, and UW on FCEL

Among the H_2-focused stocks in EMEA and North America, some of which have risen by >1,000% since Jan'19, we believe valuations appear more challenging now. Thus, we initiate coverage on ITM at OW with a 700GBp/sh PT (~34% upside potential) given its more conservative growth strategy, more capital efficient growth,

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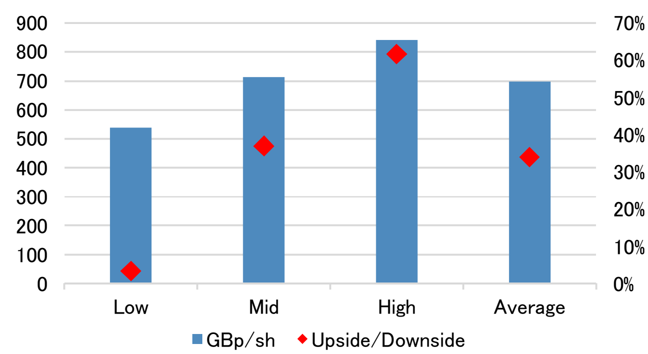
and stronger cash position. We initiate coverage of Nel ASA at Neutral and a NOK28/sh PT (~5% upside potential) given its more aggressive growth strategy which increases the risk of raising equity again before turning FCF positive in CY'25E. Among the US H_2 focused stocks, we are OW on Nikola, Neutral on Bloom Energy & Plug Power, and UW on Fuel Cell Energy Corp (all covered by Paul Coster).

Table 1: US & European H_2 focused companies covered by J.P. Morgan

Bloom Energy (BE US)	**Fuel Cell Energy (FCEL US)**	**Nikola Corp (NKLA US)**
Neutral	Underweight	Overweight
Price Target - $38/sh	Price Target - $10/sh	Price Target - $35/sh
Share price - $28.47/sh	Share price - $17.76/sh	Share price - $20.89/sh
Market cap (US$m): 4,731	Market cap (US$m): 5,726	Market cap (US$m): 8,024
Focus: Solid Oxide Fuel Cell manufacturing	Focus: Flexible Fuel Cell manufacturing	Focus: H2 Fuel Cell EV Trucks
Plug Power (PLUG US)	**Nel ASA (NEL NO)**	**ITM Power (ITM LN)**
Neutral	Neutral	Overweight
Price Target - $70/sh	Price Target - NOK 28/sh	Price Target GBp 700/sh
Share price - $48.76/sh	Share price - NOK 27.04/sh	Share price GBp 521/sh
Market cap (US$m): 24,503	Market cap (US$m): 4,494	Market cap (US$m): 4,040
Focus: PEM Fuel Cell & electrolyser manufacturing	Focus: PEM & alkaline electrolyser manufacturing & H2 refueling stations	Focus: PEM electrolyser manufacturing & H2 refueling stations

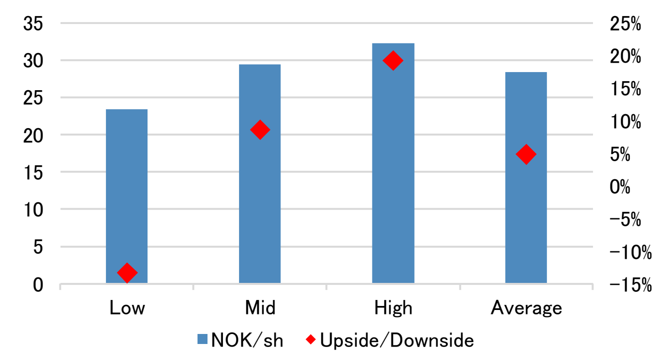
Source: J.P. Morgan estimates, Company data. Priced as of 22 Feb'21

Figure 4: ITM Fair Value scenarios
ITM Fair Value scenarios (lhs) & Upside/downside to share price (rhs)



Source: J.P. Morgan estimates, Company data. Priced as of 22 Feb'21

Figure 5: Nel ASA Fair Value Scenarios
Nel ASA Fair Value scenarios (lhs) & Upside/downside to share price (rhs)



Source: J.P. Morgan estimates, Company data. Priced as of 22 Feb'21

Table 2: Hydrogen relevant companies in EMEA

Stock	Sector	JPM Analyst	JPM Rating	JPM Price Target	Share price	Comment
ITM Power (ITM LN)	Alt Energy - Hydrogen	Patrick Jones	Overweight	GBp 700.0	GBp 521.0	PEM focused electrolyser manufacturer, recently commissioned 1GW plant in UK. Nascent H2 fueling segment.
Nel ASA (NEL NO)	Alt Energy - Hydrogen	Patrick Jones	Neutral	NOK 28.0	NOK 27.0	H2 focused company manufacturing both alkaline & PEM electrolysers and Fueling stations. Growing to >2GW by 2025
SSAB (SSABA SS)	Mining & Steel	Luke Nelson	Underweight	SEK 34.0	SEK 37.1	SSAB's HYBRIT project aiming for commercial H2-derived steel by 2025. Arguably leader for low CO2 steel
Anglo American (AAL LN)	Mining & Steel	Dominic O'Kane	Neutral	GBp 3,000.0	GBp 2,807.0	Fuel Cell Mining truck pilot project at Mogalakwena PGM Mine in South Africa. Fuel Cell vehicle adoption offers upside to Platinum demand
Rio Tinto (RIO LN)	Mining & Steel	Dominic O'Kane	Overweight	GBp 6,940.0	GBp 6,320.0	Research JV to develop low CO2 steel technology. MoU for feasibility study on industrial scale H-DRI plant in Canada
Siemens Energy ENR GY)	Cap Goods	Andreas Willi	Overweight	EUR 31.0	EUR 31.4	Produces H2 PEM electrolysers. Partnering with Air Liquide to develop large-scale green H2 projects
Siemens Gamesa (SGRE SM)	Cap Goods	Akash Gupta	Overweight	EUR 35.0	EUR 32.2	Developing combined offshore wind & H2 electrolysers in partnership with Siemens Energy & Equinor
Vestas (VWS DC)	Cap Goods	Akash Gupta	Underweight	DKK 700.0	DKK 1,230.5	Potential to follow SGRE with combined offshore wind & H2 electrolysis capacity to produce Green H2
Alstom (ALO FP)	Cap Goods	Akash Gupta	Overweight	EUR 52.0	EUR 40.4	Developing H2 Fuel Cell trains.
Air Liquide (AI FP)	Chemicals	Chetan Udeshi	Neutral	EUR 130.0	EUR 131.1	Major grey H2 producer today. Several green H2 projects inc 200MW H2V project Normandy. ~19% shareholder in Hydrogenics.
Iberdrola (IBE SM)	Utilities	Javier Garrido	Neutral	EUR 11.0	EUR 10.3	Green H2 projects in Spain & Scotland. Partnered with Nel to create Iberlyser to develop green H2 projects in Spain
Orsted (ORSTED DC)	Utilities	Javier Garrido	Overweight	N/A	983.4	Potential for combined offshore wind & H2 electrolysis to produce green H2 in Northern Europe
Snam (SRG IM)	Utilities	Javier Garrido	Neutral	EUR 4.9	EUR 4.3	Projects in partnership with FS & Alstom for H2-mobility (trains) and investments in electrolyser manufacturers (ITM, De Nora)
Plastic Omnium (POM FP)	Autos	Jose Asumendi	Overweight	EUR 40.0	EUR 32.0	Developing H2 tanks for buses. Created a JV in Oct'20 with ElringKlinger named EKPO to develop fuel cell stacks
ElringLinger (ZIL2 GY)	Autos	Jose Asumendi	Neutral	EUR 9.0	EUR 13.9	Created EKPO JV with Plastic Omnium in Oct'20 to develop fuel cell stacks
Gazprom (OGZD LI)	Oil & Gas	Alex Comer	Overweight	US$ 6.5	US$ 6.0	Major gas exporter today, developing Methane Pyrolysis ('turquoise H2') technology. Created 'Gazprom Hydrogen' subsidiary for H2 projects.
Wood Group (WG\ LN)	Oil & Gas	James Thompson	Overweight	GBp 390.0	GBp 297.3	Proprietary steam methane reformation technology. Installed ~3% global H2 demand. Concept Engineer for a number of blue & green H2 Projects
Equinor (EQNR NO)	Oil & Gas	Christyan Malek	Overweight	NOK 190.0	NOK 156.3	Best-in-class O&G CO2 intensity + Offshore wind business = EU Oil Majors ET leader. Also active approach on hydrogen/CCS.

Source: J.P. Morgan estimates, Company data. Priced as of 22 Feb'21

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Hydrogen – Quick chemistry 101

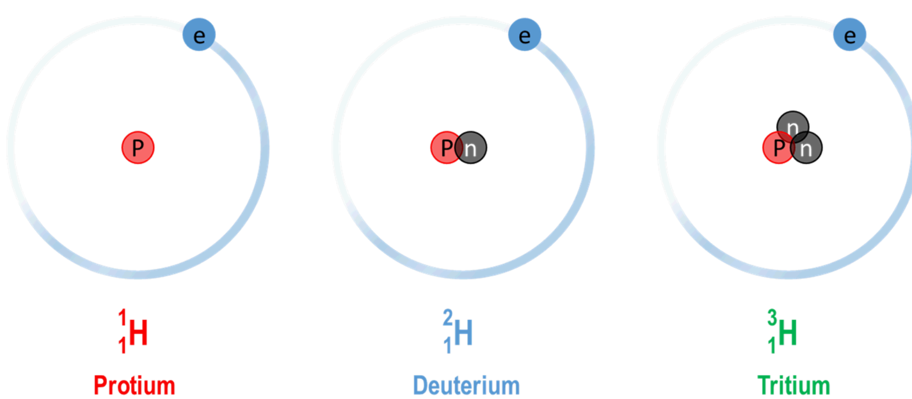
Not a new molecule

Hydrogen is anything but new. The molecule was discovered in 1766, and separated for the first time in 1800, as the first water electrolysis was performed on May 2nd 1800, by Sir W. Nicholson and Sir A. Carlisle, a few days after the invention of the first electric cell by A. Volta.

The lightest chemical element in the universe

Hydrogen is the lightest chemical element in the universe. This refers to the fact that its most common isotope (protium) has an atomic nucleus of only a single proton. This isotope represents 99.98% of hydrogen isotopes in terms abundance, while the two others, deuterium and tritium, only exist in trace amounts.

Figure 6: Hydrogen atom is the lightest chemical element in the universe

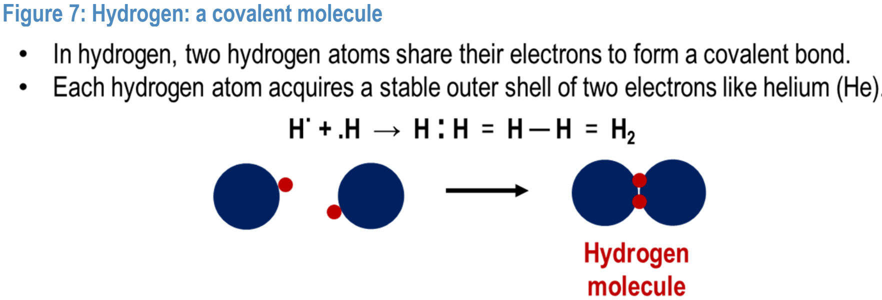


Source: J.P. Morgan

An energy vector, rather than an energy source

The fact that protium contains only 1 electron implies that it is highly instable. As a result, atoms of hydrogen tend to form a covalent bond (H_2) in order to form a more stable molecule, with a stable outer shell of two electrons like helium.

Figure 7: Hydrogen: a covalent molecule



Source: J.P. Morgan

It is worth noting that very few hydrogen molecules exist in a natural state. With the exception of rare geological formation, hydrogen basically exists only in compounds,

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e.g. water – H_2O, or hydrocarbons – CnHm – i.e. organic compounds consisting of hydrogen and carbon, such as for example methane (CH_4). As a result, significant amounts of energy must be expended to produce it, by dissociating the compound molecules. Therefore, **hydrogen is mostly considered as an energy vector, rather than an energy source.**

A less dense but more calorific gas than methane

Hydrogen's physical and energy properties are often compared to those of natural gas (methane). Hydrogen typically:

- Is less dense than CH_4. As such, it occupies a larger volume, as its mass density is almost 10 times lower than methane's.
- Has a higher calorific value: Its combustion is 2.5 times more exothermic than methane (i.e. produces more energy).

We note that during its combustion process, 1kg of di-hydrogen (H_2) consumes 8 kg of oxygen (O_2), and releases 9 l of water (H_2O). Conversely, producing hydrogen through water-electrolysis (i.e. separating the bonds between H_2 and O atoms) would require the same amount of energy. In practice, it requires more, because of efficiency losses.

Table 3: Physiochemical properties compared to hydrogen and methane

Physiochemical properties	Hydrogen (H_2)	Methane (CH_4)
Gross calorific value (GCV)	39.4 kWh	15.4 kWh
Net Calorific Value (NCV)	33.4 kWh	13.9 kWh
Volume (Nm3/kg)	11,0	1.4
Explosive energy per unit mass (g TNT/g)	24	11
Explosive energy per unit volume (g TNT/m3)	2.02	7.03
Flammable range (% vol)	13-65	6-14
Minimum ignition energy (mJ)	0.02	0.29

Source: J.P. Morgan based on France Stratégie

This high calorific value and energy density also imply some disadvantages vs. natural gas, such as a high explosivity per unit mass (but lower per unit of volume), large flammable range in air, very low ignition energy and hydrogen is exo-thermic (releases heat) when it expands. However, some of its chemical properties, such as the fact that it is lighter than air, imply that it dissipates rapidly when released in an open-air environment, which can reduce the risk.

Overall, it's important to recall that all fuels have some dangers associated with them, and that their safe use requires having appropriate systems in place to prevent situations where the three combustion factors are present: ignition source (spark), oxidant (air) and the fuel. As such, deploying H_2 requires the development of an appropriate design of the fuel systems, inc. engineering controls and guidelines to ensure safe handling and use. We comment later in this report on the implications of safety-related concerns for both the "social license to operate" of H_2 applications, and associated policymaking.

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Understanding current and future demand drivers

Yet H2's versatility makes it an ideal "energy vector"; i.e. a molecule that can be used to produce, store, move and use energy in different ways, leveraging various primary fuels.

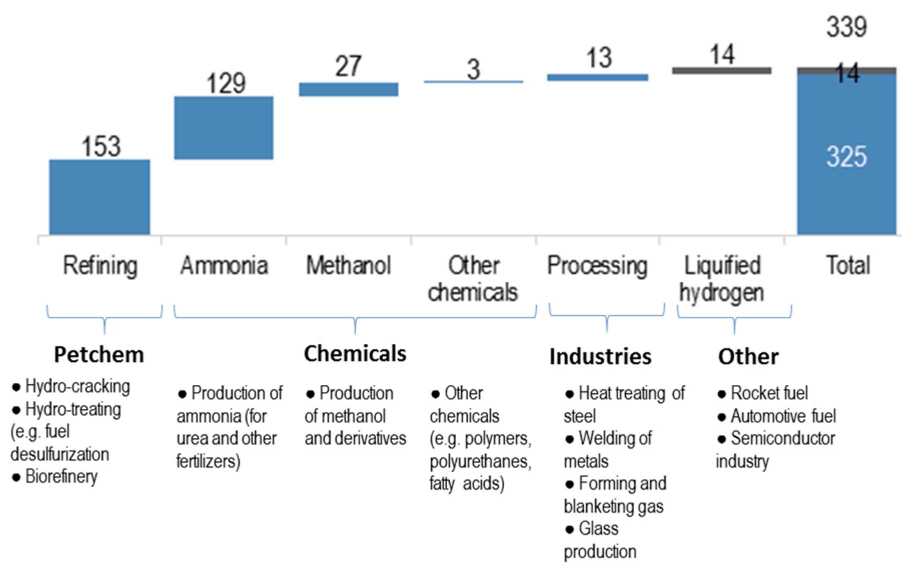
As of today, H_2 remains mostly used as a feedstock in industrial uses (oil refining, ammonia and methanol production, and steel production). As such, it currently plays no role in the energy transition. Yet H_2's versatility makes it an ideal "energy vector"; i.e. a molecule which can be used to produce, store, move and use energy in different ways, leveraging various primary fuels. We note a significant variation in the envisaged penetration of H_2 in future energy consumption depending on the decarbonization scenarios considered. However, over the recent period, key scenario providers such as BNEF and the IEA have increased the role that H_2 is meant to play in their low-carbon scenarios. In our view, there is little doubt of the opportunity that H_2 could represent in providing flexibility in the energy transition. However, realizing this opportunity will depend whether costs fall sufficiently to drive exponential demand. This will be dependent on both technological progress and political support, to unleash economies of scale.

Hydrogen is mostly used as a feedstock currently

Today, hydrogen is mostly being used as a feedstock within other manufacturing processes, rather than for its energy properties. The two largest industrial users for H_2 are the refining and chemicals industries. The refining industry uses hydrogen for hydro-cracking and hydro-treading (fuel desulfurization), while H_2 is also used for ammonia production, i.e. to produce urea and other fertilizers.

As a result, the share of hydrogen in the current energy mix remains extremely limited (e.g. < 2% of the energy mix in Europe).

Figure 8: To date, H_2 is mostly used as a feedstock rather than for its energy properties



Source: J.P. Morgan based on Fuel Cell & Hydrogen – Joint undertaking (2019)

Global demand for H_2 today is largely similar to that of the EU (above), with the majority consumed in the oil refining and ammonia industries.

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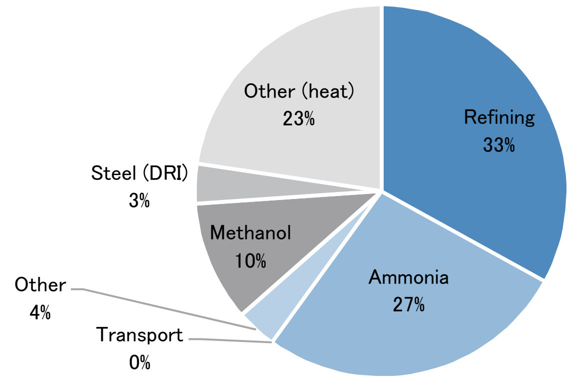
Figure 9: 2019 global hydrogen demand skewed towards refining, ammonia
Blue - consumed as pure H_2, Grey – H2 consumed with other gases



Source: J.P. Morgan, IEA, Company data.

Understanding the H_2 opportunity

The ambition of hydrogen strategies around the world is for hydrogen to move away from its use as a feedstock (number 6 in the below chart) and to grow its role as an "energy vector" in the context of the energy transition.

Indeed, as highlighted by the IEA in its "Future of Hydrogen" report, hydrogen is highly versatile, and technologies already available today would enable it to be used to produce, store, and move and use energy in a different ways:

- H_2 can be produced using various type of primary energy (renewables, nuclear, natural gas, coal and oil)
- It can be transported by pipeline or in liquid form by ships (see H_2 T&S in this report)
- It can easily be transformed into other forms of energy (e.g. methane, or electricity) to feed various end-use appliance

These potential roles are summarized in the chart below, where hydrogen is seen as:

(1) **an enabler for renewable integration**, as it helps (3) stabilize the grid to increase system resilience, while (2) allowing to distribute energy across sectors and regions at a lower cost than – for example – via the grid.

On top of this, it's seen as a **potential energy vector** to (4) decarbonize transport, in particular HDV – via the use of fuel cells, (5) decarbonize certain industrials sectors, as well as (7) building heating.

While the future potential uses of hydrogen are multiple, each of them poses different technical, policy, and economic challenges, which we explore in this report.

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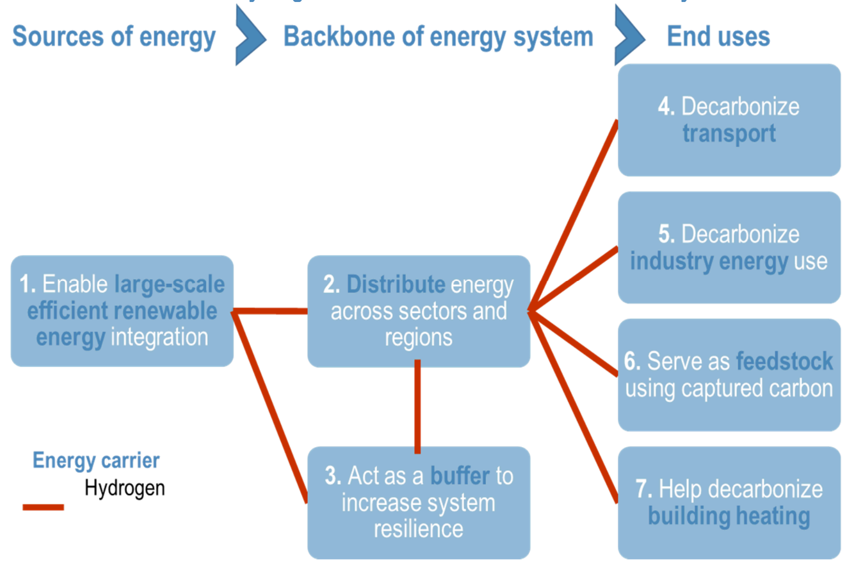
Figure 10: Potential roles for Hydrogen in the decarbonisation of the economy



Source: J.P. Morgan based on Hydrogen Europe

A silver bullet for 'hard to abate' emissions?

Decarbonising the global economy is not simply about switching from fossil-fuel-burning power to renewable power. Instead, many sectors consume fossil fuels for generating high levels of heat (steel) or as a raw material for other products (petrochemicals and ammonia). In many cases, the production process involved makes those sectors "hard to electrify", while solutions to decarbonize them carry a higher abatement cost than current higher carbon technologies, making them "hard to abate" sectors.

However, hydrogen technologies present possible solutions for several of these sectors where electrification will likely be insufficient for full energy transition. We estimate an H_2 solution could be needed for ~35% of global CO_2 emissions or ~26% of global GHG emissions.

- **Transportation** – The global Autos industry is rapidly electrifying Passenger Vehicles given improvements in battery technology and the relatively light payloads. This will likely prove more difficult with larger trucks requiring far greater energy density (i.e. Heavy Duty trucks). Fuel replacements are also needed for aerospace and freight shipping, given these cannot be easily electrified. For aircraft, H_2 could also potentially be used to produce syngas, to replace jet fuel.
- **Buildings** – Given natural gas is still a dominant fuel for building heating and home cooking in much of the world, this needs to be replaced with either electrical heating or some other technology such as hydrogen, heat pumps, or thermal storage. Moreover, H_2 can be blended up to a certain level into existing gas networks.
- **Industrial** – One of the most difficult sectors for energy transition, which also presents the greatest emissions reduction opportunity on our estimates, is steel production, which represents ~12% of global GHG emissions through the consumption of coking coal. Cement production also uses significant amounts of thermal coal and limestone.

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Table 4: Understanding hard-to-abate sectors & potential H_2 solutions

	Transport				Buildings			Industrial			
End use sector	Light Vehicles	Heavy Duty Vehicles	Air Travel	Shipping	Heating & Cooling	Cooking	Water Heating	Primary Steel	Cement	Chemicals	Oil Refining
% Global CO2 emissions	13%	11%	4%	4%	7%	6%	2%	12%	4%	1%	3%
Electrification possible?	Yes	Difficult	No	No	Yes	Yes	Yes	No	No	No	No
Hydrogen alternative possible?	Yes	Yes	Nascent	Nascent	Yes	Yes	Yes	Yes	Some	Some (specific applications)	Some (specific applications)

Source: J.P. Morgan estimates, Company data.

Where can the H_2 opportunity realistically materialize?

Hydrogen solutions might not be feasible across all hard-to-abate sectors given their unique energy requirements or chemical processes.

Both electrification and H_2 solutions possible? Long-term competition possible. Some sectors could utilize both electrical and H_2 solutions depending on local market variations or geographic limitations. For example, although electrification of light passenger vehicles is quickly accelerating, Fuel Cell EVs could take off in markets which will need to find a way to 'import' renewable power, such as Japan, South Korea. Both could also play some role in residential heating and grid regulation.

Electrification not possible, but H_2 solution possible? H_2 sweet spot. Some end uses appear far harder or impossible to fully electrify, such as heavy duty trucks or steel production. Given H_2's high energy density, FCEVs offer a solution for trucks where batteries would subtract from a vehicle's net payload. H_2 also offers a credible pathway for transitioning the steel industry which arguably requires less of a technological leap given how the steel industry uses natural gas (CH_4) today.

Electrification possible, but H_2 solution not possible? Simple electrification. Some sectors simply will not require an H_2 solution to transition, such as most electricity generation or aluminum smelting (which is already electrified).

Neither electrification nor H_2 solutions possible? CCS likely needed. Some sectors still present greater challenges for transitioning, with neither electrification nor H_2 offering clear solutions to transition to a low carbon economy. One such sector is the cement industry, which uses significant amounts of limestone in the calcination process to produce clinker. Although the energy source for this could be substituted (i.e. coal), the consumption of limestone to produce clinker is still a CO_2-intensive stage of cement production.

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Table 5: Electrification vs 'Hydrogenisation' - which approach for which sector?

		Electrification possible?	
		Yes	**No**
H2 Solution Possible?	**Yes**	**Both could compete:** home heating, most electricity output, light vehicles	**H2 sweet spot:** Steel, Heavy duty vehicles, aerospace, shipping
	No	**No opportunity for H2 likely:** aluminium smelting, most power generation	**Neither offers a large scale solution**, so CCS development likely needed: Cement

Source: J.P. Morgan estimates, Company data.

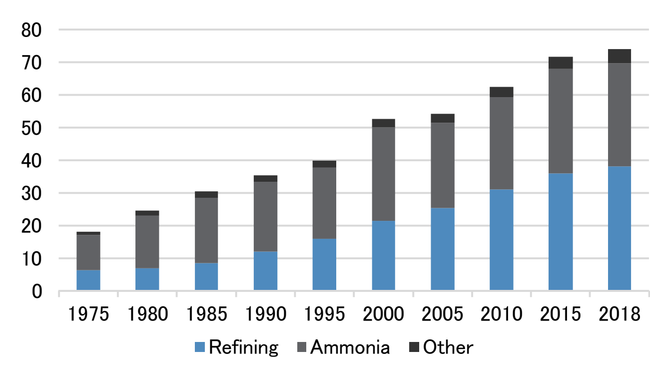
How much could H_2 demand grow?

With so many potential end-uses for hydrogen from various sectors, H_2 demand would need to grow substantially from its current level of ~75Mt in 2018. However, estimates for future demand vary depending on the level of H_2 adoption, which is mostly influenced by 1) policy support and 2) improvements in H_2 economics. We discuss these two components in detail in the following sections.

BNEF estimates the theoretical max for global H_2 demand to be ~1.4btpa by 2050E, ~20x greater than current demand. However, even with strong policy support, it is more likely to be ~700Mtpa by 2050, ~10x current demand according to BNEF. Also, the IEA's Sustainable Development Scenario – i.e. a 'backcasting' scenario compatible with delivering on the Paris Agreement's goals – envisions only ~300Mtpa of H_2 demand, ~4x higher than today.

Figure 11: Global H_2 output has grown by >3% CAGR since 1975

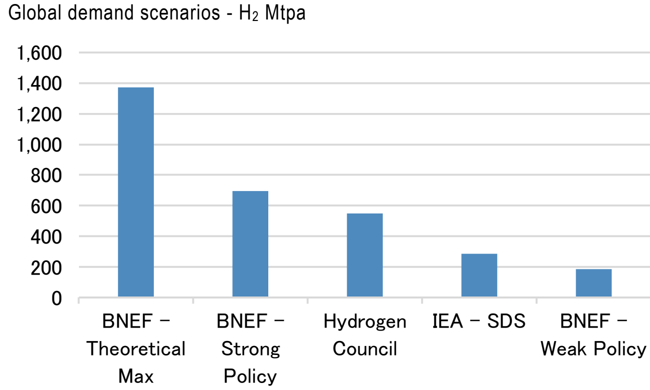
H_2 mt



Source: Company reports.

Figure 12: H_2 set to grow dramatically from ~75Mtpa today

Global demand scenarios - H_2 Mtpa



Source: J.P. Morgan estimates, Company data.

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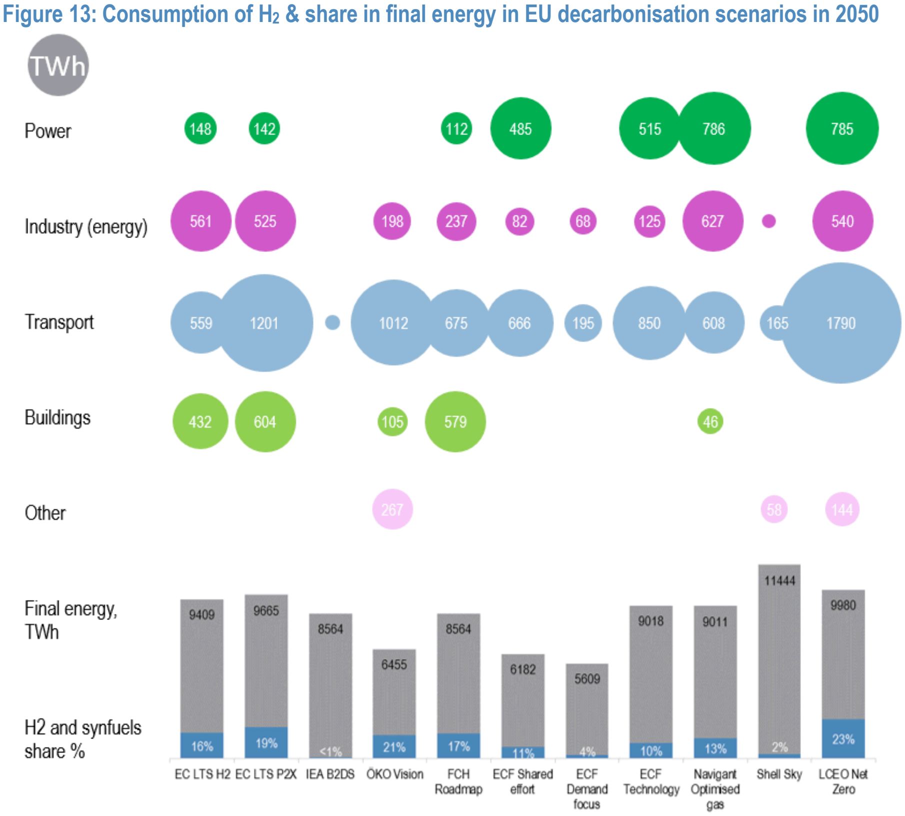
Comparing H_2 in Climate-Energy scenarios

In its Hydrogen Strategy published in July, the European Commission highlighted its ambition to grow the share of H_2 in its energy mix from less than 2% today, to up to 13-14% in 2050. The importance of the policy objective and the underlying supports can be easily understood by comparing various "Climate / Energy" scenarios.

In a Factsheet published by the EU Joint Research center in 2019, Moya et al. highlight that estimates for H_2 use in the energy mix by 2050 range from 2% to 23%, depending on Energy / Climate scenarios considered. The share of H_2 and synfuel is typically higher in the EU's own scenarios, such as the EU Commission's EC LTS H2 (16%), EC LTS P2X (19%), and the EU Joint Research Center (LCEO Net Zero, 23%). Other optimistic scenarios for H_2 penetration include the Öko Institute's (a German independent research center) "Öko Vision" scenarios.

Figure 13: Consumption of H_2 & share in final energy in EU decarbonisation scenarios in 2050



Source: J.P. Morgan based on EU Joint Research Center – 2019 (available here):

Note: Hydrogen for non-energy uses is not included, hydrogen for synfuels is included based on 75% efficiency (for EC, ECF and Öko scenarios). Hydrogen for power generation is not consumed as final energy. Scenarios: **EC**: A Clean Planet for all - A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy, European Commission, 2018, November; **IEA**: Energy Technology Perspectives 2017, International Energy Agency, 2017, June; **ÖKO**: The Vision Scenario for the European Union, 2017 Update for the EU-28, Öko-Institute, 2017, February; **FCH**: Hydrogen Roadmap Europe, Fuel Cells and Hydrogen, Joint Undertaking (FCH 2 JU), 2019, February; **ECF**: Net Zero by 2050: from whether to how, European Climate Foundation (ECF), 2018, September; **Navigant**: Gas for climate, Ecofys / Navigant, 2019, March; **Shell**: Sky - Meeting the goals of the Paris Agreement, Shell, 2018, March (regional coverage is EU+); **LCEO**: Deployment Scenarios for Low Carbon Energy Technologies, Joint Research Centre, 2019, January.

However, other scenarios considered at the time, the IEA's B2DS scenario from 2017 and Shell's "Sky" scenario, were much less optimistic, envisaging <1% and 2% of penetration respectively. Note that for some of these organizations, other modelling

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exercises, such as the IEA's new "SDS" scenario, envisage a higher penetration. In addition, one notes that the sector split of the envisaged use of H_2 varies significantly depending on the scenarios, with Transport and Industry (energy) applications being the most commonly considered.

The critical question is not how much future H2 demand can be, but instead whether costs can fall sufficiently to drive an exponential growth in H2 demand.

Thus, with such a range of growth forecasts, the critical question is not how much future H_2 demand can be, but instead whether costs can fall sufficiently to drive an exponential growth in H_2 demand.

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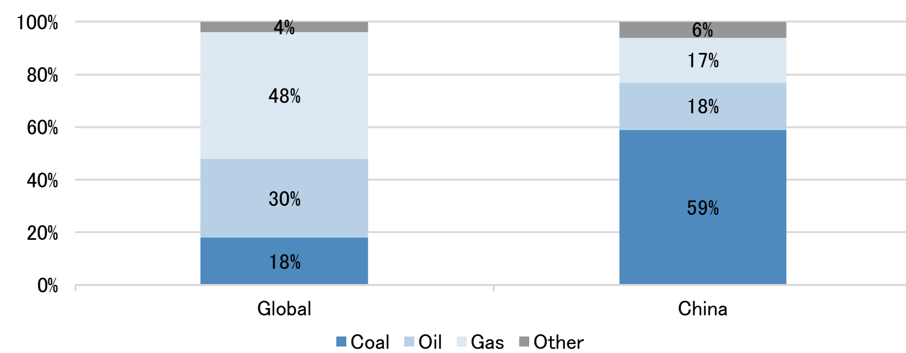
Understanding current & future supply

The H_2 industry has been dominated by fossil fuels since the 1970s when steam methane reforming became the dominant production method. However, water electrolysis ('green H_2') has been used for nearly 100 years and the industry is rapidly growing again as policy makers and corporates focus on decarbonizing 'hard to abate' sectors. Also, newer alternative H_2 production technologies, such as Blue & Turquoise H_2, could play a role as technology improves and costs fall.

H_2 output today dominated by fossil fuels

The global hydrogen industry today is dominated by fossil fuel-based production, with gas, oil, and coal consuming methods representing ~96% of global H_2 output. However, this was not always the case. Water electrolysis ('green' H_2) was the standard production method before the 1960s/70s when steam methane reformation technology became dominant. This was followed by the build-out of China's hydrogen industry, which has largely depended on coal gasification given the country's significant domestic coal resources and lack of natural gas resources.

Figure 14: Fossil fuel based H_2 production currently dominates
Global & China H_2 production by source



Source: J.P. Morgan estimates, BNEF, Company data.

How to produce hydrogen? Understanding the H_2 Rainbow

'Brown' coal gasification – H_2 can be produced by reacting coal with oxygen and steam under high pressures and temperatures to form synthesis gas (syngas), a mixture of carbon monoxide and hydrogen. However, coal gasification is extremely CO_2 intensive, with ~16kg of CO_2 emitted for every kilogram of H_2 produced. In China, given gasification is relatively inexpensive and coal is a cheaper feedstock than natural gas, this has been the predominant method of H_2 production.

'Grey' natural gas steam methane reformation ('SMR') – In this process, high-temperature steam (700-1,000C) reacts with natural gas (CH_4) in the presence of a catalyst. This process can also be used to produce H_2 from ethanol, propane, or gasoline. However, as with coal gasification, steam methane reforming is a CO_2 intensive process, emitting ~9kg of CO_2 for every kilogram of H_2 produced. This is the primary method of producing hydrogen globally ex China since the 1970s.

'Blue' SMR with carbon capture & storage (CCS) – 'Blue H_2' is simply grey H_2 combined with Carbon Capture & Storage, where the CO_2 is captured immediately

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after the reforming process and is then either utilized in another chemical process or sequestered. This dramatically reduces the CO_2 emissions from steam methane reforming by 70-90% and benefits from utilizing existing natural gas infrastructure and SMR facilities. However, it still emits 3-6kg of CO_2 per kilogram of H_2. Blue H_2 is gaining more interest, but only a small proportion of global H_2 output today is produced using SMR+CCS.

'Turquoise' methane pyrolysis – Methane pyrolysis directly splits methane into H_2 and carbon black by bringing the methane to a high temperature under pressure (starting at 300C with completion at 1,000C). This process benefits from having zero process emissions of CO_2, given no oxygen is introduced into the process. Turquoise H_2 can also utilise existing natural gas infrastructure (H_2 production at point of consumption). Commercial viability of methane pyrolysis has not yet been demonstrated, but **BASF** (Underweight, covered by Chetan Udeshi) and **Gazprom** (Overweight, covered by Alex Comer) are working to develop and commercialise the technology.

'Green' water electrolysis – Hydrogen using water electrolysis is produced by using an electrical current to split water into hydrogen and oxygen with a metal catalyst. Electrolysis requires significant power and was a relatively niche industry until recent interest sparked greater focus on using green H_2 to decarbonise various 'hard-to-abate' sectors. Given no fossil fuels are used, the process produces no CO_2 emissions. Water electrolysis technology has been used for hydrogen production for more than 100 years, but as fossil fuel derived processes became cheaper, the use of electrolysis fell sharply from the 1970s onwards.

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Table 6: Understanding the Hydrogen Rainbow - from brown to turquoise

Description of the various H_2 production technologies

Colour	Name	Production Method	Carbon credentials	Pros	Cons	% of H_2 output today
Brown	Coal Gasification	H2 can be produced by reacting coal with oxygen & steam under high pressures and temperatures to form synthesis gas, a mixture of carbon monoxide & hydrogen. CH0.8 + O2 + H2O → CO + CO2 + H2 + other species	Direct CO2 emissions ~16kg CO2/ H2, kg, inc process & supply chain emissions	Existing technology well used and offers cheap hydrogen using readily available coal. This process is predominantly used in China	Huge amounts of CO2 produced and extremely environmentally unfriendly. Also requires access to fossil fuels. Costs likely to increase as carbon taxes become higher/ more widely prevalent	18%
Grey	Steam Methane Reformation	Hydrogen from methane usually from natural gas via steam or auto thermal reformation with CO2 as a by-product (currently the main manufacturing route). CH4+2H20 → 4H2 +CO2 27KJ/mol H2	Direct CO2 emissions ~9kg CO2/ H2 kg. Overall LCE ~10-17 kg CO2 per H2 kg	Existing technology well used and offers cheap hydrogen at ~2-3x cost of input natural gas	Huge amounts of CO2 produced and extremely environmentally unfriendly. Also requires access to fossil fuels. Costs likely to increase as carbon pricing become more prevalent	Natural gas: 48%, Oil: 30%, Total 78%
Green	Electrolysis	Hydrogen from electrolysis of water using 100% renewable electricity. H2O → 2H2 + O2 285 KJ/mol H2	Zero direct CO2 emissions in production process but overall LCE of 1-5kg CO2 per H2 kg	Zero CO2 emissions; offers an integrated approach to renewable electricity generation and storage. Costs expected to fall over time. No requirement for fossil fuels, politically favoured	Currently expensive & inefficient vs direct electrification. Requires huge amounts of cheap renewable electricity and water. Greater challenges around transportation & storage	<1%, but most water electrolysis today not using renewable, zero CO2 power
Blue	SMR ('Grey') with Carbon Capture & Storage	Uses methane in the same processes as for Grey hydrogen but uses Carbon Capture and Sequestration to (CCS) to dramatically reduce CO2 emissions	Direct emissions ~ 1kg Co2 per H2 kg. Overall LCE ~ 3-6 kg of CO2 per H2 kg due to CCS	Offers 70-90% reduction in CO2 emissions. Reasonably cheap depending on carbon capture & gas cost. Uses existing infrastructure	Still leaves material CO2 emissions (inc upstream). Political resistance to CCS in a number of areas and cost of CCS could be relatively high.	Negligible
Turquoise	Methane Pyrolysis	H2 is produced by direct splitting of methane using pyrolysis to yield H2 and solid carbon black.CH4 → 2H2 + C 37KJ/mol H2	Production process produces zero CO2 but overall LCE of ~2-9 kg CO2 per H2 kg	In theory zero process emissions and in theory cheap H2. Can use existing gas infrastructure	Still from fossil fuels so political resistance as methane leakage from upstream and gas transport can push up carbon emissions. Still an unfounded technology at scale and requirement to dispose of significant carbon black	Negligible

Source: J.P. Morgan estimates, Company data.

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H2 Policies – catalysts are materializing

Hydrogen has encountered previous periods of hype which proved to be deceiving. However, political announcements in 2020, in a COVID-19 economic context, brought it back to the top of the agenda of many stakeholders. In this section, we review in detail the H_2-related policy announcements from various countries, and we outline the reasons why we think that that this time could be different for hydrogen.

Is it different this time?

Both BNEF and IEA have highlighted what they would consider as policy catalysts for the uptake of the hydrogen economy. While not all lights are green, we observe that several of them progressing well.

Table 7: Not all lights are green, but several catalysts are materializing for H2 to grow in scale

Catalyst	Status	Our comment
Establish Targets and long term policy signals	Green	Increased climate ambition already seen in 2020. More to come with COP 26
Net zero climate targets are legislated	Orange	Currently ongoing; 2% of carbon neutrality targets in law, and 9% in proposed legislation.
Support to strategic sectors that can allow for a "Fair Energy Transition"	Green	Scaling up an H2 economy has the potential to create significant amount of new direct and indirect jobs.
Harmonising standards, removing barriers	Orange	Currently ongoing; Recent uptake in international public & private cooperation networks are encouraging.
Promoting R&D, strategic demonstration projects and knowledge sharing	Green	Largely the case already. Recent technology roll out announcements represent a change in scale.
Hydrogen-ready equipment becomes common place	Red	Not yet the case. Would require scaling up both supply and demand to trigger a virtuous cost reduction cycle and "H2 culture".
Support to renewables deployment	Green	Pledges towards renewable deployment are likely to be increased at COP 26; Moreover, existing policy supports and market trends makes renewable deployment sufficient to cope with current envisaged Green H2 deployment.
Support to CCS	Orange	CCS deployment has not significantly increased in the last decade. Yet, we believe negative perceptions are weakening as the role of NET is increasingly recognized.
Mitigating Investment risks Targets with investment mechanisms are introduced	Red	Encouraging signals can be found in national strategies. However, readability of underlying financing mechanisms and support mechanisms remains too low
Support demand creation Stringent HDV emissions standards are set Mandates and markets for low emissions products are formed Industrial decarbonization policies and incentives are put in place	Orange	Encouraging signals can be found in national strategies, reinforcing pre-existing policies esp. in the mobility sector. Hard to abate sectors and industrial usages of H2 are also now increasingly a target, albeit concrete policy implementation will be needed.

Source: J.P. Morgan; Note: Red = lagging; Orange = encouraging; Green = On Track.

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An acceleration of country H_2 specific commitments in 2020

Hydrogen deployment is becoming part of announced political ambitions

2020 can be seen as a turning point in terms of announced support to the deployment of low-hydrogen. While some countries had already strategies in place, in 2020 ten countries and the European Union announced Hydrogen Strategies.

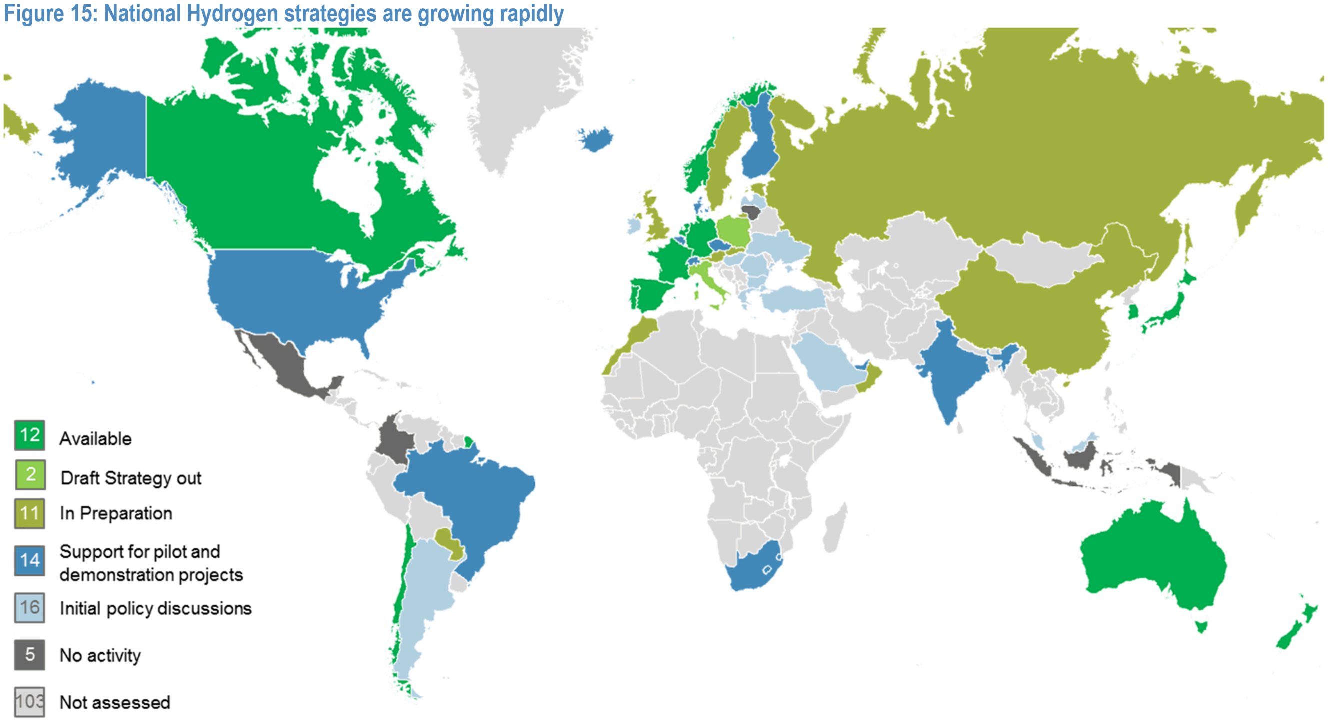
Table 8: 2020 a tipping point for countries' H_2 strategies

	January	February	March	April	May	June	July	August	September	October	November	December
2017												Japan
2018						France						
2019	South Korea								New-Zealand		Australia	
2020				Netherlands		Germany	EU		France (2nd)	Spain	Chile	Canada
							Portugal			*Poland (Draft)*	*Italy (draft)*	
											USA	
2021	United Kingdom											
Undefined	Austria	China	Estonia	Luxembourg	Morocco	Oman	Paraguay	Russian Federation	Slovakia	Sweden		

Source: J.P. Morgan; Note: as strategy, we captured both roadmaps and "strategies" as long as published by public institutions.

As of Feb 2021, 12 countries have national hydrogen strategies available, 2 have published draft strategies, and 11 others are in preparation (The UK is expected to announce its own in Q1 2021). Moreover, several countries are also supporting pilot projects and having initial policy discussions around H_2 strategies.

Figure 15: National Hydrogen strategies are growing rapidly



Source: J.P. Morgan based on BNEF and World Energy Council

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These H_2 strategies are not synonymous with policy mechanisms enacted in laws, which would warrant that envisaged targets will be reached. However, they represent significant political milestones, as they set a long-term vision shared with industries and guide multiple stakeholders. These strategies set policy priorities that consider the specificity of national conditions for the development of the parts of the H_2 value chains that are the most relevant for the respective geographies. While these strategies vary in terms of depth, we analyzed them based on the following angle: overall country positioning, envisaged investments, announced technology deployments as well as envisaged policy mechanisms and international cooperation initiatives.

Reflecting on H_2 strategies around the world

The following section analyses in details the various hydrogen strategies and related policy initiatives on which we have been able to collect information. **We highlight to the reader that the result of this work – in an Excel database format – is available on demand.** While it is obvious that 2020 represented a significant acceleration of stated H_2 deployment related strategies by large countries across the globe, we note regional differences.

Asia has been an early mover on H_2. In particular, Japan adopted an H_2 strategy as early as 2017, soon followed by South Korea, New Zealand and Australia in 2019. These strategies seem set to build an integrated ecosystem, with countries specializing on different part of the H2 value chain. On the one hand, Japan and South Korea are focusing on H_2-end uses and H_2 technologies. The two countries have similar strategies, in our view, focusing on the domestic roll-out of a large H_2 mobility infrastructure and end-use. Both countries have cost-related targets for H_2, which include assumptions of H_2 being imported from overseas. On the other hand, Australia appears to harbor ambitions to become a an H_2 export hub in the region, leveraging both its abundant renewable resources for new Green H_2 production capacity and its CCS to turn existing brown and blue H_2 production into low carbon H_2 production. New Zealand, in the absence of more detailed quantified targets, remains harder to position.

However, the announcement of the EU Hydrogen Strategy represented a game changer in our view, especially from the perspective of scaling up the Green Hydrogen value chain. In particular, EU "2x 40 GW Electrolyzers capacity in 2030" target, i.e. 40 GW in Europe and 40 GW in Europe's neighbourhood with export to the EU, makes up to 80% of currently announced targets of Electrolyzer deployment. This large envisaged uptake of Green H_2 production represents the first phase of a longer-term approach, which also provides visibility and long-term guidance on how H_2 could be used in industrial sectors. More importantly, the EU strategy was backed by several country-specific strategies which followed, providing visibility on 70% of the envisaged intra-EU installed capacity by 2030. We discussed the EU H_2 strategy in detail in the following publication: Renewable H_2 at the heart of the EU Hydrogen Strategy.

On the other side of the Atlantic, we believe that the US could announce increased H_2 targets under the new Democrat administration. We note that the DoE strategy highlights that the US has been investing steadily in both blue and green H_2 related R&D for several years, having already delivered notable cost reductions. Further to the south, Chile stands out by the size of its ambitions (installing 25 GW of electrolyzers by 2030 and becoming an exporter of the cheapest Green H_2 in the world). While the country can count on its significant renewable resources, the

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current investment pledges (USD 50m) appear largely insufficient, and the country will have to rely on heavily on the private sector, and attract foreign investments.

We note potential early discussions in Saudi Arabia. The country is considering the opportunity to leverage both its renewable resources and fossil fuel reserve to produce blue and green H_2, with the potential to export it abroad. For now, no strategy has been published, but the country – alongside various international companies – is investing in a USD 5bn plant to produce green H_2, in a mega-plant (NEOM) project. Last, but not least, we note that South Africa has been discussing the potential of hydrogen for some time, through its "HySA" platform (Hydrogen for South Africa). In particular, the country could be well positioned in the electrolyser value chain to leverage its platinum reserves (>70% of global supply). However, we saw no signs of take-off regarding hydrogen over the recent period.

Investment pledges have been multiplied by a factor of 10

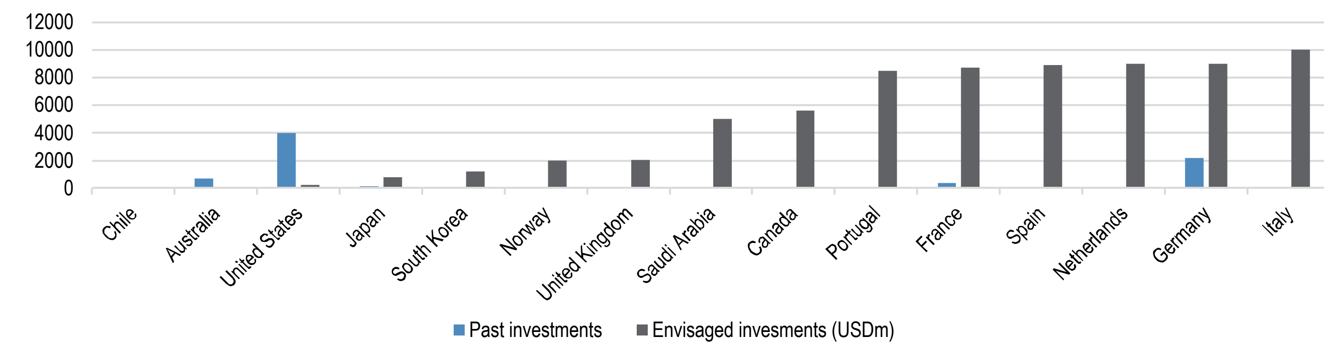
A change in scale can be observed

According to our estimates, H2 investment pledges increased x10 in 2020 vs past period, to reach USD 71bn

For most of the countries that have set strategies, these strategies have been accompanied by a change in scale in terms of investment pledges, helped by the availability of large recovery packages in response to the COVID-19 pandemic. Based on our estimates, 15 individual countries have announced envisaged investments (both public and private) for the years to come, for a total of **71 USDbn**.

As a matter of comparison, the sum of public and private investment pledges for H_2 projects referenced in the H_2 policy database from the IEA, which we complemented with desk research, represented a total of **8 USDbn**, spanning 15 countries.

Figure 16: Investment pledges have been multiplied by a factor of 10



Source: J.P. Morgan Estimates

Investment pledges still lack visibility

The EU H2 strategy estimates that public and private investments required to reach the goal it has set would represent EUR180bn-470bn for green H2 and 3bn-18bn for blue H2 by 2050.

We see our estimates as very conservative for several reasons. First, the investment pledges announced by countries cannot be easily added up to each other's. As such, we strove to consider only pledges that were specifically earmarked for hydrogen. However, in many cases, a significant share of a country's recovery package has been pledged to "green" purposes, which may include green and low carbon H_2 projects. This is the case for example in Japan, where a 2tn JPY (USD 19.2bn) new funding/tax incentives scheme was announced to support the decarbonization of private businesses, in which H_2 projects are available. We also only considered numbers announced by individual countries, to avoid double counting with announcements from supranational organizations, such as the EU. As a reminder, the EU H_2 strategy estimates that public and private investments required to reach the

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goal it has set would represent EUR180bn-470bn for green H_2 and 3bn-18bn for blue H_2 by 2050. As a result, one can expect investment pledges and projects to be scaled up further in the future. Moreover, fuel efficiency standards and subsidies for low carbon vehicles, as well as other policies (see below) represent many support mechanisms with the potential to trigger investments in H_2, which we didn't include.

While, to date, it must be concluded that there is a lack of visibility on H_2 related investment, the "change in scale" is well illustrated by some countries, when we compare past H_2 investments with most recent targets.

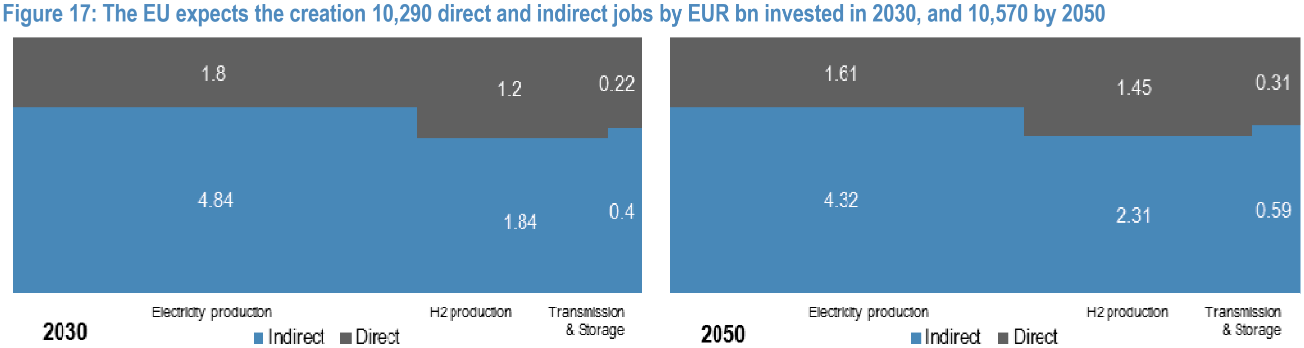
- In **France**, over the last 10y, approx. EUR 300m (USD 364m) was spent on H2 pilot projects, R&D and support to SME active in H2. The first H2 plan (2018) envisaged an investment of EUR 150m (USD 182m)/ year. The new plan targets spending EUR 7.2bn. The new hydrogen plan envisages spending EUR 7.2bn (USD 8.74bn) over the 2020-2030 period, starting with EUR 2bn (USD 2.4bn) to be spent by 2022 on Green Hydrogen, which is already earmarked in the recovery package (i.e. 2% of the EUR 100bn recovery package).
- In **Germany**, from 2006 to 2016, approx. EUR 700m in funding was approved under the National Innovation Programme on H2 and FC tech, while projects mentioned in the IEA project databases represented a total of USD 2.1 bn. Under the "Package for the future" passed, EUR 9bn (USD 10.9bn) was announced to be spent over the next 10 years. This investment can be put in perspective with the wider "climate change" component of the German recovery package (EUR 40bn – USD 49bn over a total package of EUR 130bn – USD 158bn).

COVID-19 recovery packages and ultra-low interest rate environment represent an opportunity, as an H2 economy could create jobs

The EU expects H2 to create 10,570 jobs per EURbn invested by 2050, i.e. between 1.9 to 4.9 million of new jobs.

We believe that this change in scale is driven by the specific macro-economic context, with the COVID-19 crisis effect on unemployment and the low interest rate environment making large fiscal policy packages more politically acceptable, and so an opportunity for large infrastructure projects. Moreover, we think that countries are likely to give priority support to strategic sectors that represent significant potential in terms of job creation, such as renewables and energy efficiency in buildings. Scaling up a hydrogen economy also represents a significant opportunity on that front, as mentioned by several countries in their H2 strategies, especially as it would create a significant number of jobs in electricity production. As an example, the EU provides detailed numbers on expected direct and indirect job creation expected to result from a green H2 value chain (EC; 2020), with an expected creation of 10,570 jobs per EURbn invested by 2050. Taking the EUR 180bn-470bn range of envisaged investments by 2050, this would represent between 1.9 and 4.9 million new jobs.

Figure 17: The EU expects the creation 10,290 direct and indirect jobs by EUR bn invested in 2030, and 10,570 by 2050



Source: J.P. Morgan based EU

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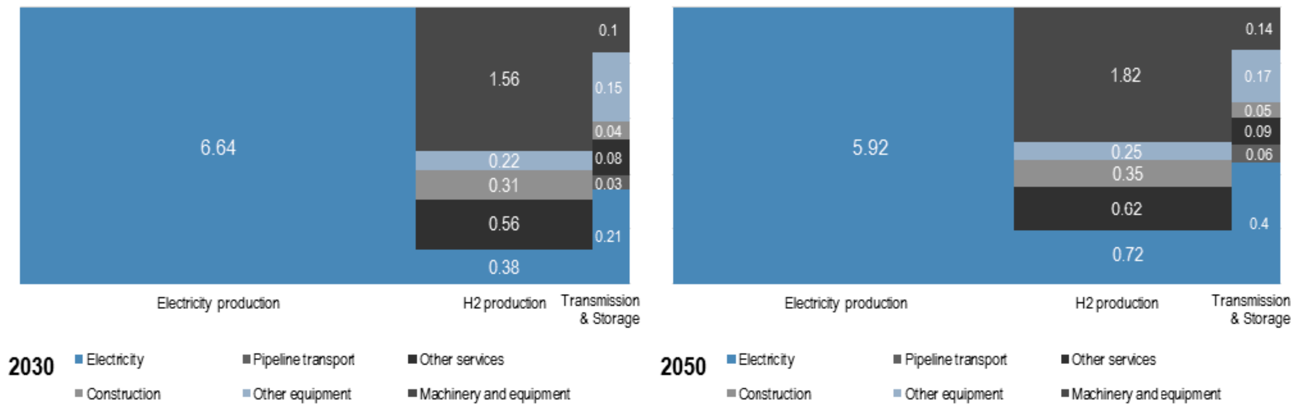
Figure 18: The EU expects ~10,600 direct and indirect job creation for every EUR 1bn invested



Source: J.P. Morgan based on EU

Cost reduction is a key strategic priority…

The ambition of countries is to support the deployment of the whole "H2 ecosystem", to trigger a virtuous circle of economies of scale by incentivizing both Green and Low carbon H2 production, while creating higher demand of for it in new applications. Several countries have set H2 production cost specific targets.

Table 9: List of countries with explicit cost targets in their H2 strategy

Country	Cost target announced
Australia	"**H2 under 2**"Target: Under its H2 strategy, Australia aims to bring H2 cost to A$2/kg (USD 1.55/kg) considered as breakeven vs alternatives in large scale deployment
Chile	Under its H2 strategy, Chile aims to bring Green H2 cost to less than USD 1.50/kg, by deploying large scale Electrolyzers capacity by 2030.
Canada	Canada ambitions to deliver a H2 production cost of CA$1.50–3.50/kg (USD 1.18 - 2.76/kg), to be achieved as production scale is realized and investment is made in distribution infrastructure.
Netherlands	Northern Netherlands envisages Green H2 to be cost-competitive with grey Hydrogen by 2030-2035n and remains cost competitive with shipping imports of green H2 while securing energy supply.
United States	The DoE in its H2 plans mentions that R&D efforts resulted in advanced production systems capable of producing carbon-free hydrogen for less than USD2/kg with CCS. Research advances in gasification and reforming technologies with CCUS including reductions in capital and operating costs, target carbon neutral H2 production at less than USD 1/kg. The DOE also mentions that the availability of lower-cost electricity (e.g.; USD 0.02-0.03/kWh) coupled with advancement in Electrolyzers technologies offers a pathway to cost competitive hydrogen at less than USD 2/kg.
South Korea	By 2040 , the annual supply of hydrogen is envisaged to reach 5,260,000 tons , and the price per kg will reach 3,000 won (USD 2.71 /kg)
Japan	The strategy ambitions to procure 300,000 tonnes of hydrogen/year by 2030. As such, the METI has set targets to reduce the cost of hydrogen to JPY30/Nm3 - normal cubic meter (by 2030), JPY 20/Nm3 (in future). The Japanese strategy aims to achieve cost parity with competing fuels, such as gasoline in the transportation sector or liquefied natural gas (LNG) in power generation.

Source: J.P. Morgan

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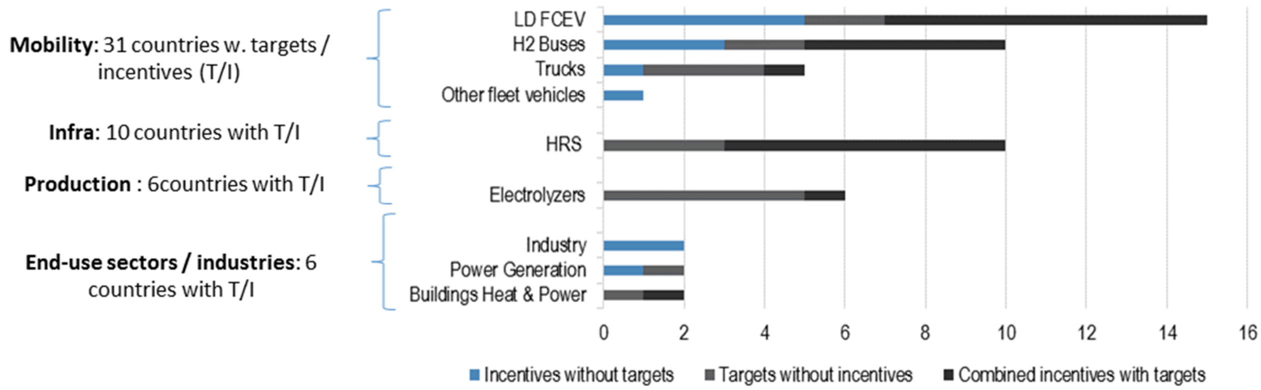
… resulting in more diversified technology rollout roadmaps

We note that the focus of countries seems to have shifted in 2020. In its Future of Hydrogen report, the IEA established a comprehensive mapping of targets and policy support for the deployment several H2 production and end-use applications. At the time, mobility related targets & incentives were dominating.

Figure 19: Pre-2020, targets & incentives were focused on mobility applications, and in particular FCEV



Source: J.P. Morgan based on IEA

Our updated mapping of countries' announced strategies seems to indicate that 2020 resulted in a more diversified set of targets. These targets are now covering the broader hydrogen value chain, addressing both supply and demand. We see this as a key condition for a successful scale-up, and a key differentiator vs. previous periods of hydrogen "hype".

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Figure 20: Overview of countries' envisaged technology roll out on H2

Geography		H2 Production		H2 Transport			Infra			Mobility						HTD sectors & Industries					Other	
Country	Region	Green H2 value chain	Blue H2 value chain (CCS)	T&S / H2 Grid	Liquid H2 ship	Blending Natgas	H2 Purification systems	HRS	HRS (HDV)	FC production	FCEV	Hydrogen Buses / HDC	Aircraft	H2 Trains	FC powered Forklift	Buildings	Power Gen	Steel	Refing & ammonia	% of energy demand (inc. In industries)	H2 Clusters	Cost targets
South Africa	Africa	■																				
Australia	Asia	■	■			■															■	■
China	Asia		■					■			■			■						■		
Japan	Asia			■	■			■			■	■										
New Zealand	Asia					■		■				■			■	■						
South Korea	Asia							■			■	■				■	■					■
European Union	EMEA	■	■	■																■		
France	EMEA	■										■	■	■							■	
Germany	EMEA	■		■				■					■	■				■	■			
Italy	EMEA	■				■								■						■		
Netherlands	EMEA	■		■		■		■			■	■	■							■	■	■
Norway	EMEA		■		■						■											
Poland	EMEA	■						■				■										
Portugal	EMEA	■				■		■			■									■	■	
Spain	EMEA	■						■			■	■		■	■					■		
UK	EMEA	■	■			■								■		■						
Saudi Arabia	MENA	■																	■		■	
Canada	NA		■																	■		■
USA	NA		■					■			■				■							■
Chile	SA	■																				■

Source: J.P. Morgan; Note: a detailed version of the envisaged technology rollout can be found in the Country "Fact Sheet" at the end of this report. The Excel database can be obtained on demand. Note that this mapping results from qualitative desk research using AI powered search tool. As such, and in spite of best efforts, it may not be fully exhaustive. We welcome any feedback to keep this database up to date.

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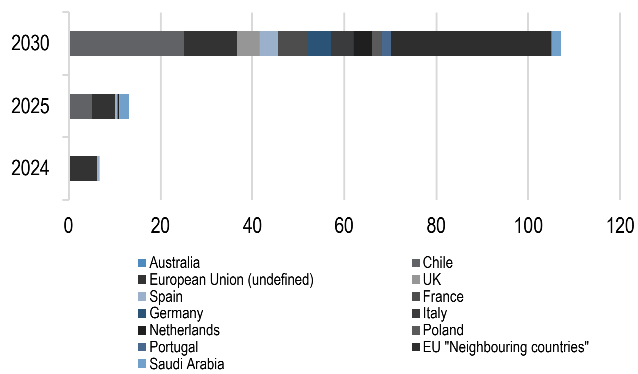
Electrolyzer deployment is now a strong target across countries, pushed by the EU's H_2 strategy

In particular, we note that a large number of countries have announced quantified targets on electrolyser deployment, which in our view should contribute to bringing the cost of Green H2 down. The EU, with its 40 GW domestic deployment by 2030, and its 40 GW in neighbouring countries, leads the charge, followed by Chile. We note that current EU country-specific targets represent 28.5 GW, i.e. approx. 70% of the envisaged 2030 target. Chile, with its 2030 "25 GW" target, is the second most ambitious, albeit envisaged investments will likely need to be private to deliver on this target.

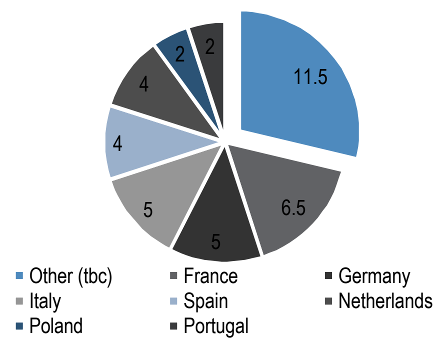
Figure 21: Expected electrolyzer capacity as per strategy targets

GW (cumulative capacity)



Source: J.P. Morgan estimates;

Figure 22: EU countries' announced 2030 targets represent 70% of 40 GW announced by the EU



Source: J.P. Morgan estimates

As we discuss later, we think that political support to Blue hydrogen and Carbon Capture and Storage – while more discrete as more controversial given its higher "social license to operate" challenges – could be an option of choice for several key geographies. As such, we note that several countries have support mechanisms in place for the development of CCUS (carbon capture, use, and storage).

Regarding demand, we note that several countries have targets in terms of % of usage in final energy consumption. While deployment in mobility remains a key deployment focus, we note that HDV (inc. trains, and – in the longer term – aircrafts) is being considered. Moreover, specific end-use sectors, inc. hard-to-abate sectors, are now considered. Yet policies to drive adoption of hydrogen in these sectors remain to be implemented.

Increased climate ambitions are likely to reduce the competitiveness of fossil fuel alternatives

Moreover, it's worth highlighting that the competitiveness of green and low carbon hydrogen production will be automatically improved as fossil fuel based alternatives are made more expensive. This can be delivered through both implicit and explicit carbon pricing. As countries have ratcheted up their long-term climate ambitions in 2020, and given that COP 26 in 2021 is likely to see another round of increased ambitions, we see a likely introduction of new carbon pricing mechanisms in the medium term.

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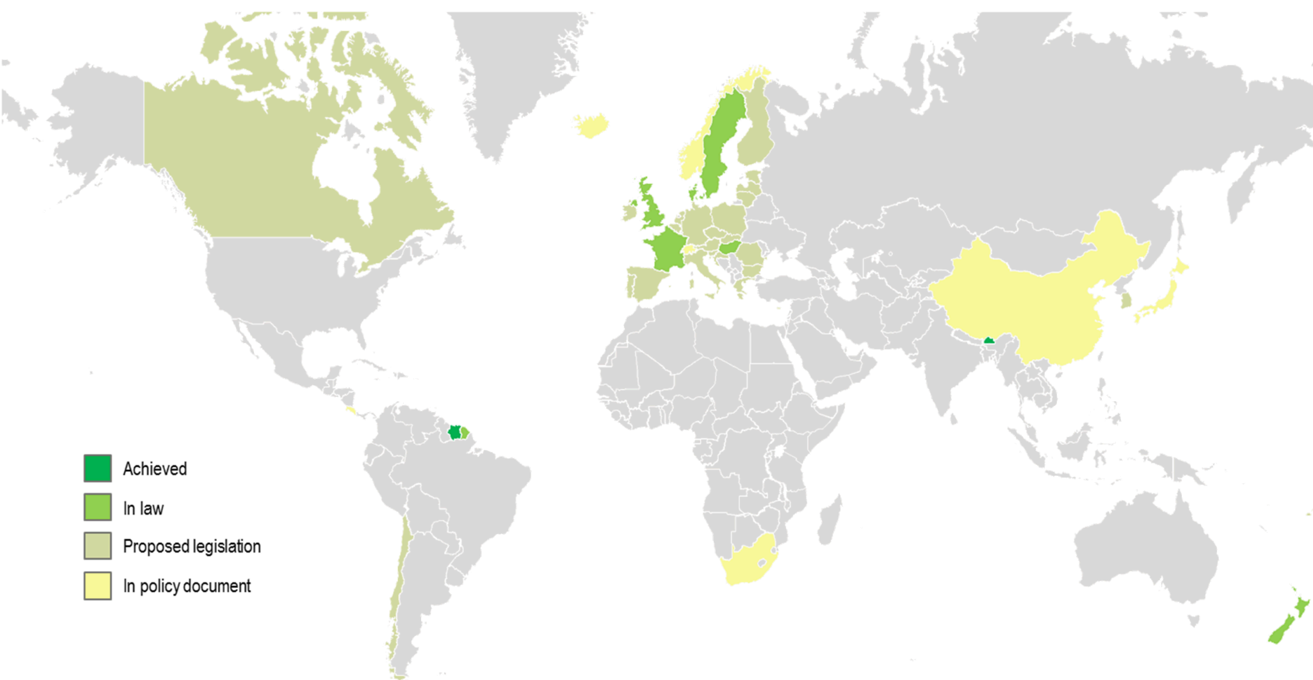
‘Net Zero’ is the new normal

2020 was a pivotal year for the fight against climate change, as several high-emitting countries announced increased GHG reduction commitments. Several focused on climate neutrality by 2050 (Europe, Japan, South Korea) or 2060 (China). Joe Biden’s win in the US presidential election added another key country to the list of those targeting “carbon neutrality” by mid-century.

A key catalyst will be to observe whether these long-term commitments are reflected within the updated “Nationally Determined Contributions” (countries' climate change strategies). These are commitments that member countries to the Paris Agreement of the UNFCCC have to submit, and to increase in ambition every five years. The first NDCs were submitted when the Paris Agreement was launched in 2015, during the COP 21. Hence, updated versions of the NDCs – looking at decarbonisation strategies over the next 10 years, accompanied by a "Long-Term low Emissions development Strategies" – are expected to be submitted at COP 26, which will take place in November 2021.

Submitting an NDC represents a first step in the enactment of Climate / Energy ambitions into law. Yet the full process may be lengthy as, once the target is passed into law, the overall energy and climate regulations need also to be updated, as is currently the case following the green deal (see our comment: EU Green Deal – Key milestones reached in 2020, paving the way for further significant reforms in 2021).

Figure 23: As of today, 28 countries representing 37% of world GHG emissions have carbon neutrality objectives, albeit for many of them these objectives remain to be enacted in law



Source: J.P. Morgan based on Net Zero Tracker

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Table 10: % of GHG emissions covered by net zero targets

Status	CO2 emissions (Mt)	CO2 emissions (% global)
Achieved (2)	3	0%
In Law (6)	877.42	2%
Proposed Legislation (6)	4649.95	9%
In Policy Document (14)	12766.86	26%
Total	**18297.23**	**37%**

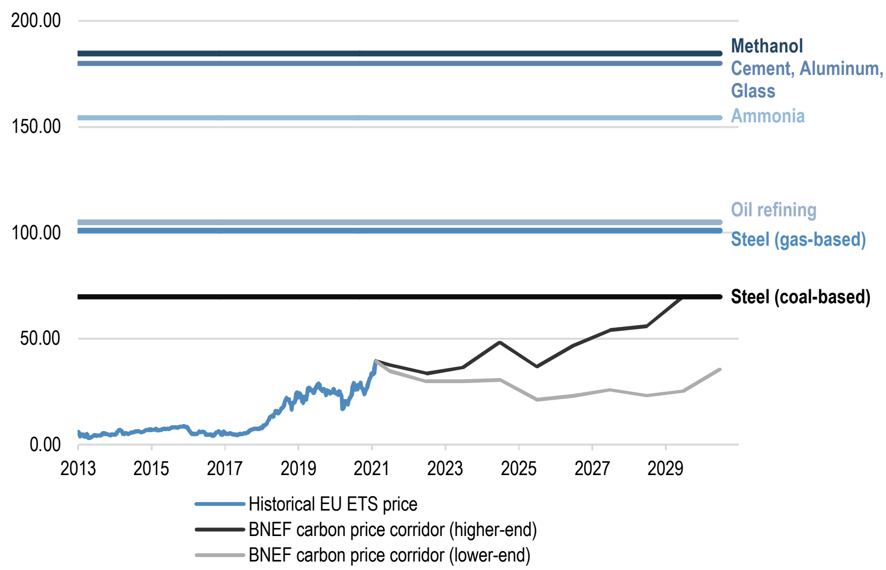
Source: J.P. Morgan based on Net Zero Tracker

Carbon prices at levels much higher than the one that can be currently observed on the EU ETS would be required for a $2/kg H2 to be competitive with the cheapest fossil fuels in use today for industrial applications

A need to develop higher explicit carbon prices for hard-to-decarbonize sectors

Explicit carbon prices are recognized among academia and policy makers as an effective tool to incentivize decarbonization across sectors, in a cost-efficient manner. However, according to BNEF, carbon prices at levels much higher than the one that can be currently observed on the EU ETS would be required for a $2/kg H_2 to be competitive with the cheapest fossil fuels in use today for industrial applications.

Figure 24: For a $2/kg H_2 to be competitive against cheap fossil fuel used in industrial applications, much higher CO2 price would be needed.



Source: J.P. Morgan based on BNEF

Yet, for H_2 production, a much lower carbon price could already make fossil-based H_2 with CCS competitive with fossil-based hydrogen. According to estimates from the EU H2 strategy document, carbon prices in the range of EUR 55-90 ($67-109) per tonne of CO_2 would be needed to make fossil based hydrogen with CCS competitive with fossil based hydrogen today.

Implicit carbon prices could drive up adoption in mobility, especially for HDV

We believe that implicit carbon prices in the form of more stringent fuel efficiency standards could drive up the adoption of FCEV. They would be particularly important to drive up demand for low-carbon HDV, such as buses and trucks. For

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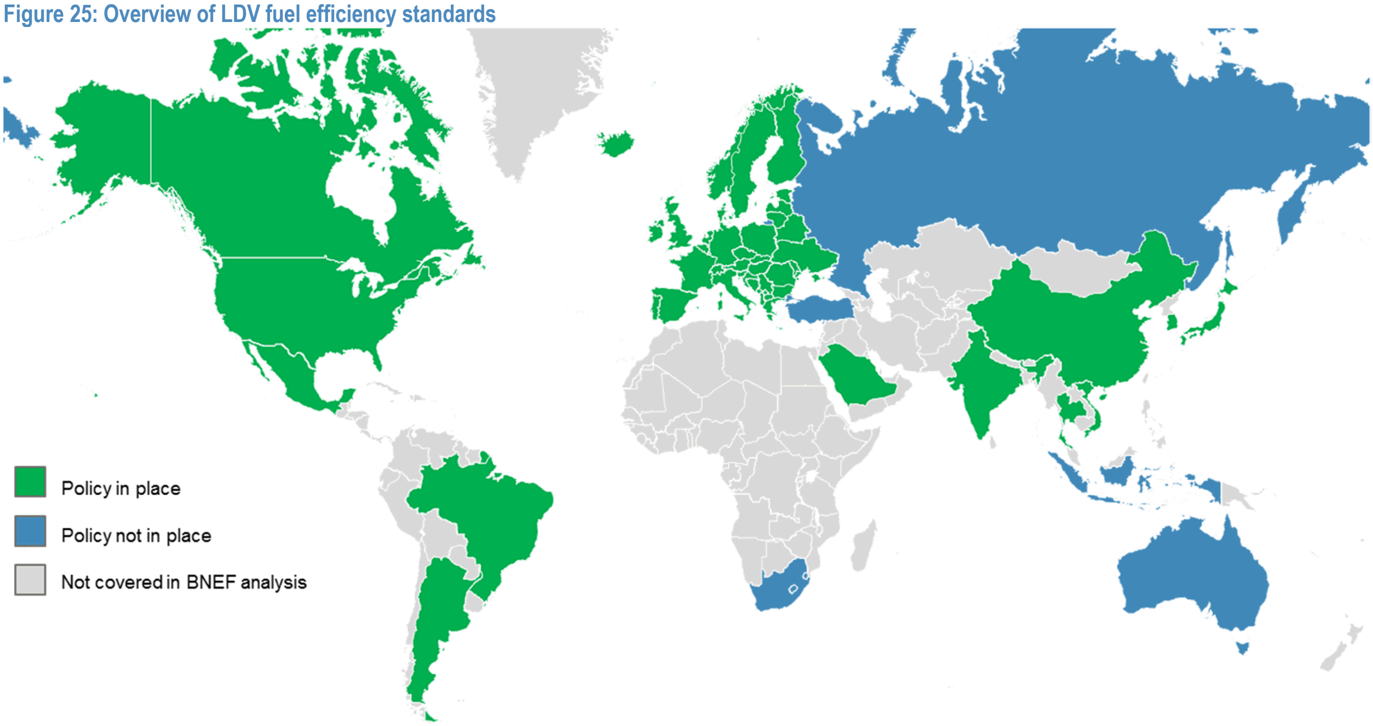
now, fuel efficiency standards mostly target LDV, albeit with varying levels of stringency.

Figure 25: Overview of LDV fuel efficiency standards



Country	Fuel efficiency targets / standards
Canada	Targeting 5% annual reductions in Co2-equivalent per mile through 2025
USA	CAFE rule, in place from March 2020, to get rewritten/fortified by Biden administration
Mexico	CO2 emission and fuel economy standards are in place but have not been tightened since 2016
Brazil	Voluntary fuel consumption targets
EU-27 + UK	CO2 targets require emissions reductions of 15% and 37.5% by 2025 and 2030, respectively, relative to 2021
China	Fuel consumption standards as of 2004 and a New Energy Vehicle program in place as of 2019
Japan	32% fuel economy improvement by 2030 relative to 2016
South Korea	Mandatory fuel economy and Co2 emissions intensity standards
India	Co2 emissions targets adopted in 2014
Australia	No fuel efficiency standards in place

Source: J.P. Morgan based on BNEF

New 'direct' policy support mechanisms are on their way to mitigate investment risks

Given that carbon prices are not likely to incentivize H2 deployment in the short to medium term, additional mechanisms may be needed to scale up renewable and low carbon hydrogen before they are cost-competitive with fossil fuel alternatives. Countries are currently working on the development of new support schemes which

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would provide corporates and investors the confidence to invest in low carbon technologies.

"Contract for differences" an intermediary tool to accelerate green and low-carbon hydrogen

One of the option envisaged by the EU is the creation of a tendering system for "Carbon Contract for Differences" for the deployment of H2 in various sectors. These instruments are a contract between two parties which stipulate that a buyer will pay to the seller the difference between the current value of an asset and its value at contract time (if the difference is negative, the seller pays instead of the buyers). For green and low-carbon H2, this may take the form of a long-term contract with a public counterpart which would remunerate the investor by paying the difference between the CO2 strike price and the actual CO2 price in the EU ETS in an explicit way, in order to bridge the cost gap vs. conventional hydrogen production.

Market-based support schemes for green H2 production

Another envisaged mechanism is the creation of market-based support schemes for renewable (green) hydrogen, which could be done through competitive tenders. This type of support mechanism would also reward electrolysers for the services they provide to the energy system (e.g. flexibility services, increasing renewable production, etc).

"Guarantees of origin": A way to increase transparency

Several countries highlighted the need to increase the readability of the environmental credential of Low Carbon and Green Hydrogen in the market by developing a system of "guarantees of origin", i.e. in the IEA definition, "an international framework is needed that is robust against mislabeling or double-counting of environmental impacts". The term guarantee of origin (GoO) refers to the power sector, where it is used to label electricity from renewable sources as green. These guarantees of origin were mentioned by the EU, Spain, Chile (under consideration), the Netherlands where, in Aug. 2020, H2 was included in the GoO system for renewable gases, as well as Australia.

Other policy instruments have been limited in use

The International Renewable Energy Agency (IRENA) notes that several other instruments are available to countries to incentivize the roll-out of a H2 economy, beyond cost, investments and capacity targets. These include tax breaks, direct grants, conditional and convertible loans, feed-in tariffs, auctions etc. However, so far, there seem to be a limited amount of strategy documents which explicitly envisage those.

Removing regulatory roadblocks at an international level represents a priority

Countries must work together to ensure regulations are not unnecessary barriers to investments, in various parts of the H2 value chain.

This is for example the case in production, where a standardized GoO mechanism should create a common language on the environmental impacts of different hydrogen supplies and facilitate trades. This is also a priority in Transport and Distribution, especially from the perspective of international safety standards to transport and store large volume of H2. Last, in many "new" end use cases envisaged, developing the associated regulation will be needed. This is for example the case to allow a higher % of blending of H2 into natural gas networks.

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Increased public and private international cooperation

We believe that the required review of existing policies, and the development of new ones will be made easier by the multiplication of public and private international cooperation mechanisms.

Among countries with a clearly articulated H2 strategy, Germany particularly stands out in terms of the importance of international collaborations in its H2 strategy.

Table 11: Overview of public & private international cooperation initiatives

Country	Initiative's name	Date	Details	Type
Germany & France	(Upcoming) cooperation	Undefined	September 2020: The French Finance minister, Bruno Le Maire, mentioned this is part of ongoing discussions	Public
United States of America	Hydrogen Forward	Feb-21	Private organization (11 companies, Inc. Shell, Air Liquide and Linde) to accelerate H2 development in the USA	Private
Germany / Australia	Hydrogen Bridge	Sep-20	Signed an agreement to carry out a feasibility study looking at the potential for closer collaboration and the future development of a hydrogen supply chain between the two countries. Focuses on Green H2	Public
Portugal / Netherlands	Memorandum of Understanding on Green H2	Sep-20	Committed to develop a strategic export-import value chain to ensure production and transport of Green hydrogen from Portugal to the Netherlands and its hinder land.	Public
Germany, Netherlands, West Germany	1000 H2 powered Zero Carbon trucks by 2025	Jul-20	Air Liquide, VDL Groep, Iveco / Nikola, Vos Logistics, Jongeenel Transport, HN Post + leading FC suppliers.	Private
Germany, Morocco	International cooperation	Jun-20	Morocco and Germany signed a partnership agreement in June 2020, to develop Green H2 production. It includes R&D projects. Two projects have been announced, inc. a Power-to-X project.	Public
United Kingdom	UK Hydrogen Strategy Now campaign	Jun-20	UK businesses committed to invest GBP 3bn	Private
Austria, Belgium, France, Germany, Luxembourg, Netherlands and Switzerland	Joint Declaration at the Pentalateral Energy Forum	Jun-20	Commitment to strengthen cooperation on H2 produced in a CO2 reducing manner.	Public
European Union	European Clean Hydrogen Alliance	Mar-20	Aims at an ambitious deployment of H2 technologies by 2030. It brings together industry, national and local public authorities, civil society and other stakeholders.	
Singapore / Japan	Agreement	Mar-20	Five Singapore and two Japanese companies have recently signed an agreement to study how H2 can contribute to a clean future.	Private
Germany, Netherlands	Cooperation agreement	Feb-20	Transnational cooperation framework	Public

Source: JPMorgan.

Countries are working together on industrial clusters using hydrogen

In addition to the above mentioned cooperation initiatives, several countries are developing industrial clusters that use hydrogen. This in some cases includes cooperation across several countries (e.g. Germany and the Netherlands). While these clusters are a way to accelerate economies of scale, we also believe they could accelerate standardization as best practices will be identified.

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Table 12: Overview of industrial clusters involving H2

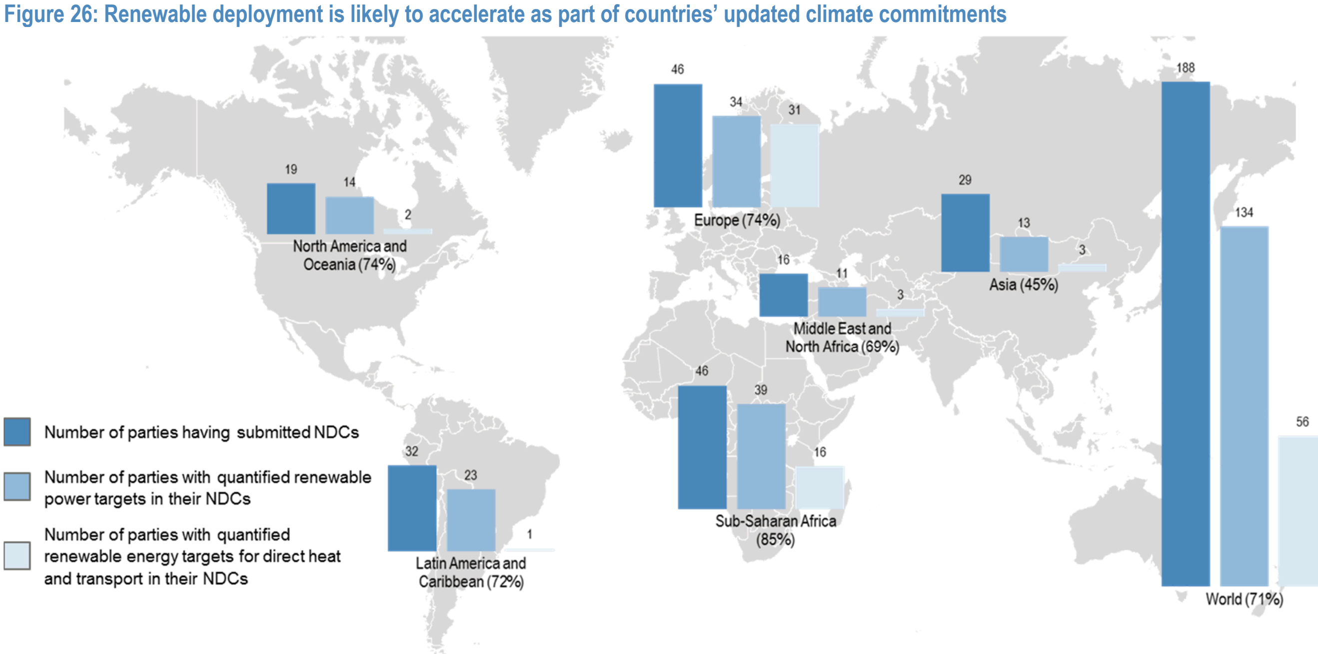
Country	Cluster name	H2 Production	Commissioning	Sectors
United Kingdom	HyNet	Fossil with CCS	2024	Ammonia, Oil refining, glass
United Kingdom	Zero Carbon Humber	Fossil with CCS	2026	Steel, oil refining, chemicals
Portugal	Green Flamingo	Renewables	2023	Export oriented; fuel Green H2 value chain (Renewables, Production, Transport, Storage, Export)
Netherlands	NorthH2	Renewable	2027	Undefined
Netherlands	Hydrogen Valley	Renewables, Fossil with CCS	N/A	Production, distribution, various end uses
Germany	WestKüste100	Renewable	2025	Oil refining, cement, chemicals
Germany	GetH2	Renewables	2023	Production, Transport, Storage, Chemicals, Refining

Source: J.P.Morgan.

Beyond H2 specific deployment, renewables will be key for the development of Green H2

As we discuss later in this report, the cost of renewable power represents a key component of the future LCOH for green hydrogen. We expect renewables penetration to keep accelerating worldwide, as renewable power technologies have become mature and cost effective vs. fossil fuels alternatives in many geographies, but also because they represent a significant part of the climate / energy targets that countries set themselves under the Paris Agreement. As shown by the below chart, 86% of the countries that have submitted an NDC worldwide have quantified renewable Energy targets in it.

Figure 26: Renewable deployment is likely to accelerate as part of countries' updated climate commitments



Source: J.P. Morgan based on Irena

Further renewable deployments are likely

According to the IRENA, renewable energy targets included in the NDCs, if implemented, would represent a renewable power installed capacity that would reach

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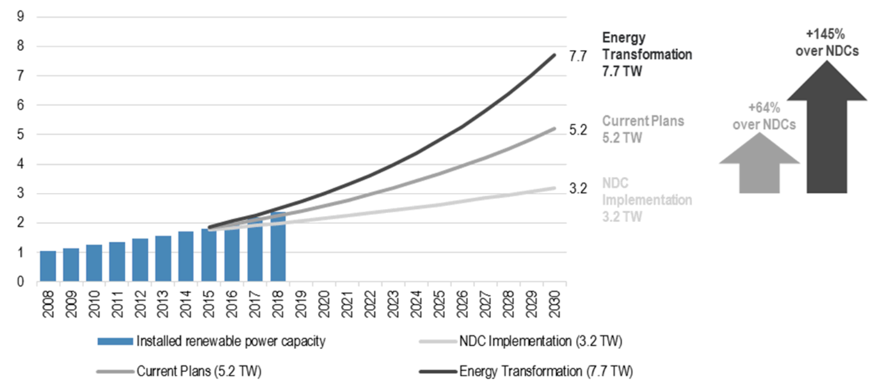
3.5 TW in 2030 (vs. current capacity of ca. 2.5 GW). IRENA considers this as currently not in line with the Paris Agreement, which would require this to double to 7.7 TW. Moreover, the current NDCs also do not reflect the wider current and planned policies regarding renewables deployment, which according to its estimates represent a 5.2 GW installation capacity by 2030.

Figure 27: Projected renewable electricity deployment in different scenarios.



Source: J.P. Morgan based on IRENA. For simplicity, constant CAGR is used to project global renewable energy deployment up to 2030 in the three scenarios.

Indeed, the envisaged renewable growth rates of current NDCs do not reflect the actual growth of renewable power. Currently, global capacity is growing by an average of 8.6% per year since 2015 (vs. a 4% growth rate from 2015 to 2030, to implement current NDCs) resulting in actual deployment having outpaced NDCs' envisaged deployment as early as 2016. As such, IRENA expects the new round of NDCs to significantly increase the envisaged deployment of renewables.

For a detailed overview of policy support to renewables, we would refer to the more detailed work of J.P. Morgan's EMEA Utilities Research team: "Beginner's Guide To Renewables: Renewable Energy, Energy Storage and Incentive Schemes".

Green vs. blue: not as clear-cut as it may seem

Recent political announcements and targets pertaining to scaling up H2 production were mostly focused on green hydrogen, and translated into a change in scale in the envisaged rollout of electrolyzer capacity. Support to blue hydrogen was, however, much more discrete.

We believe this discussion is worth taking a closer look at. We discuss some of the potential challenges associated with scaling up green hydrogen, and in particular the enormous amount of new renewables capacity that would be needed, in a later part of this report. We find that there are some advantages to fossil fuel based low carbon hydrogen vs. renewable based H2, especially as the former provides an easier pathway to a cleaner economy for existing fossil-fuel oriented countries given the ability to take advantage of existing energy infrastructure and resources (e.g. natural gas or coal).

Carbon capture risks imply dedicated government policy to mitigate them

Large-scale projects are also capital intensive with high operating costs (outlined in detail further below) and there are several key risks which have limited private sector investment, per the Global CCS Institute. First, there is the risk that the sale of CO_2

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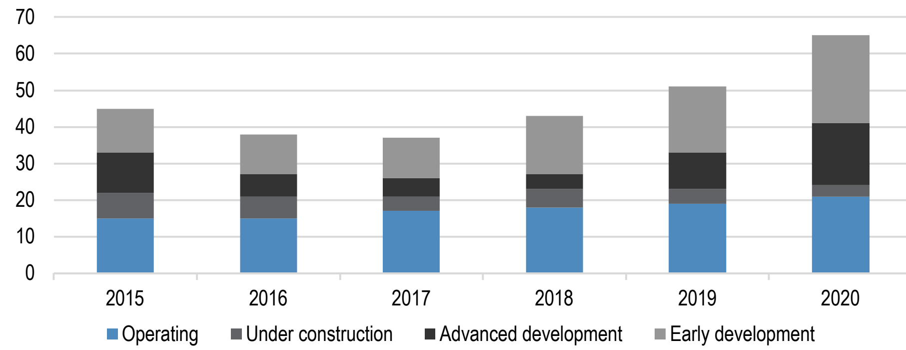
for large-scale projects will be less than the costs of capturing, transporting, and storing it. Currently, these costs are generally greater than the value placed on CO_2. The second risk is that many facilities involve just one source, carbon sink, and pipeline. The development of shared networks would diversify emissions and allow economies of scale to reduce costs. Lastly, the risk of leakage (which we discuss in more detail below) opens investors to long-term storage liabilities. Each of these risks requires government policies to mitigate them in order to entice investment and reduce capital costs, demonstrating how critical policy is to the scaling of CCS and in turn Blue H_2.

Figure 28: Number of World-Scale CCUS Facilities



Source: IEA.

Additional "social license to operate" challenges can be expected compared to Green Hydrogen.

Whether or not Blue Hydrogen will be part of the H2 equation, and at what scale, is a debate intrinsically related to the future of Carbon Capture and Storage costs (discussed in details in the later "H2 economics" section of this report). However, from an ESG perspective, we believe that the discussion on Carbon Capture and Storage cannot be reduced to cost equations which would only depend on future economies of scale related assumptions. On the contrary, several significant barriers faced by CCS are non-technical, beyond those associated with costs and energy penalty (i.e. the additional fraction of fuel that must be dedicated to CCS for a fixed quantity of work output). These barriers, as investigated by Budinis et al. 2018, include "*the lack of market mechanisms and incentives, fewer effective mechanisms to penalize major CO2 emitting sources, inadequate legal framework allowing transport and storage (both inland and offshore) and public awareness and perception*". While we see some positive developments on this side, we believe the challenges should not be underestimated.

The rollout of CCS is increasingly being recognized for hard-to-abate emissions…

In terms of perceptions, we think that the fact that it has long been supported by high-emitting sectors resulted in CCS being seen as a potential "safe conduct" for fossil fuels, which would divert attention and investments away from more direct emissions reduction options, such as renewables. This is, in our view, not unrelated to the fact that the debate on CCS was focused on the role it could play to decarbonize coal-power generation, and whether this would make it competitive vs. renewables. As a result, we believe that this "negative" perception is likely to be lower in countries which are less critical of fossil fuels, as they have their own fossil fuel industry, such as Canada, USA, Australia, and in Europe, Norway.

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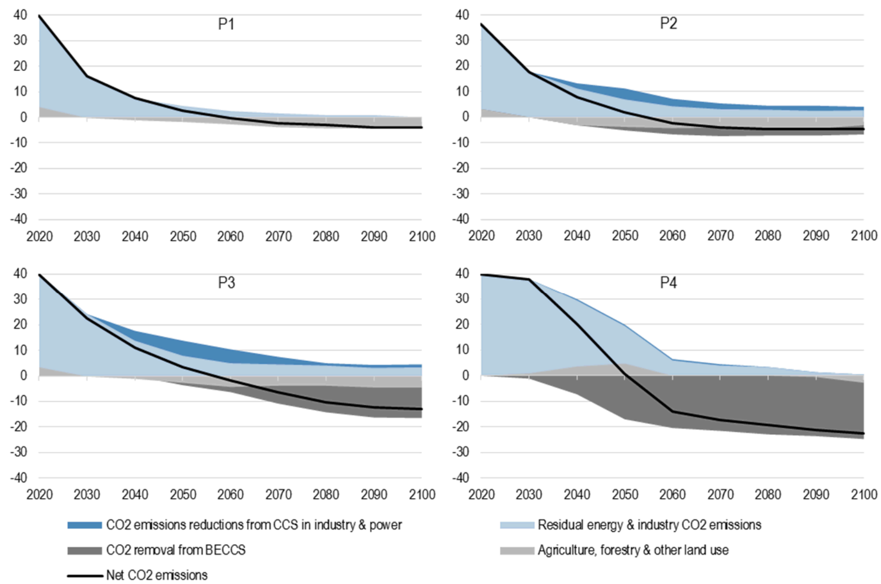
On a positive note, we believe that the negative perception of CCS as a "safe conduct" for fossil fuels is starting to change elsewhere as well. This is helped by a focus on increased climate action globally, as the work from the IPCC Working Group 3 (WG3) highlighted that most of the scenarios allowing the delivery of concentration pathways in line with the Paris Agreement require reliance on negative emissions technologies, as shown by Fuss et al. 2014. More recently, the IPCC special report on Global Warming of 1.5 degrees Celsius highlighted that the scenario that does not rely on CCS (no overshoot) is the one that requires the most radical change in human behavior.

We believe that CCS is increasingly recognized as a technology that will be required to decarbonize 'hard to abate' sectors. This is illustrated by the work we've done on the Cement sector, in collaboration with J.P. Morgan's EMEA Construction Materials team

Moreover, in the European context, we believe that CCS is increasingly recognized as a technology which will be required to decarbonize "hard to abate" sectors. This is well illustrated by the work we've done on the Cement sector, in collaboration with J.P. Morgan's EMEA Construction Materials Team: EU Cement: Revisiting consequences from Phase IV of the EU-ETS and discussing the path to decarbonisation. Hence, CCS should increasingly be perceived as complementary, rather than opposed and slowing down the rollout of other low-carbon technologies.

Figure 29: The IPCC 1.5°C report highlights several emissions reduction pathways, with different levels of reliance on negative emissions



Source:J.P.Morgan, based on IPCC

… but negative perceptions remain on safety and permanence of storage

Overcoming negative perceptions will also require social acceptance to be addressed, and in particular, concerns related to safety and permanence of storage.

With regard to permanence, up to now, the accumulated experience on CCS seems to highlight no significant risk of leakage. However, the total number of projects in operation and the associated volume of CO2 stored is rather small: projects in construction and in operation represented approx. 40Mtpa of capture capacity. As such, experience is limited vs. a large-scale deployment situation.

We note that the risk of non-permanence of storage is recognized in the academic literature, either via (1) the gradual and long-term release or (2) sudden release of

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CO2 caused by disruption of the reservoir. However, when stored in geological reservoirs, with well-designed systems, CO2 leakages are likely to be small, except where reservoirs are physically disrupted (IPCC, 2005). This limits the potential of CCS in seismically active regions.

Table 13: Chances of GHG leakage from CCS are small, except if reservoirs are physically disrupted

Property	Terrestrial biosphere	Geological reservoirs
CO2 sequestered or stored	Stock changes can be monitored over time.	Injected carbon can be measured.
Ownership	Stocks will have a discrete location and can be associated with an identifiable owner.	Stocks may reside in reservoirs that cross national or property boundaries and differ from surface boundaries.
Management decisions	Storage will be subject to continuing decisions about land-use priorities	
Monitoring	Change in stocks can be monitored	Release of CO2 might be detected by physical monitoring but because of difficulty in monitoring large areas may also require modeling
Time scale with expected high values for fraction CO_2 retained	Decades, depending on management decisions.	Very small physical leakage from well-designed systems expected, barring physical disruption of the reservoir.
Physical leakage	Losses might occur due to disturbance, climate change and land-use decisions	Losses are likely to be small for well-designed systems except where reservoir is physically disrupted.
Liability	A discrete land-owner can be identified with the stock of sequestered carbon.	Multiple parties may contribute to the same stock of stored carbon lying under several countries

Source: J.P. Morgan based on IPCC special report on CCS 2005

With regard to safety, the IPCC concludes that the local risks associated with CO2 pipeline transport could be similar to, or even lower than those posed by hydrocarbon pipelines. A sudden and large release of CO2 would pose immediate dangers to human life and health, if exposure concentrations to CO2 were greater than 7-10% by volume in air. As such, pipeline transport of CO2 through populated areas requires attention to route selection, overpressure protection, leak detection and other design factors. However, no major obstacles to pipeline design for CCS are foreseen (IPCC 2005).

Managing these risks would require dedicated community engagement to scale up

These concerns have been identified by several countries, which recognize the need for targeted community engagement. For example, Australia, in its Hydrogen Strategy, notes that, "*When compared with other hydrogen production pathways, thermochemical production coupled with CCS is likely to carry additional social license challenges. This is due to the risk associated with the capital intensive nature of these types of projects, concerns over continued use of fossil fuels and perceived uncertainty regarding the long term effectiveness of CO2 storage. Stakeholder engagement efforts intending to gain support for thermochemical hydrogen production should be targeted to both the broader Australian community and communities adjacent to prospective plants.*"

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While Green H_2 has received the most policy attention lately, we think Blue may also play a role in the scaling of infrastructure

Blue H_2 project outlook

With significant focus today on the scaling of Green H_2, we recognize the important role Blue H_2 could also play in the scaling of hydrogen infrastructure, demand, and distribution, therefore paving the way for Green to become more competitive. Large-scale Blue H_2 projects will require governmental support and investment in other infrastructure conversion, CCS, and subsidies for different steps in the process chain. Blue H_2 and CCS could benefit from economies of scale, and opportunities exist in existing industrial clusters where costs may be decreased. For example, the H-vision initiative (the first Blue project) contains parties in every step of the process chain with goals to realize four SMR facilities, store the CO_2 under the North Sea, and deliver the H_2 to local industrial parties. Another Blue initiative is the Equinor-led Hydrogen to Humber Saltend (H2H Saltend), which is a project to advance the first fully de-carbonized industrial cluster by 2040 through producing Blue H_2 at scale. The Humber already has an established hydrogen economy, and the project intends to expand to other industrial users and enable a large-scale hydrogen network for both Blue and Green.

Current Blue H_2 facilities

Per the Global CCS Institute, today there are four industrial-scale SMR hydrogen facilities with CCS worldwide, producing ~800k tons of low-carbon hydrogen per year. Three of the facilities produce hydrogen from coal, coke or asphaltene (similar to coke) with CCS for a combined capacity of ~600k tons of hydrogen per year. The world's largest clean H_2 plant, Great Plains Synfuel in North Dakota, produces ~400k tons of hydrogen per year using brown coal. This mature facility has been producing hydrogen since 1988 and capturing CO_2 for storage since 2000; ~3 Mt per year is transported to Saskatchewan, Canada for enhanced oil recovery (EOR). We think this is prime example of the economic and technical feasibility of large-scale production of Blue H_2 coupled with CCS.

It's worth noting that the US DOE notes in its hydrogen strategy, that R&D efforts resulted in advanced production systems capable of producing carbon-free hydrogen for less than USD2/kg with CCS. Research advances in gasification and reforming technologies with CCUS including reductions in capital and operating costs, target carbon neutral H2 production at less than USD 1/kg.

Government support is making the U.S. a standout in CCS

In the U.S., Congress showed support in 2018 when the tax deduction per metric tonne was increased from \$20 to \$50; however, it only applied to projects set to begin construction by 2023 (which created challenges given long project lead times). Recently, growth has begun to emerge in the commercial project pipeline which is attributable to 1) enhanced tax credits in the U.S. (45Q), 2) hubs and clusters (e.g. multiple emitters/storage locations sharing transportation infrastructure), and 3) the growing interest in Blue H_2. The recently passed COVID-19 relief bill included an extension of the 45Q tax credits through 2025, which provide facilities with \$50/mt of CO_2 stored and \$30/mt of CO_2 utilized (e.g. enhanced oil and gas recovery); the credits increase each year until the full value is reached in 2026. Per Wood Mackenzie, the 45Q credits have resulted in an additional 32 projects being announced over the last two years. The bill also added ~\$2bn to help fund six projects with goals of demonstrating real-world operability of CCS technologies, two of which are for steel/cement plants, as opposed to utilities, where previous investments have mostly failed. The sooner more CCS technology can be proven successful and applicable, the sooner lower costs and greater scale may be realized.

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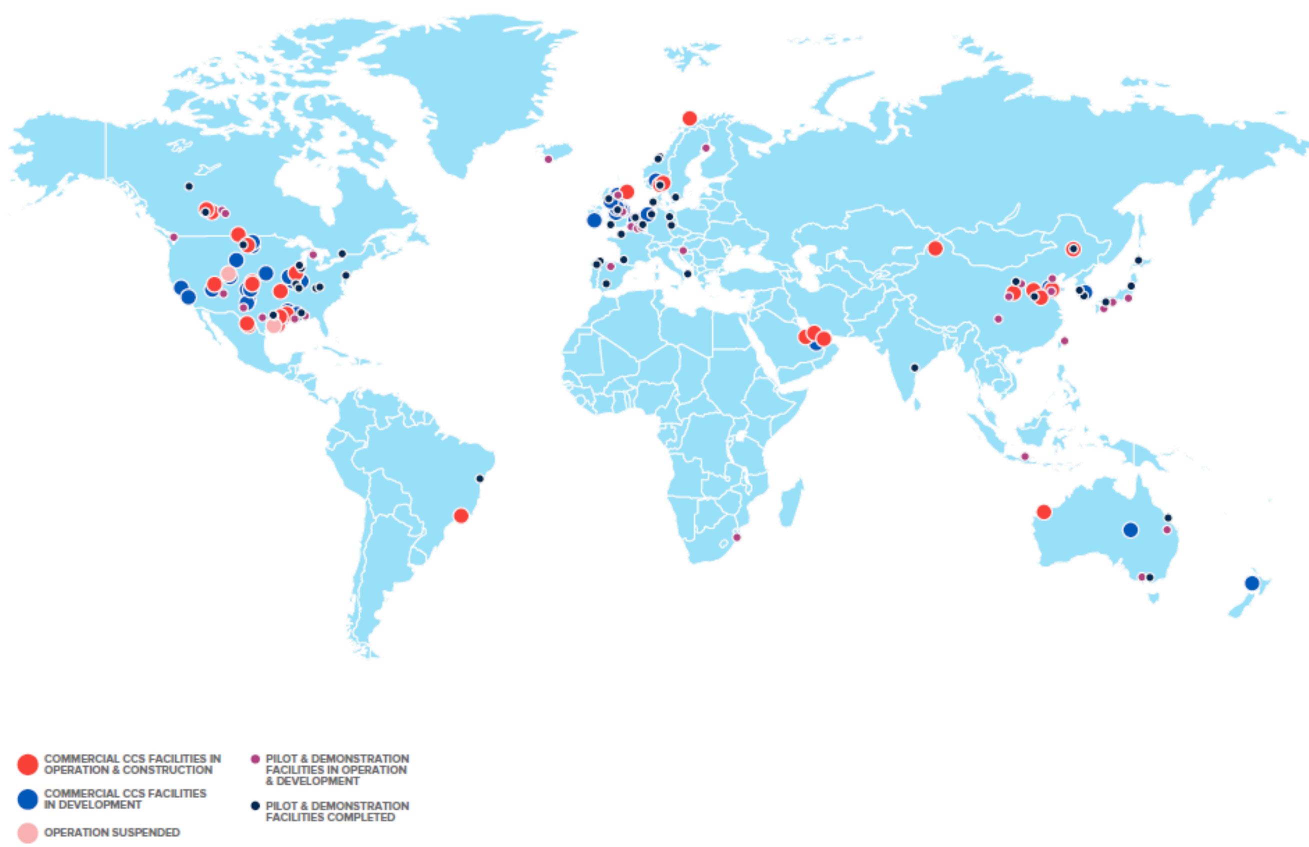
Other CCS friendly geographies include Canada, Australia, China and North Europe

In addition to the USA, we believe that CCS friendly geographies could include Canada, Australia, China, and countries in Northern Europe (Norway and UK in particular), as these are the geographies where most of the test facilities have been implemented.

Figure 30: CCS facilities to date – global overview



Source: Global CCS Institute, 2020. The Global Status of CCS: 2020. Australia.

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Economics of the hydrogen rainbow

Green H_2 – Water Electrolysis

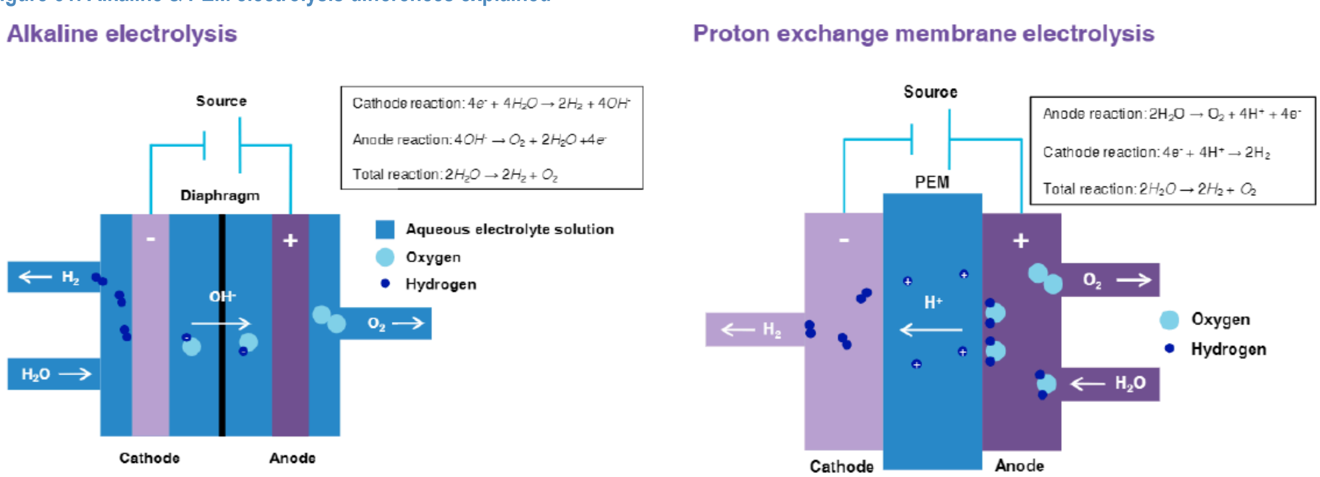
The H_2 technology that has gained the most attention recently has been water electrolysis. For example, the EU's Hydrogen Roadmap focuses almost entirely on green H_2 for the continent's H2 strategy. If powered with renewables, green H_2 is the only technology with zero CO_2 process emissions and virtually no upstream emissions. Furthermore, water electrolysis is an established technology which has been utilised for nearly a century; however, the industry has remained relatively small in scale with most units custom built and average unit size relatively small (sub-Megawatt scale). Now, the electrolyser industry is quickly scaling up and customer aspirations are increasingly on the Gigawatt scale.

Two major green H_2 technologies – Alkaline & PEM

Alkaline (ALK) technology – Alkaline electrolysis is the oldest water electrolysis technology, being utilized for more than 100 years. It uses a positively charged anode and negatively charged cathode, immersed in a liquid alkaline electrolyte (typically potassium hydroxide). The electrodes typically consist of nickel. Although alkaline systems are the more established and cheaper technology, the liquid electrolyte offers lower current density, needs regularly cleaned for CO_2 contamination, cannot respond as well to load fluctuations, and operates at a lower pressure.

Proton Exchange Membrane ('PEM') technology – PEM electrolysis is a newer technology, first developed in the 1960s, and works by a different mechanism. A solid polymer is used to conduct the ions, rather than a liquid electrolyte. Historically, PEM technology has been mainly applied to fuel cells, but several major manufacturers are now focused on PEM electrolysers. A notable difference versus alkaline is that PEM electrolysis uses platinum group metals (e.g. platinum, iridium) as catalysts, which are far more expensive than nickel. However, PEM has several performance advantages. Notably, it can respond to current fluctuations more easily given its high responsiveness (seconds) and allows for more compact stacks (often containerized). PEM also produces a higher purity H_2 (requiring less purification) and can operate at higher pressure.

Figure 31: Alkaline & PEM electrolysis differences explained



Source: J.P. Morgan, BNEF.

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Table 14: Alkaline vs PEM electrolyser technology comparison

	Alkaline Electrolyzers (ALK)	Proton Exchange Membrane (PEM)
2021E system cost ($/kw)	780	891
Load Range	15-100% nominal load	0-160% nominal load
Start-up time	1-10 minutes	1 sec - 5 minutes
Ramp up/Ramp down	0.2-20%/second	100%/second
Electrolyte	Potassium Hydroxide	Thin PFSA polymer
Operating Pressure Bar	35 bar	>60 bar
Operating Temperature	80-140 °C	20-80 °C
Current Density (A/cm^2)	0.2-0.7	1.0-202
Operating Temperature (C)	60-80	50-84
Minimum Load (%)	20-40%	3-10%
Foot print	Relatively large	1/3 of equivalent ALK plant

Source: J.P. Morgan estimates, Company data.

Alternative electrolysis technologies to ALK & PEM

Nevertheless, there are several other emerging water electrolysis technologies which are not as advanced as alkaline and PEM. We have summarized these below.

Anionic Exchange Membrane (AEM) – AEM systems operate in an alkaline environment and thus do not require more expensive Platinum Group Metals. They also can utilise stainless steel rather than titanium for the plates. However, AEM systems still use a liquid solution (KOH, similar to ALK systems) and operate at a lower pressure than PEM systems and thus require compression capacity.

Solid Oxide Electrolysis (SOE) – SOE systems utilise water as steam, rather than a as a liquid, achieving a high conversion efficiency and thus requiring less power. However, SOE systems require an external heat source to reach operating temperatures of ~800C. However, the stacks are still expensive to manufacture and require a steady power source, making the technology less compatible with renewables.

Among companies working on SOE, we noted **Schlumberger**, Vicat and **Vinci Construction** are working on the development of the first industrial deployment of CEA (French Alternative Energies and Atomic Energy commission) High Temperature reversible Solid Oxide Electrolyzer technology. Schlumberger is building the Genvia Gigafactory in France to produce solid oxide electrolysers. Other companies working on the technology include **Bloom Energy** in the USA, in partnership with **SK Engineering & Construction** (South Korea) as well as **Doosan Fuel Cell** (South Korea) and **Ceres Power** (UK).

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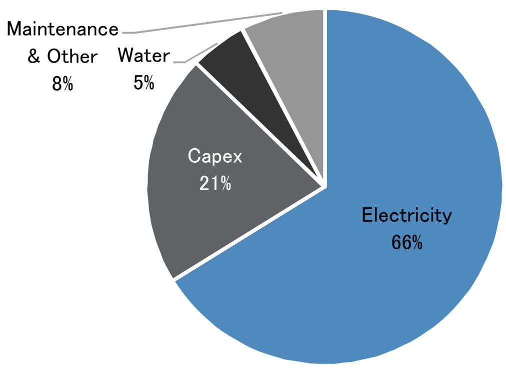
Two major drivers – electricity price & capital intensity

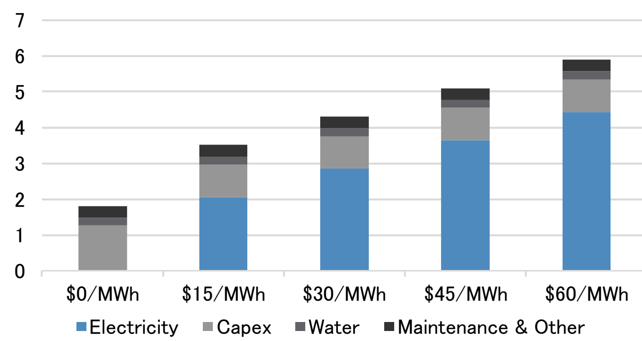
Given water electrolysis requires typically >50kwh to produce 1 kg of H2, power accounts for by far the greater proportion of the total levelised cost of hydrogen ('LCOH') production. On our estimates, if we assume a power cost of $30/MWh and capital intensity of $750/kw, electricity costs would amount to two-thirds of the total LCOH. Beyond this, the second greatest component of the LCOH is the capex for the construction and purchase of the electrolysis system. On our estimates, this would amount to ~20% of the total LCOH. Despite water being the only major raw material on an opex basis (requiring ~10 liters of water per H2 kg), we estimate this is only ~5% of the total LCOH. We discuss the risks associated with future water availability later in this report.

Figure 32: Electricity is the largest contributor to green H2 costs
Breakdown of Levelised Cost of Hydrogen for H2 electrolysis, assuming $30/MWh power costs & $750/kw capital intensity



Source: J.P. Morgan estimates, Company data.

Figure 33: Lower power costs can sharply reduce green H2 costs
Breakdown of Levelised Cost of Hydrogen for H2 electrolysis, assuming power costs & capital intensities, $/kg



Source: J.P. Morgan estimates, Company data.

Renewable power costs still falling steeply

Given that the growing market interest around H_2 is derived from the search for energy transition solutions for hard-to-abate sectors, then the critical pathway for lowering the LCOH of green H2 necessarily requires achieving lower renewable power costs. Over the last decade, we have seen the cost of solar PV and wind power fall steeply. IRENA and Lazard estimate that the Levelised Cost of Electricity ('LCOE') for solar PV has fallen ~90% since 2009 to ~$37/MWh on average globally, with many regions (Southern Europe, MENA, Latam) now witnessing Solar Power Purchase Agreements ('PPA') <$20/MWh. With panel costs still falling and solar efficiencies still improving, we expect solar LCOEs to continue to decline. Similarly, onshore wind power costs have also fallen precipitously by ~70% since 2009. Although offshore wind costs remain higher than onshore, we expect that, as project scales increase and more companies gain experience in offshore wind construction, offshore wind costs will also rapidly fall.

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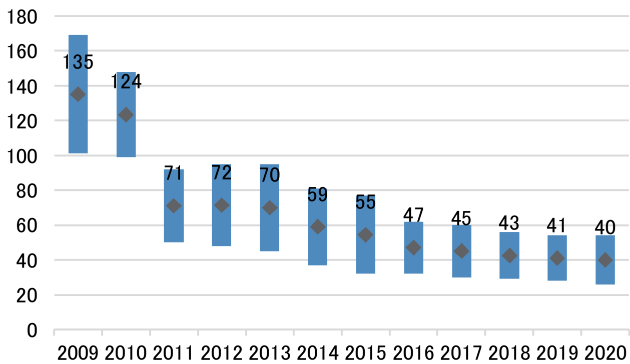
Figure 34: Wind costs have fallen 70% since 2009…

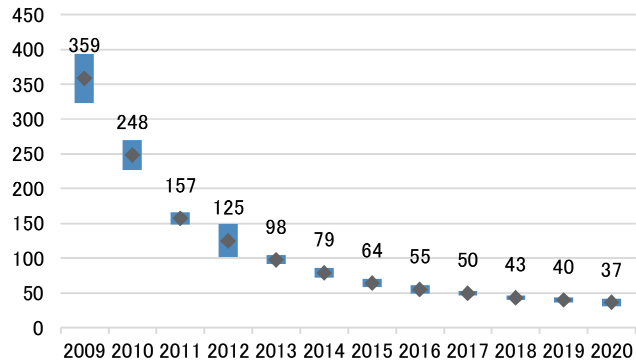
Global average onshore wind power LCOE, $/MWh



Source: J.P. Morgan estimates, Company data.

Figure 35: …while Solar PV costs have fallen by ~90% since 2009

Global average solar PV power LCOE, $/MWh



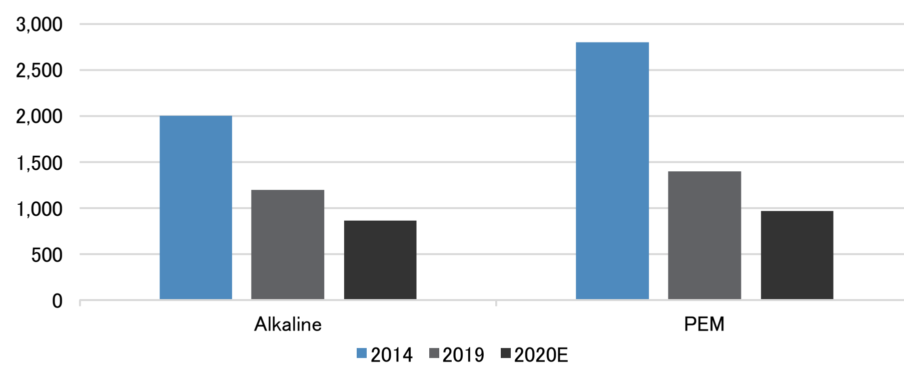
Source: J.P. Morgan estimates, Company data.

Capital intensity of electrolysers also rapidly improving

After electricity, the manufacture or purchase of the electrolysis stack is the second greatest contributor to all-in H_2 costs. Given that the electrolyser industry diminished from the 1970s onwards, production facilities also shrank with relatively smaller order sizes. When interest re-emerged in electrolysis over the last several years and order sizes started to grow, unit costs started to fall sharply. BNEF estimates that unit costs fell ~50% from 2014 to 2019. Given it's a relatively newer technology, costs for PEM systems have declined more than ALK systems. Nevertheless, we estimate that costs continue to fall and our discussions with industry experts indicate that the capital intensities of both technologies is now <$900/kw with PEM systems' costs still modestly higher than ALK today.

Figure 36: Capital intensity of Alkaline & PEM electrolysers (ex-China)

$/kw



Source: J.P. Morgan estimates, Company data.

Increasing production scale key to reducing system cost

Further cost reductions will be needed for green H2 to become cost competitive across different end uses. We expect that, as the electrolysis industry scales up, unit costs should further decline. Manufacturers are building new production facilities capable of mass-producing larger-scale units. One way this will reduce unit cost is through fixed cost dilution of the production facilities. The US National Renewable Energy Laboratory estimates that the unit cost breakdown for a 1MW unit where the facility only produced 10 units per year would be heavily skewed towards Capex, Building, & Other Costs. When production is scaled to 1,000 orders per year, these

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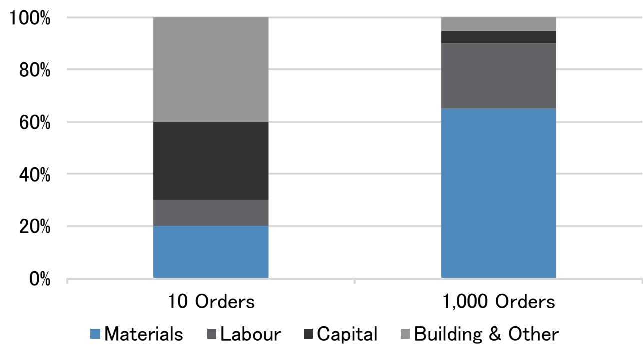
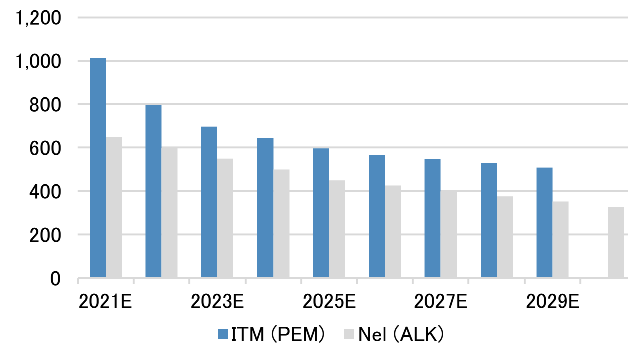
costs are diluted over a larger volume, leaving Materials and Labour ~85% of total unit cost. Both ITM Power and Nel expect their respective system costs to materially decline 7-8% per annum to reach $400-500/kw by the end of the decade.

Figure 37: Costs hindered by small industry scale, high fixed costs
Electrolyser cost breakdown at 10 Orders & 1,000 Orders (1MW scale)



Source: NREL, J.P. Morgan, Company data.

Figure 38: ITM & Nel expect system costs to fall 7-8% pa to 2030E
System price ($/kw)

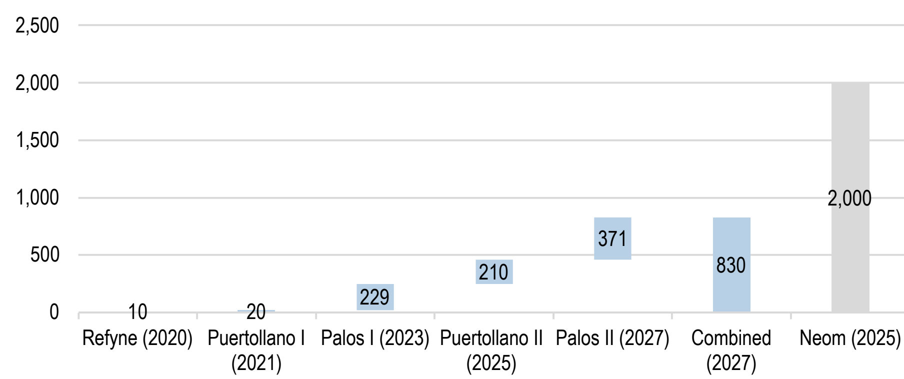


Source: ITM Power, J.P. Morgan, Company data.

Project size quickly growing with Gigawatt scale now targeted for mid-decade

Just as electrolyser OEMs are stepping up their average module size, planned project scales are also increasing as the demand for green H_2 grows. For example, **Shell's** Refhyne project (system supplied by **ITM Power**), which will reduce emissions from its Rheinland refinery in Germany, started construction in mid-2019 with planned scale of only 10MW with completion expected this year. Given the scalable nature of electrolyser systems, **Iberdrola's** Puertollano initially expects to commission 20MW of capacity in 2021E, followed by a three-phase expansion to >800MW by 2027E. Gigawatt-scale projects are also now being announced, with **Air Products'** Neom project planning to commission 2GW by 2025E to produce green ammonia. Even larger >5GW scale projects are being designed in Europe (for domestic consumption) and Australia (for exporting to Asian markets).

Figure 39: Planned green H_2 plant scale quickly increasing from tens of Megawatts to Gigawatt scale
MW



Source: J.P. Morgan estimates, Company data.

Efficiency & Utilisation also key variables, but driven by different participants

Two other critical variables are 1) the energy intensity of the electrolyser (measured as kWh/kg) and 2) the system utilization. Both PEM and ALK systems require

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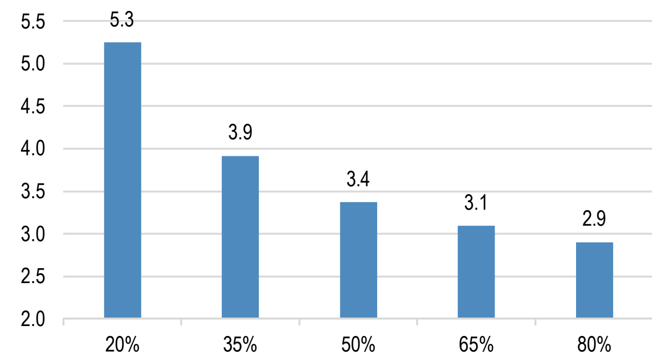
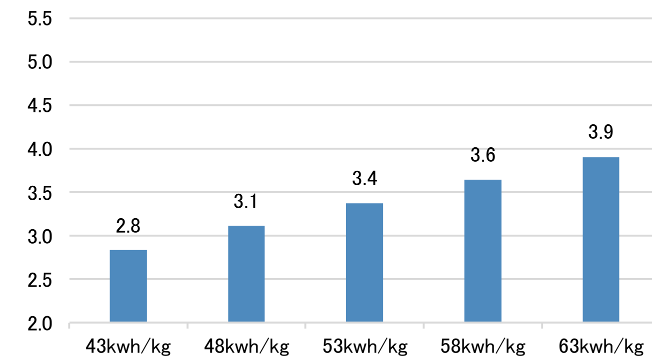
~50kWh/kg, but we expect this is something electrolyser manufacturers could optimise over time. More significant is the actual utilisation of the electrolyser system. We estimate a 15% drop in utilisation to 30% from 50% would raise the LOCH by ~16%. However, optimizing utilization will likely fall to the eventual system owner and whether the system will be on-grid (higher utilisation, but potentially higher power cost) or distributed (potentially lower utilisation, but greater power cost security). It is worth noting this sensitivity declines as the fixed cost of the electrolyser also falls.

Figure 40: Plant utilisation key to bring H_2 costs down
Green H_2 LOCH under various utilisation scenarios, $/kg



Source: J.P. Morgan estimates, Company data.

Figure 41: Improvements in energy efficiency less significant
Green H_2 LOCH under various energy intensity scenarios, $/kg



Source: J.P. Morgan estimates, Company data.

How low can Green H_2 costs go?

With our conviction that both renewable power costs and unit capital intensity for electrolysers can continue to decline, it is worth turning to the economics and potential LCOH of green H2. To achieve this, we have constructed our own financial model of a hypothetical, unsubsidized 20MW electrolyser which can calculate an LCOH under various power costs & electrolyser capital intensities. However, our base assumptions include:

- 50% utilization
- 53kWh required to produce 1kg of H_2
- 10% weighted average cost of capital
- 25% corporate income tax rate
- Water, Maintenance, & other opex of $0.5/kg

Levelised Cost of H_2 of $3.4/kg achievable today

Our analysis indicates that for an electrolyser ordered today with an electricity cost of $30/MWh and capital intensity of $750/kW (along with the above mentioned assumptions) could achieve an LCOH of ~$3.4/kg.

Significant regional variations likely, Middle East projects likely ahead

We would expect to see regional variations in the levelised costs of H2 across geographies, particularly where low cost renewable power is already achievable (i.e. Middle East, Latin America) or where low cost alkaline electrolysers are already cheaply produced (i.e. China). For example, assuming $15/MWh power costs (in-line with recent record solar PPAs) and a capital intensity of $750/kW (in-line with our base case above), then a producer could achieve an H2 LCOH of ~$2.6/kg. This is

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in-line with the expected LCOH announced for indicated for several Middle Eastern green H2 projects expected to come online in 2021/22E. In China, where alkaline electrolysers can reportedly be manufactured for <$200/kW, we estimate that <$3/kg H2 cost is likely already achievable if power can be secured <$40/MWh.

Table 15: Green H2 costs rapidly falling with lower power & electrolyser costs

Levelised cost of Green Hydrogen under various power & capital cost assumptions, $/kg

		Capital Intensity				
		$100/kW	$250/kW	$500/kW	$750/kW	$1,000/kW
Power Cost	$0/MWh	0.7	1.0	1.4	1.8	2.2
	$15/MWh	1.5	1.7	2.2	2.6	3.0
	$30/MWh	2.3	2.5	3.0	3.4	3.8
	$45/MWh	3.1	3.3	3.8	4.2	4.6
	$60/MWh	3.9	4.1	4.5	5.0	5.4

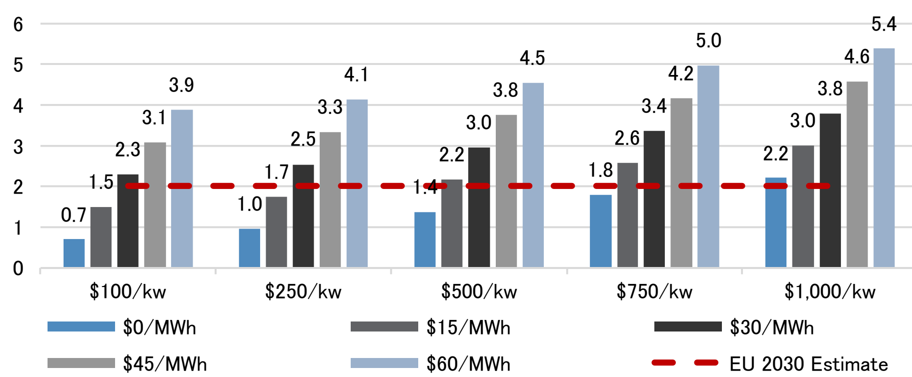
Source: J.P. Morgan estimates, Company data.

EU target of EUR1.8/kg ($2.0/kg) could be achievable before 2030

Nevertheless, we expect renewable power costs to continue to fall and electrolyser capital intensity to decline as the industry scales up. We estimate that if electrolyser costs can be reduced to $500/kW and power costs to ~$15/MWh, then a LCOH of ~$2.2/kg can be achieved, close to the 2030 EU Roadmap estimate. We believe this will likely be achievable in parts of Southern Europe (and North Africa for export to Europe) by or before 2025E.

Figure 42: Green H2 costs rapidly falling, could reach EU 2030 Target earlier than expected

Levelised cost of Green Hydrogen under various power & capital cost assumptions, $/kg



Source: J.P. Morgan estimates, Company data.

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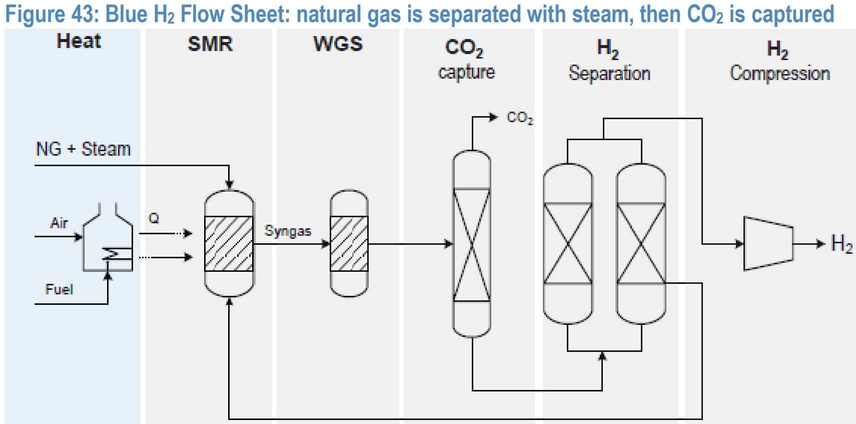
Blue H_2 – Steam Methane Reforming & CCS

One alternative approach for existing grey H_2 production is to retrofit Carbon Capture & Storage capacity to existing natural gas reformers. This approach is commonly referred to as 'Blue H_2'. A major benefit of Blue H_2 is that it would utilize existing steam methane reforming production capacity and natural gas infrastructure capacity. Once the CO_2 is captured, it can be transported to be stored in geological formations or the deep ocean. It can sometimes be utilized in other industrial processes/products (which typically only delays the release of CO_2 to the atmosphere) or converted to carbon-containing compounds requiring significant energy (producing more CO_2). Overall, once fossil fuels are out of the ground, industrial use offers limited long-term storage solutions other than asphalt road-beds and building shingles.

Figure 43: Blue H_2 Flow Sheet: natural gas is separated with steam, then CO_2 is captured



Source: Company data.

Production methods and process chain

The majority (~95%) of commercially available Blue H_2 is produced using steam methane reforming (SMR). As shown below, a mixture of natural gas and pressurized steam is combined to produce syngas (carbon monoxide and hydrogen). By separating the CO_2 from the hydrogen, ~60% of the total CO_2 produced during this process can be captured, according to the Global CCS Institute. The remaining ~40% of CO_2 which can be captured derives from the flue gas produced during the reformation process. SMR can result in a capture rate of up to ~90% once the additional CO_2 is extracted; however, this is still relatively expensive today as the CO_2 is dilute and at low pressure. The second and less used method for production is auto-thermal reforming (ATR), which combines natural gas and oxygen to produce the syngas. Though less used and proven, its capture rate is reported to be up to ~95% and has typically been used on larger plants. Once the H_2 is produced, it is then transported, stored, and put into use in certain industries for feedstock or fuel purposes.

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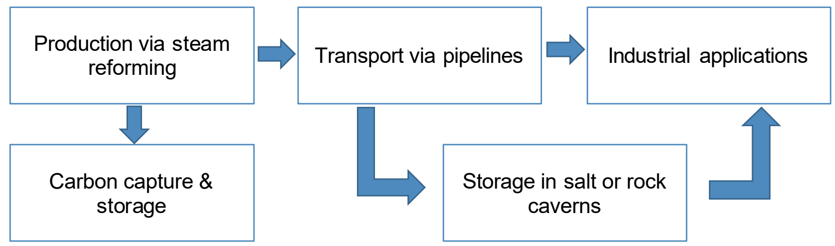
Figure 44: Blue H_2 Process Chain



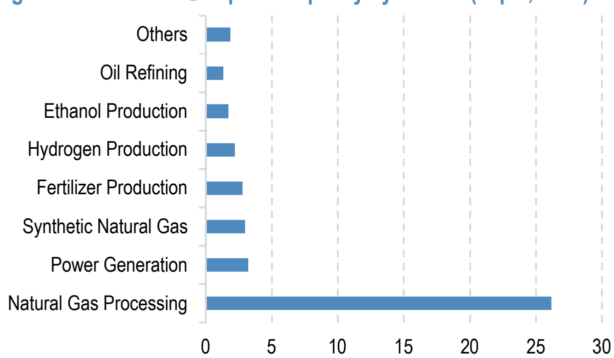
Source: CE Delft.

We view CCS as the key lever for Blue H_2 to scale, with government policy critical to its growth

Carbon capture and storage history and scalability

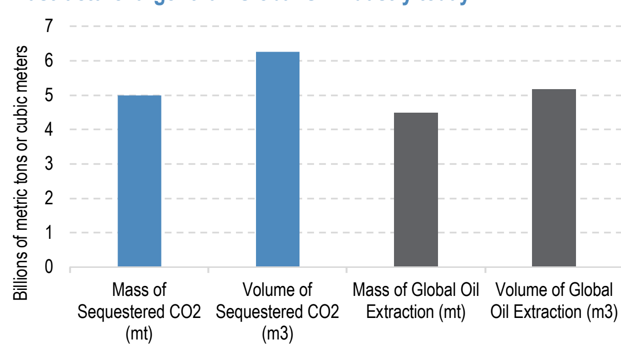
One of the key levers for Blue H_2 is the scaling of the CCS component, through which CO_2 is captured, transported, and stored underground (or utilized in select industrial processes). As highlighted above, storage sites are important to the scalability of projects and will most likely be offshore. For example, the Zero Carbon Humber project's saline aquifer, Endurance, is ~90km offshore in the North Sea and ~1.6km under the seabed. Currently, only ~1% of hydrogen is produced through the coupling of SMR or ATR with CCS. Given pressures to achieve net-zero by 2050, we think the massive existing infrastructure built for LNG is *relatively* low hanging fruit in making progress on reducing emissions via retrofitting and integrating Blue hydrogen production. Carbon capture on its own can also be retrofitted across a variety of industrial processes, helping to reduce emissions on a more micro scale.

Figure 45: Global CO_2 Capture Capacity by Source (Mtpa , 2020)



Source: Global CCS Institute, BNEF.

Figure 46: Capturing 15% of CO_2 emissions requires CCS infrastructure larger than Global Oil Industry today



Source: BP, IEA, JPMAM. Note: As of 2019. Mt: metric tons, m3: cubic meters.

CCS has a mixed track record

While CCS has languished through its history, it's viewed as a critical component of climate goals. According to the Global CCS Institute, potential annual demand for low-emissions hydrogen of ~530 Mt by 2050 could reduce annual CO_2 emissions by ~6btpa. According to the IEA, 10-20% of the ~35btpa of CO_2 we produce annually needs to be captured if society is to prevent the worst effects of climate change. After 20 years, CCS facilities store only ~0.1% of global emissions, and infrastructure would have to exceed that of the global oil industry to offset just ~15% of global emissions. The complicated nature of projects has contributed to this inconsistent history; according to the Carbon Capture Coalition (CCC), it takes about 5 years on average to attain permitting to begin construction. In the U.S., a lack of commercialization has led to the failure of projects as well as higher costs despite some government support. From 2010-2017, the U.S. government spent $1.1bn to

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The US is the leader on CCS deployment globally, with the majority of project additions occurring there.

support nine CCS projects and six were abandoned. Currently, there are only 21 CCS projects globally, according to Wood Mackenzie. Most of the active facilities are concentrated in the Americas, where 12 commercial projects were added and 38 commercial facilities were accounted for in 2020 (~50% of the total globally). The U.S. is the leader on CCS deployment globally, with the majority of project additions occurring there. The next largest region is Europe, with 13 active facilities and 11 commercial projects targeting operation by 2030.

Key variables of Blue H_2 & challenges for wider adoption

Three key variables for Blue H_2 costs are 1) the natural gas price, 2) the capital intensity of the CCS capacity, and 3) the carbon capture opex. Also, long-term CO_2 disposal could also be a major challenge, with some regions offering better geologic conditions than others. This could also prove to be a difficult long-term liability for private markets to quantify and manage. Most importantly, although Blue H_2 captures a significant amount of CO_2 emissions, it cannot achieve 100% capture and upstream emissions from the natural gas industry could still be significant. For this reason, policy support has been relatively lower vs Green H_2. We estimate the levelised cost of Blue H2 today to be lower than what is currently achievable for Green H2, even assuming a $9/mmbtu gas price and $100/t CCS cost However, as green H2 costs continue to decline and where natural gas prices are lower, the difference between Blue and Green H_2 costs could be narrower.

Table 16: Hypothetical Blue H_2 Costs

Levelised cost of Blue Hydrogen under various gas & CCS cost assumptions, $/kg

		Carbon Capture & Storage Cost				
		$20/tonne	$40/tonne	$60/tonne	$80/tonne	$100/tonne
Gas price	$1/mmbtu	1.0	1.2	1.4	1.6	1.7
	$3/mmbtu	1.3	1.5	1.6	1.8	2.0
	$5/mmbtu	1.6	1.5	1.7	1.9	2.1
	$7/mmbtu	1.8	2.0	2.2	2.4	2.6
	$9/mmbtu	2.0	2.2	2.3	2.5	2.7

Source: J.P. Morgan estimates, Company data.

Key variable (1): Natural gas prices

When it comes to Blue H_2, we have focused entirely on natural gas derived H_2. Given that LNG is ~45% less carbon intensive than coal per the EIA, natural gas will likely play a major role in the global energy mix at least until 2030E. From there, demand looks to be more dependent on how effectively the industry can produce lower emissions via grey H2 and how competitive Green H2 becomes. The LCOH increases with the natural gas prices, with CCS layering on additional costs. If natural gas prices remain at reasonably cheap levels, blue hydrogen can remain cost competitive with green hydrogen through 2030 (at least) compared to the even more optimistic cost scenarios.

Key variable (2): Capital intensity of CCS projects

As the commercialization of CCS technology expands, costs will likely fall

The second challenge to Blue H_2 is the capital intensity of CCS projects, with design and construction costs typically ranging from hundreds of millions to billions of US Dollars, per the Global CCS Institute. Specifically, CCS projects have shown capture costs of around $55-70/t CO_2 according to BNEF. The risks and lack of investment discussed earlier play into this, and look dependent upon policy intervention for real progress to be made. Given CCS benefits from economies of scale (as demonstrated in the H-vision initiative), costs can be driven down through larger scale

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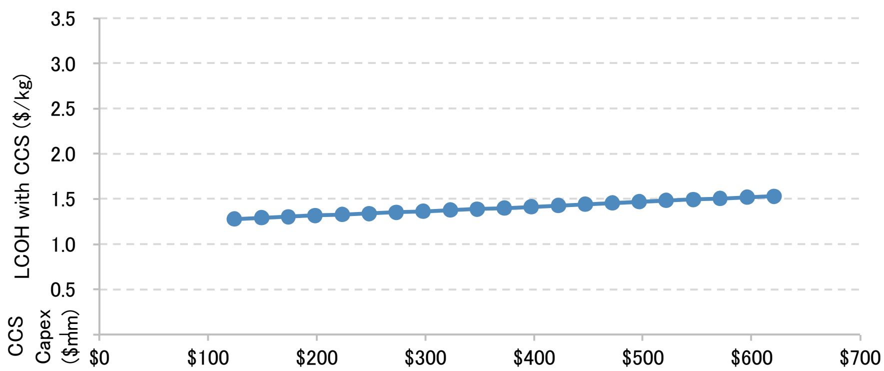
compression, dehydration, pipelines, and storage. Similarly, Scotland's Acorn project utilizes local oil & gas infrastructure, lowering capital costs. The IEA estimates that widespread scale of CCS technology could lower the capex of an SMR facility by ~52% by 2050. BNEF estimates that the commercialization could further simplify the CO_2 capture process and reduce the cost of capture to ~$45/t CO_2. However, while costs and efficiency reductions are added to the H_2 production process, production costs are typically most sensitive to fuel costs (e.g. natural gas) which lowers the risk that overruns in project costs will render it uncompetitive.

Figure 47: Sensitivity of H_2 Production LCOH to CCS Capex

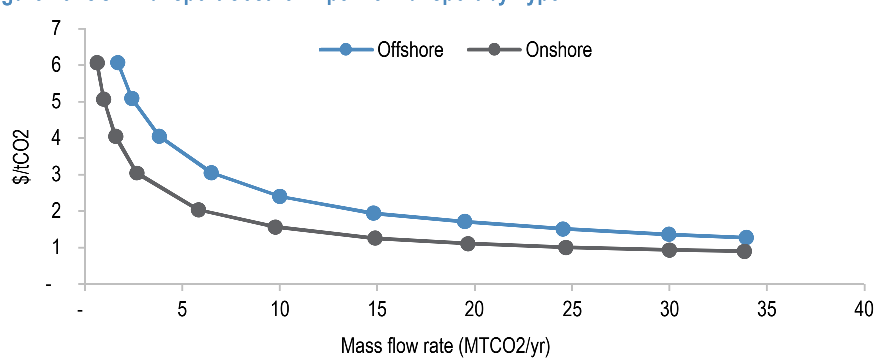


Source: J.P. Morgan, BNEF

Key variable (3): CO2 pricing & opex of CCS

The carbon price also factors into H_2 economics; at ~$71/t CO_2 and above we estimate it would be cheaper to produce blue H_2 than grey. A higher prices incentivize abatement in high-emission industries and processes. In Europe, carbon prices recently rose to their highest level in 10 years. As carbon prices rise, economics for Blue H2 stop being notably impacted at a certain point because while the end consumption of H_2 has no emissions, the unavoidable carbon footprint in the upstream remains. The final key challenge is the high opex of CCS projects. Transferring and storing CO_2 could also face high costs, but they may be brought down with scale. Since pipeline construction is a mature technology, costs do not appear likely to significantly decrease, but increasing capacity and economies of scale can help reduce the per unit pipeline costs. Another impact is the difference in costs between onshore & offshore pipeline transport, with offshore estimated to be ~40-70% more expensive than an onshore pipeline of the same size, per BNEF.

Figure 48: CO2 Transport Cost for Pipeline Transport by Type



Source: IPCC, BNEF.

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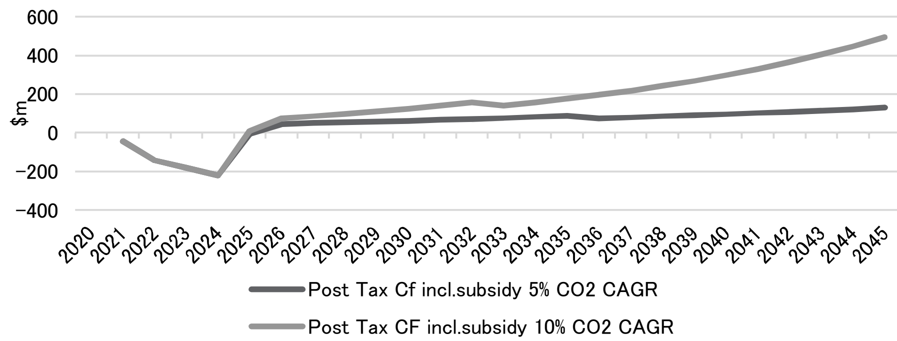
CCS Case Study – Norway's Northern Lights project

Although difficult to gauge, we estimate that with current technology & CCS costs 5-10% of Grey H_2 sites might be suitable (right scale, location) for conversion to Blue. The Northern Lights CCS project in Norway provides an example of CCS economics. Project estimates suggest lifecycle costs of approximately NOK 1,280/t ($142/t) for the initial phase (0.8mtpa stored), with potential for reductions to NOK 940/t ($104/t) at full scale (5Mtpa). This is uneconomic vs. European CO_2 Price (€39/t) and 2021 Norwegian CO_2 Price (NOK 590/t), and thus likely a key reason Norway is raising its target for CO_2 pricing to NOK 2,000/t (~$222/t) in 2030. Consequently, Northern Lights is dependent on subsidies, and in Dec'20 Norway's Parliament approved support up to ~64% of life cycle (25 yr) costs.

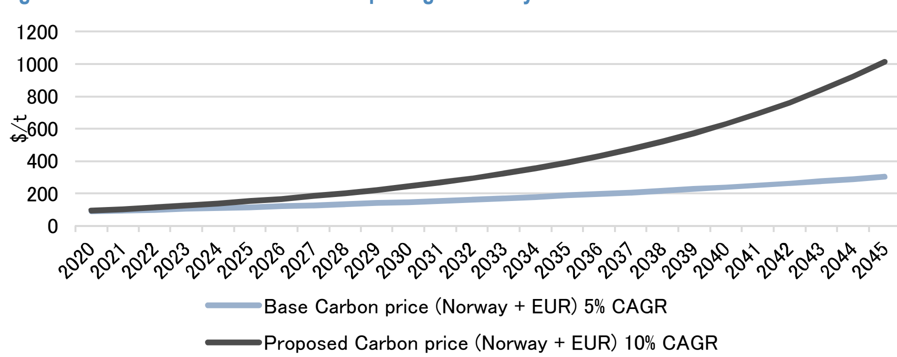
Figure 49: Implied annual CF from the Northern Lights CCS project at varying carbon prices



Source: J.P. Morgan estimates.

For Northern Lights Partners, if they can sell captured CO_2 to others at 80% of prevailing CO_2 prices, we calculate an un-levered, ex-subsidy, post-tax NPV of close to -$1bn assuming 5% carbon price inflation and 4% discount rate from 2020. This rises to +$400m (3% IRR) with the introduction of 60% government subsidy. Of note, if we model Carbon price evolution in Norway as outlined by the government in Jan'21 (link) then the calculated ex-subsidy post-tax unlevered NPV rises to +$460m (2% IRR) and to $1.8bn (17% IRR) including the Norwegian government subsidies. Thus we conclude that CCS costs need to decline by >50% to remove the need for government support, or governments need to pledge carbon tax inflation towards $200/t to incentivize wider adoption of CCS.

Figure 50: Potential outlook for carbon pricing in Norway



Source: J.P. Morgan estimates.

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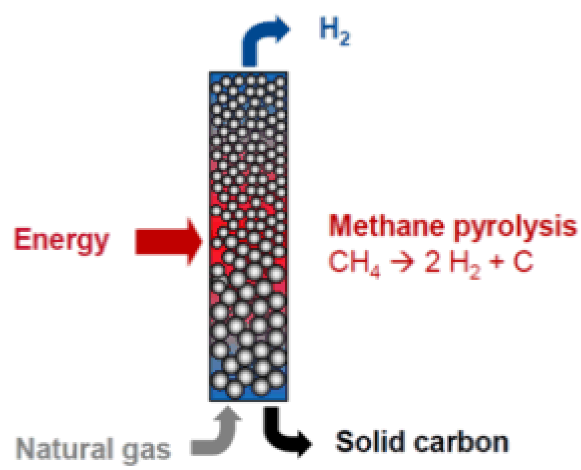
'Turquoise H_2' – methane pyrolysis

Another hydrogen production technology which has a low carbon footprint is methane pyrolysis, or 'Turquoise H_2'. In contrast to steam methane reforming, Turquoise H2 directly splits natural gas (methane) into H2 and solid carbon black (C), so from a stoichiometric perspective there are no CO2 process emissions. Methane is a very stable molecule; so, in order to split it into its constituents, high temperatures and a variety of specialist techniques (see below thermal, plasma, catalytic, microwave) are required. Although energy is used in the process (hence there will inevitably be some level of CO2 emissions unless the energy used is supplied by renewable electricity) overall emissions are very low. The major companies focused on Turquoise H2 are Gazprom (Overweight, covered by Alex Comer) and BASF (Underweight, covered by Chetan Udeshi). Similar to Blue H2, Turquoise H2 could benefit from utilising existing natural gas infrastructure with pyrolysis undertaken at the point of consumption. Also, carbon black can be sold as a byproduct although clearly if methane pyrolysis were to take off at scale the byproduct market would likely be flooded and prices could collapse. Nevertheless, the disposal of solid carbon black will likely be far cheaper and easier than CO_2.

Figure 51: Turquoise H2 flow sheet – natural gas is separated with heat and no CO2 byproduct



Source: Company data.

However, Turquoise H2 still far from commercial production

Similar to Blue H2, the key cost variables are 1) natural gas price, 2) capital intensity of the pyrolysis facility, and 3) the achievable carbon black price. Although our analysis shows that low H2 costs could be achievable through methane pyrolysis, it is not as commercially advanced as Blue or Green H2 and hence risks missing the boat as a technology option as Green H2 costs fall.

Table 17: Methane pyrolysis processes and players

Principle	Developer, facility	Target product	Period	Reactor description	State of development	TRL
Thermal	BASF	H_2	2012–	Moving bed of carbon granules	Laboratory plant, R&D project for scale-up	4
Thermal	KIT / IASS	H_2	2013–	Liquid tin bubble column	Laboratory, R&D project for process development	3
Plasma	Kvaerner	Carbon black	1992–2003	Plasma torch	Pilot plant, with subsequent scale-up (Karbomont plant)	6
Plasma	Kvaerner, Karbomont plant	Carbon black	1997–2003	Plasma torch	Production plant (decommissioned and dismantled)	8
Plasma	Monolith materials, Seaport plant	Carbon black	2014–2018	Plasma torch (similar to Kvaerner)	Pilot plant (dismantled), with subsequent scale-up	6
Plasma	Monolith materials, Olive Creek Plant	Carbon black	2016–	Plasma torch (similar to Kvaerner)	Production plant, mechanical completion planned for 2020	8
Plasma	Atlantic hydrogen, carbonsaver	Mixture H_2 / natural gas	2005–2015	Plasma torch	Pilot plant (not put into operation), development stopped due to bankruptcy	5
Catalytic / Plasma	Tomsk Universities, TOMSK-GAZPROM	H_2	2008–	Microwave, Ni catalyst bed + plasma torch	Laboratory, no further information on scale-up	3
Catalytic	UOP, HYPRO process	H_2	1963	2-stage fluidized bed with Ni catalyst	Laboratory plant, development was stopped	4
Catalytic	Florida Solar Energy Center	H_2	2003–2005	2-stage fluidized bed with C catalyst	Laboratory, no information on further development	3
Catalytic	Hazer Group	H_2	2010–	3-stage fluidized bed with Fe catalyst	Laboratory, pilot plant to be constructed by 2021	3

Source: Schneider, ChemBioEng Reviews TRL= technology readiness level

The EU Hydrogen Roadmap, whilst clearly favouring Green hydrogen, specifically mentioned methane pyrolysis as a technology eligible for subsidies which could help kick-start development. **BASF**, which appears to be the most advanced regarding methane pyrolysis technology in Europe, does not expect to begin constructing a commercial-scale unit before 2025. **Gazprom** has commented that it will build a 'large' methane pyrolysis plant close to the shore of its NS1 pipeline in Germany but details are thin and no partner has been announced. ASX-listed Hazer Group (not covered) plans to scale up its own pilot project to a 100-tonne commercial demonstration scale plant by 2021.

Table 18: Hypothetical Turquoise H2 Costs

Levelised cost of Turquoise Hydrogen under various gas & carbon black price assumptions, $/kg

		Carbon black price				
		-$50/tonne	-$20/tonne	$0/tonne	$20/tonne	$50/tonne
Gas price	$1/mmbtu	1.1	1.0	1.0	0.9	0.8
	$3/mmbtu	1.6	1.5	1.5	1.4	1.3
	$5/mmbtu	2.1	2.1	2.0	1.9	1.8
	$7/mmbtu	2.7	2.6	2.5	2.4	2.4
	$9/mmbtu	3.2	3.1	3.0	3.0	2.9

Source: J.P. Morgan estimates, Company data.

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Cost outlook for the H_2 rainbow

The success or failure of the H_2 transition will likely depend upon the trajectory of costs for the various technology 'colours'. We estimate that Green H_2 costs will fall steeply over the next 10 years as the industry matures and renewable power costs fall. However, the prospects of Blue H2 could vary by region and depend upon the commercial viability of Turquoise H2 from 2030 onwards.

Near-term (to 2025) – green H_2 competing in specific locations

Over the next several years, we expect Green H_2 costs will likely remain relatively expensive on a global basis while the industry scales up. However, in some regions (i.e. S. Europe, MENA), ultra-low solar power costs could mean ~$2/kg green H_2 is achievable before 2025. We do not expect Turquoise H2 to be commercially viable in this timeframe. Although Blue H_2 could be cost competitive, particularly in the US, lack of wider policy support could hinder near-term widespread adoption.

Medium-term (to 2030) – Green H2 competing with Blue H2; success of Turquoise technology development a key variable

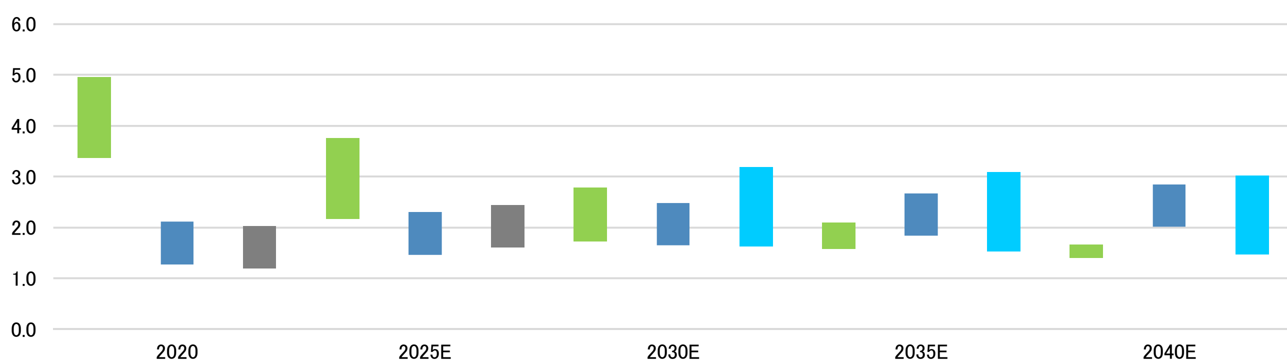
Between 2025 and 2030, the scale-up of green H_2 projects to 100s of Megawatts and further reduction in renewable power costs should help close the gap between green and blue H_2. Also, the technological development of turquoise H_2 projects could become a more critical variable. Grey H_2 will also likely become less competitive in regions where CO_2 costs become more significant (i.e. Europe).

Long-term (post 2030) – large-scale green H_2 & potential commercial-scale Turquoise H_2 likely to outcompete Blue H_2

Post 2030, we expect green H_2 will be able to compete in most regions as the electrolyser industry fully matures and H_2 transportation & storage challenges are overcome, likely displacing Grey H_2. The success of developing large-scale and commercial Turquoise H_2 will be a key variable in this period, likely determining whether Blue H_2 will either thrive longer-term or be substituted with Turquoise H_2.

Figure 52: How will H2 costs progress?

Green, Blue, Grey, and Turquoise Levelised Cost of H2 over time, $/kg



Source: J.P. Morgan estimates, Company data.

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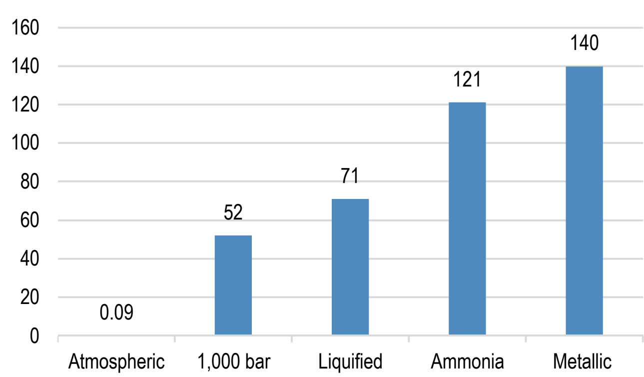
Transportation & Storage of H_2

Hydrogen production technologies are only part of the challenge for developing a hydrogen economy. Transportation & storage will also present significant challenges analogous to, but likely more significant than, those that apply to natural gas. H2 is a highly energy dense commodity at >120MJ/kg, nearly 2x that of natural gas and 3x that of gasoline but, on a volumetric basis, hydrogen has a lower energy content than natural gas, with hydrogen achieving 2.4MWh/m^3 vs natural gas of ~6MWh/m^3. Liquefying hydrogen requires a far lower temperature than natural gas and thus would require more energy to achieve and maintain liquefaction.

Figure 53: H_2 densities differ across H_2 products

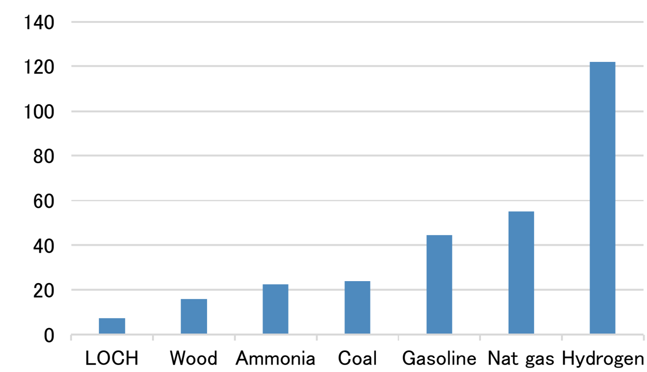
Kg/m^3



Source: J.P. Morgan estimates, Company data.

Figure 54: H_2 can provide an energy dense fuel source

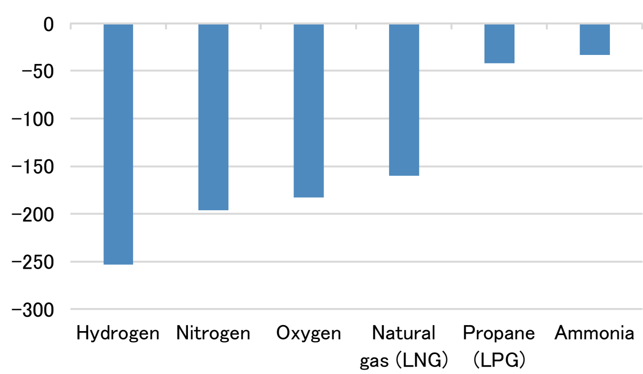
MJ/kg



Source: J.P. Morgan estimates, Company data.

Figure 55: Liquefying H_2 requires lower temperature, more energy

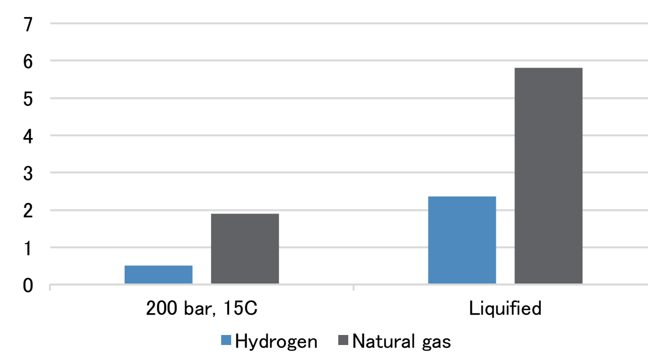
Temperature, Celsius



Source: J.P. Morgan estimates, Company data.

Figure 56:Volumetric energy density of natural gas is greater than H_2

Volumetric energy density, MWh/m^3



Source: J.P. Morgan estimates, Company data.

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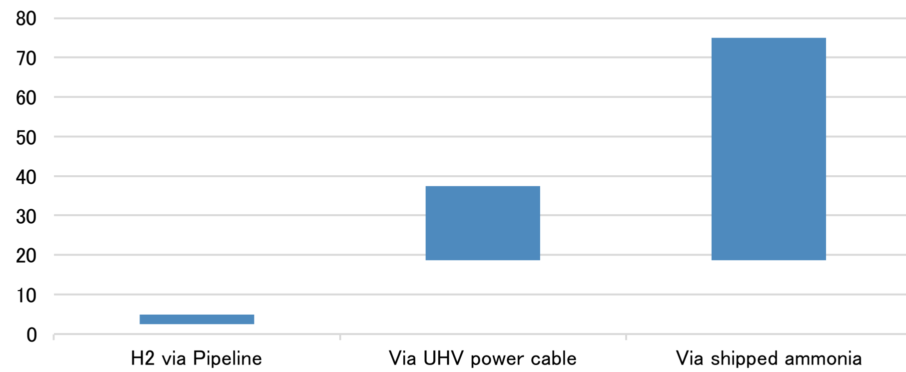
The challenge of transporting H_2

H2 pipelines would add only modestly to all-in H_2 costs

One major logistic and economic challenge for the widespread adoption of H2 is that of transportation. As discussed above, although hydrogen is an energy dense fuel on a kilogram basis, it is less efficient on a volumetric basis. For example, even when liquefied, natural gas can achieve ~4x the MWh/m^3 that pure hydrogen can. This presents significant implications for how producers and consumers will transport H2. For example, Italian utility Snam estimates that transporting power from North Africa to Italy in the form of H2 via pipeline would cost only ~$2.5-5MWh, ~13% of the cost of using a UHV power line and ~8% of the cost to produce green ammonia which is then shipped. Also, BNEF estimates that most realistic pipeline distances for hydrogen would incur only a relatively minor transportation cost.

Figure 57: Moving renewable power - H2 pipeline, power line, or ammonia shipping?
$/MWh, Cost of transporting Renewable power from North Africa to Italy.

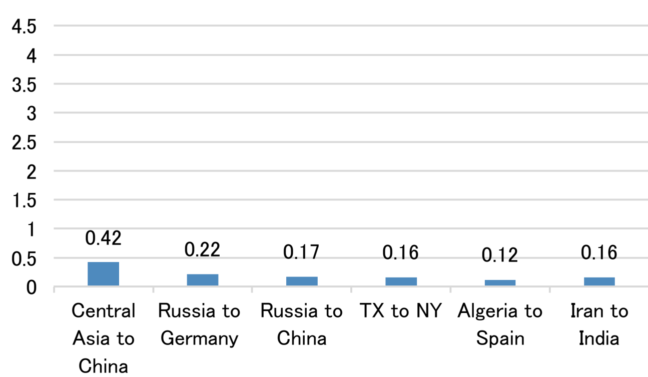


Source: Snam, J.P. Morgan estimates, Company data.

Shipping of H_2 (likely as ammonia) considerably adds to costs

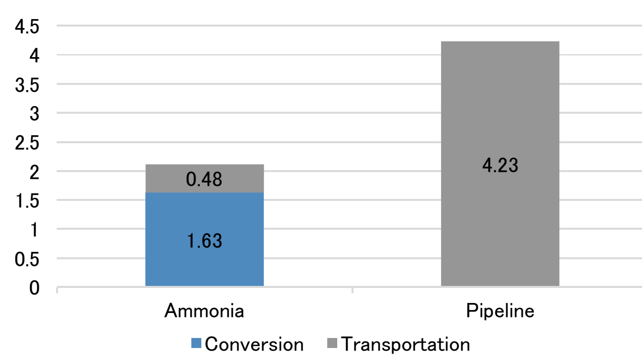
Similar to natural gas, once H_2 needs to be liquefied and shipped, costs will likely increase materially. BNEF estimates that converting H_2 to ammonia and shipping to Japan would add ~$2/kg to all-in costs, equivalent to ~70% of green H_2 costs today.

Figure 58: Overland pipeline costs appear minimal
Cost of transporting H2 via pipeline, $/kg



Source: J.P. Morgan estimates, Company data.

Figure 59: Oversea transportation more challenging
Cost of transporting H_2 10,000km to Japan, $/kg



Source: J.P. Morgan estimates, Company data.

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Understanding H_2 storage options

Additionally, storing H_2 presents several challenges, primarily for long-term storage. Given H2 molecules are far smaller than those of natural gas (CH_4), leakage over time can be a greater challenge. Also, H_2's lower volumetric energy density and H_2 liquefaction requires a lower temperature than natural gas, adding to the challenges of storing H_2. Storage options will also vary across duration (days to seasonal), geographic availability, costs, and safety considerations. We have summarized the options across time horizons below.

Short-term (days)

Given the nature of the H_2 industry today, daily storage is not a major challenge, which mostly uses pressurized containers. There is little risk of leakage short term and costs are relatively minor (<$$0.2/kg).

Medium-term (days to weeks)

For more medium-term storage (days to weeks), far more options are available with varying costs and levels of technological readiness. Caverns offer a low-cost gaseous storage option, but these will be geographically limited. Ammonia is far more costly and faces greater safety regulations and concerns. Liquid H_2 and liquid organic H_2 carriers ('LOHC', i.e. Methylcylohexane) are not as technologically advanced as ammonia.

Long-term (months to seasons)

For long-term storage options (months to seasons), fewer options are technologically or economically viable today. Depleted gas fields, rock caverns, and liquid organic H_2 carriers could offer economic options, but are not yet technologically viable.

Table 19: Hydrogen Storage Options

	Salt Cavern	Depleted Gas Field	Rock Cavern	Pressurised Container	Liquid H2	Ammonia	Liquid Organic H2 Carrier	Metallic compounds
Gas, Liquid, Solid?	Gaseous	Gaseous	Gaseous	Gaseous	Liquid	Liquid	Liquid	Solid
Possible Scale	Large	Large	Medium	Small	Small / medium	Large	Large	Small
Duration	Weeks - Months	Seasonal	Weeks - Months	Daily	Days - Weeks	Weeks - Months	Weeks - Months	Days - Weeks
Geographic availability	Limited	Limited	Limited	Not Limited	Not Limited	Not Limited	Not Limited	Not Limited
Costs	Low	Medium	Low	Low	Medium	Medium	Medium	High
Economically viable?	Medium-term	Long-term	Long-term	Available today	Medium-term	Available today	Long-term	Medium-term
Safety Concerns	Low	Low	Low	Medium	Medium	High	Medium	Medium

Source: J.P. Morgan estimates, Company data.

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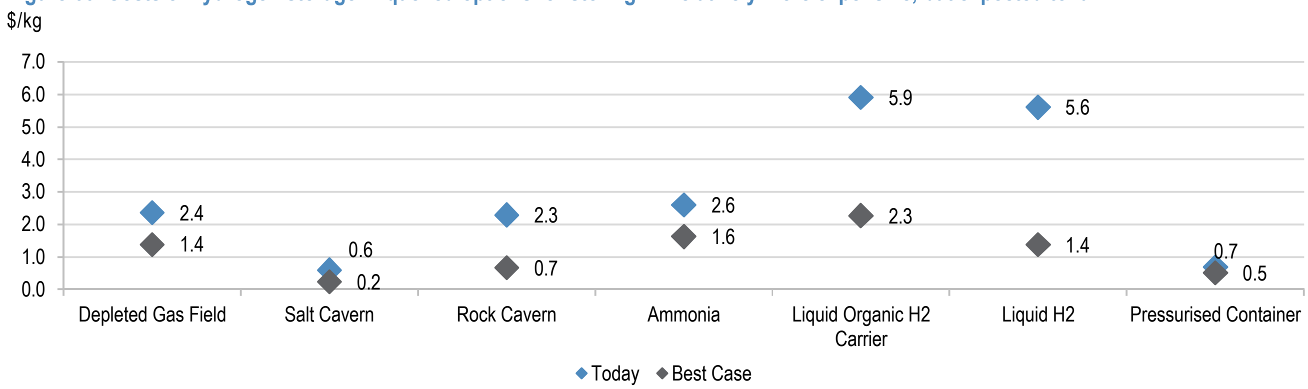
Costs of storage also vary and will often be dictated by the transport route

Today the costs of H_2 storage are relatively low where it is currently most utilized, namely pressurized containers, at <1/kg. Nevertheless, given the need for more medium- and long-term storage solutions, higher-cost options will need to be improved to be economically viable. Furthermore, we expect the storage option will also likely often be dictated by the method of transportation, namely overseas shipping. For example, given pipelines will not be economic for transporting H_2 from Australia to Japan, liquefied transportation will likely mean that liquefied storage is also more common. The most economic form of liquefied storage today is as ammonia, which costs ~$2.5/kg today but warrants greater safety concerns than other storage methods. Liquid H_2 and LOHC still need greater technological and cost improvements to be economic in the longer term.

Figure 60: Costs of hydrogen storage - liquefied options for storing H2 relatively more expensive, but expected to fall



Source: J.P. Morgan, BNEF.

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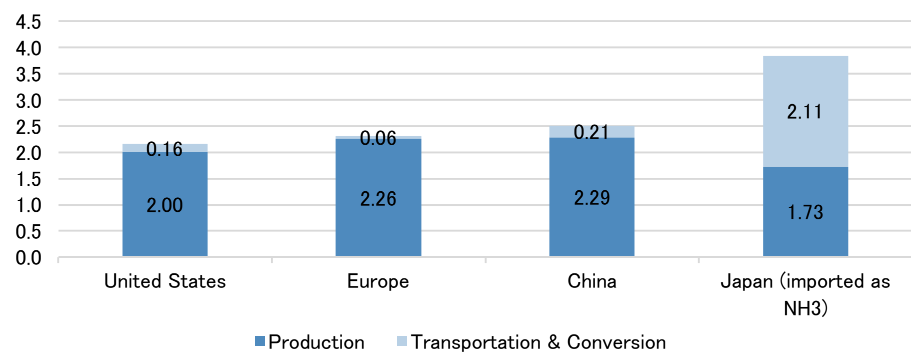
Comparing all-in H_2 costs globally

Low all-in green H_2 costs achievable (just avoid liquefying)

Given the regional variances in renewable power resources and thus LCOEs, green H_2 costs will likely vary considerably across regions. We estimate that all-in (i.e. production & storage) green H_2 LCOH in the US, Europe, and China could be <\$2.5/kg by 2030E, even if importing via pipeline. However, for countries needing to import H_2 in liquefied form (i.e. Japan and South Korea), landed costs for consumers will be considerably higher given the cost of conversion to ammonia (\$0.9-2.4/kg) and transportation (~\$0.5/kg).

Figure 61: US, Europe, China can all achieve relatively low all-in green H2 costs
$/kg All-in green LOCH, 2030E



Source: J.P. Morgan estimates, Company data.

China: significant opportunities & challenges

Green H_2 costs in China ~\$2.5/kg possible with domestic & pipeline imports

In China, all-in H_2 costs will already benefit from the domestic production of low-cost electrolysers; however, achievable power costs present greater uncertainty. If renewable power and electrolysis systems are co-located in western provinces, the pipeline cost to eastern, coastal provinces could marginally add to the all-in green H_2 costs, but water access could present challenges. Even if green H_2 is imported from Central Asia or Eastern Russia, we estimate an achievable all-in green H_2 cost of ~\$2.5/kg or lower. Also, this would still be significantly below the cost of importing green ammonia from Australia or Latin America, which would be ~\$3.9/kg.

Blue & Turquoise H_2 likely higher cost than domestic green H_2, but cheaper than imported green ammonia to 2030E

If we assume that landed cost of imported natural gas (today, predominantly as LNG) in China could be ~\$9/mmbtu, we estimate that the cost of produce blue H_2 could be ~\$2.7/kg in 2030E and turquoise H_2 could be ~\$3.4/kg (assuming development success), well above the cost of domestic green H_2, but cheaper than imported green H_2 as ammonia. Long term, if natural gas from Russia could be imported via pipeline, then the cost of blue and turquoise H_2 could be lower. However, we also expect the cost of imported green ammonia to fall post 2030E as large-scale export projects become more feasible.

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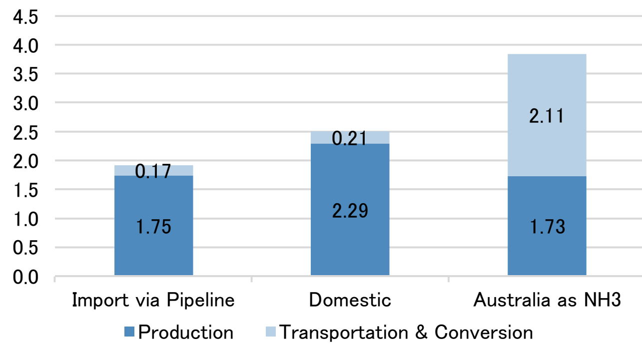
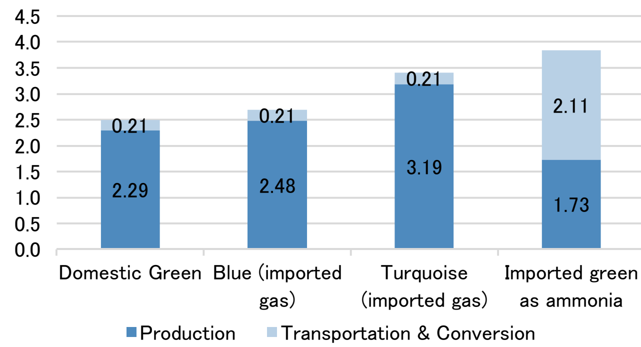
Figure 62: Green H_2 costs in China: green costs <$2.5/kg possible
All-in green LOCH 2030E, $/kg



Source: J.P. Morgan estimates, Company data.

Figure 63: H_2 rainbow in China: domestic green appears competitive
All-in LOCH 2030E , $/kg

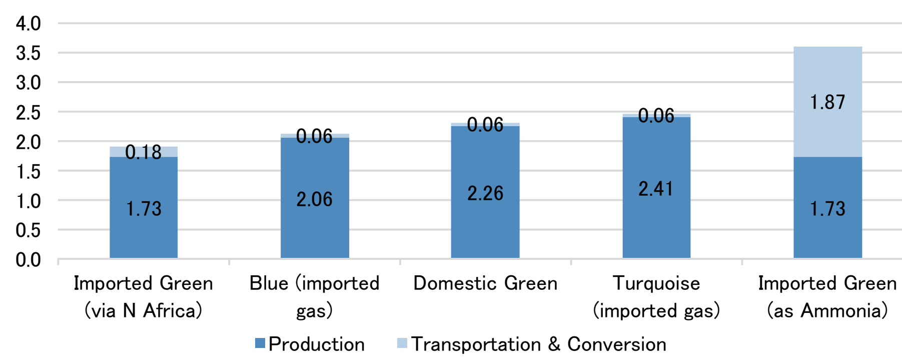


Source: J.P. Morgan estimates, Company data.

Europe: domestic & imported green H_2 likely to dominate

With the cost of green H_2 likely to be ~$2/kg or lower in North Africa and Southern Europe (given low renewable power costs), we expect green H_2 will likely dominate in Europe. We also expect policy support to remain largely focused on green H_2. We doubt that imported green ammonia would be likely to play a major role before 2030 given the cost advantage of domestic green supply, imported green supply via pipeline, and blue H_2 (which could still play a transitional role given its relatively low cost). However, the role of Blue H_2 will likely depend upon a greater shift in EU policy, which to date has largely been skewed towards favouring Green H_2, and whether Turquoise H_2 can be commercially developed by the end of the decade.

Figure 64: Europe: green options likely to dominate supply
All-in LOCH 2030E, $/kg



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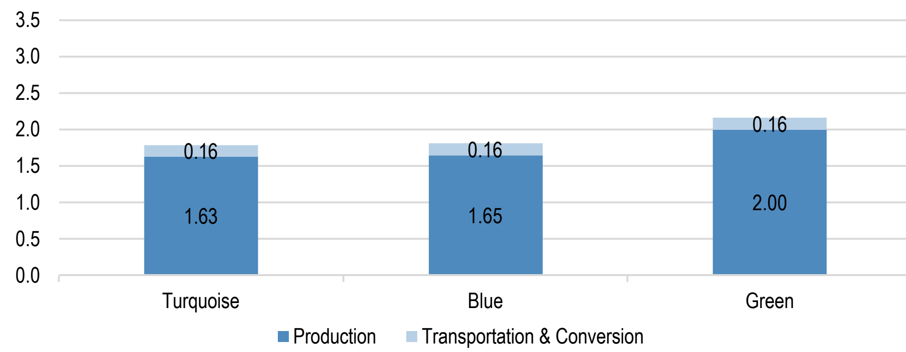
United States: greater role for blue H_2 on cost advantage

In the United States, blue H_2 could play a greater role to 2030E in our view. The US benefits from significant existing US natural gas infrastructure and low-cost supply with some of the lowest gas prices in the world (Henry Hub currently <$3/mmbtu). As such, we estimate US blue H_2 could achieve an all-in cost of <$2/kg. This could also offer a long-term pathway to turquoise H_2 if it can be commercialized (which will be challenging before 2030E in our view). We note there is also greater policy support for Blue H_2 and CCS in the US, relative to Europe.

However, given the size and regional variations within the US, green H_2 could offer a lower-cost alternative for Western states where low-cost solar & wind power from Southwestern states (i.e. Arizona, Utah, Nevada) can be used to meet West Coast demand. California and several other western states have been supportive of developing H_2 ecosystems. For example, California is effectively the only state where passenger Fuel Cell EVs are available for sale and the state has been expanding the number of H_2 refueling stations (currently 45, with 43 more under development).

Figure 65: United States: blue H2 could play a greater role to 2030
All-in LOCH 2030E, $/kg



Source: J.P. Morgan estimates, Company data.

How could the global H_2 market evolve?

Japan & South Korea likely to lead import demand

The development of a major seaborne H_2 market will likely depend upon the pace of decarbonisation for hard-to-abate sectors in countries that cannot easily or economically produce H_2 domestically. The two countries that appear most advanced on this front are Japan and South Korea. Both countries have recently committed to achieving net zero emissions by mid-century. Both countries possess autos OEMs which are focused on H_2 Fuel Cell EVs. For example, **Hyundai** is targeting 500k pa FCEV output by 2030E (equivalent to ~0.5% of global vehicle output), while Toyota and Honda are working to commercialise their respective FCEV models. Several Japanese steelmakers (i.e. **Mitsubishi Heavy Industry**, **Nippon Steel**) are exploring H_2-derived steel to decarbonize.

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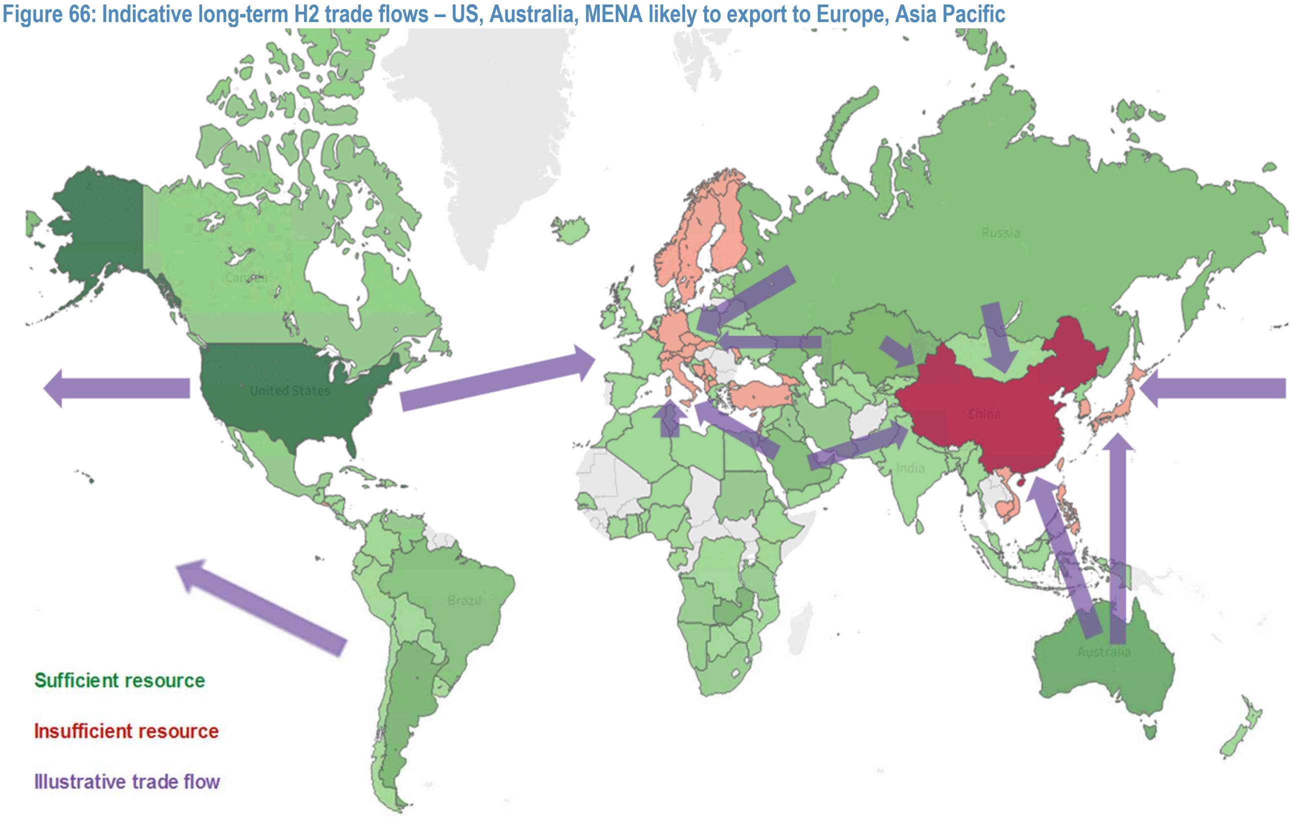
Australia, Chile, MENA could lead for export supply

We expect the countries that could become material H_2 exporters on the seaborne market are those that 1) can achieve low renewable power costs, and 2) will likely be able to produce far more green H_2 than can be domestically consumed. Three countries/regions that we believe could meet these two conditions are Australia, Chile, and the Middle East/North Africa. We are already seeing the development of large-scale green H_2 projects in the Middle East, such as Air Products' 2GW Neom green ammonia project in Saudi Arabia. In Australia, several Gigawatt scale projects are being considered, but smaller scale projects, such as Fortescue's 250MW Bell Bay green ammonia project in Tasmania could be board approved during CY'21 (link). The Chilean government has also recently announced a target of 5GW of green H2 capacity by 2025E and 25GW by 2030E (link). Engie and Enaex's HyEx initiative expects to commission a 26MW electrolyser by 2024 and eventually scale the project up to 1.6GW by 2030E (link).

Figure 66: Indicative long-term H2 trade flows – US, Australia, MENA likely to export to Europe, Asia Pacific



Source: J.P. Morgan estimates, BNEF.

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H_2 for energy storage & heating

The overarching opportunity from H_2 adoption derives from its ability to act as a large-scale storable and transportable form of energy. As discussed in the previous section, storage options for H_2 could range from small-scale for immediate use to large-scale facilities for seasonal deployment. Also, the commercial viability of globally transporting H_2 appears achievable over the next decade. Thus, if H_2 can become more commoditised, it is worth considering what role it can play in a wider energy storage context, particularly in the power sector and for heating.

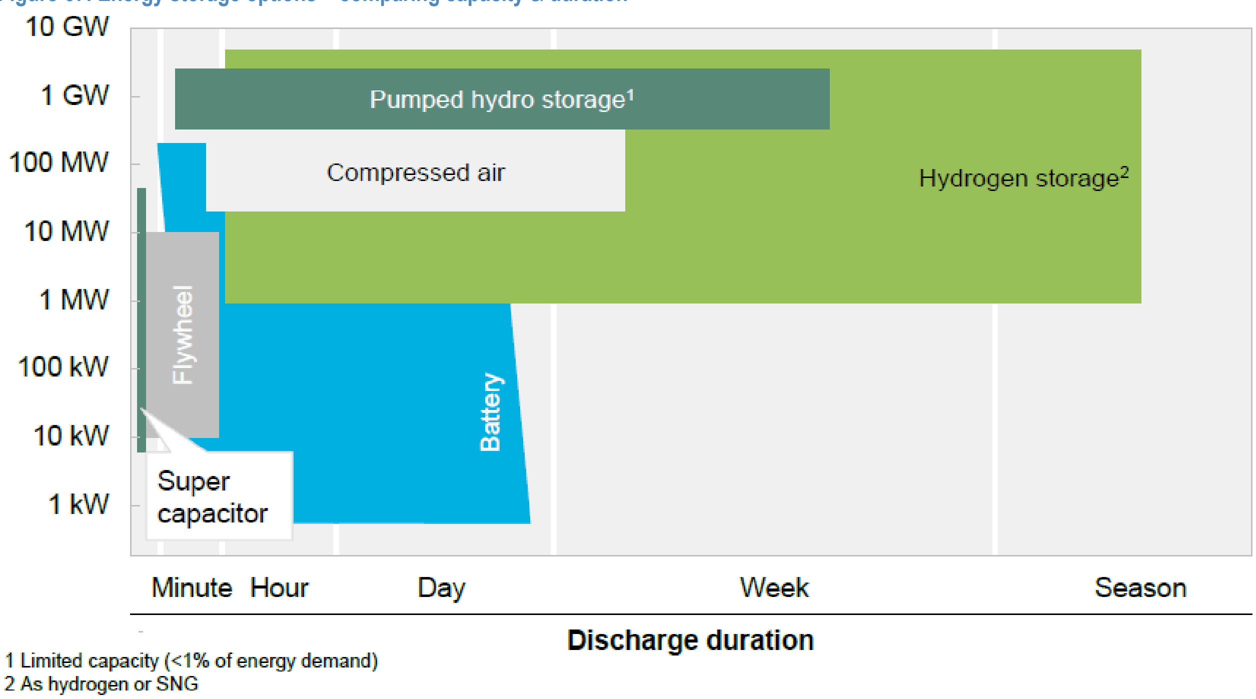
Can H_2 'Gas-to-Power' offer peak demand solutions for power grids?

The use of H_2 to create electricity on a large scale is being developed by a number of companies, typically using combined-cycle gas turbines ('CCGT'). This is commonly referred to as 'Power-to-Gas' or 'P2G'. This could present competition for lithium-ion batteries for stationary energy storage systems ('ESS'), particularly given CCGT utilising H_2 would not face a particular duration limit to help support grids during peak demand. Also, the interest and investment in H2 technology has helped increase the technological readiness of H_2 P2G over the last several years.

But significant technology competition in grid-scale energy storage

However, H_2 P2G is not the only large-scale energy storage solution which can help manage peak demand. Another technology is pumped hydro storage ('PHS'). In PHS systems, renewable or other excess electricity is used to pump water to a higher altitude reservoir. When electricity demand peaks, the water flow is reversed, powering a turbine, and creating electricity. Its primary advantage is that PHS is a mature technology and not as geographically restricted. Also, other technologies are rapidly improving, such as utility-scale lithium-ion batteries.

Figure 67: Energy storage options – comparing capacity & duration



Source: Hydrogen Council, Company data.

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H_2 G2P projects gaining attention, but economics still challenging

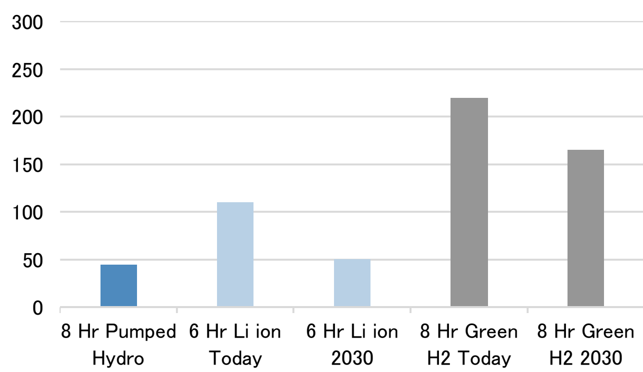
H_2 G2P projects are gaining more attention and investment. One major supporting factor for investment into P2G is that existing gas power plants could be potentially converted using a blend of natural gas and hydrogen as a fuel source, and then later converted to using 100% H_2. Two major projects under construction in the US are pursuing this strategy. The 840MW Intermountain Power Plant in Utah is being converted from coal to a 70% natural gas / 30% H_2 blend by 2025, with the expectation of eventually utilising 100% H_2. Also, the greenfield 485MW Long Ridge Energy Terminal in Ohio is designed initially to operate on 95% natural gas & 5% H_2 when it starts up in 2021 and eventually to run on 100% hydrogen. Therefore, we expect other regions with significant existing natural gas power capacity (i.e. EU, Middle East) could also consider converting their existing stations to H_2.

G2P could struggle vs Lithium-ion stationary storage

However, the continual improvement and deployment of utility-scale lithium-ion electrical storage suggests that Li-ion batteries will likely remain lower cost and thus more competitive than H_2 for meeting peak electricity demand. A study by E3 on using H_2 for grid-level power storage in California showed that Li-ion batteries will likely achieve a much lower cost than H_2 at least until 2040E. So we doubt H_2-CCGT will play a major role in this area at least over the next decade.

Figure 68: H2 for energy storage not yet economic

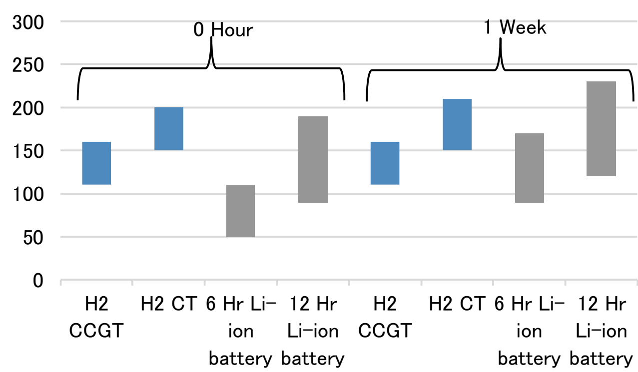
California levelised cost of storage, $/MWh



Source: E3, Company data.

Figure 69: ...but could compete in the long-term in some places

California levelised cost of storage in 2040, $/MWh



Source: E3, Company data.

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Opportunity to blend H_2 into natural gas networks

One of the easier end-use applications of green and low-carbon H_2 is to blend it into the existing natural gas infrastructure, to be used by conventional end users to generate power and heat. This can deliver both environmental and energy security co-benefits.

This use is being considered by several countries in their H_2 strategies. Pilot projects worldwide have demonstrated the feasibility of blending H_2 into natural gas networks at levels of up to 20%. However, some questions remain around the long-term impact of hydrogen on materials and equipment, and the additional costs.

Table 20: Overview of countries considering blending H2 into natural gas grids

Country	Region	Blending Natgas
Australia	Asia	Blending in Gas distribution network envisaged in H2 strategy
Italy	EMEA	Snam has been experimenting with a 10% blend into the gas transmission networks.
Netherlands	EMEA	Blending obligation under consideration. Feasibility study considered.
New Zealand	Asia	H2 vision considers injecting up to 20% of H2 into its natural gas grid by 2035.
Portugal	EMEA	10-15% of H2 in natgas grid distribution envisaged; Legislation in preparation.
UK	EMEA	H21 Leeds City Gate Project: demonstrating the technical feasibility of repurposing the existing gas distribution network for H2

Source: J.P.Morgan estimates

In a feasibility study, French gas operators conclude that it is possible to integrate a significant volume of H2 into the gas mix by 2050 with limited infrastructure adaptation costs. In the short term, they consider that the blending rate can go up to 6% in terms of volume, in the absence of sensitive structures or installations on the customer premises. An injection rate of 10% would be considered by 2030, and 20% thereafter with limited changes to the infrastructures. However, this would require coordination with European partners.

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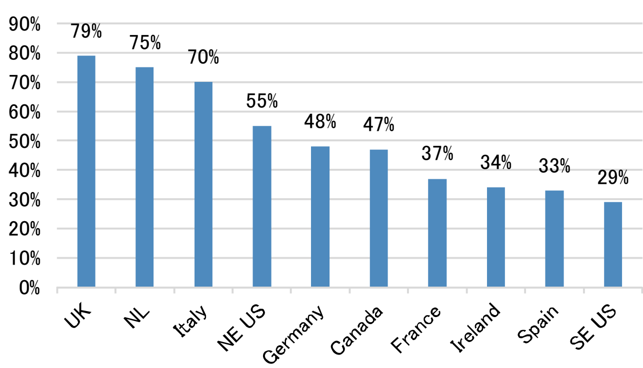
Residential heating: potential opportunity for H_2 given high gas connectivity in many countries

Another major area of potential demand for Hydrogen where it could substitute for natural gas is in residential and commercial heating. This is gaining more attention as national regulators turn attention to building-related emissions. For example, the UK announced in Jan'21 that it will ban the installation of gas boilers in new-build homes from 2025. To address this impending long-term demand risk, home boiler manufacturers such as Worcester-Bosch are developing boilers which can operate using H_2. If gas networks can be converted to transporting hydrogen, H2-combi boilers could offer a relatively simple way of achieving energy transition for home heating in many countries. For example, ~70% of residential & commercial buildings in the UK, Netherlands, and Italy already use natural gas for heating, and thus have the necessary gas connections.

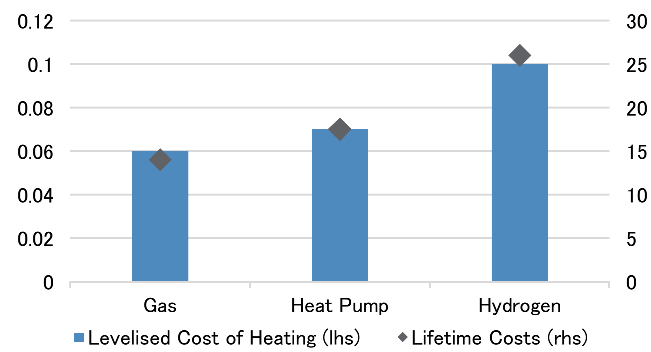
However, some practical as well as economic constraints to using hydrogen for residential heating. Firstly, hydrogen burns hotter than natural gas and its flame is almost invisible in daylight, increasing the potential safety issues for its use in homes. Nevertheless, these could be addressed with additives, similar to the additives used for natural gas which give it a strong odour. Secondly, other technology options could be more economic, such as heat pumps and thermal batteries. For example, in tandem with its ban on gas boilers in new builds by 2025, the UK government is also targeting the installation of 600,000 heat pumps by 2028. Thirdly, given the 2025 ban is now only four years away, the pressure to transition home heating could come before natural gas grids are totally transitioned over to hydrogen.

Figure 70: Many countries already have a high proportion of natural gas for residential & building heating
% of total



Source: J.P. Morgan, Company data.

Figure 71: H_2 appears expensive vs heat pumps for home heating
LHS: Levelised cost of heating (GBP/kwh), RHS: total cost of ownership over 20 years (thousand GBP)



Source: J.P. Morgan, BNEF

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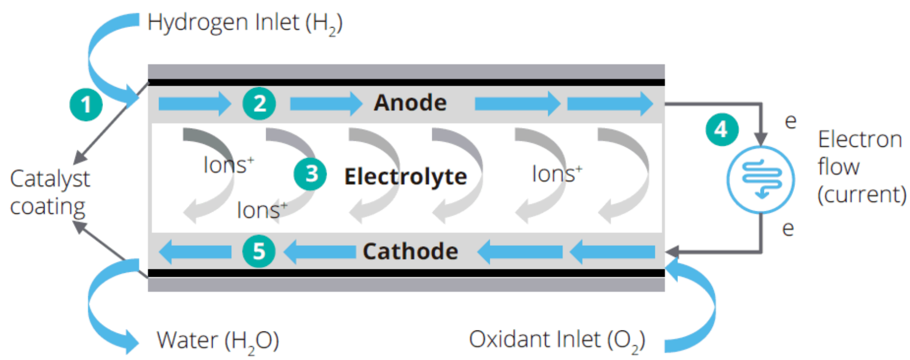
Fuel cells: key to wider range H_2 adoption

A critical element of the Hydrogen economy will likely be the consumption of H2 in fuel cells. Simply, an H2 fuel cell is an electrolyser in reverse: the chemical reaction of hydrogen with oxygen creates electricity and the byproduct is water (H_2O). The typical fuel cell technologies also fall along the same lines as electrolysers, with alkaline & PEM technologies dominating fuel cell development.

The advantage of fuel cells is that they allow the generation of electricity using hydrogen at various scales and durations with significant flexibility. Thus, fuel cells take hydrogen consumption beyond the larger industrial applications (i.e. steel, fertilisers, refining) and into more mobile and smaller scale end-uses, such as light and commercial vehicles, backup power, and shipping.

Figure 72: Hydrogen fuel cell – H_2 is used to create electricity & water is the byproduct of the process



Source: Company reports

Multiple fuel cell applications

Personal & heavy-duty vehicles – Fuel Cell Electric Vehicles ('FCEV') offer faster refueling (<10 min) with an importable energy source, which will help decarbonise passenger vehicles in countries with lower renewable power opportunities (i.e. Japan). Also, FCEVs offers greater energy density without sacrificing payload for larger Heavy-Duty trucks (i.e. lorries & mining trucks).

Trains & Shipping – Also, Fuel cells can also be utilized for powering trains and ships. For trains, similar to heavy duty trucks, the greater energy density of H2 offers a solution without sacrificing payload and also allows longer distances where it might not be possible to electrify train lines. **Alstom** (OW, covered by Akash Gupta) was the first rail OEM to have a hydrogen train in service. Maritime shipping could also decarbonize using green ammonia.

Mobile & Uninterruptible Power Systems (UPS) – Another potential use for fuel cells is where access to temporary or mobile power generation is needed or where uninterruptible power is required. Mobile fuel cells could replace diesel generators for remote industrial or construction sites and offer back-up power at other remote sites, such as telecommunications towers. **Gencell** (not covered) is targeting this market for its alkaline fuel cell systems.

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Transportation – Fuel Cell EV breakthrough approaching?

The primary interest for the market around Fuel Cells is the potential for Fuel Cell Electric Vehicles ('FCEV') for both Passenger and Commercial Vehicles. There are two key reasons for this. Firstly, FCEVs are more analogous to ICE vehicles today given an energy-dense fuel source and rapid refueling. Secondly, given hydrogen's energy density, H2 FCEVs could offer a better solution for heavy-duty transportation where battery electric vehicles ('BEV') require the sacrifice of a greater proportion of the potential payload to the battery weight. This is particularly critical for successfully decarbonizing commercial vehicles and mining-trucks.

However, FCEVs still face several disadvantages compared to BEVs. Clearly, the EV industry is well ahead of the FCEV industry, in terms of industry scale, market penetration, consumer awareness/confidence, and soon reaching cost parity. Also, FCEVs suffer from lower energy efficiency in light vehicles compared to BEVs (albeit, higher than ICEs).

Table 21: Energy efficiency of light vehicles – BEVs have a clear energy advantage

		BEV	FCEV	ICE
Well to tank	Electrolysis		70%	
	Transport, Storage & Distribution	95%	74%	85-88%
Tank to wheel	Conversion AC/DC	95%		
	Efficiency battery change	95%		
	Electricity conversion to H2		50-60%	
	Conversion DC/AC	95-97%	95-97%	
	Engine efficiency (engine & transmission)	90%	90%	16-25%
	Global efficiency	**73-75%**	**22-27%**	**14-21%**

Source: Iberdrola, J.P. Morgan

Strong policy support emerging for FCEVs & refueling infrastructure

Nevertheless, policy support is emerging globally with FCEV & refueling station targets in several countries. For example, South Korea is targeting 3m cumulative FCEVs by 2040E while Japan is targeting 800k FCEV passenger vehicles per annum by 2025E. China aims for 1.3m FCEV output per annum by 2035E as well. FCEV ambitions are not exclusive to Asia either. California is also targeting 1m FCEVs on the road by 2030E, while the EU is aiming for 3.7m FCEVs on the road by 2030E. This also comes as autos OEMs are also scaling up their long-term FCEV ambitions, with Hyundai targeting 500k FCEV output by 2030E (~0.5% of global vehicle output). For more information on the development of FCEVs & H2 infrastructure in Asia, please see the following report (link) from J.P. Morgan Korean Autos Research analyst SM Kim.

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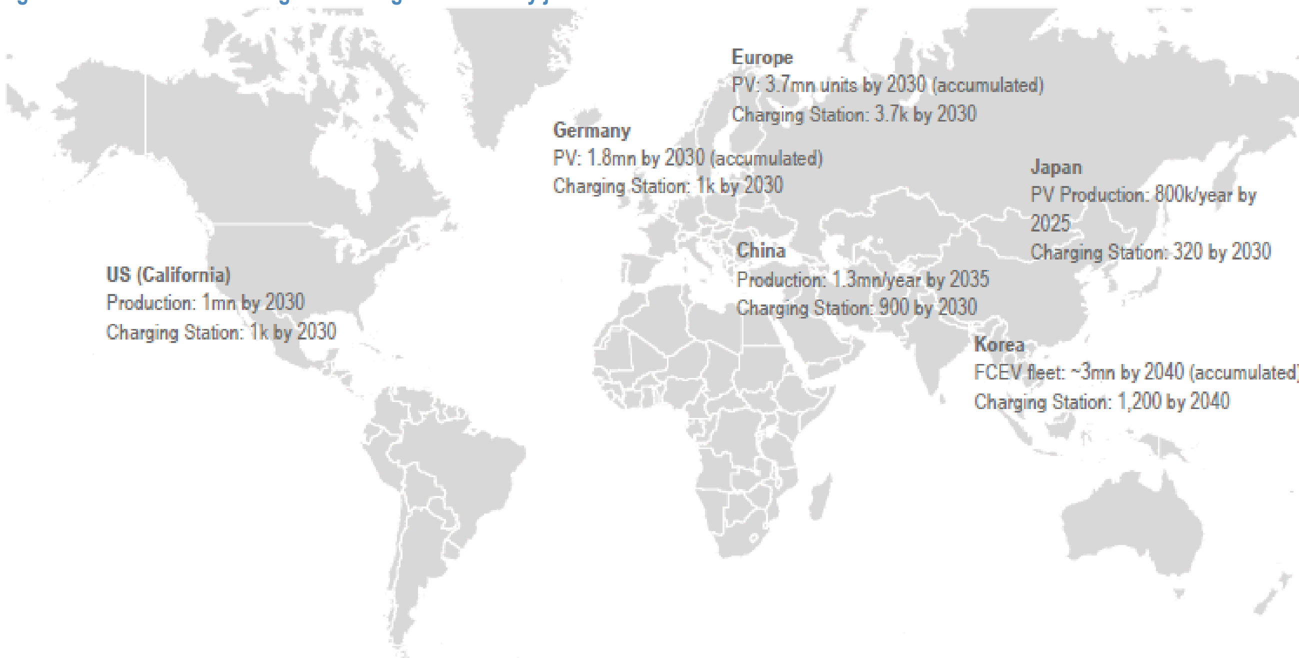
Figure 73: H2 FCEV & refueling station targets across key jurisdictions



Source: Hydrogen Council. MOTIE. J.P. Morgan estimates.

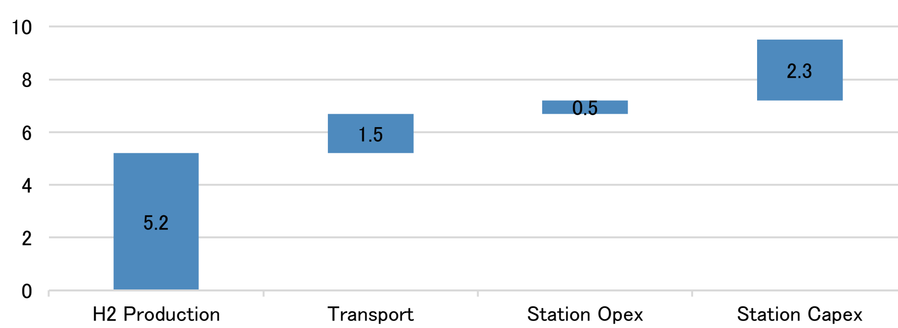
Two key challenges: refueling & total cost of ownership

Fueling – price at the pump high today, but clear direction lower

The cost of refueling a H_2 FCEV is far higher than simply the Levelised Cost of H_2. Transportation costs, along with station opex & capex are still high, combine to arrive at a 'price at the pump' of ~$10/kg or higher today. Nevertheless, we expect the cost of each component to gradually fall. As discussed before, the production cost of Green H_2 should materially decline globally by 2030E. Transportation costs could also be optimized over time as station capital intensity falls as the industry scales up. Therefore, we expect H_2 costs at the pump in US or Europe could fall to $5-6/kg by 2030E.

Figure 74: Breakdown of H_2 cost at the pump today

H2 total cost of refueling breakdown, US$/kg



Source: J.P. Morgan estimates, Company data.

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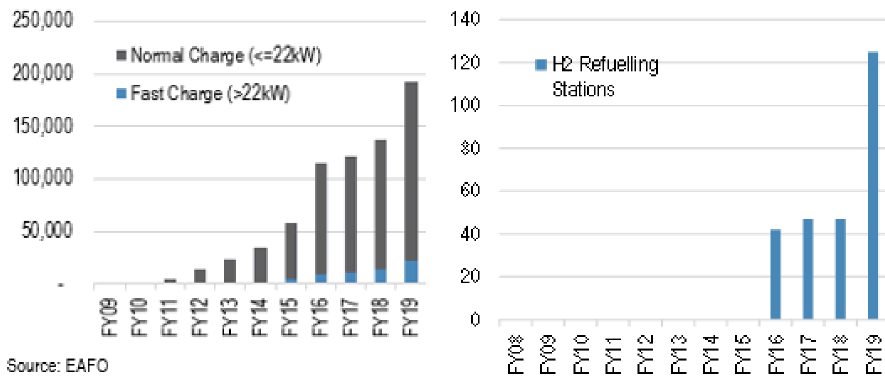
H_2 fueling stations networks today miniscule, far greater scale needed

Another critical hurdle for FCEVs will be building out the needed fueling infrastructure. As of today, there are only ~120 H2 fueling stations in Europe and 45 stations in California (with 42 more in development in CA). This compares to >10,000 gas stations today in California. This is also considerably behind the number of EV charging stations, which is now likely >200,000 in Europe.

Figure 75: EV charging stations (left) vs. hydrogen stations (right)

No of stations in Europe



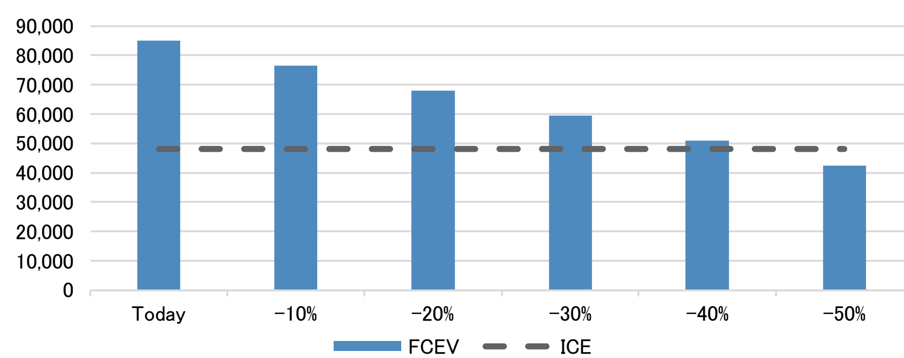
Source: EAFO

Total Cost of Ownership still high vs typical ICE

Another challenge today for wider FCEV adoption is the currently high Total Cost of Ownership ('TCO') of FCEVs. The two primary components are 1) purchase cost of the vehicle and 2) cost of refueling over the life of the vehicle. Today, only a few FCEV models are available in select markets. The latest models of the Toyota Mirai, Honda Clarity, and Hyundai Nexo are available in California with an average MSRP of ~$60,000 (although this could still be below the cost of production for OEMs). As discussed earlier, we expect the cost of refueling to fall materially by 2030E. We estimate the TCO of a passenger FCEV needs to fall by ~45% to be cost competitive vs a typical ICE sedan. This implies a FCEV cost of ~$34,000 and a H_2 price at the pump of <$6/kg.

Figure 76: FCEV TCO needs to fall ~40% to reach parity with typical ICE

Simplified Total Cost of Ownership of Passenger FCEV & typical ICE, US$



Source: J.P. Morgan estimates, Company data.

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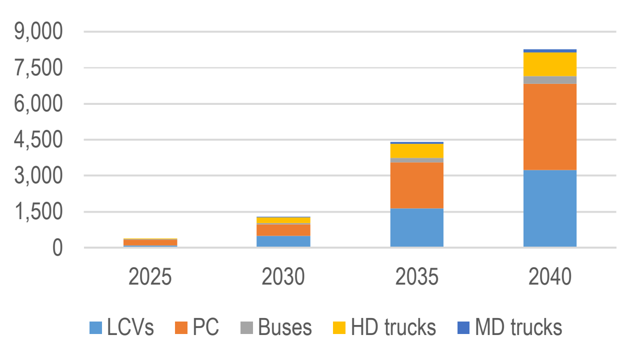
H_2 on-road mobility database: ~1.5M by 2030E & ~4.5M by 2035E FCEV output per annum

We have built a database to look at the growth potential for the hydrogen mobility market beyond 2030. Looking at the market in 2030 (and discounting it back to 2020) is not feasible, in our view. **If companies in our coverage are able to get close to their 2030 revenue ambitions, it will only mark an inflection point for the hydrogen economy, which we believe will be poised for multi-year growth in the next decade.** Our goal has been to figure out the total market potential (if the technology is widely adopted) and lay out a framework for revenues and valuation. We currently see that investors either assign zero value to Hydrogen initiatives or, in some cases, add the book value of assets (like the creation of EKPO Fuel Cell Technologies and Symbio) for the larger suppliers. For smaller suppliers, like ElringKlinger, a lot of the future growth potential has already been priced in.

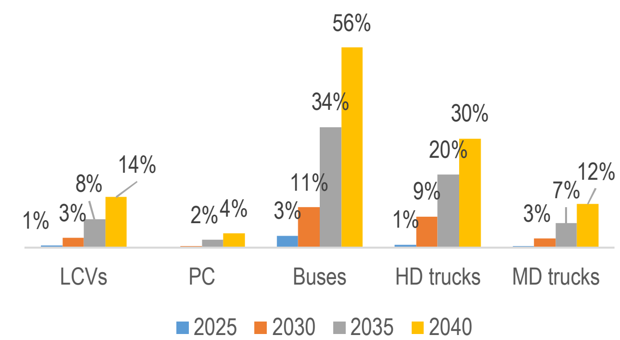
Below, we show the size of the hydrogen on-road mobility market by different applications. If the hydrogen economy crosses key economic, infrastructure and development hurdles in this decade, we could have ~4.5 million fuel cell vehicles globally by 2035 and >8 million by 2040. **Within this market, we expect relatively high penetration rates in HD trucks, MD trucks, LCVs and buses.** The hydrogen economy is still in its nascent stages and widespread adoption (starting with grey to blue/turquoise and finally green) would require significant cost reductions not only in the fuel cell powertrain, but also in the cost of fuel (hydrogen) and development of supporting infrastructure. **We currently assume hydrogen and fuel cell technologies are ideal for the de-carbonization of heavy-duty or long-range transport applications** as other alternatives fail to provide the required range, payload and refueling time. While there is an argument for higher penetration of fuel cell passenger vehicles (in heavier use and long-range requirements), we currently build in very cautious assumptions as TCO parity lies after 2030 and innovations in battery technology/development of infrastructure will take away a lot of competitive advantages of fuel cells today. **However, given the size of the global PC market, higher penetration rates could result in strong upside risks to our current projections**.

Figure 77: Size of the hydrogen market by end-application (mobile on-road applications only)
In '000 units



Source: J.P. Morgan estimates.

Figure 78: Size of the hydrogen market by end-application (mobile on-road applications only)
% penetration in different end-markets



Source: J.P. Morgan estimates.

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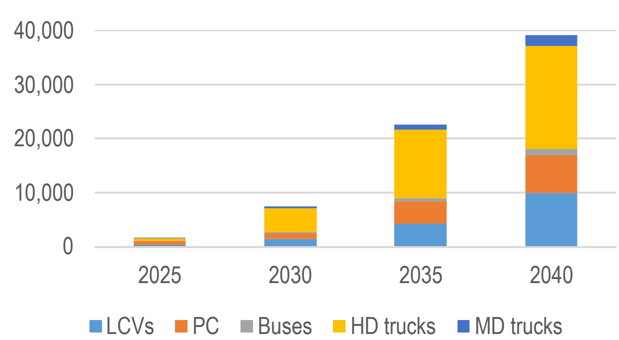
Scaling-up will be the biggest driver of cost reduction, notably in the production and distribution of hydrogen and the manufacturing of system components. This will deliver significant cost reductions before any additional impact from technological breakthroughs is considered. For instance, at a manufacturing scale of ~0.6 million vehicles per year, the total cost of ownership (TCO) per vehicle would fall by about 45% versus today, according to research institutes. While a lot is still to be done, we are now seeing increasing policy initiatives from Europe, China and a few Asian countries (Japan, South Korea specifically).

We further divide the market into hydrogen vessels/tanks and fuel cell stacks to look at the content opportunity and revenue potential for European suppliers. Up to 70% of cost reductions for transport applications are from manufacturing scale-up of end-use equipment (fuel cell stacks and tanks). Large-scale industrialization of components and vehicle integration, together with lower-cost hydrogen fuel, will drive costs down in the future. **For on-board storage systems**, size of the hydrogen tank will depend widely on the end-application and range, but we expect it to vary from 6-70kg. Faurecia and POM aim to bring down costs from €1300/kg of H_2 in 2020 to <€350/kg of H_2 in 2030 for the systems to be competitive for the global market. Three big areas for cost savings are **a) Economies of scale** with higher levels of production, as spreading of production certification costs, certification of components, automated production lines all help in lower cost per unit; **b) extent of carbon fiber use** and cost of materials and c) lower safety standards for tanks as the production process is industrialized, automated and has a proven track record. **For fuel cell systems**, size of the stack will depend widely on the end-application and range, but we expect it to vary from 80-250kW. EKPO and Symbio aim to bring down costs from €900/kW in 2020 to ~€50/kW in 2030 in order to be competitive in the global market. **A large part of the targeted cost savings here are linked directly to scale and efficiency of production**.

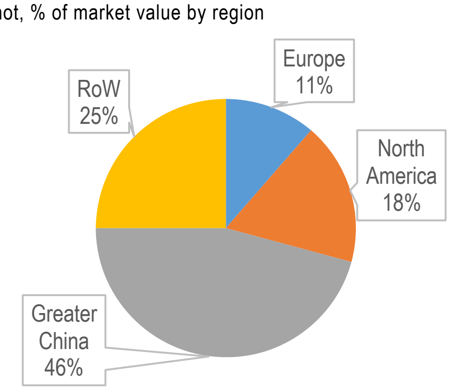
In summary, we expect the TAM across both system components to be >€20bn in 2035 and €35bn-40bn in 2040. In our assumptions, we see Asia taking up a large share in both markets, accounting for ~70% of the global share. Future competitiveness of suppliers will largely depend on partnerships and success in penetrating the Asian markets (especially China).

Figure 79: Hydrogen vessels: Total addressable market by end-application (mobile on-road applications only)
In € million



Source: J.P. Morgan estimates.

Figure 80: Hydrogen vessels: Total addressable market by region (mobile on-road applications only)
2040 snapshot, % of market value by region



Source: J.P. Morgan.

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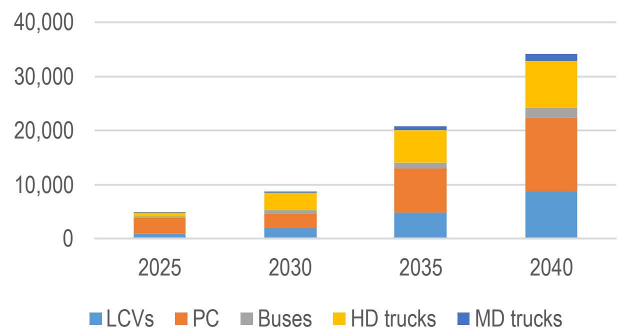
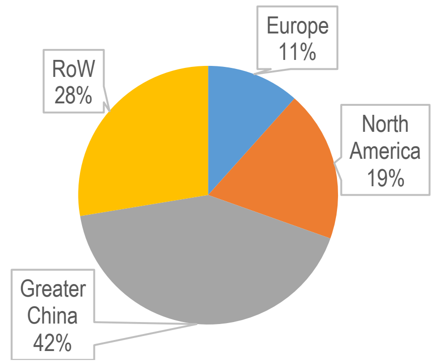
Figure 81: Fuel cell stacks: Total addressable market by end-application (mobile on-road applications only)
In € million



Source: J.P. Morgan estimates.

Figure 82: Fuel cell stacks: Total addressable market by region (mobile on-road applications only)
2040 snapshot, % of market value by region



Source: J.P. Morgan.

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What could go wrong?

Can we have enough renewable capacity to produce Green Hydrogen?

Put simply, scaling up H_2 production to levels envisaged by BNEF Strong Policy scenario would represent a massive uptake in renewable installation. Yet, we don't think it is impossible.

It is worth noting that scaling up H_2 production to levels envisaged by BNEF in 2050 (700Mt /y) would represent a massive increase in electricity demand and an even more massive increase in renewables installed capacity, given wind RE has load factors of ~40% and Solar PV RE has load factors of ~25%.

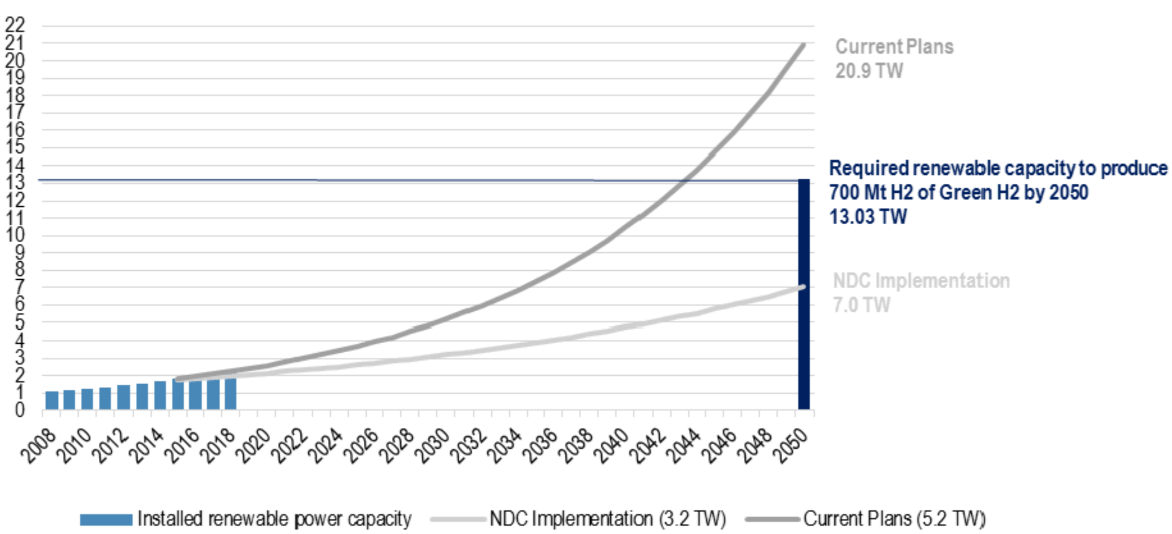
To produce 700 Mt of green H2, the required power capacity in installed renewable power would be 13.03 TW of additional renewables capacity.

Assuming that Electrolysers use 53kwh of electricity to produce 1kg of H_2, producing 700Mt of green hydrogen, as envisaged by BNEF 2050 scenario, it would require 37100 TWh of power, i.e. 1.7x the worldwide energy consumption of 2018. This is equivalent to 4.2 TWh used only for Hydrogen, every hour. Using an average load factor of 32.5% for renewable power (i.e. the arithmetic average of the Wind and Solar Load factors: wind RE has load factors of ~40% and Solar PV RE has load factors of ~25%), the required power capacity in installed renewable power would be 13.03 TW of additional renewables capacity.

Using the simplified growth rates used by IRENA in its NDC 2020 report, this deployment of capacity is extremely significant but would be achievable before 2050 (by 2044) using the current growth rate of renewable installation.

While significant, this objective is not out of reach. Even less so if you look at it from an historical perspective, recalling that the world total installed capacity for electrical power was only 1.1 TW in 1970 (IAEA, 1970).

Figure 83: Scaling up Green H2 production represents a strong increase in renewable capacity, which remains achievable



Source: J.P. Morgan

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Water use as an emerging issue to be managed locally

Most electrolysis cells require high purity water in order to limit side reactions caused by salts (ions) found in naturally occurring water. It is therefore often thought that the water consumption of electrolysis may put additional pressure on water supply in many countries.

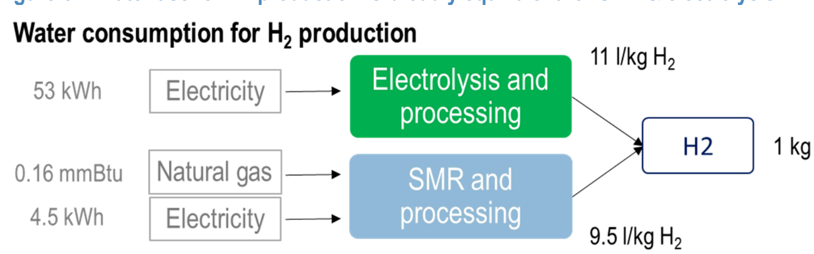
According to WWF, some 1.1 billion people worldwide lack access to water, and a total of 2.7 billion find water scarce for at least one month of the year. At the current consumption rate, this situation will only get worse. By 2025, two-thirds of the world's population may face water shortages. Production of green hydrogen requires water as one of the major inputs. Most electrolysis cells require high purity water in order to limit side reactions caused by salts (ions) found in naturally occurring water. It is therefore often thought that the water consumption of electrolysis may put additional pressure on water supply in many countries. We believe that the issue of water availability and water management should not be underestimated. However, we also note that it might not be a critical constraint with the right site selection for setting up production facilities.

Water requirement in hydrogen production

According to BNEF, the standard water consumption for green hydrogen production is approximately **10L/kg of hydrogen compared to 4.5-7l/kgH2 water consumption for hydrogen production from natural gas via steam methane reforming and 9L/kg for coal gasification.**

However, **other academic sources suggest that, in some cases, the use of water can be broadly equivalent between blue and green hydrogen.** A lifecycle assessment of hydrogen production conducted by Andi Mehmeti et al. concludes that electricity consumption is the highest contributor to the impacts associated with water scarcity in various hydrogen production technologies. Consequently, the mix of technologies deployed to produce fuels and electricity determines the associated burden on regional water resources. The study demonstrates that, if renewable resources are used for electrolysis, which is the case for green hydrogen, water scarcity impacts would be comparable with other hydrogen-production technologies. This claim is supported by the Argonne National Laboratory as well (see figure above).

Figure 84: Water use for H2 production is broadly equivalent for SMR & electrolysis



Upstream water consumption factors

Input energy		WCF
Renewable electricity	Wind	0.004 l/kWh
	Solar photovoltaics	0.068 l/kWh
	Nuclear	1.287 l/kWh
Natural gas		17.791 l/mmBtu

WCFs for H_2 production pathways are within a narrow range

Source: J.P. Morgan based on Argonne National Laboratory, 2017 – available here

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Costs remain manageable

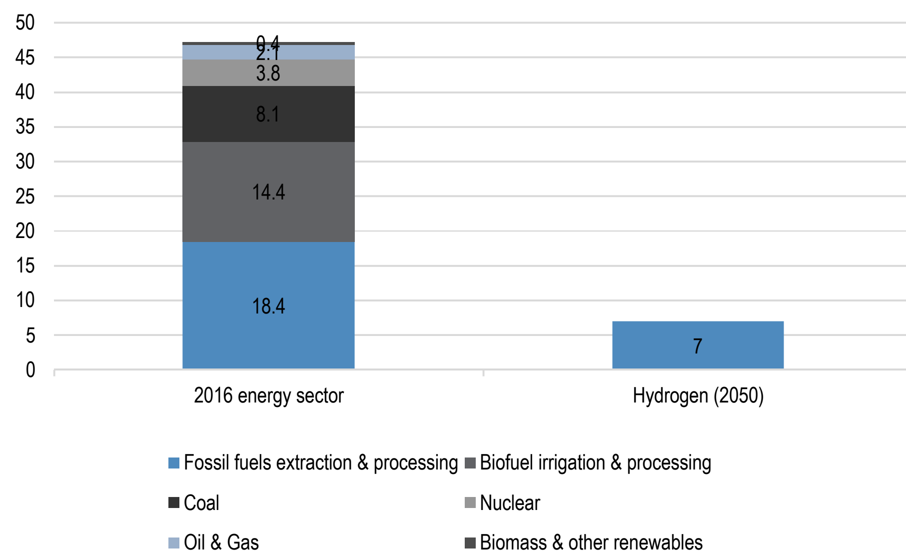
Since most electrolysis cells require high purity water, the majority of commercial electrolysers, therefore, have an integrated de-ionizer allowing them to use fairly low grade potable water as an input. The options to source water, therefore, also include sea or brackish water via desalination in addition to freshwater. Sewage water could also be used but it is likely to be more costly to treat than it would be to produce newly desalinated water. Therefore, in places where fresh water is scarce or will be in the near future, the most suitable source for green hydrogen production would be water from smaller reverse osmosis desalination plants flexibly close to the generation site and provided close to the sea. **The total cost for water desalination is around $0.7-2.5/m3, which then adds $0.01-0.02/kg to the production cost of hydrogen**. It is important to note that for green hydrogen, the energy for the reverse osmosis plants should also come from renewable sources. The continuous development of water desalination plants, alternative modes of low-grade and saline surface water electrolysis, and water provision via wastewater treatment plants will likely increase feasibility and cost-effectiveness of using alternate sources of water than freshwater.

Water use in current energy sector vs. hydrogen economy

It would be important to take into account the penetration of hydrogen and the type of fuel it would replace in the final energy mix to assess the overall water consumption impact

According to BNEF Hydrogen Economy Outlook, if strong and comprehensive policy is in force, 696 million tons of hydrogen could be in use by 2050, meeting 24% of projected final energy needs in a 1.5 degree scenario. Producing 696 million tons of hydrogen in 2050, entirely from water electrolysis, would require 7bcm of water. This accounts for 13% of water consumption in the energy sector at 2016 levels.

Figure 85: Estimated water consumption for hydrogen production in 2050 compared with global water consumption in the energy sector in 2016 (in bcm)



Source: JP Morgan, based on BNEF and IEA

Since the energy sector today is already a massive consumer of water representing 10% of global withdrawals and 3% of consumption (IEA 2016), it would be important to take into account the penetration of hydrogen and the type of fuel it would replace in the final energy mix to assess the overall water consumption impact. In particular, Fossil fuel extraction & processing, as well as Coal powered

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energy represent a large share of the water use from the energy sector. In a Decarbonization scenario, which would see the share of H2 increase, this water consumption would diminish.

Location matters: beware of site-specific water constraints

Water scarcity issues are location specific. Hence, the water scarcity footprint and the cost of production will also vary across countries and areas within the country. In regions where fresh water is available, a purifier is usually integrated in the electrolysis system, which results to water making up $0.004 of the cost of producing a kg of hydrogen (in the US). In regions where water supply is less pure, an external purifier is generally used, resulting in $0.04 contribution of water to cost of producing a kg of hydrogen (in China).

US law firm K&L Gates outlines a few regional issues to keep in mind when considering hydrogen production projects. In the US, water use as a hydrogen feedstock will run into water-use regimes that differ, depending on the jurisdiction involved, dictating where hydrogen production facilities are located. The eastern states would offer more water and more flexible water-use arrangements but will not offer the regulatory certainty of the central states. In Australia, accessibility to water will be a key consideration for producing green hydrogen as water rights are a controversial and often politicized issue. Water use diverted to hydrogen production will impact both agricultural and certain coastal communities that could be home to hydrogen export infrastructure. Further, to maintain social license and community support for projects, it may be necessary for hydrogen producers to rely on non-potable sources of water, resulting in additional production costs to purify the water. In the United Kingdom, imported hydrogen could play a complementary role to domestic hydrogen production as both options are in a similar cost range. Domestic projects integrated with a desalination unit could be located near the coast, ensuring easy accessibility to seawater and wind power for green hydrogen.

Location matters: beware of seasonal differences

Moreover, the water availability challenge may also be dependent on seasonal variations. Indeed, as noted by the EU Environmental Agency: "*In Europe, Renewable freshwater resources fluctuate greatly over the years and seasons. This creates high pressure when fewer renewable water resources are available for a given season. The level of pressure also fluctuates per type of economic activity throughout the year. Agriculture and public water supplies put high pressure on groundwater resources in spring and summer, while the use of water for cooling in energy generation puts high pressure on rivers in autumn and winter*".

In our view, the issue of water availability and water management is likely to be highly dependent on hydrogen plants' locations, as water scarcity issues are location specific. At a macro level, scaling up H2 production is not likely to represent a massive challenge, as it will likely be done jointly with a diminution of other fossil-fuel based water intensive energy production processes. However, at a micro level, water supply might not be a key factor from an economic point of view, but will be an important consideration for site selection due to its environmental and social impact.

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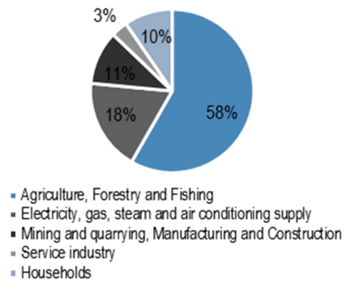
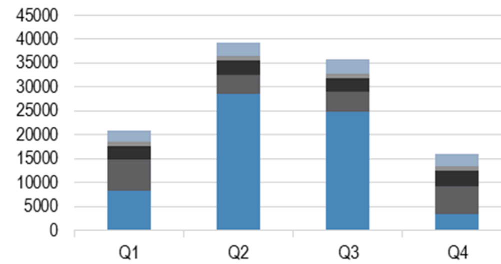
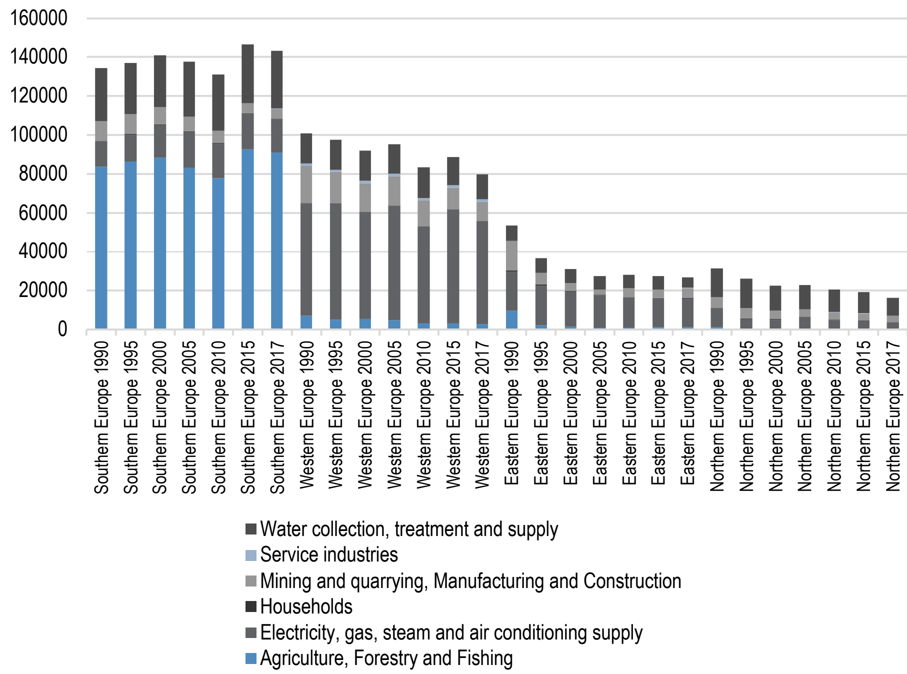
Figure 86: Water use in Europe per economic sector (2017)





Source: European Environmental Agency

Figure 87: Water use in Europe per economic sector (2017)



Source: European Environmental Agency

Safety: busting myths required to develop an H2 culture through commonly agreed safety standards

In an earlier part of this report, we discuss the chemical characteristics of hydrogen vs. other fuel and, in particular, natural gas. Many people are concerned about the fact that mainstreaming hydrogen use in various sectors would create new types of safety risk. We believe that some of these concerns may be exaggerated. While Hydrogen, similar to other fuels, needs to be handled with care, risks can be reduced with the application of appropriate safety standards.

Hydrogen has both advantages and drawbacks

Compared to other fuels, hydrogen has both advantages and drawbacks, vis-à-vis safety.

Table 22: Safety pros and cons of Hydrogen

Drawbacks	Advantages
Wide explosive range	It's 14x lighter than air and therefore disperse quickly into the atmosphere at a rate of 20m/s.
Burns with an invisible flame	Flames have a low radiant energy, making them less likely to spread fire
No odour, no taste	It's non-toxic (leakages and spills do affect the environment)
	With a lower concentration limit of 4%, it's less flammable in the air than gasoline (1.4%)

Source: J.P. Morgan

Built-in hydrogen safety systems are required to mitigate these risks

To cope with this difference, hydrogen applications are linked with specific safety systems. For FCEV, the fuel storage tanks are typically more robust than the ones used in vehicle gas tanks, which are made of plastics. H2 tanks are made of carbon-fiber wrapped cylinders lined with metals or polymers, making them stronger and more crash-safe. Moreover, these tanks are equipped with thermally-activated pressure relief devices that are designed to safely vent the tank its temperature rises.

Harmonization of safety norms would remove a roadblock to large-scale roll-out

The harmonization of regulations, codes, and standards represents a key priority to remove roadblocks for large-scale adoption of fuel cells. As such, the International Partnership for Hydrogen and Fuel Cells has established a working group on "Regulations, codes, standards, and safety" (RCSS WG), which is compiling a database from IPHE member and, where possible, non-member countries with national and regional technical regulations related to the development of a hydrogen infrastructure and hydrogen mobility, in order to identify gaps and make recommendations on standards work necessary for the safe handling of hydrogen in various use cases.

This database gathers information on: 1) Injection on natural gas streams (permitting, limits, gas quality, safety); 2) Hydrogen Refueling Stations (land and use plan, permitting requirement, safety requirement); 3) maritime rules for landing and bunkering; 4) offshore refueling and H2 based fueled vessels; and 5) regulation for

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the broad deployment of FC mobility units (tunnels, bridge, parkings), and fuel cell heavy duty mobility.

In addition, the Hydrogen Council has collected members' insights into safety-related regulatory gaps, and engaged an expert consultant to assess and prioritize these gaps. This work should result in recommendations on how to improve regulatory alignment, and should be available early 2021.

Is there a social acceptance risk for H_2 technologies?

In a recent book looking at the Hydrogen opportunity, researchers from the Mines ParisTech University point to the three main barriers to increased social acceptance of hydrogen technologies. They highlight: 1) safety concerns, 2) environmental concerns and 3) the economic aspects. In earlier sections, we discuss extensively both the environmental impacts and the economic outlook for hydrogen technologies, both in terms of production all-in costs, but also considering various end uses. We believe that GoO (guarantee of origin) systems, and foreseeable cost reductions should help overcome existing concerns.

Regarding Safety concerns, the researchers highlight the potential risks associated with hydrogen storage, as the molecule is stored under very high pressure (approx. 700bar) and highly volatile in case of leakage. As such, tank sealing and leak monitoring systems are essential for the deployment of H_2 technologies for the general public. In particular, an accident free roll out of H_2 technologies is seen as particularly important, given the past failed penetration of LPG (liquefied petroleum gas) powered LDVs on the French market following highly-publicized accidents, which resulted in these vehicles being banned from specific parking slots if they were not equipped with safety relief valves.

It is worth highlighting that results from the Hyacinth project provided a rather reassuring picture of the social acceptance of hydrogen technologies. This project, financed by the Fuel Fell & Hydrogen – Joint Undertaking from 2014-2017, aimed to improve social acceptance of hydrogen technologies, and studied the perception of both laypersons and experts across five Western European Countries: Germany, France, Spain, the UK and Slovenia. The results showed the public were rather poorly informed about hydrogen technologies, and that this knowledge level is correlated with the penetration of H_2 technologies in the relevant market, as well as with government support. Nevertheless, the study highlighted that the majority of the population had a positive attitude towards H2 technologies, and declared they would support their adoption.

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Investing in the Hydrogen theme

Although H_2 has quickly become a major theme since late 2019, investors seeking to capitalise on the opportunity face a dilemma: either invest in small, higher-risk H_2 pure plays with little to no current profitability or invest in major corporates for whom H_2 is still relatively immaterial from a profit perspective. Here, we lay out the H_2-focused corporates and how investors can navigate the nascent H_2 subsector.

Which major corporates are investing in Hydrogen?

Membership of the Hydrogen Council, which has grown dramatically from 13 founding members in 2017, is now >100 companies from >20 countries. Members include Oil & Gas producers, Oil Service companies, Chemicals manufacturers, Electrical Equipment manufacturers, Metals & Mining companies, and even financial institution such as Banks & Sovereign Wealth Funds. However, for the vast majority of members, H_2 today is either only a very small part of their current earnings, an area of potential future demand upside/downside, or a focus of R&D. There is also a growing number of H_2 'pure-play' companies that focus entirely or predominantly on H_2 related activities, such as **Ballard**, **Plug Power**, **Nel ASA**, **McPhy**, and **ITM Power**.

Figure 88: Hydrogen Council members: 109 companies from >20 countries

Hydrogen Council members as of 12 Jan, 2021

Steering Members
3M, Airbus, Air Liquide, Air Products, Alstom, Anglo American, Audi AG, BMW GROUP, BP, CF Industries, Chemours, Bosch, China Energy, CMA CGM, CNH Industrial (via IVECO), Cummins, Daimler, EDF, ENEOS Corporation, ENGIE, Equinor, Faurecia, General Motors, Great Wall Motor, Honda, Hyundai Motor, Iwatani, Johnson Matthey, Kawasaki, KOGAS, Linde, Michelin, Microsoft, MSC Group, Plastic Omnium, SABIC, Saudi Aramco (via the Aramco Overseas Company), Schaeffler Group, Shell, Siemens Energy, Sinopec, Solvay, ThyssenKrupp, Total, Toyota, Uniper and Weichai.
Supporting Members
ACME, AFC Energy, AVL, Baker Hughes, Ballard Power Systems, Black & Veatch, Chart Industries, Chevron, Clariant, Delek US Holdings, ElringKlinger, Enbridge Gas, Faber Industries, First Element Fuel (True Zero), Fortescue Metals Group, Galp, W. L. Gore, Hexagon Composites, ILJIN Composites, ITOCHU Corporation, Liebherr, MAHLE, MANN+HUMMEL, Marubeni, McDermott, McPhy, Mitsubishi Corporation, Mitsubishi Heavy Industries Ltd., Mitsui & Co, Nel Hydrogen, NGK Spark Plug Co., Nikola Motor, NYK Line, PETRONAS, Plug Power, Port of Rotterdam, Power Assets Holdings, Re-Fire Technology, Reliance Industries Limited, Sinocat, SinoHytec, Sinoma Science & Technology, Snam, Southern California Gas, Sumitomo Mitsui Banking Corporation, Sumitomo Corporation, Technip Energies, Tokyo Gas, Toyota Tsusho, Umicore, Vopak, and Woodside Energy.
Investor Group
Antin Infrastructure Partners, BNP Paribas, Crédit Agricole, GIC, John Laing, Mubadala Investment Company, Natixis, Providence Asset Group and Société Générale.

Source: Company reports.

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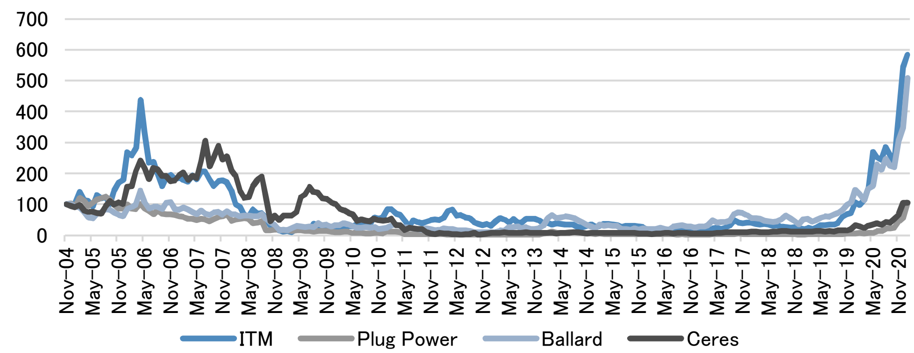
H_2 subsector: another episode or Hydrogen Hype or finally an opportunity for investors?

A common question investors ask regarding the rapidly increasing interest in H_2 economics is whether this is simply another episode of 'hydrogen hype', potentially culminating in a bubble that will subsequently burst. The recent surge in H_2 focused stocks since Jan'19 is also not the first. Many of these same companies experienced >100% share price performance in the mid-2000s. Furthermore, H_2 & fuel cell vehicles attracted considerable attention and development focus in the 1970s when high oil prices spurred interest in alternative fuels for transportation.

Figure 89: 'Hydrogen Hype' drove incredible share price performance in the past as well

H2 Pure Plays share price performance since Novt'04, rebased to 100



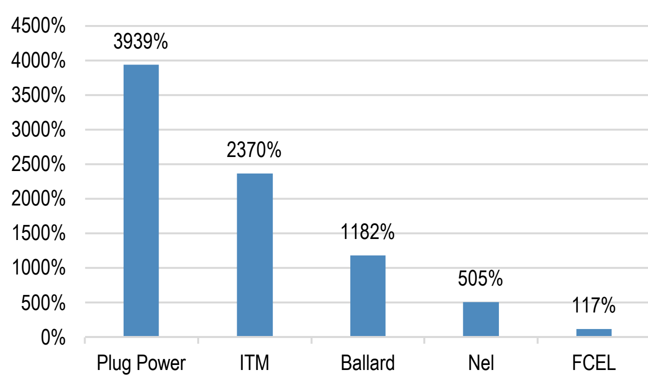
Source: Bloomberg Finance L.P.

Why resurging H_2 interest is different from previous episodes of 'H_2 hype'

Nevertheless, we believe the current market excitement around H_2 economics is different for several reasons. Previous episodes of hydrogen hype were largely driven by the search for alternative fuels when oil prices were high. Now, instead, the driving factor is energy transition, particularly for 'hard-to-abate' sectors. Also, green H_2 requires low-cost renewable power, which was not achievable until recently. Thus, we see the current focus on H_2 as more credible than previous episodes.

Figure 90: Some H_2 stocks have risen >1,000% since Jan'19

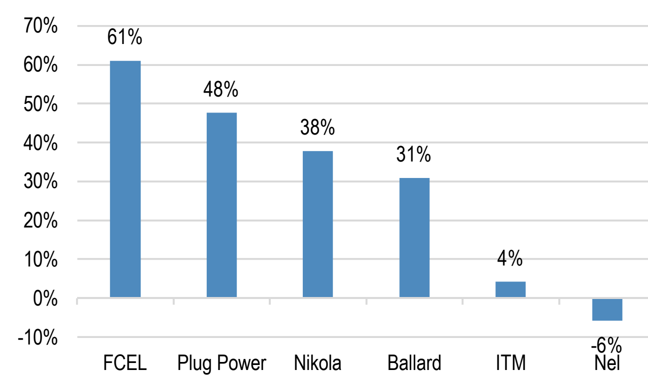
H_2 companies share price performance since Jan'19, rebased to 100 in US$



Source: Bloomberg Finance L.P.

Figure 91: YTD performance also strong for most

H_2 companies share price performance YTD, rebased to 100 in US$



Source: Bloomberg Finance L.P.

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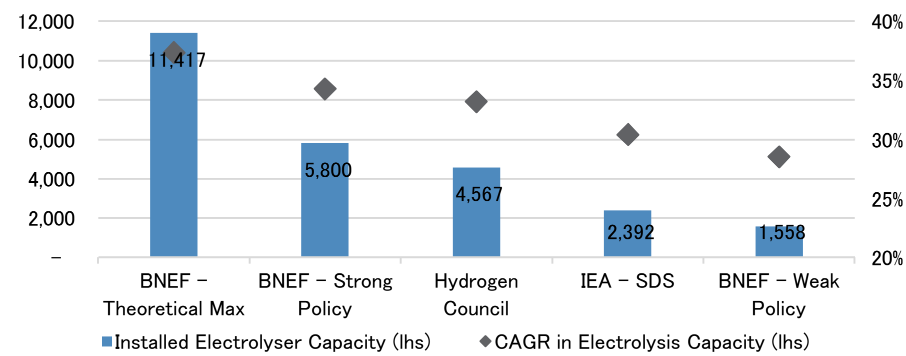
Incredible product demand growth, but with declining ASP?

We have calculated the potential electrolyser capacities needed under various H_2 demand scenarios if each scenario were to rely on green H_2 for 100% of demand. Given the installed base of electrolysers is incredibly small (we estimate ~1GW by YE'19E), the compound annual growth rates in each scenario is extremely high, ranging from ~29% in a grey sky scenario (total installed capacity of ~1,600GW assuming BNEF's weak policy scenario), to ~37% if all sectors that could theoretically consume and decarbonize with H_2 do so with installed capacity of >11,000GW. Thus, we believe investors can reasonably expect >25% pa growth in electrolyser capacity globally, so supporting sales of electrolyser manufacturers.

Figure 92: Significant growth in electrolyser capacity under all scenarios

2050 installed electrolyser capacity & CAGR to 2050 scenarios (assuming all H2 is green by 2050)



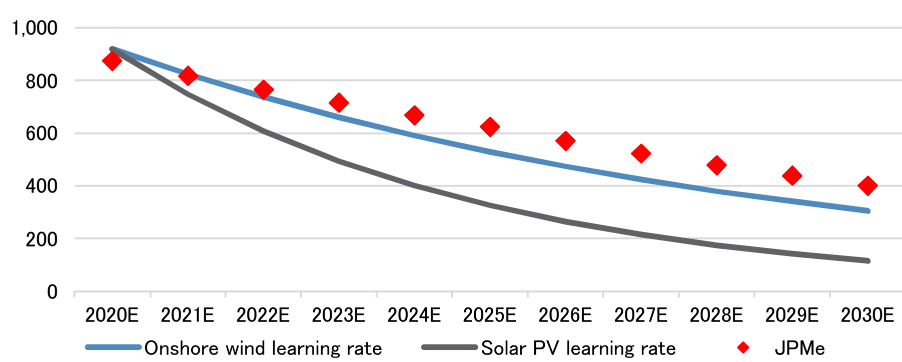
Source: J.P. Morgan estimates, Company data.

System cost catch-22: falling system costs means long-term ASP pressure

However, one of the key drivers that enables the H_2 transition, the falling electrolyser systems cost, also means a falling average selling price for electrolyser manufacturers. We estimate electrolyser costs will fall by ~7.5% pa to 2030 (in line with Nel & ITM's own guidance), but note that, if we assume the 2010-20 learnings rates for solar & wind, costs could fall even further. This presents some uncertainty for long-term average selling prices and thus margins for electrolyser manufacturers.

Figure 93: Electrolyser system costs likely to fall dramatically to 2030E

Average electrolyser system costs assuming 2010-20 wind & solar learning rates & JPMe, $/kw



Source: J.P. Morgan estimates, Company data.

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Understanding barriers to entry & Chinese competition

Barriers to entry more significant near term, but less certain long term with utilisations already low & many manufacturers scaling up capacity

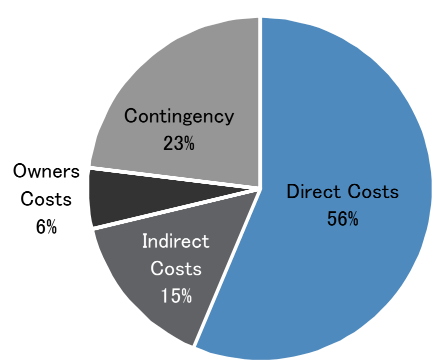
A major question the H_2 electrolysis industry faces is whether the dramatic growth in demand will lead to new entrants to the industry or whether incumbents expand manufacturing capacity faster than demand, risking long-term margin pressure for the industry. Firstly, new entrants remain possible and several (i.e. Enapter, not listed) are working to develop their own unique electrolysis technologies and expand their manufacturing capabilities. However, we believe technical and manufacturing expertise could be limiting factors for new entrants, near term. Secondly we expect electrolysis divisions of major industrial groups (Thyssen’s Uhde, Cummins' Hydrogenics, Siemens Energy) will also expand capacity with fewer of the balance sheet or financing impediments of the smaller pure play electrolysis manufacturers. We believe most electrolysis manufacturers are today operating at low utilisation rates, so future expansions could keep utilisations low and make it difficult for manufacturers to improve margins, in our view.

Threat of lower-cost Chinese competition? Several factors to consider

Another major consideration for investors is whether US or European H_2 electrolysis manufacturers could be undercut by lower-cost Chinese manufacturers. Although Chinese electrolysis manufacturers are reportedly achieving a cost of \$200/kw for alkaline electrolysers (nearly ~70% lower cost than ex China producers), we believe this comparison could miss several key factors. Firstly, EPC costs represent ~40% of total system costs and it is not obvious that referenced Chinese system costs include this. Secondly, given the significance of EPC involvement, US and European buyers might prefer a partner that is located and experienced in its own market. Thirdly, regular system maintenance, and eventually long-term stack replacement, could provide an advantage for US and European manufacturer. Fourthly, although Chinese manufacturers have been producing alkaline electrolysers, we have not yet seen whether Chinese manufacturers are building PEM systems at a significant scale.

Figure 94: Electrolysis stacks ~60% of total system costs…

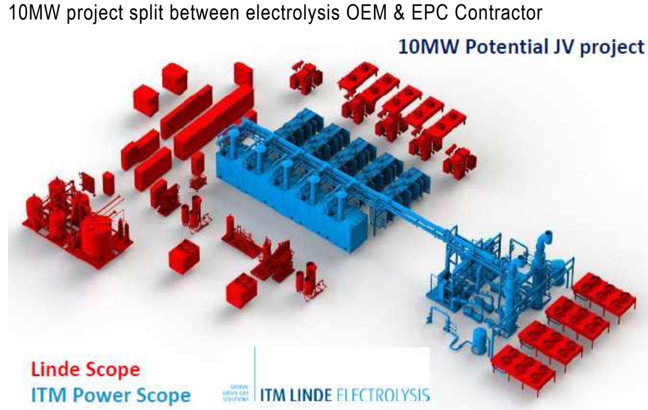
GW scale Green H2 plant cost breakdown



Source: FCH-JU, Company data.

Figure 95: …. Requiring significant EPC capabilities

10MW project split between electrolysis OEM & EPC Contractor



Source: Company reports.

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Five forces analysis: threats & opportunities for electrolyser industry

To summarise the investment attractiveness of the H_2 electrolyser industry, we have followed the general approach of Porter's Five Forces model, which assesses an industry's strengths & weaknesses across various criteria. We expect the electrolyser industry will face a relatively competitive landscape, given many existing OEMs are expanding manufacturing capacity, while several major industrial corporates could also rapidly expand capacity if they see an attractive opportunity. However, near term, we expect intellectual property, existing know-how, and the need for 'turnkey' solutions will offer an advantage to existing manufacturers. We do not expect suppliers to have material pricing power over electrolyser manufacturers given many of the key inputs for OEMs are commoditized or semi-commoditized products (metals, polymers). However, commodity price volatility could be a concern for margins, longer term. Many corporates will be adopting H_2 for the first time, but only a few electrolyser manufacturers can offer full 'turnkey' solutions today. However, as the industry scales up and orders depend on a bidding process, this could change, in our view. We also doubt that alternative H_2 technologies will displace electrolysers given the long-term cost competitiveness of green H_2 vs blue H_2 in most regions and other zero-CO_2 H_2 technologies are still far from being commercially developed.

Table 23: Five forces analysis for H_2 electrolyser industry

Category	JPMe View	Comment
Competition in the industry	High	Many electrolyser OEMs are expanding manufacturing capacity despite currently low utilisations. OEMs also scaling up module offerings. System prices rapidly falling.
Potential for new entrants	High	Many industrial conglomerates with strong balance sheets already have small electrolyser divisions, manufacturing facilities are relatively small with quick construction times, but IP & know-how a constraint
Power of suppliers	Mixed	OEMs mostly buying commodities products (metals, chemicals), given small scale of plants & industry still at early stage, still many unknowns
Power of customers	Mixed	Only a few OEMs today can today meet full system demands of customers keen to transition with H2, but this could change with new entrants.
Threat of substitution	Low	Where H2 will be the cost competitive route to decarbonize, green H2 is likely to be the more competitive than blue H2 in most of the world; other green H2 technologies are at an earlier stage of commercialisation

Source: J.P. Morgan estimates, Company data.

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After market & H_2 refueling offer earnings upside

Another factor for electrolyser manufacturers is after-market revenue from servicing & maintenance and stack replacement. As the industry is still in its infancy and installed capacity today is low, we do not expect after-market revenue to be material until after companies have delivered substantial volumes and stacks need repairs or replaced. Also, we believe H_2 companies could focus future growth in H_2 fueling stations. Nel derived ~48% of FY'20 revenue from fueling stations, while several other corporates are also active in this area.

Overview of the H_2 pure plays

The H_2 pure plays are predominantly focused on either electrolysers, fuel cells, or, refueling. Below, we summarise the main H_2 focused companies under J.P. Morgan coverage in the North America and Europe.

In North America, the subsector is more skewed towards fuel cell manufacturing and applications. The most prominent H_2 focused companies include **Fuel Cell Energy Corp** (UW), **Bloom Energy** (Neutral), **Plug Power** (Neutral), and **Nikola** (OW, all covered by Paul Coster). However, US-listed **Cummins** (Neutral, covered by Ann Duignan) moved into electrolyser & fuel cell manufacturing after its acquisition of 81% of **Hydrogenics** (remainder owned by **Air Liquide**) in 2019.

In Europe, the two most prominent companies, **Nel ASA** and **ITM Power**, are focused on electrolysis manufacturing and, to a lesser extent, H_2 refueling stations. However, there are several companies that are largely fuel cell focused. These include **Ceres Power** (market cap: ~$3bn), **Powercell Sweden** (market cap: ~$2bn) as well as smaller developers such as **Proton Motor**, **AFC Energy**, and **GenCell** (all <$1bn market cap). **McPhy** is also an emerging electrolyser manufacturer based in France.

Alongside this report, we initiate coverage on **ITM Power** with an Overweight rating (PT 700GBp/sh [link]) and on **Nel ASA** with a Neutral rating (PT NOK28/sh [link]).

Table 24: US & European H2 focused companies covered by J.P. Morgan

Bloom Energy (BE US)	**Fuel Cell Energy (FCEL US)**	**Nikola Corp (NKLA US)**
Neutral	Underweight	Overweight
Price Target - $38/sh	Price Target - $10/sh	Price Target - $35/sh
Share price - $28.47/sh	Share price - $17.76/sh	Share price - $20.89/sh
Market cap (US$m): 4,731	Market cap (US$m): 5,726	Market cap (US$m): 8,024
Focus: Solid Oxide Fuel Cell manufacturing	Focus: Flexible Fuel Cell manufacturing	Focus: H2 Fuel Cell EV Trucks
Plug Power (PLUG US)	**Nel ASA (NEL NO)**	**ITM Power (ITM LN)**
Neutral	Neutral	Overweight
Price Target - $70/sh	Price Target - NOK 28/sh	Price Target GBp 700/sh
Share price - $48.76/sh	Share price - NOK 27.04/sh	Share price GBp 521/sh
Market cap (US$m): 24,503	Market cap (US$m): 4,494	Market cap (US$m): 4,040
Focus: PEM Fuel Cell & electrolyser manufacturing	Focus: PEM & alkaline electrolyser manufacturing & H2 refueling stations	Focus: PEM electrolyser manufacturing & H2 refueling stations

Source: J.P. Morgan estimates, Company data. Priced as of 19 Feb'21

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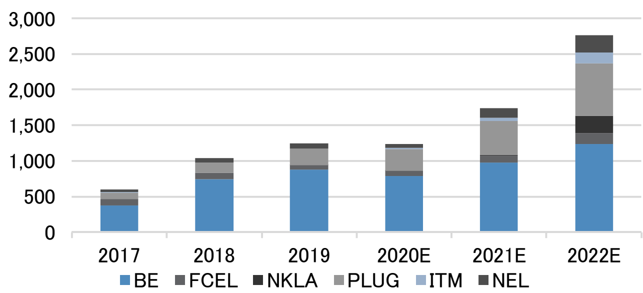
Minimal current revenue, but significant growth on the horizon for the H_2 subsector

The US & EMEA H_2 focused corporates are all relatively small, but growing, companies, while several are still EBITDA negative as they seek to scale up capacity. Only Bloom Energy was EBITDA positive as of FY'19. We expect Plug Power to turn EBITDA positive in CY'21E, ITM Power and FCEL in CY'22E, and Nel by CY'23E respectively.

Figure 96: Significant revenue growth for the subsector

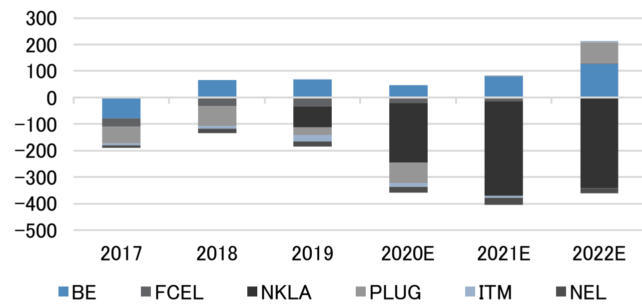
H2 focused stocks group Revenue, US$m



Source: J.P. Morgan estimates, Company data.

Figure 97: However, many H2 companies still EBITDA negative

H2 focused stocks group EBITDA, US$m



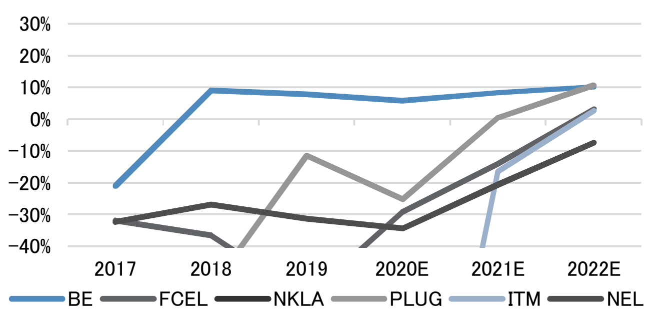
Source: J.P. Morgan estimates, Company data.

Profitability & FCF: most H_2 companies still cash burning

We expect most H_2 companies to continue burning FCF for several more years as growth in prioritised. We expect all six H_2 focused companies to be FCF negative through to CY'22. Within EMEA, we expect ITM to take a more prudent approach to electrolyser manufacturing capacity expansions, while Nel has indicated it could expand alkaline manufacturing to 'multi-gigawatt' capacity by CY'25. However, ITM could deploy additional capital to develop its nascent H_2 fueling business, ITM Motive. Consequently, we expect ITM and Nel to reach FCF breakeven in CY'24/25.

Figure 98: Only Bloom has been consistently EBITDA positive

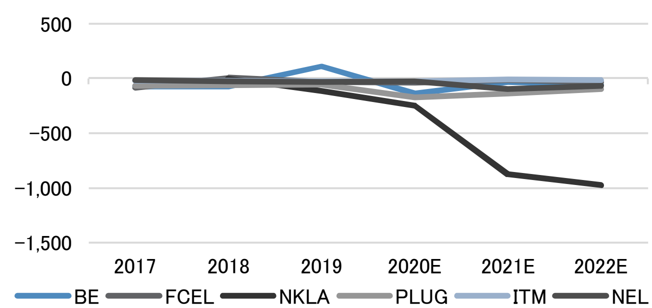
H2 focused stocks group EBITDA margin, %



Source: J.P. Morgan estimates, Company data.

Figure 99: FCF likely to remain low as growth is prioritised

US$m



Source: J.P. Morgan estimates, Company data.

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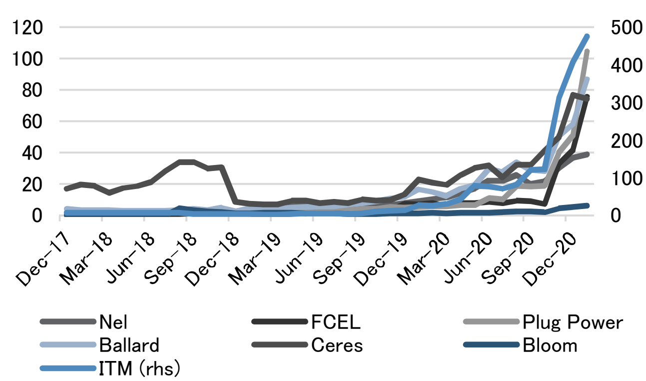
Historical valuations of H_2 stocks offer little insight, but mature Alternative Energy stocks trade on high valuations

Despite still low near-term sales & profitability, the dramatic rise in H_2 companies' share performance since late'19 has sent forward Bloomberg consensus EV/Sales metrics to extremely high levels, while near-term EV/EBITDA and P/E multiples are still largely irrelevant for the subsector.

Figure 100: Rally has sent EV/Sales to incredible levels…

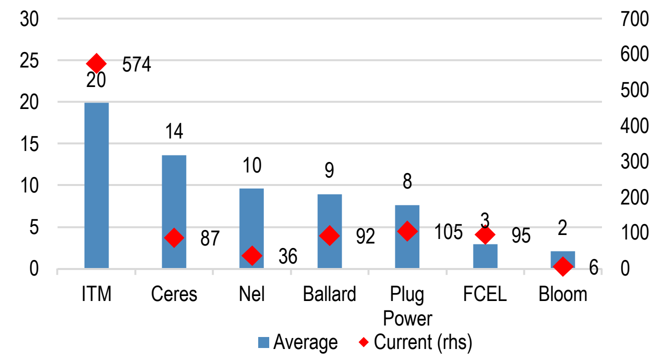
EMEA & US H_2 companies forward EV/Sales



Source: Bloomberg Finance L.P.

Figure 101: … and now trading many times their historic averages

EMEA & US H_2 companies forward historic & current EV/Sales



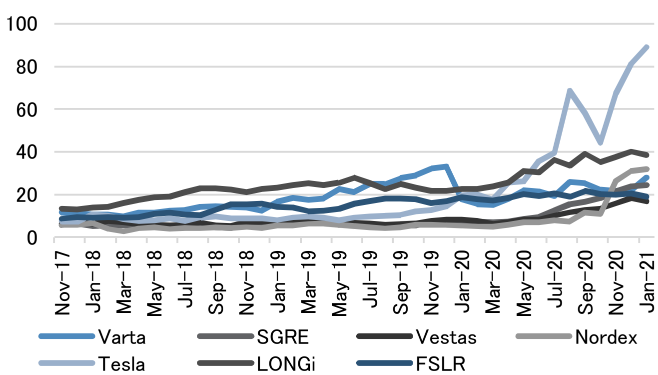
Source: Bloomberg Finance L.P.

Alt Energy manufacturers could offer a glimpse of how valuations evolve

Given the current difficulty in assessing H_2 stocks' valuation multiples, a useful parallel could be how valuation metrics evolved among the more mature Alternative Energy manufacturers. These companies have already come through periods of high growth and achieved EBITDA profitability. Nevertheless, they have also steadily re-rated on EV/EBITDA since Q2'20. In particular, the EMEA Wind OEMs have re-rated from 5-8x in Feb'20 to 17-35x EV/EBITDA now. Over the same period, Lithium-ion battery manufacturer **Varta** (not rated), re-rated from ~15x to ~29x and EV manufacturer **Tesla** (UW, covered by Ryan Brinkman) re-rated from ~20x to ~90x EV/EBITDA.

Figure 102: Alt Energy OEMs still re-rating on EV/EBITDA,,,

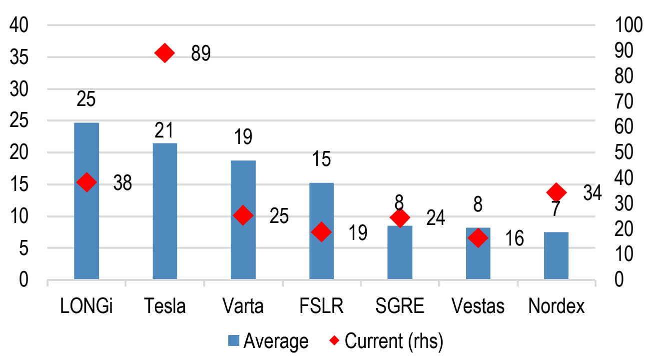
Alternative energy manufacturers forward EV/EBITDA



Source: Bloomberg Finance L.P.

Figure 103: … and trading above their historic multiples

Alternative energy manufacturers average vs current forward EV/EBITDA



Source: Bloomberg Finance L.P.

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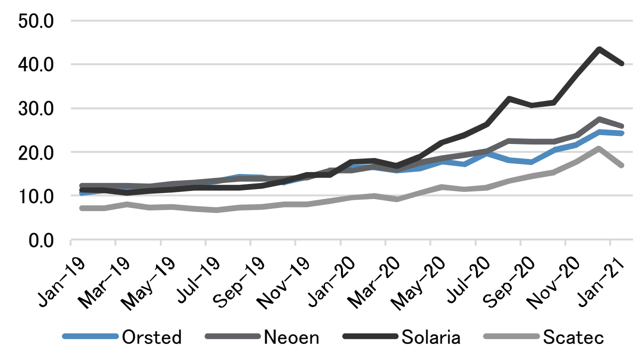
Significant re-rating across Alternative Energy operators, albeit less directly comparable to the H_2 companies (for now)

Another potential comparison in the Alternative Energy sector would be the Renewable power generators and operators. Similar to the EMEA Alternative Energy manufacturers, the operators/generators have significantly re-rated over the past several years, but particularly since Q2'20. For example, **Solaria** (not covered) is now trading on >40x EV/EBITDA, far higher than its historical average of ~20x and its Feb'20 level of ~18x. **Orsted** (OW, covered by Javier Garrido), **Neoen** (OW, covered Javier Garrido), and **Scatec** (not covered) have seen less dramatic re-ratings.

It is worth noting that the Renewable operators are less analogous today to the H_2 companies as the latter are primarily focused on electrolyser & fuel cell manufacturing (with associated after-market revenue developing longer term). However, given the H_2 subsector is still in its infancy and business models are still evolving, more operator or generator related earnings could arise over time. For example, Nel (and, to a lesser extent, ITM) have an H_2 fueling station segment. Nel is primarily manufacturing fueling stations, while ITM today develops and operates ~8 stations in the UK. Longer term, ITM expects to grow its ITM Motive fuel station segment into a more significant owner-operator model, which will be producing and selling H_2 volumes.

Figure 104: Alternative Energy operators have also re-rated...

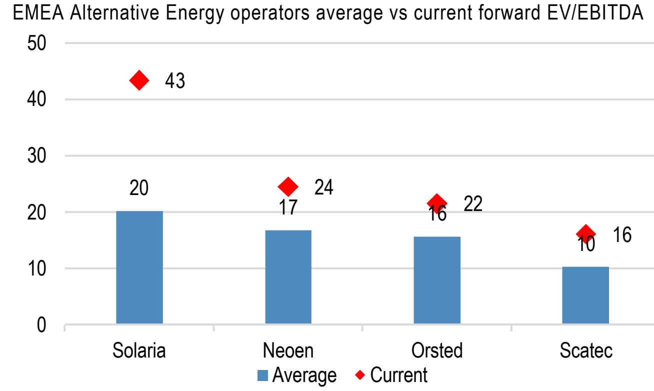
EMEA Alternative Energy operators forward EV/EBITDA



Source: Bloomberg Finance L.P.

Figure 105: ... Solaria now trading 2x its historic average multiple

EMEA Alternative Energy operators average vs current forward EV/EBITDA



Source: Bloomberg Finance L.P.

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ITM Power (Overweight) & Nel ASA (Neutral)

ITM Power and Nel ASA are the two largest pure play Hydrogen stocks in Europe by market cap, with both primarily focused on electrolyser manufacturing, in the UK and the Norway, respectively, as well as more nascent H_2 fueling segments.

ITM Power (Overweight): ITM was founded in 2001 and listed on the AIM of the London Stock Exchange in 2004. The group has been focused on developing and commercialising PEM electrolysers and recently completed construction of its first 1,000MW 'Gigafactory' in Sheffield, UK. EPC services for its systems are conducted by ILE, the 50/50 JV between ITM & Linde Engineering. ITM recently entered into another strategic partnership with Snam, with ITM as preferred system supplier for Snam's future green H_2 projects.

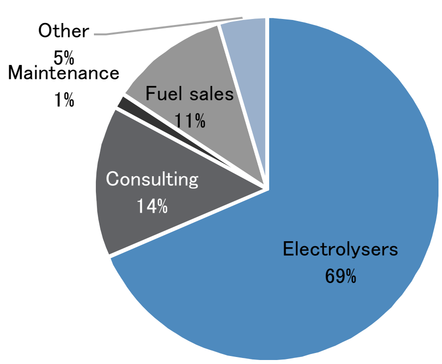
Nel ASA (Neutral): Although Nel ASA has existed in various forms since 1927, it was listed on the Oslo Stock Exchange in 2014. Over its history, the group has focused primarily on the more mature alkaline electrolysis technology. However, with its 2017 acquisition of Proton Onsite, Nel acquired PEM electrolysis manufacturing capability. Nel's H_2 fueling station segment was attained through the acquisition of H2Logic in 2015. Nel is currently expanding its Heroya alkaline manufacturing facility to 500MW (from 40MW) by Q3'21 and its Wallingford PEM facility to ~100MW (from >50MW) by 2025E.

Table 25: ITM Power & Nel Asa corporate & operational overview

Corporate Overview	ITM Power	Nel ASA
Headquarters	United Kingdom	Norway
Year founded	2001 (IPO 2004)	1927 (IPO 2014)
Market cap (US$m)	4,040	4,494
Enterprise Value (US$m)	3,808	4,329
Free float	66%	~100%
Reported Revenue (FY'20, US$m)	4.2	69.7
Reported EBITDA (FY'20, US$m)	-25.4	-26.9
Operational Overview		
Alkaline or PEM	Exclusively focused on PEM	Producing both PEM & Alkaline
Electrolysis Capacity (2021E)	1,000MW PEM	500MW ALK, >50MW PEM
Location of electrolysis facilities	Sheffield, UK	Heroya, NO (ALK), Wallingford, US (PEM)

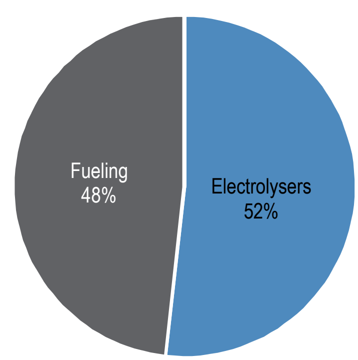
Source: Company reports.

Figure 106: ITM revenue predominantly from electrolyser sales
ITM FY'20 Revenue breakdown



Source: J.P. Morgan estimates, Company data.

Figure 107: Nel revenue split electrolysers & fueling stations
Nel FY'20 Revenue breakdown



Source: J.P. Morgan estimates, Company data.

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Both groups pursuing growth, but ITM proceeding more conservatively

Both Nel & ITM are to spend 2021 completing their respective expansion projects and ramping up output. However, there are material differences in their growth strategies & prospects, in our view. Both expect to pursue modular capacity expansions over time. Nel plans to expand its Heroya facility in roughly 500MW increments with the potential eventually to reach 'multi-Gigawatt scale' by 2025. In contrast, ITM is to wait to make a decision on next its 'Gigafactory' once its current facility reaches 60% utilization. Also, we note that Nel has guided to its 500MW Heroya expansions to have a capital intensity of NOK250m (~$60/kw), higher than ITM's Gigafactory approach which we estimate each will cost ~GBP30m (~$40/kw) for another 1GW of capacity (ITM has indicated the next facility could be at a moderately larger scale than 1GW, but we assume 1GW for this analysis). Assuming a similar long-term EBITDA margin of ~5%, we estimate ITM's incremental expansions to generate a ~16% IRR each vs Nel's at ~12%. However, we expect this margin scenario to be conservative, longer term, since after-market revenue could provide more material revenue upside by 2030.

Table 26: ITM & Nel taking different approaches to future growth

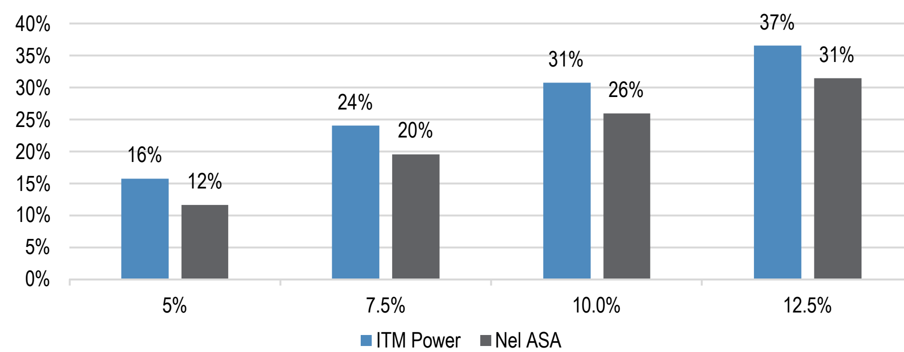
ITM & Nel incremental capacity growth

Growth Overview	ITM Power	Nel ASA
Expected growth increments	~1,000MW PEM 'Gigafactories'	500MW ALK in Heroya, NO
FY'21 System Cost (US$/kw, JPMe)	1,013	650
Guided cost of expansions (m, local FX)	£29	NOK 250
Guided cost of expansions (US$m)	39	29
Capital intensity ($/kw)	39	58

Source: J.P. Morgan estimates, Company data.

Figure 108: Capacity expansions offer relatively high returns even with low margins

IRR of ITM & Nel incremental expansion scenarios under various EBITDA margin scenarios, %



Source: J.P. Morgan estimates, Company data.

ITM & Nel pursuing rapid system cost reductions as capacity expanded

With large scale expansions under way, which will benefit from greater automation and scale, both ITM and Nel expect overall system costs for their electrolysers to fall precipitously over the decade. ITM anticipates its average system price will fall from ~EUR850/kw (~$1,000/kw) in 2021 to ~EUR500/kw (~$600/kw) by 2025 and ~EUR420/kw (~$500/kw) by 2029. Nel has guided that its alkaline system costs will fall from ~$700/kw in 2020 to ~$450/kw by 2050 and ~$300/kw by 2030. These both imply a learning rate of 7-8% over the period. However, Nel also indicated that it expects the system cost for its PEM electrolysers (which is not Nel's primary area of growth to 2025) to converge to ~$300/kw by the end of the decade.

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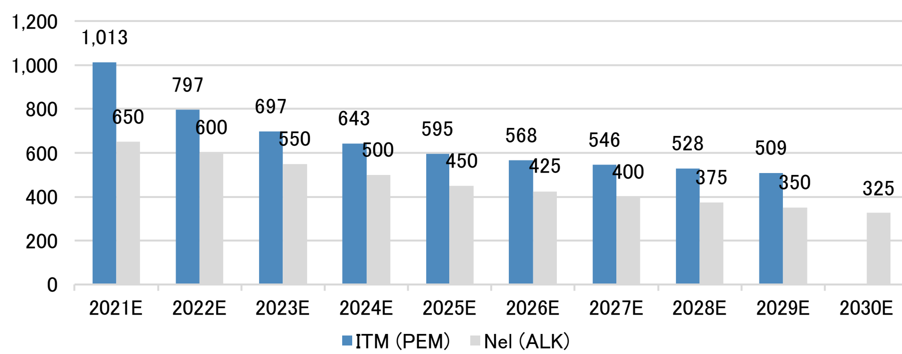
Differences in current PEM & ALK system costs potentially offset by other factors & other additional costs

Although the difference between ITM and Nel's indicated system costs would appear to indicate that PEM systems could remain more expensive than alkaline, we believe there could be several equalizing factors. Firstly, alkaline systems produce H_2 at a lower pressure than PEM, thus compression is required, which adds to both overall system capex and electricity opex. Secondly, H_2 produced from alkaline electrolysis also typically needs cleaned, which again adds to both capex & opex. We estimate that compression & cleaning add ~$180/kw to average alkaline system cost. Thirdly, PEM systems only require 1/3 of the physical space used by alkaline systems, so, depending upon the application (i.e. urban/suburban fueling station or existing industrial facility), this could be a deciding factor for a potential customer.

Figure 109: Both Nel & ITM expect system costs to fall by ~8% pa, but might not tell the full story
Nel & ITM guided system costs, US$/kw



Source: J.P. Morgan estimates, Company data. Note: ITM has not provided guidance for 2030.

EPC strategy: ITM partnered with Linde, Nel could mitigate the risk of having no exclusive partner by taking a more narrow focus, longer term

Another major difference between ITM & Nel is how they have approached the EPC requirements of the industry. As we discussed earlier, EPC components can represent ~40% of the total system cost. ITM has established a 50/50 EPC JV with Linde Engineering, which leverages Linde's global breadth and long track-record in chemicals EPC services. In contrast, Nel has not established an exclusive EPC partnership. We believe this presents greater risks for Nel compared to ITM as both groups aim to take on increasingly large customer orders. However, we expect Nel will focus more narrowly on stacks as orders increase in size, longer term, and customers bring their own EPC solutions to projects, thus offsetting this risk, in our view.

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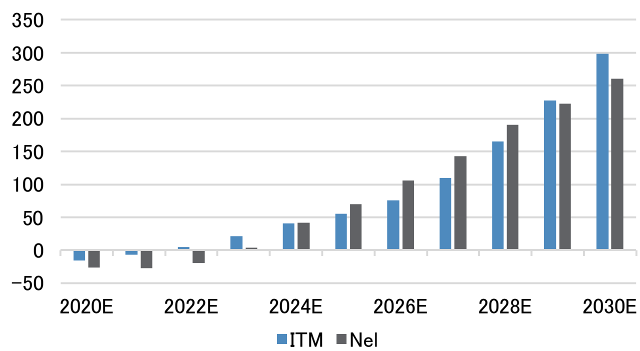
Significant EBITDA growth, but ITM could turn FCF breakeven earlier given more conservative approach

With both ITM and Nel still EBITDA negative today, we expect the commissioning of their more automated larger-scale production facilities will help ITM and Nel turn EBITDA positive in CY'22/23. However, the groups' differing approaches to expanding capacity, discussed earlier, could drive a more material divergence for FCF and balance sheet strength, in our view.

Figure 110: Both Nel & ITM likely to see significant EBITDA growth

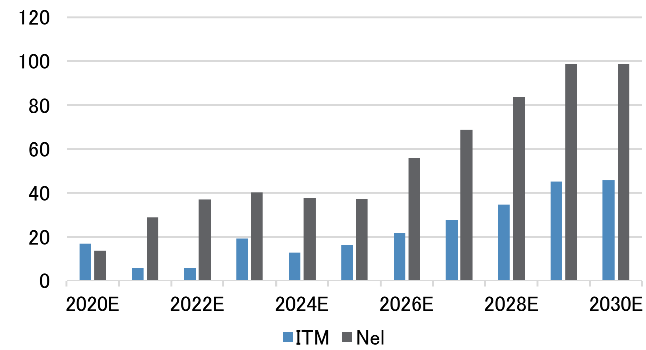
ITM & Nel ASA EBITDA, US$m



Source: J.P. Morgan estimates, Company data.

Figure 111: However, capex growth could differ given strategies

ITM & Nel ASA Capex, US$m



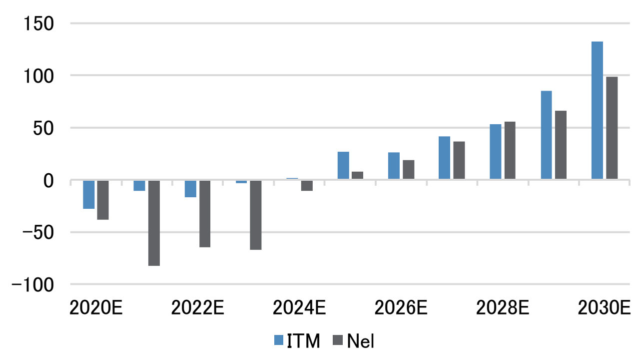
Source: J.P. Morgan estimates, Company data.

ITM & Nel likely to achieve positive FCF in CY'24/25, but Nel's declining cash position presents greater financing risk

Given Nel intends to grow capacity faster than demand, thus we expect Nel to spend greater near-term FCF burn relative to ITM. We believe this could also weigh on Nel's capacity utilisations, which could impact margins. We forecast ITM and Nel reaching FCF breakeven in CY'24/25, but we expect ITM's cash position (both groups have minimal debt today) to remain more robust, while Nel could be at greater risk of needing to raise additional capital.

Figure 112: ITM likely to turn FCF positive earlier than Nel

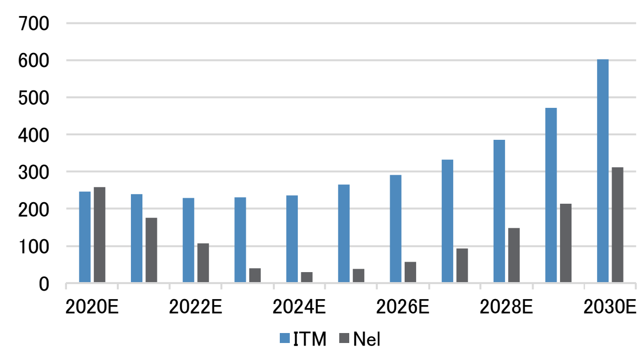
ITM & Nel ASA Free Cash Flow, US$m



Source: J.P. Morgan estimates, Company data.

Figure 113: Nel's falling cash position presenting greater risks

ITM & Nel ASA Cash positions, US$m



Source: J.P. Morgan estimates, Company data.

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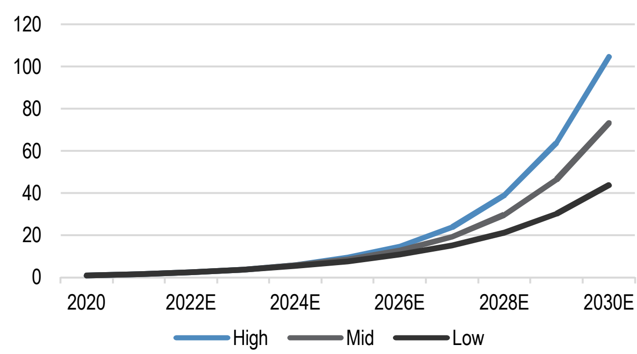
Significant market growth, and uncertainty, necessitates scenario approach to valuation

With both ITM and Nel likely to see significant growth driven by the global adoption of green H_2, but still minimal near-term profitability, we have based our valuations of both groups on three electrolyser market scenarios in CY'30E. These range from a pessimistic 'Low' scenario of only ~40GW of installed capacity by 2030 (equivalent to the EU's domestic target), to a >100GW in a 'High' scenario.

Figure 114: Installed GW could optimistically reach 70-100GW by 2030

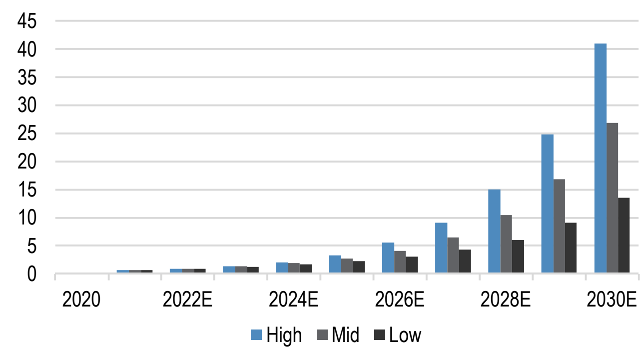
Global electrolyser installed capacity to 2030E, GW



Source: J.P. Morgan estimates, Company data.

Figure 115: ... with annual shipments reaching 25-40GW per annum

Annual global electrolyser shipments to 2030E, GW



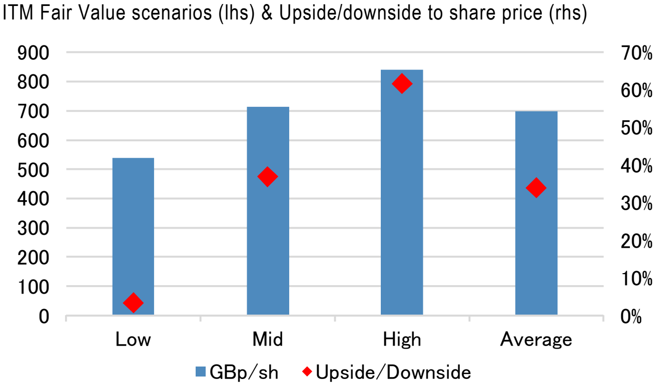
Source: J.P. Morgan estimates, Company data.

Greater upside for ITM vs Nel; initiate coverage of ITM at OW, Nel at N

With these scenarios, we have estimated fair values for ITM and Nel using a combination of 25x EV/EBITDA and 4x EV/Sales multiples in CY'30E, discounted back to 2021E. Taking an average across all three scenarios indicates a fair value for ITM of GBp700/sh with ~34% upside potential and a fair value for Nel of NOK28/sh with ~5% upside potential for Nel vs their current share prices. Thus, we initiate coverage of ITM at Overweight and Nel at Neutral.

Figure 116: ITM fair value scenarios

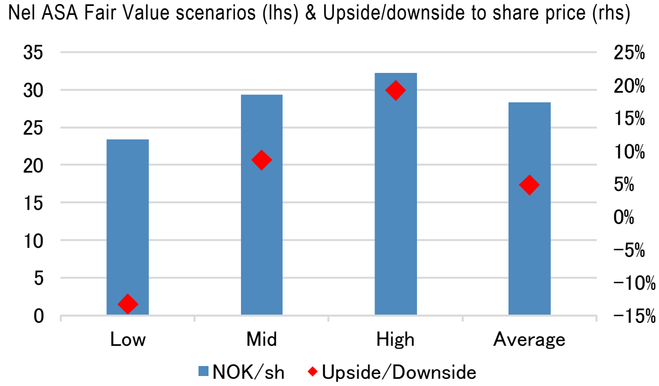
ITM Fair Value scenarios (lhs) & Upside/downside to share price (rhs)



Source: J.P. Morgan estimates, Company data.

Figure 117: Nel asa fair value scenarios

Nel ASA Fair Value scenarios (lhs) & Upside/downside to share price (rhs)



Source: J.P. Morgan estimates, Company data.

Table 27: ITM Fair Value scenarios

		Low	Mid	High	Average
EV/EBITDA					
EBITDA	GBPm	152	205	244	201
Target multiple	x	25	25	25	25
Implied EV	GBPm	3,800	5,132	6,111	5,014
Net cash/(debt)	GBPm	397	410	423	410
Implied equity value	**GBPm**	**4,197**	**5,542**	**6,534**	**5,424**
Implied equity value per share	**GBp**	**762.1**	**1,006.4**	**1,186.5**	**985.0**
Discounted back to 2021	**GBp/sh**	**468**	**618**	**728**	**605**
EV/Sales					
Revenue	GBPm	1,267	1,711	2,037	1,671
Target multiple	x	4	4	4	4
Implied EV	GBPm	5,066	6,843	8,148	6,686
Net debt/(cash)	GBPm	397	410	423	410
Implied equity value	**GBPm**	**5,463**	**7,253**	**8,571**	**7,096**
Implied equity value per share	**GBp**	**992.1**	**1,317.0**	**1,556.4**	**1,288.5**
Discounted back to 2021	**GBp/sh**	**609**	**809**	**955**	**791**
Average	**GBp/sh**	**538**	**713**	**842**	**698**
Upside/Downside	*%*	*3%*	*37%*	*62%*	*34%*

Source: J.P. Morgan estimates, Company data.

Table 28: Nel ASA Fair Value scenarios

		Low	Mid	High	Average
EV/EBITDA					
EBITDA	NOKm	1,631	2,083	2,301	2,005
Target multiple	x	25	25	25	25
Implied EV	NOKm	40,776	52,071	57,525	50,124
Net cash/(debt)	NOKm	2,607	2,394	2,270	2,424
Implied equity value	**NOKm**	**43,383**	**54,465**	**59,796**	**52,548**
Implied equity value per share	**NOK/sh**	**30.8**	**38.7**	**42.5**	**37.3**
Discounted back to 2021	**NOK/sh**	**19.9**	**24.9**	**27.4**	**24.1**
EV/Sales					
Revenue	NOKm	14,104	17,869	19,687	17,220
Target multiple	x	4	4	4	4
Implied EV	NOKm	56,416	71,477	78,749	68,881
Net debt/(cash)	NOKm	2,607	2,394	2,270	2,424
Implied equity value	**NOKm**	**59,023**	**73,871**	**81,019**	**71,304**
Implied equity value per share	**NOK/sh**	**41.9**	**52.5**	**57.5**	**50.6**
Discounted back to 2021	**NOK/sh**	**27.0**	**33.8**	**37.1**	**32.6**
Average	**NOK/sh**	**23.4**	**29.4**	**32.2**	**28.4**
Upside/Downside	*%*	*-13%*	*9%*	*19%*	*5%*

Source: J.P. Morgan estimates, Company data.

Table 29: EMEA & North American H2 subsector valuation

	Rating	PT	Price	Market Cap	Upside / downside	EV/EBITDA 2021E	EV/EBITDA 2022E	EV/Sales 2021E	EV/Sales 2022E	FCF yield 2021E	FCF yield 2022E	ND/EBITDA 2021E	ND/EBITDA 2022E
ITM Power	OW	700p	521p	$4,040	34%	n/a	948.9x	87.7x	23.7x	0%	0%	n/a	-54.7x
Nel ASA	N	NOK 28	NOK 27.0	$4,494	4%	n/a	n/a	33.5x	18.1x	-2%	-1%	n/a	n/a
Nikola	OW	$35.0	$20.89	$8,024	68%	n/a	n/a	608.0x	38.3x	-11%	-8%	n/a	n/a
Bloom Energy	N	$38.0	$28.47	$4,731	33%	66.2x	43.4x	5.5x	4.4x	1%	1%	7.8x	5.8x
Plug Power	N	$70.0	$48.76	$24,503	44%	279.2x	138.2x	47.0x	30.6x	0%	0%	-27.1x	-13.1x
Fuel Cell Energy	UW	$10.0	$17.76	$5,726	-44%	n/a	1140.4x	58.1x	38.0x	0%	0%	n/a	-4.8x

Source: J.P. Morgan estimates, Bloomberg, Company data.

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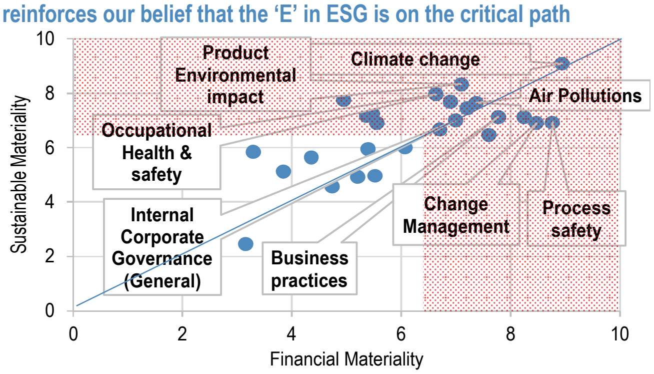
*The EU Oils are uniquely positioned to act as key global producers of clean/low carbon hydrogen across the 'rainbow'. However, the approach should be viewed in the context of much broader Energy Transition (ET) strategies. The need to solve for indirect Scope 3 GHG (80-90% of total emissions) suggests low carbon solutions for hard to decarbonise sectors will be a necessary part of delivering on long term 'net zero' ambitions. This provides strategic alignment for participating in a clean H2 economy, supported by possessing the industrial capacity to integrate it into a diversifying energy value chain. Materiality is low today and it's too early to identify a clear H2 IOC 'winner', though **technology providers within oil services (led by WG, AKSO)** have potential to develop a material hydrogen/CCS offering over the coming decade. Early phase exposure is inflecting and we expect diversified optionality to be pursued across the technologies. **Equinor's (OW) best-in-class O&G carbon intensity combined with the potential financial materiality of its offshore wind business makes it the EU Majors ET leader and we suggest this is reinforced by its active approach on hydrogen/CCS.***

Solving for the Energy Transition; hydrogen economy part of a broader jigsaw

Increased environmental scrutiny from consumers, governments and investors has made ET a central part of the sector's future 'societal license to operate'.

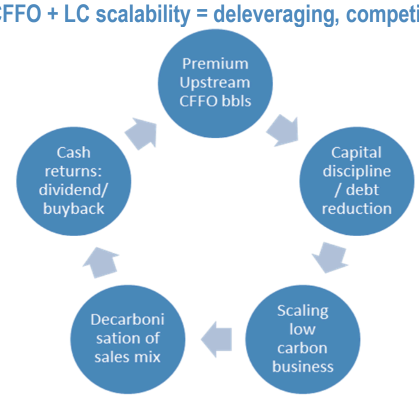
The industry's hydrogen strategy should be viewed in the context of a much broader ET roadmap – solving for long-term 'net zero' by establishing more diverse but still profitable energy businesses able to offer lower carbon crude, gas and new energies in the form of renewable power & fuels. The challenge for all EU Oils is how to structure and finance the core oil & gas business so that it generates sustainable FCF to scale up low carbon in parallel with funding competitive cash return to shareholders. This was underlined by our recent Double Materiality mapping of the sector's key ESG topics in collaboration with our ESG team, which saw ET / Climate Change lead the way on both financial and sustainability axes in Figure 118. This reinforced our belief that delivery on the 'E' in ESG through fiscally conducive decarbonization strategies will be a key determinant of medium-term performance and multiples.

Figure 118: ESG Integration through 'Double Materiality' mapping... reinforces our belief that the 'E' in ESG is on the critical path



Source: J.P. Morgan estimates

Figure 119: A (positive) virtuous cash cycle for Energy Transition; upstream CFFO + LC scalability = deleveraging, competitive TSR



Source: J.P. Morgan

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Where H2 fits; Integrated LC solutions that address scope 3 GHG on critical path of LT 'net zero' ambitions

Blue hydrogen, in particular, offers the benefit of being able to harness the industry's existing supply chain through prevailing grey hydrogen activities and the potential re-purposing of existing infrastructure such as gas pipelines and retail sites.

Our ET 1-0-1 Schematic shows that as much as 80-90% of energy sector GHG emissions are Scope 3 indirect that occur across the value chain, primarily from combustion-based end-product consumption. This equates to O&G Scope 3 GHG of ~20Gtpa, or 35-40% of total global anthropogenic (i.e. human activity) emissions. This suggests:

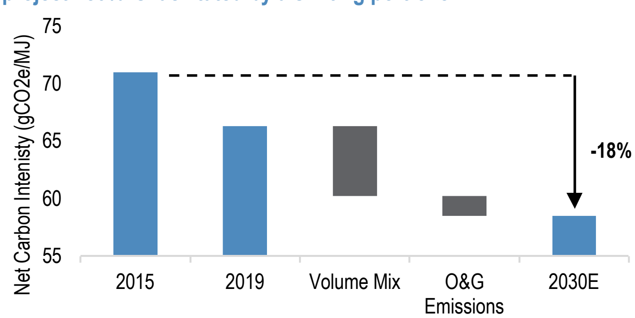
- Cross-sector collaboration will be required to establish scope 3 led solutions.
- While this is likely prove longer lead (vs. Scope 1 direct initiatives), solutions that address hard to decarbonize sectors (e.g.: shipping) will be a necessary part of delivering on LT 'net zero' ambitions. As outlined earlier in the report, this is, in particular, where hydrogen becomes a relevant part of the potential solution-set (alongside products such as biofuels).

Table 30: Five key decarbonisation levers to drive an early 2020s rate of change; Hydrogen tangential over longer term to levers 1 and 5

Key levers	Comments
Deliver on Low Carbon generation targets	**Progress on capacity targets, heightened disclosure of key financial metrics, integration optionality into green H2**
Minimize flaring/venting	Assoc. gas/CO2 from E&P & gas processing. Can account for ~40% of Upstream Scope 1+2 GHG.
Methane emission detection & reduction	CH4 only accounts for 10-15% of total GHG, but is more potent (than CO2) at trapping heat.
Oil & Gas portfolio management	Leverage A&D / FIDs to move down the carbon curve
Hard to decarbonize sector IP	**Demonstrate tangible (& scalable) 'wins' from emerging multi-industry coalition approach to LT Scope 3 GHG solutions**

Source: J.P. Morgan estimates.

Figure 120: TOTAL's Net Carbon Footprint reduction to 2030; we project ~80% is facilitated by a shifting portfolio mix



Source: J.P. Morgan estimates, Company data.

Hydrogen's role within the IOCs energy value chain

During Shell's recent CMD, it outlined a roadmap to the creation of a clean hydrogen market as follows: 1) Own use, to anchor future demand hubs; 2) Serving local hubs; 3) Build inter-regional and intl industrial demand clusters; 4) A fully developed, traded H2 market facilitated by wide-spread pipeline and import pipelines. Shell put a 2035 timeline against Phase 4.

We highlight the following key points;

- **Integrated power solutions.** These cater for energy's broad sectorial consumer base through cross-selling multi-product offerings to ensure continuity of supply (likely to become of greater significance as renewable power's role in the energy mix grows, given its more intermittent nature). The first phase is likely to pivot around gas/renewable power, with emerging fuels such as hydrogen initially being deployed to serve own assets, before providing deeper alternate integration with renewable power and gas over the long term (especially given its storage characteristics).
- **Further underpin gas resource as a 'transition fuel' – blue (and maybe turquoise).** The EU Oils possess abundant upstream gas reserves. Of 11 year 1P and ~20 year 2P reserve lives, gas (CH4) accounts for over 50% of reserves. Blue/turquoise H2 offer means of decarbonizing gas toward a 'responsibly sourced' status. This ought to enhance hydrogen's standing as a key transition fuel with a substantial role to play in the energy mix over the long term and better insure it against the scenario of accelerated green hydrogen substitution (notwithstanding the industrial and fiscal challenges to that happening) under more rapid transition scenarios.

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- **Downstream-led opportunities.** These include leveraging global retail marketing businesses for customer access (e.g. Shell already has ~50 hydrogen inclusive retails in Europe & NAM) and contributing to lowering the carbon intensity of refining through harnessing (green) hydrogen for initiatives such as carbon neutral synthetic fuels production and possibly even substituting grey hydrogen in processes such as hydrocracking.
- **Leverage IOCs global reach and 'rolodex'.** This is done through global (rather than regional) retail networks and established relationships with mobility and industrial customers.

Table 31: Potential key impacts of Hydrogen adoption on the Oil & Gas sector

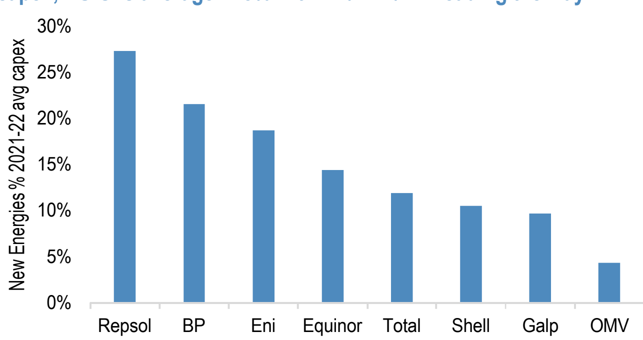
Area	Upside / downside risk	Comment
Renewable Generation	Upside	Green Hydrogen integration offers potential LT demand growth through value chain extension
Oil Products - Diesel	Downside	Potential for H2 substitution to erode European/global heavy duty transport diesel demand over the long term
Gas/LNG	Upside & Downside	Opportunity to harness blue (and potentially turquoise) H2 to convert upstream gas into low carbon end products and replicate global LNG trading models; conversely accelerated switching to green H2 could imply a potential headwind for LT gas demand, e.g.industrial customers
Marketing	Upside	Opportunity to harness existing infrastructure and retail sites to incorporate clean H2 into a diversifying and lower carbon multi-product offering

Source: J.P. Morgan estimates.

Capital allocation; New Energies capex progressive but H2 component modest…

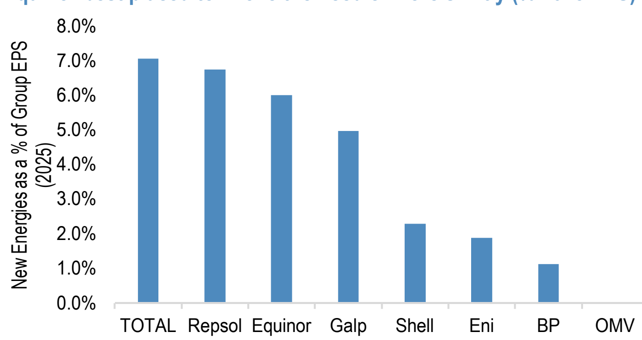
From ~5% two years ago, we now estimate the EU Oils will allocate ~15% of capex to new energies during 2021/22 (Repsol, BP sit at the upper end of the range). This rises towards 20% by mid-2020s but, as outlined previously, the maturity of clean hydrogen specific investments within that remains relatively modest today. The need to de-risk new markets and business models through an appropriate balance of ambition, but prudence, and calibrated in the context of delivering line-of-sight for investors on 8-10%+ equity IRR targets, points to an extended time horizon before hydrogen commands a more material proportion of capital and, ultimately, financial materiality.

Figure 121: Capital allocation; New Energies as a % of 2021/22 capex; EU Oils average ~15% with BP/REP/ENI leading the way



Source: J.P. Morgan estimates, Company data.

Figure 122: Low Carbon financial materiality; TOTAL, Repsol and Equinor best placed to 'move the needle' more swiftly (% 2025 EPS)



Source: J.P. Morgan estimates, Company data.

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A 'finger in every pie'… expect a diversified approach across the rainbow; standalone H2 materiality low but Equinor stands out as an ET Leader

Equinor (OW, TP NOK190) – Premium ESG rating, leading low carbon materiality + premium CFFO/bbl. 3 reasons to buy for 2021: 1) Potential for an accelerating ET strategy under newly appointed CEO Anders Opedal; 2) Improving rate of change on cash return; 3) High quality (incl. low direct carbon intensity) oil leverage, with early 2020s O&G production ~60% liquids.

Extensive upstream gas resources, renewable generation growth targets and a deeper focus on CCS technologies (Shell recently highlighted an objective to access an additional 25mtpa capacity by 2035; three existing projects total 4.5mt) suggest the EU Oils will, at least initially, take a diversified approach across the H2 rainbow. This reflects the dynamic nature of the cost structure and global portfolio exposure to variances in regional decarbonisation strategies/incentives. A number of first phase projects and consortium-based initiatives have been announced over the last 6-12M, a selection of which we summarize in Table 32 below. The scale of prevailing O&G production bases mean materiality is low and it's too early to clearly identify an EU Oils 'winner'. **However, Equinor's hydrogen/CCS activities dovetail well with best-in-class O&G carbon intensity and the potential financial materiality of its offshore wind business; this reinforces its standing as our EU Oils ET leader.**

Table 32: EU Oils headline clean hydrogen exposures and selected projects

Company	JPM Rating	JPM Price Target	Materiality	Detail
Shell	Overweight	1700	Minor	**Activity to date – both green and blue H2:** Announced green H2 projects with production capacity >4GW targeted for this decade. Other notable plans: Constructing PEM electrolyser in Germany (10MW), working on plans for an 200MW electrolyser project in Netherlands, partner in NorthH2 consortium – gross 1GW 2027 / 4GW 2030
BP	Overweight	415p	Minor	**Activity to date – both green and blue H2:** Aim to build positions in both green and blue hydrogen in the US, UK, Europe, China as well as Australia; plan to capture a 10% share of hydrogen in core markets by 2030.
TOTAL	Neutral	46	Minor	**Activity to date – both green and blue H2:** Pilot project (50/50 JV with Engie) 40 MW electrolyzer integrated with a solar farm 100MW will deliver firm green hydrogen to La Mede biorefinery
ENI	Underweight	9	Minor	**Activity to date – both green and blue H2:** ENI/ENEL studying two pilot projects that will involve electrolyzers of around 10 MW each. Ravenna (Italy CCS project) presents an opportunity for the production of blue hydrogen.
Equinor	Overweight	190	Minor	**Activity to date – blue H2 led:** Blue H2 Projects: H2H Saltend - H2 to Humber (FID 2023); H21 North of England, Magnum power plant Netherlands, H-Vision Blue H2 Netherlands. Green H2: Partner in NorthH2 European consortium
Repsol	Underweight	8.5	Minor	**Activity to date – both green and blue H2:** Ambition to become Iberian leader in renewable hydrogen (capacity target 400/1200 MW in 2025/30). Plans to build 10MW electrolyser (EUR 60m) near Petronor refinery
OMV	Overweight	44	Minor	**Activity to date – green H2 led:** 10 MW PEM electrolyser plant in Schwechat Refinery (start-up 2H23; capex share €25m), Project UpHy involving green H2 production for use in mobility and refining. Partner in H2Accelerate consortium (mass-market roll-out of H2 trucks in Europe)
Galp	Neutral	11	Minor	**Activity to date – green H2 led:** Will assess the feasibility of the H2 Sines project. An initial 10MW electrolysis pilot project may evolve to a 1GW project over the decade
Wood	Overweight	390p	Increasingly material	**Activity to date –** Proprietary steam methane reformation technology. Installed ~3% global H2 demand. Concept Engineer for a significant number of Blue and Green Hydrogen Projects
Petrofac	Neutral	220p	Minor	**Activity to date –** Selected as FEED engineer for the Arrowsmith Green Hydrogen project in Australia. Awarded Engineering an PMO support contract for the Acorn CCS and Hydrogen development in the UK
Aker Solutions	Overweight	NOK 21	Increasingly material (CCS)	**Activity to date – S**pun out its Carbon Capture technology business (Aker Carbon Capture) but retains an 11-year framework agreement for delivery of CCUS (Blue Hydrogen focus). Also concept, front end and basic engineering services across the hydrogen rainbow.

Source: J.P. Morgan estimates, Company data.

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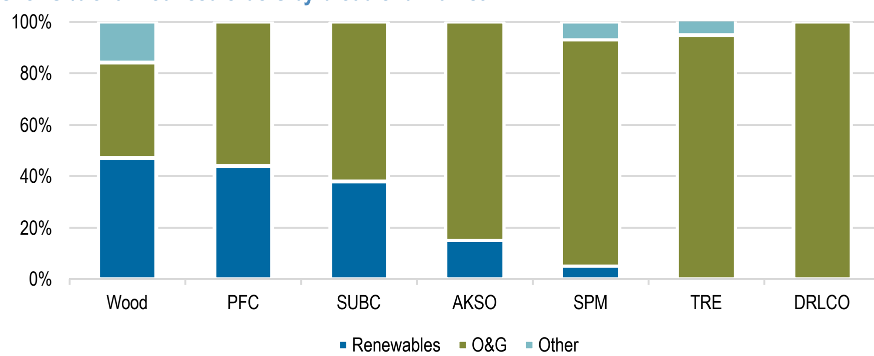
OFS – Rising inbound orders just the start as businesses pivot towards low carbon future

Most of EU OFS set out their stall on Decarbonization and Renewables during 2020.

2020 was by far the highest profile year for Renewables and the Energy Transition for our Oil Services coverage, with a significant 17% of announced order intake being renewables related. Energy transition credentials have become the focus of corporate CMDs and now have higher profile in quarterly results with AKSO and SUBC establishing specific renewables reporting lines (we expect others to follow). We look at Hydrogen and CCS through a complimentary lens given the potential for growth in blue H2. We also see OFS having a role to play in re-engineering upstream and downstream power generation to displace natural gas with % Hydrogen for fuel. We see this as a useful source of growth in LNG and Refining and potentially in offshore installations. **At this stage, we see WG, AKSO and SUBC best placed to grow their respective renewables businesses beyond ~30% of the total and therefore the most likely to reflect an Energy Transition growth premium in the near term. Of these, WG (H2 and CCS) and AKSO (CCS) are best exposed to the Hydrogen rainbow.**

Figure 123: A notable shift to announcing large low carbon or renewables contract awards. Chart shows % of announced orders by broad end market



Source: J.P. Morgan estimates, Company data. Note HTG typically doesn't announce orders given low average contract size. Data only includes announced orders, actual % will be different. PFC would have been 17% had Dalma not been cancelled.

Our analysis throughout the year has shown that EU OFS has complimentary skillsets and, in some cases, technology leadership to support the energy transition.

The question is, at what point does this growth opportunity become big enough to warrant improved multiples for the sector?

Transitioning of business activities to low carbon/renewables will remain a focus, has the potential to replace growth absent in O&G as the decade progresses. The acceleration of the climate agenda is ultimately a headwind for the Oil & Gas sector, given the potential for it to reduce O&G demand over the long run. However, the early signs are that a number of EU OFS businesses can successfully pivot to supporting the Energy Transition. There is a natural home for OFS in offshore wind given Engineering/EPC experience with offshore structures, and a natural home in CCUS given experience with the subsurface. We also see potential to navigate the Hydrogen spectrum given experience handling complex fluids and for some companies the ownership of proprietary in house SMR technology (Grey Hydrogen production). A lack of relative complexity makes the margin opportunity in Wind and Solar more of a challenge, but these two avenues offer greatest growth, whereas the challenges with CCS make this a more attractive proposition from a value add perspective; while the increasingly favourable policy backdrop for using hydrogen as a fuel source, means this energy source offers long term growth.

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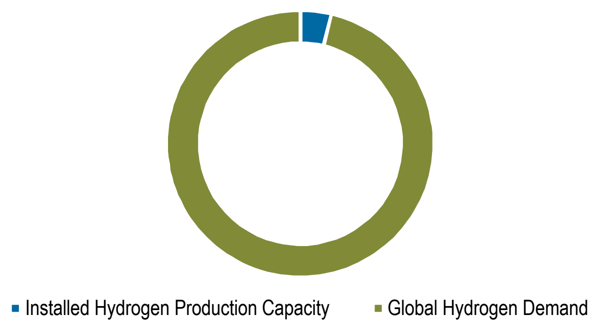
Spotlight on Wood's hydrogen offering

As discussed, hydrogen is gaining much prominence in the global energy mix, particularly in Europe, following the EU hydrogen strategy. Wood, largely through Foster Wheeler heritage, has significant experience in grey hydrogen, particularly steam methane reformation (SMR), where it is involved in hydrogen production through its Terrace Wall reforming furnace technology. Wood's technology has been used on over 120 hydrogen and syn-gas plants globally, with an installed capacity >3.5 million Nm3/h of hydrogen (~3.5% global annual industrial hydrogen demand).

Figure 124: Wood's installed base of hydrogen production units supports around 3% global hydrogen demand (Nm3)



Source: J.P. Morgan estimates, Company data.

It is this experience, combined with consulting and technology capabilities, that enables Wood to participate in the evolution of hydrogen developments, particularly the swing from blue to green. For example; Wood's clean energy group is working on feasibility studies for deploying hydrogen into transportation networks, such as ferry routes on the Western Isles of Scotland, UK.

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Gazprom is the world's largest natural gas producer and supplies ~40% of Europe's natural gas. Hydrogen, hence, represents both a huge opportunity and an existential risk to Gazprom's business should we see it replace natural gas as an energy carrier. Gazprom has focused on methane pyrolysis (turquoise) as a route to low cost & low CO_2 hydrogen from gas. If the technology can be made to work at scale Turquoise hydrogen offers an ongoing/ extended role for Gazprom/gas in the energy mix and has the advantage of low production costs and very low CO_2 emissions and, hence, avoids the need for CCS, which is expensive (cf Northern Lights project USD 800m for 1.5Mtons a year) and politically unpopular in certain EU counties (e.g. Germany). Moreover, the lack of available subsidies/tax breaks in Russia for CCS has somewhat stymied development of the technology domestically.

See more in our research reports on Gazprom and hydrogen: *Hydrogen: It's the future; but is there a role for Gazprom and turquoise in the hydrogen rainbow (June 2020); Hydrogen expert call feedback (June 2020); EU Hydrogen Strategic Roadmap (July 2020); Russia's hydrogen Road map (July 2020) Gazprom Gas: An uncertain transitional future (Oct 2020) Gazprom; Hydrogen and CO2 - A pipe dream or a dream solution for its pipes*

In Gazprom's vision of the hydrogen economy, natural gas would be transmitted from Russia to Europe using Gazprom's existing pipeline infrastructure with hydrogen then made locally at source via methane pyrolysis. Gazprom has also commented on the potential to export hydrogen from Russia to Europe via its hydrogen-ready NS1/NS2 pipelines with potential to pump CO_2 in the opposite direction for storage in Russia's depleted oil and gas reservoirs. Russia is to publish an updated hydrogen strategy white paper in early 2021, but its hydrogen road map, published earlier this year, pointed to relatively modest 0.2Mtons of hydrogen being exported to Europe by 2024 and 2Mtons by 2025 (note Gazprom's current normalized exports to the EU are ~200bcm equivalent to ~52mta of H_2), although this doesn't include turquoise hydrogen created in the EU from Russian gas.

The EU has committed to net zero in 2050 and China in 2060 – effectively meaning gas demand is likely to fall materially from 2030 in the EU and 2035 in China limiting gas's life as a transitional fuel unless it plays a significant role in the hydrogen economy. In our view, Gazprom has been late to realize the ramifications of the changing pace of the energy transition on its business, largely focusing on near-term gains from coal to gas switching. Hydrogen has clearly moved up the internal agenda in 2020 and Gazprom recently announced the formation of a dedicated subsidiary "Gazprom Hydrogen" to implement hydrogen projects. Our understanding is that one of these projects will be a 'large' turquoise hydrogen plant near the shore of the NS1 pipeline in Germany, although, to date, no plant size, time line or partner has been announced. Whilst Gazprom has been undertaking research projects with domestic institutions (Tomsk Uni, Samara State Uni etc) it is seemingly relying on the likes of BASF to push ahead with the technology and create a methane pyrolysis-based hydrogen industry. This looks a mistake to us, given the potential we see for methane pyrolysis to cement natural gas/Gazprom's role in the hydrogen economy and also the long-term existential risk that green hydrogen presents to both natural gas and Gazprom.

It's clear that the EU favours green hydrogen over any gas-related option given that the latter will almost certainly involve at least some level of CO2 emissions. The EU is also short gas and, hence, has no incentive to perpetuate its energy trade deficit, nor is it politically close to Putin's Russia. Hence, given a choice between a technology that reduces fossil fuel/Russian dependence and one that doesn't it seems fairly clear which option the EU will plump for. Hence, in our view, the onus is very much on Gazprom to push methane pyrolysis technology as hard as it can and prove that it can deliver material amounts of cheap low carbon hydrogen and hence appeal

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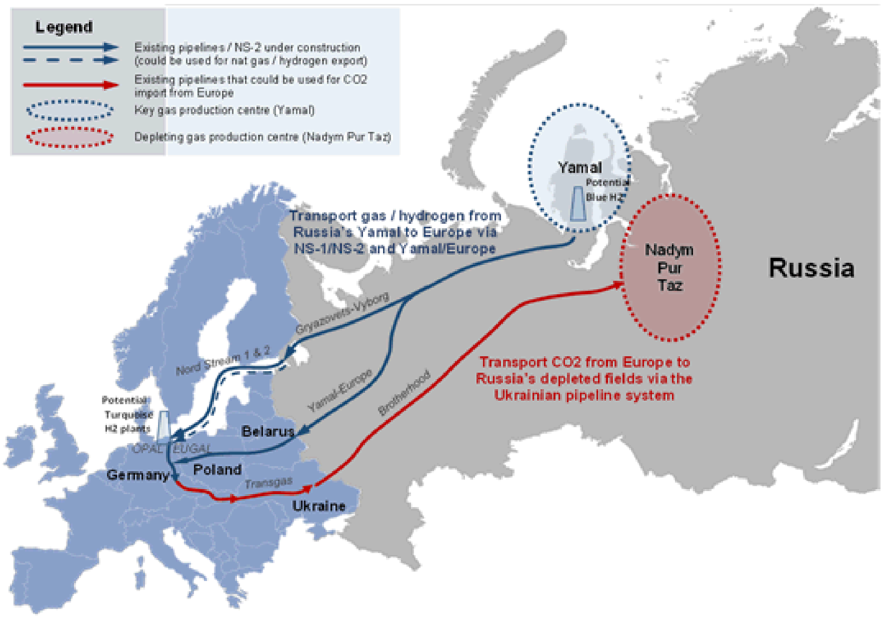
to EU pragmatism and the ability of turquoise hydrogen to help scale up the hydrogen economy.

However, there is a technology race on and we are not convinced that the development of methane pyrolysis will be rapid enough to ensure a meaningful role for turquoise hydrogen as declining green hydrogen costs and rapid scale-up occur. There is much to play for over the next decade and Gazprom could find itself either at the center of the hydrogen economy or, conversely, peering towards the collapse of its key export market and obsolescence of its key product.

Figure 125: Potential future gas, hydrogen and CO2 flows



Source: J.P. Morgan estimates, Company data.

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The Global Mining & Steel sectors represent ~12% of global GHG emissions, with the vast majority of this derived from steel production. Hydrogen offers a potential fuel source for decarbonizing several areas in the sector, particularly steel and heavy-duty trucks. Furthermore, the rapid adoption of platinum intensive fuel cell vehicles could present upside risk to long-term platinum demand and help offset demand losses from ICE diesel vehicles. We view SSAB (UW) as the EMEA steel energy transition leader for its advanced H2-derived steel HYBRIT. Among the PGM Miners, we prefer Impala and Sibanye (both OW).

Table 33: Potential impacts of Hydrogen adoption in the EMEA Mining & Steel sectors

Area	Upside / downside risk	Detail
Coking coal	Downside	Adoption of H2 for steel transition could lead to coking coal demand destruction
Platinum Group Metals	Upside	Adoption of FCEVs, which use PGM intensive PEM fuel cells, could offer significant new demand for platinum & offset losses from BEVs
H2-Derived Steel	Upside & Downside	H2-derived steel can be opex competitive vs BOF steel at $2/kg H2, transition capex requirements could be lower than BOF maintenance long-term
Trucking	n/a	FCEV trucks could offer a more viable route to decarbonise mining truck fleets given higher energy density & less net payload loss

Source: J.P. Morgan estimates, Company data.

H_2-steel gaining momentum among steel, iron majors

Given the global steel industry represents ~10% of global GHG emissions, decarbonising the steel sector is a clear focus of policy makers and corporates alike. However, as a 'hard-to-abate' sector, energy transition for steel is not as simple as switching to renewable power; a substitute for coking coal is needed as a heat source. Hydrogen reduction of iron ore offers one solution which is quickly gaining traction with steel and iron ore majors, particularly in Europe. Our analysis of H_2-derived steel opex shows that it can break even vs typical blast furnace steel, if H_2 costs of $2/kg can be achieved and with a $25/t CO_2 price. In contrast, carbon capture & storage technology requires a ~90/t CO_2 price to be cost competitive vs blast furnaces.

H_2-derived steel more a piecemeal technological shift than leap

Furthermore, we do not believe that H2-derived steel is the technological leap that it is often thought to be. About 50Mt of global steel production (~3% of global output) today utilises direct reduction iron (DRI), which uses natural gas (CH_4), rather than coking coal to reduce iron ore. The shaft used for H2-steel is a similar DRI process, with the DRI then processed through an electric arc furnace (EAF). Therefore, we believe the technological hurdles for H2-derived steel are lower than they are often perceived to be.

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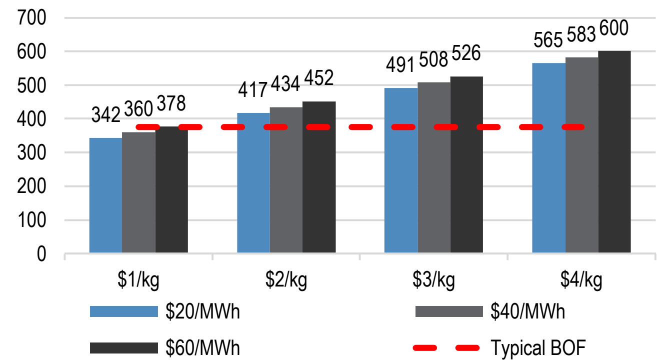
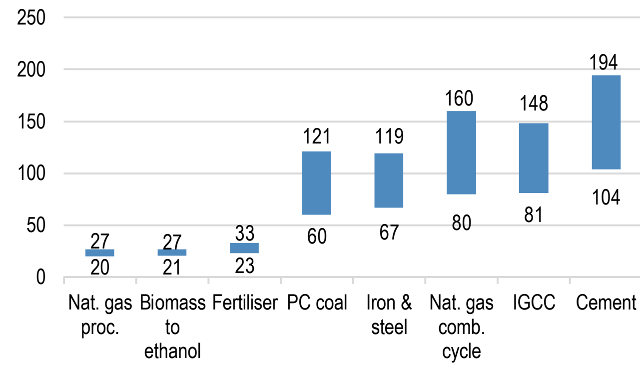
Figure 1: H_2-derived steel could be viable at lower power, H_2 costs
$/tonne steel



Source: Company data, J.P. Morgan estimates.

Figure 2: Carbon capture & storage costs vary across industries
US$ per tonne CO_2



Source: Global CCS Institute

Race accelerating among EU Steel producers to bring low CO_2 steel to the market: Furthermore, many EU steel producers are now accelerating plans to bring low-CO2, including H2-derived, steel tonnes to the market. **Arcelor Mittal** (OW) recently announced (link) it is targeting ~120ktpa low CO_2 capacity by 2021 and ~600ktpa by 2022. Before this announcement, we do not believe the market had any visibility on MT reaching any capacity level beyond what pilot projects could realistically deliver. **Voestalpine** (UW) commissioned its H2FUTURE pilot in late 2019 and is now scaling this up to ~250ktpa during 2021 in collaboration with Mitsubishi. **SSAB**'s (UW) HYBRIT pilot project was commissioned in Aug'20. SSAB also recently announced (link) that it is progressing its plan to construct a demonstration plant 'on an industrial scale', with construction expected to commence in 2023 and completion in 2025. In tandem with converting the Oxelösund BF furnace to EAF, this will allow SSAB to deliver significant low CO_2 steel volumes to the market by 2026E. Recently, **ThyssenKrupp** (not rated) announced that it will build a 1.2Mtpa DRI facility by 2025 with the goal of operating the facility eventually on 100% hydrogen (link). Natural gas will be used to top up at the new Duisberg plant until sufficient hydrogen is available. In contrast to SSAB's HYBRIT project, the H-DRI product from TKA will then be liquefied in an integrated melting unit, and the 'blast furnace 2.0' will produce 'electric hot metal' processed in the existing metallurgical plant. TKA is targeting 3Mtpa of low CO_2 steel production by 2030. Also, **Salzgitter** (Neutral) and its partners recently commissioned a feasibility study at the end of June for the construction of a DRI plant with an upstream hydrogen electrolyser at the deep water port of Wilhelmshaven (link). The study is expected to be completed by end-Mar'21. The study is assessing the economics of 2Mtpa DRI for use in SZG's Flachstahl integrated steelworks.

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Table 34: EU Steel companies rapidly setting hard low CO_2 volumes targets, adding up to >6Mtpa

EU Steel low CO_2 hard volume targets

Company	Targets	Volume	Year
Voestalpine	Small-scale H2FUTURE pilot in commissioned in late 2019. Large scale pilot with Mitsubishi under construction.	250ktpa	2021
SSAB	SSAB plans to scale up its HYBIT H_2-DRI project to commercial scale of 600-1,000ktpa	600-1,000ktpa	2026
Salzgitter	Studying a potential H-DRI project at Wilhelmshaven, Germany paired with H_2 electrolysis capacity	2Mtpa	N/A
Arcelor Mittal	Targeting ~600ktpa of low CO2 steel capacity through both H_2 & CCS focused projects	600ktpa	2022
ThyssenKrupp	Planning an H-DRI plant at Duisberg by 2025 & 3Mtpa of low CO_2 steel by end of decade	3Mtpa	2030

Source: J.P. Morgan estimates, Company data.

Multi Mtpa low CO_2 steel capacity for EU no longer a pipedream: Combining MT's 2022 target of ~600ktpa, SSAB's 2026 HYBRIT target of 600-1,000ktpa, TKA's 2030 target of 3Mtpa, and SZG's Wilhelshaven 2Mtpa H-DRI project, implies material capacity of low CO_2 steel/steel inputs is no longer simply a long-term aspiration. Instead, we increasingly believe a non-inconsequential share of EU carbon steel output could be derived from low CO_2 sources by 2030. We would note that the EU Hydrogen Roadmap envisions ~10Mtpa of green H_2 output by 2030. Although the roadmap did not specify expected demand/consumption by sector, Hydrogen Europe estimates that ~1Mtpa of the ~10Mtpa H_2 output target could be allocated for steel production. Based on our assumption of ~50kg of H_2 to produce 1tonne of H-DRI, this would imply as much as 20Mtpa of H_2-derived steel output by 2030E.

MT taking an 'all-of-the-above' technology approach, but are fault lines emerging between H_2 & CCS for Steel decarbonisation? Before Mittal's Oct'20 announcement, one might have argued that MT was technology agnostic for decarbonisation since it has multiple pilot projects involving both H_2 and CCS. However, given MT is now targeting ~600ktpa of 'green steel' by 2022 and it has not disclosed the breakdown of volumes across these sites (and thus technologies), it seems it expects that steel decarbonisation will require multiple technologies to be achieved. In our view, this mirrors the strategy of BHP's (OW, Top Pick) for addressing Scope 3 emissions, which more heavily focuses on CCS, but leaves room open for alternative technologies for steel energy transition.

Green H_2 & H-DRI could also present an opportunity for iron ore majors

Over the past 12-24 months, the EU steel industry has largely started to coalesce around H_2-focused technologies, while major iron ore miners Rio Tinto (OW), Fortescue (OW), and Vale (OW, covered by Rodolfo Angele) have also shifted in this direction. Rio Tinto recently announced that it entered a MoU with Paul Wurth and SHS-Stahl to complete a feasibility study for an industrial scale H-DRI project in Canada, while Fortescue is considering several green H_2 projects in Australia. Given ample renewable power resources, Australia, Brazil, and other major iron ore producing countries will likely benefit from relatively lower H_2 costs, longer term, compared to major iron ore importers, such as Japan and South Korea. We believe this could also offer another long-term opportunity for the Western Australia iron industry. With iron ore grades likely to gradually decline, longer term, costs and product quality will likely become greater considerations. So iron ore reduction in Australia using H2 could offer miners the opportunity to sell a premium low CO2 product and address some long-term structural cost headwinds, while on-shoring part

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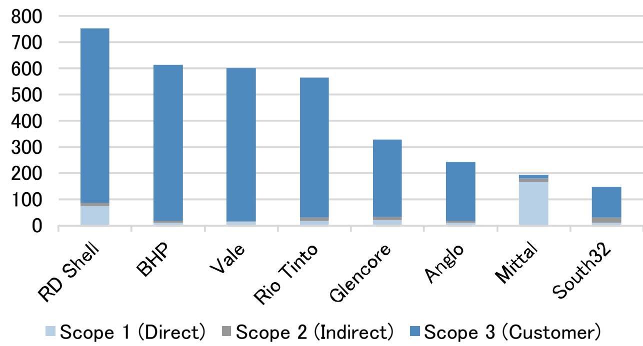
of the steel supply chain from locations in which H2 costs will likely remain uncompetitive. The latter opportunity could potentially also help persuade policy makers to support miners' H2 aspirations given the potential to support employment and increase the level of value-adding beneficiation within the country of origin.

Figure 3: Including Scope 3, BHP, VALE, RIO emissions ~1% of global GHG emissions each

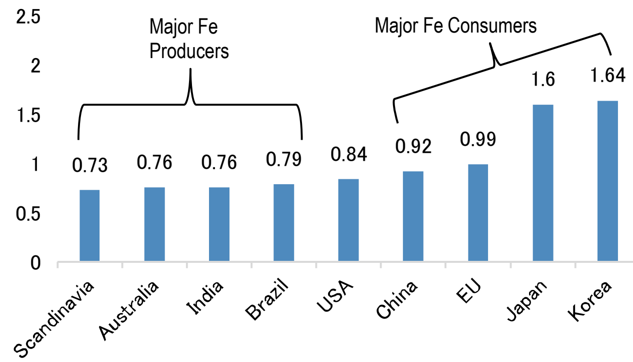
Millions tonnes per annum, 2018



Source: Company data, J.P. Morgan estimates.

Figure 4: Major iron exporters could see H_2 cost advantage vs major iron importers – opportunity to shift parts of steel supply chain?

2050E Levelised Cost of Hydrogen, $/kg



Source: BNEF, J.P. Morgan.

H_2 fuel cells could boost Pt demand, advance mining truck decarbonisation

Growing interest in H_2 fuel cell vehicles supportive for long-term PGM demand, but cutting Platinum intensity a key priority of FCEV OEMs. At the time of our major Oct'19 report (link), we believed mainstream uptake of fuel cell vehicles to be likely beyond 2030. Fuel cell vehicle (FCEV) adoption could represent a long-term transformation for platinum demand given a typical FCEV requires 10-20 grams of Platinum per vehicle compared to a typical diesel ICE vehicle, which requires 5-6 grams (0.5 grams platinum & 4.5 grams palladium per typical gasoline vehicle), and could help offset lost demand from hybrid or battery electric vehicles (BEV). However, with the EU's Green Deal & Hydrogen Roadmap, as well Hyundai's (OW, covered by SM Kim) recently announced 2030E FCEV output target of 500k unit pa, the outlook for Fuel Cells could be worth reconsidering. Hyundai's 2030E target would represent ~0.5% of current global vehicle output. Also, Nikola (OW, covered by Paul Coster) expects first production of its FCEV truck in 2023 and is guiding to reach full production of 30k units pa by 2027. Toyota, long an advocate for FCEVs, recently announced (link) a JV with five Chinese autos OEMs to develop fuel cell systems in the country.

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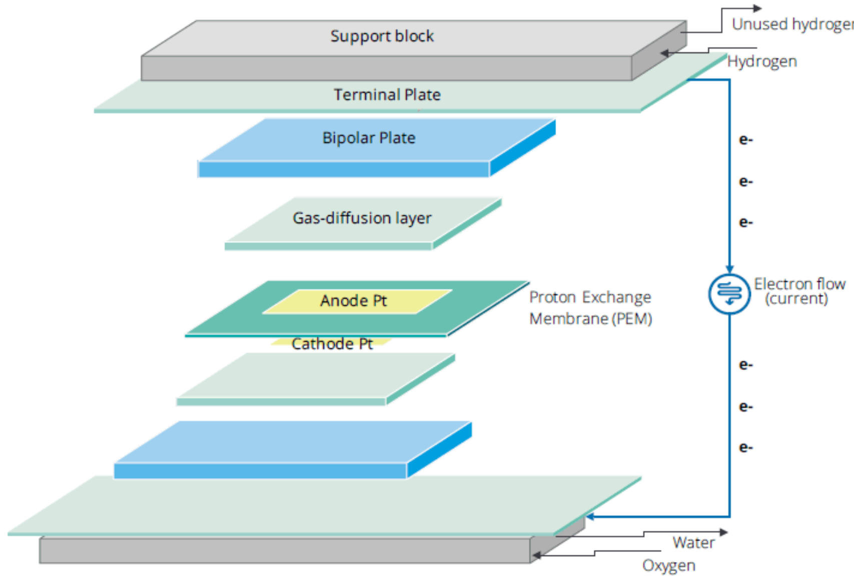
Figure 126: PEM fuel cell stack components & key materials – Platinum required in a PEM fuel cell & electrolyser anode & cathode



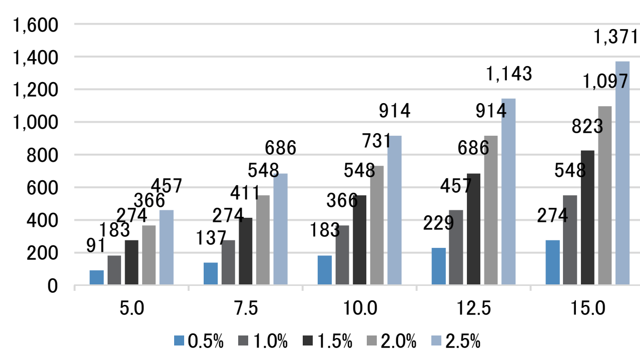
Source: Company reports

FCEVs could become material contributor to global Pt demand by 2030E

Although these developments would signal positive momentum for FCEVs and thus long-term Platinum demand, reducing platinum requirements per vehicle is a key priority for FCEV OEMs discussed at the conference. We estimate that, if FCEVs can reach 1% of global vehicle sales with an average Platinum requirement of 10grams/vehicle, this could add ~400koz pa to global platinum demand, equivalent to ~4% of global platinum demand, vs <100koz of FCEV related demand today. The build-out of PEM electrolysers could also add additional upside to long-term platinum demand. Among the PGM Miners, we rate Sibanye and Impala Overweight.

Figure 8: Potential 2030E platinum demand from FCEVs…

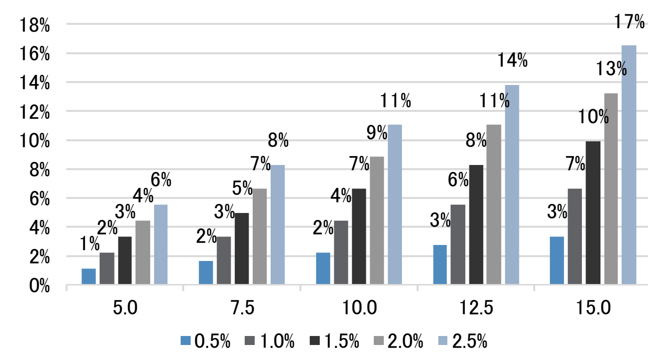
Platinum demand (koz) under various Penetration & Loading scenarios



Source: J.P. Morgan estimates.

Figure 9: … could become a significant proportion of demand

% of total platinum demand, under various Penetration & Loading scenarios



Source: J.P. Morgan estimates.

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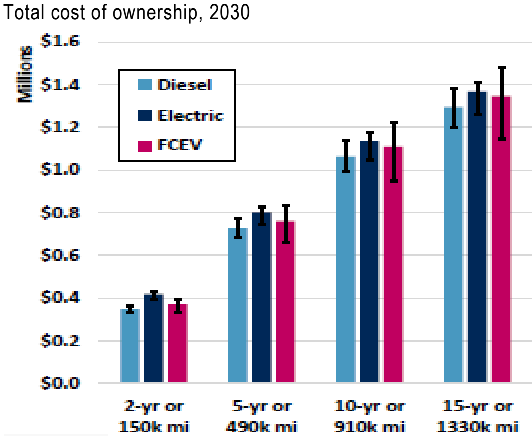
Improving H_2 FCEV trucks economics offer a possible route to decarbonize mining trucks & further cut miners' emissions. Furthermore, fuel cell technology has also garnered more attention in the commercial vehicle industry given the greater challenge of electrifying large pay-load vehicles. The JPM US Machinery Research team recently compared the economics of a 23-tonne diesel truck vs BEV and FCEV alternatives (link). Although the FCEV truck is still today ~30% more expensive than the BEV and ~4x more expensive than the diesel truck, the BEV truck example lost ~34% of its available payload to battery weight, compared to only ~9% for the FCEV truck. S&P Platts estimate that by 2030, the total cost of ownership for a long haul semi FCEV could be on par with that of an equivalent ICE or BEV semi. The Hydrogen Council estimates that decarbonizing heavy & medium duty vehicles could be more competitive with H_2 fuel cells than BEVs at ~$5/kg H_2. H_2 fuel cells could also offer a broader opportunity across the mining sector beyond simply long-term PGM demand upside.

Fuel cell could offer a route to decarbonizing mining truck fleets

Moving material with diesel trucks represents a significant proportion of miners' greenhouse gas (GHG) emissions, specifically Scope 1 (Direct) emissions. On our estimates, fuel for trucks and other heavy equipment represents ~30% of copper production emissions. Fully electrifying large earth-moving trucks could be difficult given the energy density required for any such vehicle's battery. From our discussions with mining industry contacts, some trials even of smaller EV trucks had mixed results. This could, however, present an opportunity for FCEV trucks given the energy density possible with H_2. In Oct'19, Anglo American announced a partnership (link) to develop FCEV mining trucks. This initiative is to start at Anglo Platinum's Mogalakwena mine in South Africa, where Anglo is to install Ballard's FCveloCity-HD 100kw fuel cells (link) in several of its 290-tonne Komatsu trucks (link). These will be fueled with green H_2 produced onsite using solar power. Ballard has also supplied fuel cells for Weichai's 200t mining truck prototype in China (link).

Figure 10: FCEV trucks could be cost competitive by 2030E

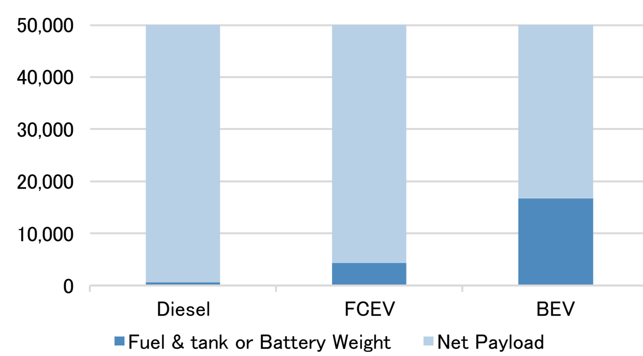
Total cost of ownership, 2030



Source: S&P Platts, J.P. Morgan estimates.

Figure 11: Net payload comparison of Diesel, FCEV, & BEV truck

Lbs, example is a 2025E 50,000lbs (23tonne) truck



Source: Company data, J.P. Morgan estimates.

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Table 35: EMEA Mining & Steel corporates involved in Hydrogen

Area	JPM Rating	JPM Price Target	Materiality	Detail
Rio Tinto	Overweight	GBp 6,940.0	R&D Investment, so minor	Research JV with Baowu & Tsinghua Uni to develop H2-steeltechnology. Feasibility study under way for industrial scale H-DRI plant in Canada
SSAB	Underweight	SEK 34.0	Increasingly material	SSAB's HYBRIT project aiming for commercial H2-derived steel by 2025. Arguably leader for low CO2 steel
Anglo American	Neutral	GBp 3,000.0	Pilot project, so minor	Fuel Cell EV mining truck pilot project at its Mogalakwena PGM mine in South Africa.
Arcelor Mittal	Overweight	EUR 26.5	Increasingly material	Several H2-derived steel pilot projects; aiming for 600ktpa of low CO2 steel by 2022 (combination of both CCS & H2-DRI)
Voestalpine	Underweight	EUR 26.0	Increasingly material	~250ktpa pilot project with Mitsubishi under construction for completion during 2021.
ThyssenKrupp	NR	N/A	Increasingly material	Planning an H-DRI plant at Duisberg by 2025 & 3Mtpa of low CO_2 steel by end of decade
Salzgitter	Neutral	EUR 21.5	Increasingly material	Studying a potential H-DRI project at Wilhelmshaven, Germany paired with H2 electrolysis capacity

Source: J.P. Morgan estimates, Company data.

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The EMEA Utilities sector will be presented with a mixture of opportunities and threats as green hydrogen attempts to go mainstream. Renewable generation will experience a fillip in the form of increased power demand, electricity and gas networks will need to invest to install, prepare or repurpose grids for the transition and gas supply will be challenged in terms of managing the sourcing transition while also resisting competition from likely new entrants. On balance, we feel that green hydrogen is more opportunity than threat for the sector. The most relevant stocks, in our view, will be: Iberdrola, Orsted, Enel, Engie, RWE, Enagas, Snam and Endesa.

Table 36: Potential impacts of Hydrogen adoption in the EMEA Utilities sector

Area	Upside / downside risk	Details
Renewable Generation	Upside	Green Hydrogen production will result in a meaningful source of incremental demand for renewable generation capacity
Electricity Transmission	Neutral / Upside	There could be two models for green H2 production: (a) a giga electrolyzer model combined with building of dedicated renewable facilities at the foot of the electrolyzer and (b) a distributed electrolyzer model with smaller-scale electrolyzers that can be fed with green energy from remote locations.
Gas Transmission	Upside	We feel that, while both models will co-exist, initially green hydrogen model is more likely to be developed around the concept of reaping scale benefits to quickly reduce overall production costs thus, at this early stage, the pipeline companies will be bigger beneficiaries than the electricity network companies
Gas Supply	Downside	Gas suppliers risk getting stuck with undesired volumes of already contracted natural gas (a threat that will likely provide further impetus to the trend of shorter-term and more flexible gas sourcing contracts); Additionally, they may face new competition in hydrogen supply to industrial clients from suppliers of Industrial gases, who can leverage existing client relationships
Gas-fired Generation	Neutral	In the initial phase of energy transition gas peakers will become important for security of supply – operating as back-up capacity thereby reducing load factors, reducing CO2 emissions and shifting to fixed remuneration; In the long run and from a net zero perspective, subject to technological developments, economically viable options may emerge to convert them to run on H2 (or its blends with Natural Gas) as fuel

Source: J.P. Morgan estimates, Company data.

We believe that the commercial development of green hydrogen constitutes a combination of threats and opportunities for the utilities sector:

- **A source of meaningful incremental demand for renewable generation:** The production of green hydrogen with electrolyzers should result in additional demand for the development of renewable power generation capacity. The European Commission in its communication, “A hydrogen strategy for a climate-neutral Europe”, states that the EU industry has developed an ambitious plan to reach 2x40 GW of electrolysers by 2030 (40 GW in Europe and 40 GW in Europe’s neighbourhood with export to the EU). These 80GW are as much as 20%+ of all the renewable capacity additions expected in the European continent in 2021-2030.

- **Opportunities for gas networks – the giga electrolyzer model of deployment:** A green hydrogen industry built predominantly around giga-electrolyzers would mean a larger opportunity for gas companies, which can adapt gradually their networks to the transportation of hydrogen as, for such large-scale projects, the rationale would suggest the combined building of dedicated renewable facilities at the foot of the electrolyzer. Once produced, the green hydrogen would need to

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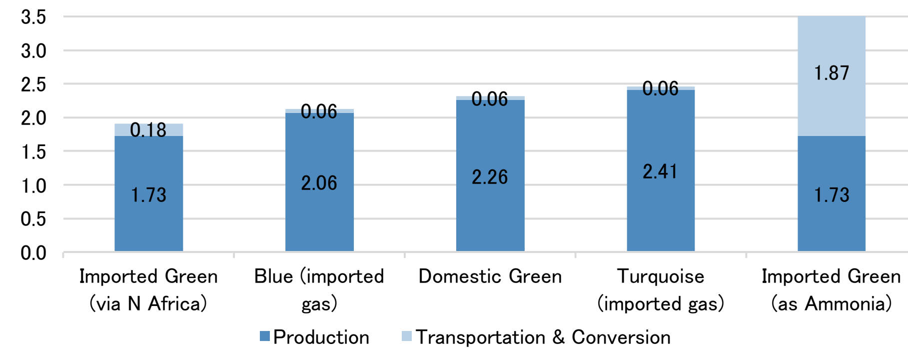
be transported to clients and we agree with Snam that pipelines would have a competitive advantage vs ships in such scenario.

Figure 127: Europe: green options likely to dominate supply
All-in LOCH 2030E, $/kg



Source: J.P. Morgan estimates, Company data.

- **Opportunities for electricity networks – the distributed electrolyzer model of deployment:** If the successful model is one built around distributed electrolyser capacity, then there would be a stronger rationale for the building of smaller-scale electrolyzers that can be fed with green energy from remote locations where the geographical and network connections allow for the developing of renewables with meaningful scale. This model would require incremental investments in electricity networks to ensure the supply of green power to the distributed electrolyzers.

- **Giga electrolyzers may be more favorable, at least in the initial stages:** While we believe that both development models will likely co-exist (with distributed electrolyzers playing a bigger role in the production of green hydrogen for transport and for peaker power plants), we believe the green hydrogen model is more likely to be developed around the concept of reaping scale benefits to bring a fast reduction in overall production costs and, hence, we believe that, at this early stage, the pipeline companies will be bigger beneficiaries than the electricity network companies (which, on the other hand, are the biggest winners from most other aspects of the Energy Transition, in our view).

- **Gas-fired generation to support variable RE and transform in the process:** We believe that, for gas-fired generation capacity, the development of green hydrogen could provide a very long-term opportunity to extend the duration of the investments made in a portion of the existing capacity. Gas peakers are set to play an increasingly important role from a security-of-supply point of view, as they are ideally fit to provide a manageable and fast reaction to dispatching instructions. We expect them increasingly to receive a fixed remuneration to reflect this status as back-up capacity and, hence, this would make their operation compatible with a very low number of hours in operation. As a result of their low load factor, they should be generating a low level of carbon emissions and, hence, be compatible with the first portion of the energy transition.

  However, they are not compatible with the full implementation of a net zero target and hence their adaptation to operating with green hydrogen as a fuel could represent the opportunity for the technology to survive beyond the next decade. At this stage, the economics of conversion of OCGTs and CCGTs to green hydrogen are not yet clearly established as the most economical option to play

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such a role of back-up capacity in the future. But, if the adequate technology is developed at the right cost, the existing plants could continue to use a meaningful proportion of the existing facilities (i.e. the connections to the pipeline system and to the electricity grid) and, hence, prolong the period through which a portion of the initial investments continue to generate cash flows. The first steps in this direction will be made by adding a blend of hydrogen to the natural gas to gradually reduce the emissions per MWh generated.

- **Gas supply is likely to see the biggest threat from the development of green hydrogen within the utilities' value chain:** In the end, gas suppliers should gradually adapt the duration and size of their portfolios of gas-sourcing contracts to incorporate a higher proportion of green hydrogen purchases; this, in the end, means a higher risk of finding themselves with undesired volumes of contracted gas. This threat should provide further momentum to the trend started last decade for gas suppliers to sign shorter-term more flexible contracts with gas producers, in our view. Besides, the appearance of green hydrogen should result in the emergence of new competitors in the "supply of molecules" business, particularly to industrial clients, where industrial gases companies may leverage on their existing client relationships to capture market share away from gas suppliers. Still, we see this as a very long-term threat and we believe gas suppliers should have enough time to rebalance their purchasing portfolios and adapt to the new competitive landscape.

More opportunity than threat

Both from the quantitative and timing point of view, we believe that green hydrogen is more an opportunity than a thereat for the utilities sector, as

1) The size of the potential opportunity in renewable power generation is significantly larger than the portion of gas supply earnings at risk. The opportunity to extend the duration of the investments made in the gas pipeline sector is a bonus for these pipeline companies vs the status quo, in our view.
2) Green hydrogen will not only replace natural gas, it will also replace oil-derivative products, particularly in mobility. In fact, mobility is likely to be one of the first sectors, together with ammonia production, where green hydrogen should be competitive, which should mean that the combination of green hydrogen and natural gas gain market share vs oil derivatives.

Green hydrogen has still a long way to go until it reaches cost parity with blue hydrogen and, even longer, to reach cost parity with natural gas. The latter will be largely dependent on political action to drive up the price of CO2 and internalize the carbon price in the price of gas for all the natural gas usages.

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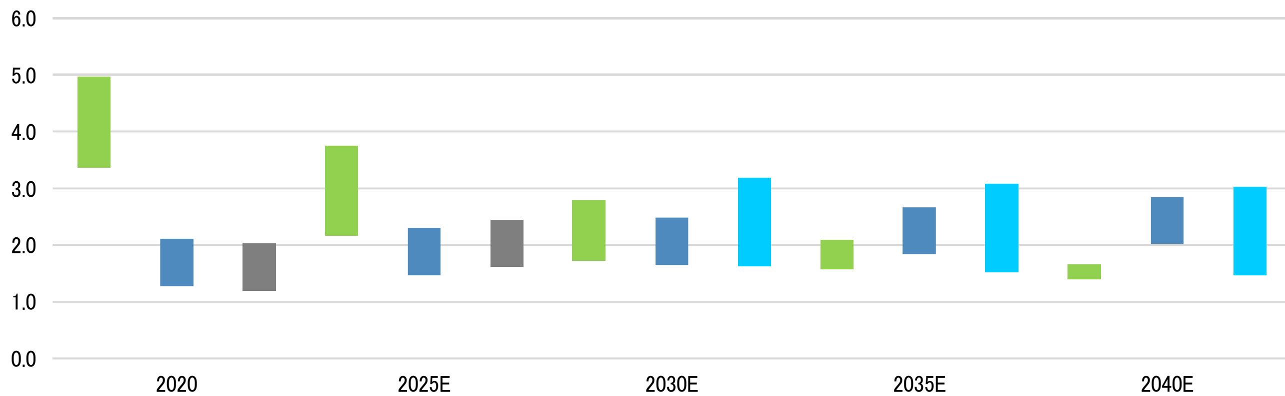
Figure 128: How will H_2 costs progress?

Green, Blue, Grey, and Turquoise Levelised Cost of H2 over time, $/kg



Source: J.P. Morgan estimates, Company data.

Most relevant stocks: Iberdrola, Orsted, Enel, RWE, Engie, Snam, Enagas, and Endesa

These utilities have been at the forefront of efforts to develop green Hydrogen and have announced several projects and strategic investments already. This is a very fluid space, with new projects and initiatives announced constantly by the European utilities. Recent noteworthy announcements include: 1) The Green Hydrogen Catapult Initiative in which seven companies, including Snam, Orsted and Iberdrola, will jointly attempt to scale up production of “green” hydrogen in the next six years and to halve the current cost of the fuel to below $2 per kg; 2) Endesa presenting a macro-plan for 340 MW of electrolyzer capacity, which would require investments totaling up to €2.9bn; and 3) Engie and Total announcing plans to develop France’s largest site for production of green hydrogen with 40MW of electrolyzer capacity. Numerous other projects, partnerships, concepts etc. have been unveiled by utilities.

Iberdrola, in fact, hosted a dedicated webinar on the subject of green hydrogen where it gave more color to how it views the technology and how it plans to play the space. Our key takeaways can be viewed in the published Daily.

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Table 37: EMEA Utilities involved in hydrogen

Company	JPM Rating	JPM Price Target	Materiality	Details
Iberdrola	N	€ 11.00	Small, but not minor	Multiple projects across geographies and value chain: Puertollano project for fertilizer co. Fertiberia, 'Green Hydrogen for Scotland' project for H2-Mobility, Iberlyzer – a new co. for integrating electrolyzers on a large scale
Orsted	OW	DKK 800.00	Pilot projects; so minor	Multiple hydrogen projects being studied for co-funding (e.g. BP Lingen factory project) or in pilot stage (H2RES and WESTKUSTE 100)
Enel	OW	€ 9.40	Pilot projects, so minor	Two projects – one for production of synthetic methanol (Haru Oni) in Chile and one with Eni in Spain
RWE	OW	€ 37.50	Pilot projects, so minor	Actively considering as many as 8 Hydrogen projects most of which are early stage (feasibility study or pilot)
Engie	OW	€ 17.00	Pilot projects, so minor	3 projects across technologies including high temperature electrolysers and H2-mobility; most are in pilot stages
Snam	N	€ 4.90	Increasingly material	Projects in partnership with FS and Alstom for H2-mobility (trains) as well as investments in players in the electrolyzer value chain (ITM, De Nora) along with multiple other MoUs (Rina, Tenaris) and agreements (CNHi)
Enagas	UW	€ 17.70	Small, but not minor	Green Hysland project which is being negotiated for EU funding; another project with Naturgy recently announced, being pitched for EU funds
Endesa	N	€ 25.70	Small, but not minor	Endesa has announced almost 23 projects in one 'macro-plan' for green hydrogen with a total electrolyzer capacity of 340 MW and investments totaling €2.9bn but we feel these projects will take long time to mature

Source: J.P. Morgan estimates, Company data.

Table 4: EMEA Utilities hydrogen projects/investments overview

Company	Tech. Research/Demo/Feasibility Study	Pending Investment Decision	Pilot Development WIP	Strategic Investments
Iberdrola	* Green Hydrogen Catapult		* Green H2 with Fertiberia * Green H2 for Scotland	* Iberlyzer: electrolyzer integration JV
Orsted	* Green Hydrogen Catapult	* Lingen Refinery project * Sluiskil Green Ammonia project	* H2RES Project * Westkuste 100 Project	
Enel	* MoU with FNM for green H2 in rail transport	* Joint pilot with Eni at Eni's refineries * Joint project with Rusnano in Russia * Joint project with NextChem in the US	* Haru Oni Project in Chile	
RWE	* NorthH2 Project with Shell, Equinor etc. * AquaVentus family of projects * Rostock project * LNG Terminal Brunsbuttel re-purposing	* Eemshydrogen Project * Joint project with ThyssenKrupp * Get H2 Nukleus Project		
Engie	* HyEx initiative with Eanex * MULTIPLHY: H2 for biofuels * Masshylia Project with Total		* HyGreen Provence	
Enagas	* Green Hysland Project			
Endesa	* Hydrogen Macro-plan			
Snam	* Green Hydrogen Catapult * Tenaris Steel Mill Project * Joint research with Israel's H2Pro * Joint Research with Israel's Dan * Study with Ferrovie del Stato on H2-mobility * MoU with A2A * MoU with Saipem * Joint project with Alstom for H2 Trains			* Stake in De Nora * Stake in ITM Power

Source: J.P. Morgan estimates, Company data.

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*Hydrogen could impact the European Cap Goods sector in several ways. Below, we summarise: 1) the upside potential for the European Wind OEMs from greater wind power demand to drive the EU's green H2 ambitions, 2) the potential for hydrogen trains and Alstom's initiatives in this area, and 3) Potential market opportunity in hydrogen electrolyzers for Siemens Energy and the impact of hydrogen on the future of gas turbines. Here, we highlight **Siemens Energy**, **Siemens Gamesa**, **Vestas**, **Alstom**, and **Wärtsilä** as most exposed to H_2.*

Table 38: Potential impacts of Hydrogen adoption in the EMEA Cap Goods sector

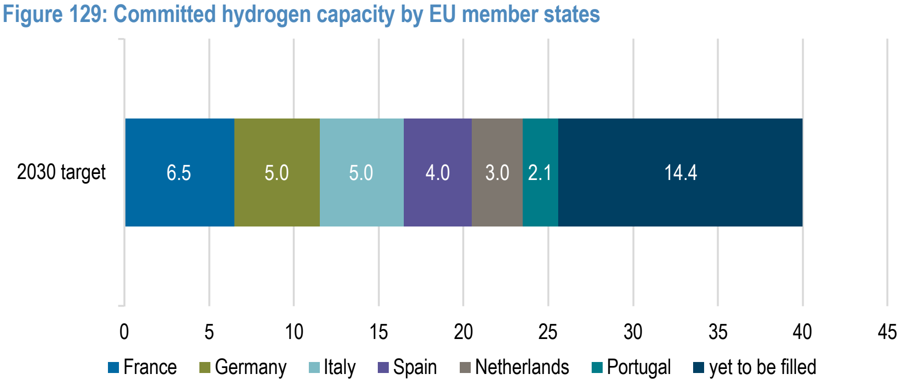
Area	Upside / downside risk	Detail
Power generation	Upside	Market opportunity for H2 electrolyzers. Use of hydrogen fuel in gas turbines improves market opportunity for peak power supply
Renewable Power gen	Upside	Upside driven by increased demand for renewable for electrolysis
Mobility	Upside	Positive for rail market as hydrogen trains to accelerate replacement cycle for diesel trains
Marine	Upside	Green Ammonia to decarbonize shipping. Upside for Wärtsilä if it drives an accelerated ship upgrade cycle with new engines capable of burning ammonia.

Source: J.P. Morgan estimates, Company data.

Wind power & hydrogen

The EU sees renewables and low-carbon hydrogen with potential to reduce greenhouse gas emissions ahead of 2030 and it will be a key building block towards a climate neutral and zero pollution economy by 2050. In the first phase, the EU sets a vision of achieving >6GW of renewable powered electrolyzers by 2024 and hydrogen produced is to be used for existing applications including rail. Under the second phase, the EU has a strategic objective to install >40 GW of renewable electrolyzers by 2040, with hydrogen in phase 2 being used in steel making, trucks and other transport markets. EU assumes it will required 80-120GW of renewable capacity to meet green hydrogen targets (wide range due to different load factors for onshore, offshore and solar). As summarized in the chart below, so far 6 EU countries have pledged ~25.6GW hydrogen capacity by 2030.

Figure 129: Committed hydrogen capacity by EU member states



Source: Bloomberg Finance LP

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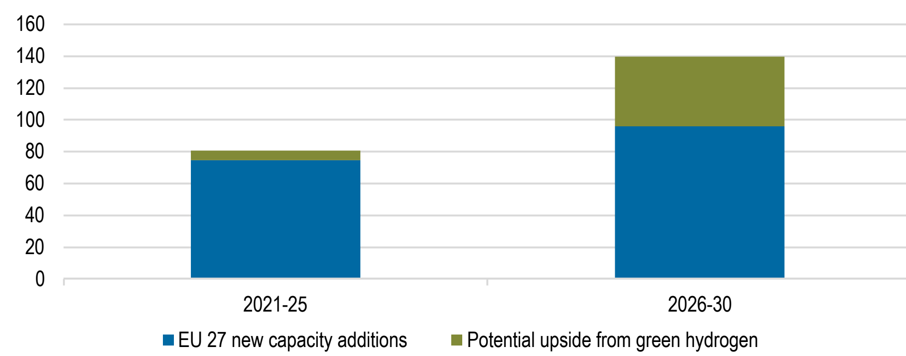
Renewables will be, by far, the key beneficiary of the EU hydrogen plan as the European Commission estimates more than 2/3rd of required investments for 2030 green hydrogen targets will go towards producing renewable energy (including balance of plant).

The key question is what will be the mix of renewable type to achieve the 2030 goal. Electrolysis of water is a very expensive way to produce hydrogen today and from a revenue point of view, we expect renewable hydrogen to be a meaningful driver only post 2025 when falling cost of both renewables and electrolyzers will boost competitiveness of green hydrogen. We believe the choice will depend on the country to account for LCoE (levelized cost of electricity) and availability of renewable resources and soft factors such as acceptability of larger wind turbines in their backyard. In countries like France, Germany and the Netherlands, we believe that wind, particularly offshore, could be the preferred choice of renewable energy for hydrogen, while in Southern Europe (Italy, Spain, Portugal) solar will be more competitive. While we expect solar to be overall winner of the hydrogen push, given the lower LCoE, we also expect hybrid renewables to gain more traction as a hybrid system will provide round the clock supply of renewable energy.

Several companies in Europe, including SGRE and Siemens Energy in our coverage, are working on demonstration hydrogen projects that should validate the technology and economics in the next couple of years. The chart below summarizes upside potential from EU green hydrogen plans on wind installations.

Figure 130: Potential upside from EU green hydrogen plan on wind demand

GW cumulative installed during the period



Source: Wood Mackenzie Q4'20 outlook and J.P. Morgan estimates assuming wind and solar each gets 50% share in 2030 targets

Hydrogen train opportunity

Transport & emissions

The transport industry accounts for a quarter of greenhouse gas (GHG) emissions in the EU. Unlike other major sectors that have seen a decline in GHG emissions vs. 1990 base, Transport has seen an increase of roughly 20% (see Figure 131). As part of the 2050 climate-neutral targets, GHG emissions from the transport sector need to come down by 2/3rd vs 1990 levels, which would mean that transport emissions need to reduce by >70% vs. most recent year for which data is available. Emissions from rail accounts for <2% of transport total (see Figure 132), making it the most environmentally-friendly mode of transport for both freight and passengers. The EU is taking a number of actions to reduce emissions from transport, including a push toward low-carbon rail from other modes and has announced 2021 to be a year of rail. The EU has also identified hydrogen and fuel cell technologies that could help decarbonize the transport sector. The EU published its hydrogen policy in June 2020,

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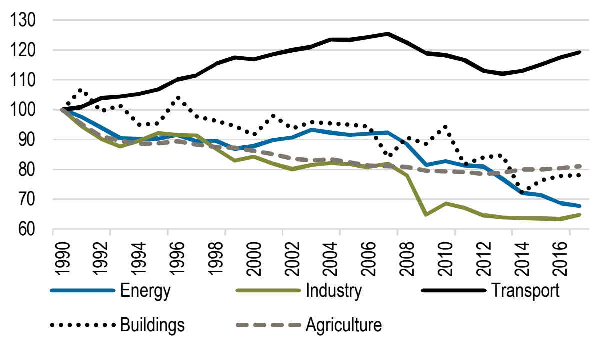
where it sees rail as a potential market to create demand for green hydrogen. Hydrogen train technology is already available in the market and is easy to deploy compared to other transport markets (e.g. cars or trucks) due to the limited number of refueling stations required in rail. We expect a push toward hydrogen in transport will be led by the rail industry despite contributing to the lowest share of emissions in the transport sector. As part of the EU's increased target of 2030 emission reduction to at least 55% (vs. 1990 levels) compared to 40% before, we expect the push to decarbonize the transport market to accelerate in the coming years.

Figure 131: EEA emissions by type

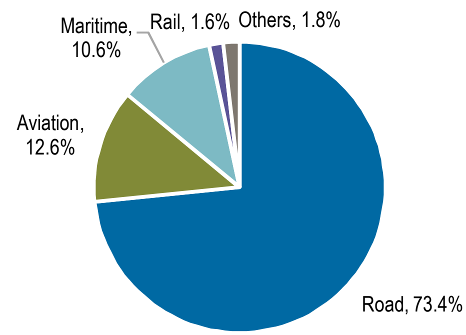
Indexed 1990 at 100



Source: European Commission

Figure 132: Transport sector emission by type

For the year 2017



Source: European Commission

Up to €50bn addressable market in Europe for hydrogen trains by 2035

According to the European Commission, ~40% of the railway track is unelectrified in Europe. This is primarily because most of these routes have low frequency of trains (the 40% unelectrified network handle just 20% of total traffic), making electrification uneconomical. Many operators use bi-mode diesel trains that run on electricity on electrified routes and are powered by diesel on non-electrified parts. Figure 133 and Figure 134 show share of diesel powered trains as a percentage of total and the percentage of rail lines (measured by length) that are not electrified. Our channel checks show that there are ~12,000 diesel powered rail cars corresponding to 3,600 diesel trains in operation in Europe. In our base case, we believe at least 75% of these will be replaced by green alternatives by 2035, where hydrogen-powered trains will be the key beneficiary.

We therefore estimate the hydrogen train market in Europe from replacement of existing diesel trains would be a €35bn-40bn (cumulative) revenue opportunity through 2035 (based on average price for hydrogen trains in recent Alstom orders). The addressable market rises to up to €50bn if we take the increased push to rail leading to demand for more trains as well as potential opportunities on replacing diesel locomotives. A hydrogen powered rail car is currently >2x expensive than a conventional electric rail car and therefore the replacement of diesel trains by hydrogen (rather than electric trains) leads to a higher addressable market for the OEMs. Despite a higher price tag, hydrogen trains are competitive on total lifecycle costs due to lower fuel consumption (high efficiency) and lower maintenance costs. An accelerated replacement of diesel trains before end of their useful life in Europe as well as commercial opportunities outside Europe would further increase the

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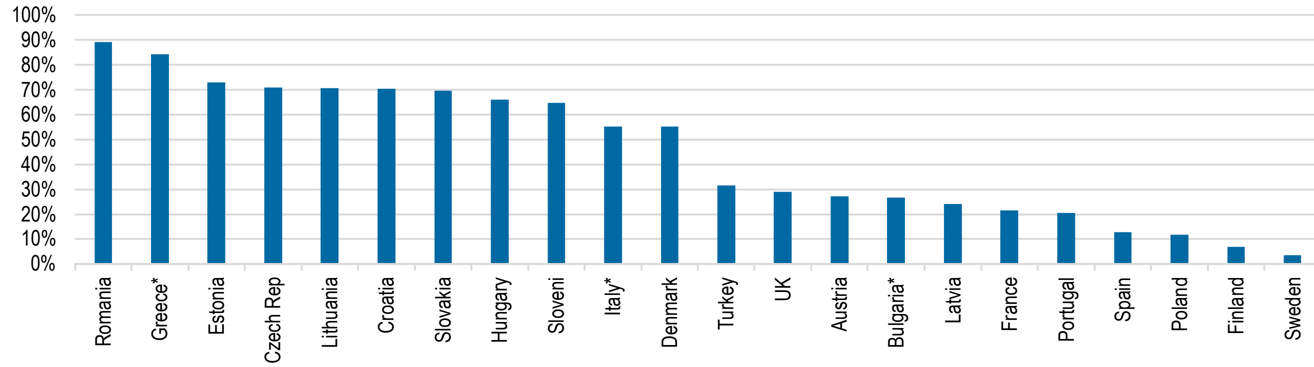
addressable market for the rail OEMs. On the other hand, a potential electrification of part of rail lines would reduce the market opportunity.

Figure 133: Share of diesel powered trains

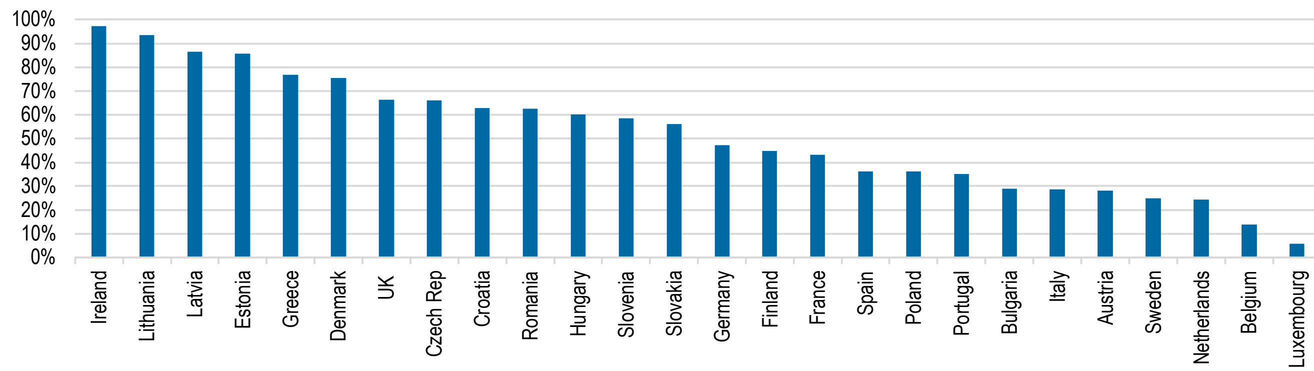
2018



Source: European Commission. *2010. No data for Germany but ~40% of German mainline network is not electrified.

Figure 134: Percentage of railway line unelectrified

2016



Source: European Commission

Where are different OEMs on hydrogen train development?

Alstom is the first and only rail OEM to have a hydrogen train in service. The company presented the hydrogen powered Coradia iLint at InnoTrans (the rail industry's largest trade fair) in Berlin in 2016. After two years the iLint entered into commercial service in Germany. Meanwhile, Stadler has won a couple of small orders for hydrogen trains. Deutsche Bahn and Siemens are working on a hydrogen train, which is to be trialled in 2024. Talgo has also announced a plan for hydrogen train which is to be ready in 2023.

Electrolysis – Siemens Energy

Market opportunity

Estimating the future market potential is difficult given the early stage of the development and importance of subsidies on the future development. Market growth rates estimates from firms such as Technavio and FutureMarketInsights put the market CAGR at 7-10% vs the low triple digit market size of 2019. These estimates would fall significantly short of the requirements resulting from the decarbonization

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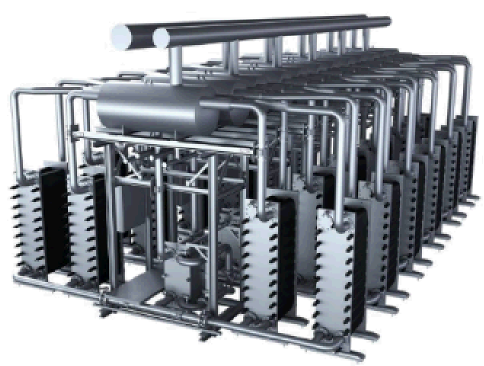
strategies announced, particularly by Europe. BNEF estimates a need of a global installed base of 3,200GW by 2050.

Siemens Energy Hydrogen offering and strategy

Siemens Energy Electrolyzer outlook: Siemens Energy has stated that it expects costs to grow faster than revenues to 2025 as the company develops higher efficient products and participates in demonstration projects. The Hydrogen division is accounted for under Corporate at Siemens Energy. Siemens Energy is to host a Hydrogen CMD on March 19 ,where we expect the company to flesh out its strategy and size the financial opportunity.

Siemens offering in Electrolysis: Siemens offers a PEM electrolysis system (Proton Exchange Membrane). Its Silyzer 300 can produce up to 2 tonnes of Hydrogen per hour with an efficiency ratio of up to 75%. It uses 10 liters of water for every kg of Hydrogen, resulting in a very high water consumption (20,000 liters per hour) one of the main concerns from an environmental perspective.

Figure 135: Siemens Silyzer 300 PEM Electrolyzer



Source: Siemens.

Offshore hydrogen alliance with SGRE: The proposed alliance for producing green hydrogen by Siemens Gamesa and its parent Siemens Energy is in line with our expectations and a good example of synergies between the two companies. The important piece of news announced so far is the adaptation of SG14-222, the largest offshore wind turbine under development, to incorporate electrolyzers at the bottom of the tower. Such a system would allow other customers to produce hydrogen at times when electricity demand is lower than supply and avoid curtailments. The development timeframe, with the two companies aiming for a system by 2025/26, highlights that green hydrogen development is a longer-term opportunity. However, with longer lead times in offshore wind, we would expect potential turbine orders could start to come through by end of 2022 or early 2023. For Siemens Energy, this alliance brings an opportunity to grow its electrolyzers business and the turnkey offering would allow it differentiate from competitors. However, there could be impact on SGRE long-term hydrogen prospects if it has to stick with a single provider of electrolyzers. The EU has a target of 40GW of green hydrogen through electrolyzers by 2030. We expect offshore wind to be the key beneficiary of green hydrogen plans in Northern Europe where countries including France (6.5GW), Germany (5GW) and Netherlands (3GW) have targeted at least 14.5GW of green hydrogen capacity by 2030. SGRE is the market leader in offshore wind and should

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be a key beneficiary of the any incremental offshore wind demand for green H_2 (albeit only likely post 2025E).

Announcement on Jan 13, 2021: Siemens Gamesa and its parent Siemens Energy have announced that they are joining forces to combine their ongoing wind-to-hydrogen developments. As part of the plan, the two re to invest €120mn over the next five years (SGRE €80mn, Siemens Energy €40mn) to develop an industrial scale system capable of harvesting green hydrogen from offshore wind by 2025/26. Siemens Gamesa is to adapt its development of the world's most powerful turbine, the SG 14-222 DD offshore wind turbine, to integrate an electrolysis system seamlessly into the turbine's operations. Each giant offshore turbine would have an electrolysis system with a capacity of 5-10 megawatts, Bloomberg reported citing Poul Skjaerbaek, Siemens Gamesa's chief innovation and product officer. Siemens Energy is to develop a new electrolysis product to meet the needs of the harsh maritime offshore environment and be in sync with the wind turbine. The fully integrated offshore wind-to-hydrogen solution aims to produce green hydrogen using an electrolyzer array located at the base of the offshore wind turbine tower, blazing a trail towards offshore hydrogen production. The solution should lower the cost of hydrogen by being able to run off grid, opening up more and better wind sites. The developments are part of the H2Mare initiative, which is a lighthouse project likely to be supported by the German Federal Ministry of Education and Research ideas competition "Hydrogen Republic of Germany".

Green Hydrogen use in power generation – Siemens Energy and Wärtsilä

By using green hydrogen in power generation, gas turbines and gas engines could produce electricity with no CO2 emission from the combustion effort. Today's gas turbines can already burn hydrogen mixed in with natural gas. They are generally located at chemical plants where hydrogen is generated as a byproduct and used to generate electricity. Most of these are older B and E class turbines. The challenge is that burning hydrogen in turbines results in very high temperatures and hence very high levels of NOx, at a level similar to coal plants. This means scrubbers would be used (Andritz supplies scrubbers to power plants). This adds up to another 30% to costs.

We don't believe that burning hydrogen for general power generation is a sensible use of the material in the near to medium term. It's not a very elegant or cost effective way to decarbonize. It does not make sense to build massive offshore wind farms or solar farms to generate electricity, converted at low efficiency in electrolyzers to hydrogen, transport it and store it next to power plants where it is burned creating of NOx to generate electricity again. Hence, we see its role for peak demand to complement renewables for time frames that batteries can't reach at a sensible costs. We expect bulk power gen to be "crowded out" by other industries where hydrogen can achieve more decarbonization per $ capex spent.

Siemens Energy hydrogen strategy

Siemens decided in its January 2019 roadmap to ramp up hydrogen capabilities at its gas turbines to adapt the technology so they can burn at least 20% hydrogen efficiently by 2020 and 100% by 2030. The targets stretch from its small gas turbines and aeroderivative turbines all the way to the large H frame. The key challenge for turbine design and material is the up to 300c higher temperatures. The company has already achieved a 100% target for its new aeroderivative turbines. Siemens is also working on a dry hydrogen technology given the high consumption of water

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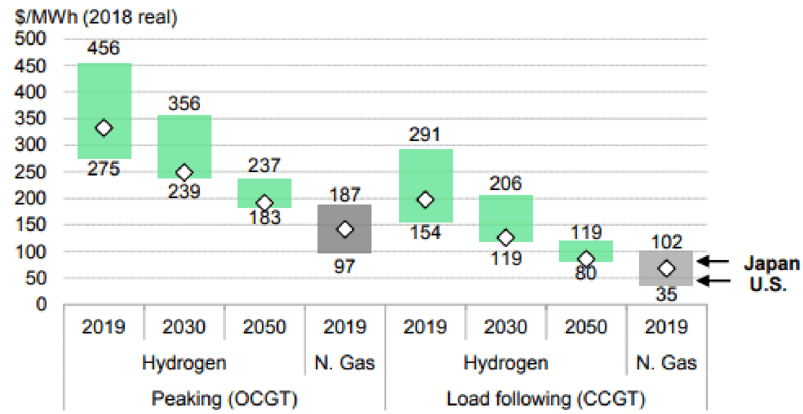
typically used for cooling (20,000 liters per hour). Siemens expects the first customers for heavy-duty 100% hydrogen turbines by the late 2020s, indicating that 100% hydrogen is not a commercial technology for some time.

Opportunity for peak power generation

With renewables likely to dominate power generation, H_2 could be used to provide flexible and dispatchable power to complement the intermittency of wind and solar – a role currently played by natural gas. The idea is to use excess renewable electricity that would otherwise be curtailed and so fuel costs would be zero. Hydrogen could be used to provide back-up power either through fuel cells or turbines. From an economic perspective the Hydrogen Council calculates that hydrogen needs to be priced at under $1.10/kg (~$7MMBTU) in 2030, with CO2 at $50/ton, and under $1.50/kg, with CO2 at $100/ton, for hydrogen to be competitive with natural gas and coal for industrial power use. BNEF suggests a carbon price of $50/ton with hydrogen at $1/kg to compete with mid-cost natural gas at $6-7MMBTU and a carbon price of USD 115/ton to compete with gas at $2MMBTU. Overall, BNEF Strong Policy scenarios see potential for 50% of gas peaking and load following generation to be replaced by hydrogen generating ~219Mta of demand.

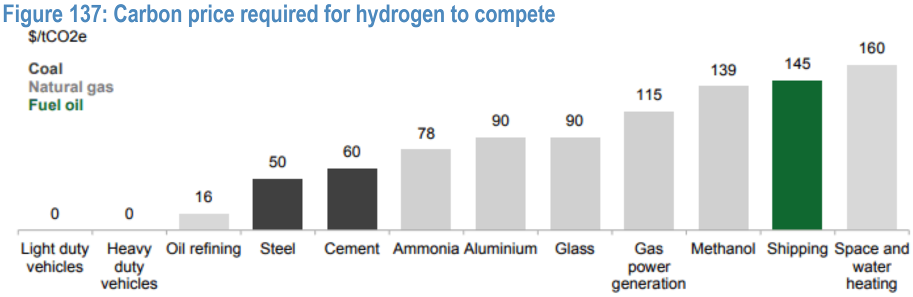
Figure 136: Potential LCOE of hydrogen fueled power plants



Source: BNEF, JP Morgan. Natural gas LCOEs vary with fuel price: $2-12mmbtu and do not include a CO_2 price.

A cleaner alternative is the use of hydrogen in fuel cells to generate power. The challenge is the high capex costs of fuel cells at around $5mn per MW or 3x that of combined cycle gas plant. Gas turbines or engines get cheaper per MW as they get bigger and, hence, can be scaled, which is not the case for fuel cells given the majority of the costs are expensive materials.

Figure 137: Carbon price required for hydrogen to compete



Source: BNEF, JP Morgan. Based on an $1/kg H2 price

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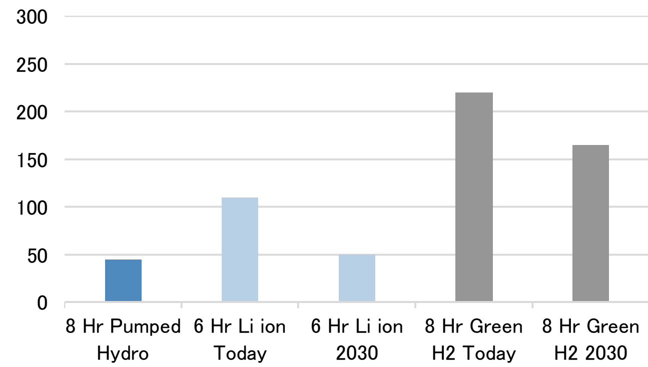
Figure 138: H2 for power grid regulation not yet economic

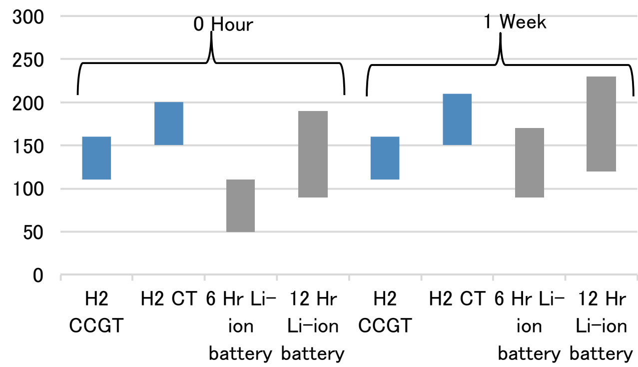
Levelised cost of storage, $/MWh



Source: E3, Company data.

Figure 139: ...but could compete in the long-term in some places

California levelised cost of storage in 2040, $/MWh



Source: E3, Company data.

Engines vs turbines for hydrogen burning

Wärtsilä has been developing its processing for hydrogen burning in its gas engines for the past 20 years. Its new turbine offering has been tested at up to 60% hydrogen in the mix. The company announced that it is exploring to allow its gas engines to run on 100% hydrogen.

Both engines and turbines can be converted to using H2 as a fuel but in turbines, the conversion to high shares of H2 requires change of major components since the air & combustion gas flow and respective heat do not follow the same linear behaviour as with conventional fuel. Based on published material, the limit comes with 30-40% hydrogen energy of the fuel. In reciprocating engines, the performance is not limited by a ratio of air & gas flow compared to heat and therefore the conversion of technology when shifting to H2 rich fuels is limited mainly to fuel handling components only.

NOx formation depends a lot on the combustion technique used. With a lean combustion concept (typical for today's natural gas engines), it is possible to get very low emissions performance, even with rich H2 mixtures, and thus NOx formation should not cause challenges for market introduction of hydrogen engines, according to Wärtsilä.

Marine

Use of ammonia in ship engines a major step towards decarbonizing the shipping industry

Wärtsilä has initiated combustion trials using ammonia. The research will help the company to prepare for the use of ammonia as a fuel that can contribute to reducing both the shipping and the energy sectors' greenhouse gas emissions. As part of the tests, ammonia was injected into a combustion research unit to better understand its properties. Based on initial results, the tests are to be continued on both dual-fuel and spark-ignited gas engines. These will be followed by field tests in collaboration with ship owners from 2022. The first tests have yielded promising results, according to the company.

Ammonia is a promising, carbon-free fuel, in our view, as shipping explores how to fulfil the International Maritime Organization's vision of reducing greenhouse gas emissions by at least 50% by 2050. Although ammonia is derived mainly from fossil

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sources today, ammonia's greenhouse gas footprint can be nearly eliminated if it is produced using electricity from renewable sources with hydrogen.

Wärtsilä is developing ammonia storage and supply systems as part of the EU project ShipFC to install ammonia fuel cells on Eidesvik Offshore's supply vessel Viking Energy by 2023. The company has also gained significant experience with ammonia from designing cargo handling systems for liquid petroleum gas carriers, many of which are used to transport ammonia.

Ammonia has a number of properties that require further investigation. It ignites and burns poorly compared to other fuels and is toxic and corrosive, making safe handling and storage important. Burning ammonia could also lead to higher NOx emissions unless controlled either by after-treatment or by optimizing the combustion process. A regulatory framework and class rules will need to be developed for its use as a marine fuel.

Wärtsilä has extensive experience in converting engines to other fuels, including diesel to dual-fuel, as well as engines capable of burning methanol and volatile organic compounds from crude oil cargoes. The modularity of modern engines means conversions can be made with a very limited exchange of components. Wärtsilä's investment in modular engines and in storage and supply systems should enable shipping's transition from current fossil fuels to bio- and synthetic fuels.

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EU's Renewable hydrogen supply targets

- **The EU aims to produce 1m tonnes of renewable hydrogen per annum by 2024, and 10m tonnes per annum by 2030 as part of its Hydrogen Strategy.**
- **Phase 1 (2020-24)** will be focused on facilitating take-up of renewable hydrogen in new end-use applications such as the chemical sector, other industrial processes and possibly in heavy-duty transport like rail.
- **Phase 2 (2025-30)** is expected to see renewable hydrogen gradually become cost-competitive with other forms of hydrogen production, and gradually include new applications, including steel-making, trucks, rail and some maritime transport applications, and other transport modes.

Table 39: Potential impacts of Hydrogen adoption in the EMEA Autos sector

Area	Detail
Chicken and egg problem - trucks and fuelling	Companies starting to focus on one-stop solutions, shifting to "freight/transport as a service" business models
Technology cost	High cost of powertrain for FCH trucks in the short-term and uncertainty on second life use
Gray-green H2 Costs	High fuel costs remain a barrier for widespread adoption. Unlike PCs, TCO for trucks and commercial vehicles is largely made up of running costs.
H2 storage technology	Dilemma of using 700 bar in the short-term vs. waiting for further development of LH2
Fuel cell stacks	Limited lifetime of FC stack and challenges in avoiding FC degradation
Synergies	Important to harvest synergies in production costs, infrastructure utilisation across industries like buses, LCVs/PCs, trains and maritime for the roll-out of trucks

Source: J.P. Morgan estimates, Company data.

Commercial vehicle roadmap by OEMs

- **Daimler and Volvo:** have formed a 50/50 JV to develop FCEVs in HD trucking. Plan to offer FCEVs by second half of decade.
- **Scania:** Four FCEV trucks delivered to Norwegian wholesaler ASKO in 2020. Further, Scania is also developing fuel cell refuse collection trucks with Renova, a waste handling company in western Sweden.
- **Hyundai:** Contract to deliver 1600 FCEVs to Swiss Commercial vehicle market from 2020-25. 7 trucks delivered as of Oct'20.
- **CNH:** 50/50 JV with Nikola to produce BEV and FCEV trucks for the EU market. CNH has a $250m stake in Nikola as a Series D investor. BEV deliveries to begin in 2021 and FCEV in 2023.
- **Hyzon Motors:** based in Groningen, Netherlands, expects to ship hundreds of fuel cell heavy vehicles by 2021.
- **VDL:** As part of the EU funded H2-Share project, 27ton FCEV truck manufactured by VDL has started testing with Breytner Group in Netherlands.
- **Renault:** FCEV range extender offered in Kangoo ZE and Master ZE Vans. Developed in partnership with Symbio (Michelin and Faurecia JV). Renault recently announced a partnership with Plug Power to make vertically integrated fuel cell stacks, manufacture systems, and provide hydrogen refueling stations, hydrogen fuel and services to customers.

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Suppliers working on Hydrogen

- **Michelin and Faurecia:** Created a 50/50 JV "Symbio" with a start-up capital of €140m to develop new fuel cells for commercial vehicles. Target to achieve a market share of 25% by 2030 and sales of around €1.5bn.
- **Plastic Omnium:** won an order from a German manufacturer for the development pf 350-Bar Hydrogen tanks for bus equipment.
- **Plastic Omnium and Elringklinger** created a JV called EKPO in October 2020 to focus on fuel cell stacks.
- **MAHLE** is developing a modular fuel cell systems portfolio focused on CVs.
- **Bosch** is to start large-scale production of the FCEV "stack", which converts hydrogen into electrical energy. Also partnered with Nikola to develop a 240kW fuel-cell powertrain for the Nikola Two HD truck. To further improve efficiency and manufacturing of these stacks, Bosch has allied itself with a Swedish manufacturer of fuel-cell stacks, Powercell Sweden AB.

Implications for Plastic Omnium

We run a few scenarios to evaluate different revenue opportunities for Plastic Omnium. Broadly speaking, if POM is able to achieve a 25% share in vessels and 15% in stacks, it would represent a ~€11bn revenue opportunity (bottom-right on the table below). **The table below shows us the range of revenue possibilities for Plastic Omnium in 2040, based on future development of market shares across different components**. This scenario assumes 2030 component costs of €330/kg for the H_2 tank and €50/kW for the cell stack and 0.5%-2% improvement in system efficiency per year. **This gives us a revenue range of €2bn-11bn in 2040. Our base case takes a 10% share across both technologies.** As Asia will form a considerable part of the future pie (China, Japan, Korea, etc), strategic partnerships and JVs will be key to harness that market potential and achieve targeted global market shares. We also should discount for other technologies (like liquid H_2 and 500bar) currently in development that could reduce the TAM going forward.

Figure 140: Plastic Omnium Revenue Potential 2040*: scenario analysis on key component costs
In € million

		Hydrogen tanks market share (%)				
		5.0%	10.0%	15.0%	20.0%	25%
Fuel cell stack market share (%)	5.0%	2,301	4,260	6,220	8,180	10,139
	7.5%	2,472	4,431	6,391	8,350	10,310
	10.0%	2,642	4,602	6,561	8,521	10,480
	12.5%	2,813	4,773	6,732	8,692	10,651
	15.0%	2,984	4,943	6,903	8,862	10,822

Source: J.P. Morgan estimates. ***Assuming 2030 vessel cost of €330/kg and fuel cell stack cost of €50/kW and further efficiency improvement over the next decade**

Risk of liquid hydrogen: Industry stakeholders still need to address H2 on-board storage, refueling station design and H2 supply chain as a whole. The aim is to identify the best overall TCO option with sufficient flexibility for logistics operators. **While LH_2 cryogenic liquid refueling will give the highest range on fuel cell trucks and potentially the lowest cost of on-board storage, the technology is still in development** and today there are only 3 hydrogen liquefaction plants in Europe. It looks like demand for hydrogen storage initially will be met by compressed gaseous refueling (350-bar and 700-bar pressure tanks). The 700-bar technology provides more flexibility for H2 sourcing (e.g. pipeline supply, on-site electrolysis production) and synergies between end applications (e.g. cars and other LDVs). **However, we should also note that further refueling/storage technology options like 500-bar**

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and cryo-compressed H2 are being investigated at R&D stage and could offer possibilities to improve the TCO economics in parts of the value chain.

Below, we have also run a few scenarios to value the hydrogen potential for Plastic Omnium today. The first table on the left hand side shows us the range of current hydrogen valuation (in €/share), based on 2040 TAM and market shares of 10% in tanks and stacks. If we assume POM can achieve and maintain these market shares in the hydrogen market, it would add €7 to the current share price on an assumption of 1x EV/Sales (on a mature market) and 8% equity risk premium, discounting back 20 years (this is our base case). **As the technology gets closer to the inflection point, we often see investors accepting lower rates of return to get exposure to limited quality assets. Valuation for electric vehicle OEMs and battery manufacturers is a key example of that today.** The second table on the right hand side shows how the €7/share changes on different market share assumptions on hydrogen tanks and fuel cell stacks.

Figure 141: Plastic Omnium Current Hydrogen valuation*: based on 2040 TAM and market shares
In € / share (for Plastic Omnium share price)

		EV/Sales				
		0.50	0.75	1.0	1.25	1.50
Equity risk premium (%)	3.0%	8	11	15	19	23
	5.0%	5	8	11	14	16
	8.0%	3	5	7	8	10
	10.0%	2	4	5	6	7
	12.0%	2	3	4	5	5

Source: J.P. Morgan estimates. ***Assuming 10% global market share in hydrogen vessels and 10% share in fuel cell stacks**

Figure 142: Plastic Omnium Current Hydrogen valuation*: based on 2040 TAM
In € / share (for Plastic Omnium share price)

		Hydrogen tanks market share (%)				
		5.0%	10.0%	15.0%	20.0%	25%
Fuel cell stack market share (%)	5.0%	3	6	9	12	15
	7.5%	4	6	9	12	15
	10.0%	4	7	10	12	15
	12.5%	4	7	10	13	16
	15.0%	4	7	10	13	16

Source: J.P. Morgan estimates. ***Assuming 1x EV/Sales and 8% equity risk premium**.

Implications for ElringKlinger

We have run a few scenarios to value the hydrogen potential for Elringklinger. The table below shows us the range of current hydrogen valuation (in €/share) based on 2040 TAM and mature market EV/Sales of 1.2x. If we assume EKPO can achieve a 10% market share (with no equity dilution in future) and we use an equity risk premium of 8%, it would add €4 (or €260m) to the underlying business. This is also shown as our base case in the valuation table below. The bullish top-right hand side scenario of ~€14/share reflects a 15% global share and high investor appetite to gaining hydrogen exposure as the technology is close to inflection point (reflected by the low equity risk premium). **Again, as a reminder, the base-case scenario does not factor in the electrolyzer market potential**, **which could roughly double the addressable market for EKPO by 2040**. <u>Based on different inputs, total hydrogen potential could be valued up to €28/share.</u>

Table 40: Elringklinger Hydrogen valuation*: based on 2040 TAM (on-road mobility)
In € / share (for Elringklinger share price)

		Fuel cell stack market share (%)				
		5.0%	7.5%	10.0%	12.5%	15.0%
Equity risk premium (%)	3.0%	4.6	6.9	9.2	11.5	13.8
	5.0%	3.3	5.0	6.7	8.3	10.0
	8.0%	2.1	3.1	4.1	5.2	6.2
	10.0%	1.5	2.3	3.0	3.8	4.5
	12.0%	1.1	1.7	2.2	2.8	3.3

Source: J.P. Morgan estimates. ***Assuming 1.2x EV/Sales on 2040 on-road mobility TAM**

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Table 41: EMEA Autos companies involved in Hydrogen

	JPM Rating	JPM Price Target	Materiality	Detail
OEMs				
Volvo	OW	SEK 235.0	R&D Investment, manageable transition	Formed 50/50 JV with Daimler to develop FCEVs in HD trucking. Plans to offer FCEVs by the second half of the decade
Daimler	OW	EUR 79.0	R&D Investment, manageable transition	Formed 50/50 JV with Daimler to develop FCEVs in HD trucking. Plans to offer FCEVs by the second half of the decade
Traton/Scania	NR	N/A	R&D Investment, manageable transition	Four FCEV trucks delivered to Norwegian wholesaler ASKO in 2020. Further, Scania is also developing fuel cell refuse collection trucks with Renova
Renault	OW	EUR 67.0	Low, focus on LCVs	Renault recently announced a partnership with Plug Power to vertically integrated fuel cell stack and system manufacturing, provide hydrogen refueling stations, hydrogen fuel and services to customers.
Stellantis (PSA Group)	OW	EUR 18.0	Low, focus on LCVs	Groupe PSA, a part of Stellantis, will launch a fleet of LCVs in 2021, namely, Peugeot Expert, Citroen Jumpy and Opel Vivaro
Suppliers				
Michelin and Faurecia	OW	ML: EUR 125.0, EO: EUR 60.0	Medium for Faurecia, >30% of current profitability comes from ICE	Faurecia working on tanks and system integration. Also created a 50/50 JV “Symbio” with a start-up capital of €140m to develop fuel cell stacks for commercial vehicles
Plastic Omnium	OW	EUR 40.0	Medium, eventually fill-in for declining fuel tank sales in PCs	Plastic Omnium is aiming for a 25% market share in hydrogen tanks, similar to its share in ICE fuel tanks. Plastic Omnium and Elringklinger also created a JV called EKPO in October 2020 to focus on fuel cell stacks. POM targets €3bn revenues by 2030, 2/3rd of it coming from tanks.
Elringklinger	N	EUR 9.0	High, share price already builds in high value for future hydrogen business	Plastic Omnium and Elringklinger created a JV called EKPO in October 2020 to focus on fuel cell stacks. Elringklinger owns 60% of the JV and will consolidate the JV on its books.

Source: J.P. Morgan estimates, Company data.

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A limited decarbonization opportunity in the cement sector

We highlighted in a recent report ('European Cement: Revisiting consequences from Phase IV of the EU-ETS and discussing the path to decarbonization'), that due to the size of "process emissions" (2/3 of the total emissions from the cement manufacturing process), we believe carbon capture storage (CCS) technology is the ultimate path to full decarbonisation for the cement sector, beyond optimising energy efficiency of plants, and decreasing the clinker ratio and the use of greener fuels.

However, for the remaining third of emissions that need to abated, we also highlighted the potential opportunities presented by the use of hydrogen in reducing emissions from the cement manufacturing process. Moreover, we believe that the development of CCS for blue hydrogen should contribute to the reduction of CCS project costs and, therefore, indirectly benefit the sector.

Table 42: Potential use / opportunities of hydrogen in the cement sector

Area	Upside / Downside Risk	Detail
Substitute to fossil fuel for kiln	Upside	Possibility to power cement kiln with H2 & Plasma instead of fossil fuels. This would reduce direct emissions linked to energy consumption. However, this would require to use green H2 to deliver carbon reduction over the life cycle. For this technology to break even vs. current fossil fuel usage, green / low carbon H2 costs should go down, and / or fossil fuel prices should go up.
Deployment of H2 could help cost reduction in CCS infrastructures	Upside	As per our December study, we expect CCS to remain the ultimate decarbonisation technology that will tackle the majority of the process emissions. As such, the roll out of a Hydrogen value chain, esp. if accelerating blue H2, should accelerate the reduction of CCS costs, and benefit to cement companies.
Use of excess O2 from green H2 production as part of industrial clusters	Upside	Excess O2 produced during Green H2 production can be used in the combustion process of cement plant.
CO2 captured from cement maker can be used with O2 to produce syngas	Upside	As CCS will be necessary to reduce cement's GHG emissions, the captured CO2 could be used as a feedstock to produce syngas (e.g. Methanol)

Source: J.P. Morgan estimates, Company data.

Key coverage initiatives

Two companies are part of pilot projects, albeit this does not represent a material investment opportunity.

HeidelbergCement: In the UK, the company is investigating a switch from the use of fossil fuels to hydrogen and plasma technology. The project at the company's Ribblesdale plant was funded by a £3.2m award from the Department for Business, Energy and Industrial Strategy (BEIS). Essentially, what is being investigated here is the use of hydrogen as fuel for within the kiln, which could substantially lower emissions produced given that water is produced during this combustion process. However, at present the majority of Hydrogen is currently produced using fossil fuels, which may be conflicting with the overall objective of reducing fossil fuel emissions.

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LafargeHolcim: is also involved in a CCS project in Austria and Spain. In Austria, the project dubbed 'Carbon2ProductAustria' is a collaboration between LafargeHolcim, OMV, Verbund and Borealis. The objective is to operate a full-scale plant by 2030, which will eventually capture c100% of LafargeHolcim's Mannersdorf (Austria) plant (0.7mt). As part of the project, green hydrogen produced by Verbund, will help convert the transformation by OMV of the captured CO2 into renewable based hydrocarbons, which can be used to produce renewable based fuels or used by Borealis as a product to manufacture value-add plastics. Also, a further project being conducted in Europe by LafargeHolcim, labelled Westkuste100 (see our list of H2 industrial clusters), is to use Oxyfuel technology (a type of CCS technology), which will then involve surplus oxygen from hydrogen production (by 100% green power) being fed into the plant's combustion process. The high-purity CO2 will then be captured and used as a raw material in industrial-scale methanol production.

Also, during the J.P.Morgan Carbon Cement ESG Seminar (link to our feedback report), **Vicat** (not covered) highlighted the potential benefit of using Hydrogen after capturing carbon, stating that by combining CO2 with hydrogen they may be able to produce methanol. The company said that in a project it is working on, hydrogen can cut more than 30% of total CO2 emissions of a considered plant.

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In European Chemicals, multiple companies are already exposed to the hydrogen market or are likely to have exposure to it in the future. At this stage, we don't expect the likely increase in the adoption of hydrogen to have a very material positive or negative impact on the earnings of European chemical companies over the next 3-5 years. There is a promise of better upside for a few companies over the very long-term but this is difficult to assess given a number of moving parts. In Table 43 below, we show the current and possible future exposures of European chemical companies to the hydrogen supply chain.

In European Chemicals, there tends to be greater focus on the opportunity for industrial gases companies from the potential transition to hydrogen energy. Air Liquide continues to see the role for natural-gas based hydrogen production in the future with the CO2 intensity of this production process (which is currently high) reduced by the adoption of carbon capture and sequestration technologies. As can be expected, Air Liquide aims to play a leading role in the production, packaging, transportation and storage of green or renewable hydrogen. The company's management has previously highlighted the potential upside from hydrogen transition to be a 2025+ opportunity.

While green hydrogen ecosystems and the very long-term growth opportunities are continuing to evolve, we see possible pros and cons from this potential green hydrogen transition for Air Liquide. Specifically, the company already generates a very significant ~€2bn sales (~10% of group sales) per year, with high margin and returns, from selling natural-gas based (CO2 intensive) hydrogen, primarily to oil refining companies to produce transportation fuels. Some of this existing, high-return, hydrogen earnings stream might see structural growth headwinds from the transition to EVs and hydrogen vehicles as this transition will likely negatively impact the demand for transportation fuels. On the other hand, new growth opportunities from the blue/green hydrogen market might come with a tougher competition (from utility and oil & gas companies, for instance) than is the case currently in the natural-gas based (grey) hydrogen production/distribution market, and also likely lower returns, at least in initial years.

The exposure of other European chemical companies to the hydrogen supply chain is primarily on the supply of polymers/components used through this supply chain.

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Table 43: Known exposure of the European Chemical companies to the hydrogen ecosystem

Company	Summary exposure/thoughts	Grey H2 exposure	Blue/Turquoise H2 exposure	Green H2 exposure	Other H2 supply-chain exposure
Air Liquide	Leading grey H2 production/distribution player, currently ~10% of group sales. Likely to be an important player in blue H2. We see possible pros and cons from the potential green H2 transition for Air Liquide long-term – some existing high-margin / high-return grey H2 will likely to see structural growth headwinds while green H2 opportunity to come with lower returns, more competition vs grey H2 today.	Production/Distribution	Production/Distribution of Blue H2 with Carbon Capture	Production/Distribution	
Arkema				Possibly for polymers for the production of membranes used in electrolysers in the future	Possibly for fuel cell membrane polymers in the future
BASF			Company working to commercialize low-carbon methane pyrolysis process.	Possibly electrolyser coated catalyst membranes (CCM) polymers in the future	Existing coated catalyst membranes (CCM) supplier for fuel-cells. Possibly for fuel cell membrane polymers in the future
Clariant		Leading supplier of chemical catalysts used for grey H2			
Evonik				Possible for electrolyser membrane polymers in the future	Possible for fuel cell membrane polymers

Source: Company data; J.P. Morgan estimates.

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Table 44: Known exposure of the European Chemical companies to the hydrogen ecosystem (continued)

Company	Summary exposure/thoughts	Grey H2 exposure	Blue/Turquoise H2 exposure	Green H2 exposure	Other H2 supply-chain exposure
Johnson Matthey	Exposure to different elements of H2 ecosystem. Leading share in catalysts for grey H2 market which might decline in the long-run due to decline in transportation fuel consumptions & transition to green H2. Offset from potential upside from green H2 opportunity in the long-term not yet clear.	A leading supplier of chemical catalysts used for grey H2 production with ~40% share.	JMAT has a solution for low-CO2 H2 production process.	Company is qualifying its products for the CCM market for the electrolysers.	Catalyst coated membrane (CCM) & membrane electrode assembly (MEA) component supplier for fuel-cells
Solvay				Possibly for polymers for the production of membranes used in electrolysers in the future.	Possibly for fuel cell membrane polymers in the future. Possible carbon-fiber based composite supplier used in H2 storage tanks.
Umicore				Can theoretically supply CCM for electrolysers. Not known if this is material for sales.	A leading supplier of catalyst coated membrane (CCM) for the fuel-cells
Victrex				Possibly for polymer membranes used in electrolysers long term	Possibly for polymers in fuel cell membranes
Yara		A significant captive grey H2 producer for ammonia production used in nitrogen fertilizers.		Aims to use green H2 in its nitrogen production, subject to public funding as green H2 use will likely materially increase ammonia production costs	
OCI		A significant captive grey H2 producer for ammonia (nitrogen fertilizers).		No specific plans announced but likely similar strategy as Yara long-term.	

Source: Company data; J.P. Morgan estimates.

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Within our Machinery, Engineering & Construction coverage, we see the largest impact of a developing hydrogen economy on those most levered to heavy truck production and stationary power generation. Hydrogen fuel cell electric vehicles (FCEVs) have emerged as a plausible zero-emission technology for long-haul heavy duty trucks rather than battery electric vehicles (BEVs) due to the longer range and minimal payload capacity reduction. However, we note that the cost of a Class 8 FCEV is substantially higher than a diesel truck and that hydrogen refueling infrastructure is limited. Additionally, renewable (green) hydrogen (central to decarbonization) is prohibitively expensive, given high costs of renewable energy, electrolyzers and distribution. Within our coverage, CMI (following its acquisition of Hydrogenics in 2019) has become a leader in the development of scalable alkaline and PEM electrolyzers in addition to its fuel cell technology. CMI hosted its first *Hydrogen Day* event in November 2020, where senior management presented the company's hydrogen strategy as a supplier of both electrolyzers and fuel cells. It is targeting: 1) at least $400m in electrolyzer revenue in 2025 (at an assumed price of $750,000/MW); and 2) the supply of >100 fuel cell systems for hydrogen-powered trains ($100,000-500,000 revenue opportunity per train).

Table 45: Potential impacts of Hydrogen adoption in the US Machinery & Construction Sector

Area	Upside / Downside Risk	Detail
Truck OEMs	Upside & Downside	Mixed outcomes depending on strategy (i.e., vertical integration or partnerships); we view partnering as a more prudent strategy
Component Suppliers	Downside	Alternative powertrains displace legacy component businesses; zero-emission parts require R&D investment and reshape competitive dynamics

Source: J.P. Morgan estimates, Company data.

Cost Considerations

- **Renewable "green" hydrogen costs are high.** Although "grey" hydrogen is available today via natural gas (at a much cheaper price point), the decarbonization of transportation utilizing FCEVs can only be achieved through the expansion of renewable "green" hydrogen as well as "blue" hydrogen ("grey" hydrogen with carbon capture and storage). Today, CMI estimates renewable energy costs of $2.50-5.00, electrolyzer costs of ~$0.60 and distribution costs of $4.00-7.00 to produce just one kg of green hydrogen utilizing centralized production (comparable to one gallon of diesel). However, we note that: 1) on-site hydrogen generation greatly reduces distribution costs; and 2) renewable energy and electrolyzer costs are expected to continue to fall rapidly. As an example, the price of CMI's electrolyzers is currently $1m/MW and is expected to fall 5% annually to $750,000/MW in 2025. We acknowledge Nel's (a competitor to CMI's electrolyzer business) $1.50/kg green hydrogen target for a large-scale renewable hydrogen production facility by 2025.
- **Class 8 FCEVs are expensive vs. diesel-powered vehicles.** We estimate a long-haul Class 8 FCEV would cost ~$360,000 today, largely driven by fuel cell costs of $600/kW, which implies $144,000 for a 240kW application. Other key component costs include the hydrogen tank(s) (~$47,000), the battery (~$34,000), the electric motor (~$25,000) as well as other integration/equipment costs. Assuming a comparable new diesel tractor costs ~$150,000, steep component

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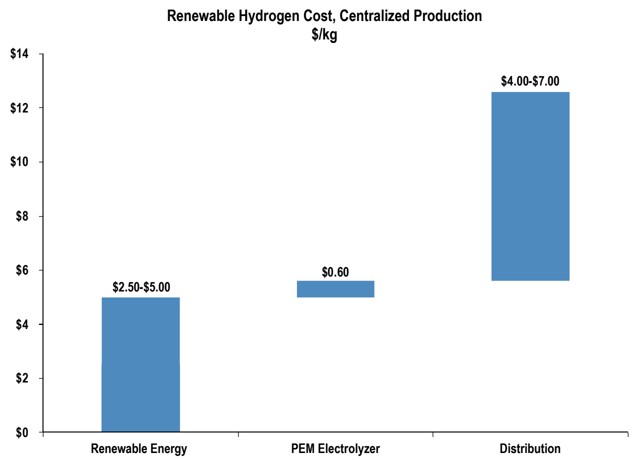
cost reductions and/or fiscal incentives will be imperative for FCEVs to be competitive in the near/medium term. Therefore, we do not expect FCEV production to represent a material part of revenues for our coverage until at least the second half of this decade.

Figure 143: Renewable hydrogen costs remain elevated



Source: CMI company reports

Figure 144: We estimate A Class 8 FCEV would cost ~$360k today

Fuel Cell Truck Assumptions	
Estimated Chassis Cost ($)	$80,000
Fuel Cell System Cost ($/kW)	$600
Fuel Cell Power Requirements (kW)	240
Total Fuel Cell System Cost ($)	$144,000
Hydrogen Tank Capacity (kWh)	2,031
Hydrogen Tank Cost ($/kWh)	$23
Total Hydrogen Tank Cost ($)	$46,720
Battery Cost ($/kWh)	$137
Battery Capacity (kWh)	250
Total Battery Cost ($)	$34,250
eAxle Cost ($)	$25,000
Additional Systems ($)	$10,000
Estimated Hydrogen Tractor Cost ($)	$339,970
Profit Margin (%)	6%
Estimated Hydrogen Tractor Price ($)	**$360,368**

Source: J.P. Morgan estimates, CMI company reports, NKLA company reports, ALSN company reports, BNEF, ICCT, FCH JU

Key coverage initiatives

- **CMI (N):** By far the most active participant in the developing hydrogen economy within our coverage universe (especially since its acquisition of electrolyzer/fuel cell supplier, Hydrogenics, in 2019), CMI has numerous projects announced, recently completed or in progress, including: 1) it recently constructed a 20MW PEM electrolyzer plant in Canada with the capacity to produce >3,000 tons of hydrogen per year; 2) it was recently awarded >$7m (two separate grants) by the US Department of Energy for PEM stack and fuel cell powertrain development; it is collaborating with NAV to develop a Class 8 FCEV utilizing a portion of these funds; 3) it announced a contract to install a 5MW PEM electrolyzer for Douglas County Public Utility District in Washington (expected to be operational in 2021); 4) it is opening a fuel cell assembly facility for hydrogen trains in Herten, Germany, with 10MW of annual capacity in July 2021 and; 5) Australia-based Bustech is to use CMI's fuel cell and battery-electric technology on its new bus fleet starting in late-2021/early-2022. To-date, CMI has installed >2,000 fuel cells (mostly MD trucks and buses) and >500 electrolyzers across a variety of applications.

- **CNHI (OW):** In 2019, CNHI announced a 50/50 European manufacturing JV between its commercial vehicle brand, Iveco, and startup heavy duty truck OEM, Nikola Motors (NKLA covered by JPM Alternative Energy Analyst, Paul Coster) in addition to its $250m Series D investment (earlier in 2019). The focus of the JV is the Nikola TRE, a highly anticipated heavy duty truck model (based on the Iveco S-Way) that will be offered in BEV (2021) and FCEV (2023) versions.

- **PCAR (N):** Under a partnership with Toyota Motor North America, PCAR has developed several Class 8 Kenworth T680s utilizing Toyota's fuel cell technology for use in the Port of Los Angeles with refueling infrastructure support from Shell. Of its three brands, Kenworth is the standard bearer for FCEV development (vs. Peterbilt for ICE and DAF for BEV), though the technologies are available across the portfolio.

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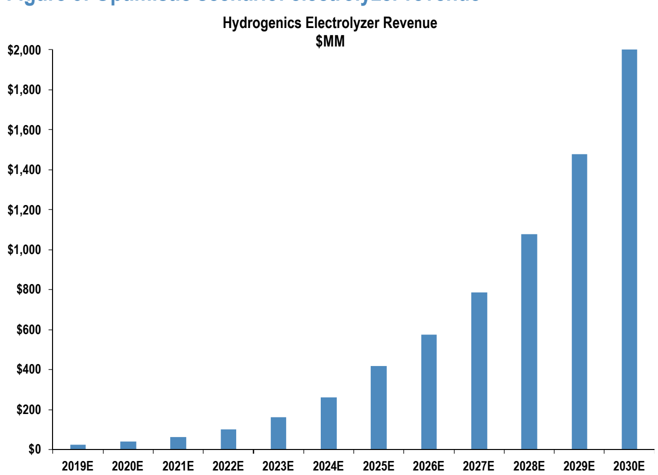
Coverage views

- **CMI (N):** The company has presented a compelling two-pronged strategy including: 1) the supply of PEM and alkaline electrolyzers for renewable hydrogen production and; 2) the supply of fuel cells into rail, on-highway and stationary power applications. We have concerns regarding electrolyzer commoditization and the profitability of this business, longer term, as well as the cannibalization risks associated with fuel cell deployment, as each FCEV conversion likely represents a displaced diesel engine (though not necessarily a CMI engine).

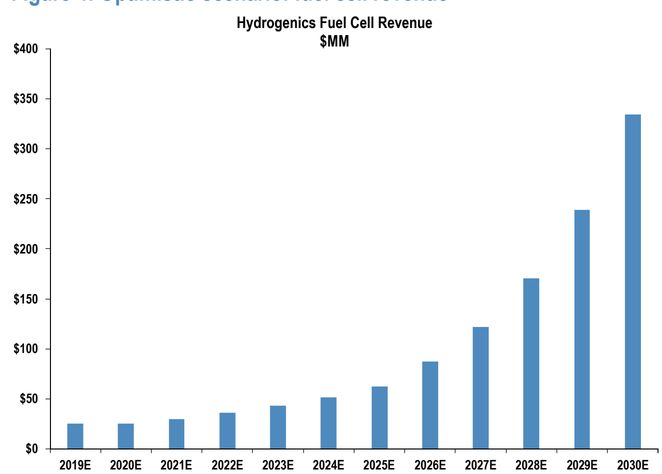
  At its first ever *Hydrogen Day* last November, the company targeted at least $400m in electrolyzer revenues in 2025 assuming a 15% share of a ~3.5GW electrolyzer market at a price of $750,000/MW (down 5% annually from $1m/MW today). This implies an annual CAGR of ~60% from a 2019 base of $25m (JPMe) and the business, *under an optimistic* scenario, could achieve a ~37% CAGR from 2026-2030 to reach revenues of ~$2bn. Under a similar *optimistic* scenario, CMI's fuel cell business could see annual growth of ~20% from 2021 and ~40% from 2026-2030, reaching revenues of ~$330m. To put this into context, the combined 2030 fuel cell and electrolyzer revenue would represent only ~10% of CMI's 2019 revenue and, therefore, we remain cautious.

Figure 3: Optimistic scenario: electrolyzer revenue



Source: CMI company reports, J.P. Morgan estimates

Figure 4: Optimistic scenario: fuel cell revenue



Source: J.P. Morgan estimates

- **CNHI (OW):** Its partnership with Nikola Motors provides a distinct competitive advantage in Iveco's core European markets (in addition to its industry leading natural gas offering) as the EU phases in stricter emissions requirements for commercial vehicles. The 50/50 manufacturing JV will further enable Iveco to capture super credits until 2024 (and benchmark-based credits thereafter) to help achieve EU fleet-wide average CO_2 emissions reduction targets of 15% and 30% in 2025 and 2030, respectively (which may be revised upwards upon review of the regulation in 2022).

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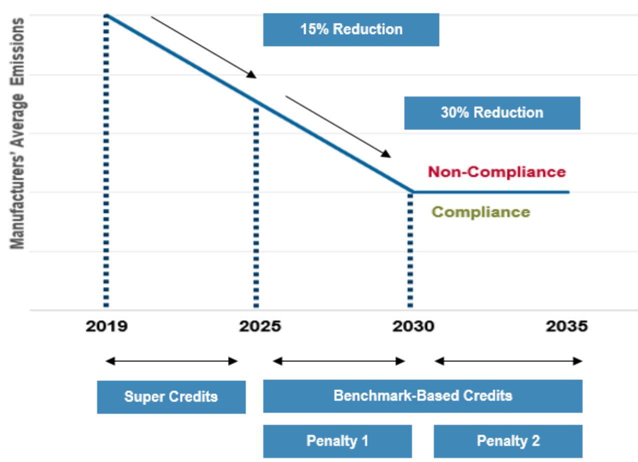
Figure 5: Regulation (EU) 2019/1242 emissions standards timeline



Source: European Commission, J.P. Morgan

Figure 6: Credits & penalties summary

Super Credits 2019-2024	▪ ZEVs: 2x multiplier ▪ LEVs: 1x-2x multiplier depending on emissions level ▪ 3% cap on credits to preserve environmental integrity
Benchmark-based Credits 2025-onwards	▪ 2025: 2% ZLEV share benchmark (≥0.75% must be vehicles subject to CO_2 targets) ▪ 2030: benchmark to be set in 2022
2025 Penalty	▪ €4,250 penalty per gCO_2/tkm above 15% reduction target level
2030 Penalty	▪ €6,800 penalty per gCO_2/tkm above 30% reduction target level

Source: European Commission, J.P. Morgan

- **PCAR (N):** The company continues to position itself as powertrain agnostic, which is evident in its continued innovation across fuel cell electric, battery electric and internal combustion powered vehicles; its strategy includes: 1) push pilot tests in the near term; 2) ensure it has dealer and service capabilities for all technologies; and 3) create flexible manufacturing facilities that can seamlessly produce vehicles utilizing all types of powertrains. Therefore, we believe that its strategy for alternative drivetrains is best-in-class as it is supporting the development of a viable supply chain while taking a conservative, though measured, approach to broader commercialization.
- **ALSN (UW):** The focus on lower emissions and the emergence of alternative drivetrains poses significant risks to its core NA business, long term. In the meantime, ALSN has increased R&D and M&A spend to react to the potential changes in its end markets as it tries to pivot as an integrator/supplier of alternative drivetrains and, as such, we believe that its margins may have peaked and the risks appear weighted to the downside from here.

Table 46: US Machinery, Engineering, & Construction companies involved in hydrogen

Company	JPM Rating	JPM Price Target	Materiality	Detail
Cummins Inc.	N	$255	Increasingly material	Targeting >$400MM in electrolyzer revenue by 2025 and >100 fuel cell train applications
PACCAR Inc.	N	$101	Pilot projects, minor for now	Pilot projects through Kenworth/Toyota North America Class 8 FCEV partnership
CNH Industrial	OW	$15.50	Increasingly material	50/50 European manufacturing JV with Nikola Motors; Nikola TRE (based on Iveco S-Way) will be offered in BEV (2021) & FCEV (2023) versions
Allison Transmission	UW	$36	Very minor	Core markets will transition to BEVs providing new competitors with access to its existing business and dominant market share

Source: J.P. Morgan estimates, Company data.

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Oil, hydrogen expectations heading in opposite directions

In the wake of 2020's epic strategic shift by European IOCs away from O&G production and the European Union's emphatic push for a zero emission economy by 2050, we've been fairly amazed by the pace of sentiment shift among investors towards the warm embrace of renewables, though we're less surprised to see the stiffer headwinds to O&G share prices. Solar and wind's decades-long path to respectability as energy sources has caught the attention of many hardened, cynical energy investors, and we suspect few want to be caught napping on a hydrogen break-through. We posit that many of the billions raised in the coming years will likely be destroyed in such a pursuit, but potentially to the long-term benefit of humanity, with many parallels to the capital cycle of shale (particularly shale gas) in the US over the past two decades.

While not all will be successful, we expect the engineering-heavy and offshore-oriented parts of USOFS to attempt to pivot towards new energy solutions, including the hydrogen value chain

Figure 145: Hydrogen and new energy: U.S. OFS sector impact

Area	Upside / downside risk	Detail
Diversifieds	Upside & Downside	Engineering expertise across onshore and offshore services can be applied across the value chain; acceleration of hydrogen may erode demand for traditional O&G services
Capital Equipment	Upside & Downside	Subsea expertise can be levered to build out required infrastructure for renewables (e.g. offshore wind) and storage; acceleration of hydrogen may erode demand for traditional O&G services
Energy Distributers	Upside & Downside	Opportunities exist to supply hydrogen end markets; acceleration of hydrogen may erode demand for traditional O&G services
Land Drillers	Downside	Acceleration of hydrogen may erode demand for traditional O&G services
Onshore Services	Downside	Acceleration of hydrogen may erode demand for traditional O&G services
Offshore Drillers	Upside & Downside	Subsea expertise can be levered to build out required infrastructure for renewables; acceleration of hydrogen may erode demand for traditional O&G services

Source: Company filings.

Hydrogen: just a new molecule to master

While the acceleration to hydrogen is a headwind for traditional upstream O&G spending (and thus OFS companies), we still see a unique opportunity set for select companies to utilize existing engineering expertise and play a meaningful role in the space. Prospects for service companies encompass the full value chain and include MMO, transportation and infrastructure, rigs, and engineering across the full hydrogen rainbow. As more projects come online and spending is unlocked, Rystad estimates that the value of the opportunity could be ~$400mm for OFS companies by 2035, with green hydrogen projects alone commanding ~63 GW in capacity. If CCS can come to scale, the potential competitiveness of blue also screens well for our LNG-levered stocks. Among our NAM OFS coverage, FTI, BKR, and SLB appear to be the best positioned so far among those vying to become major players in the space.

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Figure 146: US OFS company relevance

Area	JPM Rating	JPM Price Target	Materiality	Detail
Schlumberger	N	$23	Increasingly material	JV Genvia aims to accelerate industrial use of green hydrogen with SOE technology
Baker Hughes	OW	$25	Increasingly material	TPS business offers differentiated rotating equipment and compression technology for use across the hydrogen value chain
TechnipFMC	OW	$20	Increasingly material	Deep Purple combines offshore wind/wave energy with subsea power storage (e.g. fuel cells); Recently spun Technip Energies (FTI 49.9% equity share): Full rainbow of hydrogen (~$50bn market opportunity), ~35% market share in grey

Source: Company filings.

BKR is showing differentiation in hydrogen but path to materiality remains a function of tech developments and government support

Baker's TPS business offers differentiated rotating equipment and compression technology, giving it exposure to the hydrogen market irrespective of how the "hydrogen rainbow" evolves in the coming decades. BKR manufactures turbines that can be powered by gas or hydrogen, as well as compressors and expanders which are primarily required in the production, transportation and utilization phases.

BKR has sizable experience with using a variety of fuel mixtures, some with high hydrogen content, including ~70 projects worldwide using both its Frame and aeroderivative gas turbines. In one of its case studies, the NovaLT16 turbine was able to burn natural gas then switch to blends, including 100% hydrogen, importantly with no hardware modifications. Baker has worked on equipping over 70 projects worldwide with H_2-capable turbines and, as the market develops, we think its offering will continue to gain traction for either new projects or to enhance existing infrastructure.

The most recent data point from Baker is that construction on an ammonia site in Australia is in progress, which will use a NovaLT16 turbine on 100% hydrogen. The NovaLT12 will also be installed at Snam's gas compressor station in Italy after its successful 10% hydrogen blend test. We think BKR is a strong play on the energy transition (at least amid OFS peers), but management is rightly conservative in noting 1) obstacles facing much-needed government intervention/support and 2) for hydrogen to scale, it needs to be located near point of use, given current transportation limitations resulting in loss of energy.

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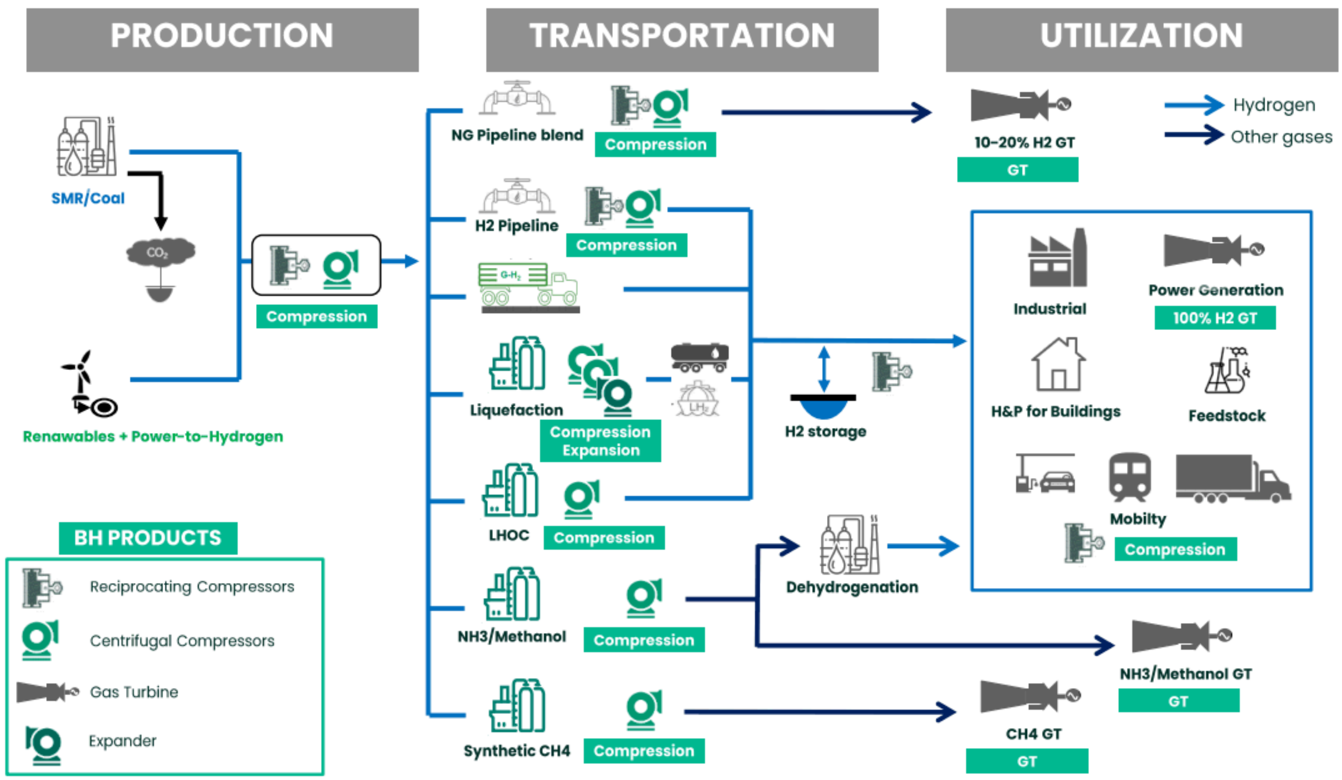
Figure 147: BKR's TPS Portfolio across the Hydrogen Value Chain



Source: Baker Hughes.

SLB investing for hydrogen success with plenty of work (and potential) ahead

Schlumberger's current exposure to hydrogen is lower than BKR's (but still higher than the rest of our coverage). Last year, SLB announced its partnership with the French Alternative Energies and Atomic Energy Commission (CEA), as well as Vinci Construction, on a new venture tied to clean hydrogen, called **Genvia**. The objective is to accelerate industrial use of green hydrogen with SOE technology.

While electrolyzer technologies are early stages in general, SOE is still considered among the more advanced, but products are not commercially viable yet. The process could offer advantages around higher conversion efficiency with the potential for producing a synthesis gas directly from steam and CO_2, which could be applied in several areas including synthetic liquid fuels. SLB is investing in this technology with that expectation to provide clean hydrogen more efficiently in a market it expects to surpass 10 megatons of volume by 2035 (comparable to the Sustainable Development Scenario below).

We highlight that while some in the industry consider electrolyzer technology to be fairly commoditized, the relatively high cost of the process is also consistently cited as a barrier to making green hydrogen economic. If SLB can develop next-gen technology on this front and lower the cost curve, its venture could capture a large share of the enhanced economics through an IP moat.

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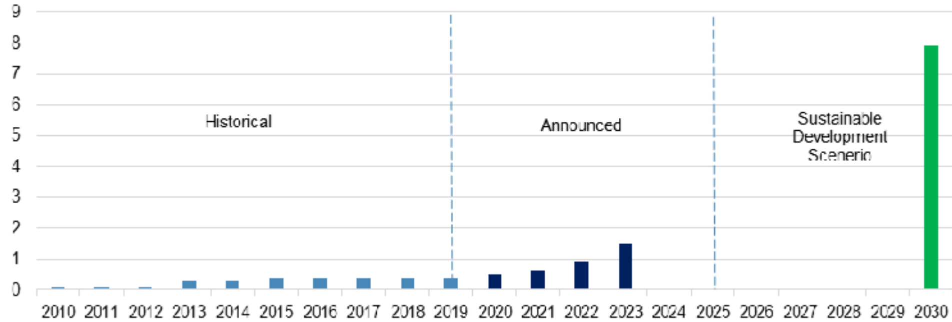
Figure 148: Low-Carbon Hydrogen Production (Mt/y)



Source: IEA.

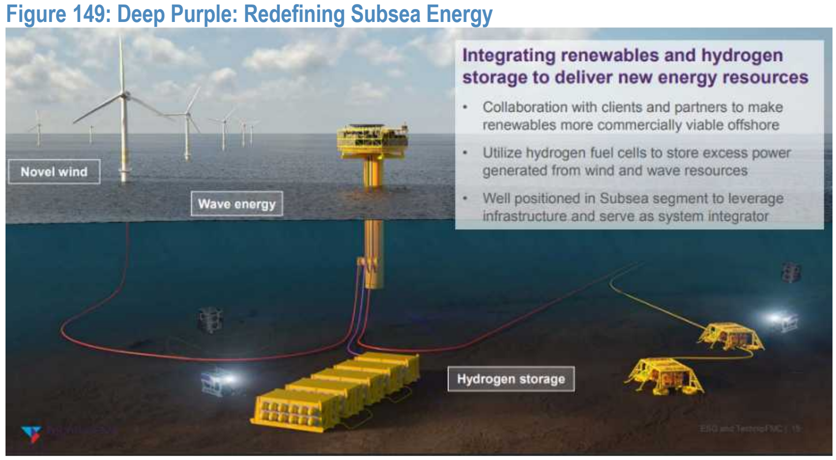
FTI's Deep Purple offers long-term offshore potential; monetization of recent TE spin offers indirect (but more immediate) H_2 exposure

As disclosed at our JPM Energy Technology Tour last November, The Deep Purple project looks to integrate offshore wind/wave energy with subsea power storage (e.g., hydrogen fuel cells) to power both subsea infrastructure and eventually the onshore grid. This not only builds from FTI's clear subsea expertise but also its extensive installed base of infrastructure, which in many cases is relatively well-located to support future renewables projects. While even further away, we think the second iteration of Deep Purple could leverage the natural extension of carbon capture in offshore reservoirs. This opportunity looks to be ahead of the current market (with no $ opportunity provided by FTI), but clearly it is viewed as material enough for FTI to disclose as a medium-to-long term opportunity.

FTI leveraging subsea expertise to provide scale to the energy transition

While the hydrogen exposure is largely confined to the now separate Technip Energies business, FTI's Subsea business is also adapting to be part of the energy transition. The company has been developing its Deep Purple offering for four years to use offshore to provide much needed scale to match ambitious renewable uptake forecasts. The plan integrates renewables and subsea power storage (i.e. hydrogen fuel cells), and we think the second iteration could also play into blue H_2 by incorporating CCS technologies. We therefore reason this solution would help with the massive infrastructure buildout and avoid the NIMBY political/social pushback, but continue to contemplate potential permitting/legal hurdles.

Figure 149: Deep Purple: Redefining Subsea Energy



Source: TechnipFMC presentation.

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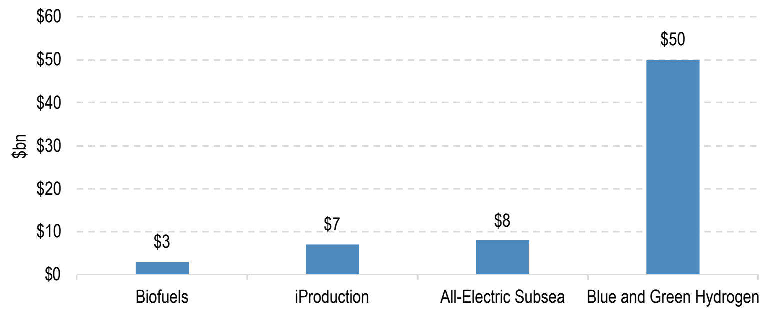
FTI's TE spin takes most of new energy IP, but cash monetization on horizon

TechnipFMC's recent completion of its spin of Technip Energies offers a path to monetizing a significant portfolio of hydrogen-related technology. Post-spin, FTI is retaining 49.9% of TE's equity, with a plan to monetize through stock sales over what we expect will be an 18-24 month process. Measured by installed base with a presence in over 270 plants worldwide, TE has a market leading 35% share in grey hydrogen. This core expertise gives TE the ability to pivot irrespective of how the hydrogen market develops. Amid the fanfare of 2050 green hydrogen targets, grey hydrogen can be overlooked, but TE's steam reforming technology in this industry will be needed (in addition to carbon capture) to ramp blue hydrogen. We view blue as a solid opportunity given its current emission profile and cost (compared to green) but note the usual caveats of logistical/economic obstacles need to be overcome to displace current technology. TE plans to deploy its engineering and project management capabilities to bolster commercial viability for green hydrogen. With McPhy's recent private placement offering, it plans to develop capacity stacks for large-scale projects (>100MW) and hydrogen refueling stations (>2 tons per day).

Figure 150: FTI & TE's largest new energy opportunity through 2030 is hydrogen



Source: Company filings.
Note: Technip Energies was spun out of TechnipFMC in February 2021.

Given the developments on hydrogen highlighted above, TE estimates its opportunity as an EPC supplier for blue and green hydrogen represents a +$50bn opportunity through 2030. While longer-term adoption scenarios are wide-ranging, dependent on policy and technological step changes to improve the cost curve, the required buildout could be ~7x the current installed base. If green takes longer than expected to develop, Technip would benefit from its positions in blue and LNG. The main tradeoff would be taking higher volume of blue while giving up the more valuable work with green (if FTI's investments in the market prove successful). For FTI, the hydrogen exposure is largely confined to the now spun Technip Energies business (and FTI's equity stake) but RemainCo's Subsea segment is adapting to be a part of the energy transition.

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Air transportation

H2 power commercial airlines are still remote in time

Few experts believe that a hydrogen-powered commercial aircraft could be in service before the mid-2030s at the very earliest, even then that would likely only be a small regional jet. Hydrogen might play a role in the broader airline ecosystem, powering the transport that takes people to/from airports, the support vehicles that move aircraft around airports, or even powering the auxiliary units than provide electricity for an aircraft's systems. But we are a long way from having hydrogen-powered planes.

One could summarize the challenges faced by H2 deployment in aviation as twofold:

1) **First, technical challenges:** Rolling out H2 will require engineers to develop a technology compatible with aircraft operations, in terms of weights, costs, and storage (considering weight and volume requirements). Moreover, it will also require the retrofitting of existing airport infrastructures with H2 T&S infrastructures to ensure widespread availability of H2 at airports.

2) **Second, regulatory:** the roll out of H2 in aircraft would require the development of specific safety-related standards, which will need to achieve a performance at least equivalent to the safety record of kerosene-powered aircraft.

H2 powered flights mainly prototypes in the short term

Back in history, hydrogen was used in the air transportation sector, as scientists would use its lower density than air to fly airships. The first was launched in 1783 in Paris, and they developed via craft such as Zeppelins up to the Hindenburg accident in 1937, which ended H2 airships for good, in a period where H2 was being increasingly replaced by Helium. Now hydrogen applications in the air transportation sector remain extremely long term vs. other mobility applications, and limited in scalability. As of today, the vast majority of aviation's GHG emissions comes from commercial airlines. However, existing pilot projects are focusing on light aviation and drone applications, and remain prototypes.

Among the first experiments, Boeing Research and Technology Europe flew a fuel-cell powered motor-glider 3300 feet, for 20 min, as early as 2008. This was followed by another flight of an H2 powered airplane, developed by the German space center in Sept. 2016. This prototype transported 4 people, achieved 750-1500 km autonomous flights at an average speed of 145 kmh, and was powered by an 80 kW fuel cell. Drone applications could represent an interesting opportunity, esp. as they pave the way for larger applications, in areas such as telecommunications and/or defense. China recently developed a 21kg H2 powered drone, which could reach 80km/h in helicopter mode and 120kmh in fixed wing, i.e. similar performance than its thermic powered equivalent.

Airbus H_2 airplane concept represents an extremely ambitious R&D target

In September 2020, Airbus announced its ambition to develop the world's first zero-emissions commercial aircraft by 2035, and presented three "ZEROe" concept aircraft, exploring a variety of configurations and hydrogen technologies that could shape the development of future zero-emission aircraft. In particular, the concept planes envisaged the use of a hybrid-electric propulsion system: aircraft would be

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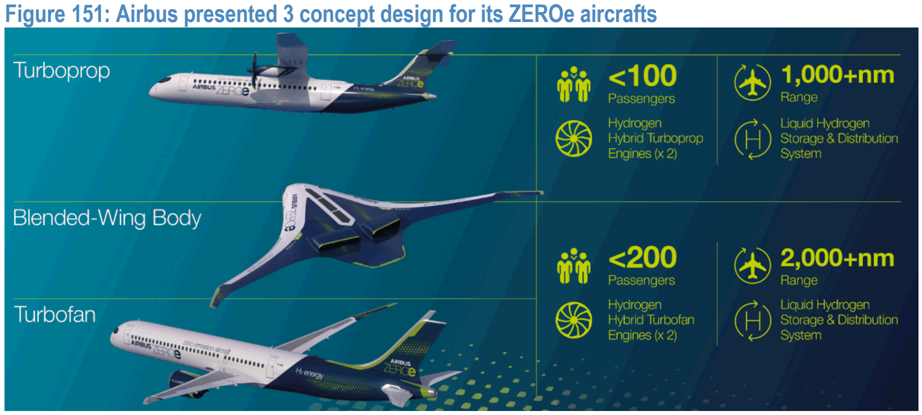
powered partly by H2 combustion through modified gas turbine engines, using liquid hydrogen as fuel for combustion with oxygen, and partly by H2 fuel cells creating electrical power complementing the gas turbine.

Figure 151: Airbus presented 3 concept design for its ZEROe aircrafts



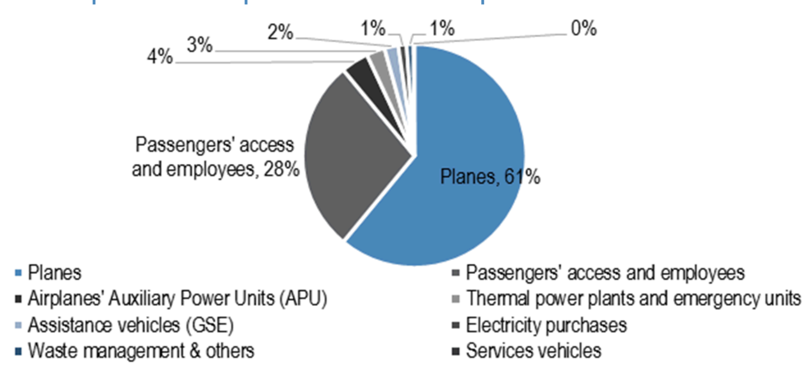
Source: Company report

These concept designs remain, however, in the R&D phase. Airbus is conducting several tests to determine which hydrogen technology is best placed to fuel its ZEROe concept aircraft. Potential cross-industry partnerships on hydrogen combustion are envisaged to advance this development. As such, the 2035 date remains, in our view, highly theoretical and is likely to be delayed.

Hydrogen offers limited opportunities for airports to reduce GHG emissions

Researchers from the MinesParis Tech envisage the use of hydrogen in the air transportation sector from a wider ecosystem perspective, considering it from the perspective of an airport infrastructure. They recall that beyond direct emissions from airplanes, airports also have other sources of emissions (see below).

Figure 152: Airport carbon footprint are not limited to airplanes' direct emissions



Source: J.P. Morgan, based on Aeroport de Paris (2016)

As such, they consider four types of potential application for hydrogen technologies. However, for most of the options envisaged below, it's hard to see any likely near term deployment. Only one option (replacing the assistance vehicles fleet with H2 powered vehicles) is considered potentially viable in the short term vs. gasoline, albeit it would imply a significant upfront investment.

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1) **Direct GHG emissions reductions for airplanes (61% of GHG):** while planes can't be powered by H2 during flights, current R&D projects are considering using it to power engines during the taxiing phase on the airport tarmac.
2) **Access of passengers and employees (28% of GHG):** i.e. directly related to the deployment of H2 solutions in road transportation (see relevant sections).
3) **Using H2 instead of fuel to power the auxiliary and ground units used by airplanes top power their internal systems when they are on the ground (5%) –** APU (Auxiliary Power Unit) and GPU (Ground Power Unit). The researchers point out that powering APU and GPU with hydrogen would deliver environmental co-benefits by reducing both local air pollution and reducing noise. According to the researchers, the breakeven cost vs. kerosene would be about EUR 5.12/kg H2.
4) **Using H2 for services vehicles and assistance vehicles** during stopovers, to replace diesel. According to Mine ParisTech researchers, these solutions could be economically viable vs. diesel at a cost of EUR 8.24/kgH2. However, their calculations do not consider the required upfront capex to convert the existing fleet to H2 powered vehicles.

Syngas for jet fuel has limited potential for now

Using H2 in the production for synthetic jet fuel remains unlikely to become economically viable in the foreseeable future and would require an update of regulations

Another application for H2 in the air transportation value chain, and discussed by the MinesParis Tech researchers, would be the production of "e-fuel", i.e. fuel produced from the combination of both captured CO2 and green H2. This is, for example, the case for methanol (CH3OH)

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$

However, methanol's physical properties prevent it from being used in its pure state in vehicle and aircraft engines, due to its toxic and corrosive nature, but also to its weak calorific power (energy content to mass). As a result, methanol must undergo several treatments to be turned into a synfuel that can be blended with gasoline (in the EU, the EN 228 norm allows for a 3% blending). Yet, in the case of aircraft, the lack of regulatory standards makes it de-facto impossible to blend it with kerosene. To be blended with kerosene, a fuel must be characterized as "drop in" – i.e. a fuel that can be partly or fully substituted for jet fuel without operational impact and without requiring changes to existing engines – and certified under the ASTM (American Society for Testing Materials). Moreover, a study on methanol production from the EU Joint Research Center also outlines breakeven costs for methanol production which seem quite unrealistic. Under the assumption of an electricity cost of EUR 95/MWh, a producer methanol producer would need to be paid EUR 695/t of CO2e reduced, for their installation to be economically viable.

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Companies Discussed in This Report (all prices in this report as of market close on 19 February 2021, unless otherwise indicated)
Air Liquide(AIRP.PA/€132.15/N), Airbus SE(AIR.PA/€95.8[22 February 2021]/OW), Aker Solutions(AKES.OL/Nkr12.92/OW), Allison Transmission Holdings(ALSN/$38.14/UW), Alstom(ALSO.PA/€41.00/OW), Anglo American(AAL.L/2870p/N), ArcelorMittal(ISPA.AS/€19.70[22 February 2021]/OW), Arkema(AKE.PA/€90.50/OW), BASF SE(BASFn.DE/€67.97/UW), Baker Hughes(BKR/$23.40/OW), Bloom Energy(BE/$32.04/N), CNH Industrial(CNHI/$15.12/OW), Clariant(CLN.S/CHF19.72/UW), Cummins Inc(CMI/$246.76/N), Daimler AG(DAIGn.DE/€67.04/OW), ENEL(ENEI.MI/€8.20/OW), ENI(ENI.MI/€9.20/UW), ElringKlinger(ZILGn.DE/€14.56/N), Enagas(ENAG.MC/€17.11/UW), Endesa(ELE.MC/€21.71/N), Engie(ENGIE.PA/€12.90/OW), Equinor ASA(EQNR.OL/Nkr151.85/OW), Evonik(EVKn.F/€28.02/OW), Fortescue Metals Group Ltd(FMG.AX/A$24.74[22 February 2021]/OW), FuelCell Energy(FCEL/$20.22/UW), Galp Energia(GALP.LS/€9.49/N), Gazprom(GAZPq.L/$6.1/OW), HeidelbergCement(HEIG.DE/€65.20/N), ITM Power(ITM.L/550p[18 February 2021]/NC), Iberdrola(IBE.MC/€10.51/N), Johnson Matthey(JMAT.L/3128p/N), LafargeHolcim Ltd(LHN.S/CHF49.95/OW), Michelin(MICP.PA/€119.05/OW), Nel ASA(NEL.OL/Nkr26.93[18 February 2021]/NC), Nikola Corp(NKLA/$21.36/OW), OCI(OCI.AS/€18.20/UW), OMV(OMVV.VI/€38.96/OW), Orsted(ORSTED.CO/Dkr1019.00/OW), PACCAR Inc.(PCAR/$95.19/N), Petrofac(PFC.L/125p/N), Plastic Omnium(PLOF.PA/€32.66/OW), Plug Power(PLUG/$55.89/N), Public Storage(PSA/$234.70/N), RWE(RWEG.DE/€32.46/OW), Renault(RENA.PA/€38.04/OW), Repsol(REP.MC/€9.94/UW), Royal Dutch Shell A(RDSa.L/1397p/OW), SSAB-A(SSABa.ST/Skr37.65/UW), Salzgitter(SZGG.DE/€23.10/N), Schlumberger(SLB/$26.12/N), Siemens Energy(ENR1n.DE/€32.41/OW), Siemens Gamesa(SGREN.MC/€33.23/OW), Snam(SRG.MI/€4.36/N), Solvay(SOLB.BR/€96.42/OW), TOTAL(TOTF.PA/€36.95/N), TechnipFMC PLC(FTI/$7.28/OW), ThyssenKrupp(TKAG.DE/€11.23/NR), Traton SE(8TRA.DE/€23.46/NR), Umicore(UMI.BR/€48.02/UW), Vale(VALE3.SA/R$97.77/OW), Vestas(VWS.CO/Dkr1274.50/UW), Victrex(VCTX.L/2194p/N), Volvo(VOLVb.ST/Skr216.50/OW), Wood Group(WG.L/288p/OW), Wärtsilä(WRT1V.HE/€8.69/UW), Yara(YAR.OL/Nkr417.70/N), voestalpine(VOES.VI/€32.19/UW)

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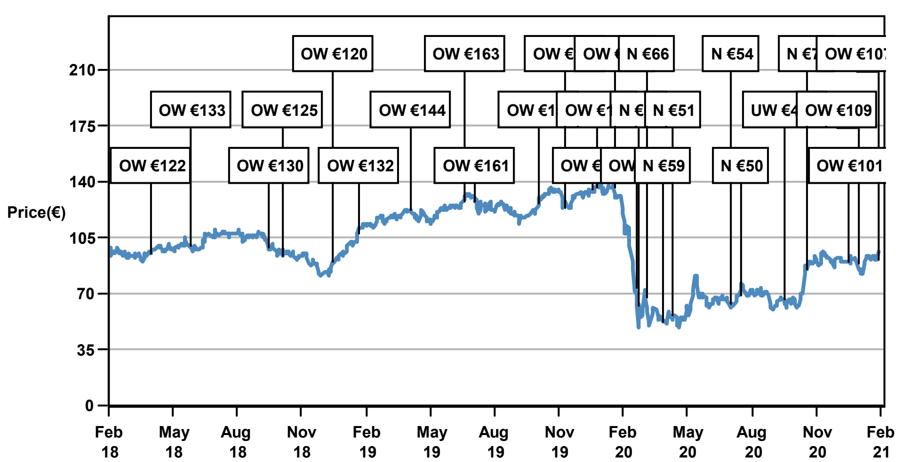
Airbus SE (AIR.PA, AIR FP) Price Chart



Source: Bloomberg Finance L.P. and J.P. Morgan; price data adjusted for stock splits and dividends.
Initiated coverage Sep 13, 2000. All share prices are as of market close on the previous business day.

Date	Rating	Price (€)	Price Target (€)
27-Apr-18	OW	95.5	122
21-Jun-18	OW	99.9	133
11-Oct-18	OW	99.0	130
31-Oct-18	OW	93.9	125
10-Jan-19	OW	89.7	120
15-Feb-19	OW	107.2	132
30-Apr-19	OW	123.0	144
15-Jul-19	OW	127.7	163
31-Jul-19	OW	127.7	161
30-Oct-19	OW	125.8	156
04-Dec-19	OW	124.1	149
15-Jan-20	OW	135.1	160
20-Jan-20	OW	136.8	157
13-Feb-20	OW	136.6	156
16-Mar-20	OW	74.3	95
18-Mar-20	N	63.0	68
30-Mar-20	N	68.2	66
22-Apr-20	N	52.0	59
06-May-20	N	56.4	51
27-Jul-20	N	63.9	54
10-Aug-20	N	69.3	50
13-Oct-20	UW	66.0	46.5
13-Nov-20	N	84.6	75
11-Jan-21	OW	90.1	101
25-Jan-21	OW	88.8	109
22-Feb-21	OW	91.8	107

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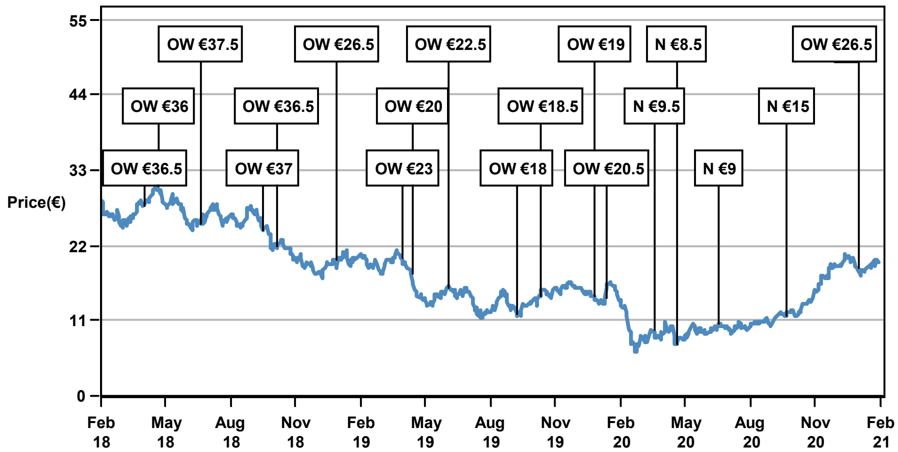
ArcelorMittal (ISPA.AS, MT NA) Price Chart



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Date	Rating	Price (€)	Price Target (€)
30-Apr-18	OW	27.80	36.5
18-May-18	OW	30.62	36
17-Jul-18	OW	25.12	37.5
12-Oct-18	OW	24.20	37
01-Nov-18	OW	22.04	36.5
22-Jan-19	OW	19.85	26.5
25-Apr-19	OW	20.16	23
09-May-19	OW	17.77	20
01-Jul-19	OW	15.74	22.5
03-Oct-19	OW	11.95	18
07-Nov-19	OW	14.52	18.5
21-Jan-20	OW	14.60	19
06-Feb-20	OW	14.33	20.5
14-Apr-20	N	9.58	9.5
14-May-20	N	7.50	8.5
14-Jul-20	N	10.38	9
16-Oct-20	N	11.80	15
25-Jan-21	OW	18.64	26.5

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