HYDROGEN AND STUPIDITY

WHEN EXPECTATION MEETS REALITY

INDUSTRY BACKGROUND FROM LONGSPUR RESEARCH

7 November 2023
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HYDROGEN

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HYDROGEN AND STUPIDITY

Science fiction writer Harlan Ellison once said that the two most common elements in the universe are hydrogen and stupidity. In the case of hydrogen, the stupidity used to be that hydrogen was expected to be the solution to decarbonising almost everything. Now, the stupidity is that it is seen as the solution to decarbonising almost nothing. Sense lies between these limits with hydrogen an essential component in the decarbonisation toolbox. Effective demand for green hydrogen already exists but not necessarily where we expect it. Notably we are seeing growing demand for the hydrogen derived molecules ammonia and methanol. Major policy developments could create further traction and the ability of hydrogen to maximise biofuels use is also gaining traction.

Demand Developing Today in Key Areas

While hydrogen project demand has been weak, it is developing quickly in certain areas. Recent EU mandates requiring 42% of industrial hydrogen to be from green sources by 2030 is likely to fuel demand growth. Existing policy mandates in shipping and aviation are already seeing demand for hydrogen derived fuels, and there are now over 200 methanol fuelled vessels on the water or on order.

Biofuel Upgrading Could be Significant

While these fuels can come exclusively from biomass, we see the use of hydrogen for biofuel upgrading to have significant potential. We are also seeing emerging demand for specific industrial heating solutions fuelled directly by hydrogen or dimethyl ether. Green ammonia, while slowed by grey pricing, is seeing opportunity where renewable power is abundant, and prices are in any case firming.

Hydrogen is Not a Universal Solution

There is also a greater realism emerging about where hydrogen does and does not make sense. We have analysed road transport options and rule out hydrogen cars but see hydrogen or hydrogen derivative fuelled heavy trucking as viable.

Balancing Driven by Low Utilisation Economics

We also see an increasing role for hydrogen in power system balancing. Notably our analysis of the economics of low utilisation electrolysis shows that hydrogen can be a valid option where low cost off-peak (not just curtailed) power is available.

Total Demand Potential Remains High

Based on the use cases that can be justified we estimate long term annual demand for hydrogen to reach 447Mt. We see flexible electrolyser technologies working better in the new world and fuel cells in niche applications. For hydrogen transportation, compressed solutions are better than liquefaction or derived products. We see the main opportunities related to projects in ammonia, methanol, biomethane, grid balancing and refuelling.

Industry background from Longspur Research

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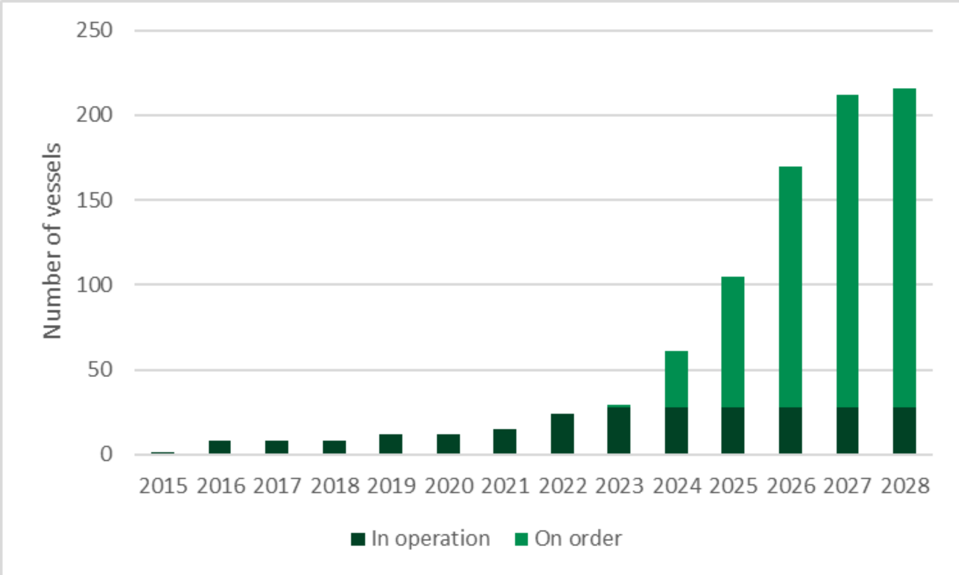
HYDROGEN AND STUPIDITY

Opportunity in hydrogen today tends to lie with hydrogen derived fuels driven by blending mandates, notably in shipping and aviation. There are now over 200 methanol fuelled vessels on the water or on order and Maersk parent A.P. Moller Holdings has created its own e-fuels business, C2X, to deliver low carbon methanol.

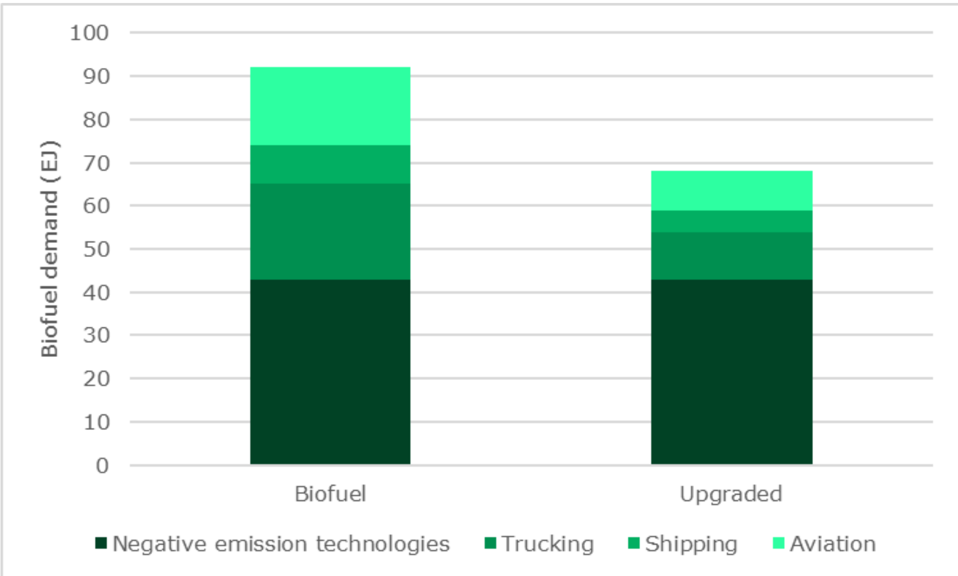
Methanol Fuelled Vessel Numbers



Source: DNV

We are beginning to see projects which combine biofuels with hydrogen in a process known as biofuel upgrading and we expect more hydrogen demand in this area going forward. Canada's largest electrolyser deployment is a co-location with a biomass gasification plant for green methanol in a project backed by Proman, Enerkem, Shell and Suncor.

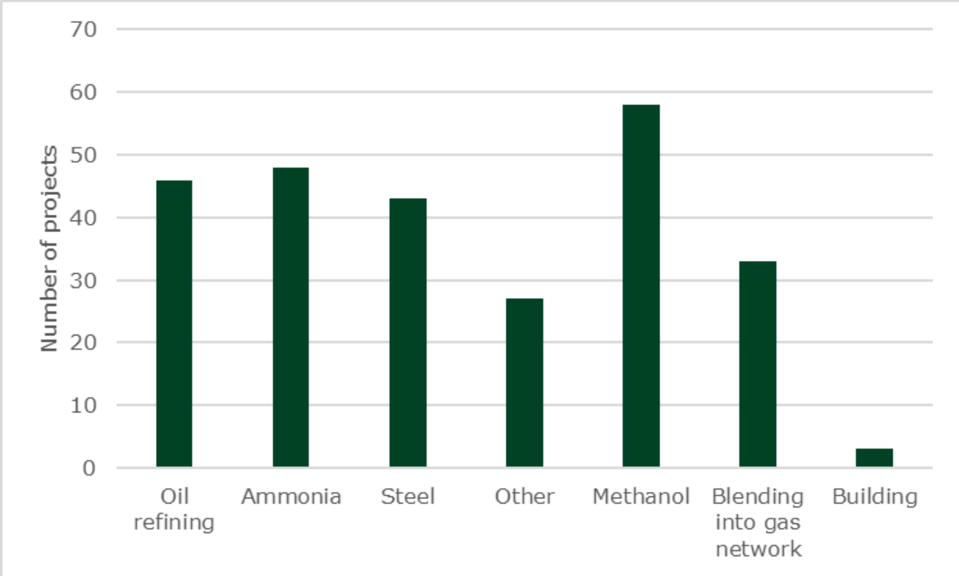
Bioenergy Feedstock Demand Reduced by Hydrogen Upgrading



Source: BNEF

Industrial demand is also growing for products such as ammonia and this is likely to continue, driven by EU policy changes requiring 42% of industrial hydrogen to be from green sources by 2030.

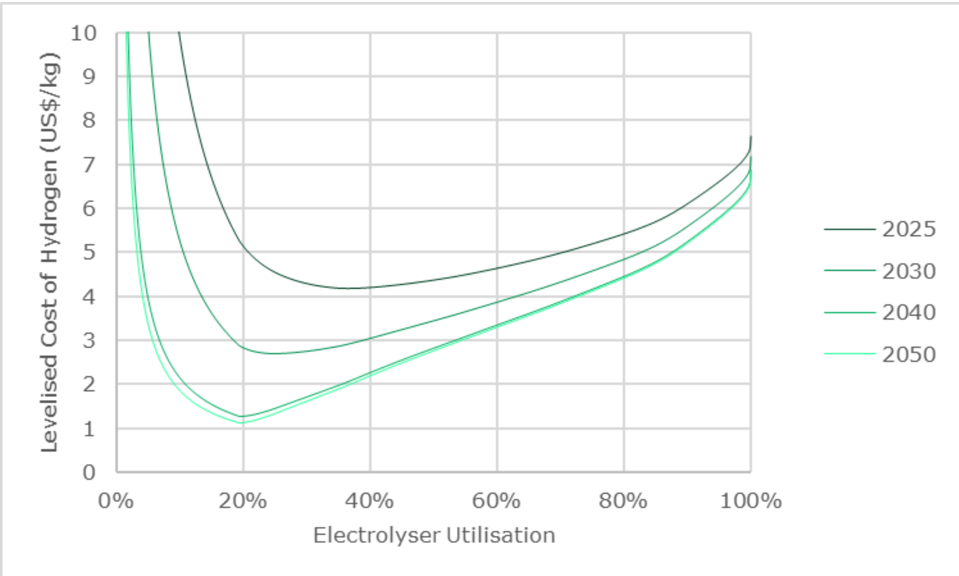
Announced Pipeline of Industrial and Heating Projects



Source: BNEF

We also see an increasing realisation of the role of hydrogen in power system balancing. Notably our analysis of the economics of low utilisation electrolysis means balancing economics makes sense.

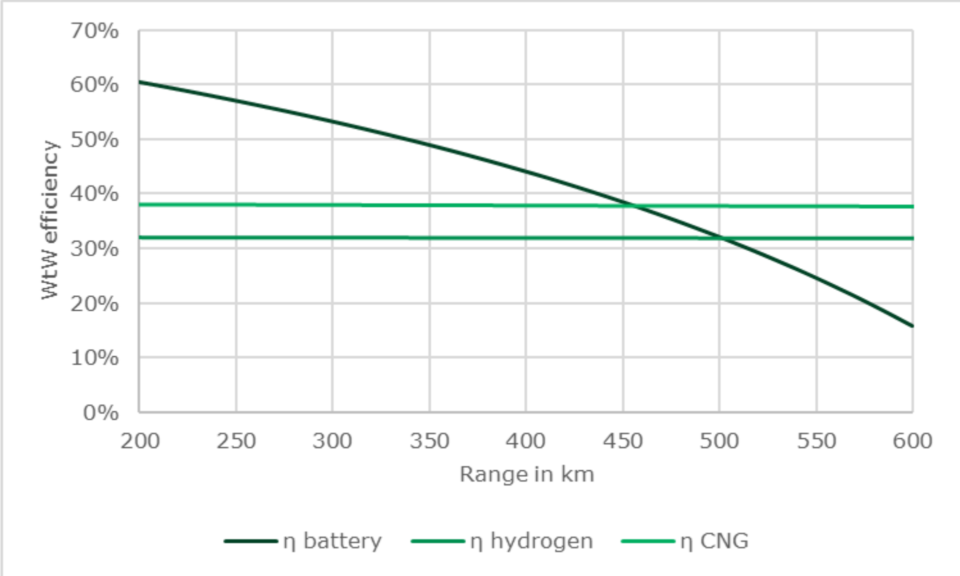
Levelised Cost of Hydrogen Against Utilisation



Source: Longspur Research

There is also a greater realism emerging about where hydrogen does and does not make sense. We have analysed road transport options and rule out hydrogen cars but see hydrogen or hydrogen derivative fuelled heavy trucking as viable.

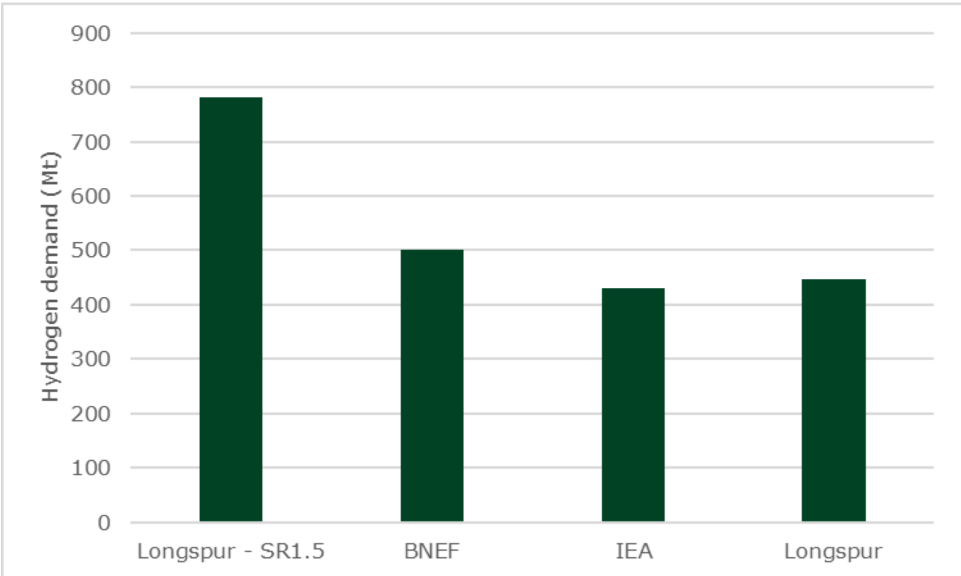
Heavy Trucking Efficiency Against Range



Source: Longspur Research

Based on the use cases that we think can be justified we estimate annual demand for hydrogen to reach 447Mt. This is lower than our estimate of the demand implied in our analysis of the IPCC's Special Report on Global Warming of 1.5°C (Simple Not Easy, Longspur Research, 18 February 2021) but in line with other forecasts in the market.

Hydrogen Demand Forecasts in 2050



Source: IEA, BNEF, Longspur Research

INVESTABLE OPPORTUNITIES

Investment opportunities include project developers especially those involved in hydrogen derivative fuels, ammonia, methanol, biomethane and DME.

Electrolyser manufactures are seeing mixed fortunes as demand and supply appear out of sync but in time we see opportunities especially in the more flexible options of Polymer Electrolyte Membrane (PEMEC), Anion Exchange Membrane (AEMEC) and membrane free (MFEC) technologies. We also see demand emerging for solid oxide electrolysers (SOECs) to support nuclear power and industry.

Fuel cell manufactures find demand in key niche applications some of which could be significant. Developers of heavy hydrogen or bioCNG trucks and refuelling sites and of compressed hydrogen pipelines and shipping should see demand.

In the listed space there are companies covering most activities in the hydrogen value chain. We have split these according to activity and also where they add value with innovators primarily providing new technologies into the industry, manufactures producing established technologies and developers deploying and commercialising these. Most companies are small though reflecting the nascent nature of the industry. A number of larger more integrated companies also have exposure to the hydrogen market as minority activities.

Hydrogen Activity Acronyms

AFC	Alkaline Fuel Cell
PEM	Proton Exchange Membrane / Polymer Electrolyte Membrane
SOFC	Solid Oxide Fuel Cell
HT PEM	High Temperature PEM
PAFC	Phosphoric Acid Fuel Cell
DMFC	Direct Methanol Fuel Cell
MCFC	Molten Carbonate Fuel Cell
AEC	Alkaline Electrolyser
PEMEC	PEM Electrolyser
SOEC	Solid Oxide Electrolyser
MFEC	Membrane Free Electrolyser
AEMEC	Anion Exchange Membrane Electrolyser
HRS	Hydrogen Refuelling System
WtH	Waste to Hydrogen
PtX	Power to X
FCEV	Fuel Cell Electric Vehicle

Source: Longspur Research

Listed Hydrogen Companies

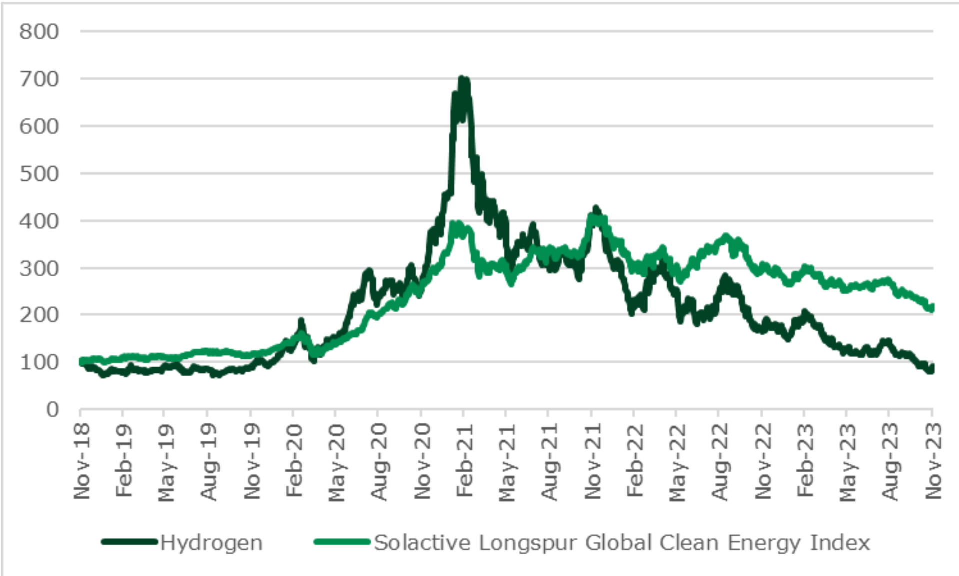
	Market Cap (£m)	EV (£m)	Category	Key activity
Hydrogen distribution				
Everfuel	42	29	Developer	HRS
Hexagon Composites	381	483	Manufacturer	Storage
Hexagon Purus Asa	205	197	Manufacturer	Storage
Hydrogen Refueling Solutions	190	183	Developer	HRS
Hyon As	1	0	Developer	Marine HRS
Iljin Hysolus Co Ltd	426	269	Developer	Storage
Lhyfe Sas	131	41	Manufacturer	HRS
Provaris Energy Ltd*	15	12	Innovator	Shipping
Hydrogen manufacture				
Clean Power Hydrogen	41	36	Innovator	Membrane fee
Enapter Ag	252	270	Innovator	AEM
Fusion Fuel Green	9	4	Innovator	PEM/PV
Green Hydrogen Systems	139	216	Manufacturer	AEC
Haffner Energy Sa	43	17	Innovator	WtH
Hydrogen Utopia	24	24	Developer	WtH
Hydrogenpro Asa	66	54	Manufacturer	AEC
ITM Power Plc	395	120	Manufacturer	PEM
John Cockerill India Ltd	137	127	Manufacturer	AEC
Mcphy Energy Sa	88	9	Manufacturer	PEM
NEL ASA	896	637	Manufacturer	AEC/PEM
Powerhouse Energy*	11	5	Innovator	WtH
Hydrogen systems				
Advent Technologies	18	19	Innovator	HT PEM FC
AFC Energy Plc	97	66	Innovator	AFC
Ballard Power Systems Inc	821	115	Manufacturer	PEM
Beijing Sinohytec Co Ltd-A	887	843	Manufacturer	Fuel Cell
Bloom Energy Corp- A	1,930	2,505	Manufacturer	SOFC/SOEC
Bumhan Fuel Cell Co Ltd	99	66	Manufacturer	Fuel Cell
Cell Impact Ab	4	1	Manufacturer	Flow plates
Ceres Power Holdings Plc	379	220	Innovator	SOFC/SOEC
Doosan Fuel Cell Co Ltd	640	821	Manufacturer	PAFC
Fuelcell Energy Inc	405	257	Manufacturer	MCFC/SOFC/SOEC
Gencell Ltd	26	23	Manufacturer	AFC
Plug Power Inc	2,923	2,574	Manufacturer	PEM FC/PEM EC
Powercell Sweden Ab	165	157	Manufacturer	PEM FC
Proton Motor Power	89	207	Manufacturer	PEM FC
Sfc Energy Ag-Br	248	213	Manufacturer	DMFC
S-Fuelcell Co Ltd	60	51	Manufacturer	PEM FC
Teco 2030 Asa	67	82	Manufacturer	Marine FC
Hydrogen applications				
Atome Energy Plc*	32	35	Developer	NH3
Hyzon Motors Inc	157	22	Manufacturer	FC Trucks
Nikola Corp	762	878	Innovator	FC Trucks
Pure Hydrogen Corporation Lt	30	23	Developer	FCEVs
Bioenergy				
EQTEC Plc*	6	9	Innovator	WtH
Refuels Nv*	140	11	Developer	HRS
Velocys Plc*	5	11	Innovator	SAF
Minority hydrogen involvement				
Air Liquide Sa	73,398	84,370	Developer	Full supply chain
Air Products & Chemicals	51,726	59,437	Developer	Storage & shipping
Cummins Inc	25,258	30,968	Manufacturer	H2 ICE
Iberdrola Sa	57,409	122,88 2	Developer	Developer in NH3
Industrie De Nora Spa	2,283	2,280	Manufacturer	AEC
Johnson Matthey Plc	2,734	3,752	Manufacturer	PEMFC
Linde Plc	151,676	173,35 6	Manufacturer	Full supply chain
Siemens Energy Ag	5,734	6,985	Manufacturer	PEMEC
Snam Spa	12,621	25,375	Developer	AEC
Thyssenkrupp Ag	3,502	1,422	Manufacturer	AEC
Weichai Power Co Ltd-H	13,205	13,983	Manufacturer	SOFC and H2 ICE
Yara International Asa	6,798	846	Developer	NH3

Source: BNEF, * Longspur Research Client

WHEN EXPECTATION MEETS REALITY

Listed hydrogen companies have shown poor performance over the past two and a half years despite preceding this with the best performance of any clean energy subsector. This has reflected a changing view of hydrogen which was seen three years ago as a universal solution to decarbonisation but is now seeing uses increasingly questioned. It should be stressed that low or zero carbon hydrogen is an essential component of the decarbonisation tool kit and we will not reach net zero without it. However, there is a major question of the extent of the role it will play, and we analyse the opportunities in this note.

Five Year Hydrogen Subector vs SOLANZ



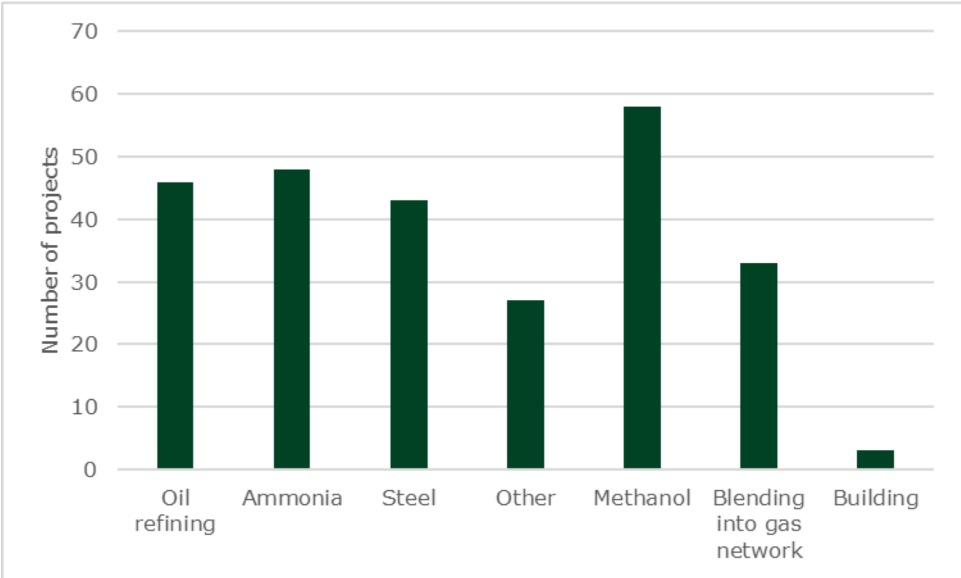
Source: Longspur Research

Demand Developing in Industry and Derived Fuels

There is strong demand today for grey hydrogen with c. 95Mt being supplied in 2022 with the vast majority produced by steam methane reformation (SMR) of natural gas, reforming of oil and gasification of coal. These resulted in 2% of all global greenhouse gas emissions. Decarbonising this hydrogen demand should be a priority and we see near term investment opportunities accelerating, driven by the EU policy move which will mandate that 42% of industrial hydrogen must come from green sources by 2030 rising to 60% by 2035.

Projects are already coming forward in oil refining, steel and methanol. Green ammonia production has been slowed by weaker product pricing but remains a strong opportunity in key geographies where cheap and abundant renewable energy is available. The efficiency losses in domestic heating make electric heat pumps and even direct electric heating more viable in most locations, but certain industries and certain locations can benefit from hydrogen or hydrogen derivatives for heat. We are starting to see the use of hydrogen derived DME emerging as heating solution for some specific applications and locations.

Announced Pipeline of Industrial and Heating Projects



Source: BNEF

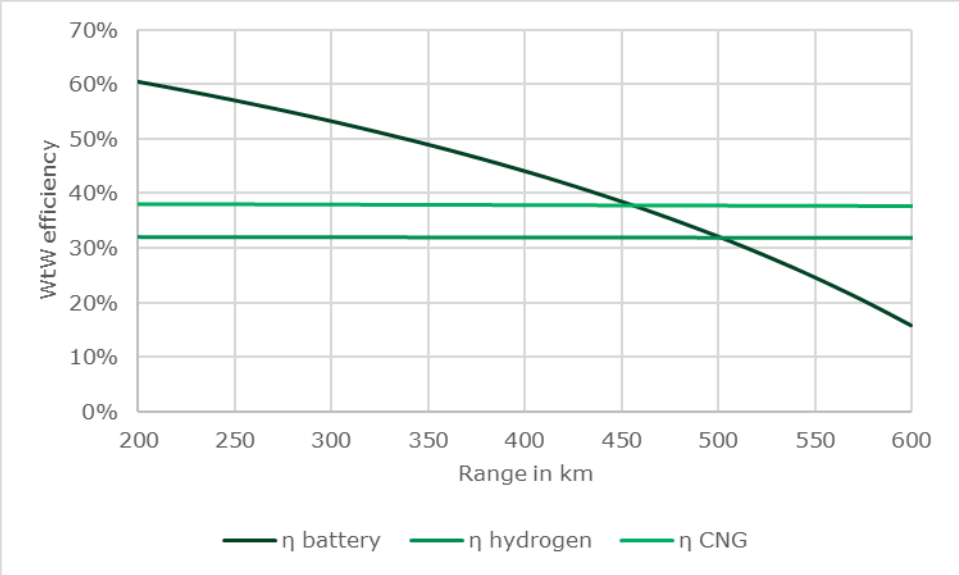
Shipping and Aviation Driving Demand for Hydrogen Derived Fuels

Changes in regulation from the IMO and EU are pushing ship owners to move on lower carbon solutions. While hydrogen could be a solution, the high cost of delivery and bunkering make hydrogen-derived methanol or ammonia better solutions. Methanol is seeing strong momentum with over 200 methanol fuelled vessels on the water or on order. Demand is growing for green methanol production either from biomethanol or e-methanol. However, combining green methanol from gasification with additional hydrogen from electrolysis can result in twice as much methanol produced from every kilo of biomass and we see growing demand for hydrogen from this biofuel upgrading route.

Forget Cars, But Trucking Could Use Hydrogen or Biomethane

Battery vehicles (BEVs) have been seen as the key solution for road transportation with hydrogen ruled out because of poor efficiency. However, as range and weight increase, efficiency drops much faster for BEVs than for hydrogen vehicles. Hydrogen cars still do not make sense, being less efficient than BEVs even out to 1,200 km. Our analysis shows that heavy hydrogen trucks could make sense at ranges over about 300 miles and that biomethane solutions can be better at even shorter ranges. This is for the largest long-range trucks. Short range local distribution makes most sense as BEVs.

Heavy Trucking Efficiency Against Range



Source: Longspur Research

Biomethanol and Biomethane Supercharged by Hydrogen

While biomethane is the winner from this analysis of trucking decarbonisation, production from anaerobic digestion can be combined with green hydrogen to double the amount of biomethane produced from the same amount of feedstock and we see this growing as a source of demand for hydrogen production. This is also true of the production of biomethanol and Canada's largest electrolyser deployment at 88MW is in support of a biomethanol gasification project, again doubling the methanol output for every unit of biomass used.

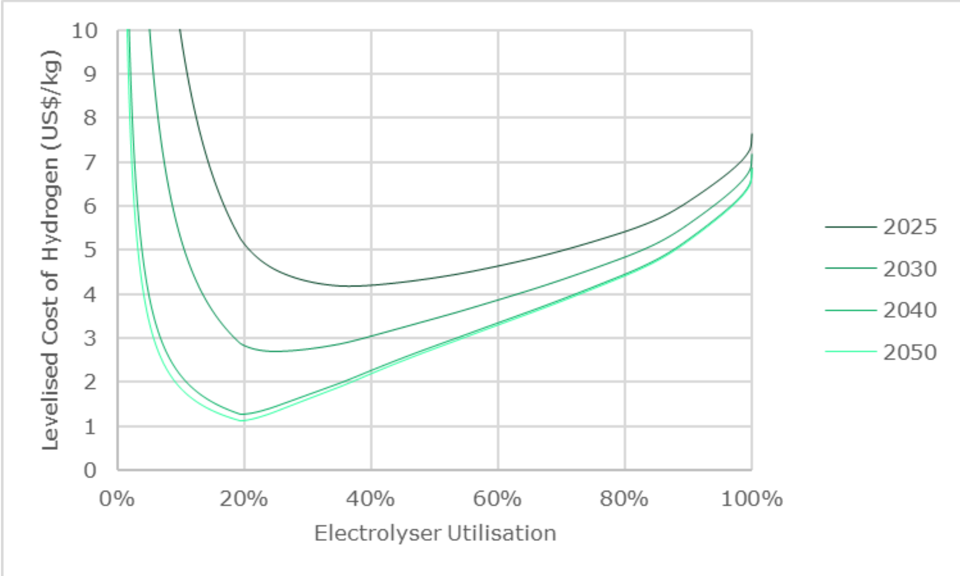
Low Utilisation Electrolysis Makes Sense

Using electricity to produce hydrogen and then return it back to electricity has a poor round trip efficiency when compared to other forms of long duration storage. However, hydrogen can be a valid option where low cost curtailed power cannot reach markets easily. But it is not just curtailed power that can benefit hydrogen production. Low cost off-peak power is also available and likely to grow as more low marginal cost renewables enter markets. We show that a low utilisation electrolyser benefiting from off peak power can be cheaper than a fully utilised project using grid power.

Policy Support Growing

Policy support is evolving rapidly, and we are beginning to see meaningful support for hydrogen applications. In the EU the Delegated Acts are expected to see a ten-year fixed support mechanism at €4/kg. Low carbon mandates in industry, shipping and aviation are already starting to drive demand. In the USA the Inflation Reduction Act sees up to US$3/kg in tax credits and the Bipartisan Infrastructure Law sees US$114bn of support including the recently announced US$7bn for seven clean hydrogen hubs. In the UK the first Hydrogen Allocation Round is under negotiation for 262MW of capacity in 17 projects although pricing may be modest and offtake requirements may limit the balancing opportunity that hydrogen can bring.

Levelised Cost of Hydrogen Against Utilisation



Source: Longspur Research

Is Hydrogen the Best Use of Renewable Energy?

Renewable energy delivers more carbon reduction when used for direct electrical applications. However, this alone will not deliver a net zero outcome by 2050. We need to decarbonise everything that we can, even if some applications require more renewable energy than others. This is the concept behind marginal abatement curves and the optimal point is where demand (a net zero outcome) is satisfied, which is not the lowest point on the curve. And hydrogen's place in the curve needs to be seen in the context of its interaction with the rest of the system where it can play a strong balancing role.

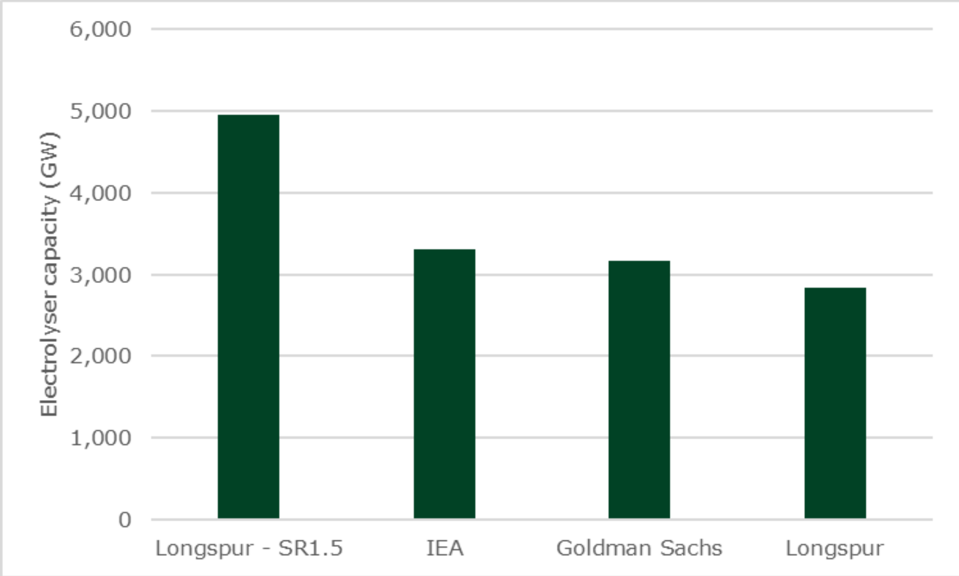
Hydrogen can play an important part in a balanced clean energy system and should not be seen as a stand-alone component. In particular, its balancing effect with renewables makes low utilisation electrolysis offer better economics than baseload systems and as such helps to provide economic balance to the system reducing the still major need for storage. For developers this can offer great optionality between selling power or selling molecules and this increases where biofuel upgrading is employed.

The clean energy project of the future may be an integrated project with a grid connected solar farm powering an electrolyser with battery storage and with hydrogen produced sold to the market or upgrading the output from a biomethane or biomethanol plant. This brings the operator lots of optionality with real time optimisation into multiple energy markets including baseload power, peak load power, peak power, hydrogen and biofuel, with carbon credits on the side and perhaps pure oxygen as a by-product. It will be more like a downstream oil refinery managing its output mix in real time to meet the needs of varying markets.

There is Still Significant Demand for Hydrogen Solutions

Based on demand for the use cases that can be justified we estimate total demand for hydrogen in a fully decarbonised world to be 447Mt, creating demand for 3TW of electrolyser capacity. The forecasts match well with others in the market giving us some confidence in this level of demand.

Electrolyser Capacity Forecasts in 2050



Source: Hydrogen Council, BNEF, Longspur Research

Production Choices

Our utilisation analysis means that despite initial higher costs, flexible electrolysis solutions, including PEMEC and AEMEC and MFEC technologies, are potentially more valuable than low cost alkaline electrolysers. Solid oxide also has a key role notably where nuclear power is developed as a low carbon solution in order to address the relative inflexibility of that power source. Electrolyser developers and manufacturers face a lag in demand relative to supply and many still need to prove reliability and deliverability. But we see opportunities especially for those delivering flexible solutions.

Compression the Efficient Solution for Transport

The high loading and unloading costs of liquefaction and ammonia cracking make these expensive solutions to transport except where the ammonia is the end product. Compression does make sense and is essential for pipelines which are the key solution where volumes are large enough. But this is a scale solution not suitable for all distributed production or demand and compressed shipping is potentially emerging as a suitable option.

Development Opportunities

Project developers are few and far between but at the project level we think emerging policy support will augment emerging demand especially with IRA support in the USA, delegated act support in the EU and CfD revenue in the UK. Companies developing projects serving ammonia, methanol, biomethane, DME, grid balancing and truck refuelling could all offer good investment cases.

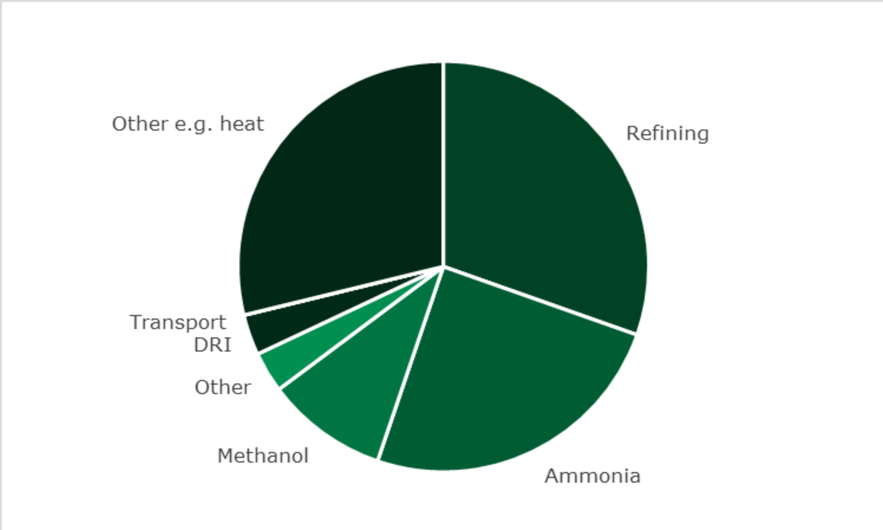
Fuel Cells Still Have Markets

Finally fuel cells will see demand in niche markets some of which could be substantial. We are seeing increasingly specialised options including high temperature PEM, ammonia reforming alkaline, solid oxide and marinized solutions with valid use cases in key niches.

THE HYDROGEN ECONOMY

A significant hydrogen economy already exists with current production of 95Mt annually, primarily used in oil refining and in the production of ammonia and methanol.

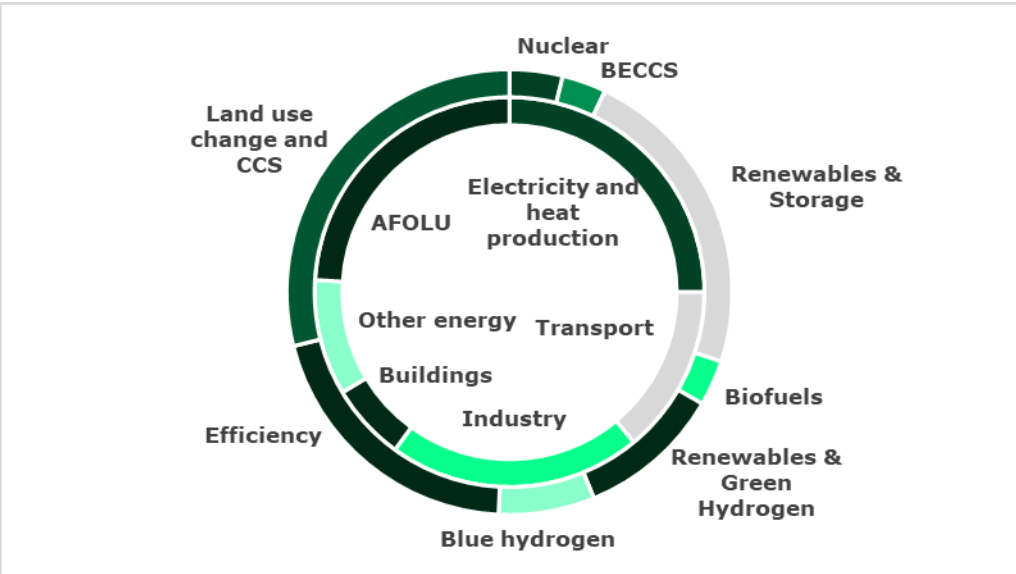
Current Uses of Hydrogen



Source: Hydrogen Council

Hydrogen will be a key tool for cutting greenhouse gas emissions. Identified use cases include decarbonising industries such as ammonia production. It can provide a transport fuel for heavier transport uses where lithium-ion batteries lack power and range. It can be used to provide power as an electricity balancing solution. Finally, it can be used for heating although this may not be as efficient as other solutions. In Simple Not Easy (Longspur Research, 18 February 2021) we analysed the median decarbonisation pathways in the IPCC Special Report on 1.5ºC (SR1.5). This suggested that hydrogen can be a major part of the decarbonisation toolkit, potentially removing 17% of current greenhouse gas emissions.

Global Emissions and Solutions Based on SR 1.5



Source: IPCC, Longspur Research

HYDROGEN DEMAND FORECASTS

We have now taken a more bottom up approach to our demand forecasts, reviewing the key use cases for low carbon hydrogen and have revised our overall forecast for demand.

We have assessed demand from hydrogen for the following use cases:

Transport:

- Shipping using green methanol from biogenic sources with hydrogen upgrading
- Heavy trucking using biomethane with hydrogen upgrading
- Aviation using sustainable aviation fuel with hydrogen upgrading

Industry:

- Ammonia using green hydrogen via the Haber Bosch process
- Methanol using biogenic gasification and hydrogen upgrading
- Refining using green or blue hydrogen
- Specific high temperature and off grid heating using hydrogen or DME
- Steel using hydrogen direct reduction (H DRI)

Power:

- Power balancing using green hydrogen

This results in a lower demand than our top down approach with much of the energy replaced by bioenergy and the direct use of electricity.

Hydrogen Demand Forecasts Breakdown

Use case	**Mt**	**Solution**
Shipping	35	Upgraded biomethanol
Heavy trucks	78	Upgraded biomethane
Aviation	63	Upgraded SAF
Transport subtotal	**176**	
Ammonia	32	Hydrogen/Haber Bosch
Methanol	16	Hydrogen
Refining	10	Hydrogen
Heating	7	Hydrogen/rDME
Steel	29	H-DRI
Industry subtotal	**94**	
Power balancing	177	LDES
Total	**447**	

Source: Longspur Research

We have also estimated the demand for green hydrogen production from the above demand assumption combined with an assumption that green hydrogen production will be 60% of the total.

Hydrogen Electrolysis Forecast

Total hydrogen (Mt)	447
Green hydrogen supply (Mt)	268
Electrolysis efficiency (kWh/kg)	50
Total electrolysis required (TWh)	13,407
Utilisation (%)	54%
Capacity (GW)	2,834

Source: Longspur Research

In our analysis of SR 1.5 we had already discounted hydrogen for domestic heating and light vehicles but we now assume that elements of heavy transport including shipping are better met through biofuels. However, a key change is to upgrade biofuel production with hydrogen which mitigates some of the impact. There is also a reduction in renewable energy capacity as there is less demand for green hydrogen but, because we now see low utilisation green hydrogen making sense, the impact on renewable capacity is more limited.

We continue to assume that blue hydrogen is part of the mix. We are concerned that the potential level of fugitive emissions makes this a bad solution, but it can continue to have a role if these are properly controlled. Fuel cells become a smaller part of the overall solution but still have strong demand in a number of niche applications.

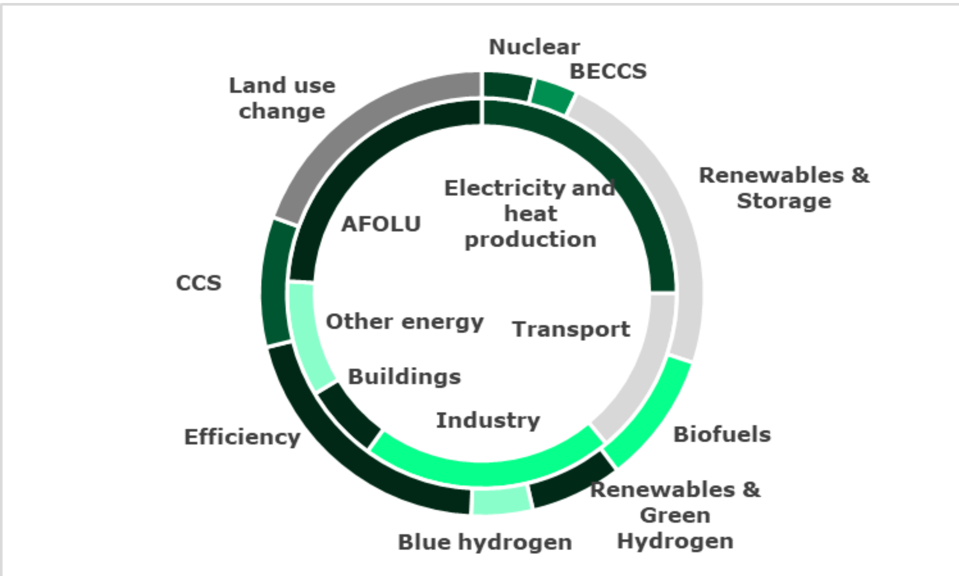
Longspur Hydrogen Forecasts Compared

	SR 1.5	Longspur	Difference
Renewable Energy (GW)	22,486	19,482	-13%
Hydrogen production (Mt)	781	447	-43%
Green hydrogen (GW)	4,957	2,839	-43%
Fuel cells (GW)	78	24	-69%
Bioenergy (EJ)	21	68	222%

Source: Longspur Research

These changes see our overall decarbonisation picture amended as below.

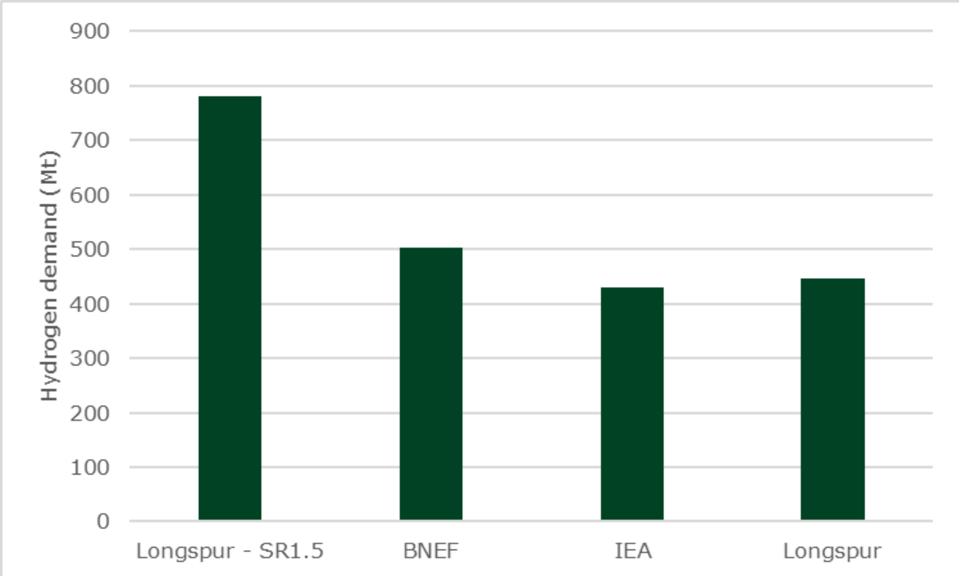
Global Emissions and Solutions



Source: IPCC, Longspur Research

Our original analysis of SR1.5 suggests hydrogen fuelled energy equal to 781Mt per annum by 2050. Adjusting this to reduce hydrogen use cases sees it fall to 447Mt per annum. Checking against other forecasts with the Hydrogen Council at 549Mt, BNEF at 502MT and IEA at 430Mt, this seems reasonable for a full net zero solution with hydrogen use maximised. If anything, we would expect our forecast to be slightly higher than others as we include co-location of hydrogen with nuclear and with biofuel co-production.

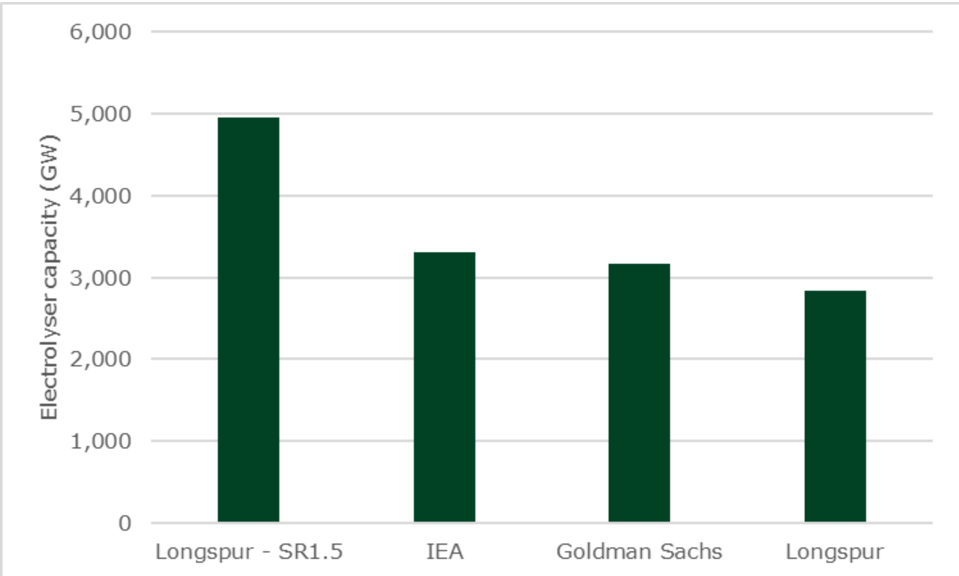
Hydrogen Demand Forecasts in 2050



Source: IEA, BNEF, Longspur Research

We have translated this into demand for electrolysis assuming a 60/40 green/blue split in line with the Hydrogen Council. This is again in line with other forecasts.

Electrolyser Capacity Forecasts in 2050



Source: Hydrogen Council, BNEF, Longspur Research

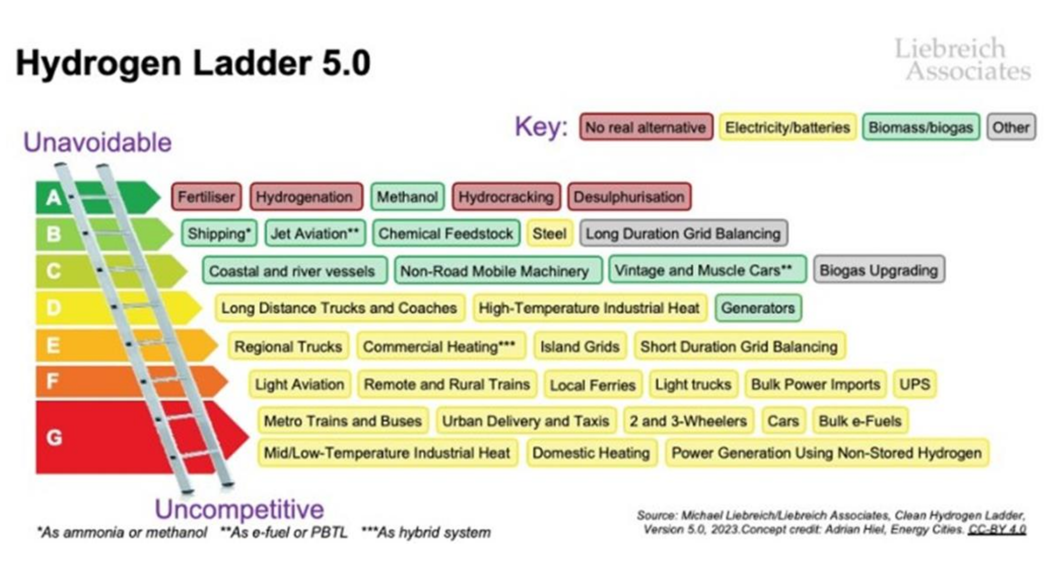
PROBLEMS OF EFFICIENCY AND ECONOMICS

One of the key criticisms of hydrogen is that of its sometimes poor efficiency when compared with existing processes or potential solutions. The main arguments against the use of hydrogen in many scenarios primarily involve the physics and efficiency of the gas from an energy density and loss perspective. This then has a knock on impact on the logistical issues surrounding transport and infrastructure both of which will also need to be developed and are contingent on whether it is gasesous hydrogen or one of the P2X solutions identified previously.

Michael Liebrich, founder of BNEF, has popularised the concept of a "hydrogen ladder". Liebrich's main contention with hydrogen is that wasting money and time on hydrogen where it is clearly not suitable is a poor use of both, and ultimately a distraction. This is arguably a criticism of both hydrogen advocates and policy makers rather than of hydrogen itself.

Hydrogen can theoretically be used as a decarbonising solution across a plethora of industries, however whether this comes to fruition or not is dependent on the associated costs and alternatives in the market and global public policy.

The Hydrogen Ladder



Source: Michael Liebrich Associates (concept credits: Adrien Hiel/Energy Cities & Paul Martin)

The ladder splits key areas that require decarbonisation on a sliding scale based on hydrogen's suitability in decarbonising them whilst showing the main alternative.

We think that the ladder is broadly correct and we do not see many of the categories below D resulting in any meaningful hydrogen demand although we will examine some excptions later in this note. Some of D and C we would scale back and most of these categories have elements where hydrogen makes sense and elements where it doesn't. In particular we would remove coaches and certain elements of heating. We would also specify long distance trucks as heavy long distance trucks and we would remove many coastal and river vessels which we think are better served by batteries.

Looking at BNEF's own forecasts (New Energy Outlook 2022), categories A and B account for 80% of all demand depending on how the categories are defined. We would add heavy trucking into the mix but this is not split out by BNEF. The road category is low and we think BNEF have effectively already discounted light transport with just 5% of road transport energy supplied by hydrogen. On that basis we assume the road category is largely heavy trucking. That would give 88% of demand at the "unavoidable" end.

Hydrogen Demand by Category

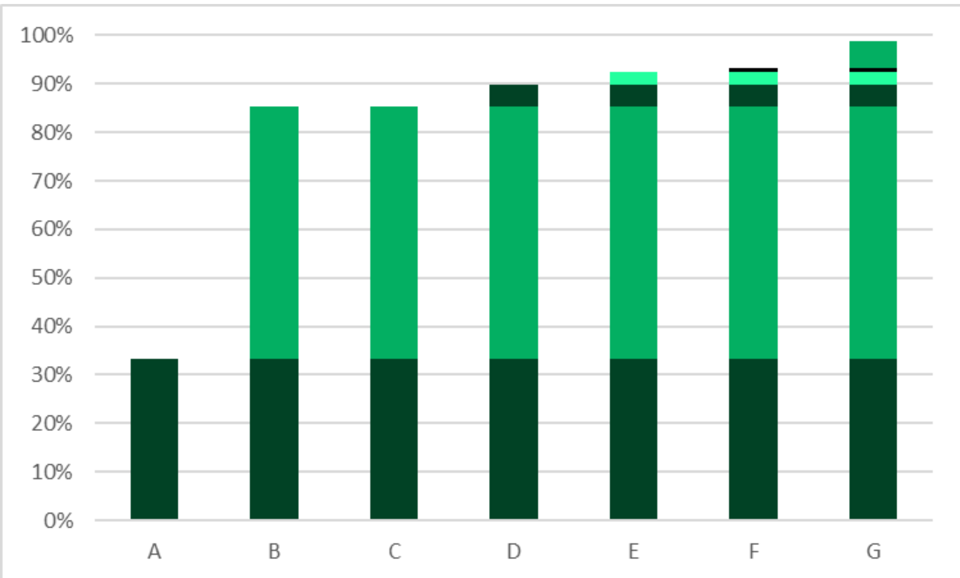
	Mt	Category
Energy industry	163.4	A
Steel	144.5	B
Aluminium	4.9	D
Cement	2.0	D
Other industry	16.3	D
Residential b.	17.1	G
Commercial b.	13.3	E
Road	11.7	G
Shipping	31.3	B
Aviation	42.2	B
Rail	2.9	F
Other	5.8	na
Power	43.4	B
Hydrogen	3.0	A
Total	**501.7**	
Total A&B	427.8	
A&B %	85%	
Add road	439.4	
Revised %	88%	

Source: BNEF, Liebrich Associates, Longspur Research

We are trying to fit the definitions used in the ladder with those used by BNEF. The ladder refers to long duration grid balancing whereas BNEF refers to power. As we will show, there is a case for matching curtailed energy with peaking power demand for grid balancing so we think the conflation here can be justified.

Clearly as one moves down the ladder demand increases but the important point is that at stage B demand is already at 85% of the total and by stage D it is at 90%. This is of course because BNEF have already been realistic in their forecasts and not include demand from many of the lowly rated categories. We think it shows that despite the ladder having a high profile, it does not mean that large parts of existing market expectations need to be readdressed.

Percent of Hydrogen Demand Under Ladder Categories



Source: BNEF, Liebrich Associates, Longspur Research

DEMAND IN DETAIL

We have reviewed numerous forecasts and the technologies available and have produced a non-exhaustive review of key areas where hydrogen is likely and is not likely to have a demand in the future, noting limits on forecasts or technology where appropriate.

HYDROGEN FOR INDUSTRY

Hydrogens current use in industry is predominantly related to oil refining, ammonia and methanol production. Production is currently dominated by steam methane reformation of natural gas which produces CO_2 emissions of between 8 and 12kgs per tonne of hydrogen. We expect these industries to remain key markets for hydrogen in the future, albeit with a change in the mix (lower refining and higher ammonia and methanol production).

Refining – Hydrocracking, Hydrogenation and Desulphurisation

Currently there are no alternatives to using hydrogen in a number of refining processes, namely hydrogenation, desulphurisation and hydrocracking. Oil refineries currently represent the largest consumers of hydrogen in the world at around 41Mt as of 2022.

Whilst this ought to be a declining market on the road to net zero, from a practical perspective given the role of hydrocarbons in plastics, chemicals and pharmaceuticals it seems unlikely that we will eliminate the need for these processes entirely. Forecasts regarding peak oil have long been proven wrong, but assuming the goal of net zero by 2050, refining demand ought to decline from 2030. Regardless, we see this continuing to be a significant demand source for hydrogen moving forwards and see few other solutions other than hydrogen in refining, due to the nature of the processes involved. Refining presents one of the clearest demand pictures for hydrogen and a significant scale up in production is likely in the short term to decarbonise the industry while longer term it is expected that hydrogen or hydrogen products will then be exported to offset declining revenues from the traditional refining business.

While refining currently uses 41Mt of hydrogen we expect this to reduce as fossil fuel usage declines in a decarbonised scenario. The IEA expects just 25% of current oil demand to remain in a post 2050 decarbonised world and this seems a reasonable figure to use to estimate long term refining demand for hydrogen, giving 10Mt.

Chemicals

Production of chemicals (predominantly for use in fertilisers and thermoplastics) is an area that has been identified as being both a high emitter of CO_2 (5% of total global emissions, 1.5GT CO_2) and suitable for clean hydrogen solutions. Current chemical production of ammonia and methanol is highly dependent on grey hydrogen and decarbonisation here will likely be a significant early source of green hydrogen demand. De-carbonised solutions are in early test stages to produce chemicals like BTX (benzene, toluene, xylene which are the key aromatic building blocks for a variety of chemicals and plastics) using clean hydrogen and captured CO_2. In a low carbon economy, the Hydrogen Council has estimated that using hydrogen to produce aromatics could account for 50Mt of hydrogen demand per annum by 2050. Given the early nature of this technology, however, it is difficult to estimate this with any great certainty.

Methanol for plastics and other industrial uses currently uses 16Mt of hydrogen and we think this is a fair estimate of long term demand. Ammonia currently uses 32Mt of hydrogen. We expect this to move from grey to green and blue. There are positive and negative pulls on demand here but we think this is a reasonable estimate of long term demand.

Steel

Hydrogen may be the only realistic way to decarbonise industrial processes used in steel making. Currently 70% of steel produced globally uses blast furnaces that are powered by burning metallurgical coal in order to melt iron ore. Blast furnaces need to be heated to approximately 1,400-1,500 degrees Celsius in order to achieve this creating an emissions intensive process producing (on average in the USA) 2.1t of CO2 per tonne of crude steel (scope 1,2 & 3 emissions). Cumulatively, steelmaking accounts for approximately 7% of total global CO2 emissions.

Alternatives to blast furnaces already exist, with electric arc furnaces providing an alternative means of steel production with a much lower emissions profile at 0.37t CO2 per tonne of crude steel. Electric arc furnaces are, however, unable to process raw iron ore unlike blast furnaces meaning that iron ore must be processed into direct reduced iron (DRI) before being used in an arc furnace.

Hydrogen is already used for DRI which currently accounts for demand of approximately 5Mt of hydrogen per annum, producing 126Mt of steel. However, this process only uses the hydrogen as a reduction agent and still uses natural gas resulting in emissions. A full hydrogen solution, H-DRI, would increase the use of hydrogen but cut emissions especially using low carbon hydrogen. Swedish private company H2Green Steel hopes to have a 2.5mt low carbon steel facility in Boden, Sweden, operating in 2024.

Steel currently sees 108Mt of DRI output. Wood Mackenzie estimate that this will grow to 320Mt in a decarbonised world. Assuming 90kg of hydrogen is required per tonne of DRI steel including the energy requirement we see demand of 29Mt.

Cement

Cement is a high carbon emitter at approximately 7% of global CO2 emissions and 2.2GT per annum, however it is generally not seen as one of the hard to de-carbonise industries in which there is a significant role for hydrogen to play. There is potentially a role for hydrogen in heating cement kilns (with early pilot kilns being tested) however, this would likely be the extent of hydrogen's role in the sector and would not contribute significantly to demand. Approximately 60% of the CO2 emitted from cement use is in the calcination process from heating the limestone. The primary means of reducing the emissions in cement is likely to be through carbon capture or the development of alternative building designs or innovations in cement chemistry.

High Temperature Industrial Heating

Industrial heating makes up a significant proportion of global industrial emissions at present, predominantly fuelled by the burning of natural gas and coal. There are a number of options for decarbonising this sector, including biomass, direct electrification and carbon capture. For industrial heating, this is likely to be very process specific and we are likely to see a variety of engineering solutions emerge. It is reasonable to assume that hydrogen will play a role, through combustion, in providing process heat for specific industrial uses. BNEF expects 19% of hydrogen demand in 2050 to be driven by historic industrial uses such as process heating and for equipment operations and the Hydrogen Council estimates that approximately 70Mt could be used across industry. This is again an area where demand is mainly theoretical.

We are seeing some uses of hydrogen for specific uses in industry and we expect some greater use of renewable DME with hydrogen upgrading to create some additional hydrogen demand. We see a figure of 7Mt as a reasonable estimate of long term demand.

HYDROGEN FOR DOMESTIC HEATING AND COOKING

Before 1968 UK domestic gas supply typically contained up to 50% hydrogen. This town gas was produced from coal and also contained carbon monoxide and methane, all in varying quantities depending on the source coal. The hydrogen content was significant.

Currently all gas products in the EU are required to be able to burn gas with 23% hydrogen. Burners may require modification or replacement for higher levels. However, the largest claimed benefit to switching to a high hydrogen mix and even to 100% is that most of the existing infrastructure can be used. Projects in France (GRHYD), Italy (SNAM) and the UK (H21 Leeds City Gate and H21 North of England) have all proved successful. The UK Government's Hydrogen Strategy has been targeting 3m homes for hydrogen heating but recently the National Infrastructure Commission said that there was no public policy case for this, and former energy minister Grant Shapps has said that piping gas to domestic properties is less likely.

Hydrogen heating for homes remains one of the more contentious end use cases. The arguments here surround the efficiency of hydrogen and how it can be transported. To use in existing gas burning homes would not require a complete relaying of existing gas networks but would require significant levels of work in addition to high levels of ongoing maintenance as hydrogen can embrittle the welding in metal pipes making them more susceptible to damage and leaks. There are also issues surrounding hydrogen escaping from the network, hydrogen storage at each end of a pipeline in order to maintain flow pressure and the requirement for additives as hydrogen burns clear. Whilst there is scope for the development of hydrogen heating we expect an increased level of electrification with heat pumps to be a more dominant solution in this space.

This does not mean that hydrogen will not be used to heat houses. Rather than divergence across technologies, in regard to heating and cooling we expect this to be on a regional basis. There may be areas where hydrogen is clearly a better solution due to the renewable energy mix in an area or the nature of the existing or prospective housing stock. The option to produce or import hydrogen in order to use this for domestic heating and cooking could be a more viable solution in certain instances.

Off grid heating

6% of all energy use worldwide is in the form of locally and unsustainably sourced biomass such as locally gathered wood, animal waste and traditional charcoal. This is largely in the developing world. There are active moves to replace this with canisterised liquid pressurised gas (LPG). There has already been significant progress in this direction in India where the government's Pradhan Mantri Ujjwala Yojana (PMUY) scheme, which includes a "smokeless village" initiative, has tripled the use of LPG for cooking. Launched in 2016, the scheme targeted 50m LPG connections given to women in families below the poverty line. A budget allocation of US$1bn was made available and the scheme has resulted in a reduction in particulate matter (PM) emissions of 2,190kt per annum, a 64% reduction in deaths from air pollution and an estimated US$8bn in annual cost savings from improved health and productivity gains.

The opportunity now exists for similar programmes elsewhere, notably in sub-Saharan Africa. And increasingly the opportunity is to replace LPG with renewable dimethyl ether (rDME). This is created from the dehydration of methanol or from biomass. Again this potentially puts pressure on bio methanol feedstock but as we will show the move to co-locate green hydrogen production with gasification alleviates this and increases demand for green hydrogen. We are also seeing a few cases of rDME being used for industrial heat.

NOT JUST HYDROGEN

Oxygen as a by-product

We have estimated demand for electrolysers based on demand for green hydrogen. However, hydrogen is not the only valuable product from an electrolyser. A number of industries require oxygen and while oxygen on its own does not always demand a high price, using an electrolyser to provide both oxygen and energy in the form of hydrogen can make strong economic sense.

This is already seeing demand emerging in the water treatment industry. Using injected oxygen in the wastewater treatment process allows bacteria to regenerate quickly and breakdown sewage more effectively. It also avoids the creation of hydrogen sulphide and methane. The normal aeration process is costly and accounts for around 50% of the carbon emissions and energy consumption in municipal treatment works.

Anglian Water is deploying an electrolyser at its Cambridge Sewage Recycling Plant and Northern Ireland Water has ordered a membrane free electrolyser for its Belfast site.

Chlorine as a By Product

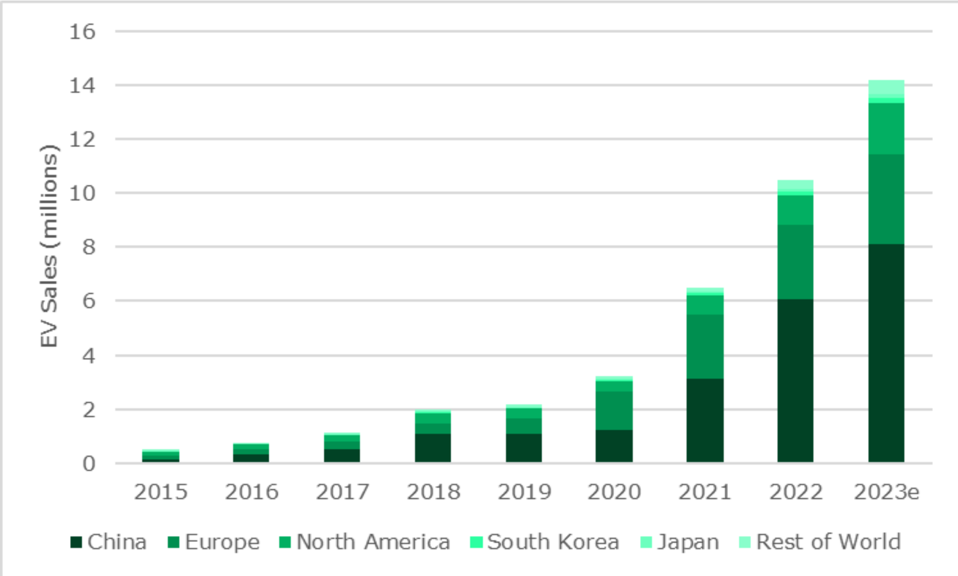
Chemicals group Ineos already produces hydrogen from its chloralkaline manufacturing process which is effectively a salt water electrolysis process. This uses salt water to produce chlorine and caustic soda (sodium hydroxide) with hydrogen as a by-product. The company's Inovyn subsidiary has been operating the technology for over 50 years with a membrane cell electrolyser. While this has been done in the past using predominantly fossil fuelled grid electricity, a move to renewable energy means it is creating green hydrogen from the process as well as chlorine and caustic soda.

HYDROGEN FOR TRANSPORT

BATTERIES ARE NOT THE ONLY ANSWER

Ground transportation has an obvious solution in battery electric vehicles (BEVs). These are already capturing market share notably in Norway where over 80% of new vehicle sales are battery electric.

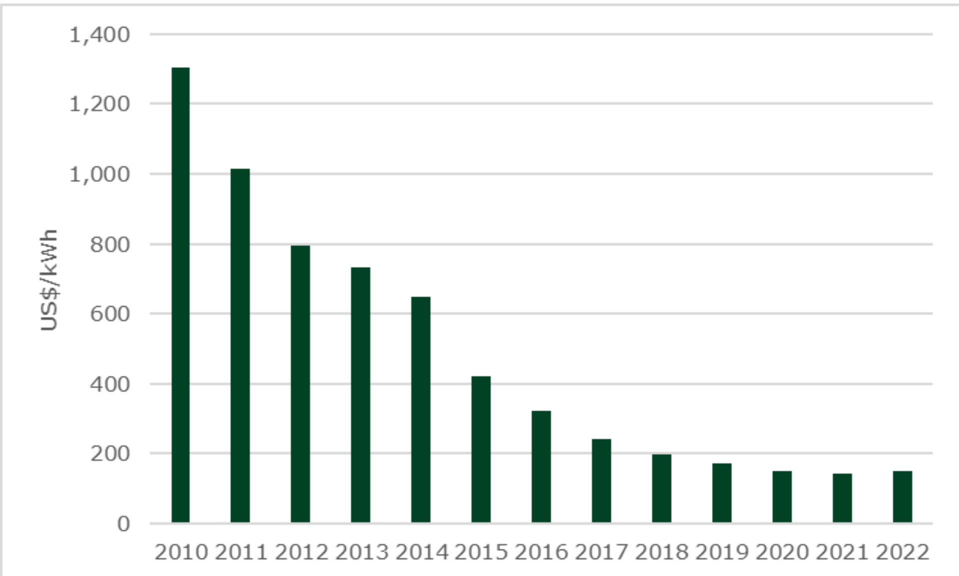
Global EV Sales



Source: BNEF

Lithium-ion batteries have allowed battery electric vehicles to emerge as a valid solution to low carbon transport. Costs have fallen and energy density (which drives vehicle range) has risen. Battery electric vehicles (BEVs) are likely to be the go-to solution for passenger cars and light duty commercial vehicles especially for urban duty cycles.

Lithium-ion battery pack prices



Source: BNEF

We think lithium-ion is already testing its limits for transportation. For example, the new Porsche Taycan was originally promoted with a 350kW charger but following feedback from battery supplier LG Chem have downgraded this to 270kW. For Porsche, performance over the life of the vehicle is important and battery degradation due to overly rapid charging is an issue.

New battery technology can push these limits out in time, with silicon anodes and solid-state electrolytes the most likely areas of progress. However, electrochemistry is a difficult area and we do not expect new technologies in mainstream applications overnight. As a result, we see alternative solutions, notably those based on hydrogen, gaining ground in specific applications especially in long range and high-power.

The biggest issue for batteries is range limitation. Physically, the only way to get greater range with a battery is to add weight in a linear manner. With low energy density, efficiency falls off by comparison with traditional fossil fuelling or hydrogen vehicles.

Range is not an issue for many, especially cars used for city journeys. But for longer journeys and high intensity users this can be an issue. The problem with range is that a battery is not especially energy dense so additional range can only come with significant additional weight. For trucks with higher weights, range limitations become a bigger issue.

We can estimate the impact by looking at where energy is consumed in a car journey.

Energy is required to overcome two forms of resistance, aerodynamic resistance and rolling resistance. The total energy is the force overcome times distance travelled and the total force equals the combination of the forces required to overcome aerodynamic resistance and rolling resistance. These are calculated as follows:

$E = F \cdot d$ where $F = F_{rolling} + F_{aero}$ and d is the distance travelled or vehicle range.

$F_{rolling} = m \cdot g \cdot C_{rr}$

Where m is the vehicle mass, g is acceleration due to gravity and C_{rr} is the coefficient of rolling resistance.

$F_{aero} = 0.5 \cdot p \cdot V^2 \cdot A \cdot C_d$

Where p is the density of air, V is the speed of travel, A is the frontal area of the vehicle and C_d is the coefficient of drag.

While aerodynamic resistance is not impacted by weight, rolling resistance is and increases the heavier the vehicle. This means that as an EV adds more batteries to increase range the weight goes up and vehicle requires more energy per km travelled. This reduces the overall efficiency of the vehicle. This is also true for fuelled vehicles where the added weight of fuel reduces overall efficiency. However, the energy density of fuels is much greater than batteries so the impact is trivial by comparison.

THE AUTOMOTIVE EXPERIENCE

We can compare a BEV with a fuel cell electric vehicle (FCEV), in this case a Tesla Model 3 against a Toyota Mirai 2. We use the following data in our calculations.

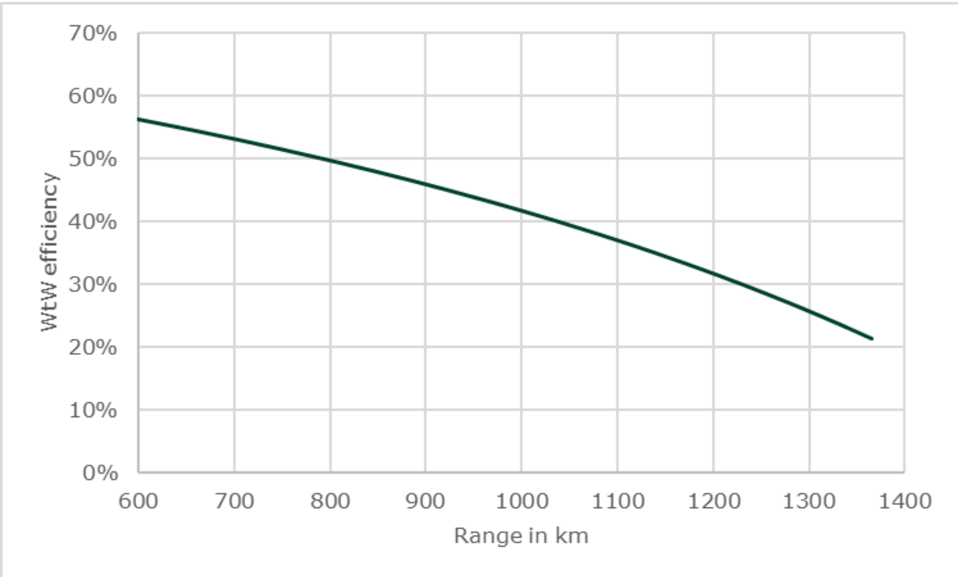
Key Data Assumptions for Vehicle Efficiency Analysis

	Tesla Model 3	Toyota Mirai 2
Battery/fuel density (Wh/kg)	160	33333
Efficiency η (TtW)	72%	50%
Efficiency η (WtW)	61%	32%
Coefficient of drag (Cd)	0.23	0.29
Air density p (kg/m3)	1.293	1.293
Frontal area (m2)	2.369	1.810
Coefficient of rolling resistance (Crr)	0.015	0.015
Velocity (m/s)	26.822	26.822
Shipping weight (kg)	1,858	2,409

Source: Longspur Research

For the Tesla, if we want to increase the range, we need to add more batteries which increases the weight. That means for each km of range we add we need an extra 2.85Wh of energy just to overcome the additional rolling resistance. This reduces the overall energy efficiency of the vehicle so that as range increases efficiency drops.

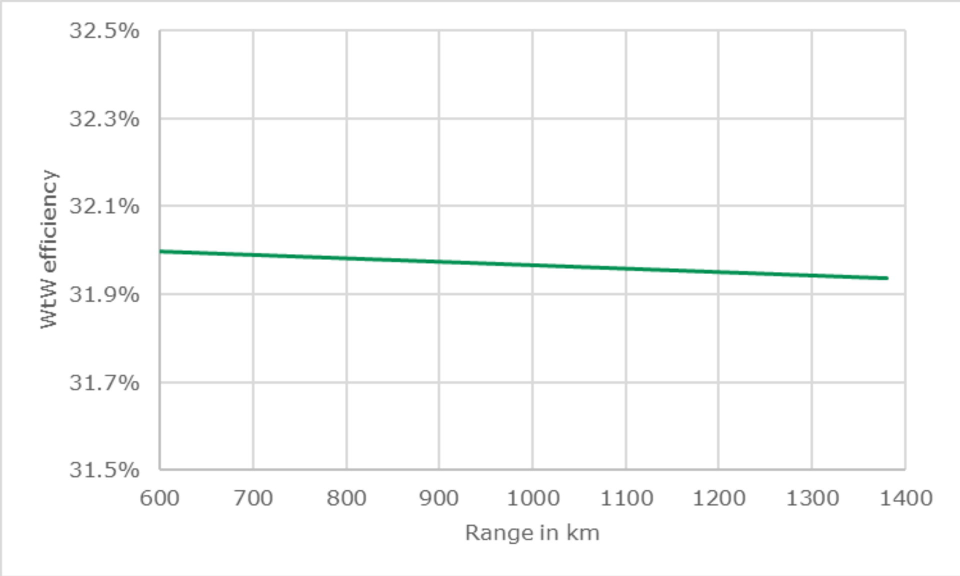
Efficiency Against Range – Tesla Model 3



Source: Longspur Research

We can compare this against a hydrogen vehicle, in this case the Toyota Mirai. This has less energy efficiency to begin with which is often cited as a reason for not pursuing hydrogen automobiles. However, because hydrogen has a high energy density, the impact on rolling resistance of adding more hydrogen to increase range is much less than in the battery example. Just an extra 0.01Wh is required to overcome rolling resistance per kilometre.

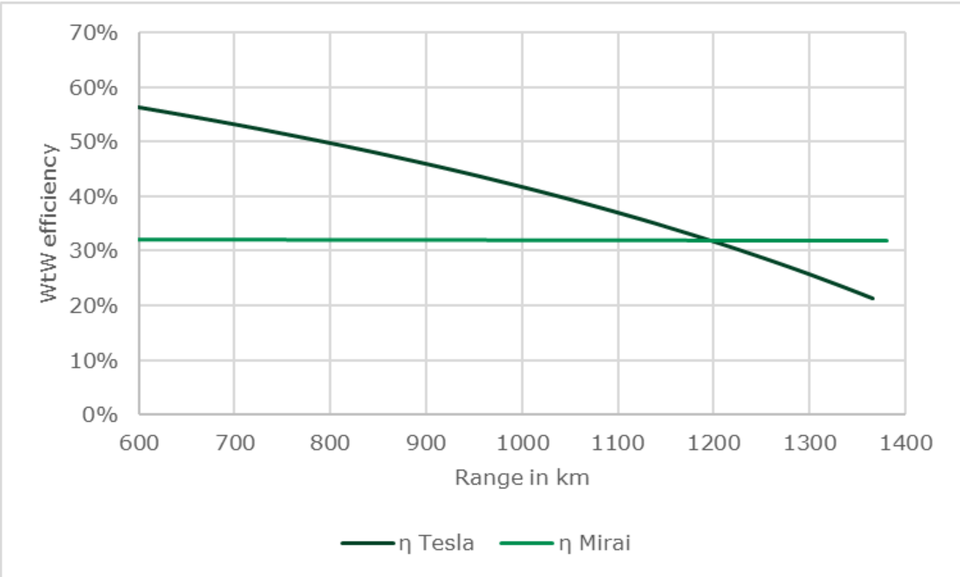
Efficiency Against Range – Toyota Mirai 2



Source: Longspur Research

If we compare the impact of range on efficiency for both vehicles it becomes apparent that the much lower starting efficiency of the Mirai means it only beats the Tesla at ranges of c.1,200km and above. We see limited demand (possibly zero) for ranges of this nature and as a result conclude that there will be limited demand for hydrogen automobiles.

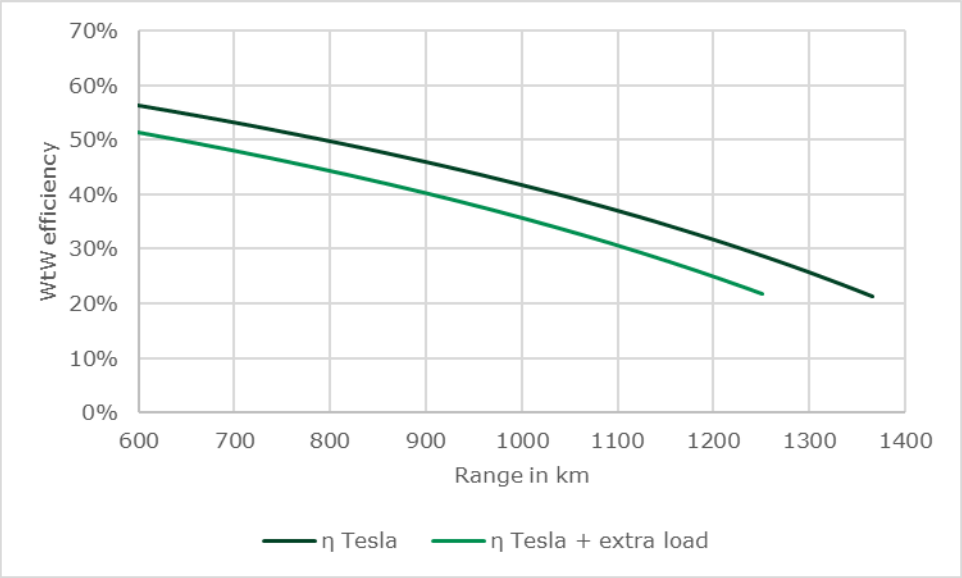
Efficiency Against Range – Models Compared



Source: Longspur Research

One key feature of the physics is that even for BEVs, the heavier the vehicle, the more the efficiency curve moves to the left. If we add extra cargo or passenger load into our calculation for the Tesla we can see that the efficiency is reduced with the curve shifting to the left.

Efficiency Against Range – Tesla Plus Extra Load

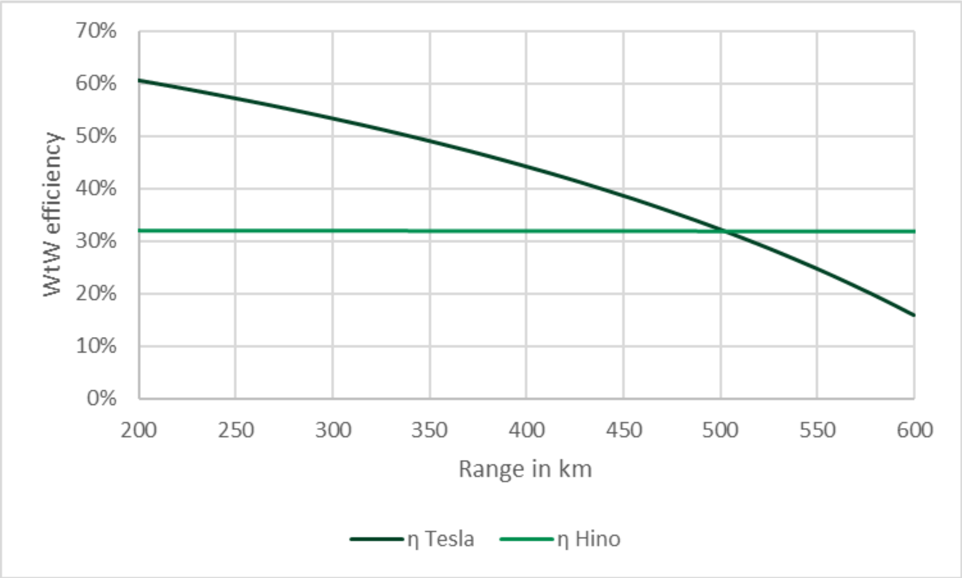


Source: Longspur Research

TRUCKS ARE A DIFFERENT STORY

If we look at the heavy end of the commercial vehicle market and do the calculations for the Tesla Semi and the hydrogen fuelled Toyota backed Hino Profia with 40t loads, we see that the crossover point is less than 500km or 300 miles. For even heavier vehicles the cross over would be even lower.

Efficiency Against Range – Tesla Semi Against Hino Profia

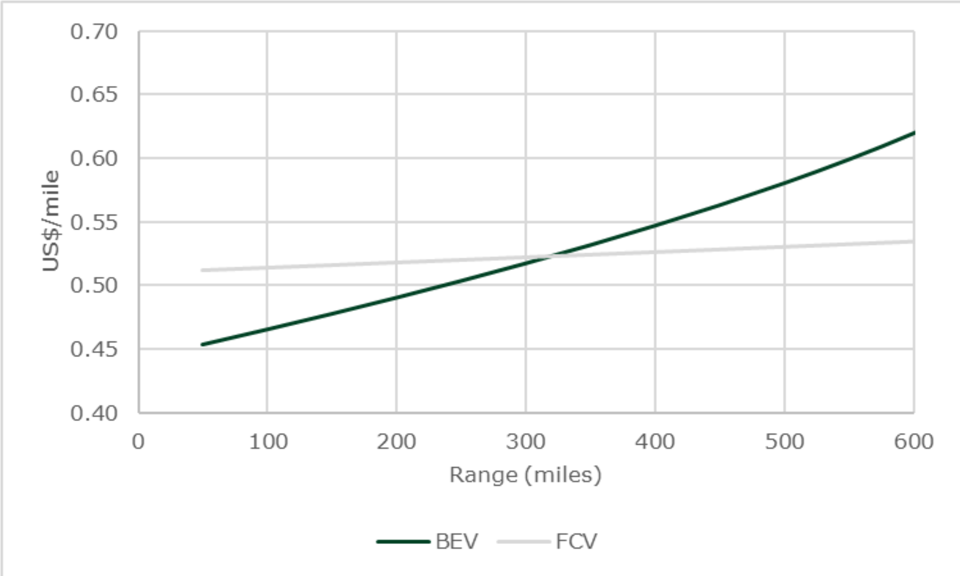


Source: Longspur Research

As a result, we do see a role for hydrogen powered heavy long distance trucks and moving into the off road market for even heavier mining trucks and similar vehicles, hydrogen begins to make more sense especially when taken into account with other factors such as fuelling times and a more familiar fuelling procedure.

A similar analysis by Bloomberg New Energy Finance shows their estimates of the cross over point for a heavy-duty truck in a supportive policy environment for hydrogen. This suggests that at ranges over 300 miles hydrogen is a better option, confirming our analysis.

Total Cost of Ownership Class 8 Heavy Duty Truck (Strong Policy)



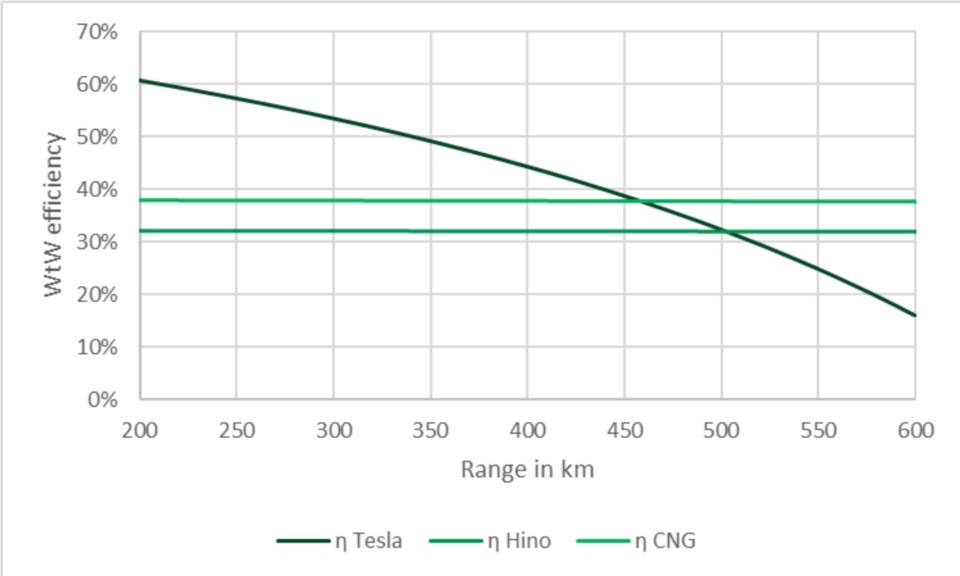
Source: BNEF

This is worsened for heavier, more powerful applications. We are already seeing a move by Chinese bus OEMs to make use of fuel cells notably for longer distance buses. There is also interest in trucking, including mining, and in areas such as forklift trucks and logistics vehicles, including airport or port service vehicles. All these benefit from the fact that they can be fuelled at their depots without the need for a hydrogen infrastructure.

CNG OFFERS AN EFFICIENT SOLUTION FOR LONGER RANGES

The analysis looks even better when we look at renewable compressed natural gas (rCNG). Biomethane has a lower energy density than hydrogen but is still much denser than batteries and, because biomethane is even more efficiently produced, the cross over point is actually slightly less than hydrogen at about 280 miles.

Efficiency Against Range – Comparing CNG



Source: Longspur Research

There are 174 thousand CNG trucks in the US alone with 64% of these using biomethane. With gas engines are now available from most of the major OEMs, we see biomethane as a major low carbon solution for trucking in the near term. Hydrogen may become a valid option further out but we do not see this as a given and therefore would not include trucking in our immediate market size considerations for pure hydrogen.

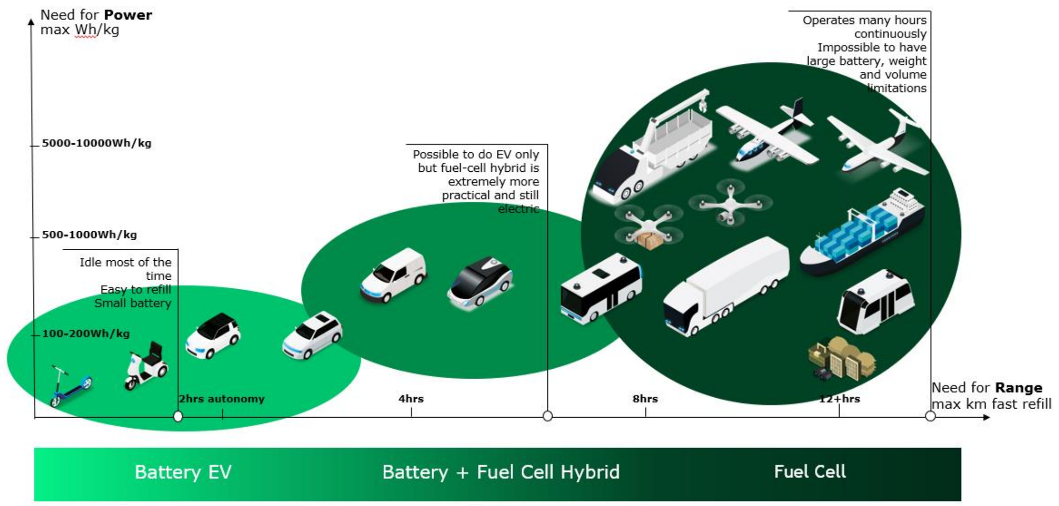
However while biomethane can be produced entirely using anaerobic digestion of agricultural waste, the need for feedstock can be effectively halved by adding power to gas in the form of hydrogen electroysis. We examine this in more detail further in this note but for now we see this as a potential demand source for hydrogen.

LOW CARBON LIQUID FUELS

As a result of the current cost of green hydrogen production it is not economic without some kind of subsidy in cases where the hydrogen is being used directly. However, hydrogen can be further processed into a range of derivative produces with economics that may be more attractive. This is known as Power to X or P2X where the X refers to the derivative products and the power is that used for the electrolysis. In addition to being more economically attractive, P2X fuel solutions also have a number of other benefits compared to pure hydrogen such as an increased ease of handling or the need for less retrofitting on existing transport methods.

As we have shown, while batteries are suitable for short range, the key long haul, heavy, transport solutions are likely to be hydrogen based fuels of one form or another unless battery electrochemistry or small modular reactors develop significantly in the near future.

Low Carbon Vehicle Market Segments



Source: Advent Technology

Many industry commentators looking at the decarbonisation of heavy duty transport are focusing on green ammonia, green methanol or biomethane as hydrogen carriers. Their key characteristics are shown below against those of the major fossil fuel alternatives. Ultimately, a solution in this area is going to be molecule based rather than electron based due to the difficulties in getting enough power out of a battery due to the lower energy density in order to power substantially sized vessels and vehicles.

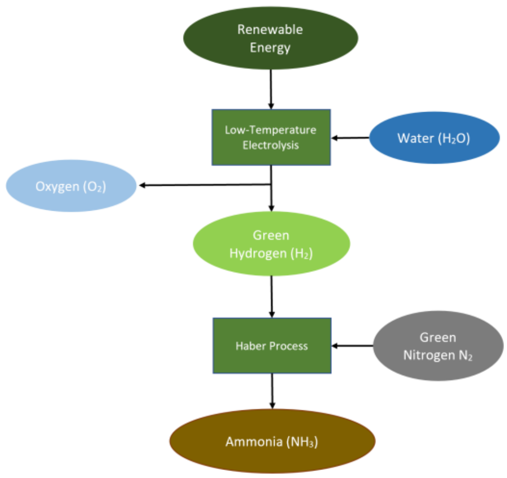
Main Liquid Fuel Options

Fuel type	LHV	Volumetric energy density	Storage pressure	Storage temperature	Tank volume*
	(MJ/kg)	(MJ/l)	(bar)	(°C)	(l)
Hydrogen	120	8.5	1	-253	7.6
Ammonia	19	12.7	1 or 10	-34 or 20	4.1
Methanol	20	15.8	1	Ambient	2.1
Methane	50	23.4	1	-162	2.3
LPG	46	25.5	1	-42	2.0
MGO	43	36.6	1	Ambient	1.0
HFO	40	35.0	1	Ambient	1.0

Source: KR (2020), Vries (2019), MAN (2019), * hydrogen and ammonia assumed as liquids

AMMONIA

Green Ammonia Process Map

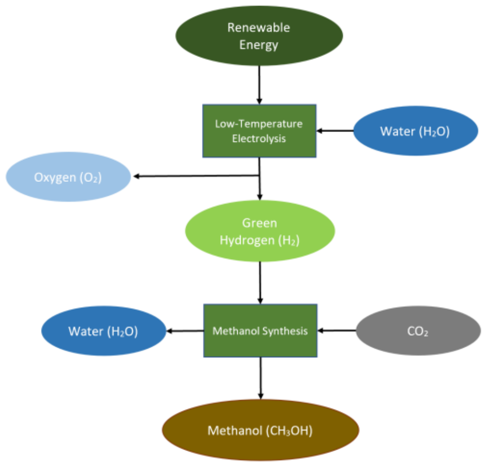


Source: Longspur Research

Ammonia is liquid fuel that can be either combusted or used in a fuel cell and can still be produced using green hydrogen, alleviating some of the problems of hydrogen storage. Ammonia is basically a hydrogen carrier but is arguable more suitable as a fuel source as it has a higher energy density. Ammonia (NH3) is produced by combining hydrogen and nitrogen. The nitrogen required is extracted from the air and the hydrogen produced through the process of water electrolysis, using either renewable or fossil fuel sources in the process. These hydrogen feedstocks are generally gasified to form synthesis gas (CO and H2), which can then be reacted with water and nitrogen to produce ammonia. The well-established Haber Bosch process enables the nitrogen and hydrogen to be reacted to create ammonia. There are however notable drawbacks surrounding ammonia, including toxicity and its volatility. The high nitrogen content of the fuel itself raises issues of NOx emission although engine developers say this can be controlled.

METHANOL

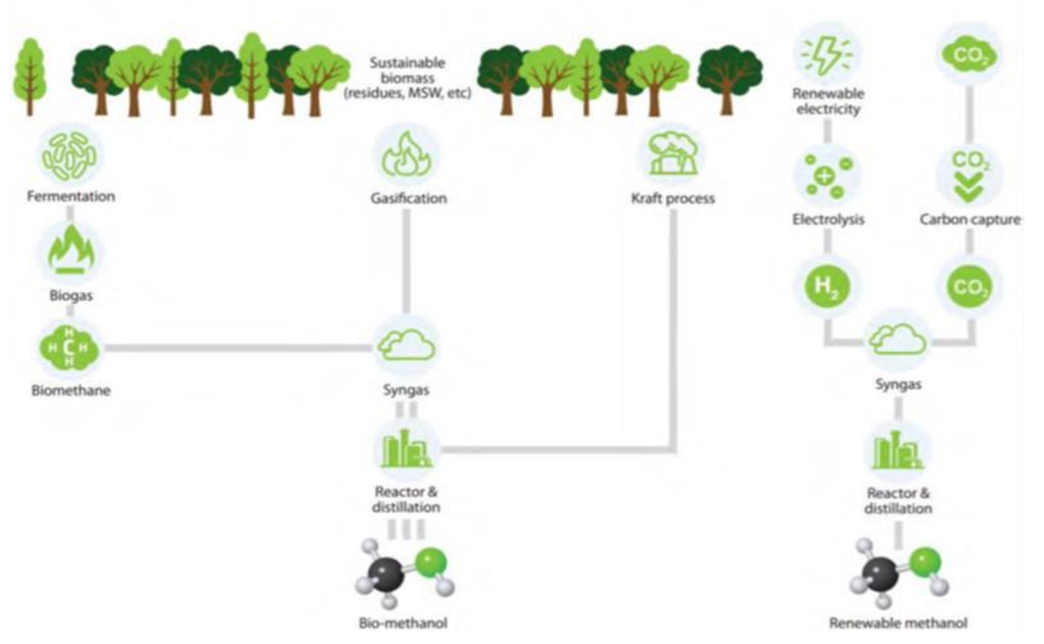
Renewable Methanol Process Map



Source: Longspur Research

Renewable methanol can be produced using renewable feedstocks and renewable energy in the form of either bio-methanol or e-methanol. Bio-methanol is produced from biomass from sustainable biomass feedstocks such as forestry and agricultural waste, biogas from landfill, sewage, municipal solid waste (MSW) and black liquor from the pulp and paper industry (IRENA 2020). Green e-methanol is produced by combining green hydrogen from renewable energy through electrolysis and CO2 from carbon capture.

Biomethanol and Renewable Methanol Compared

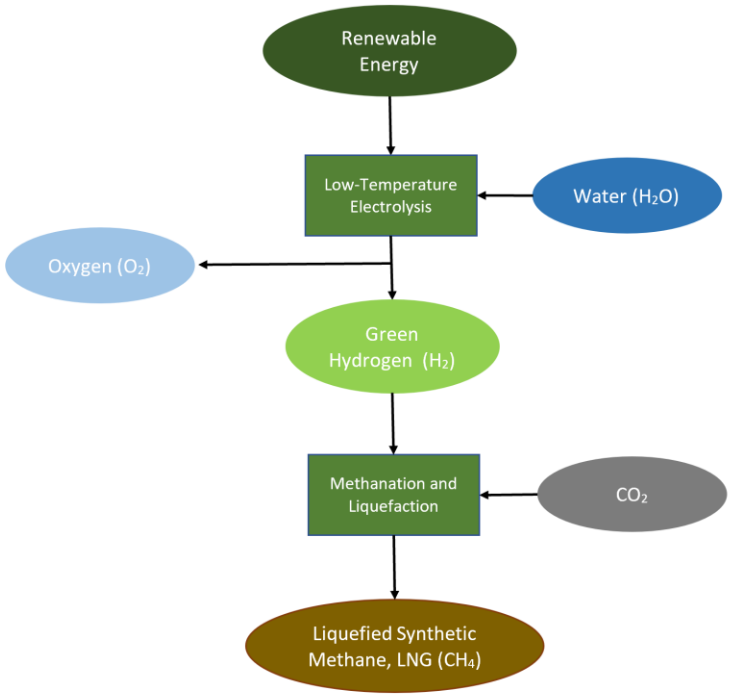


Source: Proman - Sea Commerce presentation 2021

As a solution for shipping, methanol is available in over 120 ports and there are now over 200 vessels in operation or on order globally. One of the reasons for this is the ability of methanol to be stored and transported using current infrastructure as it remains in liquid form at normal air temperature and pressure. Bunkering is already available on a vessel to vessel or shore to vessel basis.

METHANE - CNG/LNG

e-CNG/e-LNG Process Map



Source: Longspur Research

Natural Gas is considered by many as an ideal transitioning fuel for decarbonisation because it has a lower carbon intensity than oil or coal. Whilst natural gas is a fossil fuel, it does have some environmental benefits when compared to other fuels and can be deployed today at a fraction of the cost of alternative low carbon green fuels. It has seen some early popularity in shipping largely due to its ability to short term regulatory requirements implemented by the IMO. However, better still is biomethane produced from the anaerobic digestion of biogenic waste especially agricultural waste. This creates a biogas which is a mix of methane and CO2 but which can be further processed to remove the CO2 which if sequestered can result in a negative emission biomethane.

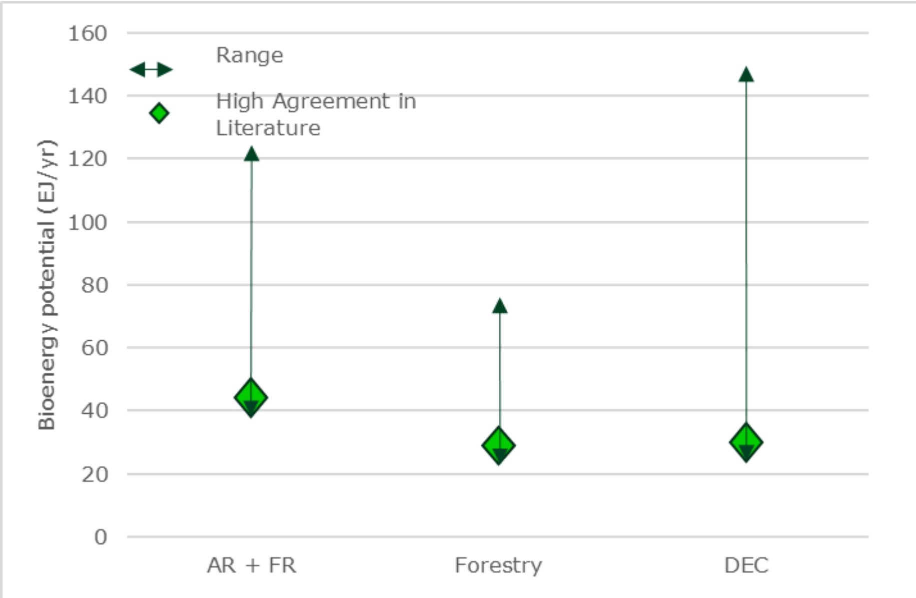
For road transport compressed biomethane (CNG) is already making progress with all major truck OEMs now offering CNG engines. Fuelling these with eCNG or rCNG delivers a low carbon solution in a familiar format with refuelling and operating being similar to diesel. Refuelling stations can be sited on existing gas grids with the rCNG injected and a mass balance approach taken so that gas withdrawn can be considered low carbon.

HYDROGEN AND BIOFUELS

Both biomethane and biomethanol are made from biomass either from gasification in the case of biomethanol or anaerobic digestion in the case of biomethane. One of the criticisms of these fuels is based on concerns that there may be insufficient biomass that can be harvested in a sustainable fashion to make the process genuinely low carbon.

A broad examination of all biomass sources shows availability with a high level of agreement in scientific literature pointing to a figure of about 100 exajoules (EJ) of sustainable biomass available annually.

Ranges/High Literature Agreement on Sustainable Bioenergy Potential



Source: Grantham Institute, AR + FR = Agriculture and Forestry residues, DEC = dedicated energy crops

We have estimated the gross energy requirements needed by all the key mitigation pathways that are likely to draw on biomass as a solution and are comfortable that the 100EJ sustainability limit is not reached, but it is close.

Sustainable Biomass Demand and Availability

Demand	Solution	Likely Sources	EJ
NETS	BECCS	Forestry, AR, FR	43
Trucking	BioCH4	AR, DEC	22
Shipping	BioCH3OH	AR, DEC	9
Aviation	SAF	Forestry, AR, FR	18
Total			92
Sustainably available			100

Source: Longspur Research

What is becoming obvious is that hydrogen can be a key to unlocking better utilisation of biomass reducing potential pressure on land and food, moving it back from sustainability limits.

GREEN HYDROGEN CAN MAKE THE FEEDSTOCK GO FURTHER

Anaerobic digestion for biomethane

A normal anaerobic digestion facility turns carbohydrate into biomethane and CO2. If the CO2 then undergoes methanation with hydrogen from a green electrolyser this can result in the creation of an equal amount of methane.

Anaerobic digestion $C_6H_{12}O_2 \rightarrow 3CO_2 + 3CH_4$

Electrolysis $12H_2O \rightarrow 12H_2 + 6O_2$

Methanation $12H_2 + 3CO_2 \rightarrow 3CH_4$

Gasification for methanol

Gasification of carbohydrate normally results in a syngas with roughly equal amounts of hydrogen and carbon monoxide. Methanol requires twice as much hydrogen as carbon monoxide so the output from normal gasification does not have enough hydrogen when run efficiently. Taking the additional hydrogen from an electrolyser gets round this and avoids less efficient gasifier operations. Gasification is slightly more complex than outlined below and more hydrogen can be created at the gasification stage. But the addition of electrolysis results in an efficient process that maximises fuel production per unit of biomass.

Gasification $2C + 2H_2O \rightarrow 2H_2 + 2CO$

Electrolysis $2H_2O \rightarrow 2H_2 + O_2$

Hydrogenation $2CO + 4H_2 \rightarrow 2CH_3OH$

Note that in both cases the amount of resulting fuel is maximised for the biomass input and, unlike pure e-fuels, no carbon capture is required other than the initial biomass photosynthesis.

The mixing of biogenic processes with green hydrogen is now known as biofuels upgrading. We are already seeing developments in both methanol and methane.

Norwegian Hydrogen AS has formed a JV with energy entrepreneur Jens Peter Lunden to develop anaerobic digestion biogas projects co-located with wind and electrolysis with an initial project in Denmark.

Canada's largest electrolyser project is a 88MW unit integrated in the Varennes Carbon Recycling project with will produce 125ml of biomethanol annually using biogenic waste as feedstock along with green hydrogen from the electrolyser.

KBR (formerly Kellogg Brown & Root) have launched an advanced green methanol technology, PureM, combining green hydrogen with carbon from biogenic sources or from carbon capture.

If these combined solutions are widely adopted they would reduce the amount of sustainable biomass required to reach net zero to well below the level that can be produced.

Sustainable Biomass Demand and Availability

Demand	Solution	Likely Sources	EJ
NETS	BECCS	Forestry, AR, FR	43
Trucking	BioCH4	AR, DEC	11
Shipping	BioCH3OH	AR, DEC	5
Aviation	SAF	Forestry, AR, FR	9
Total			68
Sustainably available			100

Source: Longspur Research

HYDROGEN PRIME MOVERS

HYDROGEN FUEL CELLS

There may be a scope for hydrogen and hydrogen fuel cells to be used for long distance road haulage, however we consider it to be less likely for other heavy transport such as aviation and shipping, preferring hydrogen derivative fuels for this. At present long haul trucking is dominated by one technology - diesel. In terms of the logistics of a long haul journey this is most easily replicated with the use of hydrogen, however that is where most of the similarities end. Fuel cells, whilst a reasonable technology, are faced with the similar constraints that surround hydrogen around infrastructure - namely around refuelling. The cost and effort of building up such a network will likely be significantly more expensive than an electrified solution, significant strides in which have already been made. Creation of an entirely separate hydrogen refuelling infrastructure for a more limited end use case will likely struggle to attract capital to achieve this. BNEF estimate that hydrogen trucks will be just under 4.5% of the global fleet in 2050 with the dispersion skewed more heavily towards nations like China, Germany and the UK. This will add to the demand case for hydrogen, but we do not expect this to be a material addition to global hydrogen consumption in the future.

We think the jury is still out on whether hydrogen trucks will use fuel cells or reciprocating engines and we also see hydrogen upgraded biomethane as driving the outcome towards reciprocating engines. However, fuel cells have strong use cases in other niches. A key feature of a fuel cell is its relatively low noise and vibration in operation. In the presence of an operating fuel cell some have been known to ask whether it is actually running ("Is it on?"). There are at least four yards offering luxury yachts with fuel cell propulsion for this reason. Lighting generators units for the film industry also benefit.

Key niche applications include the following.

- Back up power
- Transport including marine
- On site generation
- Military
- UAVs
- Forklifts

HYDROGEN ENGINES

The first ever internal combustion engine, the De Rivas engine, was fuelled by hydrogen. This was designed in 1804 and first used to propel a vehicle in 1807, the first ever automobile power by an internal combustion engine.

Automobile Fuel History

Date	Fuel	Developer
1807	Hydrogen	Issac de Rivaz
1839	Electricity	Robert Anderson
1883	Gasoline	Siegfried Marcus
1894	Diesel	Rudolf Diesel

Source: Longspur Research

Yamaha, Honda, Kawasaki and Suzuki have formed a technical research association, HySE (Hydrogen Small Mobility and Engine), to produce H2 ICEs. In the US, Werner Enterprises (WERN US) has signed a letter to intent to secure 500 Cummins X15H 15l hydrogen engines.

UK construction equipment manufacturer JCB found that H2ICEs were a better solution than fuel cells in the robust environment of construction sites where fast reacting high power sources were required to run at much higher utilisation rates than most road transport.

The key issue with H2 ICEs is NOx emissions. When any fuel is burnt in air with 80% nitrogen, oxides of nitrogen (NOx) are formed when combustion is at a high temperature. However, lean burn operation and catalytic converters as already used with diesel engines can minimise this problem.

CNG ENGINES

An alternative to hydrogen engines are biomethane engines. At present there is a growing use of compressed biomethane with the six largest European truck manufacturers all offering CNG engine solutions.

CNG Engine Availability in Europe

Manufacturer	Model/Series	Power (HP)
Scania	OC09	260, 340
Scania	OC13	410
Iveco	CURSOR 9	460
Volvo	FH	420, 460, 500
Mercedes Benz	OM 936	302
Renault Trucks	NGT9	320
MAN	E3268	496

Source: Longspur Research, Company Data

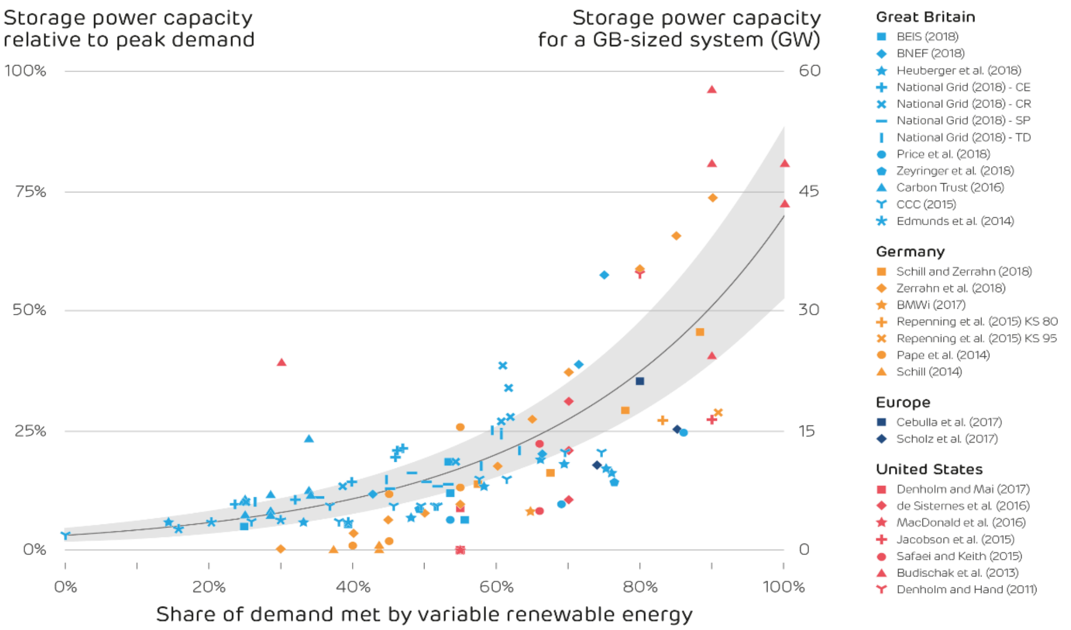
DEMAND FROM TRANSPORT

We have broadly used the transport indicators by mode in table 2.8 of SR 1.5 to estimate energy required to decarbonise transport. We have reduced shipping to account for the proportion of battery fuelled short range shipping. We have then assumed that half of the energy required is from hydrogen through PtL or biofuel upgrading. This gives 35Mt for shipping, 78Mt for heavy trucks and 63Mt for sustainable aviation fuel.

HYDROGEN FOR POWER

Decarbonised electricity systems will be largely reliant on intermittent renewable energy, mainly wind and solar PV. As we add more intermittent renewable energy, the demand for storage and long-duration storage in particular increases. The following meta study of research by Imperial College London shows this fairly clearly.

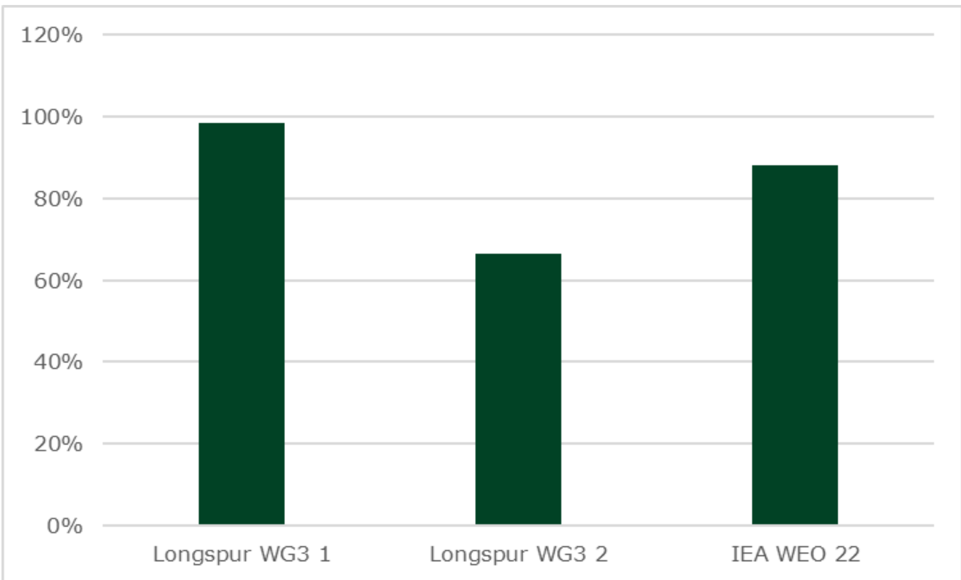
Storage Capacity Relative to Renewable Penetration



Source: Imperial College based on Zerrahn et al., 2018.

The key driver is the penetration of variable renewable energy as a percentage of total electricity demand. Using forecasts based on the IPCC Working Group 3 (WG3) report and the IEA's World Energy Outlook, we can see a range of penetration from 67% to 98%.

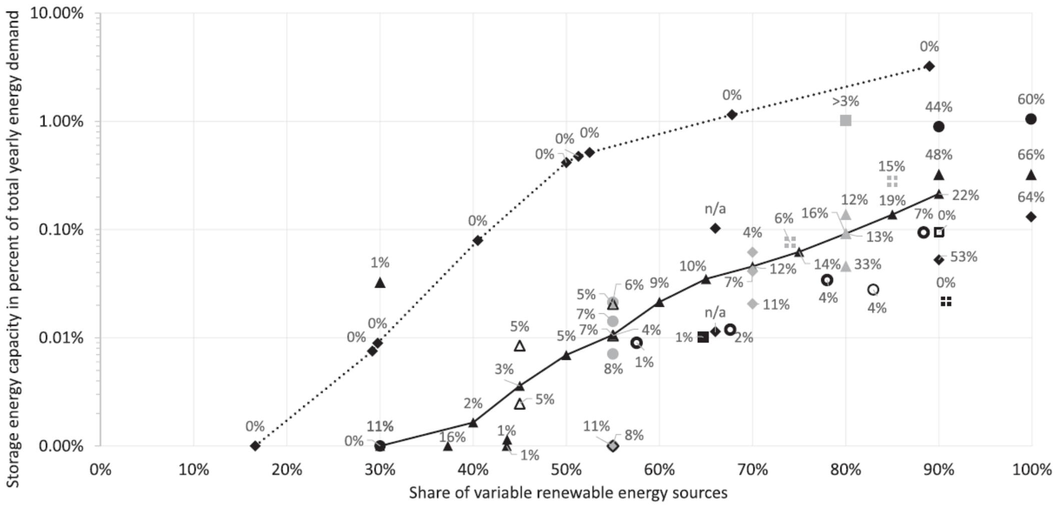
Renewable Energy Penetration Forecasts for 2050



Source: Longspur Research, IPCC, IEA,

The Imperial work shows storage power capacity as a percent of peak demand. However, to really work out storage demand we need to know how much storage energy capacity is needed rather than power capacity. Another meta study (Zerrahn, A, Schill, W, Kemfert, C, *On the economics of electrical storage for variable renewable energy sources*, European Economic Review 108 (2018) 259–279) shows the storage energy capacity as a percentage of total annual energy demand. Two lines are shown. The higher assumes that storage overcomes all curtailment and the lower shows modelled curtailment in percent.

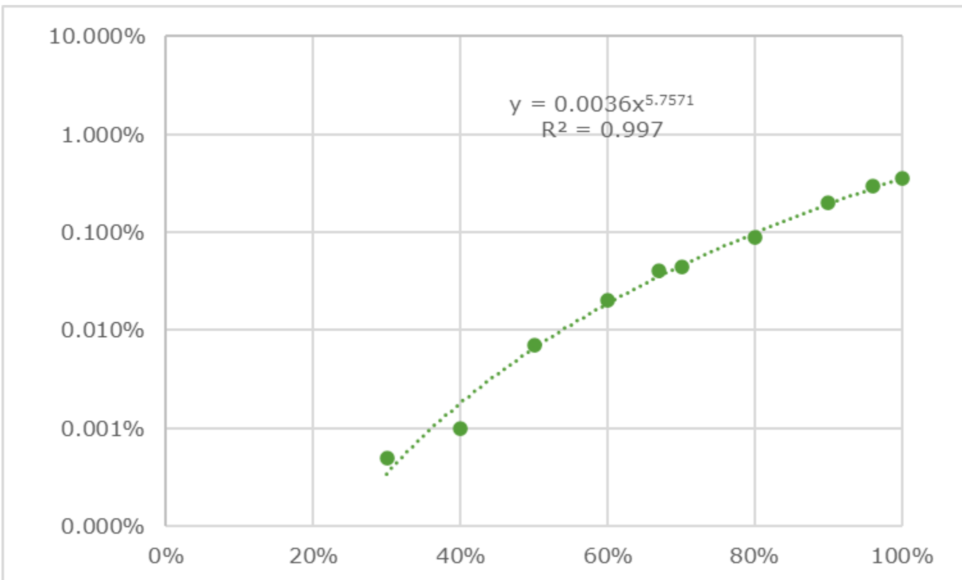
Storage Energy Requirements in Recent Research Lliterature



Source: Zerrahn et al., 2018. Percentages show curtailment. Upper line assumes no curtailment.

We have plotted a trendline based using the date on the lower line to derive a relationship between variable renewable energy penetration and the required storage energy capacity demanded to minimise curtailment. Note that this does not eliminate curtailment but represents the least cost outcome. Even with significant energy storage, curtailment varies from 2% at 40% renewable penetration to 22% at 90% with 66% if there is 100% variable renewable energy supply. Our trendline has the equation $S = 0.036P^{5.7571}$ where S = storage as a percent of annual energy demand and P = variable renewable energy penetration.

Best Fit Line to Zerrhan et al.



Source: Zerrahn et al., 2018.Longspur Research

We can use this with the penetration forecasts to estimate demand for storage. This suggests that the Paris compliant scenario with 98% renewable penetration would mean storage of 0.3% of yearly electricity demand and the non-compliant scenario with 67% penetration would mean 0.03% of yearly demand.

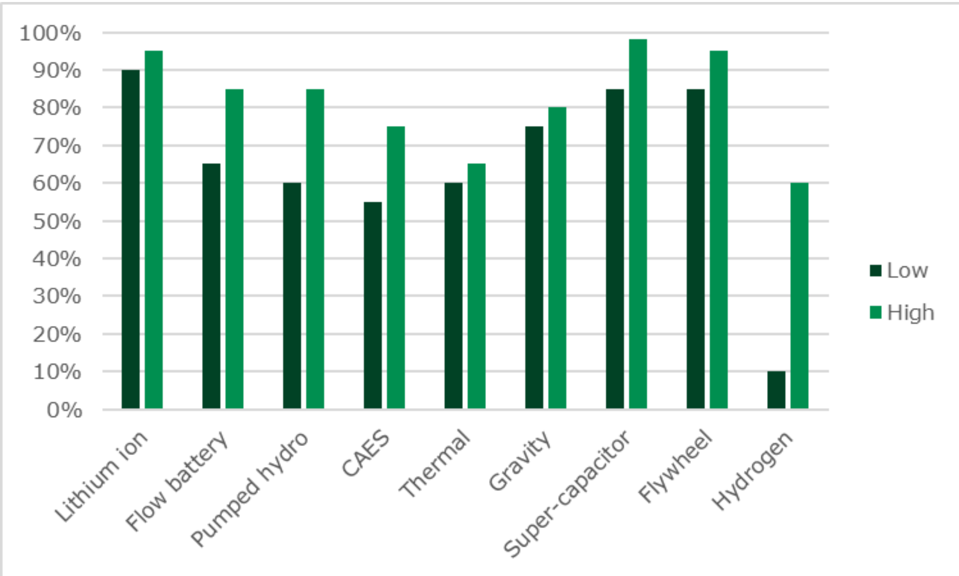
Global Total Addressable Market for Energy Storage

Source	**Longspur**	**Longspur**	**IEA**
Scenario	IPCC WG3 1	IPCC WG3 2	WEO 22
Total electricity generated (TWh)	108,444	111,111	73,231
Renewable generation (TWh)	106,667	73,889	64,447
% Renewable	98%	67%	88%
Storage as a % of generation	0.327%	0.034%	0.173%
Storage required (GWh)	354,962	38,197	127,002

Source: IPCC, Longspur Research, BNEF, IEA

So there is a lot of potential demand for storage. However, there are also a lot of storage technologies. Most have round trip efficiencies of between 60% and 95%. Hydrogen performs far worse in this regard with round trip efficiency ranging from just 10% to a maximum of 60%.

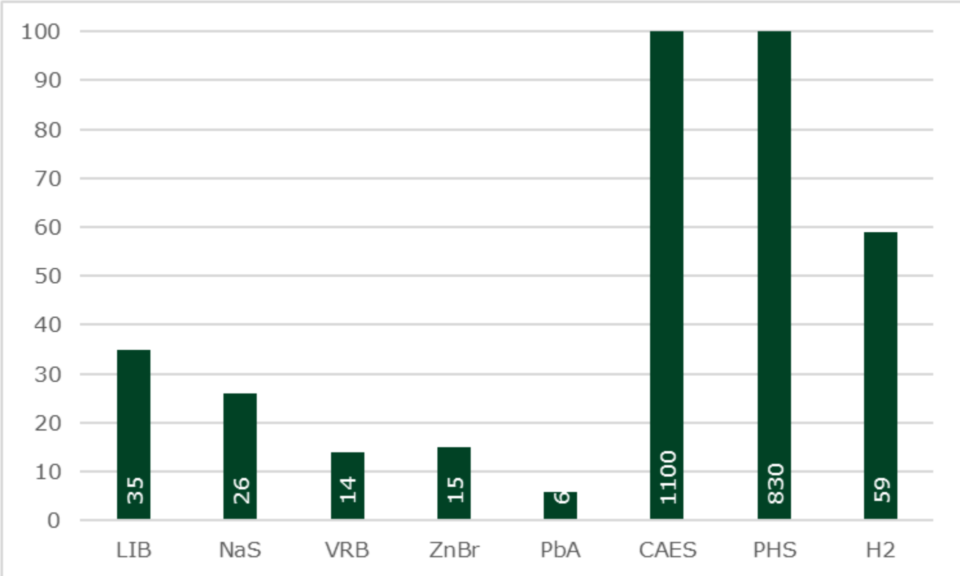
Storage Round Trip Efficiency



Source: Longspur Research

This would seem to rule out hydrogen as a long duration storage option. However, overall efficiency is questionable as a relevant measure when the input energy does not cost anything. A more effective measure might be the electrical energy storage on invested ratio (ESOIe) which is the ratio of electrical energy returned by the device over its lifetime to the electrical-equivalent energy required to build the device. Hydrogen performs better here than most of the electrochemical solutions but behind compressed air or pumped hydro.

ESOIe for Key Storage Technologies



Source: Energy Environ. Sci., 2015, 8, 1938

Essentially the key here is the overall economics of storing power from hydrogen even if the hydrogen is not turned back into electricity. An argument against this has been that coupling electrolysers with intermittent renewables would result in low utilisation and that in turn would mean weak economics for the electrolyser. However, most of the analysis has not factored in the different electricity prices at different utilisation rates.

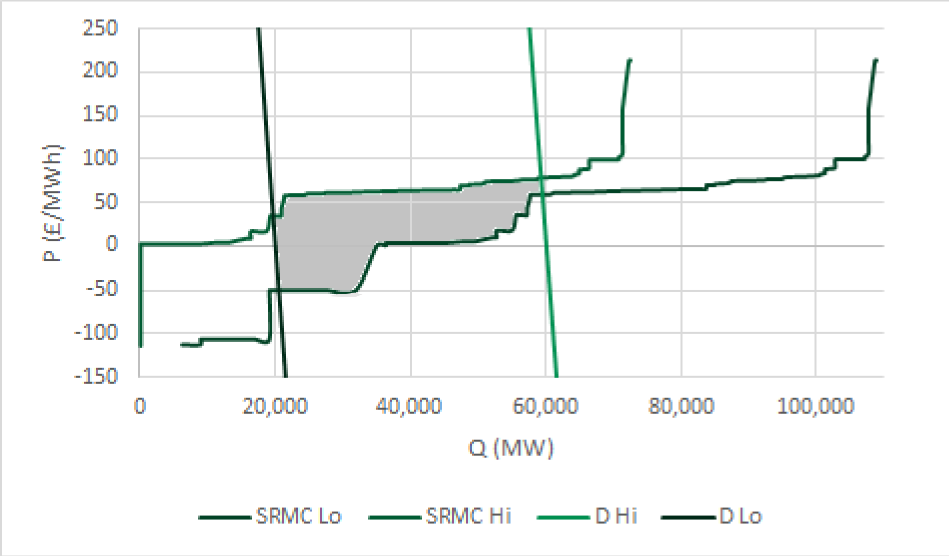
RENEWABLES AND HYDROGEN - HYDROGEN AS A STORAGE MEDIUM

The opportunity to profitably combine hydrogen electrolysis with renewable energy is about more than just utilising energy that would otherwise be lost. Because renewable energy has a near zero marginal cost, in most markets this means there is a lot of low-cost energy that can be better exploited by making hydrogen than by directly selling into energy markets. The potential scale of this can be seen by examining the UK (GB) wholesale electricity market.

In an economic analysis of the market, because of the instantaneous nature of the market with demand changing every 20 ms (in a 50Hz system) we really need to show two demand curves, one with the maximum demand in the year and one with the minimum demand. Also, because intermittent renewable supply varies, we think it helpful to show the limit points in two supply curves, one with all renewable capacity available (when the sun is shining, and the wind is blowing) and one with no renewable capacity available (at night and no wind).

Prices across the year should all fall in the shaded area between the near vertical high and low demand curves and the high and low short run marginal cost curves in the supply demand graph below.

GB Electricity Market Supply and Demand



Source: Longspur Research, BNEF, National Grid FES

The average price for the year will be roughly in the middle of this area. It can be estimated using assumptions of average demand and supply. Full forecasts are available using Monte Carlo simulation techniques to capture the variation in demand and weather-related supply to pinpoint the exact point in the middle of this area.

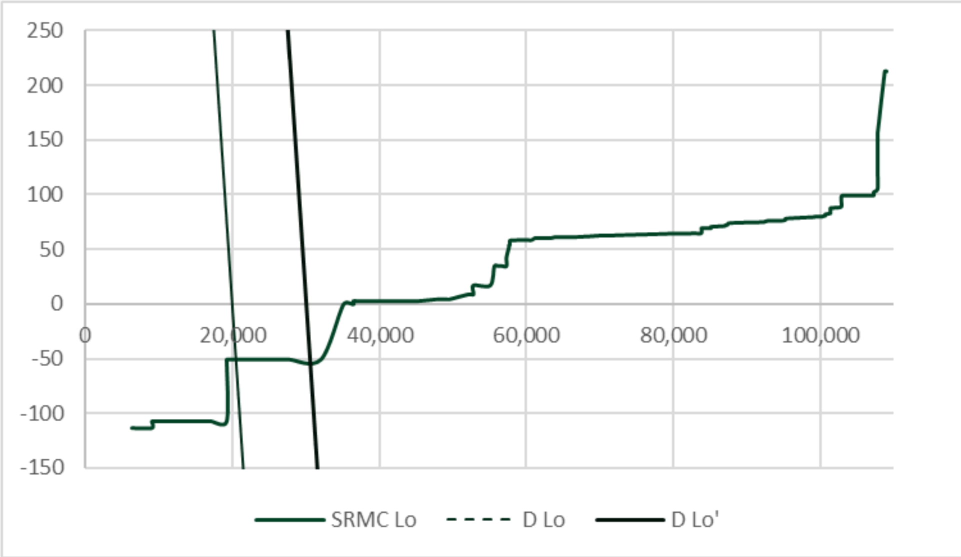
The low supply curve includes renewables with negative short run marginal costs. This is a result of subsidy programmes. The generators only get the subsidy when they run so should be prepared to bid negatively down to the level of subsidy. This may be rare but does happen and is on the increase as more renewables are added to the system.

Adding Hydrogen

Hydrogen represents a source of demand but one which has complete flexibility about when it can take its power. This is very different to most demand on the electricity network. Electrolysis can choose to take place when supply is at a maximum and demand at a minimum. With negative pricing, electrolysers could be paid to take power, although in practice we think the actual low charging point will be zero.

The supply/demand graph below shows that 10GW of electrolysis could be operated receiving c.£50/MWh rather than paying for power. A further 20GW could be run at an extremely low electricity price. Of course, the amount of time these prices are available is not defined here but we think this shows that there is a much more considerable opportunity for low-cost electrolysis than curtailment alone suggests.

Impact of 10GW of Hydrogen Electrolysis Demand

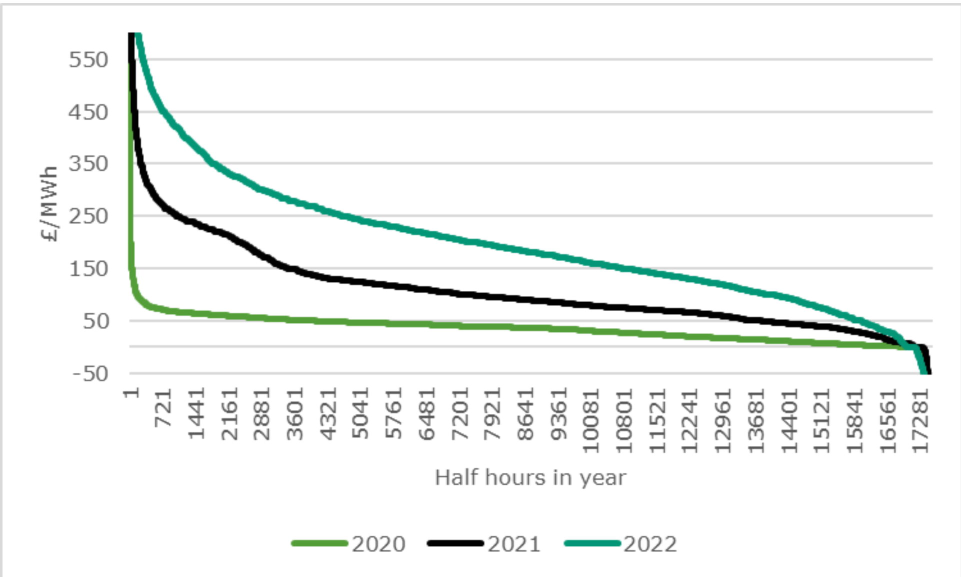


Source: Longspur Research

This only tells us that prices can remain low over a large amount of capacity but not for how long. However, we can look at recent pricing to estimate how low pricing periods could affect the cost of hydrogen.

The electricity industry typically represents prices across a year in a price duration curve which displays all prices in order starting with the highest prices and ending with the lowest. As more renewables operate on a system we expect more lower prices.

UK Recent Price Duration Curves

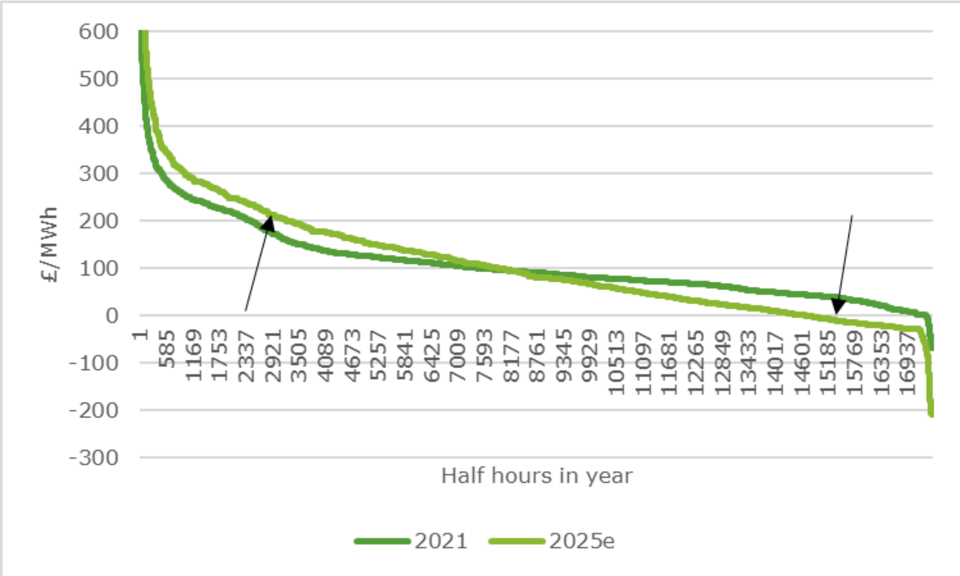


Source: Longspur Research

The UK price curve for 2022 was exceptional thanks to the impact of the Russian invasion of Ukraine. We expect gas prices to fall back towards 2021 levels but to still remain well above 2020 levels as more reliance is placed on higher cost LNG trains as opposed to relying on pipeline gas supplied by Russia. We also expect renewable penetration to increase.

The likely longer term outcome is that high prices will drop compared with the exceptional 2022 outcome but remain above 2021 and a gradually more extended low price regime will apply at the right hand end of the curve. High prices may stay above 2021 levels as CCGTs try to recover income from fewer hours of operation.

Price Duration Curve Development



Source: Longspur Research

The price curves shown here are for the UK (GB) power market. EU markets generally show a similar price distribution.

Even if storage and hydrogen electrolysis adds demand at the lower end of the price curve the supply – demand analysis earlier suggests that considerable demand could be added without having a major effect on these low prices.

Using the 2021 price duration curve we can examine the levelized cost of hydrogen (LCoH) for a baseload operation, a plant at 33% utilisation and one at 20% utilisation. For baseload operation we have taken the average of prices across the year which comes out at £113/MWh. We have assumed that the electrolyser is a Chinese alkaline unit with a cost of US$339/MW based on BNEF capital costs for 2023.

At 33.3% we have taken the average of the lowest third of prices which gives us £40/MWh. In this case we have assumed that a more expensive PEM electrolyser is required for the flexibility to work with an intermittent power sources.

PEM electrolysers along with AEM and membrane free technologies can respond to demand changes very rapidly whereas alkaline are slower to react. PEM electrolysers need to keep utilisation above 40% to retain this flexibility but this can be managed with modular set ups.

BNEF show a capital cost of US$1,383/MW for a PEM electrolyser. For 20% we assume the same PEM electrolyser but that all the electricity is curtailed energy at zero cost.

These show that both the low utilisation intermittent operations give a lower levelized cost of hydrogen than the baseload option even where a cheap alkaline electrolyser is used for the baseload option.

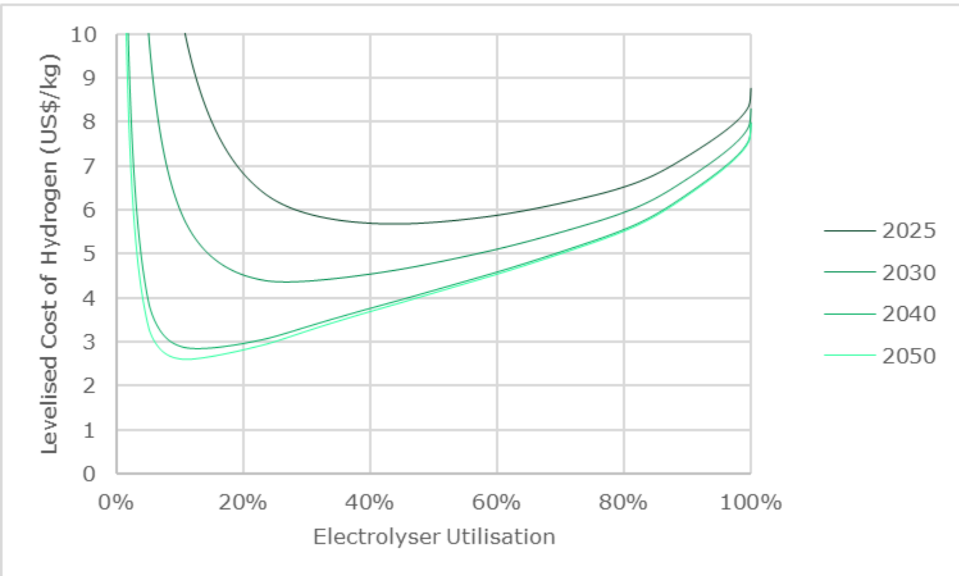
Levelised Cost of Hydrogen at Different Utilisation Levels

Utilisation	**Baseload**	**Off-peak**	**Curtailed**
Life (years)	25	25	25
CoE	10.0%	10.0%	10.0%
CoD	6.0%	6.0%	6.0%
Gearing	60.0%	60.0%	60.0%
Effective tax rate	25.0%	25.0%	25.0%
WACC	6.7%	6.7%	6.7%
Capital Recovery Factor	0.0835	0.0835	0.0835
Electrolyser Output (tonnes)	40,000	40,000	40,000
Utilisation	90.0%	33.3%	20.0%
Electrolysis efficiency (kWh/kg)	55	55	55
Electrolyser capacity (MW)	279	754	1,256
Electrolyser electricity (GWh)	2,200	2,200	2,200
Water consumption (l/kg)	11.12	11.12	11.12
Water consumption (m3)	446	446	446
Electricity unit cost ($/MWh)	113	40	0
Water unit cost ($/m3)	2.21	2.21	2.21
Fixed O&M ($/MW/year)	5,700	5,700	5,700
Variable O&M ($/MWh)	6.00	6.00	6.00
Electrolyser Unit Capex ($k/MW)	391	1595	1595
Electricity	249,238	88,000	0
Water	1	1	1
Maintenance	14,791	17,499	20,358
Total opex	264,030	105,500	20,359
Total capex	109.1	1,202.9	2,002.9
Costs per kg of H2			
Operating cost	6.60	2.64	0.51
Capital cost	0.23	2.51	4.18
Total LCoH	**6.83**	**5.15**	**4.69**

Source: BNEF

Most commentators expect the cost of electrolysers to reduce over time and we examine this in more detail later on in this note. We can look at how the picture evolves based on the 2021 price duration curve and reducing electrolyser capex, initially assuming not benefit from curtailed energy, nor assuming any benefit from negative pricing.

Levelised Cost of Hydrogen Against Utilisation



Source: Longspur Research

Levelised Cost of Hydrogen at Different Utilisation Levels

	2025	2030	2040	2050
Min LCoH (US$/kg)	5.68	4.36	2.84	2.60
Utilisation	44%	27%	13%	11%

Source: BNEF

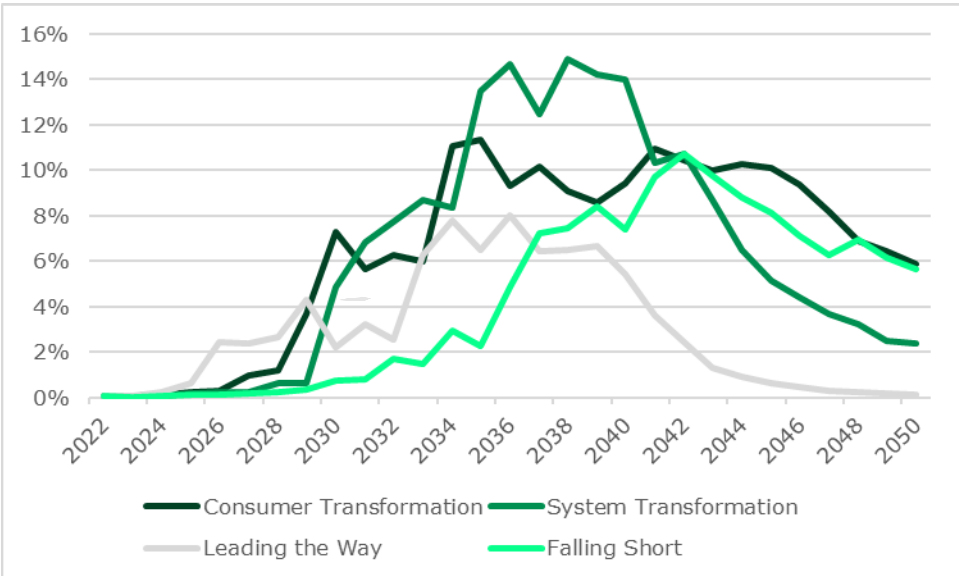
Curtailment

Curtailment is where electricity can be generated but is not, resulting in a deliberate reduction in what could have been produced. There is no single agreed definition of curtailment but we broadly split it into two groups, economic and technical. Economic curtailment occurs where there is oversupply in the market relative to demand. Technical curtailment occurs where grid capacity is unavailable often for reasons connected to voltage or frequency. Curtailed energy can be made use of at the point of generation where there are alternatives to grid offtake and this could include co-located hydrogen electrolysis.

Our utilisation graphs above assume that no curtailed energy is available to the electrolyser. In our first example we have included an assumption of 20% curtailed electricity being used to power the electrolyser as one of the scenarios. While this is on the high side we are already seeing this level of curtailment in the Australian market as high deployment of distributed PV has created system stability (voltage) problems limiting how much generation can be exported. This is consistent with the academic work which suggests 22% curtailment where renewable penetration reaches 90%, in line with decarbonisation targets.

The UK's National Grid in its Future Energy Scenarios FES under the customer transformation scenario forecasts peak curtailment at 15%. This is the highest scenario figure but we feel happy using it given the experience in Australia. While the FES curtailment forecasts drop beyond 2040 but this is only because the forecasts assume that curtailed energy will be used to manufacture hydrogen and this is not included in these longer term curtailment figures.

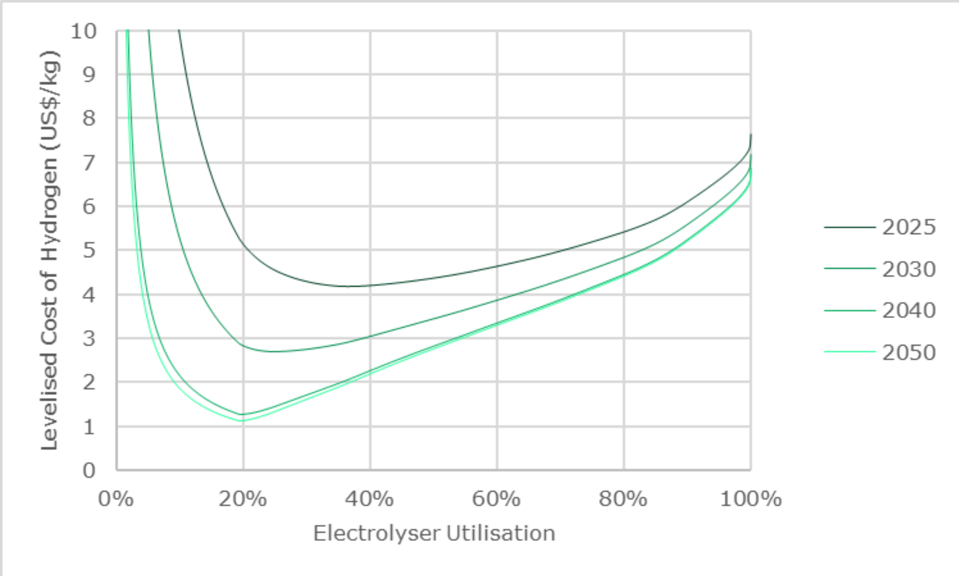
Curtailment Under UK Future Energy Scenarios



Source: National Grid FES

Curtailment can occur at any time but is more likely when demand on the network is high and lots of generation is trying to get access. As a result, it is more likely to take place when prices are high. So curtailed supply available to an electrolyser would be in addition to the electrolyser being able to source low price power from the grid. If we model this assumption, we get a set of utilisation graphs with even lower LCoH values.

Levelised Cost of Hydrogen Against Utilisation



Source: Longspur Research

Levelised Cost of Hydrogen at Different Utilisation Levels

	2025	2030	2040	2050
Min LCoH (US$/kg)	4.18	2.70	1.27	1.12
Utilisation	37%	25%	20%	19%

Source: BNEF

USING BATTERIES TO IMPROVE ELECTROLYSER UTILISATION

We have also looked at whether it would make more sense to install a battery to increase the utilisation of the electrolyser. We have modelled a slightly simplistic scenario where we assume that the electrolyser is fed by an intermittent renewable source with 33% load factor where the only intra-annual variation is the daily load swing which is 8 hours generating and 16 hours off.

If we add an 8 hour battery with 50% of the power of the generation source and halve the electrolyser to the same size but run it twice the time we halve the cost of the electrolyser. But we add the cost of the battery.

Using a BNEF figure of $324/kWh for an installed ESS battery system this adds more cost than it takes away and results in a higher LCoH at $7.85/kg. We have already calculated the LCoH of a 33% utilised electrolyser and no battery at $6.3/kg. This does not mean we will not see batteries installed alongside electrolysers, but they are more likely to cover any ramp up periods and we expect duration to be limited to 30 minutes. This is likely to be required anyway given the 40% utilisation limit on flexible operation of a PEM electrolyser.

HYDROGEN TO POWER

LOW CARBON GAS TURBINES – H2GTS

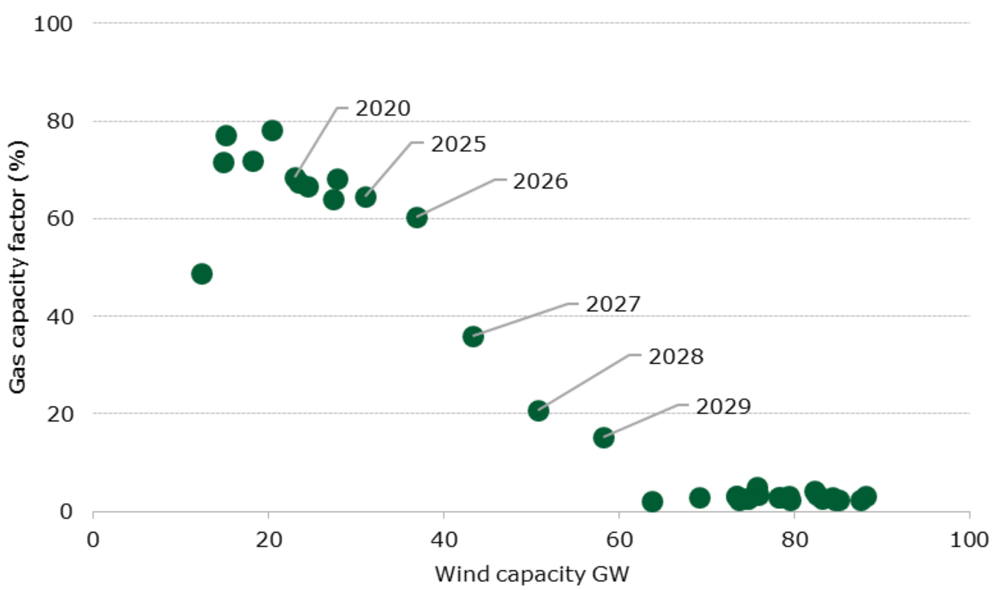
For storage to be fully utilised it must be able to return power to the market. However, hydrogen electrolysis can still help balance the system without doing this by providing demand when there is an excess of supply over demand. The round trip efficiency of hydrogen back into electricity suggests that it may make more sense to keep hydrogen generated from curtailment and off peak pricing periods for use as hydrogen or a hydrogen derivative.

This does not help in situations where there is not enough supply to cover demand. Other storage options are available and we expect these to be deployed in considerable quantities. (See "A Car Without Brakes", Longspur Research, 31 January 2023). But there is also the option to to turn the hydrogen back into electricity. Fuel cells are one option and again we would look to the more responsive PEM cells as likley options here.

But an analysis of the cost of power generation using hydrogen gas turbines (H2GTs) suggests that this could be an option for flexible power generation when demand is high. Combined cycle gas turbines (CCGTs) have been a key part of providing electricity market flexibility and the design can be readily adapted to hydrogen instead of methane. Many manufacturers are already offering hydrogen ready gas turbine designs.

However, as more renewables come onto the system, load factors are expected to fall making existing CCGT economics more challanging. BNEF forecasts the average load factor to drop from 68% in 2020 to below 20% in 2030.

CCGT Capacity Factor Reductions with Wind Pentration



Source: Bloomberg New Energy Finance

The retrofitting of existing CCGTs to burn hydrogen or ammonia is possible, creating hydrogen fuelled combined cycle gas turbines or H2GTs. New diffusion burners would be required which could burn these gases. Additionally, retrofitting would require additional pipework to cope with the higher volumes of gas per unit of energy and the installation of Selective Catalytic Reduction (SCR) technology to manage the emissions of nitrogen dioxide. The investment would allow the combustion of "green" low carbon hydrogen or ammonia.

Overall Economics

If our curtailed electrolyser analysis can deliver hydrogen at a price of $1.27/kg by 2040 then we calculate the marginal cost of electricity at US$94/MWh, slightly lower than a gas fired unit assuming the current EU carbon price of €80/t and a (European) gas price at 90USc/therm. This suggest that H2GTs could be competitive and may become the flexible price setting generation unit in the market.

Short Run Marginal Cost of H2GT versus CCGT

	H2GT	CCGT	Notes
GJ/tonne / GJ/therm	130	0.106	
Fuel emissions factor	0.06	0.06	kgCO2/MJ
Full load efficiency	50%	50%	DUKES
Part load efficiency factor	75%	75%	@36% plf
Part load efficiency	38%	38%	
Gas price	1.27	90.00	US$/kg / c/therm
Fuel cost	93.78	81.89	$/MWh
Carbon price	0.00	80.00	€/t
Carbon cost	0.00	35.88	$/MWh
Marginal cost	93.78	117.77	$/MWh

Source: Longspur Research

So combining offpeak and curtailed energy as feed into a H2GT could enable hydrogen to act as an efficient form of balancing and storage. However it would be competing against existing long duration energy storage technologies including flow batteries, compressed air (CAES), thermal storage and pumped hydro storage. CAES and pumped hydro will have locational advantage where there are salt domes or mountains respectively. Otherwise we think market share will broadly split. If we added hydrogen to this mix it would achieve 20% of the market. On our central case of 52,595TWh of renewable energy generated per annum to hit a 1.5°C target, we estimate a hydrogen storage soluion with 15% market share would need to deliver 6,964TWh of electricity per annum to the market representing 177Mt of hydrogen.

Our thematic on energy storage (A Car Without Brakes, Longspur Research, 31 January 2023) took the view that hydrogen would best cover the market created by a zero curtailment outcome. We estimate that curtailment in a high penetration renewable energy market will be between 15% and 20%. Again, using our total renewable energy market figure of 52,595TWh and a low curtailment figure of 15%, this implies 7,889TWh of curtailled energy available. That would just about cover the full hydrogen share of the storage market calculated above.

The UK's Royal Society has highlighted the need for hydrogen to play a major role in providing long duration storage in a recent policy briefing.

DON'T FORGET NUCLEAR

Nuclear energy is a genuine low carbon generation source. However, in our view it has issues in complementing a market faced with increasing levels of intermittent generation and also with more volatile demand. With very high capital costs to be recovered and slow ramp up times and shut down times, nuclear tends to be inflexible in operation, preferring to be always on. Small modular reactors (SMRs) can be designed for flexibility but still need to cover high capital costs. Nuclear therefore runs baseload while flexibility in the market is provided by other generating assets. In a market with a major element of intermittent renewables, this can potentially lead to an increase in curtailed output when nuclear and renewables are competing for the same level of demand.

This is not necessarily bad if there are opportunities to use the curtailed power and this is where the production of hydrogen emerges as a clear solution. Without such opportunities we see nuclear as tending to increase price volatility especially at the low pricing points. We note that during the COVID 19 lockdown in 2020, National Grid did a deal with EDF to reduce the output of Sizewell B, halving its output for six weeks in order to make balancing the system easier for the system operator.

Water electrolysis using any of the electrolysers currently available on the market is possible. EDF are already evaluating the concept of "night-time nuclear" using water electrolysis. Thermochemical processes are also under evaluation. However, nuclear reactors produce steam for their turbines which could be diverted to support efficient solid oxide electrolysis.

We think this is one of the relatively understated benefits of a hydrogen economy. 25EJ (7,000TWh) of nuclear supply has been identified in the IPCC median outcome to reach net zero and this could represent a similar amount of electrolyser demand.

The US Department of Environment is already backing four trial projects.

U.S. DOE-Backed Nuclear/Hydrogen Pilot Projects

Project	Site	Size	Electrolyser	Funding
Energy Harbor	Davis-Besse	1MW	PEM	$10M INL grant
Exelon	TBD	1MW	PEM	$13.8M total project forecast
Arizona Public Service	Palo Verde	20MW	PEM	TBD
Xcel Energy	Prairie Island	150KW	HTSE/SOE	$10M federal funding

Source: BNEF

We see this night time nuclear opportunity as a key use case for solid oxide electrolysers.

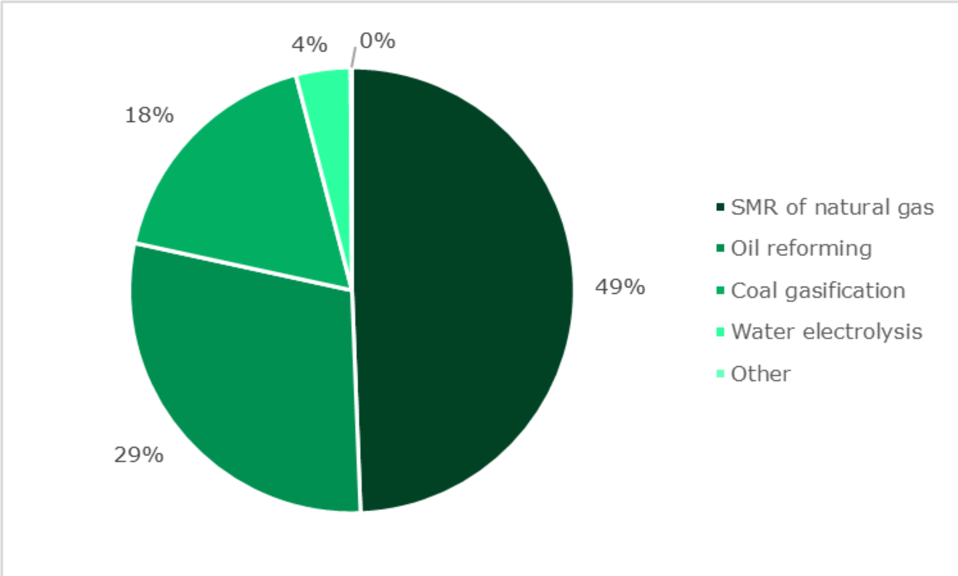
HYDROGEN AND STORAGE

One other point is that there is an emerging use case where compressed air energy storage is co-located with hydrogen storage, both taking advantage of salt domes. The hydrogen is then used to power the CAES compression system improving round trip efficiency.

Corre Energy (CORRE ID) is working with Eurowind Energy A/S and Danish state-owned transmission system operator Energinet (through its subsidiary Gas Storage Denmark) on one of the world's largest green hydrogen production, storage and CAES hubs in Denmark. This will combine CAES and green hydrogen production via electrolysis with two large scale energy storage solutions with a planned 350 MW of electrolysis, 200 GWh of hydrogen and 320 MW of CAES.

HYDROGEN PRODUCTION

Current Hydrogen Production



Source: European Mechanical Science

Currently, hydrogen is mainly produced by steam reformation of natural gas. This "grey" hydrogen production using steam methane reformation (SMR) is energy intense and a major emitter of CO_2.

As a result, the key pathways for low carbon hydrogen production are either the electrolysis of water or SMR combined with carbon capture and storage (CCS) to minimise the emissions problem, creating "blue" hydrogen. Adding the likely cost of CCS increases the cost of SMR. Also CCS does not remove fugitive methane (CH_4) emissions. There is currently some debate about the extent of these and in reality it varies case by case.

Recent work from authors at Cornell and Stanford universities has suggested that blue hydrogen could be a significant emitter thanks to these fugitive emissions. They have used a top-down approach to these emissions and we have seen criticism of this suggesting they are overestimated. Either way, it is clear that blue hydrogen is not emission free to the extent that green hydrogen can be. Where emissions are subject to a carbon tax, this potentially puts blue hydrogen at a cost disadvantage.

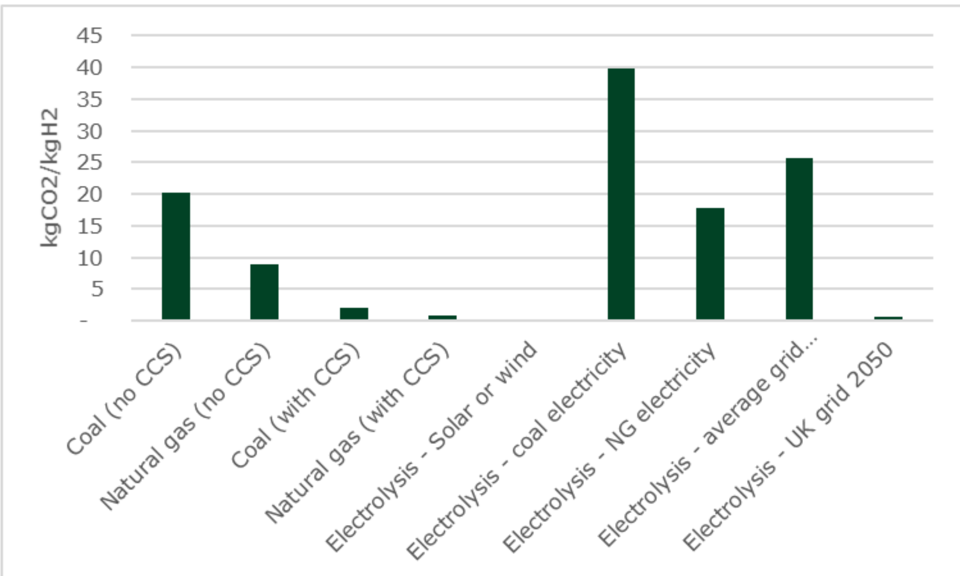
Truly low carbon, or "green", hydrogen can be created from the electrolysis of water with renewable energy providing the electricity. If powered by nuclear power this is termed "pink" hydrogen. Naturally occuring hydrogen is also found underground giving "white" hydrogen.

The Hydrogen Rainbow

	Colour of hydrogen	Feedstock	Production technology	Direct GHG emissions[a] kg CO_2e/kg H_2	Indirect GHG emissions[b] kg CO_2e/kg H_2
Produced using electricity	Green	Renewable electricity, water and/or steam by thermolysis	Electrolysis	-	>0[c]
	Yellow	Grid electricity, water		-	<1 - 30 *Depends on the carbon intensity of the grid mix*
	Pink	Nuclear electricity, water		-	>0[c]
Produced using fossil fuels	Grey	Natural gas	Methane reforming	9 - 11	0.5 - 4
	Brown	Lignite	Gasification	18 - 20	1 - 7
	Black	Black coal	Gasification	18 - 20	1 - 7
	Blue	Natural gas or coal	Methane reforming with CCS Gasification with CCS	0.5 - 4	0.5 - 7
	Turquoise	Natural gas	Pyrolysis	Solid carbon (by-product)	0.5 - 5
	Green	Biogas or biomass	Reforming with or without CCS Gasification with or without CCS	Possibility of negative emissions with CCS	1 - 3
Other	Red	Nuclear heat, water	Thermolysis	-	>0[c]
	Purple	Nuclear electricity and heat, water	Thermolysis and electrolysis	-	>0[c]
	Orange	Solar irradiance, water	Photolysis	-	>0[c]
	Green	Waste wood, plastic, municipal solid waste	Thermochemical	Possibility of negative emissions with CCS	Not assessed as variabilities in the value chains are too great to accurately represent the GHG equivalent emissions

Source: DNV

CO2 Emissions from Hydrogen Production

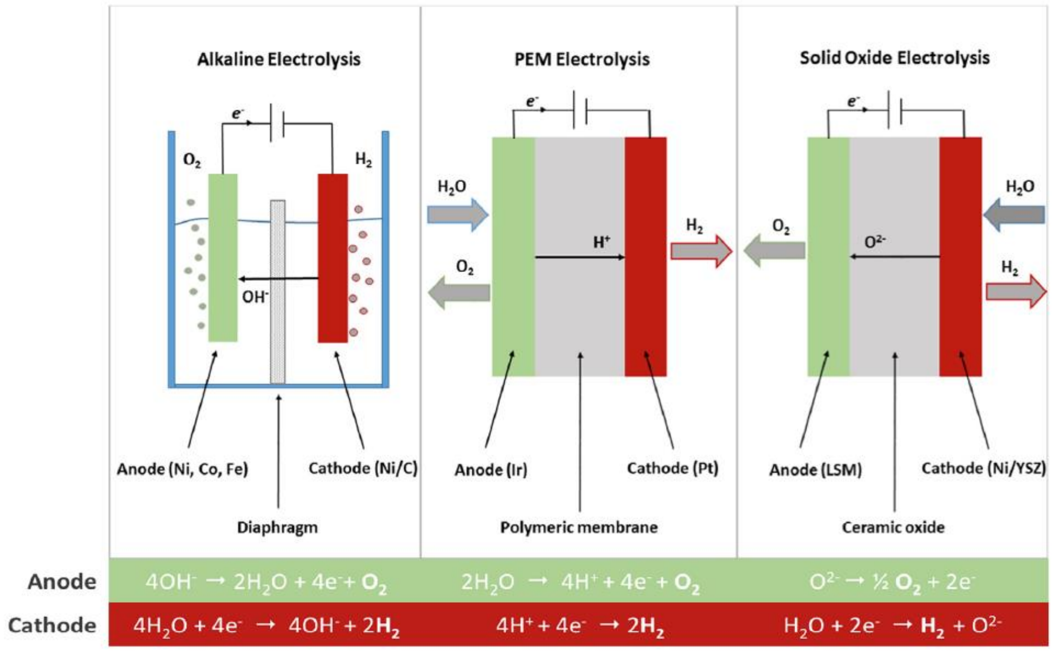


Source: BNEF

HOW AN ELECTROLYSER WORKS

In an electrolyser, hydrogen is created by the electrolysis of water. Two molecules of H2o are reduced to two of H2 and one of O2 by passing a current between two electrodes in the water. Hydrogen will appear at the cathode and oxygen at the anode. The efficiency of the electrolysis is improved by the addition of an electrolyte such a salt or acid to the water and the use of electrocatalysts.

Main Electrolyser Designs



Source: Sapountzi et al, 2017

TYPES OF ELECTROLYSER

There are several types of electrolyser with proton exchange membrane (PEMEC) and alkaline (AEC) electrolysers dominating the market at present. Solid oxide electrolysers (SOEC), anion exchange membrane electrolysers (AEMEC) and membrane-free electrolysers (MFEC) are developing and beginning to find markets.

PEMECs can be a fully responsive technology but are higher cost thanks to the use of expensive catalysts. Alkaline electrolysers are cheaper but less responsive, taking longer to start up when needed. Electrolyser manufacturer NEL (NEL NO) manufactures both PEM and alkaline types and expects the capital cost of these to converge by 2030. Solid oxide electrolysers offer greater efficiency and membraneless electrolysers have long lives reducing overall lifetime costs.

Alkaline electrolyser technology is well proven with large scale alkaline units being operated since the 1920's. Driven by demand for hydrogen for ammonia production, many projects were completed with output in the 2-3 ton per hour (50 –70tpd) range. However, these were rendered uneconomic by steam methane reforming as plentiful natural gas became available. Recent rises in the price of natural gas are beginning to reverse this differential demnd

Several factors come into play when choosing between electrolysers. Flexibility can be important with PEM electrolysers offering millisecond response times and flexible operation. This makes them a better choice for pairing with intermittent renewable energy where operators are targeting electricity response markets for some of their income. For the hydrogen derivative market and Power to X, cost and efficiency are more important considerations and solid oxide may be the best option here.

Electrolyser Technologies Compared

	AEC	PEMEC	SOEC	MFEC
Voltage efficiency (%HHV)	62-82	67-82	<110	73-78
Operating Temp. (C)	60-80	50-80	650-1,000	20-80
Operating Pressure (bar)	<30	<200	<25	35
Gas purity (%)	>99.5	99.99	99.9	99.999
System Response	Seconds	Milliseconds	Seconds	Seconds
Cold-start time (min.)	<60	<20	<60	<20
Stack Lifetime (h)	60,000-90,000	20,000-60,000	<10,000	219,000
Maturity	Mature	Commercial	Demonstration	Demonstration
Capital Cost (€/kWe)	1,000-1,200	1,860-2,320	>2,000	1,860-2,320

Source: Imperial College, CPH2, Longspur Research

ELECTROLYSIS CRITICISMS

There are several common criticisms about the scaling up of green hydrogen production. Whilst there is a degree of validity to these in certain contexts, it is worth contextualising some of these broad based criticisms, the main of which are the demand for water and electricity required to produce commercial volumes of green hydrogen. Blue hydrogen, being derived through SMR of natural gas does not have these input issues, although does face the issue of fugitive emissions, so it is not controversy free.

Below is a table showing the input demands for various hydrogen volumes assuming that there are no improvements in electrolyser efficiency achieved through an increase in production or in the future from technological advances. We have used total hydrogen demand from the IEA and IPCC net zero scenarios and assumed 100% green hydrogen production. This will not however be the case with blue hydrogen likely to make up a significant proportion of hydrogen supply with estimates ranging from 10-40% depending on the forecast provider.

Scaled Electrolysis Production

Mass of H2 Produced	Energy Contained	Electrical Energy Required Assuming 75% System Efficiency	De-ionised Water Required	Freshwater Required
1kg	39.4kWh	52.5kWh	11L	17L
1 Tonne	39.4MWh	52.5MWh	11m3	17m3
1 Million Tonnes	39.4TWh	52.5TWh	11mn m3	17mn m3
528 Million Tonnes (IEA Net Zero Target)	20,803TWh	27,737TWh	5.8bn m3	9.0bn m3
781 Million Tonnes (IPCC net zero assumptions)	30,771TWh	41,029TWh	8.6bn m3	13.2bn m3

Source: Longspur Research

Water Demand

Addressing water demand, the assumption on the amount required in electrolysis is based on commercial details from electrolysers. From a stoichiometric perspective, 9kg of water can be split to produce 1kg of hydrogen, however, in practice this is higher due to losses and inefficiencies in the electrolysis process. The true water requirement is higher still, and is likely closer to 17kg/1kg H2 for standard mains water due to losses involved in getting the water into a deionised state (where it has a lower electrical conductivity) whereby it can be used in the electrolyser. For our maximum hydrogen demand forecast of 447Mt with 60% made by electrolysis this would imply water demand of 4.6bn m^3.

Whilst the freshwater consumption figures look significant, in the context of the 4tr m^3 of freshwater consumed globally per annum it is less so. Whilst environmental concerns continue to exist around the future scarcity of water arising due to population growth and climate change, there will be considerable offsetting in the availability of freshwater with the oil and gas industry and coal fired generation consuming far less than current levels. It is estimated that in 2021 global water consumption for fossil fuelled power production was 11.2bn m^3, with coal, oil and gas consumption at 18.8bn m^3. This implies a net reduction in water consumption in moving away from fossil fuels to a solution including hydrogen.

The option to desalinate exists at an increasingly moderate cost (£0.006/kgH2) as does treating wastewater for input into an electrolyser, both of which could be used in hydrogen project development plans. Clearly there are technical challenges to overcome in terms of matching renewable energy with an available water source for hydrogen production, however these problems are not insurmountable and are unlikely to severely impinge on the development of the global hydrogen industry in the long term.

Electricity Consumption

Electricity consumption is one of the other main issues raised surrounding green hydrogen reaching the volumes forecast under the various net zero scenarios that have been presented. The concerns are twofold, the first is around quantum of electricity required to produce the required amounts of hydrogen under net zero scenarios. The second is the source of the electricity, with concerns that electrolysers connected to the grid will not be producing green hydrogen if the grid still has a high level of fossil fuel fuels in the mix and that the addition of electrolysers will increase fossil fuel consumption in the short term. And the second grid related issue is the concern that grids that are already constrained in terms of power dispatch and with extensive connection queues are going to be further strained by these additions.

Based on our forecast of 447Mt of hydrogen with 60% from green hydrogen we estimate an energy requirement of 38EJ 13,400 TWh. Against our total renewable energy forecast of 51,200TWh this represents 26% of the total. This is not an unreasonably large figure and certainly doesn't line up with some of the more outlandish claims that there would not be enough renewable energy capacity to support a green hydrogen economy.

THE ELECTROLYSER MARKET

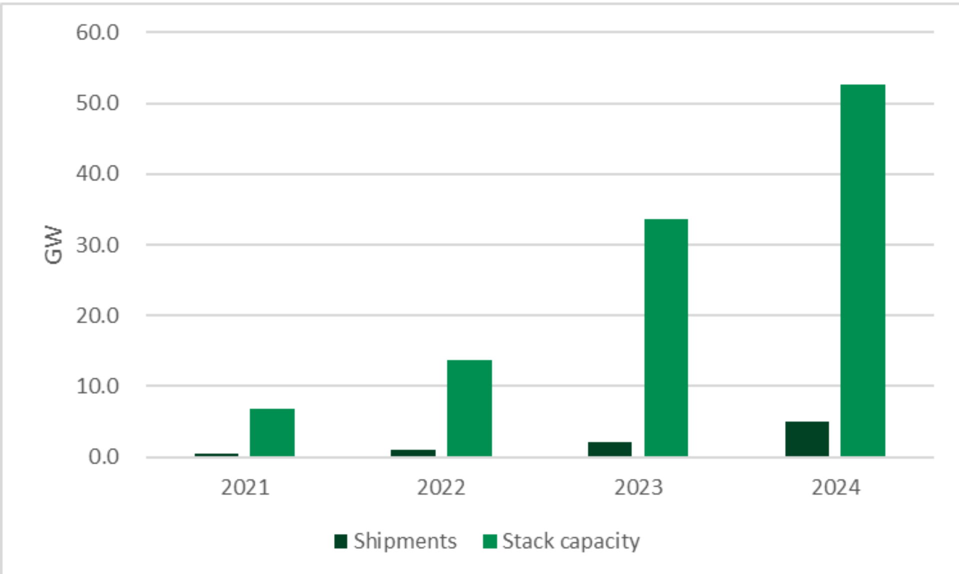
The electrolyser market is facing scale up challenges across the board and this will likely have a significant impact on the roll out and developing demand picture for hydrogen. BNEF expects electrolyser supply to enter into a difficult period from 2024, with significant manufacturing capacity (50GW per annum) expected to come online in the near future, which is expected to vastly exceed demand of 10GW. This is largely based on company announcements on manufacturing capacity. In practice, to date there has not been a significant oversupply of electrolysers into the market.

Electrolyser producers are struggling with scale up challenges meaning that actual production capacity is significantly lower than nameplate, with BNEF estimating it could be as low as 30% of nameplate. This is due to a number of factors, principally continued supply chain bottlenecks post-Covid, over-optimism in production timelines and scale from electrolyser manufacturers and quality control issues arising from the growth in demand. These are ultimately combining to add delays to projects and project delivery from companies across the industry from established manufacturers like Cummins and Siemens down to newer electrolyser specialists like ITM Power and Plug Power.

Whilst some projects are moving rightwards in timing, this is not significantly downgrading to forecasts for installed electrolyser capacity in the near future. BNEF estimates that this is due to more than double in the conservative case for 2023 and to double again in 2024. The bulk of the growth is being driven by growth in Chinese alkaline electrolysers which are able to deliver on 6 months' notice, compared to significantly longer timeframes than their European and American counterparts.

Currently national governments have set a combined total target of 105GW of electrolyser capacity by 2030 where policies have been announced. This will likely continue to develop further in the coming years as more countries look to have some domestic production.

Forecast Electrolyser Shipments and Electrolyser Production Capacity



Source: BNEF

CAN WE GET THE COST DOWN?

The hydrogen industry needs to bring costs down for electrolysers in order to compete with SMR. There is an expectation that this will happen with volume increases leading to cost reductions in a similar fashion to Moore's Law in semiconductors or Swanson's Law in PV solar.

IRENA has identified that electrolysers have similar learning rates to solar PV and could experience similar cost decreases with large-scale deployment. In our view, this gives a lot of comfort to the view that electrolysis can overtake fossil fuel produced hydrogen in cost terms.

Learning Rate Estimates for Electrolysers and Fuel Cells

Learning rate (%)		Notes	Reference
9	Electrolysis	Alkaline for 2020-2030	Hydrogen Council, 2020
13	Electrolysis	PEM for 2020-2030	Hydrogen Council, 2020
18 +/- 6	Electrolysis	1956-2014 data (alkaline)	Schmidt et al., 2017
18 +/- 13	Electrolysis	1972-2004 data	Schoots et al., 2008
8	Electrolysis	Floor cost of USD 350/kW (alkaline)	Gül et al., 2009
18 +/- 2	PEM fuel cell	1989-2012 data	Schmidt et al., 2017
18	PEM fuel cell	Initial capacity of 1.1 GW	McDowall, 2012
15	PEM fuel cell	Based on proprietary data	McKinsey, 2010
21 +/- 3	PEM fuel cell	1996-2006 data	Schoots, Kramer and van der Zwaan, 2010
15	PEM fuel cell	Floor cost of USD 50/kW	Gül et al., 2009
0%	Solid oxide fuel cell	California self-generation incentive programme	Wei, Sarah Josephine Smith and Sohn, 2017
16 +/- 3	µCHP	Based on EneFarm, Korean demonstration and PEMFC manufacturer	Staffell and Green, 2013
18 +/- 2	µCHP	Based on EneFarm	Wei, Sarah J. Smith and Sohn, 2017

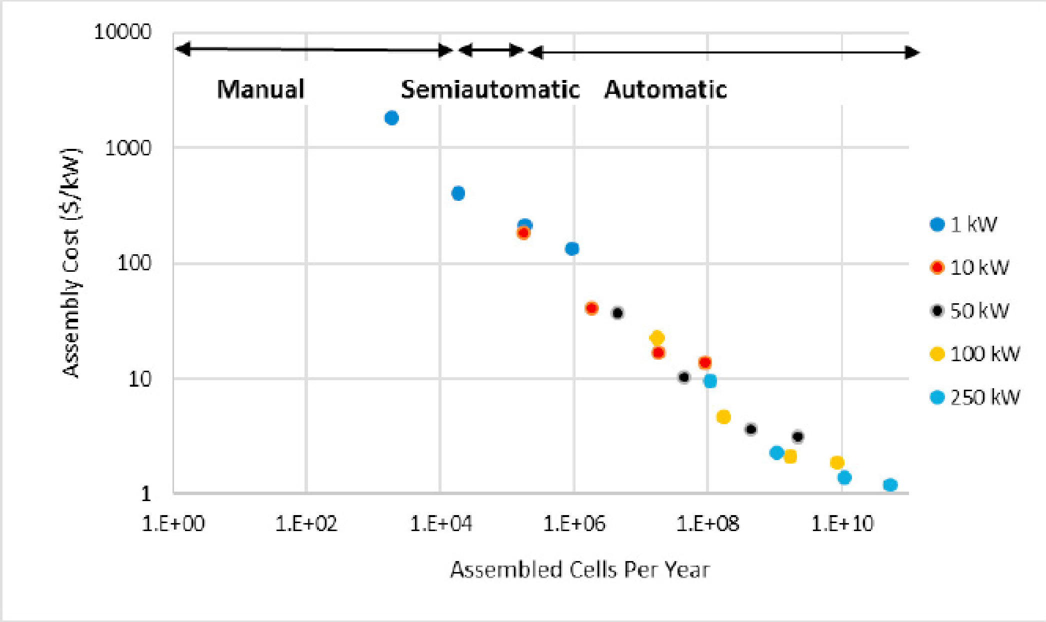
Source: IRENA

However, these cost reductions are not axiomatic. The classic work on learning curves is Abernathy and Wayne, Limits of the Learning Curve, Harvard Business Review 1974:

"The frequency with which this cost reduction/ volume increase pattern is found in practice sometimes leads to the incorrect impression that the learning-curve effect just happens. On the contrary, product design, marketing, purchasing, engineering, and manufacturing must be carefully coordinated and managed."

It requires work to bring costs down, volume alone will not do this. In manufacturing, companies can drive faster throughput with a number of initiatives. Stack assembly is still often undertaken as a manual process. Higher volume battery and fuel cell manufactures have already moved to robotic stack assembly. This can reduce stack assembly time and cost dramatically.

Automation Impact on Stack Assembly Costs

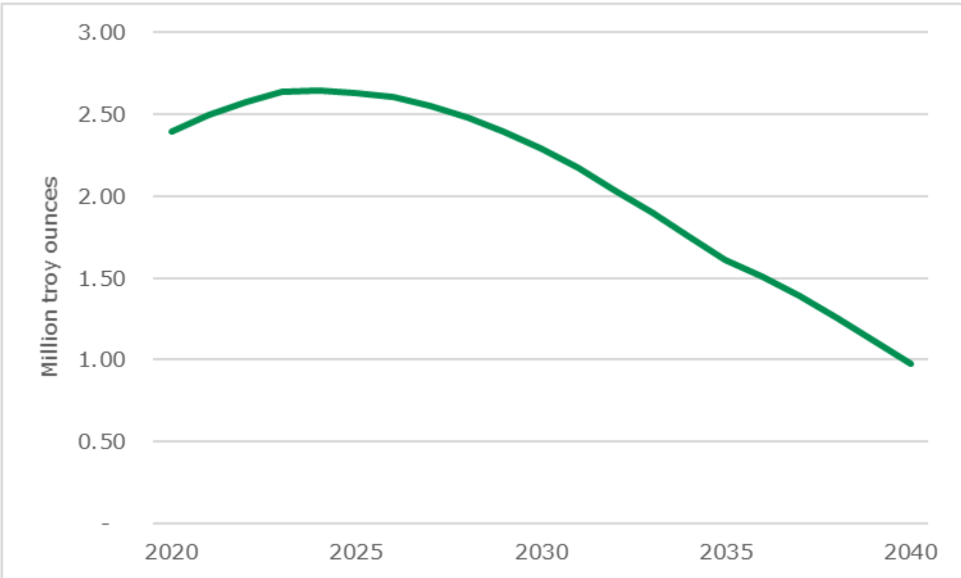


Source: National Renewable Engineering Laboratory

Material efficiencies are important when dealing with expensive inputs including platinum catalysts. Catalysts are often deployed by spray deposition. While overspray can be recycled there are always some losses. Moving to screen printing will reduce losses and allow for more efficient use of the expensive catalyst.

PEM electrolysers are differentiated from alkaline electrolysers in their use of platinum cathodes and iridium anodes which can add to their costs. PEM manufacturers are reducing the quantity of platinum group metals with significant gains over the past ten years and further savings targeted. Additionally, if the automotive market is successful in decarbonising, the move away from internal combustion engine vehicles is likely to result in a net reduction in global demand for platinum currently used in catalytic converters.

Forecast Reduction in Platinum Demand Due to the Energy Transition



Source: BNEF

While cost cutting with volume is not axiomatic, volume will help manufacturers to reduce costs. If they can take advantage of economies of scale, these could be considerable.

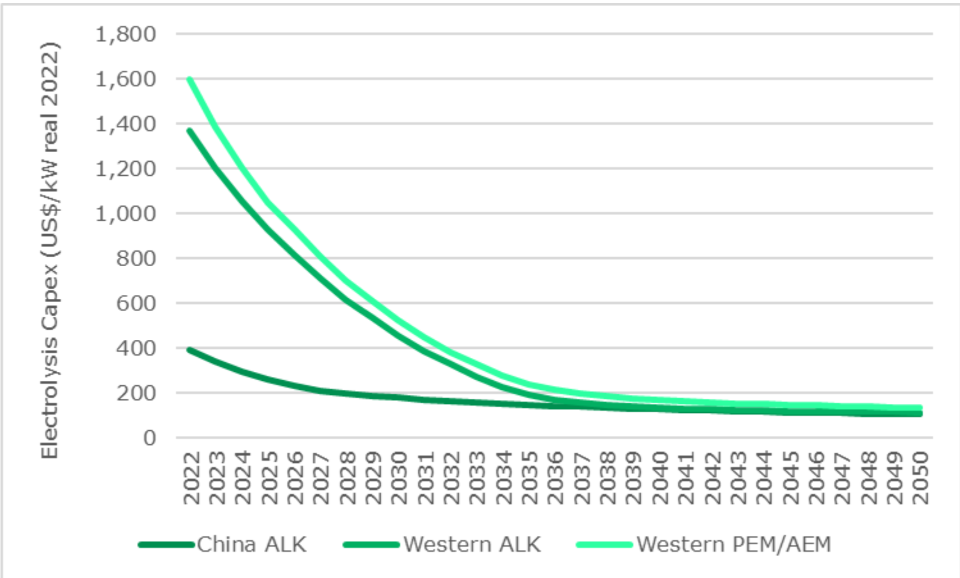
Economies of Scale for PEM Stack Manufacturing

Stack component	Capacity to reap most of the economies of scale	Dominant costs at high production rates	Cost penalty for low production volumes	Cost achieved at 1,000 units/ year
Catalyst coated membrane	1,000 units/year	Platinum, iridium, (Nafion) membrane	75%-80%	≈ USD 46/kW
Porous transport layer	20-100 units/year	Titanium powder, gold (coating material)	110%	≈ USD 26/kW
Frame	1,000 units/year	Materials (95%)	800%-900%	≈ USD 1.8/kW
Membrane Electrode Assembly	1,000 units/year	Materials (90%)	350%	≈ USD 11/kW
Assembly	1,000 units/year	Labour (50%)	1000%	≈ USD 2/kW

Source: IRENA

As a result, other forecasts for the capital costs of electrolysis for green hydrogen confirm the NEL view and also show convergence with the very low cost of Chinese alkaline electrolysers.

Electroysis Capex at the System Level



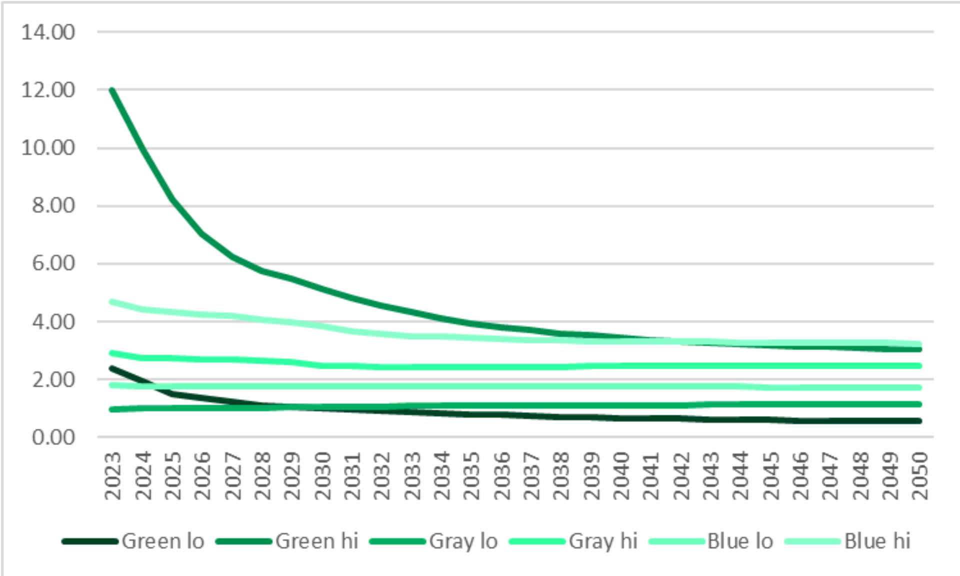
Source: BNEF

Grey SMR hydrogen is still generally the most economic method of producing hydrogen in many locations. While green hydrogen may currently approach parity in Europe and Asia this may not last if the gas price drops back towards historic levels. As a result there is currently not enough certainty for investors to back most hydrogen projects wtihout some kind of subsidy or where local market conditions create uniquely attractive conditions for green hydrogen and its derivative products.

In the long term, learning rates suggest that green hydrogen will get to a point where it is competitive with grey (and blue) hydrogen at which point the market demand is likely to be significant.

Bloomberg New Energy Finance has published calculations of current levelized costs of hydrogen and forecasts electrolyser technology becoming competitive with SMR by 2030.

Levelised Cost of Hydrogen Forecasts



Source: BNEF

THE HYDROGEN SUPPLY CHAIN

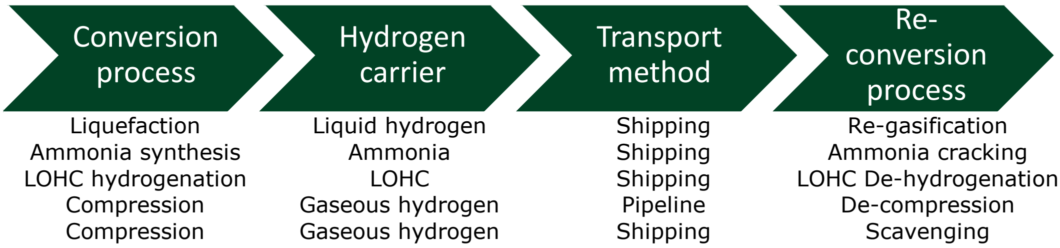
The listed market is dominated by electrolyser and fuel cell companies with only a handful representing other important parts of the hydrogen supply chain. This misses the fact that there is a lot of value in delivering and processing hydrogen and in addressing the key requirements of efficient and low cost ways to store and transport hydrogen at scale. We see this as a key area of opportunity for investors as the hydrogen market grows.

Hydrogen Supply Chain

Source: Longspur Research

The supply chain starts with hydrogen creation with green hydrogen being produced from renewable energy using electrolysis. But there is more to hydrogen than electrolysis. To move hydrogen, it must be converted to a form that can be easily transported. This may be as simple as compression but liquefaction using cryogenics and conversion to hydrogen rich fuels such as ammonia are also possible. Liquefied hydrogen or converted alternatives when used in shipping also require a subsequent conversion back into useable hydrogen or hydrogen derived products at the point of use, something that compressed technology does not require. There is a perception that shipping itself can be both expensive and inefficient in distributing hydrogen, however this is largely dependent on the hydrogen carrier used.

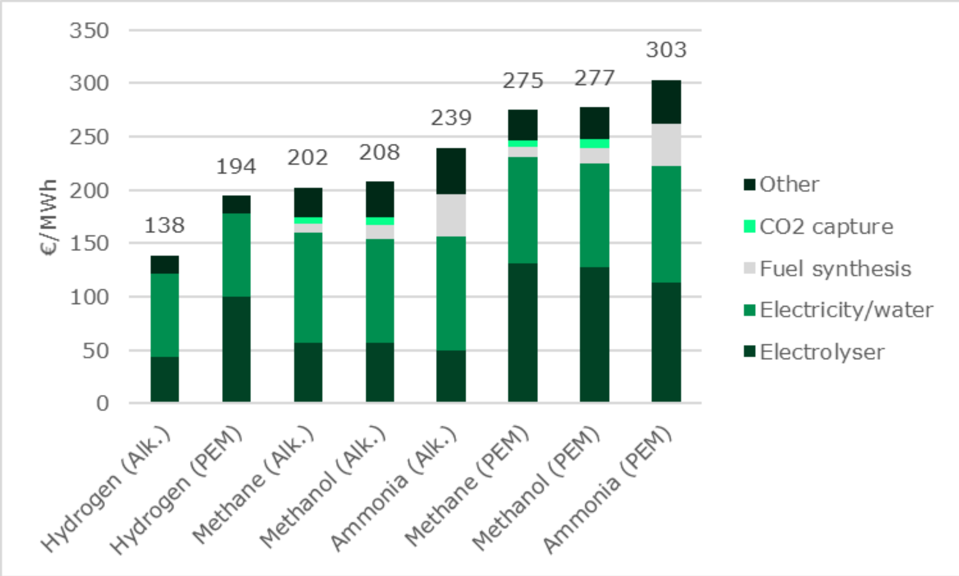
Transport pathways for hydrogen



Source: Longspur Research, IRENA

As a result, while hydrogen can be the lowest low carbon fuel source for a number of applications when considered at the point of creation it is not always the cheapest solution at the point of use.

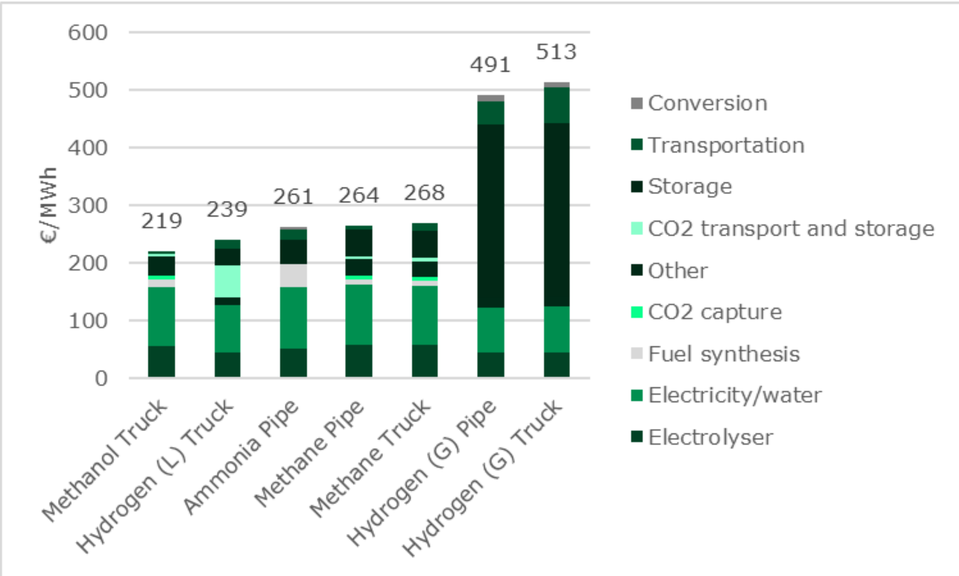
Production Costs for Low Carbon Fuels Suggest Hydrogen Lowest Cost



Source: Longspur Research, Dias et al

Our analysis of low carbon solutions for hydrogen logistics found that it was more efficient to convert hydrogen into methanol or ammonia to deliver the most cost effective fuel at the point of use.

Full Delivered Costs Show Methanol as the Lowest Cost Option



Source: Longspur Research, Dias et al

But this assumes that the end market requires methanol or ammonia. Where hydrogen is required the costs of reconversion can make these fuels less efficient.

Critical to any analysis is the overall efficiency of the energy used on a well to wheel basis. We can show that the main options of liquefaction and ammonia have lower efficiencies than another option – the more straightforward solution of compression.

Hydrogen Delivery Efficiencies

Liquid H2	Renewable energy	Electroysis	Liquefaction	Storage/ Shipping	Regassifcation
Efficiency	85%	72%	83%	84%	95%
Cumulative	85%	61%	51%	43%	**41%**
Ammonia	Renewable energy	Electroysis	Haber-Bosch	Storage/ Shipping	Cracking
Efficiency	90%	72%	86%	95%	76%
Cumulative	90%	64%	55%	52%	**40%**
Methanol	Renewable energy	Electroysis	Methanation	Storage/ Shipping	Reforming
Efficiency	90%	72%	88%	100%	87%
Cumulative	90%	64%	56%	56%	**49%**
Compressed H2	Renewable energy	Electroysis	Compression	Storage/ Shipping	Scavenging
Efficiency	96%	72%	98%	90%	98%
Cumulative	96%	69%	67%	61%	**59%**

Source: Provaris, Longspur Research

What this table shows is that all means of energy transport result in loss of energy resulting in low energy efficiency. Liquefaction is poor with energy lost in the liquefaction process itself and in boil off en-route. Ammonia also sees energy lost in cracking and compression is the best outcome in terms of overall lowest energy lost.

COMPRESSION AND PIPELINES

Pipelines using compression are really suitable for high volumes. The economics are related to the volume transported. Because the area of the pipeline, and thus the volume of gas moved, increases with the square of the radius ($A=\pi r^2$) but the wall material is related to the circumference which increases linearly with the radius ($C=2\pi r$) then the capital cost of the pipeline per unit of volume reduces the higher the volume. As a result, we think pipelines are a good solution for major trade routes but will still need feeder and subsidiary transport options around them.

There is also the possibility of repurposing existing natural gas pipelines. Existing subsea pipelines are likely to remain in use for natural gas for some time as existing fields deplete. The need for hydrogen to come into the market is likely to happen before full depletion so we don't see these becoming available when required. However, onshore pipelines may be repurposed and this has already happened in the Netherlands.

Pipelines are planned in the North Sea and include a MoU for joint project between Equinor and RWE for a pipeline from Equinor blue hydrogen production facilities in Norway to Germany. While the project also plans to facilitate the movement of green hydrogen the output will have a high proportion of blue hydrogen which we think will not appeal to every off-taker.

COMPRESSION AS A SHIPPING OPTION

Provaris has created a midstream solution for hydrogen based on compression rather than liquefication or conversion to another carrier. Basic hydrogen compression technology is well proven with over 50 years of operational track record. The Provaris solution compresses hydrogen to 250 bar before storing and transporting the gas in a proprietary cargo containment system at ambient temperature, and a closed system to prevent boil-off. Decompression and scavenging pressure are required at the destination with hydrogen distribution generally at a lower pressure of 50 to 70 bar.

Compression has tended to be discounted because of the poor volumetric density of hydrogen and no precedent of a commercial CNG carrier. Gaseous hydrogen has a lot of energy per unit of weight but not so much per unit of volume so requires greater capacity in transport. This can explain the industry's focus on cryogenic or chemical carriers.

Main Hydrogen Shipping Options

Properties	Unit	Compressed hydrogen	Liquid hydrogen	Methanol	Liquid ammonia
Storage method	-	Compression	Liquefaction	Ambient	Liquefaction
Temperature	oC	25 (room)	-252.9	25 (room)	25 (room)
Storage pressure	MPa	69	0.1	0.1	0.99
Density	kg/m3	39	70.8	792	600
Explosive limit in air	%vol	4–75	4–75	6.7–36	15–28
Gravimetric energy density (LHV)	MJ/kg	120	120	20.1	18.6
Volumetric energy density (LHV)	MJ/L	4.5	8.49	15.8	12.7
Gravimetric hydrogen content	wt%	100	100	12.5	17.8
Volumetric hydrogen content	kg-H2/m3	42.2	70.8	99	121
Hydrogen release	-	Pressure release	Evaporation	Catalytic decomposition T>200oC	Catalytic decomposition T>400oC
Energy to extract hydrogen	kJ/mol-H2	-	0.907	16.3	30.6

Source: Aziz, M., Wijayanta, A.T., Nandiyanto, A.B.D., Ammonia as Effective Hydrogen Storage: A Review on Production, Storage and Utilization, Energies 2020, 13, 3062; doi:10.3390/en13123062

The lower volumetric density means that shipping compressed hydrogen will require greater shipping capacity where seaborne delivery is being considered thus it will require greater vessels compared with cryogenic or chemical solutions. However, on an integrated basis, the reduction in energy loss for conversion and reconversion can off-set the increase in shipping fleet costs over the lifetime of a project, resulting in a lower delivered cost of hydrogen.

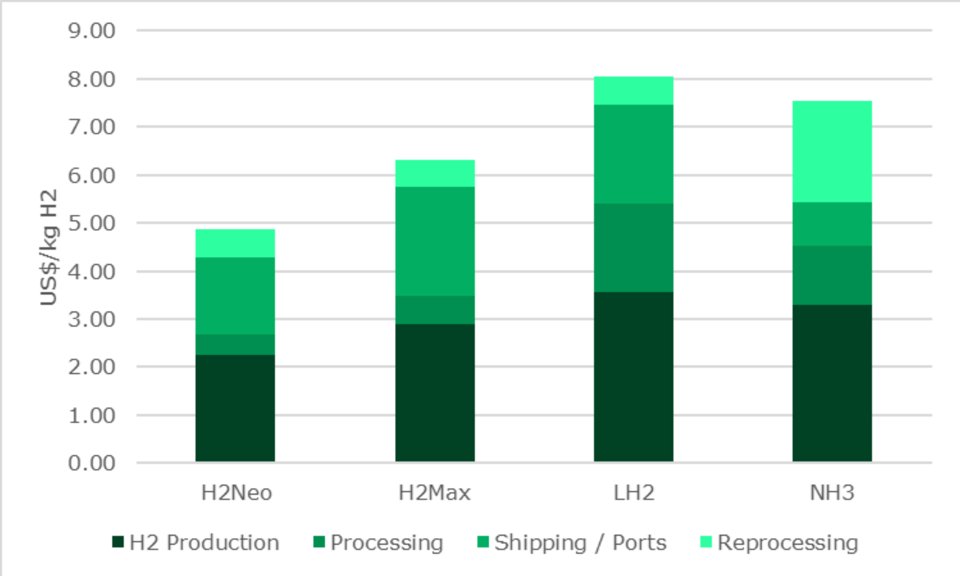
BUT ISN'T COMPRESSION EXPENSIVE?

It is not disputed that compression requires additional vessels when compared to alternatives, but this is outweighed by the benefits.

(a) significantly less capex at the production end (no liquefaction/ammonia facilities)
(b) the vessel design minimises the costs of vessels so that the cost burden of more vessels is not as great as some expect
(c) a more efficient process means less upstream renewable energy capacity is required per tonne of hydrogen produced

The capital required for compressed shipping also needs to be compared against the higher costs of processing hydrogen, either liquefying it or converting it to ammonia, and reprocessing it back to hydrogen at the destination. A full comparative analysis of these costs shows that compression solution is the cheapest overall at voyage lengths of up to 2,000 nm using a full sized vessel (H2 Max) and even better at shorter voyage lengths using a smaller vessel (H2 Neo).

Hydrogen Value Chain Cost Breakdown



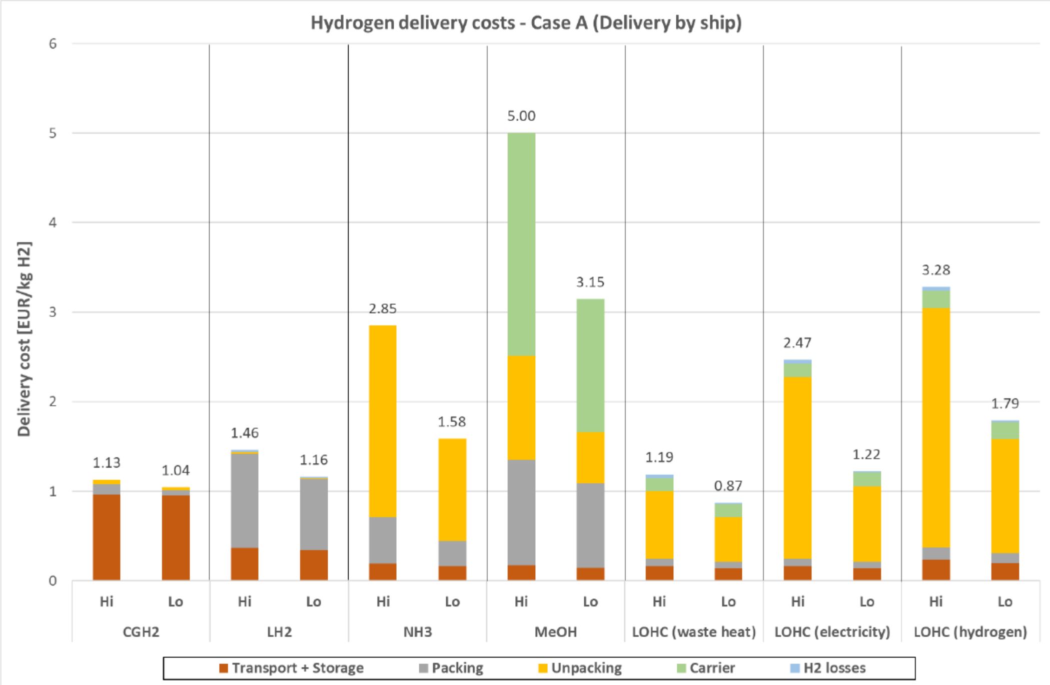
Source: Provaris' Comparison Report 2023 Based on a solar/wind renewable generation profile, 2,000 nm and 100,000 tpa of delivered hydrogen. H2Neo at 620 nm.

ECONOMICS INDEPENDENTLY CONFIRMED BY EU

The EU Joint Research Council (JRC) has also reached similar conclusions for the benefits of compressed hydrogen shipping. Their 2022 report [Ortiz Cebolla, R., Dolci, F. and Weidner Ronnefeld, E., Assessment of hydrogen delivery options, EUR 31199 EN] is clear that this is the most attractive option for distances up to 2,500 km (1,300 nm). Note this analysis is for 1 million tonnes per annum.

"In the case of compressed hydrogen delivered by ship, it can be seen that the final cost is dominated by the transport costs. Due to its lower density, transport of compressed hydrogen requires a bigger and more expensive fleet than any other packaging mode. However, the packing and unpacking costs (i.e., compression costs) are low enough to compensate for the higher transport costs. This makes compressed hydrogen by ship an attractive option, for Case A, with a delivery distance of 2,500 km"

Hydrogen Delivery Costs by Ship



Source: JRC

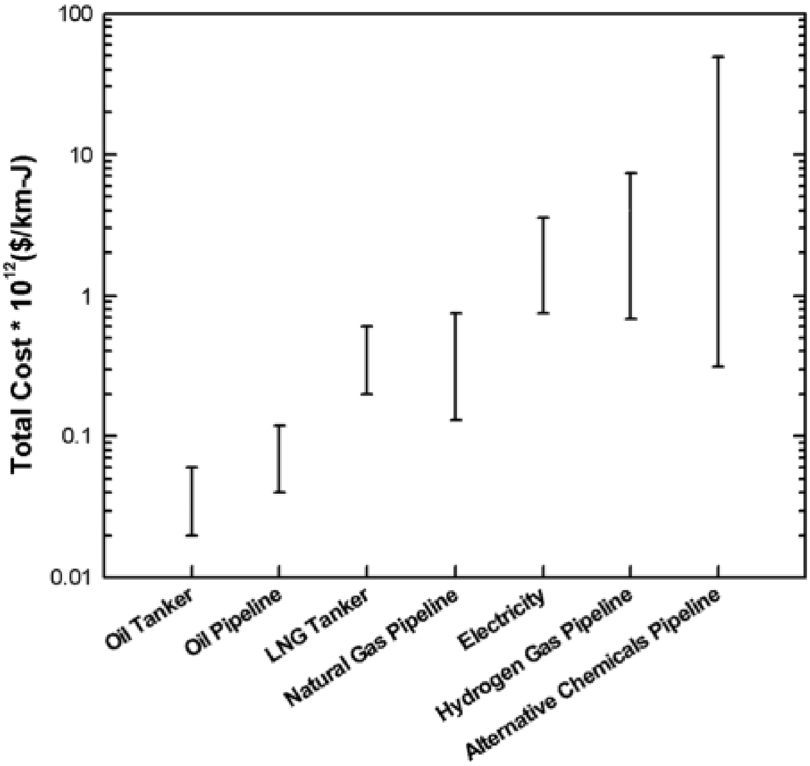
All these studies show a benefit to using compressed hydrogen based on immediately deployable technology. If this solution is fully adopted it is likely that know-how and volume savings will lead to lower costs improving the economic benefits of the solution. These have been further backed by two studies from Agora and Fraunhofer ISE, both of which show that compressed gaseous hydrogen shipping will likely be a cost competitive option for the distribution of the gas in the future.

OTHER DELIVERY SOLUTIONS

CO-LOCATING ELECTROLYSERS WITH DEMAND CENTRES

The mooted alternative to distributing hydrogen over distance is to locate electrolysers alongside demand or in the very near vicinity in order to eliminate the midstream infrastructure as far as possible. Theoretically this makes a great deal of sense as there will likely be both water and electricity availability in high industrial demand centres. There are several issues with this in practice however. From a purely locational perspective, demand centres are typically not near significant renewable energy generation, meaning that electricity will either need to be taken from the grid or renewable energy distributed directly on a private wire potentially to the electrolyser. If taken from the grid, then without suitable safeguards in place this could result in increased fossil fuel consumption in grids that are not already significantly decarbonised. If transmitting via private wire, then the cost of installing cabling combined with transmission losses puts electricity delivered on a per unit basis comparable to that of hydrogen pipeline as evidenced in the graphic below.

Unit Costs for Transporting Energy

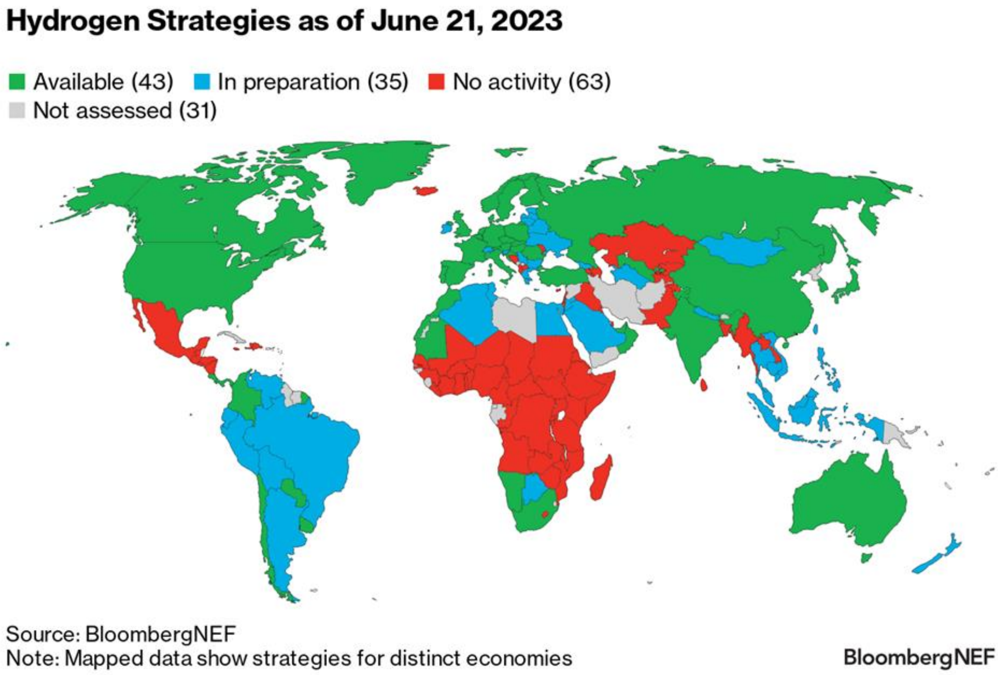


Source: Energy Environ. Sci., 2018, 11, 469

POLICIES TO DRIVE GROWTH

Policy is now driving the hydrogen economy driven by the realisation that hydrogen is essential to achieving net zero emissions. 28 countries now have climate neutrality targets representing over 60% of global CO_2 emissions. Forty-three countries now have hydrogen policies in place with more in preparation.

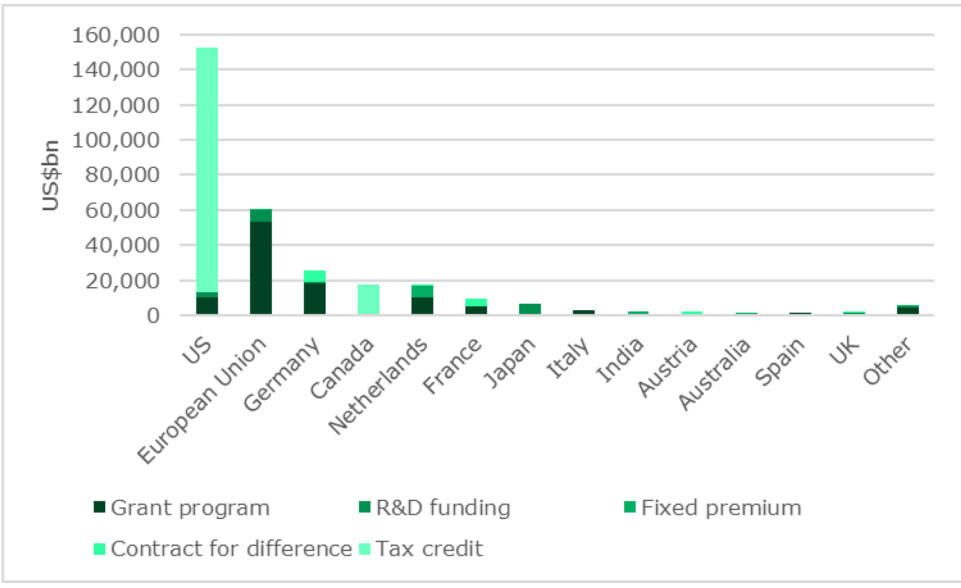
National Hydrogen Strategies as of June 21, 2023



Source: Bloomberg New Energy Finance

Also notable here is China which sees a major role for hydrogen mobility. The country is currently drafting proposals said to cover the period of the 14th five-year plan to 2025 and with a strong focus on the fuel cell industry.

Hydrogen Direct Policy Support



Source: Bloomberg New Energy Finance

HYDROGEN POLICY DEVELOPMENTS IN THREE KEY MARKETS

European Union - €4/kg support likely

The Council of the EU has now approved the new Renewable Energies Directive which moves forward the framework of the EU "Fit for 55" package of policy proposals, named after the 55% greenhouse gas emissions reduction, it is targeting for 2030. The new directive includes a target for 42% of all industrial hydrogen to be green by 2030 rising to 60% by 2035. This has been estimated to create demand for 4Mt of green hydrogen by 2030. A clause also allows France's nuclear heavy grid to be considered as supplying renewable hydrogen. The new directive also targets faster permitting for projects including accelerating permitting procedures to fast-track deployment, considering renewables projects to be of 'overriding public interest' to avoid bottlenecks and further integrating renewable energy in energy grids.

Additionally, 1% of all transport fuel needs to be a Renewable Fuel of Non-Biological Origin by 2030. This effectively means hydrogen derived e-fuels and could lead to demand of 360kt by 2030. A separate ReFuelEU Aviation Directive has mandated 1.2% of aviation fuel to be synthetic fuel from green hydrogen by 2030.

In RePowerEU, the EU has targeted both producing 10Mt and importing 10Mt of renewable hydrogen by 2030, with the purpose of accelerating the uptake of renewable hydrogen, ammonia and other derivatives in hard-to-decarbonise sectors and to reduce the demand for Russian gas. The EU estimates that it will need approximately 80-100GW of electrolyser capacity, compared with 160MW of existing capacity to achieve their domestic production target and this is expected to require an investment of €335-471bn (covering production, transport and consumption) with an additional €200-300bn for additional renewable electricity production (500 TWh of additional power generation required to reach the 2030 goals).

Separate from RePowerEu, the EU has announced the creation of a European Hydrogen Bank in March 2023 with the purpose of unlocking private investment across the hydrogen value chain in order to meet the aforementioned goals.

The EU delegated acts on green hydrogen have also now passed the European Council and Parliament. The first of the two acts contains the definition for what is classed as renewable hydrogen. The act contains three key characteristics that the hydrogen (or derivative product) must meet in order to qualify as being renewable hydrogen, importantly this will apply to imported green hydrogen, meaning that this could set a global benchmark for green hydrogen production standards.

The three main standards for producers to consider are:

- Additionality- meaning that developers will have to install new renewable energy assets at most 3 years before the electrolyser starts producing hydrogen.
- Temporal correlation- meaning that hydrogen production needs to be matched on a monthly basis (until 2030 and then hourly) against renewable energy production.
- Geographical correlation- meaning that the renewable energy assets have to be located in the same electricity zone bidding area as the electrolyser.

The second act sets out the methodology for calculating emissions generated in production of hydrogen in order to allow for a 70% reduction in CO_2 for equivalent fuels.

The delegated acts have been somewhat controversial and some in the industry have said the requirements will drive up the cost of green hydrogen in the continent. Policy support on the demand side is expected with an auction announced for December 2023. This will feature a ten-year fixed premium support mechanism which is expected to come in at €4/kg

H2. There are also several exclusion clauses allowing the use of low carbon intensity grids such as France's nuclear heavy system to produce renewable hydrogen.

Away from direct hydrogen support the Fit for 55 package already includes blending mandates for sustainable aviation fuel SAF which include a sub mandate for synthetic fuels. These are fuels made from hydrogen and captured carbon. However, other SAF is made from biomass which can also be upgraded using hydrogen.

European SAF Blending Mandates

	2025	2030	2035	2040	2045	2050
Percentage of SAF used in air transport:	2%	5%	20%	32%	38%	63%
Of which: sub-mandate Synthetic fuels (or e-fuels):	-	1%	5%	8%	11%	28%

Source: EASA

In shipping both the EU and International Maritime Organization (IMO) are toughening emissions regulation. The EU has brought shipping into the Emissions Trading Scheme (EU-ETS), the Fuel EU Maritime initiative and the EU Energy Tax. All these moves are already feeding demand for low carbon shipping solutions with green methanol currently showing strongest traction. We cover this in more detail in our shipping decarbonization notes, All at Sea, Longspur Research 25 January 2022 and Attention All Shipping, Longspur Research, 21 March 2023.

FuelEU Proposed GHG Reductions

From 1 Jan	GHG cut from 2020 baseline
2025	2%
2030	6%
2035	20%
2040	38%
2045	64%
2050	80%

Source: European Parliament

USA – Up to US$3/kg Available as Tax Credits

The Bipartisan Infrastructure Law (BIL) reached agreement on its overall objectives on 28th of July 2022. This should see at least US$114bn in expenditure related to the energy transition. While the bulk of this will be in grid enhancement, hydrogen directed spend is expected in the following areas: US$8bn spend is expected on hydrogen to clean hydrogen hubs aimed at demonstrating the production, transportation and use of zero carbon hydrogen technologies, US$1bn to develop electrolyser efficiency to allow for US$2/kg hydrogen production from electrolysis by 2026 and US$500m for supply chain and recycling of components. US$7bn has now been allocated to seven hubs with a mix of green and blue hydrogen but predominantly green.

BIL Regional Clean Hydrogen Hubs

Funding Recipient	Location	Tech Focus	Funding (US$bn)
Alliance for Renewable Clean Hydrogen Energy Systems	California	Electrolysis powered by renewable energy, biomass conversion	$1.2
Appalachian Regional Clean Hydrogen Hub	West Virginia, Ohio, Pennsylvania	Natural gas reformation paired with carbon capture and storage (CCUS)	$0.925
Heartland Hydrogen Hub	Minnesota, North Dakota, South Dakota	Electrolysis powered by renewable and nuclear energy, used to produce fertilizer	$0.925
HyVelocity H2Hub	Texas	Natural gas reformation paired with CCUS, electrolysis powered by renewable energy	$1.2
Mid-Atlantic Clean Hydrogen Hub	Pennsylvania, Delaware, New Jersey	Electrolysis powered by renewable and nuclear energy	$0.75
Midwest Alliance for Clean Hydrogen	Illinois, Indiana, Michigan	Electrolysis powered by renewable energy, used for industrial and transportation decarbonization	$1.0
Pacific Northwest Regional Hydrogen Hub	Washington, Oregon, Montana	Electrolysis powered by renewable energy	$1.0

Source: U.S. Department of Energy

The package includes a larger US$18bn for carbon capture and storage solutions which could signify a major role for blue hydrogen in the USA. This would not be too surprising given the quantity of cheap gas available although is likely to be a poor outcome from an emissions point of view. However, we still see growth in a hydrogen economy as driving demand for green solutions and PEM electrolysis in particular.

The USA is also helping to develop the sector through its Energy Earthshots Initiative run by the Department of Energy. The first of these is a Hydrogen Shot aimed at reducing the cost of hydrogen to US$1 for 1kg in 1 decade (“111”). We see this initiative and ones like it as boosting the overall hydrogen environment to the benefit of all in the industry.

The Inflation Reduction Act, one of the more important pieces of American legislation for renewable energy and clean tech more broadly, has some positive policy support for the hydrogen space. In particular there is a hydrogen production tax credit, which has been introduced to help increase the competitiveness of clean hydrogen with SMR-produced hydrogen. To qualify for the highest level tax credit available (US$3/kg H_2 produced), the hydrogen will require lifecycle GHG emissions rate of less than 0.45 kg of CO_2e per kg of hydrogen. Whilst there are complexities involved in the bill, surrounding the matching of renewable energy to the grid and carbon intensity, Wood Mackenzie see certain scenarios where green hydrogen becomes economically competitive under this.

To support the BIL, the USA has also published its Clean Hydrogen Strategy and Roadmap, one of the more comprehensive hydrogen strategies released from a government to date. The strategy has key targets in place through to 2026 addressing production (cost and volume), infrastructure and supply chains and end use cases. Tracking is to be monitored by the Department of Energy in addition to aiding stakeholders with progress.

UK – CfD Pricing in Negotiation

The UK government is targeting 10GW low carbon hydrogen production capacity by 2030 and 1GW of electrolytic hydrogen and 1GW of CCUS-enabled hydrogen operational or in construction by 2025. There will be a twin track approach supporting both green and blue hydrogen. The government will provide up to £100m of taxpayer funding for projects operational before March 2025 beyond which all revenue support for hydrogen will be levy funded, subject to consultation and legislation being put in place.

The Hydrogen Production Business Model will follow a Contract for Difference (CfD) approach as used to support offshore wind with the CfDs termed Low Carbon Hydrogen

Agreements (LCHAs). The approach allows government to set demand but the market to determine supply and price. Once in place, price is guaranteed which should support low-cost infrastructure finance for hydrogen production.

Contracts on 17 projects in negotiation with a capacity of 262MW are expected to be awarded before the year end under the first Hydrogen Allocation Round (HAR 1). However, the required offtake agreement in the eligibility rules may imply high utilisation targets and not allow merchant output or sales to trading houses (risk taking intermediaries). This would seem to remove the wider benefits to the energy system that electrolysis can provide as a balancing demand tool. HAR 2 is targeting 750MW of capacity.

Funding will be through the imposition of a hydrogen levy to be implemented after 2025. There will also be a £240m Net Zero Hydrogen Fund supporting deployment of production plant. Other funds and competitions to trial and develop related solutions include the £26m Industrial Hydrogen Accelerator and the £55m Net Zero Innovation Portfolio Industrial Fuel Switching Competition. Network and storage infrastructure is to be reviewed.

A Low Carbon Hydrogen Standard has been introduced, as of April 2023. This states that in order to be low carbon, hydrogen must be produced with an emissions intensity of 20gCO2e/MJLHV hydrogen. This is calculated based on Scope 1, 2 and partial scope 3 emissions. This will be followed by a hydrogen certification scheme in 2025, in order to both regulate UK hydrogen production and set standards for imported hydrogen.

Uses of hydrogen in the UK economy will include the more obvious transport and industry applications with shipping, HGV transport and rail identified. The strategy also aims to replace natural gas in powering c.3m homes directly, strategic decisions on the role of hydrogen in heating are to be taken in 2026. The government is also assessing a 20% hydrogen blend in the existing gas network with a decision due this year although recently the National Infrastructure Commission said that there was no public policy case for this, and former energy minister Grant Shapps has said that piping gas to domestic properties is less likely.

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