Energy Transitions Commission:
The Making Mission Possible Series

Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy

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Technical Annex

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A.1 SUPPORTING INFORMATION

This technical annex supports the 2021 ETC report *Making Clean Hydrogen Possible*. The following chapter will describe further aspects on supply, transportation and storage, demand as well as hydrogen as GHG in more detail.

A.1.1 Supply

A.1.1.1 Electrolyser components and balance of plant design

As discussed in Sections 1.2 and 2.1 in the main report, electrolyser costs are likely to decline strongly. It is critical to differentiate between three different parts of the electrolyser (Exhibit 1.a):[1]

- **Cell:** composed of the anode and cathode immersed in a liquid electrolyte (alkaline electrolyser) or adjacent to a solid electrolyte membrane (PEM, SOE[2] and lower TRL technology AEM[3]).

- **Stack:** multiple cells electrically connected in series with spacers (insulating material between two opposite electrodes), seals, frames (mechanical support) and end plates (to avoid leaks and collect fluids).

- **System** (or balance of plant (BoP)): includes equipment for cooling, processing the hydrogen (e.g., drying, compression), deionising the water supply and providing power to the electrolyser (e.g., transformer and rectifier)

Exhibit 1.a Electrolysers – the heart of green hydrogen production

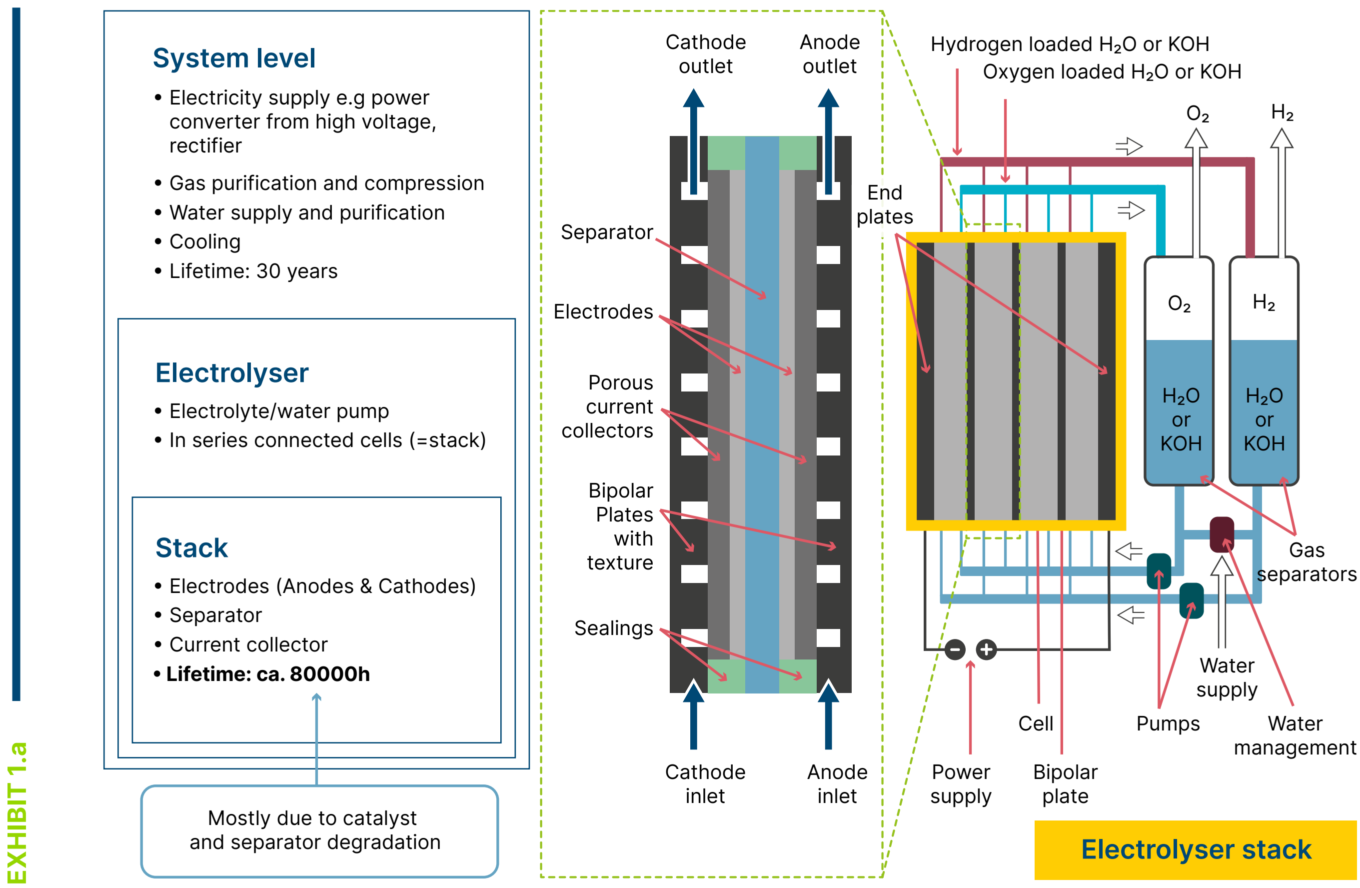


Figure adapted from Schalenbach et al. (2018), *Int. J. Electrochem. Sci.*

1 IRENA (2020), *Green hydrogen cost reduction.*
2 PEM: Polymer Electrolyte (or Proton-exchange) Membrane Electrolysis. SOEC: Solid-Oxide Electrolysis.
3 AEM: Anion Exchange Membrane. Companies working on this technology include Enapter, EvolOH among others.

Further details on all of the different electrolysis technologies can be found in a recent IRENA report.[4]

The BoP for alkaline electrolysers is more complex due to the alkaline electrolyte handling and the more complex hydrogen gas separation steps (Exhibit 1.b):[5]

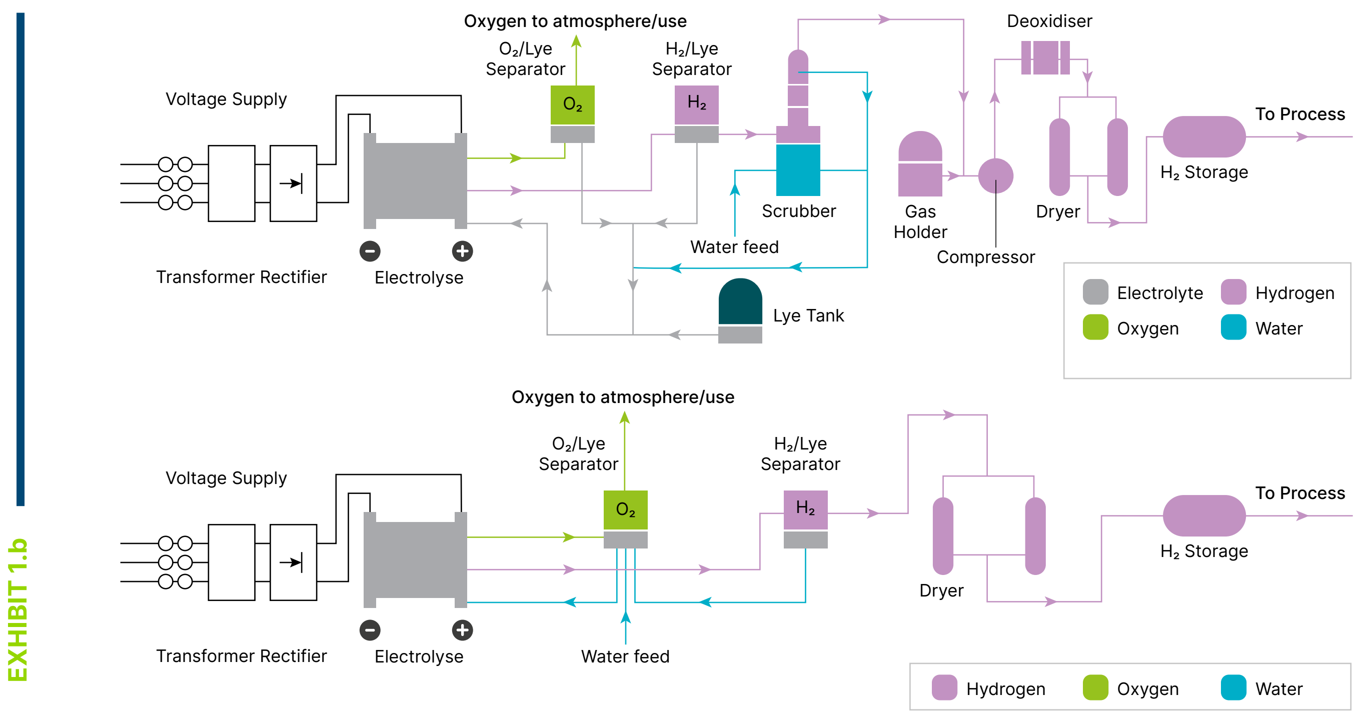
- The concentration of the lye needs to be kept constant in the process which requires a separate tank and concentration adjustment with fresh feed water. In a PEM electrolyser the hydrogen is separated from the electrolyte and the oxygen production via a solid polymer membrane, it is therefore lower in oxygen and residual water content.[6] For this reason, the operating pressure can typically be higher in a PEM electrolyser lowering the demand for compression after the electrolyser.

- SOE require a different BoP design due to the high operating temperatures (~600°C) which necessitates pressurised steam handling and careful thermal management.

The simpler BoP contributes to the faster response time of PEM electrolysers compared to alkaline electrolysers. However, future developments as well as the anion exchange membrane electrolysis (AEM; a hybrid of PEM and liquid alkaline electrolysis) will likely lower the response time of alkaline electrolysers in the future.

Alkaline electrolysers are forecasted to remain lower cost than PEM electrolysers at least for the next 10 years.[7] SOE electrolysers will require further development and scaling to become cost competitive.[8] But given the different application characteristics described in Box C in the main report and the opportunities for further innovation discussed in Section 3.5, it is likely that the cost differential between the technologies will shrink. It remains open which technology will ultimately win the largest market share.

Exhibit 1.b Balance of plant is more complex for alkaline



Source: NET (2021), *Electrolyser Brochure.*

4 IRENA (2020), *Green hydrogen cost reduction.*
5 Further detailed comparison: https://www.energy.gov/sites/default/files/2022-02/7-TEA-Liquid%20Alkaline%20Workshop.pdf
6 Materials Science for Energy Technologies (2019), *Hydrogen production by PEM water electrolysis – A review.*
7 BloombergNEF (2019), *Hydrogen – Economics of Production from Renewables.*
8 Science (2020), *Recent advances in solid oxide technology for electrolysis.*

A.1.1.2 Hydrogen production efficiency

Throughout the report, the energy consumption to produce hydrogen was typically quoted as “kWh/kg” to avoid confusion with different definitions described below. Efficiencies (if used) were referred to the lower heating value (LHV) according to IEA definitions (see below).[9] A brief description of key concepts:

- **Cell vs. stack vs. system efficiency for electrolysers:** These simply illustrate the different levels of complexity building up an entire green hydrogen plant (see Exhibit 1.a). One cell consists of only one cathode and anode, a stack is the connection of many individual cells, and the system then considers power supply / electrolyte circulation / water desalination etc. The efficiency decreases with each step of complexity; hence cell efficiencies and stack efficiencies are always higher than whole system efficiencies. To enable useful comparisons, the efficiency quoted needs to refer to full system efficiency (including losses in parts of the balance of plant such as the power supply or electrolyte pumping in the case of green hydrogen).

- **Higher vs. lower heating value:** The lower heating value (LHV) for water is 33.3 kWh/kg and the higher (HHV) is 39.5 kWh/kg. They describe the energy released upon combustion of 1 kg of hydrogen with oxygen. The HHV is larger as it includes the heat of vaporisation of water where the reaction product is liquid water, rather than water vapor.

- **Efficiency calculation for electrolysers:** The energy required to produce 1 kg of hydrogen differs depending on whether it refers to the HHV or LHV and therefore the term “efficiency” can be ambiguous and requires clear labelling:

    - For blue hydrogen, and high-temperature electrolysis, using HHV is more common since part of the water condensation heat is re-used in the process.[10]

    - For green hydrogen, it is more common to refer to the LHV, but differences exist between different geographies.[11,12] Efficiencies in the report (if used) were referred to the lower heating value (LHV) according to IEA definitions.

It is noteworthy, that efficiencies beyond 100% based on the electrical energy input are feasible if the HHV is used as reference and thermal energy inputs are not considered (particularly important for high-temperature electrolysis).[13] While not commonly spelled out, water electrolysis requires both the input of electrical as well as thermal energy (to overcome so called ‘entropic losses’ that are thermodynamically inevitable):

H_2O(liquid) + 237.2 kJ/mol *electricity* + 48.6 kJ/mol *heat* → $H_2 + ½ O_2$

$$\textit{Electrical efficiency}_{\mathrm{LHV}} = \frac{\textit{LHV}_{H2}}{\textit{Electricity used}}$$

This additional heat required is generally provided via waste heat within the electrolyser due to resistive losses. However, in particular in the case of high-temperature electrolysis, heat can also be provided through an external source (e.g., waste heat from an industrial plant). If heat inputs are not explicitly considered, the electrical energy consumption can be higher than 100%. The overall (heat + electricity) energy consumption can of course never be higher than 100%.

In most common low temperature electrolysis setups exclusively electrical energy is provided as energy input. The required heat in the electrolyser (see equation above) stems from resistive heat losses that originate from the electrical energy input, hence considering only electrical energy input is sufficient to accurately quote electrolyser efficiency. This approach was chosen within this report.

9 IEA (2019), *The Future of Hydrogen Appendix.*
10 Cadent (2019), *H21 North of England.*
11 IEA (2019), *The Future of Hydrogen.*
12 NREL (2010), *Hydrogen Production: Fundamentals and Case Study Summaries.*
13 Ibid.

A.1.1.3 SMR/ATR/POX technology overview and capture rates

Retrofitting existing steam methane reforming (SMR) assets to capture over 90%[14] CO_2 brings about significant engineering challenges, which often makes ATR and POX more attractive (Exhibit 1.c):

- In the SMR process, CO_2 is a component of two streams: the product stream made up of concentrated CO_2 and hydrogen, and a low concentration CO_2 stream heavily diluted with nitrogen (from air) from the combustion of natural gas to heat the reformer. If all of the concentrated flow (=process emissions) is captured, the capture rate would be about 55 to 60%; if the more dilute flue gas emissions from combustion are captured, a capture rate of 90% (or higher) can be achieved, but this then becomes much more expensive (Exhibit 1.11).[15] Two SMR + CCS plants with circa 60% capture rate are operational today.[16]

- In the autothermal reforming (ATR) and partial oxidation (POX) processes, all of the CO_2 is contained in the concentrated product stream and therefore CO_2 capture rates of 95% can be easily achieved.[17] ATR is currently used commercially in methanol and ammonia plants, but no dedicated ATR+CCS plant has been constructed to date. The combination of autothermal reforming (ATR) with a Gas Heated Reformer (GHR) is an improved design of ATR that allows achieving higher efficiencies, lower CO_2 production and lower oxygen consumption. The ATR and GHR are in series and the GHR acts both as a pre-heater and cooler of the inlet/outlet of the ATR. The GHR benefit is that it pre-reforms the gas going to ATR using the heat from the exhaust gases of the ATR and performs part of the reforming that would otherwise take place in the ATR.

In addition, blending of the natural gas feedstock with biomethane, blue hydrogen could be made net-zero or potentially even net-negative emissions.[18] This will however likely be limited due to the large amount of biogas/biomass required per reformer unit. Challenges exist around the size mismatch of ATR units and biomass digestors. One would require at least 12 average European size biogas digestors to support one small scale GHR+ATR+CCS reformer unit capable of producing 150 t ammonia/day.[19] A standard ammonia plant is commonly 2000 t ammonia/day.[20] In other words, all of the biogas produced in Austria would only suffice to transform into 50 t ammonia/day.[21] Furthermore, the role of the distribution gas grid that biogas is typically injected into will likely decline in a net-zero future.

ATR and POX are similar technologies (ATR is a sub-form of POX) which subtle differences:

- Both technologies require oxygen as input (and therefore an air-separation unit) and combust a part of the natural gas feedstock within the reforming process to produce steam and heat for the reaction;

- The POX process operates at higher temperatures and is a non-catalytic process while ATR is at slightly lower temperatures and uses a catalyst;

    - The ATR process is therefore more sensitive to input impurities due to the risk of catalyst poisoning;

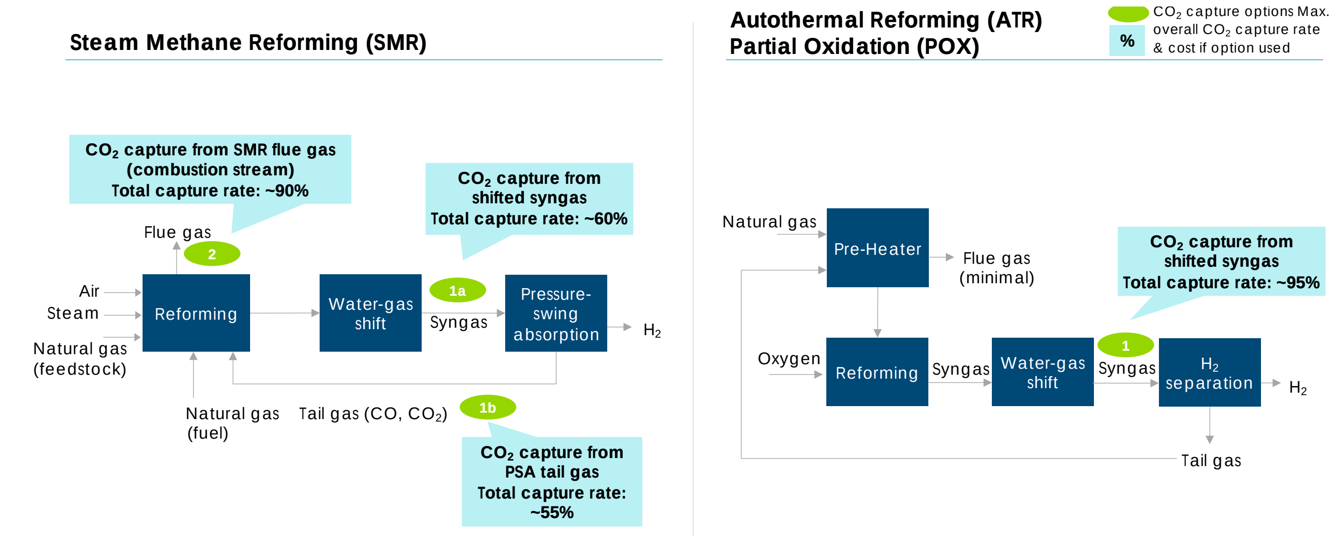
    - The output gas purity is higher for the ATR process;

    - The POX process is not limited to natural gas as input and can operate with more versatile feedstock (e.g., heavy fuel oil).

14 As discussed in section 1.2 and 3.7 in the main report, high capture rates beyond 90% are essential to enable low lifecycle emissions for low-carbon hydrogen.
15 In the case of 90% capture rate the tail gas from the pressure-swing absorption process (which contains the process CO_2 emissions) is combusted to provide heat for the process, hence the combustion emissions contain the process emissions. (Source: IEAGHG (2017), *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS)*.
16 BloombergNEF (2020), *Hydrogen – Economics of Production from Fossil Fuels*.
17 Depending upon plant design capture rates beyond 97% are feasible. (Source: HyNet project).
18 Element Energy (2019), *Hydrogen production with CCS and bioenergy*.
19 In 2017, 540 biogas plants in Europe produced 19,352 GWh energy in the form of biogas (Source: European Biogas Association (2018), *EBA Statistical report*). Assuming a consumption of 28.4 GJ/t of ammonia (Source: Mission Possible Partnership (2022), *Making net-zero 1.5°C aligned ammonia possible, Technical Appendix*), an average biogas plant could support of maximum of 12.4 t/ammonia per day.
20 Mission Possible Partnership (2022), *Making net-zero 1.5°C aligned ammonia possible, Technical Appendix*.
21 Austria produced a total of around 150 GWh biogas on average between 2018-2020 (Source: European Biogas Association (2021), *EBA Statistical report*).

Exhibit 1.c For Blue production, the critcal issue is to ensure CO_2 capture rates are sufficiently high (>90%) to ensure productio is truly 'low-carbon'

EXHIBIT 1.c



Note: Designs are often bespoke in nature and depend on existing infrastructure, feedstock and product needs. These simplified flow-sheets try to illustrate high-level differences. Source: H21 North of England Report, HyNet, The Chemical Engineer, Expert interviews.

A.1.1.4 Sensitivity analysis for green and blue hydrogen production costs

The economics of clean hydrogen clusters can be greatly improved by focusing on levers which can lower the costs of clean hydrogen production. As discussed through section 1.2 and section 2.1, the key cost drivers for green hydrogen are the levelized cost of electricity (LCOE), capacity utilisation factor, electrolyser CAPEX and for blue hydrogen, the main cost driver is the natural gas price.[22] No hydrogen storage costs for blue hydrogen were assumed since the production is usually operating stable and produces a constant hydrogen output. Exhibit 1.d and Exhibit 1.e illustrate the impact on selectively varying one lever for green and blue hydrogen costs to identify the most impactful ways to lower delivered cost of hydrogen:[23]

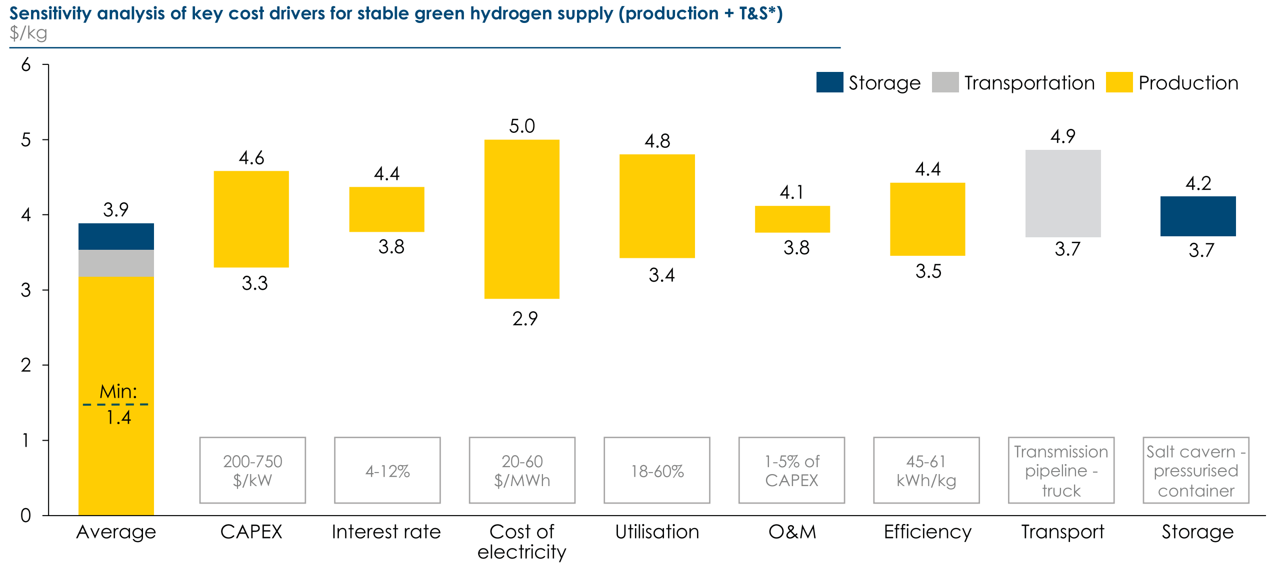
- The cost of electricity has the largest impact on the cost of green hydrogen – lowering the cost from 40 $/MWh to 20 $/MWh decreases the cost from 3.9 to 2.9 $/kg while keeping all other cost parameters unchanged. Decreasing the electrolyser CAPEX from 475 $/kW to 250 $/kW reduces the cost from 3.9 to 3.3 $/kg delivered cost of hydrogen while keeping all other cost parameters unchanged.

- Blue hydrogen costs are almost exclusively driven by natural gas prices. Decreasing the gas price from 10 to 1 $/MMBtu, decreases the cost from 3.2 $/kg to 1.6 $/kg.

22 In both cases the required amount of storage and transport impacts the overall delivered cost (see section 1.3).
23 Note that the different cost parameters influence each other, e.g., LCOE has a higher relative impact on the cost of green hydrogen at low electrolyser CAPEX.

Exhibit 1.d For green hydrogen, key cost drivers will be electricity prices, electrolyser CAPEX, load factors and transport

EXHIBIT 1.d



* 50% annual demand for storage, there might be less (e.g., 20%) required only. Stack replacement cost (% of CAPEX) - currently assumed 50%. if vary from 40-60% impacts cost by $0.03 $/kg. In 2020s usage of large volume transmission pipelines and salt caverns in most cases unattainable, thereby likely significant T&S costs for all-in delivered LCOH cost.

TABLE 1

Table 1 Green hydrogen cost parameters for Exhibit 1.d. The base case numbers were used besides varying one parameter at a time from Min case to Max case

	Base case	Min case	Max case
CAPEX ($/kW)	475	200	750
Cost of electricity ($/MWh)	40	20	60
Utilization factor	32%	60%	18%
Distance transported (km)	200	200	400
Volume (tonne)	10 - 100	100 - 1000	1 - 5
Transportation type	Distribution pipeline	Transmission pipeline	Truck
Storage type	Rock cavern (50% annual demand)	Salt cavern (50% annual demand)	Pressurised container
Interest rate	6.5%	4%	12%
Capital recovery factor	8%	6%	12%
Electrolyser OPEX excl. electricity (% of CAPEX)	3%	1%	5%
Total cost delivered hydrogen ($/kg)	**3.94**	**1.39**	**9.27**

Exhibit 1.e Blue hydrogen production: natural gas price is the key cost driver with minimal contribution from CAPEX

EXHIBIT 1.e

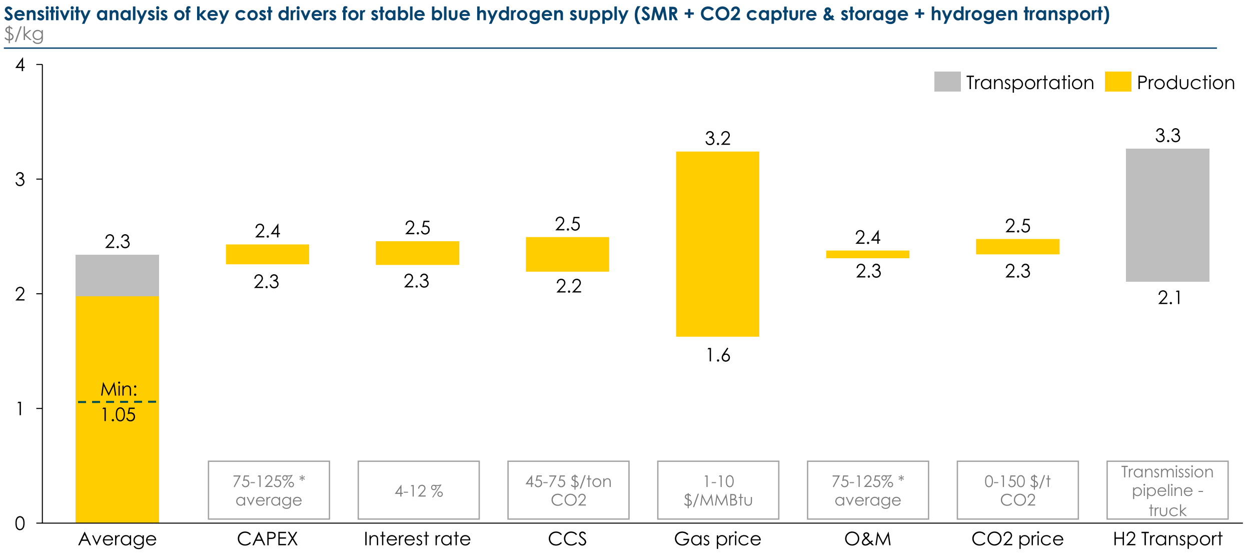


TABLE 2

Table 2 Blue hydrogen cost parameter for Exhibit 1.e

	Base case	Min case	Max case
CAPEX (USD million)	442	331.5	553
Volume H_2 capacity (tonne/day)	350	350	350
O&M (USD million)	16.6	12.45	20.75
Plant life (years)	30	30	30
Interest rate	8%	4%	12%
Capital recovery factor	9%	6%	12%
Natural gas price (USD / MMBtu)	5	1	10
CCS ($/t CO_2)	0.6	0.45	0.75
H_2 Transport ($/kg H_2)	0.36	0.12	1.28
Total cost delivered hydrogen ($/kg)	**2.34**	**1.05**	**4.58**

Section 2.1 in the main report describes that the relevant electricity price for green hydrogen production is in part dependent on the electrolyser costs. Falling electrolyser costs enable different utilisation rates and electricity prices:

- High-cost electrolysers require high utilisation rates to spread the electrolyser CAPEX over as many hours as possible. Therefore, high-capacity factor power sources such as grid power or hydro power are required to provide a continuous power supply (Exhibit 1.f).

  Significant reductions in electrolyser CAPEX are required to enable low-cost green hydrogen. However, as electrolyser costs fall, the relative cost contribution of the electrolyser cost to the overall cost of green hydrogen decreases significantly and costs are primarily driven by the cost of electricity. Low-cost electrolysers powered by low-cost electricity from curtailment or dedicated photovoltaics with low utilisation rates will be able to deliver cost-competitive green hydrogen (Exhibit 1.g). At low electrolyser CAPEX, the cost of electricity essentially dictates a floor price for green hydrogen (Exhibit 1.h).

  While it remains difficult to predict how far electrolyser costs will fall (Section 1.2 and 2.1), the impact on green hydrogen costs is minimal below electrolyser costs of circa $200/kW:

- At feasible utilisation factors for solar and wind (considering overbuild of renewable asset compared to electrolyser capacity), the green hydrogen price difference between an electrolyser CAPEX of $200/kW vs. $100/kW is only $0.15-0.25/kg (Exhibit 1.i).

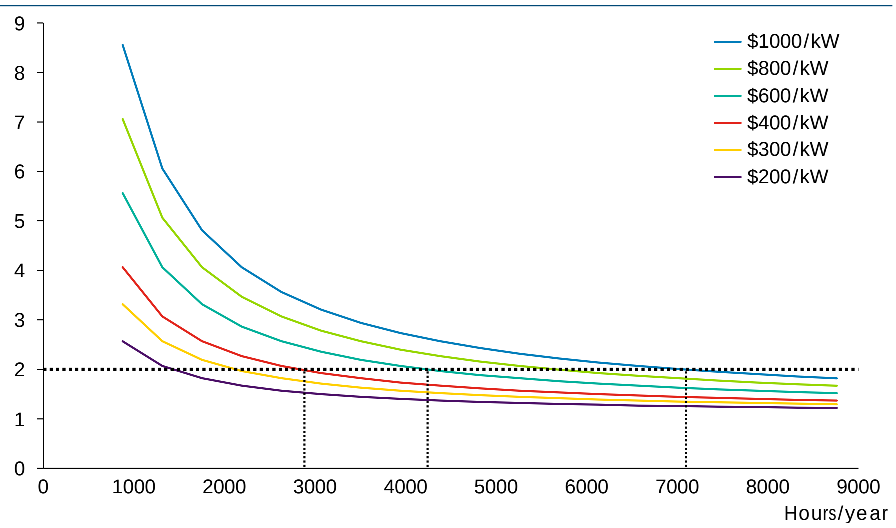
- A very low but possibly feasible 10 $/MWh (=0.01 $/kWh) for LCOE at an electrolyser efficiency of 45 kWh/kg (73% system efficiency vs. LHV) would therefore translate to 0.45 $/kg hydrogen cost.

In conclusion, this suggests that green hydrogen prices below $0.5/kg will likely not be within reach considering today's technologies and optimistic techno-economic assumptions for electrolyser CAPEX and renewable power.

Exhibit 1.f High electrolyser utilisation is required at high electrolyser CAPEX to enable low-cost green hydrogen production

EXHIBIT 1.f

Green hydrogen production cost (excl. transport & storage) at $20/MWh and different electrolyser CAPEX and utilisation
$/kg Hydrogen



How many hours per year does an electrolyser need to operate at $20/MWh to produce green hydrogen at $2/kg?

Electrolyser CAPEX	Load hours
$400/kW	2800
$600/kW	4300
$1000/kW	7000

Exhibit 1.g Lower load hours from dedicated renewables become relevant at lower electrolyser cost

EXHIBIT 1.g

Load hours at different electrolyser CAPEX and power prices to achieve $2/kg green hydrogen production cost
hours

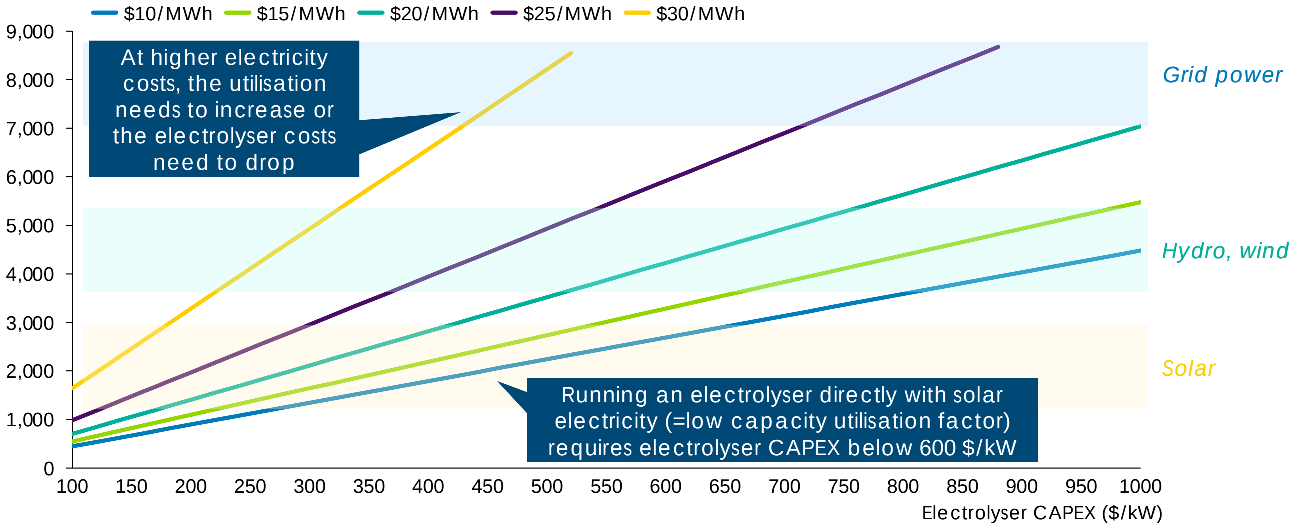
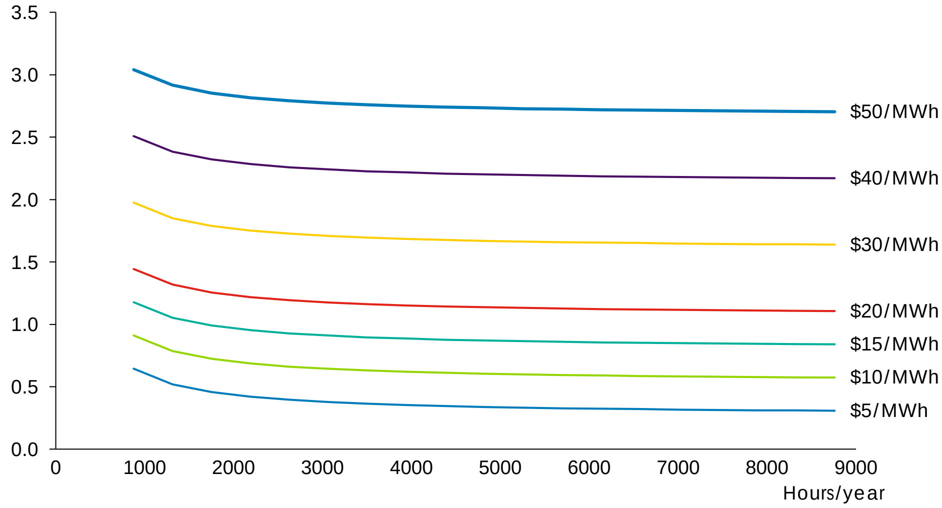


Exhibit 1.h Electricity is almost solely dictating the price floor for green hydrogen

EXHIBIT 1.h

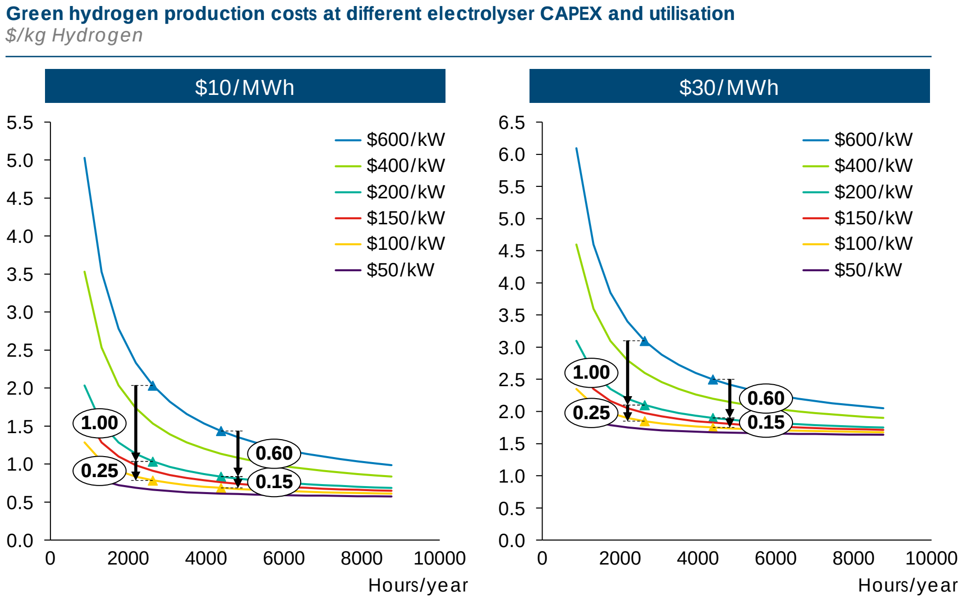
Green hydrogen production cost at $50/kW electrolyser CAPEX, different electricity prices and utilisation
$/kg Hydrogen



At exceptionally low electrolyser CAPEX ($50/kW) the green hydrogen production price is exclusively dictated by the cost of electricity. Costs below $0.5/kg hydrogen will likely remain out of reach for many decades.

Exhibit 1.i Clean Hydrogen supply-side ramp-up model: Variations of electrolyser CAPEX below circa $200/kW do not reduce green hydrogen production costs significantly

EXHIBIT 1.i



Electrolyser CAPEX reduction is critical to enable low cost green hydrogen production. Reducing the CAPEX from $600/kW to $200/kW reduces green hydrogen production cost by $0.6-1 at 30-50% utilisation.

The production cost differential between electrolyser CAPEX of $200/kW to $100/kW is minimal and independent of electricity price:

- 30 % utilisation: $0.25/kg
- 50 % utilisation: $0.15/kg

The hydrogen supply ramp-up model was based on three different models for grey, blue and green hydrogen. Overall, three different illustrative scenarios for green/blue mixes were evaluated as discussed in Section 2.3 of the main report

1. Grey hydrogen retrofitting: CCS deployment within the existing stock of dedicated grey hydrogen facilities (by-product hydrogen was not considered) was modelled based on an S-curve approach with different retrofitting speeds (Exhibit 1.j).

- No new grey hydrogen plants were assumed to go online.
- In the “low” and “medium” scenario only natural gas based hydrogen plants (71%) were considered since the residual uncaptured emissions of a coal gasification + CCS plant were considered too high at 90% capture rate. In the “high” scenario, natural gas and coal-based plants were considered.
- All grey hydrogen plants were either retrofitted or retired by 2035.
- Plants retrofitted with CCS were assumed to extend their lifetime by 20 years from the point of retrofit.

2. Greenfield blue hydrogen: The model was based on a pipeline of projects in the last 10 years and projects announced for the next three years. A rapid acceleration of new projects was modelled via exponential and S-curve functions reaching a plateau of new projects in 2030. This timepoint was based on the relative economics of blue/green hydrogen, which sees green hydrogen outcompeting blue hydrogen over time, slowing down the blue hydrogen project pipeline beyond 2030 close to zero by 2040 with the same rate as the prior ramp-up (due to stranded asset risk, except in the very low cost natural gas regions, Exhibit 1.k).

- The project planning process was based on CCS projects of the last 10 years with the stages: “early planning”, “advanced planning”, “construction”, “completion” (at which stage the plant is considered online).
- For example, the “high” scenario assumes an earlier increase of project pipeline and a wider bell-shape curve leading to a significantly larger number of projects reaching completion stage (although process still takes ~5 years)
- For simplicity, the ratios of these respective project stage categories were kept constant, assuming a constant ratio of the relative planning stages.

Time delays between the respective planning stages were taken into account and adjusted depending on the scenario (shorter time delays for high scenario than for low scenario).

Exhibit 1.j 3 scenarios for feasible ramp up speed of blue production modelled

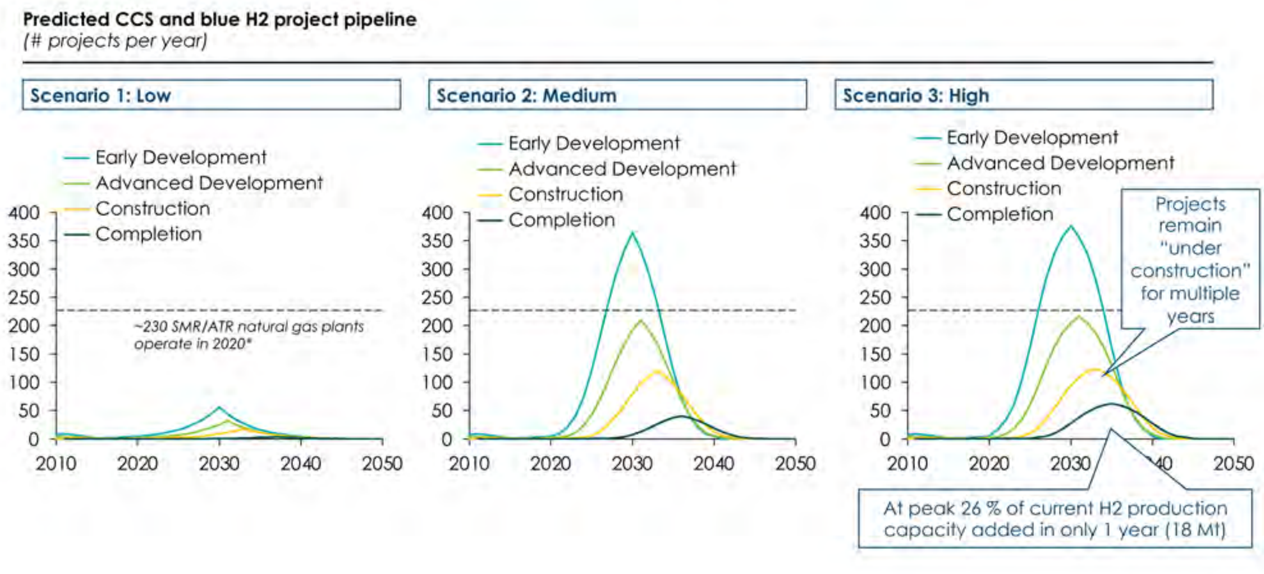
EXHIBIT 1.j

		Scenario 1: Low	Scenario 2: Medium	Scenario 3: High
Retrofitting CCS to existing grey production	# of plants	**Gas** SMR/ATR only	**Gas** SMR/ATR only	**Gas+coal** (all dedicated production)
	Grey H2 stock	Constant until **2025** **4 %/year retirement** post 2025	Constant until **2027** **2 %/year retirement** post 2027	Constant until **2030** **2 %/year retirement** post 2030
	CCS deployment	Retrofitted ca. 1/3 by **2030** Retrofitted c.35% at maximum	Retrofitted ca. 1/3 by **2028** Retrofitted c.60% at maximum	Retrofitted ca. 1/3 by **2027** Retrofitted 100% at maximum
Building new blue production facilities	Up to 2023	Based on publicly announced projects (IEA database)		
	Project development (vs. 2023 blue production and 2020 grey production)	2x capacity by 2034 **4x** capacity by **2038** **7%** vs grey (2020) by **2038** (Exponential base)	2x capacity by 2028 **55x** capacity by **2038** **88%** vs grey (2020) by **2038** (S-curve base)	2x capacity by 2024 **129x** capacity by **2038** **208%** vs grey (2020) by **2038** (S-curve base)
	Lead times, years	**7**	**6**	**5**
	Plant size, Mt/year	**500**	**700**	**800**

All new and retrofitted assets have a **20 year asset lifetime** before retirement

Exhibit 1.k At peak, almost 400 blue hydrogen projects in development needed for aggressive ramp-up.

EXHIBIT 1.k



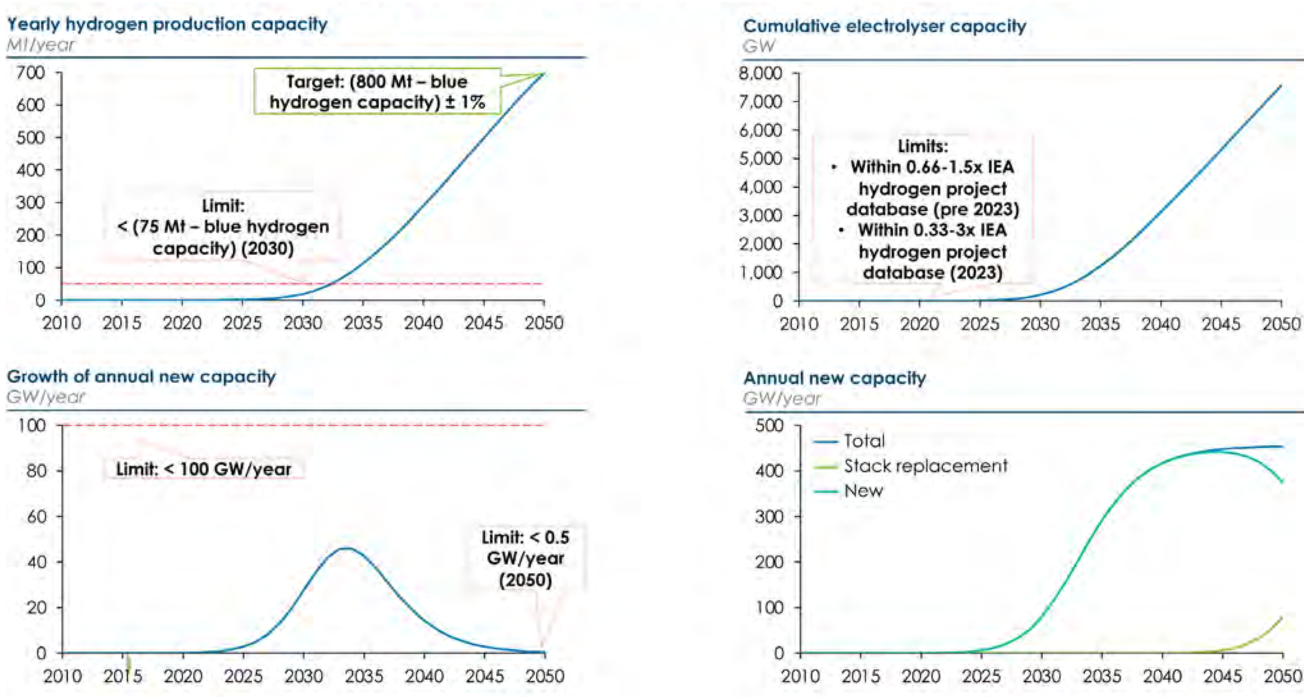
Note: Scenario 1 is modelled with an exponential function while Scenario 2&3 use an S-curve. *assuming 500 t/day capacity

3. **Green hydrogen:** In contrast, the green hydrogen model was used in a “goal-seek” to fill the gap between the blue and grey hydrogen models with the 800 Mt clean hydrogen target by 2050 (assuming supply side decarbonisation only). The S-curve fitting green hydrogen model is based on:

- A linear electrolyser efficiency improvement from 53 kWh/kg to 45 kWh/kg[24] and constant 50% load factor.
- Past projects and publicly announced projects to 2023 (where completion dates estimated) were taken into account.[25]
- Using a "best-fit" approach by averaging all potential S-curves that follow the applied constraints and the desired hydrogen production volume in 2050 (Exhibit 1.l). This S-curve at the centre of all scenarios has the highest probability that upon leaving its trajectory, another S-curve leading towards 800 Mt in hydrogen will be available (Exhibit 1.m).
- Taking into account electrolyser stack replacement by including production capacity required to replace end-of-life units (assuming 20-year stack lifetime).
- The scenario assumes constant clean hydrogen demand beyond 2050 which will likely create an electrolyser overproduction capacity. The increase in electrolyser capacity growth in 2050 was constrained (Exhibit 1.k) to lower the amount of overproduction past 2050 by shifting the ramp-up of production forward (Exhibit 1.n). If the hydrogen demand grows beyond 2050, the additional capacity may be a smaller concern.

Exhibit 1.l Green hydrogen supply ramp-up model: constraints and results

EXHIBIT 1.l



24 BloombergNEF (2019), *Hydrogen – Economics of Production from Renewables*.
25 Based on IEA hydrogen project database. Source: IEA (2020), *Hydrogen Projects Database*.

Exhibit 1.m Mapping of S-curves to find "best-fit" scenario

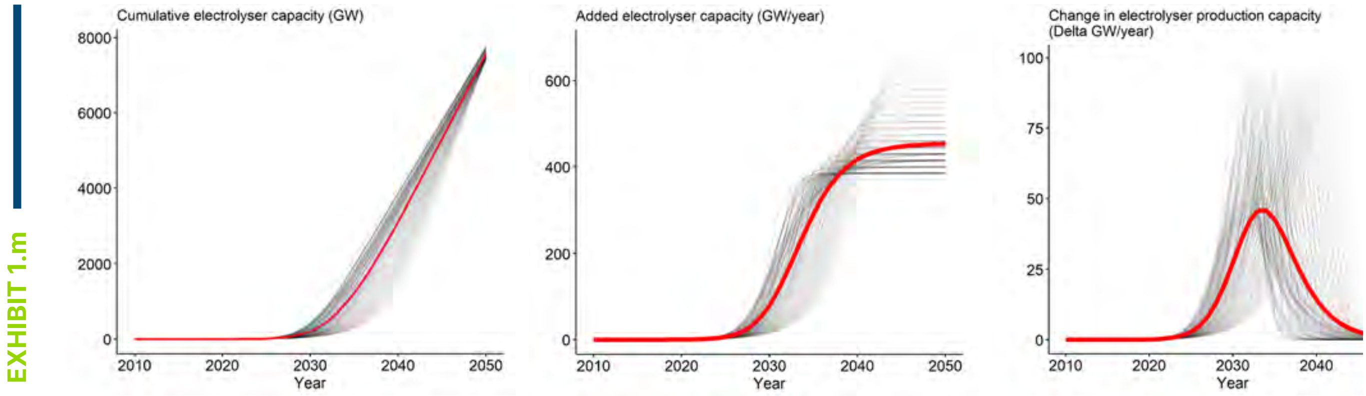
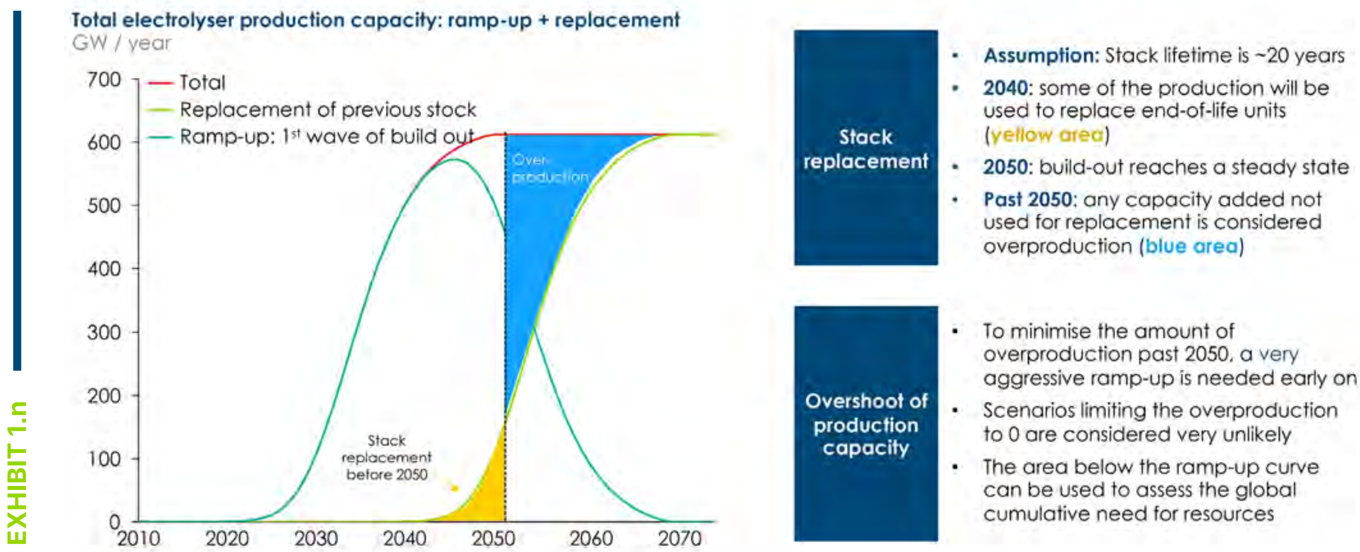


Exhibit 1.n Considerations around stock replacement and overproduction capacity



Source: Stack lifetime according to International Journal of Hydrogen Energy, 44, 33, 17431-17442

A.1.1.5 Bioresources technology options to produce hydrogen

As laid out in further detail in the ETC bioresources report,[26] it is also possible to use biomass gasification to convert biomass to hydrogen and other products, without combustion.

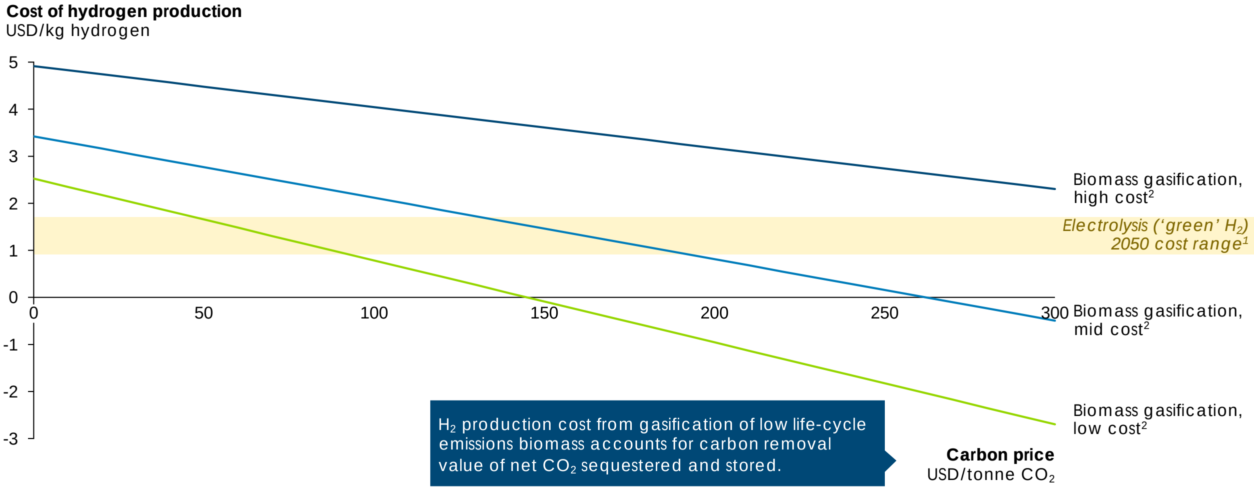
It is likely that bio-based hydrogen at any biomass price above $4 per GJ will be more expensive than green hydrogen. In addition, green hydrogen will be far more resource efficient: hydrogen production via biomass gasification will require 10 times as much land devoted to biomass production than needed for renewable power generation for green hydrogen production.[27] Lastly, sustainable carbon from biomass is a scarce commodity and should ideally be reserved for sectors that require carbon (e.g., chemical industry, synthetic aviation fuel). Biomass routes for low-carbon hydrogen production are therefore not included in this report.

26 ETC (2021), *Bioresources within a net-zero Emissions Economy: Making a Sustainable Approach Possible.*
27 For assumptions, see ETC (2021), *Bioresources in a net-zero economy – Technical appendix (to be published in 2021).*

However, as set out in the ETC bioresources report, it is also possible to add CCS to bio-based hydrogen production which may generate a significant "CCS profit" at high enough carbon prices. If biomass costs were low (3.9 $/GJ) and carbon prices above $100 per tonne, biobased hydrogen might therefore compete with green hydrogen (Exhibit 1.o) in the future. Hence, some studies[28] therefore see a significant role for biobased hydrogen production as a means to achieve carbon removal.

Exhibit 1.o Producing hydrogen from biomass is only cost-competitive under scenarios with a high price for concurrent carbon dioxide removals

EXHIBIT 1.o



(1) Assumes 2050 LCOE of $10-29/MWh and CAPEX of $60-145/MW. (2) Hydrogen produced from biomass gasification assumes supply chain and process emissions losses of 50%, 25%, or 0% (in high, mid, and low cost scenarios, respectively) – these reduce the net carbon dioxide removal achievable. Biomass feedstock prices modelled are 11.7, 7.8, or 3.9 $/GJ (0.17, 0.11, or 0.06 $/kg). CAPEX for gasification and carbon capture is assumed to be 4,050, 2,700, or 2,160 $/kW H_2 (HHV). All scenarios assume an average energy content of biomass feedstock of 14 GJ/tonne, production yield of 0.095 kg H_2/kg biomass feedstock, plant size of 300 MW, lifetime of 20 years, interest rate at 6%, utilisation of 95%, non-feedstock OPEX (operations & maintenance) of 6% of CAPEX, CO_2 capture rate of 90%, and a CO_2 transport & storage cost of $20/t$CO_2$.

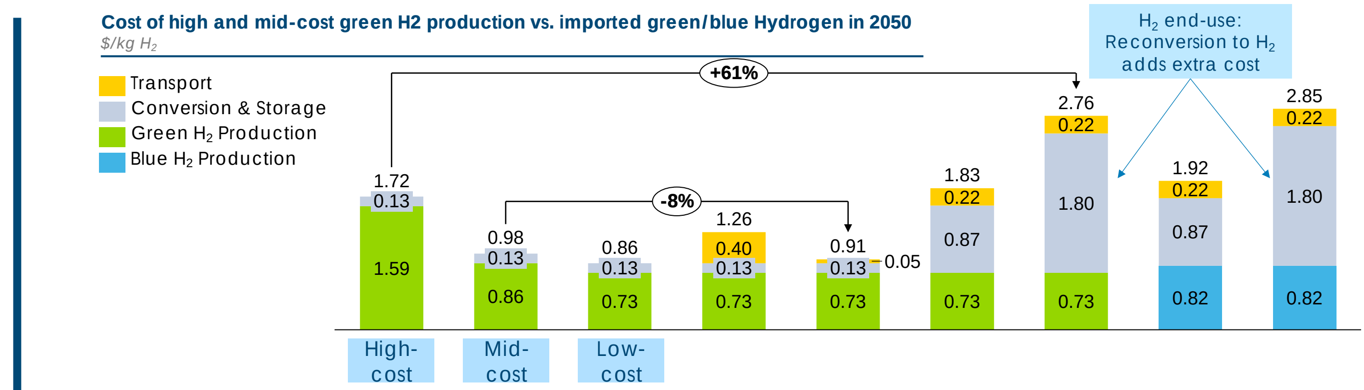
Sources: ETC (2021), *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy*; IEA (2018) *Hydrogen from biomass gasification*; Larson et al. (2020) *Net-Zero America*; IEA (2020), *Advanced Biofuels – Potential for Cost Reduction*; IEA (2021) *Net-Zero by 2050.*

28 Larson et al. (2020), *Net-Zero America: Potential Pathways, Infrastructure, and Impacts - Interim Report.*

A.1.2 Transport and storage

Exhibit 1.o to Exhibit 1.q refer to Exhibits 1.19-1.21 in the main text and illustrate the split of transport, conversion & storage and production costs.

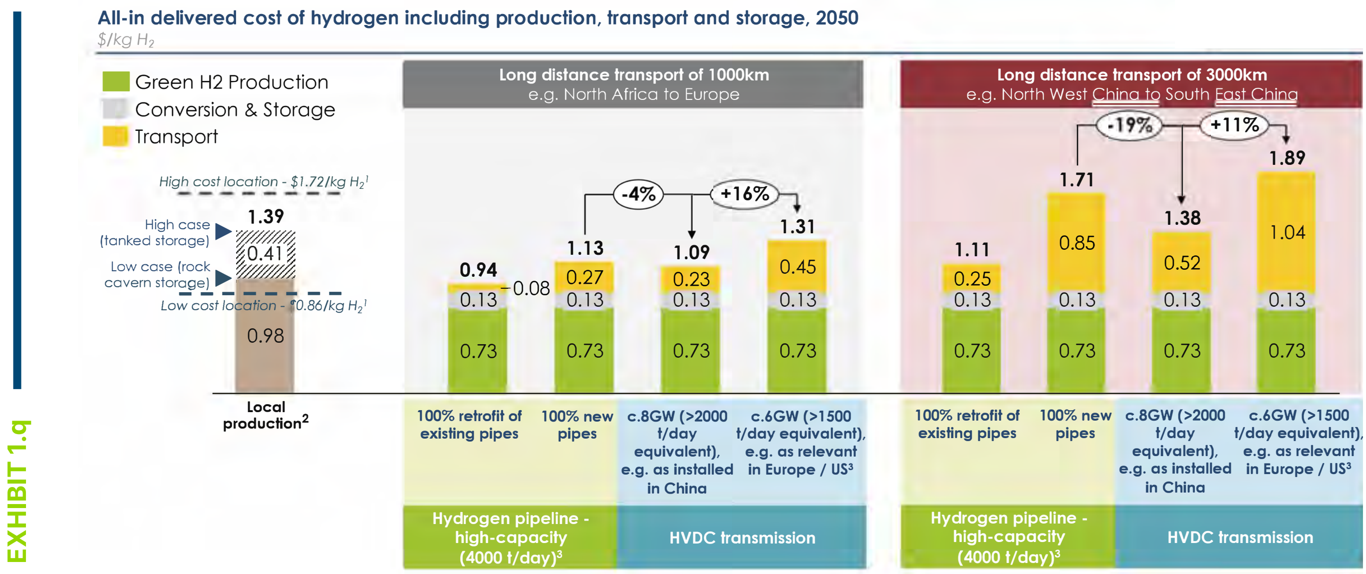
Exhibit 1.p Local hydrogen production potential and costs determine if import by pipeline or ship makes economic sense



Transport	Mode	**Local production**			**H_2 Pipe**		**NH_3 Ship**			
	Volume	-	-	-	<1000 t/day	5000 t/day	9000 t H_2 equivalent			
	Distance	-	-	-	1000 km		7000 km			
Conversion & Storage		Rock cavern					NH_3 end-use	H_2 end-use	NH_3 end-use	H_2 end-use

Green hydrogen production takes storage costs of 50% annual demand into account. Blue hydrogen production via ATR + CCS.

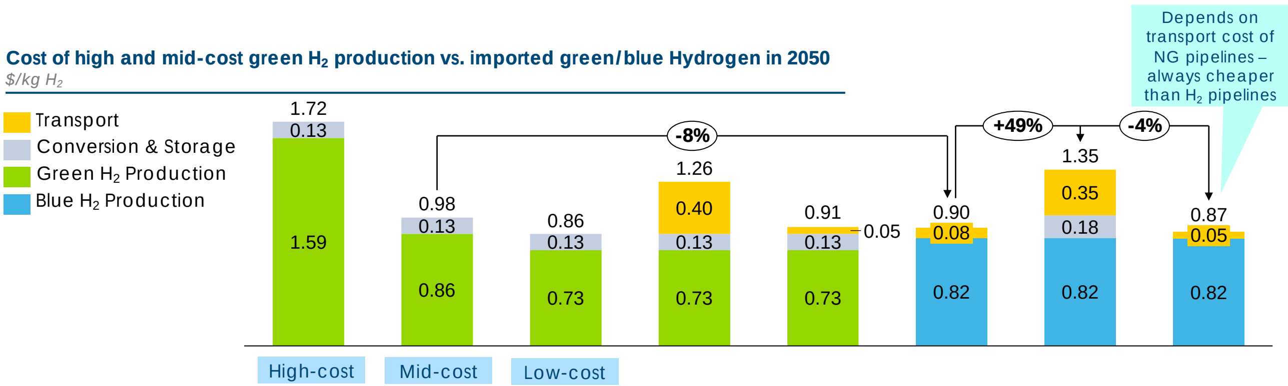
Exhibit 1.q Over longer distances, transport of electrons from areas of favourable renewables via high capacity HVDC cables is increasingly competitive with new hydrogen pipelines



Notes: 1) Green hydrogen production + low-cost rock cavern storage. LCOE $13/MWh (mid), $10/MWh (low), $29/MWh (high). CAPEX: $140/kW; 2) Green hydrogen production takes storage costs of 50% annual demand into account. (3) Capacity utilisation factor for pipelines: 57% and 50% for HVDC. Sources: BloombergNEF (2019), *Hydrogen: The Economics of Transport & Delivery*; BloombergNEF (2016), *Global HVDC and interconnector database and overview*; Guidehouse (2020), *European Hydrogen backbone. Industry interviews.*

Exhibit 1.r Lowest cost natural gas may enable cost-effective blue hydrogen production even in 2050

EXHIBIT 1.r



H_2 production	Location	**Local**			**Remote**			**Local**	
	Gas price ($/MMBtu)	-					1	4	1
Transport	Mode	**Local production**			**H_2 pipe**			**LNG ship**	**NG pipe**
	Volume	-	-	-	<1000 t/day	5000 t/day	5000 t/day	70000 t LNG (~27000 t H_2)	>1000 t/day
	Distance	-	-	-	1000 km			> 1000 km	> 1000 km
Conversion & Storage		Rock cavern					-	-	-

Note: Green hydrogen production takes storage costs of 50% annual demand into account. Blue hydrogen production via ATR + CCS. Natural gas cost 1 $/MMBtu with LNG and pipeline cost addition of 3 $/MMBtu and 1 $/MMBtu, respectively. Natural gas pipeline will likely always be lower cost than hydrogen pipeline.

A.1.2.1 High-voltage direct current electricity transmission

As discussed in Section 1.3 in the main report, HVDC offers an alternative way to transport energy derived from variable renewable generation to demand centres.

The competitiveness and feasibility of HVDC differs according to the geographic context. Key factors include the transport distance, form of transmission (e.g., overground vs underground vs subsea cables) and land acquisition costs:

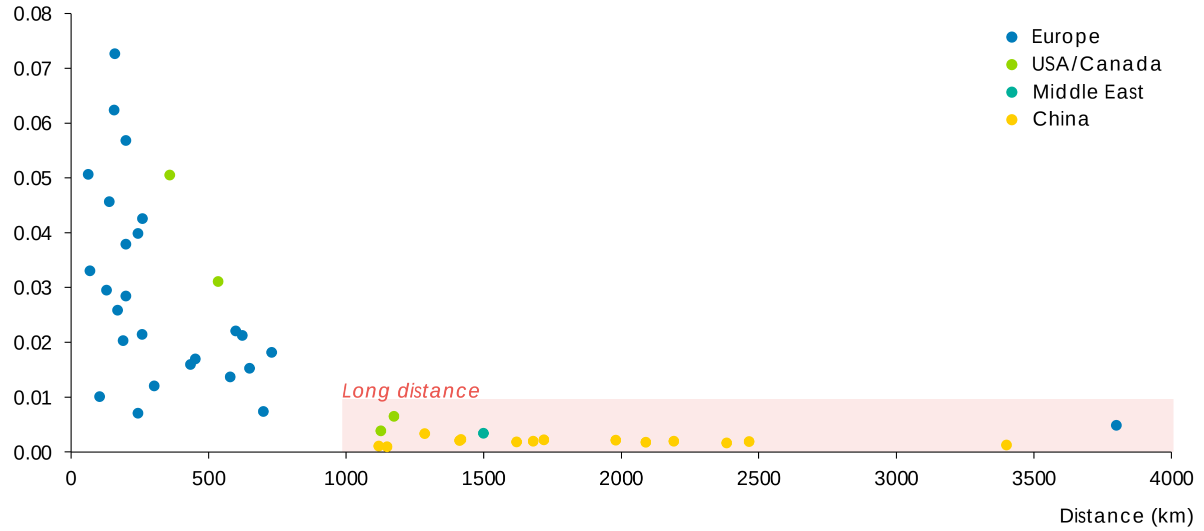
- HVDC transmission line costs ($/(kWh*1000km)) fall with distance, as high fixed costs (e.g., converter stations) are spread over a longer distance (Exhibit 1.r). Today, high capacity (circa 8 GW) and long distance (e.g., 2000 km+ distances) HVDC transmission lines are primarily found in China, to connect e.g., renewables resources in the Northwest with demand centres in the Southwest.

- Where cables pass over land, the costs vary greatly in line with population density, land costs, and degree of local opposition to development, and increase dramatically if undergrounding is required.

Exhibit 1.s HVDC Capex declines with distance, as fixed costs are spread over longer distances

EXHIBIT 1.s

HVDC Capex cost of electricity transport (projects in development, excludes financing cost)[1]
*\$/(kWh*1000 km)*



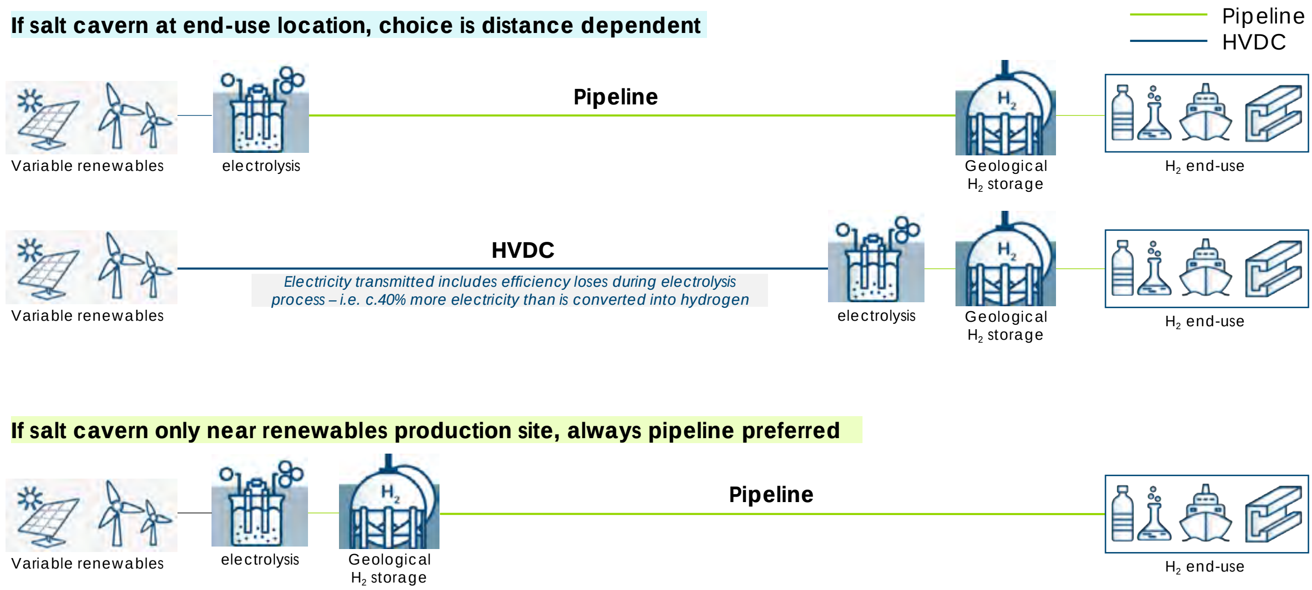
(1) Excludes financing costs. Data is primarily from BNEF project database from 2016; represents data from all HVDC and UHVDC projects since 2005 (across all project stages, e.g., announced, commissioned, and permitted) evaluated with known project cost and length, assuming 50% utilisation, and project lifetime of 30 years.

Source: Industry interviews, BloombergNEF (2016), *Global HVDC and interconnector database and overview.*

As discussed in Section 1.3 in the main report, the location of large-scale, low-cost hydrogen storage is a critical consideration for the choice of HVDC vs. pipeline. Exhibit 1.s highlights that HVDC transmission for hydrogen end-use is only a viable consideration if hydrogen storage is available near the hydrogen end-use location to balance intermittencies of supply.

Exhibit 1.t The importance of geological hydrogen storage for HVDC or pipeline choice

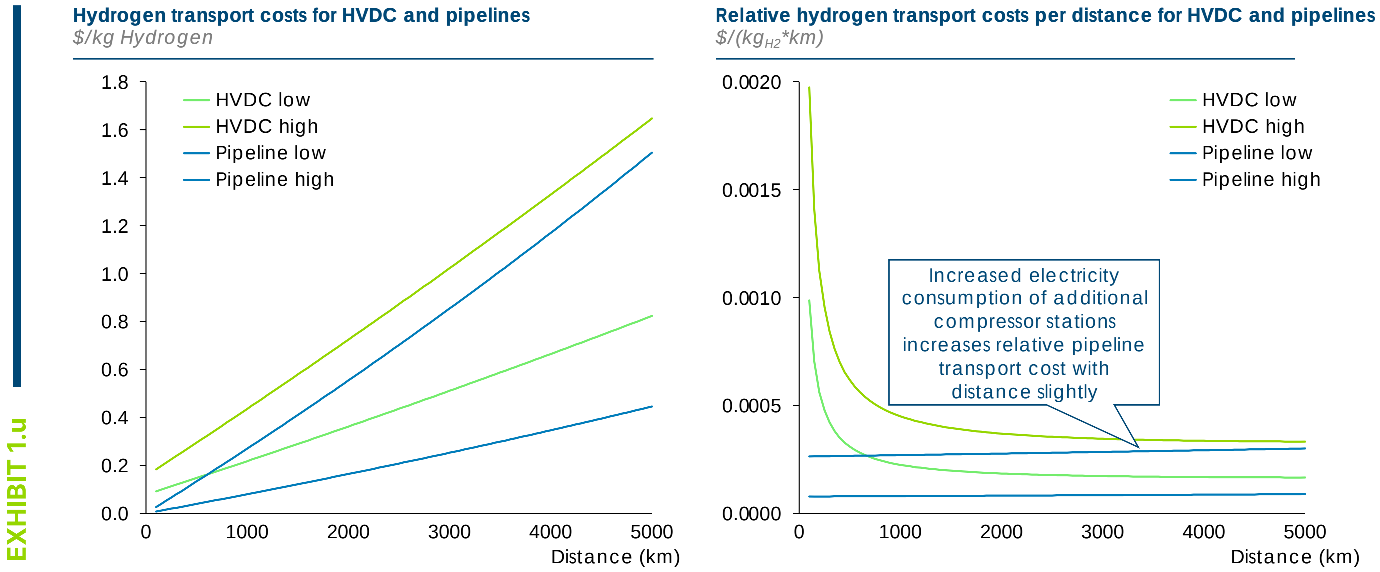
EXHIBIT 1.t



While absolute hydrogen transportation costs generally increase with increasing distance, the relative increase per kilometre is fundamentally different for pipelines compared to HVDC. Hydrogen pipelines require a compressor station every 100-600 km which increases both the CAPEX and OPEX (electricity consumption for compressor station). The relative hydrogen transport costs of HVDC lines on the other hand decrease with distance since the main cost driver are the transformer stations at the beginning and end of the HVDC line which dilutes with increased length of the HVDC line as mentioned above. The major cost drivers for the low and high scenario illustrated below are as follows: for gas pipelines it is the pipeline cost itself, whereas for HVDC it is a combination of the transformer station and the cable cost.

In conclusion, high capacity HVDC lines may play a role under some circumstances in comparison to hydrogen pipelines, likely driven by local circumstances (e.g., retrofitting of pipelines, local geological storage, etc.).

Exhibit 1.u Relative hydrogen transport costs increase with distance for pipelines while they decrease for HVDC transmission



Notes: Capacity utilisation factor for HVDC 50% and 57% for pipelines.

A.1.3 Demand

A.1.3.1 Blending of 5-20% hydrogen into natural gas grid

Technical and safety constraints dictate that the blending of hydrogen into the natural gas grid cannot be linearly increased from 0-100%, but instead hits an upper bound of around 20% before a new dedicated hydrogen pipeline would be needed. Ultimately, the weakest part of the network is critical, for instance, compressor stations or gas turbines may be the limiting factor rather than the pipeline (Exhibit 1.v).[29] There are two tipping points that are commonly referred to when blending natural gas into the grid:

- **5%:** The lower explosiveness boundary for hydrogen in air is 4%[30] and 5% is therefore perceived as a cautious lower blending limit.

- **20%:** At a relative volumetric concentration of above 20% hydrogen in the gas grid, appliances (e.g., boilers) need to be changed and made "hydrogen-ready". Surpassing this threshold therefore requires significant retrofitting in all end-use applications.

29 Marcogaz (2019), *Overview of available test results and regulatory limits for hydrogen admission into existing natural gas infrastructure and end use.*
30 Thuy Minh Hai Le, PhD Thesis (2015), *Flammability Characteristics of Hydrogen and its mixtures with light hydrocarbons at atmospheric and sub-atmospheric pressures.*

Exhibit 1.v Taken from Marcogaz (2019), Overview of available test results and regulatory limits for hydrogen admission into existing natural gas infrastructure and end use

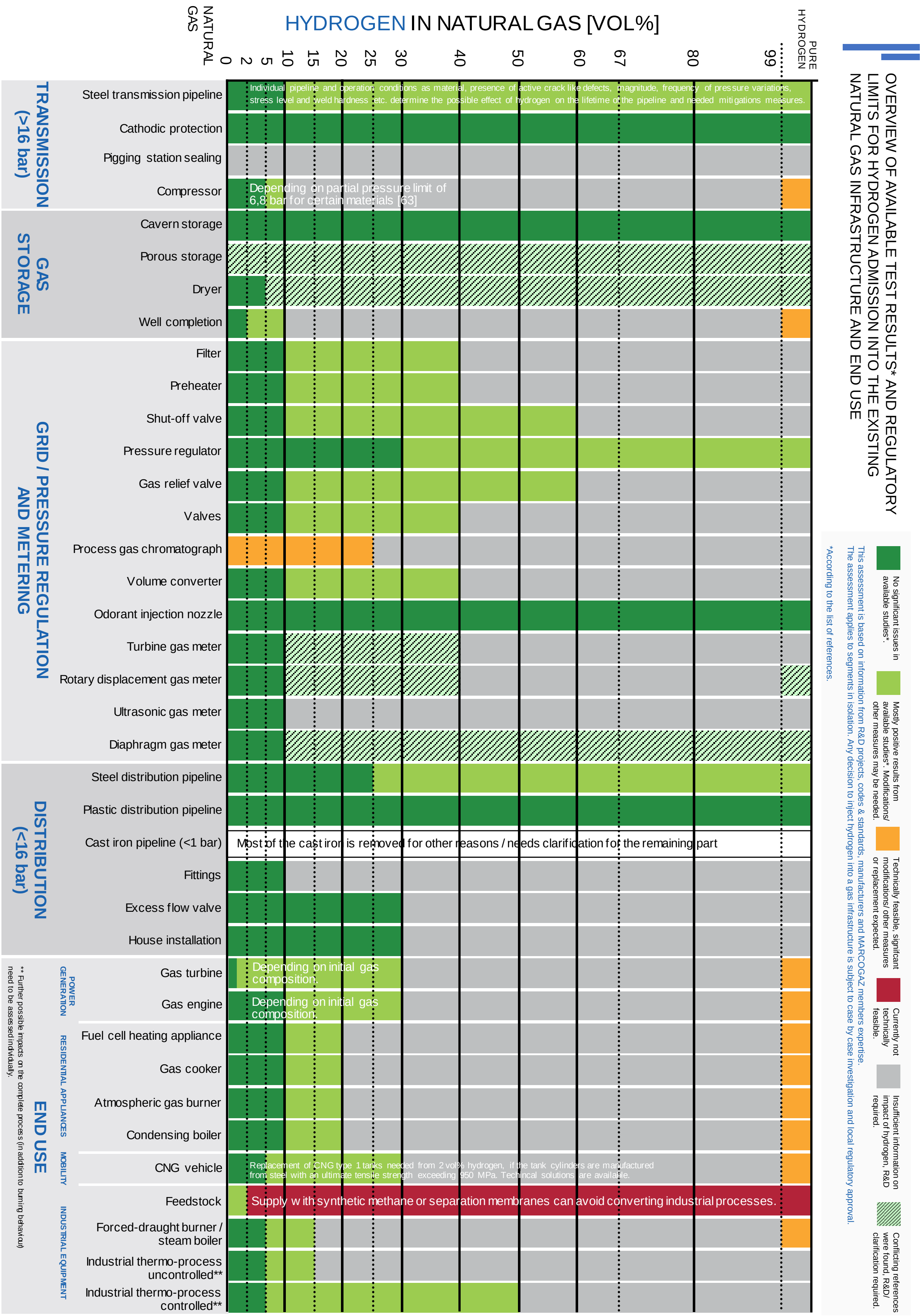


EXHIBIT 1.v

A.1.3.2 Road transport decarbonisation

Additional considerations for the decarbonisation of road transport and specific advantages of hydrogen vs. battery electric vehicles are discussed in the following section. While battery electric vehicles will dominate the light-duty market, the relative economics and advantages/disadvantages of hydrogen in other surface transport applications remains somewhat unclear.

Improvements in battery chemistry will increase the energy density of batteries and increase the types of feasible BEV applications. However, depending on technological progress, solid-state batteries may have low cycling rates and may therefore not be suitable for charging with very high power.

Hydrogen may be relevant in applications where:

- Fast refuelling times are required due to high duty cycles of fleet and long-range vehicles;
- Trucks are seldom returning to the depot over night;
- At shorter distances for high gross combination weights;
- For energy demanding applications with high load (e.g., construction, mining, forestry and agricultural machines) or intensive need of power supply to the body, like refrigerated bodies, slurry vehicles and concrete pumps;
- In locations where high-capacity charging points cannot be installed, the electricity transmission grid is not fully developed (e.g., remote locations)

A.1.3.3 Fertiliser decarbonisation

Nitrogen based fertiliser are the most important nutrients in global fertiliser use and require energy-intensive production (Exhibit 1.w). All nitrogen-based fertilisers are derived from ammonia which is produced in the Haber-Bosch process from nitrogen (from air) and hydrogen.

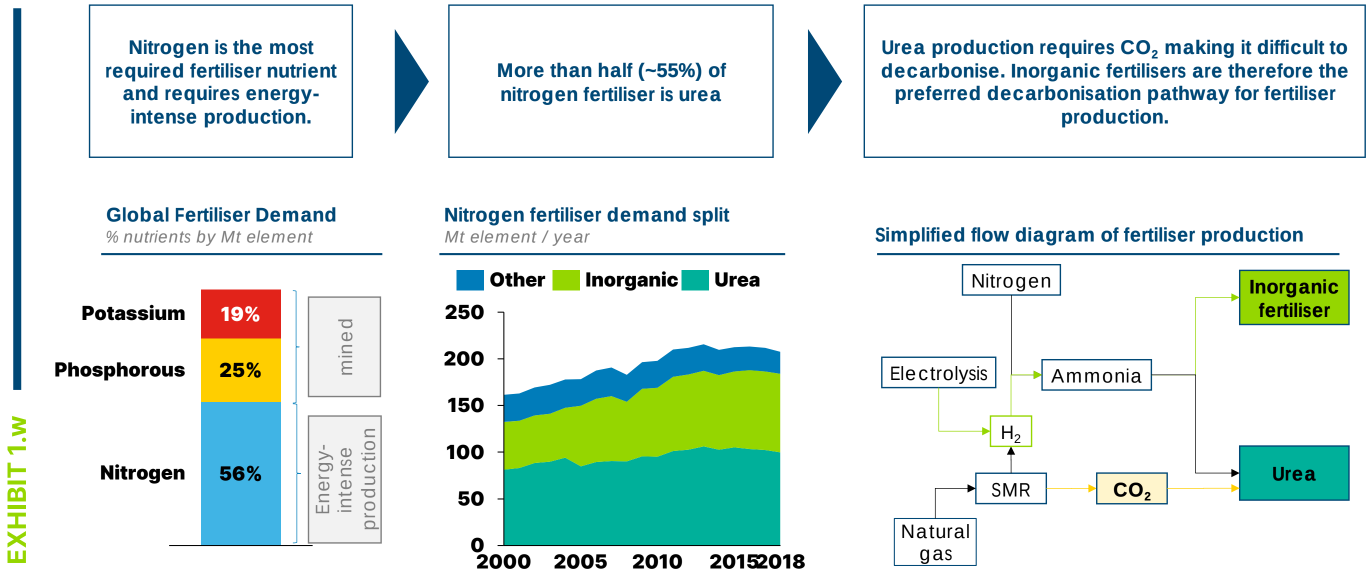
Urea is the most important nitrogen-based fertiliser, but its production requires CO_2 and typically, the fossil by-product CO_2 from natural gas based hydrogen production is used as chemical feedstock. Decarbonising urea production would therefore not only require a clean hydrogen input but also a sustainable CO_2 source (e.g., DAC or derived from sustainable biomass) which is typically high-cost and limited volumes are available in the near-term.

The CO_2 contained in the urea is ultimately released upon use on the field. Beyond CO_2 emissions, urea also possesses a higher GHG emissions intensity due to higher ammonia volatilisation and N_2O formation during application.[31]

Fertilisers that do not contain carbon (e.g., ammonium nitrate) on the other hand can be produced without the need for CO_2. The production of inorganic fertilisers can therefore be fully decarbonised via the use of clean hydrogen and is therefore considered the lowest emissions pathway over the full lifecycle of the fertiliser.

31 EMEP/EEA(2016), *EMEP/EEA air pollutant emission inventory guidebook*; International Fertiliser Society (2018), *The Carbon Footprint of Fertiliser Production: Regional Reference Values.*

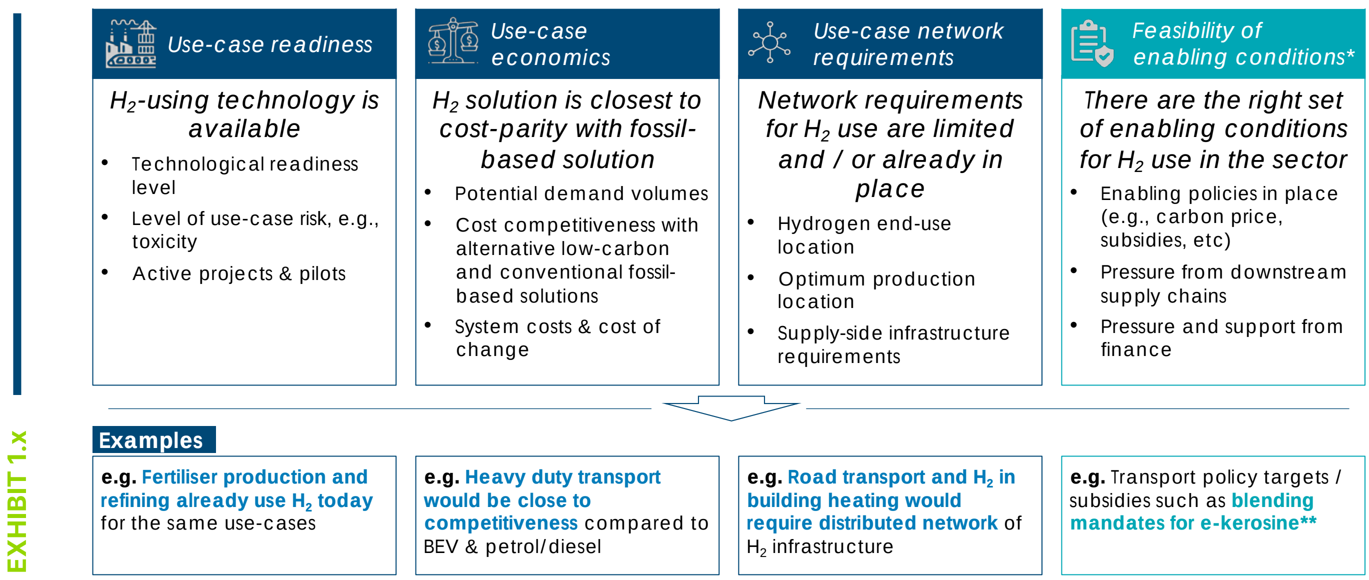
Exhibit 1.w Hydrogen as decarbonisation vector for fertiliser production



A.1.3.4 Further details for evaluation of early-demand sectors for hydrogen

Early demand sectors for hydrogen are likely based on favourable technological readiness, economic competitiveness (vs. other decarbonisation solutions), network requirements and enabling conditions (Exhibit 1.x).

Exhibit 1.x Demand in the 2020s is most likely to come from sectors that fulfil four criteria



Note: * Likely to differ across regions. ** e-kerosine refers to synthetic jetfuel produced via green H_2 and CO_2.

To form a shortlist of early demand sectors shown in Table 1, a two-step screening methodology was undertaken, as shown in Exhibit 1.y.

STEP ONE – first a full list of all sectors or sub-sectors that could feasibly use hydrogen (now or in the future) was formed, established through synthesis of all sectors analysed across previous studies and research by organisations such as BloombergNEF, Hydrogen Council and IEA.

Once this list was established, each sector was taken through a 3-question exclusion process, to remove sectors for which hydrogen use is highly unlikely or unsuitable, as follows:

1. *Could the sector use renewable hydrogen at significant scale?*

At this point a few niche sectors were excluded that either only demand very low volumes of hydrogen today with little foreseen future increase, e.g., hydrogen use for generator cooling, or sectors where renewable hydrogen is already providing niche requirements, such as through onsite electrolysers at polysilicon manufacturing sites in China that are too remote to access grey hydrogen supply.

2. *Is hydrogen expected to be cost-competitive with alternative low-carbon solutions by 2030?*

If hydrogen use within a sector isn't forecast to be cost-competitive with alternative low-carbon solutions, then it is excluded on the grounds that it is unlikely to be selected by industry and shouldn't be supported by policy or finance as the extra effort / investment required could be place elsewhere. The main sectors excluded here are road transport sub-sectors where battery electric vehicles (BEV) are forecast to be more cost competitive (e.g., compact urban vehicles) and the building heating sector for new builds where more efficient electric heat pumps are expected to win.

3. Are there major pilots or projects in development or operation today?

If there are no major projects in the pipeline for hydrogen use within each sector today, this is seen as an indication that widespread demand is unlikely to arise from the sector by 2030. The main sectors excluded here were those that could use hydrogen for high-temperature heat such as cement or aluminium production. Whilst hydrogen use for this application will likely be feasible and required in the long-term, currently hydrogen kilns and furnaces are not technologically ready, and many studies do not expect widespread implementation until 2035.[32]

STEP TWO – Once the exclusion questions were applied, the next step taken in the process was further refinement of the list to give a short-list of high potential early demand sectors; this refinement was done through sector-based assessment across the four criteria mentioned before.

a. Use-case readiness – assessment of technology readiness level of hydrogen using tech, level of use-case risk, number of decisions required to create hydrogen demand at scale, and whether there is potential to use current use-case assets

b. Use-case economics – assessment of 2050 demand volume forecast, potential to be cost-competitive with fossil-based solutions by 2030, sectors ability to absorb extra cost of hydrogen use, and current asset lifetimes (i.e., potential for stranded assets)

c. Use-case network requirements – assessment of potential to use current supply infrastructure, and whether end-use of hydrogen is centralised or decentralised

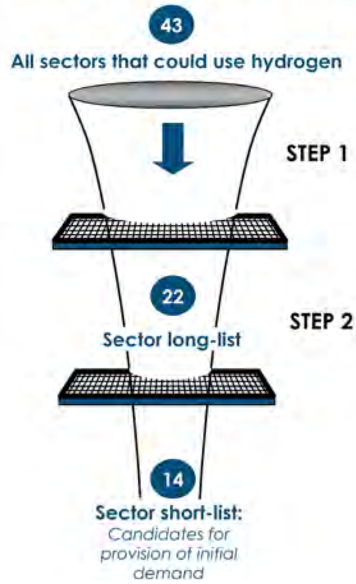
d. Feasibility of enabling conditions – assessment of whether there is currently policy support / pressure for use of low / zero-carbon hydrogen, and whether there is evident downstream pressure for "clean" products across the sector

Table 3 Potential uses of hydrogen by sector and subsector (long list prior to application of filter)

Use	Sector		Sub-sector	Note
FEEDSTOCK	Chemicals		Ammonia	Feedstock Haber-Bosch synthesis
			Petroleum refining	Desulphurisation and hydrocracking
			Methanol	Chemical intermediate for plastics and fuels
			High value chemicals	Via methanol to olefin technology
			Biomethane	Local CO_2 remediation (biogas, landfill, fermentation CO_2 emissions
	Products	Steel		Hydrogen-Direct Reduced Iron (H_2-DRI)
				Hydrogen Plasma Smelting Reduction (HPSR)
		Food industry		Hydrogenation of oils / fats
		Glass		Inerting gas
		Metalworking		Alloying
		Electronics		Carrier gas, cleaning, etching, reduction
		Polysilicon		Chemical reduction agent
FUELS	Industry	Steel		Heat provision
		Chemicals		
		Cement		
		Aluminium		
		Glass		
	Buildings	Buildings	New build	On gas grid - 100% hydrogen
			Existing building	Off gas grid - District heat networks
				On gas grid - 100% hydrogen
				On gas grid - Blending
	Transport	Road vehicles	Passenger vehicles (LDV)	SUV (400 miles)
				Compact urban car (100 miles)
				Specialist and legacy vehicles
			Commercial vehicles (M/HDV)	Bus - short-range (100 miles)
				Bus - long-range (300 miles)
				Medium Duty Truck (van) - urban (200 miles range)
				Medium Duty Truck - regional haul (300 miles range)
				Medium Duty Truck - long haul (500 miles range)
				Heavy Duty Truck - long haul (500 miles range)
			Captive fleet	Forklift / warehouse handling
				Taxi fleet (400 miles)
				Ground operations (e.g., airport, port)
				Municipal vehicles (e.g., garbage trucks, street sweepers)
				Other (e.g., mining, agriculture, construction)
		Aviation	Short range	Via hydrogen
			Long range	Via synfuels
		Shipping	Short range	Via hydrogen
			Long range	Via ammonia
		Rail		Non-electrified rail
	Power	Power	Distributed generation (fuel-cell generator)	Fuel-cell generator (e.g., island grids)
				Generator cooling
			Bulk generation / grid (e.g. hydrogen in CCGTs)	Flexible capacity / baseload in constrained regions

Exhibit 1.y Screening methodology to identify early demand sectors: 2-step screening process used to narrow down from ~40 to 9 sectors with 14 early demand use-cases

EXHIBIT 1.y



Objective	Screening criteria / questions
Exclude unsuitable sectors	Exclude at each step if "no": 1. Could the sector use renewable hydrogen at significant scale beyond what is already being used today? 2. Is hydrogen expected to be cost-competitive with alt. low-carbon solutions by 2030? 3. Are there major pilots or projects in development or operation today?
Refine long-list to short-list of **high potential initial demand sectors** by assessing across the four areas	• **Use-case readiness**, e.g., TRL, level of risk, potential to utilise current assets • **Use-case economics**, e.g., demand volume potential, cost-competitiveness, asset lifetime • **Use-case network requirements**, e.g., supply infrastructure, centralised vs. distributed • **Enabling conditions**, e.g., policy support, supply-chain pressure

Exhibit 1.z We have identified 14 high potential "early demand" use cases for hydrogen – likely to form the basis of hydrogen clusters

EXHIBIT 1.z

Hydrogen use	Sector grouping	Sector	Sub-sector		1. Use-case readiness Summary assessment	2. Use-case economics Summary assessment	3. Use-case network requirements Summary assessment	4. Enabling conditions Summary assessment
Feedstock	Chemicals	Chemicals	Ammonia					
			Petroleum refining & Methanol production					
	Products	Steel	Hydrogen-Direct Reduced Iron (H2-DRI)					
Fuel for heat	Buildings	Buildings	Existing building	*On gas grid - Blending*				
Fuel for mobility	Transport	Road vehicles	Commercial vehicle (H/MDV)	*Bus - long range*				
				Medium-Duty Truck - long-haul				
				Heavy Duty Truck - long-haul				
			Captive fleet	*Forklift / warehouse handling*				
				Ground operations (e.g., airport, port)				
				Other, e.g., mining, construction				
		Aviation (synfuels)	Long range (>1000km)					
		Shipping (ammonia)	Short range					
			Long range					
		Rail	Non-electrified long distance rail					

A.1.4 The Global Warming Potential of Hydrogen

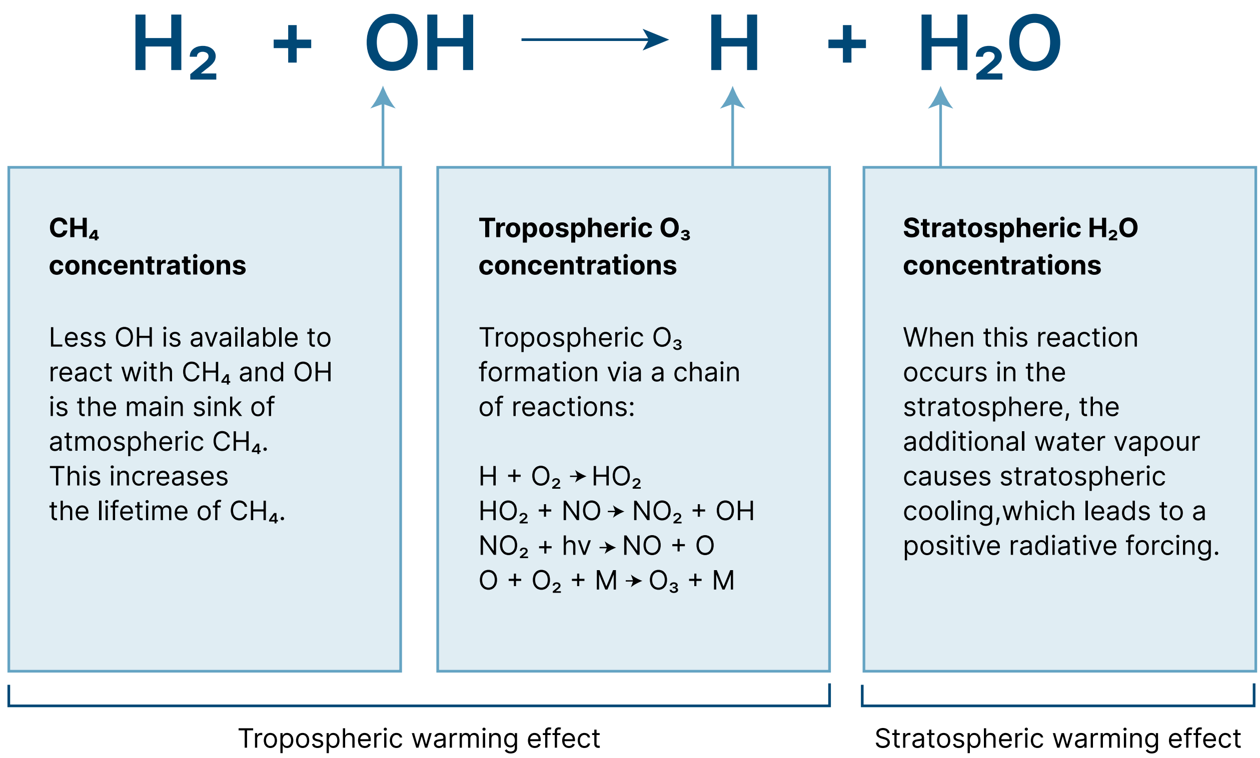
Hydrogen is a Greenhouse Gas (GHG), and Hydrogen molecules (H_2) could leak out of point sources, pipelines and storage infrastructure throughout production and transportation processes in a hydrogen energy system. This section provides a brief summary of the potential impact of this leakage on global warming, as well as some numerical estimates to put this into context, notably in comparison to current methane (CH_4) emissions.

A.1.4.1 How does hydrogen lead to radiative forcing and temperature increases?

Once hydrogen leaks, most of it is absorbed in soil, but around a quarter ends up in the atmosphere where it reacts with OH (hydroxyl), producing a radiative forcing effect on temperatures (see Exhibit 1.aa).[33,34,35,36]

Exhibit 1.aa Effects of the oxidation of hydrogen on atmospheric greenhouse gas concentrations

EXHIBIT 1.aa



What is the Global Warming Potential of hydrogen?

The impact of hydrogen leakage on mean global temperature increases depends strongly on the considered timescale. The metric of Global Warming Potential (GWP), over 20 or 100 years, can be used as a rough guide to quantify this impact. The value of GWP for a greenhouse gas quantifies the impact of releasing one tonne of the gas into the atmosphere, relative to the warming that would be expected due to one tonne of CO_2 over the same timescale. A recent study estimates the Global Warming Potential of hydrogen over twenty years as ~33 (see Table 1, which also includes reference values for methane, nitrous oxide, and CO_2).[37]

33 Ocko, I., & Hamburg, S. (2022), *Climate consequences of hydrogen leakage.*
34 Derwent, R. G., Stevenson, D. S., Utembe, S. R., Jenkin, M. E., Khan, A. H., & Shallcross, D. E. (2020), *Global modelling studies of hydrogen and its isotopomers using STOCHEM-CRI: Likely radiative forcing consequences of a future hydrogen economy.*
35 Paulot, F., Paynter, D., Naik, V., Malyshev, S., Menzel, R., & Horowitz, L. (2021). *Global modelling of hydrogen using GFDL-AM4.1: Sensitivity of soil removal and radiative forcing.*
36 Warwick, N., Griffiths, P., Keeble, J., Archibald, A., Pyle, J., & Shine, K. (2022), *Atmospheric Implications of Increased Hydrogen Use.*
37 Recent studies have emphasized that the values of GWP-20 underestimate the very short-term warming impacts of hydrogen, due to its short lifetime (Derwent, et al., 2020; Paulot, et al., 2021), and that the global warming potential over very short (1-3 year) timescales could be much higher, with values over 100 (Warwick, et al., 2022; Ocko & Hamburg, 2022). However, as such estimates are very recent and somewhat uncertain and there is no quantification of the GWP equivalent over such short timescales for methane, we have used GWP-20 in order to calculate the estimates outlined in this annex.

TABLE 4

Table 4 Values of the Global Warming Potential (GWP) over 20 and 100 years for various greenhouse gases. As GWP measures the impact on warming of the emissions of one tonne of gas relative to one tonne of CO_2, the values for CO_2 are always equal to 1.

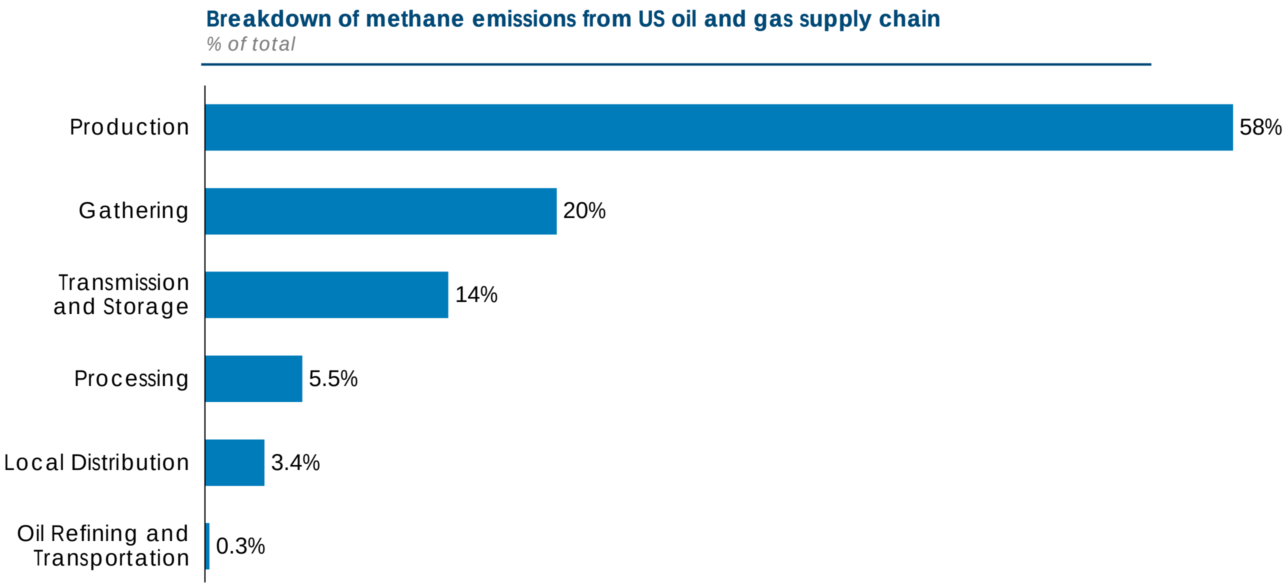
	Greenhouse Gas	GWP-20	GWP-100
Warwick, et al., 2022	Hydrogen (H_2)	33 (20-44)	11 (6-16)
Ocko & Hamburg, 2022		38 (based on Paulot et al., 2021)	10 (based on Paulot et al., 2021)
		19 (based on Derwent et al., 2020)	5 (based on Derwent et al., 2020)
Field & Derwent, 2021		-	3.3 (1.9-4.7)
IPCC AR6 (Masson-Delmotte, et al., 2021)	Methane (CH_4)	81-83	27-30
	Nitrous Oxide (NO_2)	273	273
	Carbon Dioxide (CO_2)	1	1

What is a realistic leakage rate for hydrogen?

Current estimates of total leakage rates for methane are approximately 1-2% in developed economies[38,39] although these are subject to substantial variations across sites, operations and geographies.[40,41,42] Leakage of methane occurs throughout the energy system (see Exhibit 1.bb), but is concentrated heavily in production and gathering, which together account for over 75% of leakage.[43]

Exhibit 1.bb Distribution of methane leakage across different stages, from production to distribution.

EXHIBIT 1.bb



38 Enervis, & EDF (2021), *Scenarios, Effectiveness and Efficiency of EU Methane Pricing in the Energy Sector.*
39 Alvarez, R. A. et al. (2018), *Assessment of methane emissions from the U.S. oil and gas supply chain.*
40 Lin, J. B., Fasoli, B., Garcia, M., Crosman, E., & Lyman, S. (2021), *Declining methane emissions and steady, high leakage rates observed over multiple years in a western US oil/gas production basin.*
41 Omara, M., Sullivan, M. R., Xiang, L., Subramanian, R., Robinson, A. L., & Presto, A. A. (2016), *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin.*
42 Enervis, & EDF (2021), *Scenarios, Effectiveness and Efficiency of EU Methane Pricing in the Energy Sector.*
43 Alvarez, R. A. et al. (2018), *Assessment of methane emissions from the U.S. oil and gas supply chain.*

Hydrogen is a smaller molecule than methane and is more mobile in the polymer materials that are used as sealants in natural gas pipelines, implying that leakage rates during transportation in pipelines could be higher than for methane.[44,45] However, initial studies indicate minor difference in leakage rates between natural gas and hydrogen, both in transmission through pipelines[46,47] and across the whole energy system.[48,49] Further, one might expect leakage rates at hydrogen production sites to be carefully monitored alongside increased scrutiny and attention to methane leaks. Given that less than 20% of methane leakage occurs during transportation and distribution[50], we would thus expect hydrogen leakage rates to be similar to if not lower than those for methane, implying realistic rates of a few percentage points across the whole hydrogen system.[51]

What is the impact of hydrogen leakage?

The impact of hydrogen leaking into the atmosphere can be quantified in terms of the amount of CO_2-equivalent per unit of energy contained in one tonne of hydrogen. It is important to use the per-unit-energy metric (rather than purely GWP) so that a meaningful comparison can be made with leakage of natural gas which is currently used in the energy system.

Using the value of GWP-20 = 33 and a leakage rate of 1%, one tonne of hydrogen would yield a carbon intensity of 10 gCO_2e/kWh.[52] The equivalent calculation for methane leakage yields a value of 60 CO_2e/kWh, and this increases to 260 CO_2e/kWh once the impact of the CO_2 emitted from combustion is included.

Thus, over a 20-year timescale the impact of hydrogen leakage from the energy system on radiative forcing is over 25 times smaller than that from methane. Put another way, hydrogen would need to leak at a rate of approximately 25% in order to match the impact of a 1% leakage of methane – a highly unlikely prospect.

How significant could hydrogen leakage be by 2050?

The ETC projects that hydrogen use could reach at most 800 Mt per annum by 2050, making up around 15% of final energy demand. In such a scenario, assuming a realistic leakage rate of 2% and using the value for GWP-20 of 33, the impact of hydrogen leakage would be equivalent to roughly ~530 Mt CO_2e of annual emissions. In comparison, current emissions of ~45 Mt per annum of methane from natural gas production and processing[53] have a warming impact of ~3700 Mt CO_2e per annum – a much more significant amount, even without considering additional methane emissions from the coal and oil energy systems (including these would yield ~10,000 Mt CO_2e per annum).

Overall, potential warming from future hydrogen leakage may be small but positive, contributing 0.06°C of warming in 2050, in the case where hydrogen contributes 20% of final energy demand and has a very high leakage rate of 10%.[54] Warming could be more substantial if hydrogen is used more widely or is mainly manufactured using methane.[55,56]

However, realistic leakage rates for hydrogen (discussed above) imply warming would be well below this level, and the impact would be much smaller than current warming associated with emissions from methane throughout the natural gas and energy system. Careful monitoring and evaluation of hydrogen leakage should develop alongside the scale-up of the production and distribution industries and low carbon hydrogen certification schemes. Nevertheless, the net benefits of hydrogen in abating carbon dioxide emissions are still very strong, especially over the long term.[57,58]

44 Melaina, M. W., Antonia, O., & Penev, M. (2013), *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues.*
45 Frazer-Nash (2022), *Fugitive Hydrogen Emissions in a Future Hydrogen Economy.*
46 Mejia, A. H., Brouwer, J., & MacKinnon, M. (2020), *Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure.*
47 Melaina, M. W., Antonia, O., & Penev, M. (2013), *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues.*
48 Cooper, J., Dubey, L., Bakkaloglu, S., & Hawkes, A. (2022), *Hydrogen emissions from the hydrogen value chain-emissions profile and impact to global warming.*
49 Frazer-Nash (2022), *Fugitive Hydrogen Emissions in a Future Hydrogen Economy.*
50 Alvarez, R. A. et al. (2018), *Assessment of methane emissions from the U.S. oil and gas supply chain.*
51 Frazer-Nash (2022), *Fugitive Hydrogen Emissions in a Future Hydrogen Economy.*
52 Calculation as follows: CO_2-equivalent impact of 1000 kg of hydrogen over 20 years is 1000*33 = 33,000 kg CO_2e (using GWP-20 = 33 for hydrogen). Energy embedded in 1000 kg of hydrogen is 1000*33.3 = 33,300 kWh (using a lower heating value for hydrogen of 33.3 kWh/kg). Overall carbon intensity is 33,000/33,300 = 990 gCO_2e/kWh if all of the hydrogen leaks. If only 1% leaks, then the carbon intensity is approximately 10 g CO_2e/kWh. The same calculation was used to quantify the impact of methane leakage, using GWP-20 = 82 and a lower heating value of 13.9 kWh/kg. To include the impact of combustion, an additional warming of 1000*44/16 = 2750 kgCO_2e was included in the numerator (44/16 is the mass ratio of carbon dioxide to methane).
53 IEA (2020), *Methane Tracker 2020.*
54 Ocko, I., & Hamburg, S. (2022), *Climate consequences of hydrogen leakage.*
55 Howarth, R. A., & Jacobson, M. Z. (2021), *How green is blue hydrogen?*
56 Ocko, I., & Hamburg, S. (2022), *Climate consequences of hydrogen leakage.*
57 Field, R., & Derwent, R. (2021), *Global warming consequences of replacing natural gas with hydrogen in the domestic energy sectors of future low-carbon economies in the United Kingdom and the United States of America.*
58 Ocko, I., & Hamburg, S. (2022), *Climate consequences of hydrogen leakage.*

A.2 INPUT VARIABLES AND ASSUMPTIONS

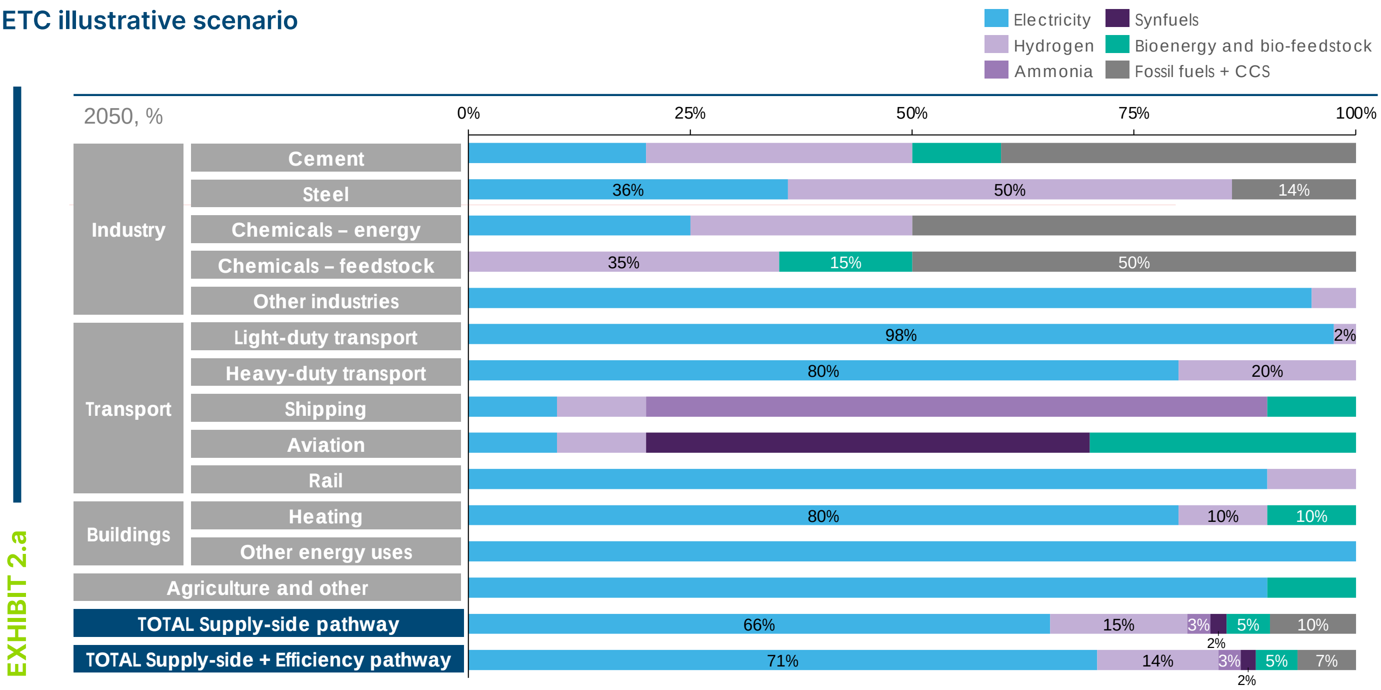
This chapter focusses on laying out critical input variables and assumptions from the report.

A.2.1 ETC illustrative scenario: final energy technology mix

The ETC illustrative scenario is based on four different decarbonisation vectors: electrification, hydrogen and its derived fuels ammonia and synfuels, bioenergy and CCUS. The relative split of these decarbonisation vectors in the total final energy demand is illustrated in Exhibit 2.a (a refined version based on the ETC *Making Mission Possible report*. This exhibit continues to be updated and refined as part of the ETC's ongoing work).

It is worth noting that these percentages do not directly correspond to the shares of the respective technologies on the market due to different end-use efficiencies. For example, the energy efficiency of heat pumps (part of the electrification share of building heating) is significantly higher than hydrogen boilers (see Section 1.1 in the main report). This means that 10% hydrogen in the final energy demand corresponds to less than 10% of buildings using hydrogen boilers due to the energy efficiency difference. Similarly, less than 20% of heavy-duty trucks will use hydrogen, although 20% of final energy demand stems from hydrogen since the FCEV energy efficiency is lower compared to battery electric vehicles.

Exhibit 2.a Final energy mix in a zero-carbon economy
ETC illustrative scenario



Note: Steel energy mix represents the supply-side pathway only. For chemical feedstock, inputs are not used as energy but in order to provide the molecules required to build the chemicals. In our model, for comparison we express it in EJ equivalent.

Source: SYSTEMIQ analysis for the Energy Transitions Commission (2020)

A.2.2 Electrolyser key parameter overview

When comparing electrolyser CAPEX, all costs including soft cost (including project design, management and overhead) as well as construction and mobilisation need to be considered for an accurate CAPEX representation for fully installed cost. Exhibit 2.b compares key electrolyser parameters from this report with other sources illustrating that not all cost parameters are included in all reports.

Exhibit 2.b Comparison of CAPEX / efficiency / LCOE / load factor across major sources

EXHIBIT 2.b

Source	CAPEX ($/kW)			Efficiency LHV (%)		LCOE ($/MWh)		Comment
	2020	2030	2050	2020	2050	2020	2050	
ETC	1200	160-290	60-140	63%	74%	22-39	10-17	Fully installed cost
BNEF[1]	200-1200	115-135	80-98	62%	75%	19-86	10-23	Fully installed cost
Hydrogen Council	660-1050	200-250	n/a	n/a	n/a	25-73	7-25	Include stack and balance of plant (voltage supply and rectifier, drying/purification and compression to 30 bar); exclude transportation, installation and assembly, costs of building and any indirect costs.
IEA[1]	500-1400	400-850	200-700	64%	74%	n/a	18-63	n/a
IRENA	650-1000	n/a	130-307	65%	>74 %	53	20	Include cell stack, balance of plant (power rectifiers, hydrogen purification system, water supply and purification, cooling and commissioning); exclude shipping, civil works and site preparations.

Notes: (1) Assumptions for alkaline electrolyser.

Sources: BloombergNEF (2019), *Hydrogen – Economics of production from renewables and 1H2021 Hydrogen Levelised Cost Update*; IEA (2019), *The future of hydrogen*; IRENA (2020), *Green hydrogen cost reduction*; Hydrogen Council (2021), *Hydrogen Insights*.

Exhibit 2.c compares learning rates[59] used in this study with those used in other studies. IRENA recently published a report highlighting that the learning rates for different sub-components of the electrolyser differ. This will ultimately lower the cumulative learning rate with increased capacity (as the cost contribution of the components with highest learning rate decreases). They illustrate a decrease of learning rate of circa 19% to circa 13% when the cumulative capacity is increased by a factor of circa 5,000 (e.g., from cumulative capacity of 0.2 GW in 2020 to 10,000 GW in 2050).[60]

A recent report from the Hydrogen Council notes that learning rates of 39% for batteries, 35% for solar PV and 19% for onshore wind were observed between 2010-2020 hinting at possibly higher learning rates for electrolysers. But as pointed out by IRENA, the cost structure is different for electrolysers compared to solar cells likely limiting the learning rate.[61]

Exhibit 2.c Comparison of CAPEX / efficiency / LCOE / load factor across major sources

EXHIBIT 2.c

Learning rate (%)	Reference	Source
13	Alkaline	This study – low scenario
18	Alkaline	This study – high scenario
9	Alkaline for 2020-2030	(Hydrogen Council, 2020)
13	PEM for 2020-2030	(Hydrogen Council, 2020)
18 ± 6	1956-2014 data (alkaline)	(Schmidt et al., 2017)
18 ± 13	1972-2004 data	(Schoots et al., 2008)
8	Floor cost of USD 350/kW (alkaline)	(Gül et al., 2009)

Source: adapted from IRENA (2020), *Green Hydrogen Cost Reduction*.

59 The learning rate describes the cost decline for one unit (e.g., electrolyser) for each doubling of the total cumulative number of previously produced units.
60 IRENA (2020), *Green hydrogen cost reduction*.
61 Hydrogen Council (2021), *Hydrogen Insights*.

A.2.3 Underlying literature review for advantages / disadvantages overview (Box A)

TABLE 5

Type of storage	Volumetric energy density (MJ/m³)	Source
Hydrogen ambient	12.8	Hydrogen Tools - Pacific Northwest National Laboratory & Department of Energy (2020), *Lower and Higher heating values of hydrogen and other fuels.*
H_2 pressurised (700 bar)	5600	Renewable and Sustainable Energy Reviews (2012), *Hydrogen as an energy carrier: Prospects and challenges.*
Hydrogen liquified	10039	Hydrogen Tools - Pacific Northwest National Laboratory & Department of Energy (2020), *Lower and Higher heating values of hydrogen and other fuels.*
Li-Ion Batteries	2880	Roland Berger (2020), *Hydrogen – a future for aviation.*
Ammonia (liq.)	15600	Progress in Energy and Combustion Science (2018), *Ammonia for power.*
Jet fuel	37440	Roland Berger (2020), *Hydrogen – a future for aviation.*

TABLE 6

Type of storage	Gravimetric energy density (MJ/kg)[62]	Source
Hydrogen (ambient)	142.2	Hydrogen Tools - Pacific Northwest National Laboratory & Department of Energy (2020), *Lower and Higher heating values of hydrogen and other fuels.*
Ammonia	22.5	Progress in Energy and Combustion Science (2018), *Ammonia for power.*
Li-Ion Batteries	1.1	Roland Berger (2020), *Hydrogen – a future for aviation.*
Nat gas	52.2	Hydrogen Tools - Pacific Northwest National Laboratory & Department of Energy (2020), *Lower and Higher heating values of hydrogen and other fuels.*
Gasoline	46.5	Hydrogen Tools - Pacific Northwest National Laboratory & Department of Energy (2020), *Lower and Higher heating values of hydrogen and other fuels.*

62 Based on chemical energy density, excluding weight of storage tanks.

TABLE 7

Conversion step	Efficiency	Source
Electrolysis (Alkaline, 2050)	45 kWh/kg (74%, LHV)	BloombergNEF (2019), *Hydrogen – the economics of production from renewables*.
Hydrogen CCGT	50 %	Mid-point from Joule (2019), *Projecting the Future Levelized Cost of Electricity Storage Technologies*.
Ammonia CCGT	50 %	Note: Used Hydrogen CCGT efficiency as proxy.
Haber Bosch	94 %	Note: Haber-Bosch process assumes use of by-product heat in adjacent processes. Sources: Energy and Environmental Sciences (2019), *Current and future role of Haber-Bosch ammonia in a carbon-free energy landscape; Expert Interviews*.

TABLE 8

Sector	Technology Option	Energy efficiency[63]	Source/Note
Building Heating	Hydrogen Boiler	46%	Source: Building heating: LETI (2021), *Hydrogen – A decarbonisation route for heat in buildings?* Note: Other studies suggest similar results such as Nature Climate Change (2021), *Potential and risks of hydrogen-based e-fuels in climate change mitigation*.
	Electric heat pump	270%	
Road transport (light-duty)	Fuel Cell Electric Vehicle	26%	Averages from three independent reports: Teri (2020), *The potential of hydrogen in India*; Transport & Environment (2018), *Roadmap to decarbonizing European cars;* VDI (2019), *Brennstoffzellen- und Batteriefahrzeuge*.
	Battery Electric Vehicle	70%	
High temperature heat	Hydrogen technologies	55-80%	Multiple available technologies for both hydrogen and direct electrification. Source: *Agora (2021), No-regret hydrogen – Charting early steps for H_2 infrastructure in Europe*.
	Direct electrification technologies	50-90%	

63 Energy efficiency describes the ratio of final output energy to input energy. It includes losses from hydrogen production, electricity & hydrogen transmission, reconversion processes and end-use.

A.2.4 Assumptions table for illustrative demand acceleration 2030 scenario (Exhibit 2.7)

The underlying assumptions for the illustrative scenario in Exhibit 2.7 in the main report are shown in Exhibit 2.d. As described in further detail in the main report, the aim of this exercise was to illustrate a potential scenario of how fast demand for clean hydrogen could grow in the 2020s. The assessment is based on qualitative judgement based on technological and market readiness the respective sectors.

Exhibit 2.d Assumptions behind illustrative scenario assessing potential demand acceleration in 2020s

EXHIBIT 2.d

	40 Mt illustrative scenario	
	Mt/year (2030)	Description
LDV	0.1	800000 FCEV cars in 2030 (in line with current policy committemnts in Japan)
Forklift and ground operations	0.4	50% new forklifts from 2020 use H2 plus 0.2 Mt demand from ground operations.
Bus	0.7	10% new buses from 2027 are FCEV
Blending	0.8	5% of global gas grids for residential and commercial heating blend 5% H_2
Rail	0.8	50% new non-electrified trains from 2025 used H2
Air	1.0	3 commercial PtX synfuel plants (each 0.4 Mt/year SAF)
Steel	2.0	17 large scale plants using H2-DRI ((32 Mt/year green steel, <2% of global steel demand)
HDV	3.8	10% new trucks from 2027 are FCEV
Sea	5.3	5 % of total shipping demand decarbonised (corresponds to ~900 small container ships)[1]
Refining	13.5	35% of global facilities transition to clean H_2 (ca. 500-700 plants)
Fertilizer	15.0	50% fertiliser production switches to green production
Total	**43.0**	

Notes: (1) The UN Climate Champions have set 5 % zero emission fuels by 2030 as the Race to Zero Breakthrough for international shipping (Global Maritime Forum (2021), *Five percent zero emission fuels by 2030 needed for Paris-aligned shipping decarbonization.*)

Source: SYSTEMIQ analysis for the Energy Transitions Commission (2021)