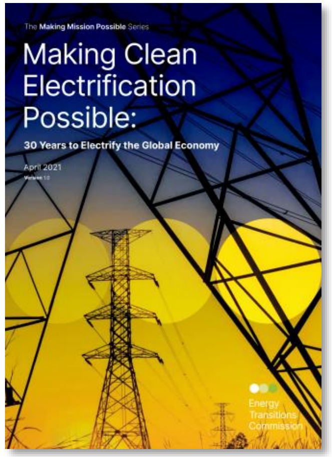
Energy
Transitions
Commission

The **Making Mission Possible** Series

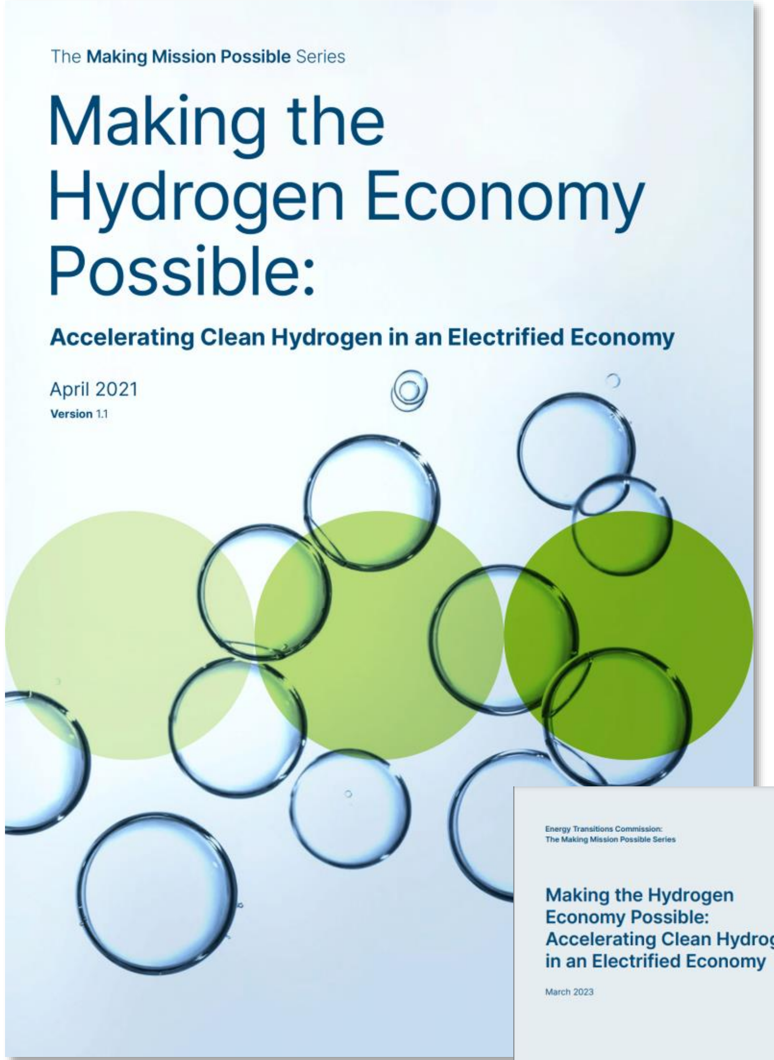
Making the Hydrogen Economy Possible
Accelerating Clean Hydrogen in an Electrified Economy

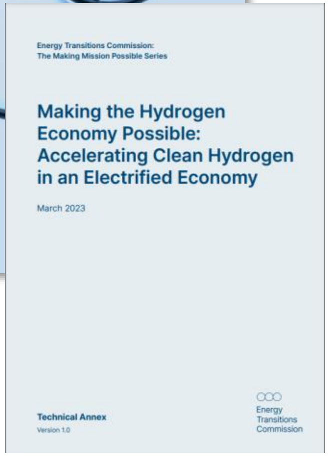
ETC member briefing
April 2023

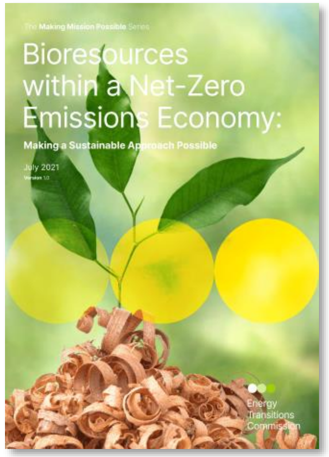
Mission Possible Series – Hydrogen deep-dive



April 2021







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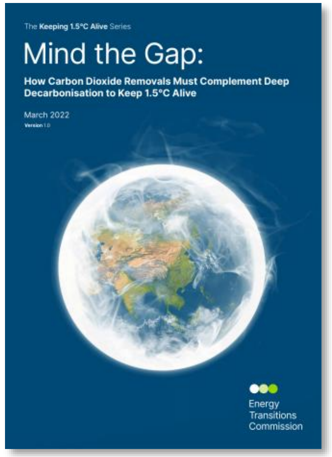

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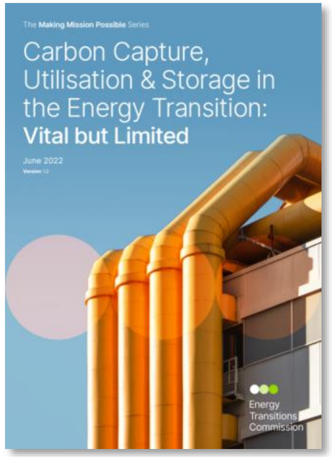

June 2022

Making the hydrogen economy possible:
Accelerating clean hydrogen in an electrified economy

Hydrogen

Major, complementary role for clean hydrogen alongside clean electrification, with 5-7x increase in global hydrogen production

1. **Overview of a deeply electrified future as the cornerstone of the energy transition**
2. **A vision for 2050: Hydrogen's role in a zero-carbon, deeply electrified economy**
    - The situation today and potential demand growth
    - Scale-up of renewables and green hydrogen
    - Falling production costs and implications for the cost of decarbonisation
3. **Considerations on scaling hydrogen**
    - Choices on blue vs. green hydrogen
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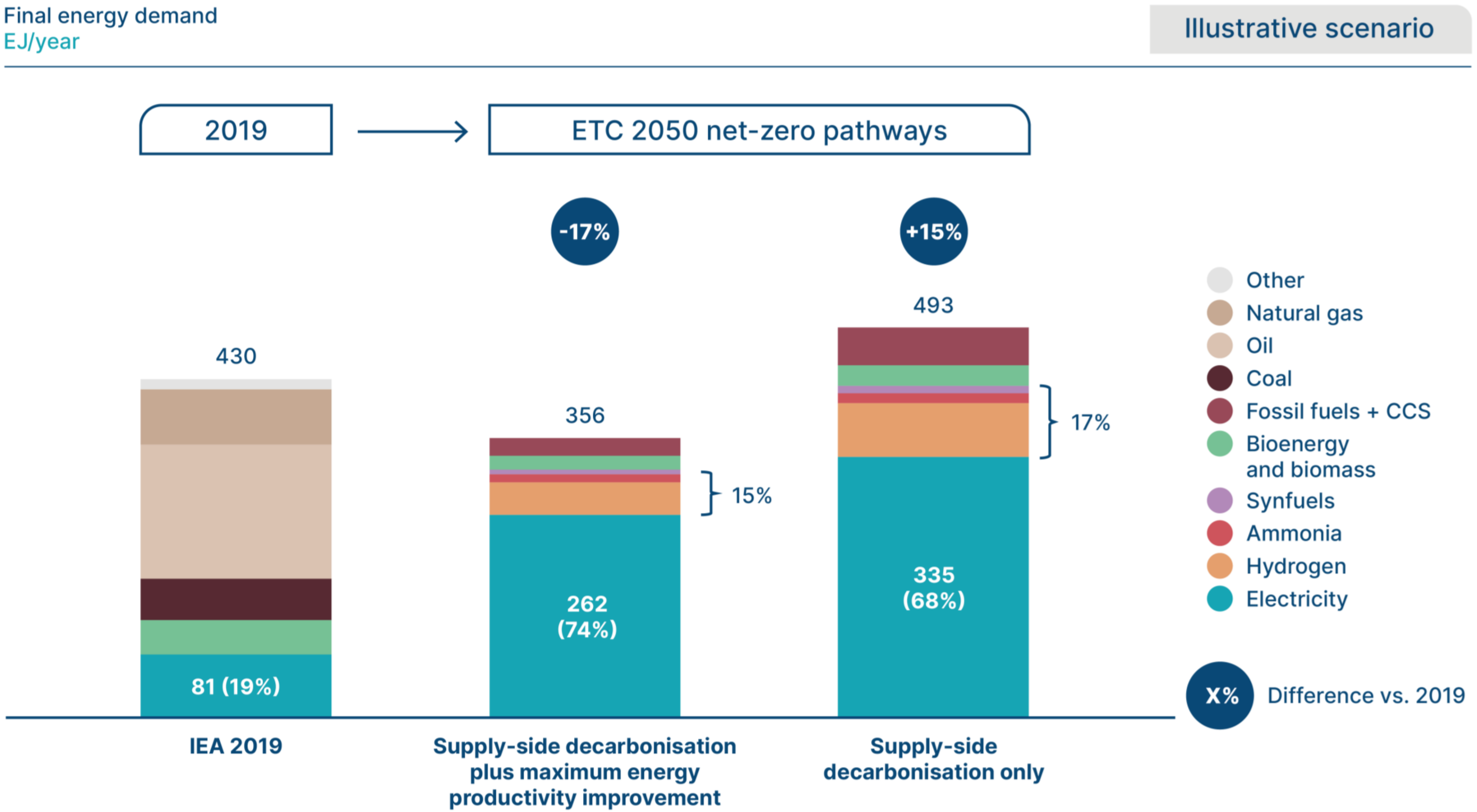
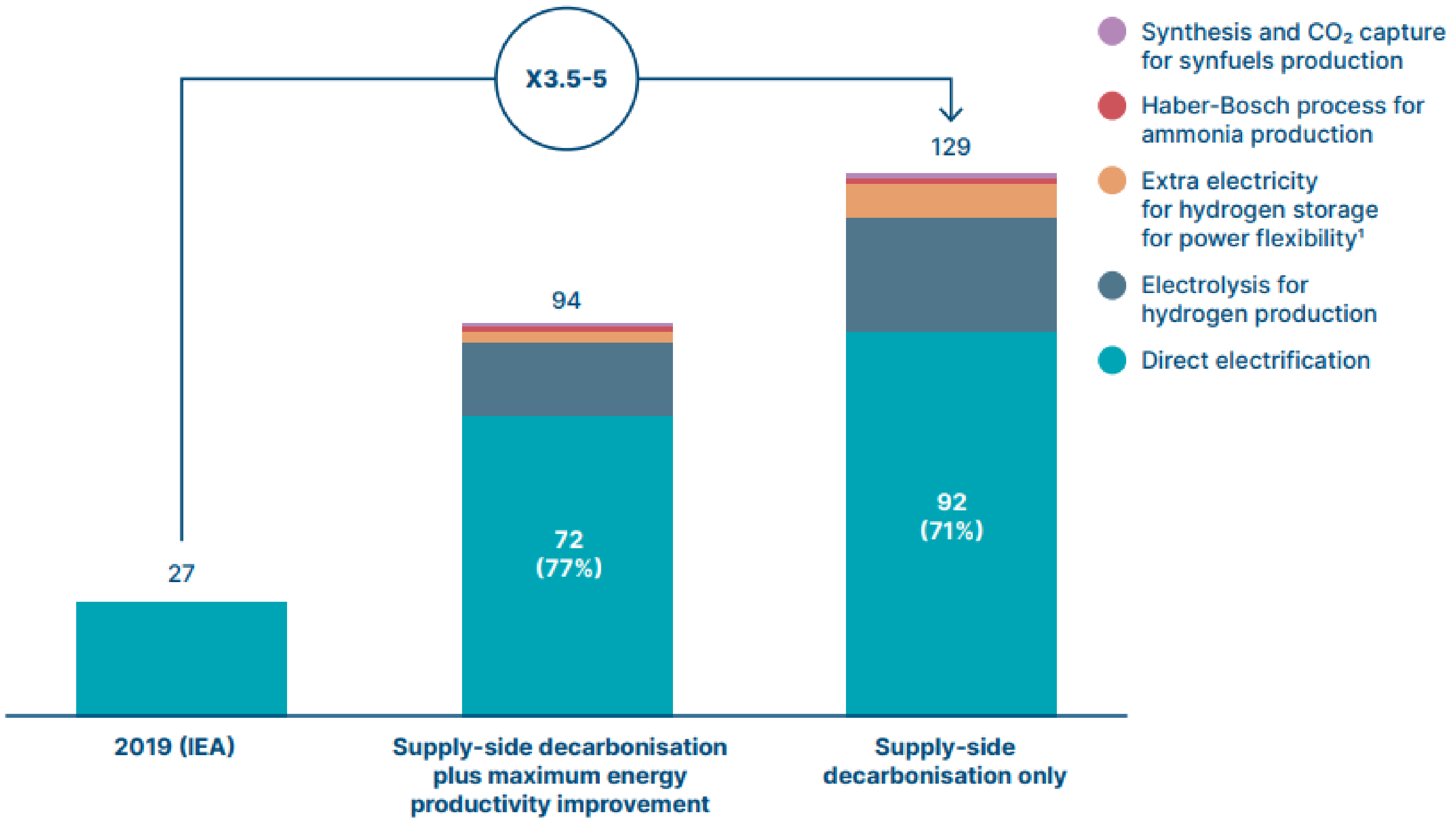
    - Practicalities & trade-offs
4. **Recent developments and how to progress**

Final energy mix in a zero-carbon economy: Electricity will become the dominant energy vector, complemented by hydrogen and fuels derived from it

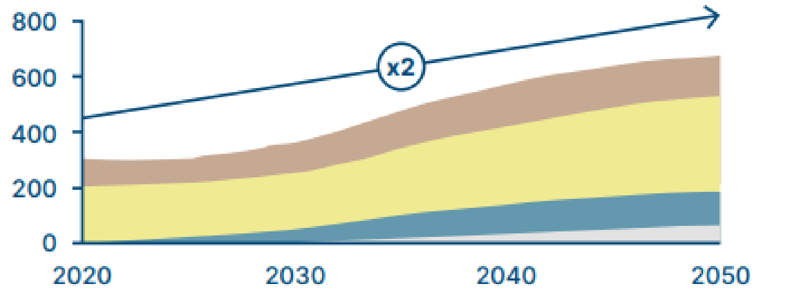


By 2050, global electricity demand expected to grow 3.5-5x to 90-130,000 TWh; the pace and scale of growth will vary by region

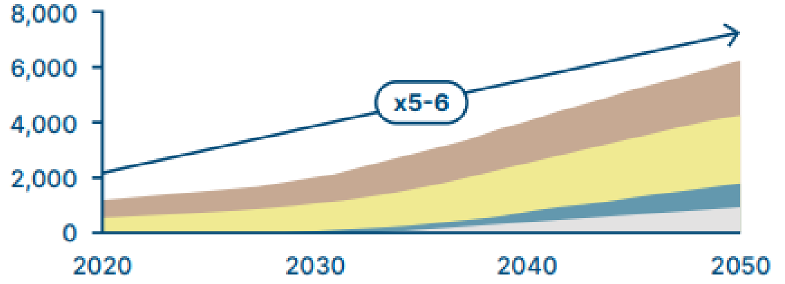
Total electricity generated by 2050 in the ETC indicative pathways
000 TWh/year



United Kingdom, electricity use
TWh/year



India, electricity use
TWh/year



Industry Buildings Transport Indirect electrification

Household Non-household Other

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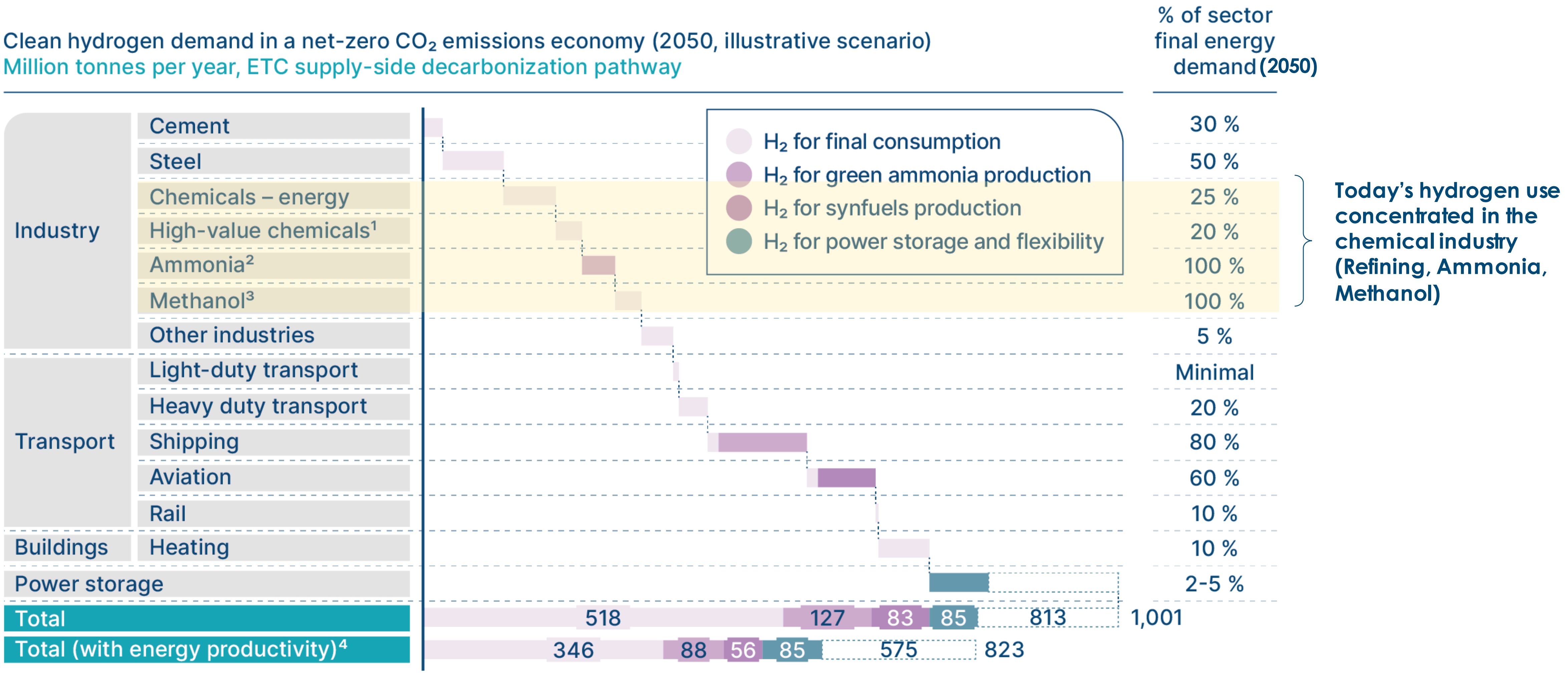
Clean hydrogen will play a growing role across the economy as the world transitions towards net-zero

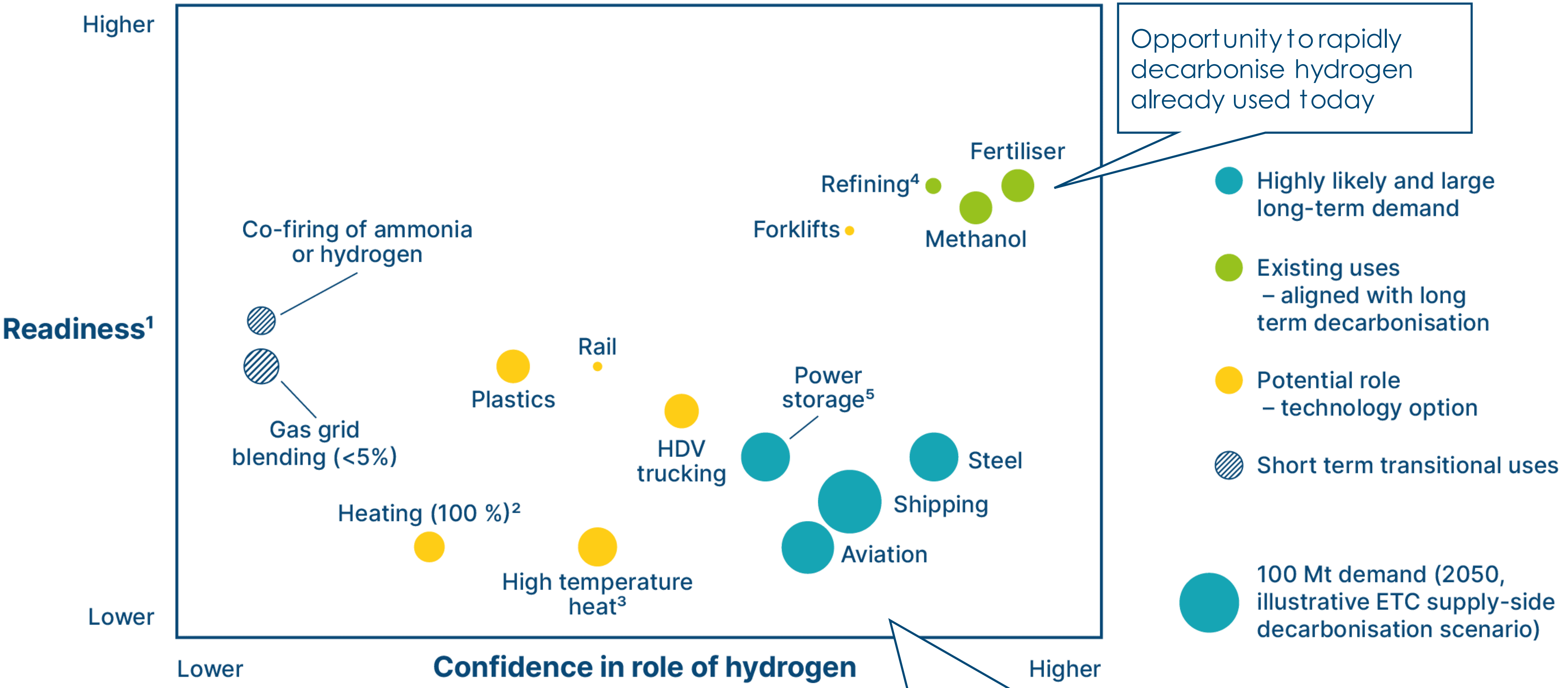
Clean hydrogen demand in a net-zero CO_2 emissions economy (2050, illustrative scenario)
Million tonnes per year, ETC supply-side decarbonization pathway



NOTES: [1] High value chemicals predominantly used to produce plastics, which could potentially be produced via Hydrogen and CO_2 in the future (via methanol and MTO process); [2] Around 80% of ammonia (excl. shipping) is used to produce fertilisers; [3] Methanol is used as intermediate in numerous chemical processes, including plastics production. [4] ETC scenario including maximum energy productivity improvements.

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

Beyond existing uses: Multiple potential uses of hydrogen in a low-carbon economy, could reach 500-800 mt of p.A. By mid-century



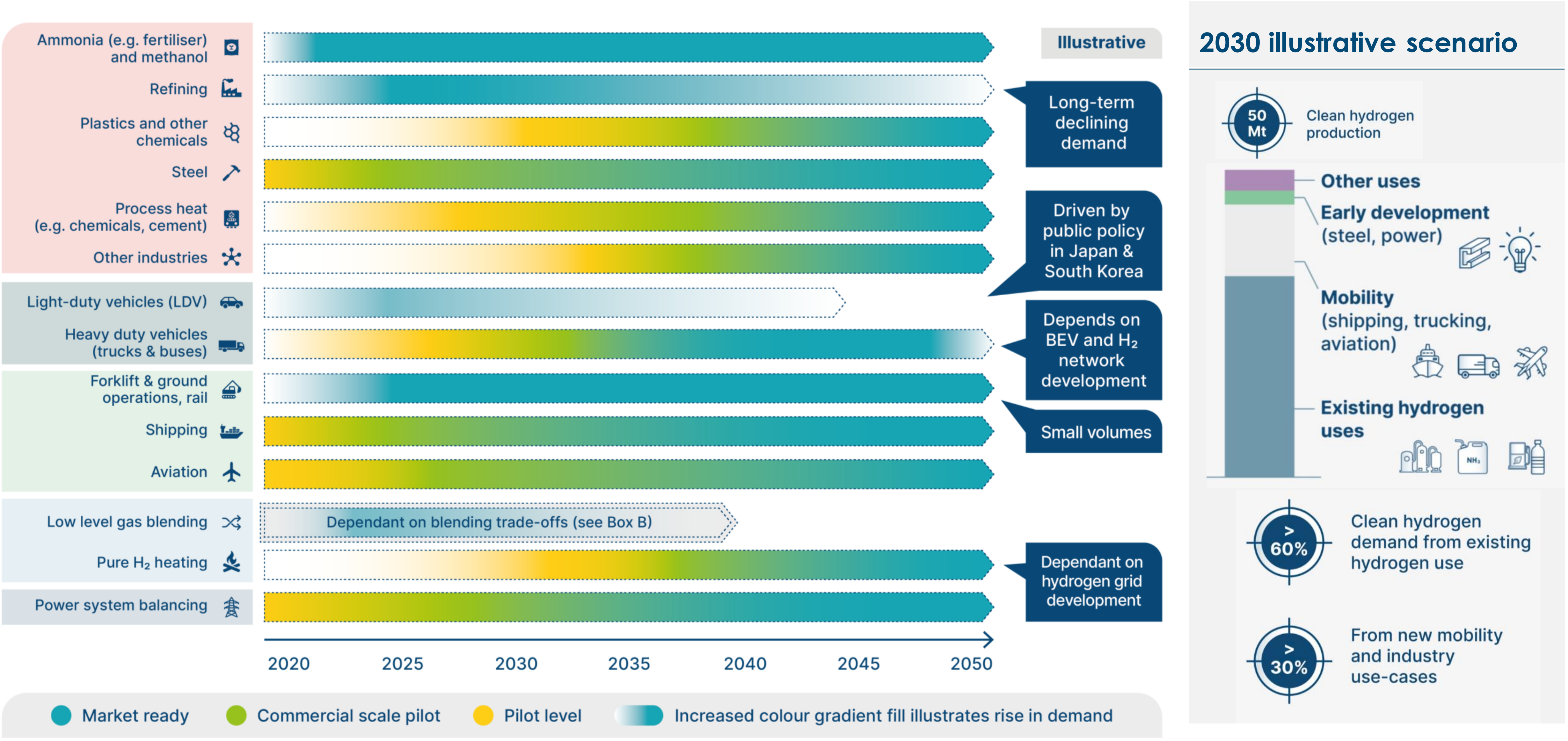
Growing R&D and early commercial momentum, e.g.

- Multiple **demonstrator projects** using H2 for primary iron production in Europe
- **Several PtX plants for SAF fuel production** planned in Europe
- A number of **green shipping corridors** starting to be established

NOTES: [1] Readiness refers to a combined metric of technical readiness for clean hydrogen use, economic competitiveness and ease of sector to use clean hydrogen. [2] 'Heating (100%)' refers to building heating with hydrogen boilers via hydrogen distribution grid, [3] 'High temperature heat' refers to industrial heat processes above ca. 800°C [4] Current hydrogen use in refining industry is higher due to greater oil consumption. [5] Long-term energy storage for the power system.

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

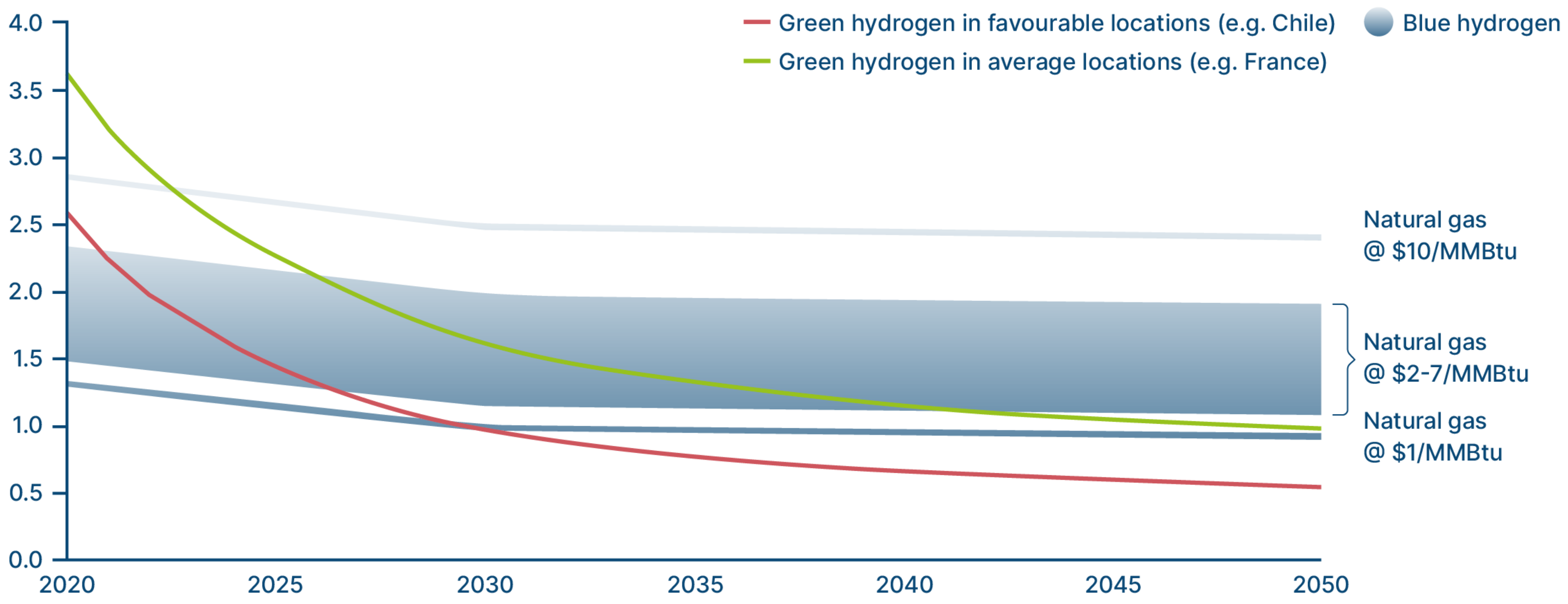
Pulling forward early demand to enable clean hydrogen scaling will follow sequencing of demand sector “take off” over next 3 decades



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

Green hydrogen from electrolysis likely to become cheapest clean production route in the long-term; in favourable locations it could be competitive with blue in the 2020s

Cost of hydrogen production from different production routes (excluding transport & storage costs)
$/kg H_2



Note:

- European **gas prices 2022 have been ~$30-50/MMBtu**
- At these prices **blue hydrogen would cost >$9/kg**
- **Gas price uncertainty** also tips in favour of green hydrogen

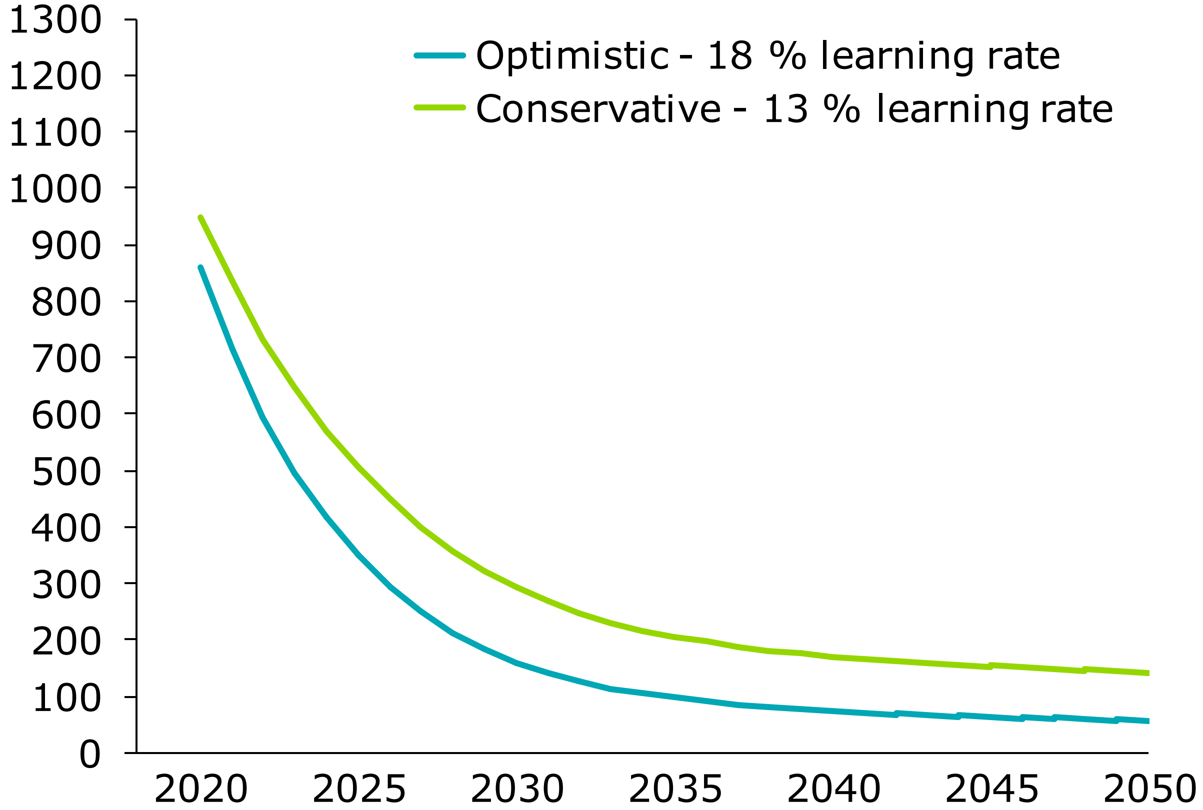
NOTES: Blue hydrogen production: i) forecast based on SMR+CCS costs (90% capture rate) in 2020 transitioning to cheaper ATR+CCS technology in the 2020s; Green hydrogen production: i) favorable scenario assumes average LCOE of PV and onshore wind of lowest 33% locations (falling from $22/MWh in 2020 to $10/MWh in 2050) and average scenarios assumes median LCOE from lowest 75% locations (falling from $39/MWh in 2020 to $17/MWh in 2050) from BloombergNEF forecasts, ii) additional 20% (favorable) and 10% (average) LCOE savings included due to directly connecting dedicated renewables to electrolyser, iii) 18 % learning rate for favorable & 13 % for average scenario. Electrolyser capacity utilization factor: 45%. Comparison to BloombergNEF most favorable ($0.55/kg) and average ($0.86/kg) and Hydrogen Council favorable (ca. $0.85/kg) and average (ca. $1.45/kg) in 2050.

SOURCE: BloombergNEF (2021), *Natural gas price database* (online, retrieved 01/2021), BloombergNEF (2020), *2H 2020 LCOE Data Viewer*; BloombergNEF (2021), *1H2021 Hydrogen Levelised Cost Update*; Hydrogen Council (2021), *Hydrogen Insights*

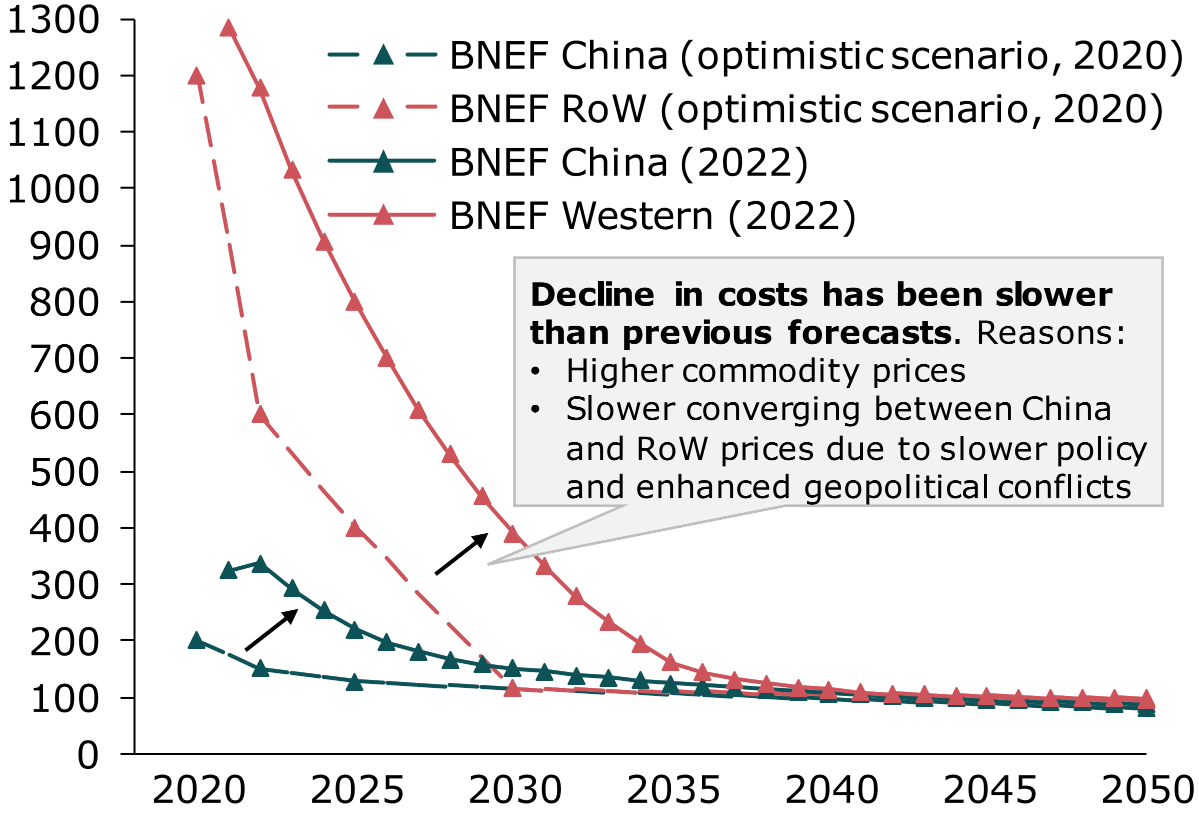
Cost declines in the near-term largely driven by falling costs of electrolysers

Fully installed system capex forecast of large alkaline electrolysis projects

US$ (2020)/kW



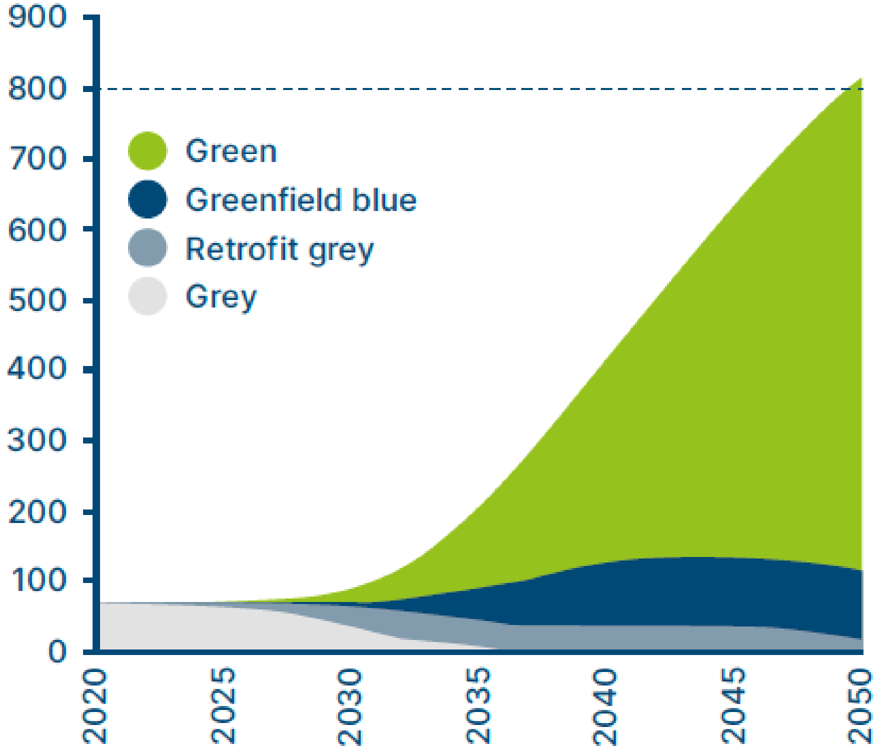
Electrolyser capacity (GW)	15	225	1300	3300	5500	7800



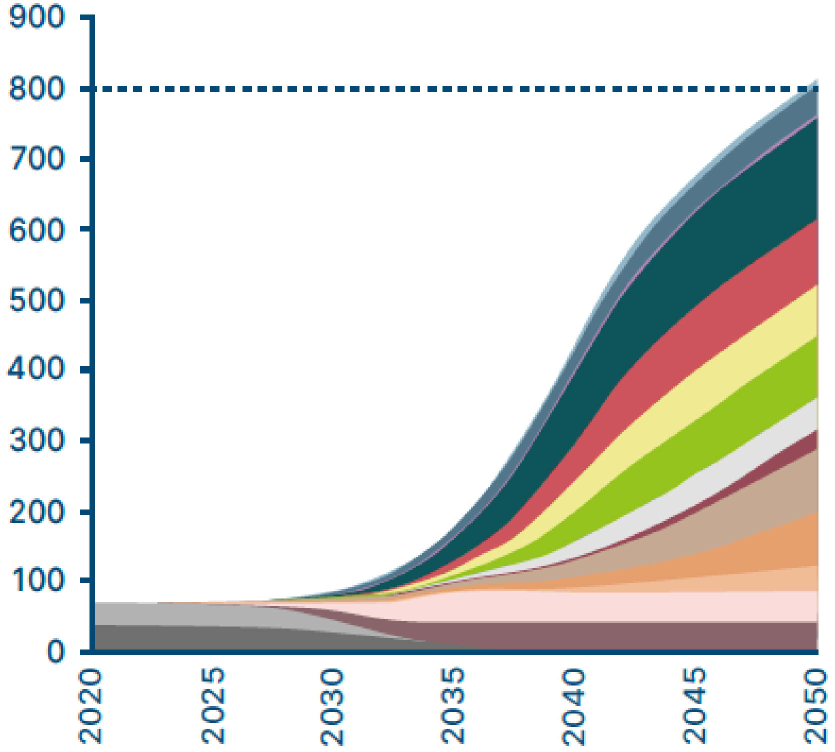
In a mass-electrification scenario, the major share of hydrogen will stem from green hydrogen with an important but transitional role of blue hydrogen (< 25% in 2050)

Scenario 2: ~85% 2050 supply green, ~15% blue

Hydrogen supply
Mt Hydrogen / year



Hydrogen demand
Mt Hydrogen / year



Illustrative scenario

Clean hydrogen

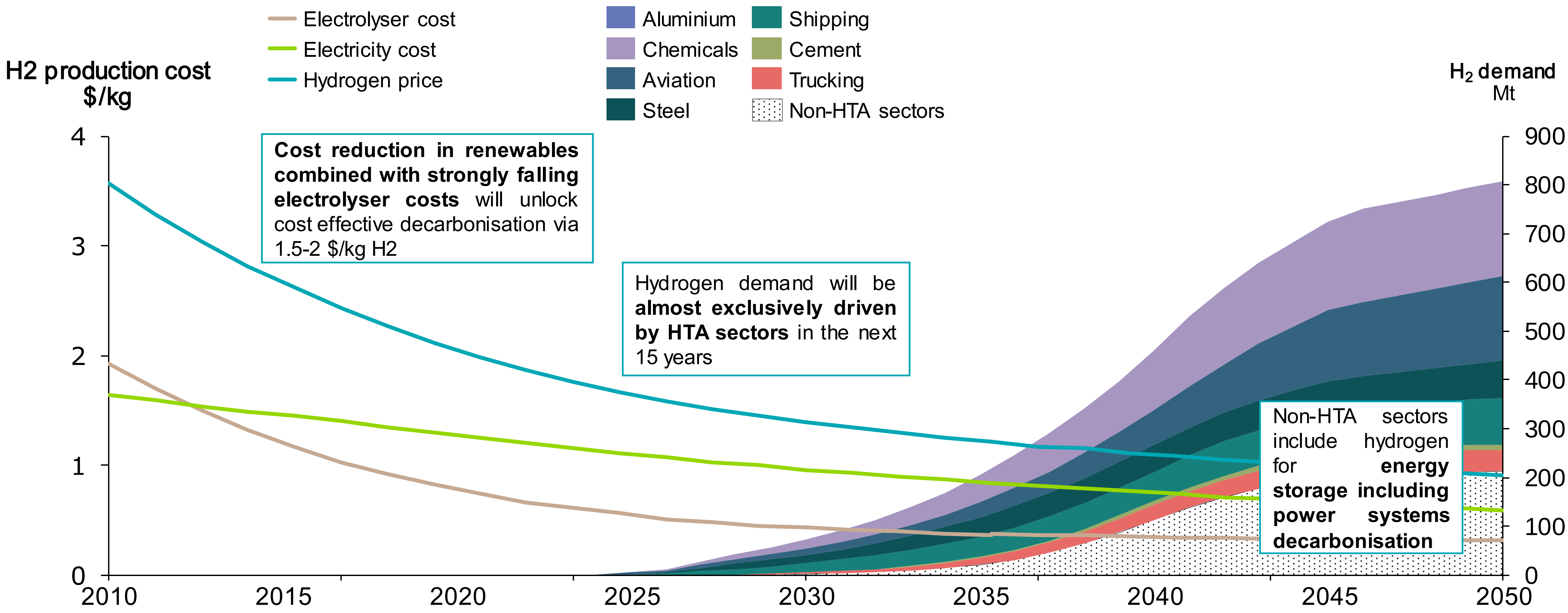
- Light duty transport
- Heavy duty transport
- Rail
- Shipping
- Aviation
- Building heating
- Power flexibility
- Other industries
- Cement
- Iron and Steel
- Chemicals process energy
- High value chemicals
- Ammonia
- Methanol

Fossil hydrogen

- Ammonia (grey)
- Refining (grey)

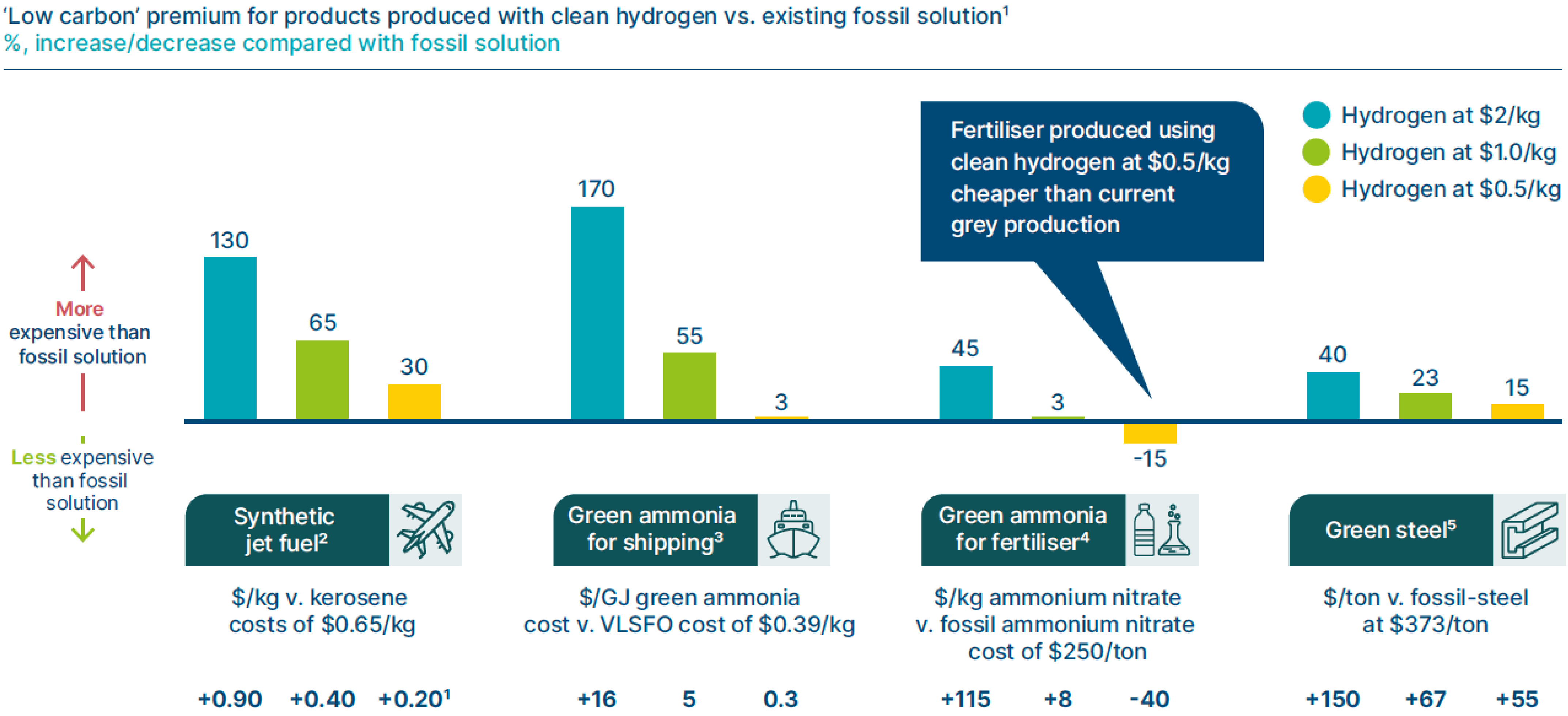
HTA Sectors will drive electrolyser cost reduction of hydrogen this decade

Projected clean hydrogen demand based on MPP and ETC analysis and production cost



Note: The hydrogen production cost for the "Middle East" region from MPP is illustrated. Electrolyser cost refers to capex for utility scale plants of >1GW. Non-HTA sectors accounted for are light duty transport, rail, building heating, power flexibility and other industries.
Source: Mission Possible Partnership (2023); ETC (2021), Making the Hydrogen Economy Possible.

Even at very low clean hydrogen costs (e.g. $0.5/kg), majority of hydrogen technologies more expensive than current fossil technologies



Making the hydrogen economy possible:
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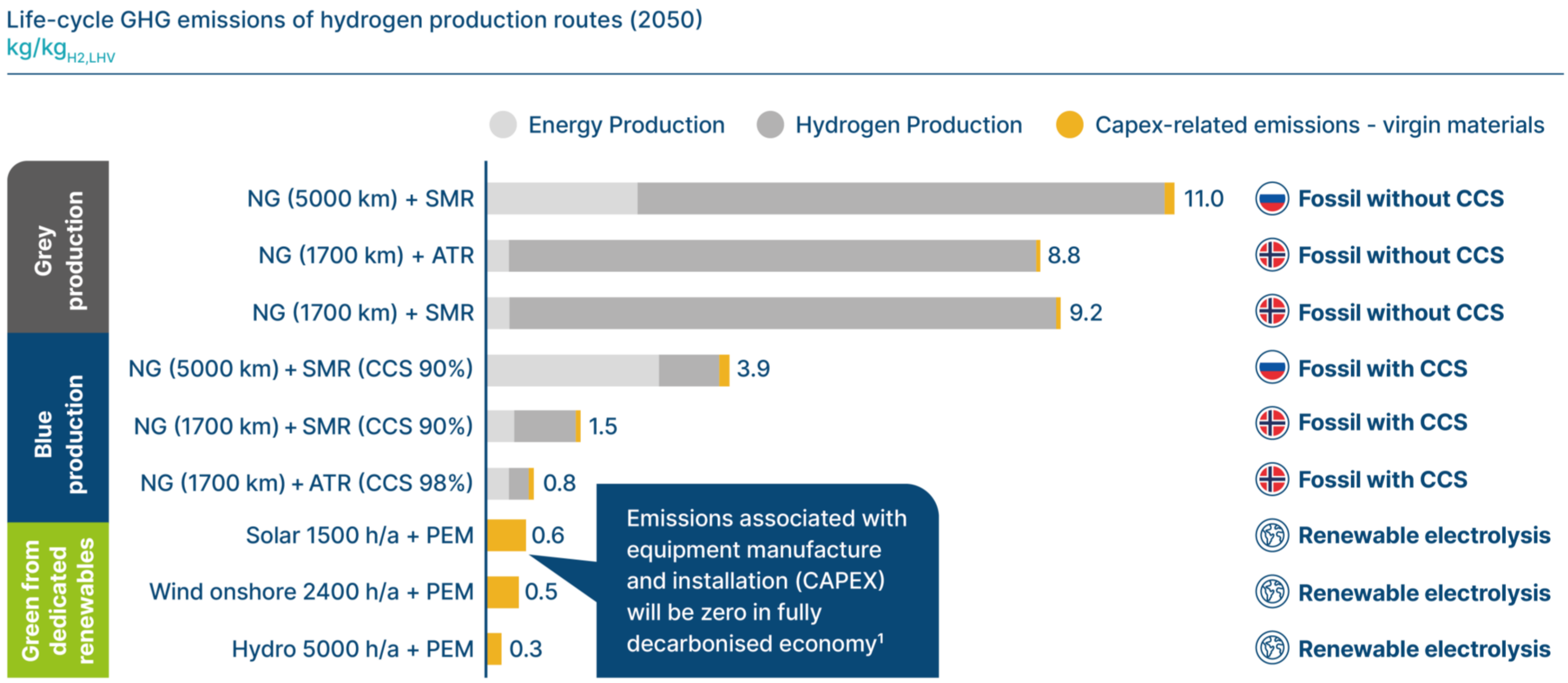
Beyond costs, it is essential that 'clean' hydrogen is truly clean: For blue, upstream natural gas production, methane 'leakage', and capture rates drive bulk of emissions; green from dedicated renewables is near zero-carbon



NOTE: Energy production category includes upstream methane emissions; equals leakage rates of ca. 0.15-1.2 % based on natural gas source and transport distance; H_2 production refers to process emissions from SMR/ATR; [1] GHG emissions for CAPEX due to carbon emissions associated with grid electricity used to manufacture equipment.

SOURCE: Adapted with permission from Hydrogen Council and LBST(2021), *Hydrogen decarbonization pathways – A life-cycle assessment*

Transport, storage and international trade of hydrogen

Transport of hydrogen

- Many carrier forms (e.g., **gas, liquid, ammonia**) and technology options (**truck, pipeline, ship**)
- Most economic format depends on **volumes & distances**; **gas pipelines preferred** in most cases

Storage of hydrogen

- **Large scale geological storage** (e.g. salt caverns) cheapest but **uneven geographical distribution** and further development needed (esp. rock caverns and depleted oil & gas fields)
- **Rapid build out required** to support growing hydrogen economy

Alternatives to hydrogen transport

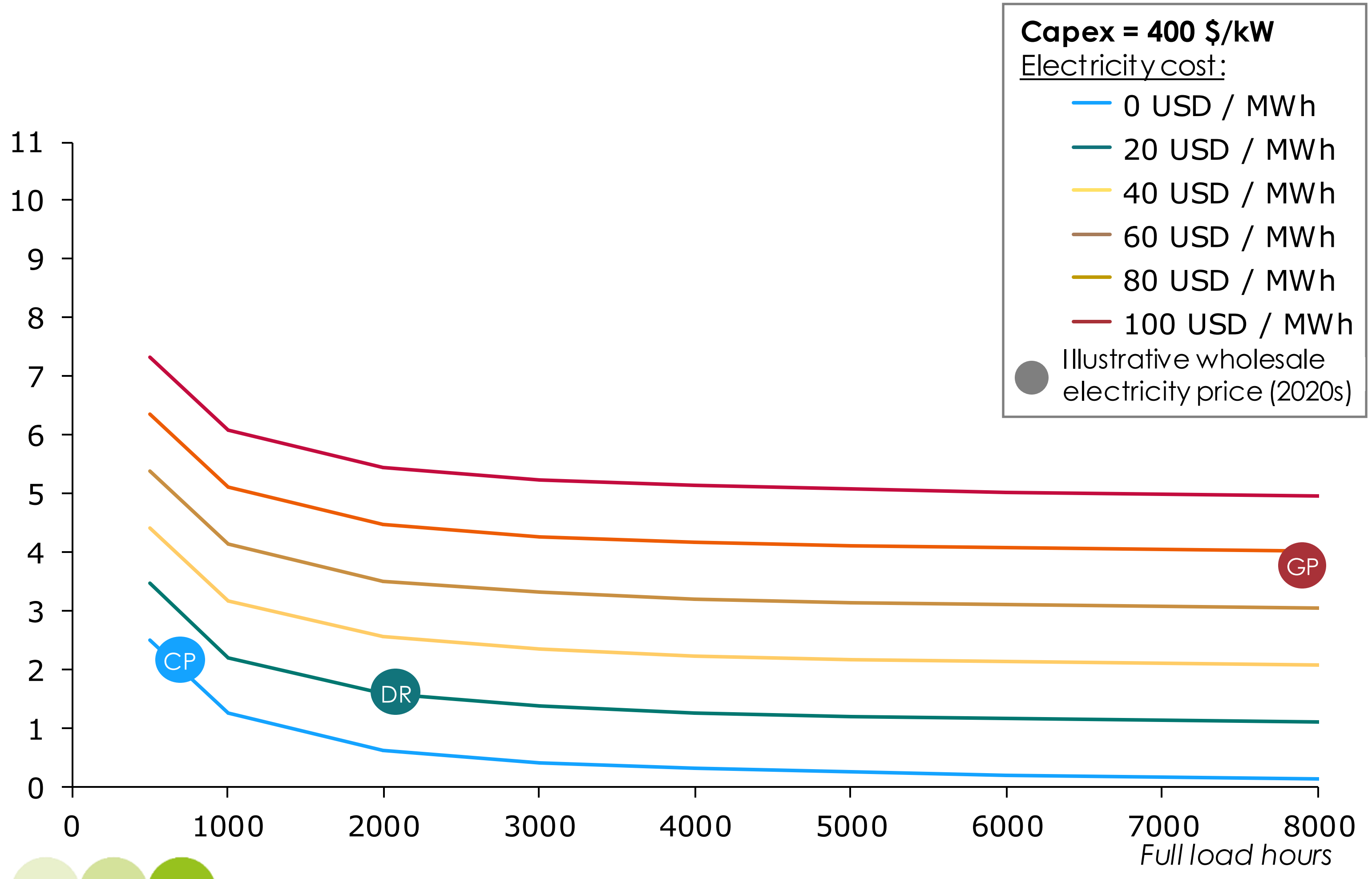
- **Moving electrons**: Over long distances (>1000km) transporting electrons via HVDC transmission lines may be competitive – partly dependant on location of geological hydrogen storage
- **Moving natural gas**: Where very cheap natural gas is available, transport via existing pipelines to areas with CCS infrastructure cheaper than transport of blue hydrogen

International trade of hydrogen / energy

- **Cost differential between production locations may drive trade of hydrogen**, but cost differential between low/high cost production regions decreases over time
- Domestic production in the long term likely to be approximately same cost as imported hydrogen
- International trade opportunities in long-term likely limited to:
  - **Cheap high-capacity pipeline** (4000t/day), especially retrofitted
  - **Ammonia transport via ship** with ammonia end-use
  - **Renewable resource constrained** countries
- In the long-term, **shift of production sites for energy intensive processes** also likely

Above ca. 2000 hours annual electrolyser utilisation electricity cost is key determinant of green hydrogen cost; dedicated renewables likely to be best source of zero-carbon power

Green hydrogen production costs
$/kg



Notes: Electricity consumption 48 kWh/kg, Electrolyser lifetime = 25 years, Discount rate = 8%
Source: SYSTEMIQ analysis for the Energy Transitions Commission (2020) based on IEA (2019), *The Future of Hydrogen*

Electricity sources for green hydrogen production – commentary

DR **Dedicated renewables**: **reasonable load hours (> 2k)** and **competitive electricity cost** (below $20/MWh in future), likely H_2 market price for will be set by H_2 price when produced with dedicate renewables

CP **Curtailed power volumes will develop if electrolyser CapEx declines considerably** (e.g., to $200/kW)

Increased variable renewables results in higher number of hours with cheap power (curtailment)

GP Given **higher average electricity price**, **grid power** would likely not be used

Load hour advantage (100%), but minimal costs benefits above ~2k hours

Note, in a renewables dominated power system (as discussed in the ETC's clean electrification report) **curtailed power** and **grid power** will start to overlap and merge, with electrolysers able to support grid balancing by **offering flexible demand** at times of over-supply

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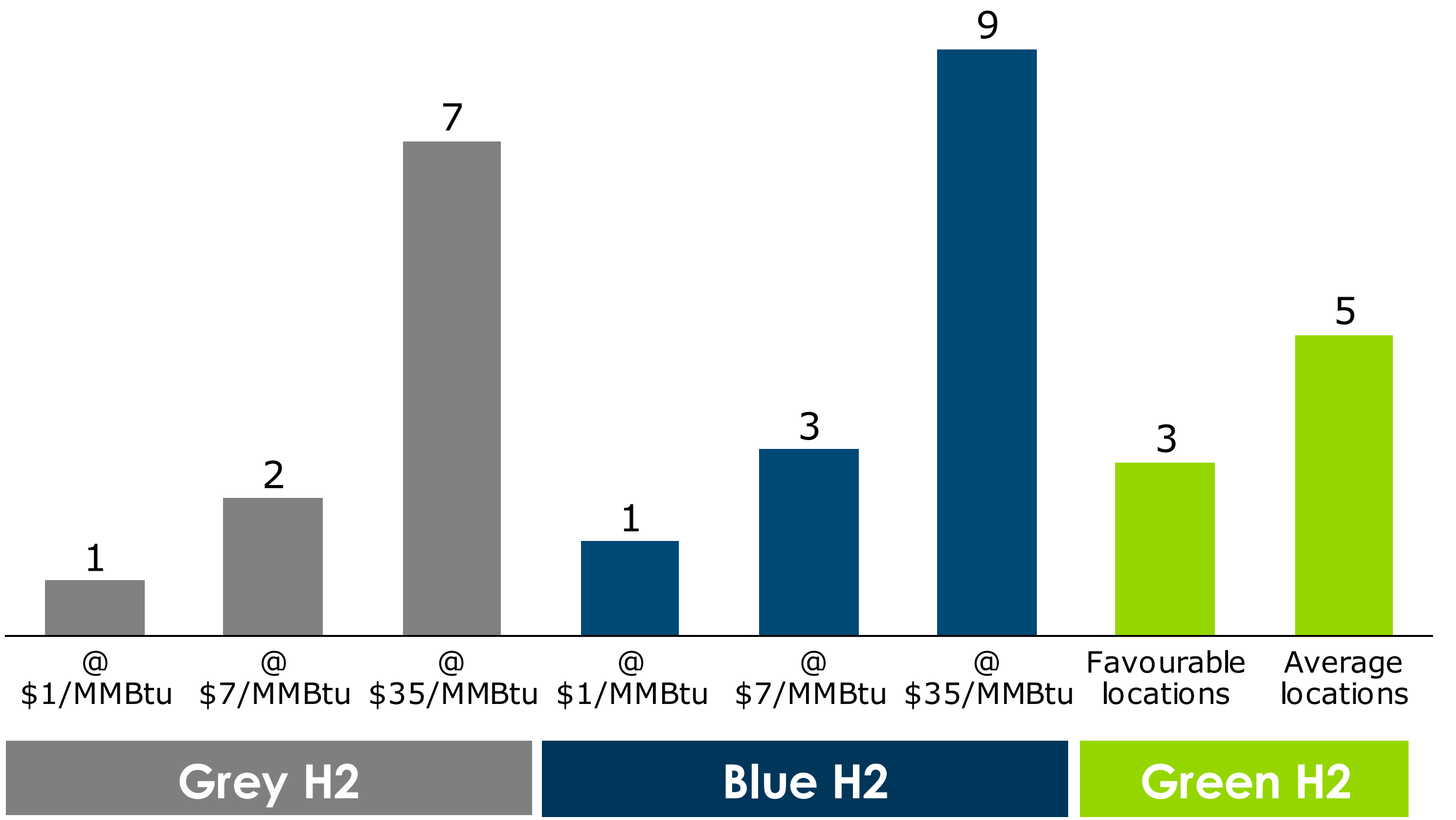
Gas price increases as seen recently, tip balance in favour of green over blue hydrogen

Impact of increased gas prices hydrogen production costs
$/kg

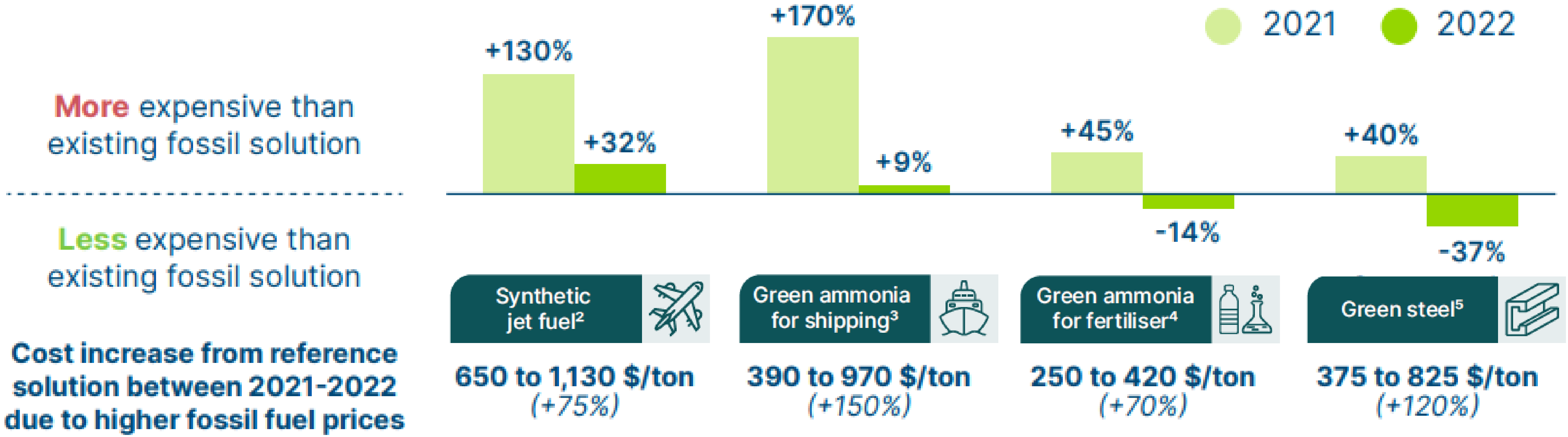


- Sustained high gas prices tip **low-carbon hydrogen production in favour of green**. Risks of future volatile gas prices also compounds this.
- Impact on current grey producers will largely depend on how exposed they are to short-term gas prices vs. long-term contracts.
- Low cost gas producers with low volatility (e.g. Middle East, US) **likely to still favour grey/blue hydrogen in the near-term.**

The green premium is much smaller upon comparison to 2021-2022 fossil prices

Low carbon premium for products produced with clean hydrogen at 2€/kg vs. existing fossil fuel solution in % change

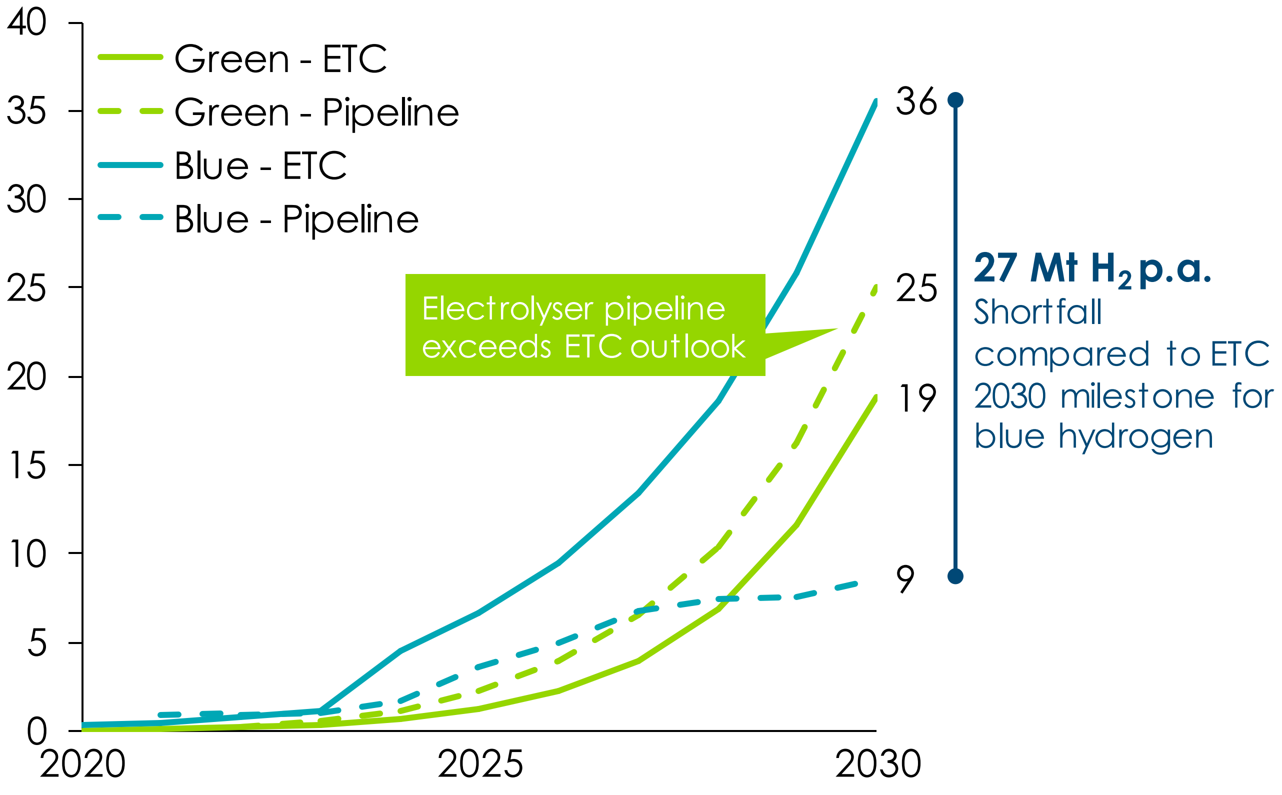
$/kg



Current supply pipeline has ~25 Mt of green hydrogen production by 2030, driven by installations in China and Europe; demand starting to grow from industry but more slowly

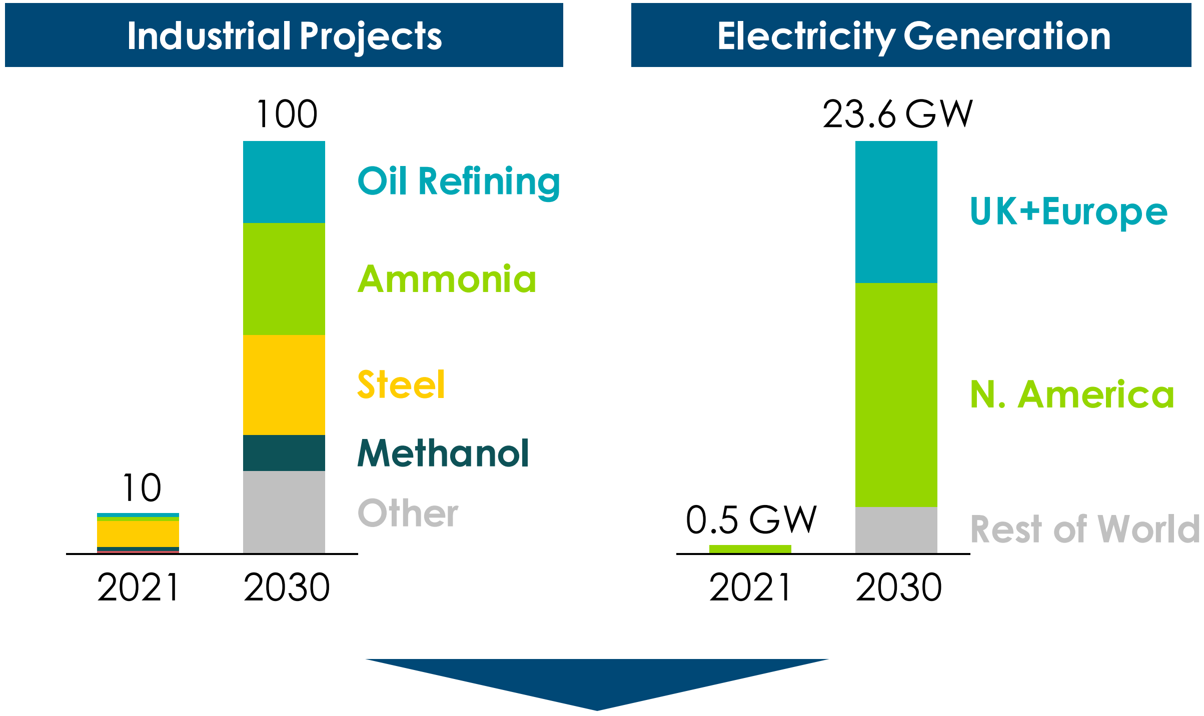
Electrolyser pipeline is growing rapidly, but blue hydrogen projects need to scale faster

Million tonnes of hydrogen



Demand for low-carbon hydrogen is growing in industrial and power applications, but not quickly enough

LHS = Pipeline of industrial projects; RHS = Pipeline of H2-ready power turbines



Demand for ~15 Mt H_2 p.a. by 2030*

*Assuming all industrial projects are large-scale, requiring roughly: oil refining – 0.1 Mt H_2 p.a.; ammonia – 0.13 Mt H_2 p.a.; steel – 0.1 Mt H_2 p.a.; methanol – 0.13 Mt H_2 p.a.; assuming all power generation projects fully use hydrogen at a 40% capacity factor and 50% efficiency

Source: ETC (2021) *Making the hydrogen economy possible*; BNEF (2022) *2H Hydrogen market outlook*; BNEF (2022) *Global electrolyzer outlook*

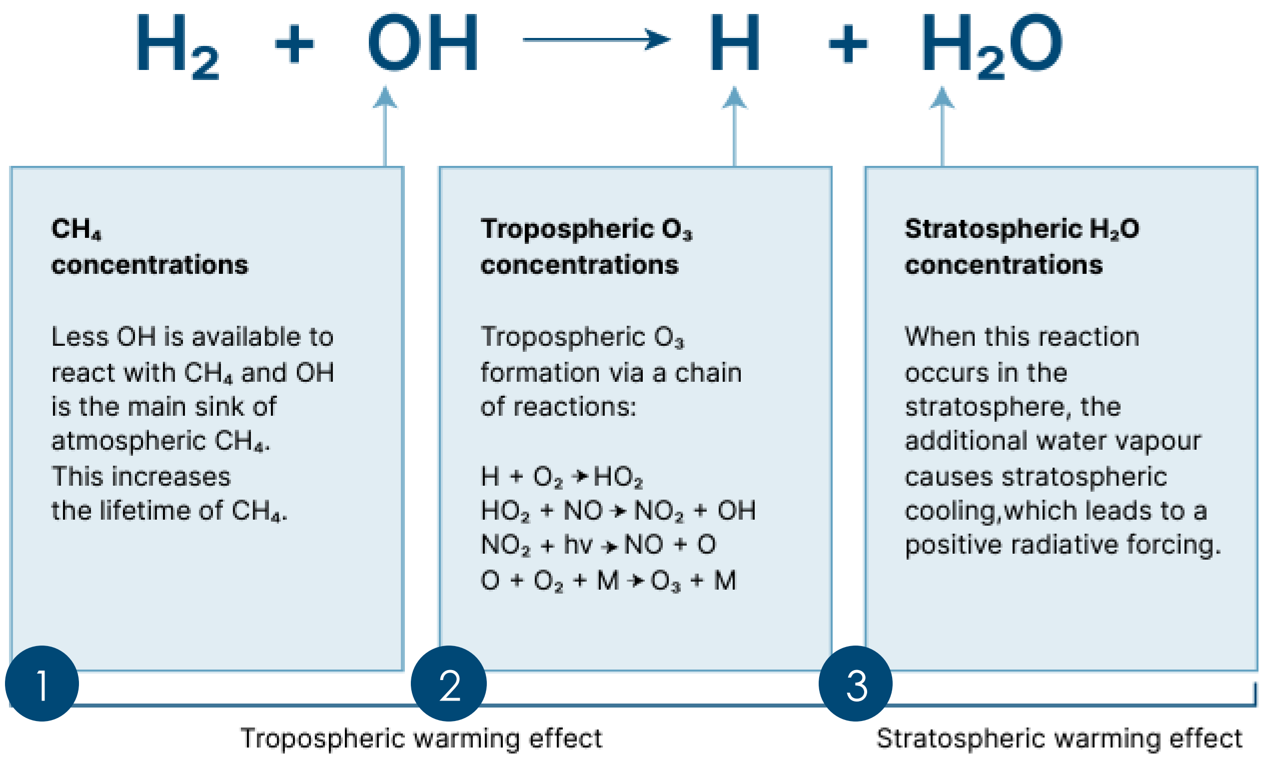
The global warming potential of hydrogen

Hydrogen is a Greenhouse Gas (GHG), and hydrogen molecules (H2) could leak out of point sources, pipelines and storage infrastructure throughout production and transportation processes in a hydrogen energy system.

It affects the atmosphere in 3 ways:

1. **Increases the lifetime of methane** (by reacting with OH)
2. **Creates more Ozone molecules**
3. **Increases water vapour** (a GHG when released at altitude)

Estimated GWP	20 year lifetime	100 year lifetime
CO_2	1	1
CH_4	81-83	27-30
H_2	33 *(20-44)*	11 *(6-16)*



Source: ETC (2023) *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy – Technical Annex*

…depends on how much it might leak

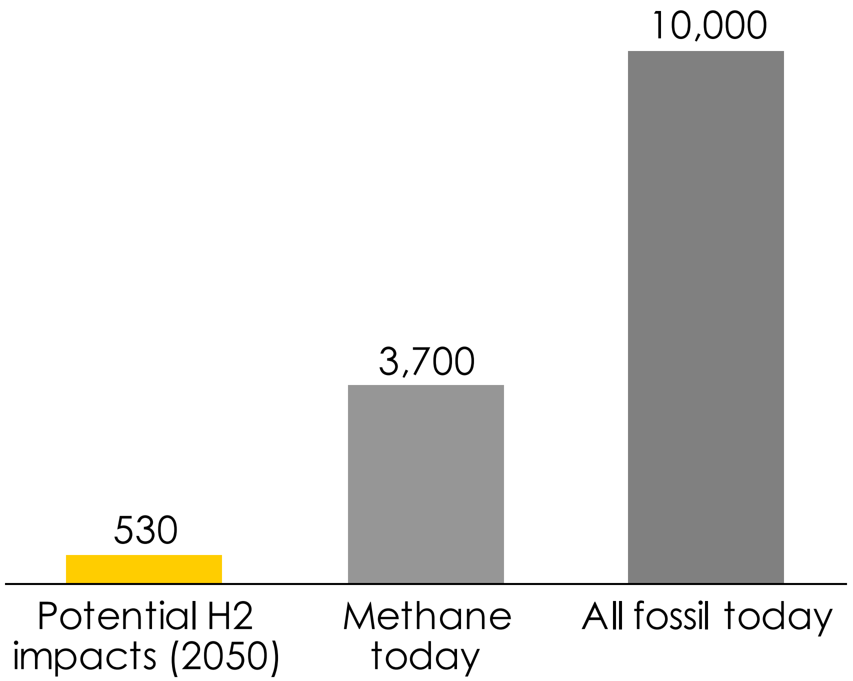
- Leakage rates for methane are usually around 1-2% across production, transportation, distribution. Most occurs in production phase.
  - Controlled production processes and **higher value of H2 might point to lower leakage rates**…
  - …however H2 is a smaller molecule and **may leak more in transportation and distribution**

A quick calculation:

- Hydrogen use could reach at most 800 Mt per annum by 2050, around 15% of final energy demand.
- Assuming a realistic leakage rate of 2% and using the value for GWP20 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 have a warming impact of ~3700 Mt CO_2e per annum
- Additional methane emissions from the coal and oil energy systems would yield ~10,000 Mt CO_2e per annum

Warming impact of hydrogen, compared to other fossil fuels

CO_2e/year based on GWP20



Source: ETC (2023) *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy – Technical Annex*

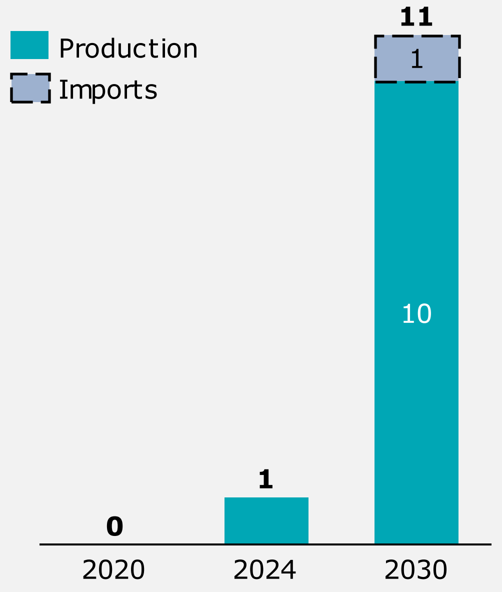
Recent policy developments highlight ambition on US and EU to lead

EU: Raised ambition for green hydrogen supply, especially for imports, given major energy security challenges

July 2021

Fit for 55

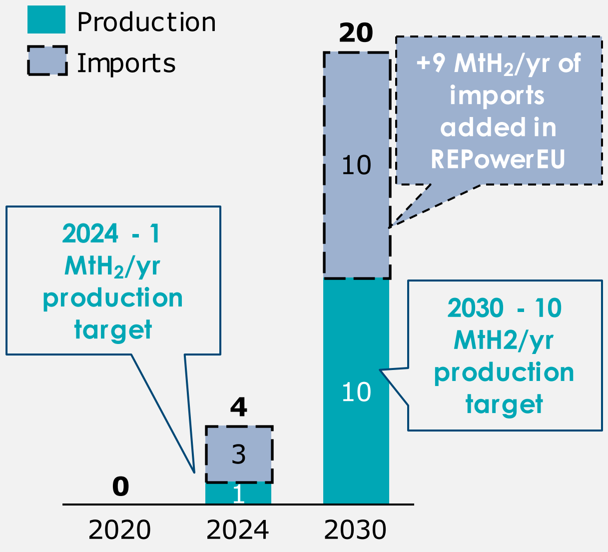
Green H_2 production and import targets for the EU - In million tons H_2 /year (MtH_2/yr)



May 2022

REPowerEU

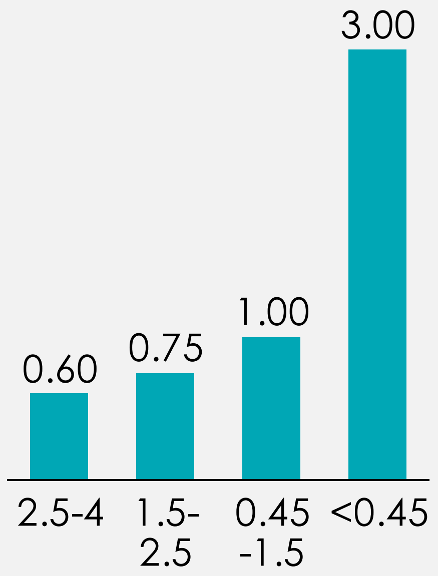
Green H_2 production and import targets for the EU - In million tons H_2 /year (MtH_2/yr)



USA: The inflation reduction act provides unmatched OPEX support

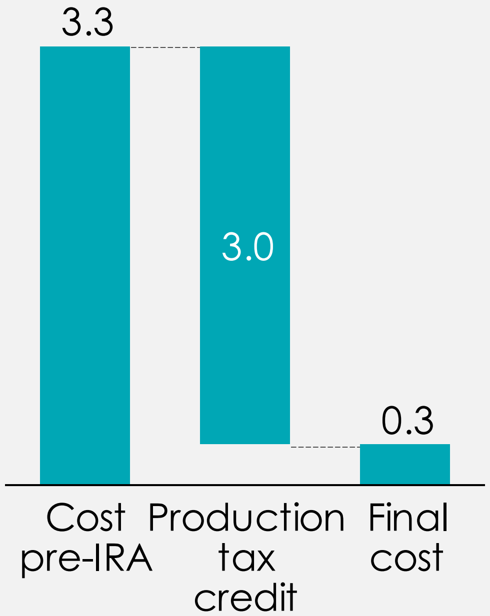
IRA production tax incentive

Clean hydrogen incentive depending on emissions intensity ($ support / kg H2 produced)



Cost reduction following IRA

Clean hydrogen production cost decline $/ kg H2 produced)



Source: Systemiq Analysis for the Energy Transitions Commission; BCG (2022), US Inflation Reduction Act: Climate & Energy Features and Potential Implications

Policy and industry measures to cover the green premium are already on their way – particularly in EU and USA

- Preferred
- Possible
- Impractical

			Long-term, cross-sectoral policy	Key instruments in the 2020s			
			Carbon Pricing	Mandates or product standards	Voluntary green premium	Public procurement	Contracts for difference
Actor			Policy makers		Industry / Consumer	Policy makers	
Mechanism			Decrease fossil competitiveness	Create demand for green products			Cover cost differential
Main cost bearer			Diluted through all end-users	Green product end-user		Government budget	
Regional and sector specific examples are emerging…			EU ETS expected to be >€50 in 2022; Carbon boarder adjustments being considered by EC	ReFuelEU considering SAF blending mandate on all flights departing from Europe	Volvo and Mercedes-Benz commitment to green steel in vehicles in few years	Green public procurement in the Netherlands (CO_2 performance ladder and 'DuboCalc tool)	Germany's National Hydrogen Strategy includes plans for ammonia & steel CfDs
Most appropriate lever varies by sector…	Existing uses	Fertiliser	Carbon tax likely to have impact at moderate CO_2 price	Lifecycle-emissions standards for fertiliser production	Premium sector occupied by organic farming	Little government procurement activity	Contract for difference vs. ammonia spot price
	Large long-term uses with significant lead times	Steel	Feasible but high risk of carbon leakage, will require border carbon adjustments	Lifecycle/Embodied carbon emissions standards for automotive & construction	Attractive for short, consolidated value chains (e.g. cars - ca. 12% current steel production)	Leverage national infrastructure projects; however, large share of scrap-based steel	Carbon contract for difference for primary (ore-based) steel production
	Possible future uses where relative adv. vs. other options no yet clear	Long-distance buses & trucking	Via diesel taxation	Progressively tightened emissions standards, or ICE bans	Development of a "green logistics" offer with cost pass through to end consumer	Leverage procurement of buses for long distance travel, but limited volumes	Small consumption volumes makes CfD impractical

Accelerating clean hydrogen in the 2020s: Many critical actions focus on industrial clusters, which coordinate production & off-take, and minimise network needs

SUPPLY

1. Direct investment support and access to low-cost capital for clean hydrogen industrial clusters
2. Access to lower power prices through corporate purchase agreements, grid-tariff waivers and power market design
3. Ban new greenfield unabated grey hydrogen plants
4. Streamline permitting process for VRE generation and CCS for clean hydrogen production

TRANSPORT AND STORAGE

1. Adapt and expand existing regulatory & safety frameworks for hydrogen and ammonia
2. Geological siting of potential hydrogen storage locations (e.g. salt caverns)
3. National infrastructure planning to design (inter-) national hydrogen networks where required
4. Government support (e.g. blended finance) for storage & transmission network build out

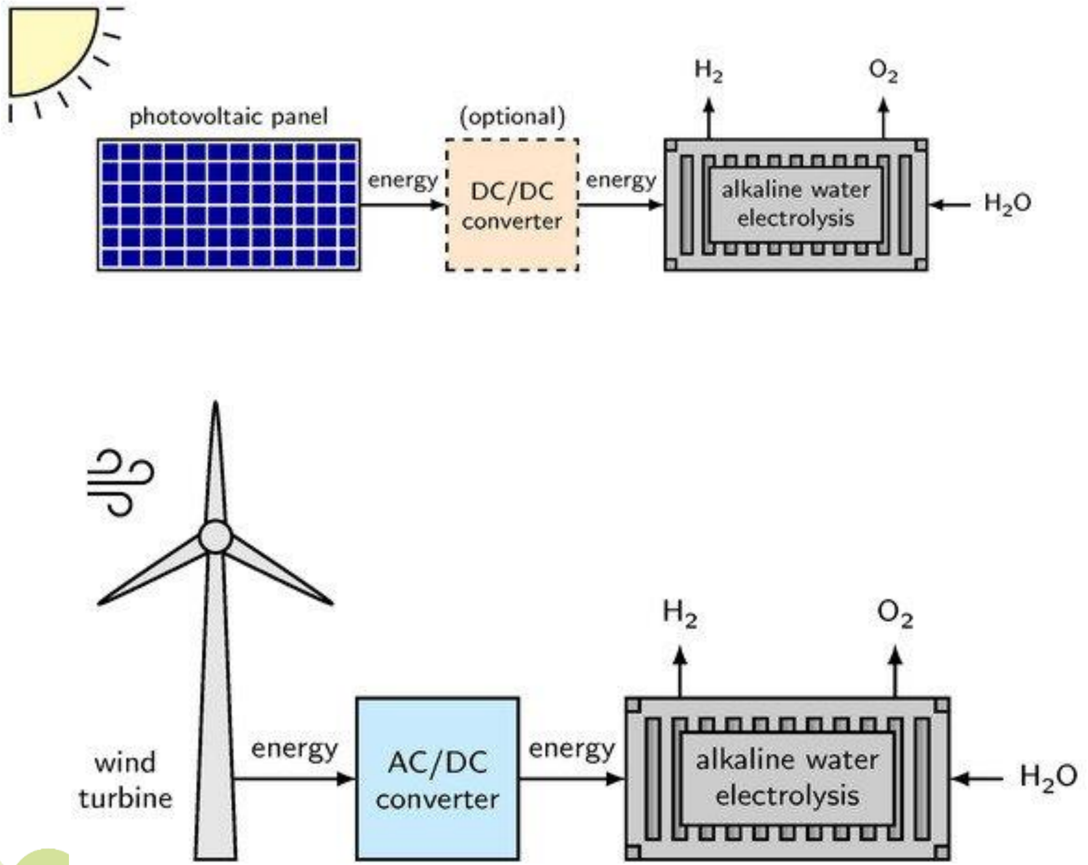
DEMAND

1. Carbon taxes of $100/ton by 2030 with further increase until mid-century
2. Sector specific policies & actions to create early demand (e.g. mandates, public procurement, voluntary green market)
3. Sector specific financial support mechanisms for investments and to overcome the cost premium (e.g. contracts for difference)
4. Establish clean hydrogen & product certification scheme

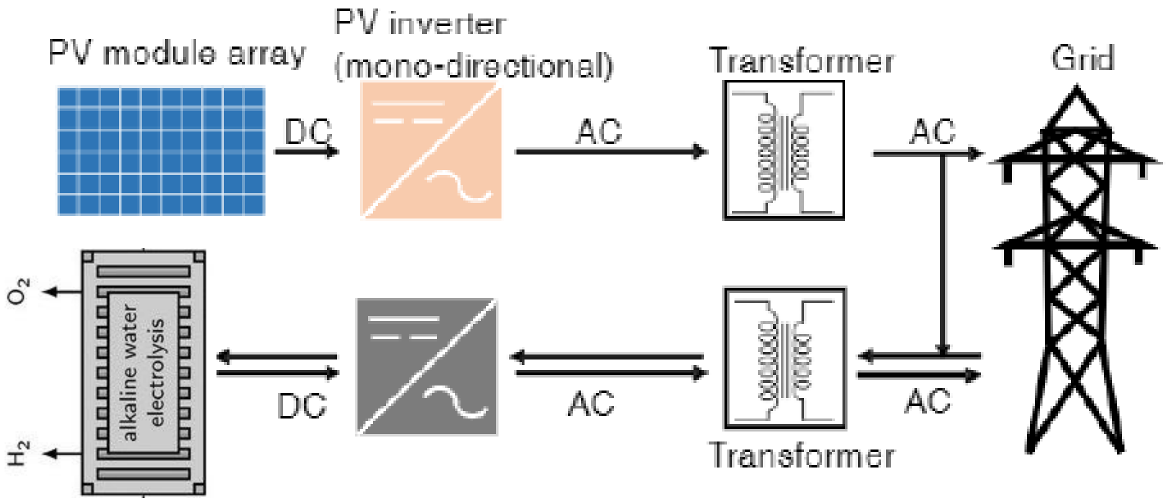
Backup

LCOEs from dedicated renewables can be up to 15% lower than grid connected generation due to savings in power electronics

Dedicated renewables



Grid connected and/or curtailed power

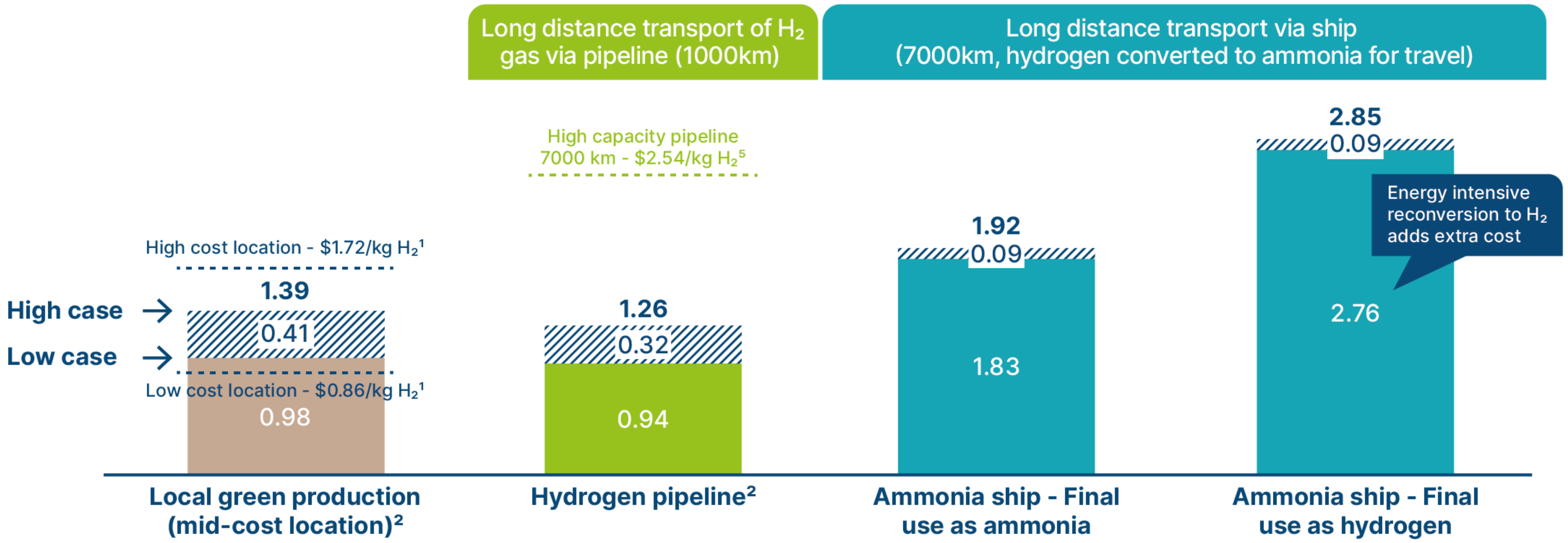


Source: Adapted from BloombergNEF (2019), Hydrogen – the economics of production from renewables

Example: Pipeline transport of hydrogen cheaper than shipping, in particular when end-use is hydrogen (high reconversion costs), but local green production often competitive

All-in delivered cost of hydrogen including production, transport and storage, 2050
$/kg H_2

See technical Annex for further information



	Local green production (mid-cost location)[2]	Hydrogen pipeline[2]	Ammonia ship - Final use as ammonia	Ammonia ship - Final use as hydrogen
Low case	Rock cavern storage	High capacity retrofitted pipeline (4000 t/day, 48 inches)[3]	Green production in favourable region	Green production in favourable region
High case	Tanked storage	Transmission pipeline (<1000 t/day, 13 inches)	Blue production in favourable region[4]	Blue production in favourable region[4]

NOTE: [1] Green hydrogen production + low-cost rock cavern storage; [2] Green hydrogen production takes storage costs of 50% annual demand into account. [3] Lowest cost retrofitted natural gas pipeline according to European Hydrogen backbone report. [4] Blue hydrogen production via ATR + CCS (90%+ capture rate). [5] Assuming medium levelized cost of greenfield high-capacity pipeline according to European Hydrogen backbone report.

SOURCE: BloombergNEF (2019), Hydrogen – The Economics of Transport & Delivery, Guidehouse (2020), European Hydrogen backbone. Industry interviews.

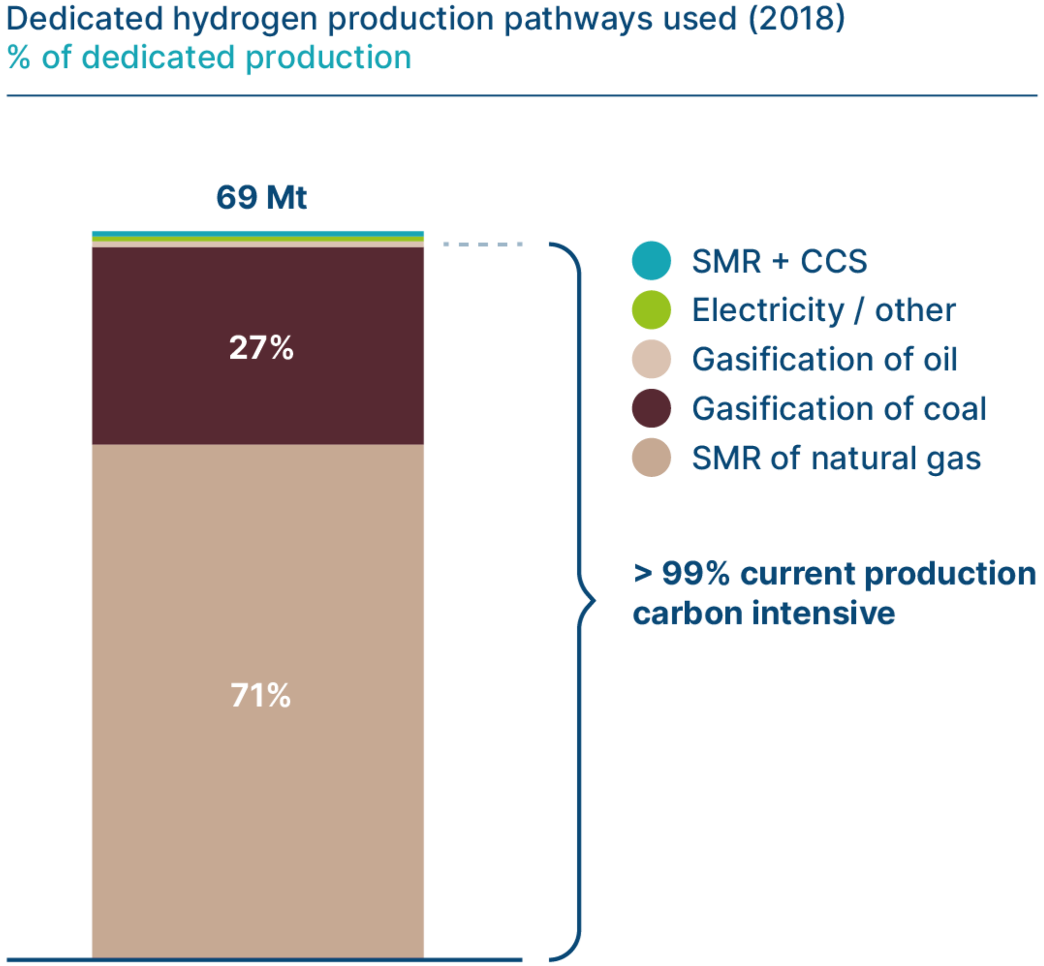
Industrial clusters: Hydrogen project size is increasing (although average remain less than 1GW), but large, multi-sector 'hub' projects have longer lead-times

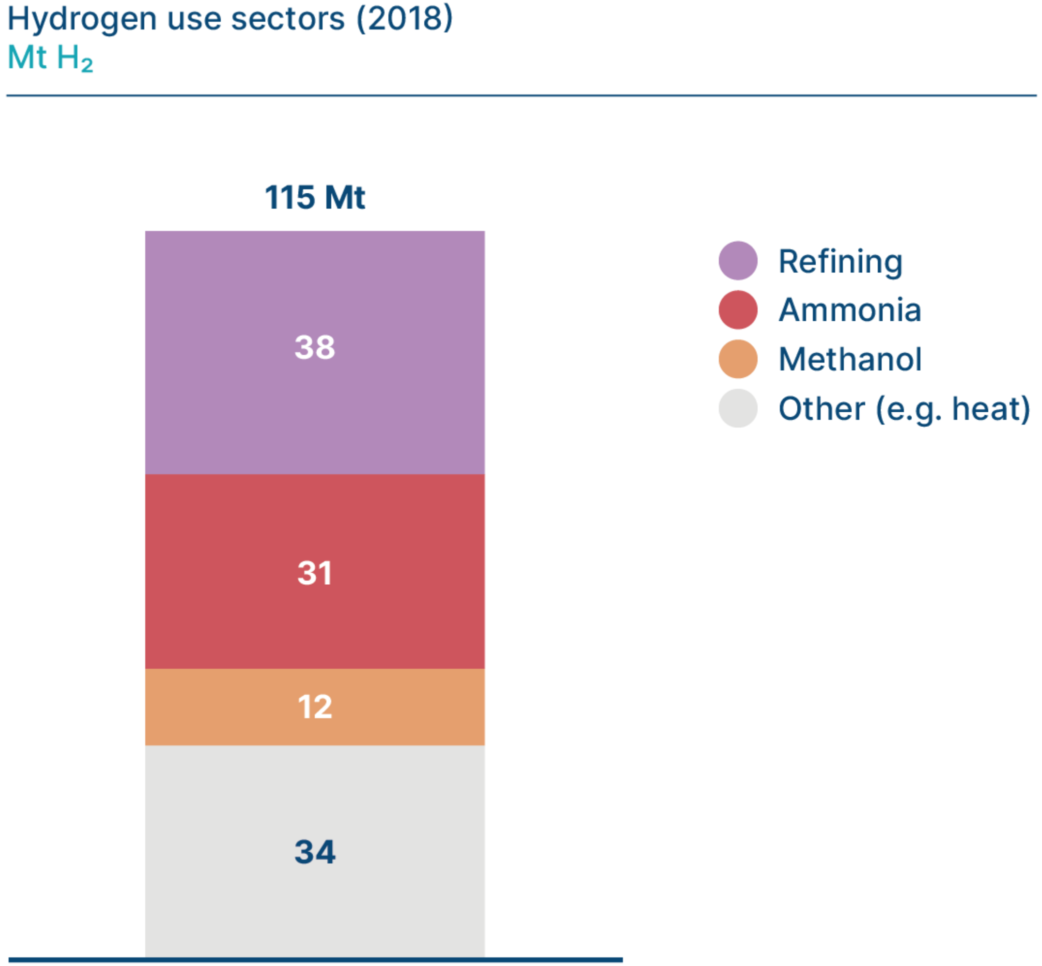
	Small scale projects can be brought online quickly	**Medium scale** projects need to be started by 2025 to go online before 2030	**Large scale** projects need to be developed soon for 2020s
	Fast (~1-3 years)	Medium (~4-5 years)	Slow (~6-12 years)
Project size	< 50 MW	> 100 MW	> 1 GW
# partners	~1-3	~2-5	~3-10
# decisions	few	medium	many
Investment need	< $200 million	> $200 million	> $1 billion
Bureaucracy	trivial	medium	extensive permit processes
Likelihood of failure	Small	medium	high
Examples	Iberdrola & Fertiberia, Spain (Link): 10% co-feed of H2 into fertiliser production	BP, Nouryon and Port of Rotterdam, Netherlands (Link): green H2 for refinery	Gasunie, Groningen Seaports and Shell, Netherlands (Link): multiple industry off-taker

Potentially significantly faster in e.g. China

Large scale projects relevant for 2030 need to be in planning within the next few years

Today's production of hydrogen is via carbon-intensive processes; use of hydrogen concentrated in the chemical industry (refining, ammonia, methanol)





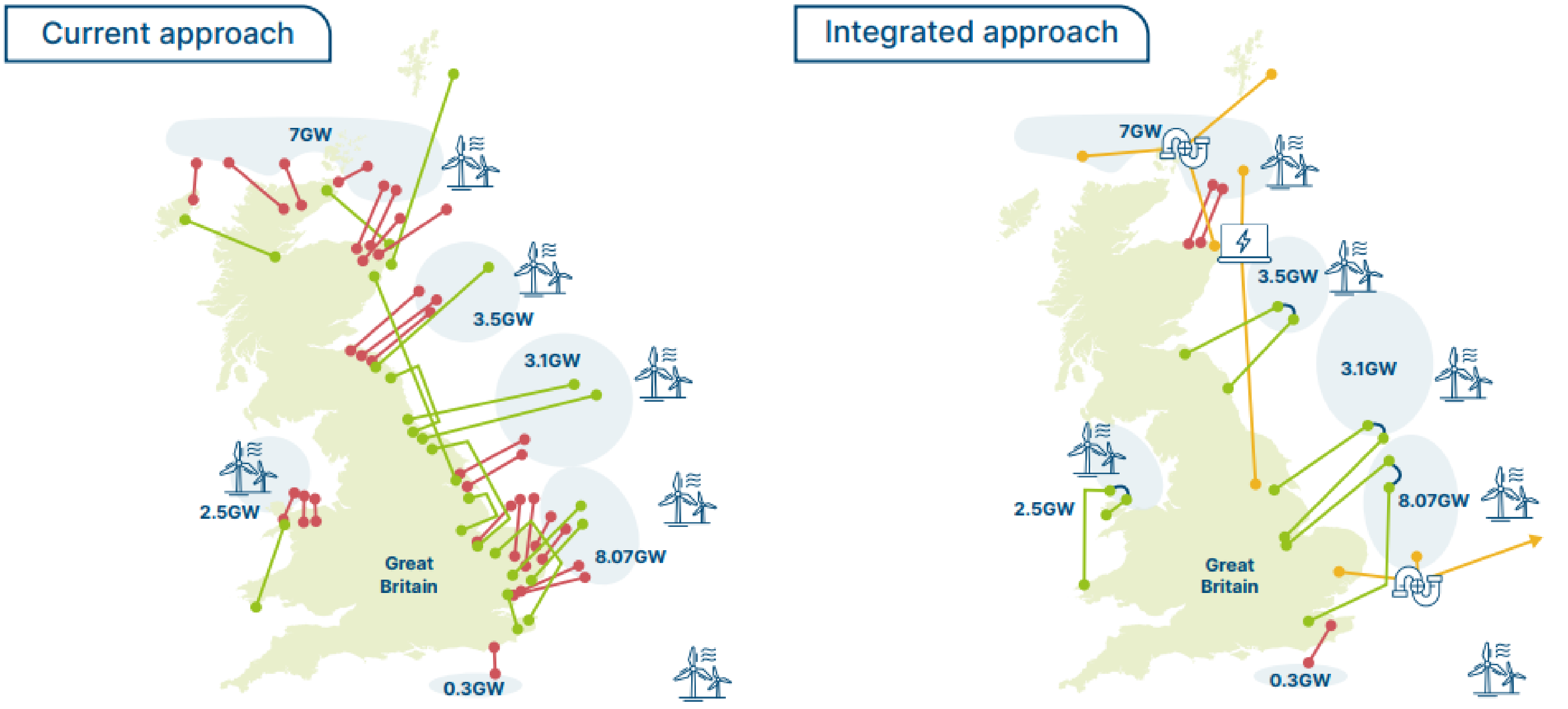
SOURCE: IEA (2019), *The Future of Hydrogen*

Favourable locations for industrial clusters will combine a range of attributes

Supply - Blue	**CCS**	Are geological formations or empty gas fields available for CCS? Are regulations in place that allow the construction/development of CCS? What is the level of public acceptance for CCS?
	Gas price	Is cheap and abundant natural gas available for the production of blue H2?
Supply - Green	**Electrolyser CAPEX**	Can low-price electrolysers be sourced? Is the supply chain present in the location to develop large scale green hydrogen projects?
	Renewable energy	Does the location offer favourable solar and wind resources? Is sufficient land (or offshore) area available to deploy them?
	LCOH (2030)	What is the predicted cost of H2 in 2030 taking into account the LCOE, CAPEX, available load factor and transportation & storage costs?
Demand	**Shipping**	Are large scale ports located in the location to serve as transport hub and demand site?
	Gas grid/ Transport	Does the location offer an existing natural gas grid which could be used to blend H2? Are gas storage facilities available that enable the large scale blending into the gas grid? Is the location a road transport hub?
	Refining & Fertiliser	Does the location have refining and fertiliser industry?
	Steel	Are steel plants present in the location?
Enabling conditions	**Policy**	Can local subsidy schemes be used to improve the economics of the cluster?
	Customers	Is there a large interest in low-carbon products (e.g. "green" steel)?

Planning, permitting and land acquisition systems must support large scale and rapid development, including for transmission and networks

UK offshore wind network development models



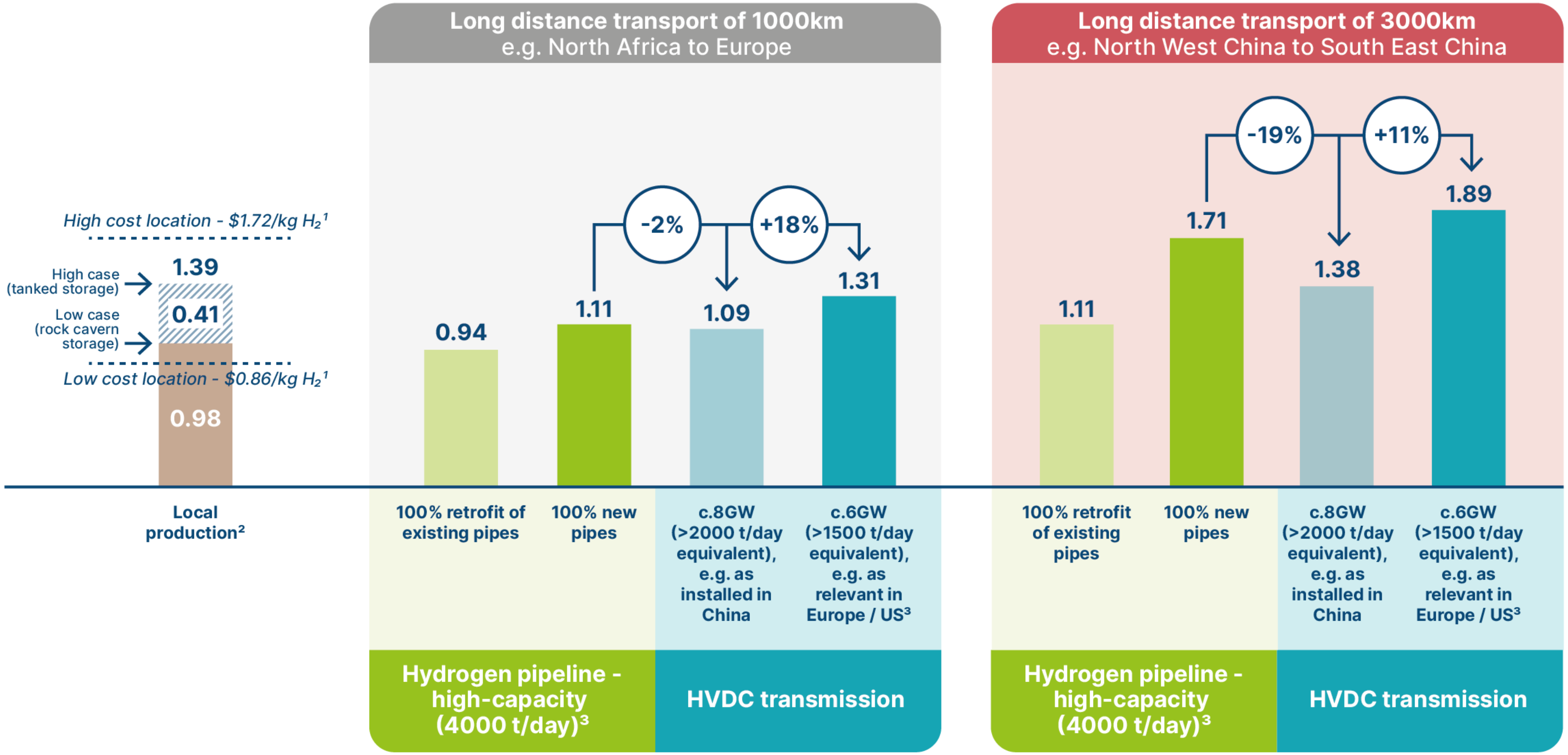
Critical enablers

- Simplifying and streamlining permitting and land acquisition processes
- Strategic approach to planning the siting of generation projects in conjunction with network design
- Anticipatory investment framework for T&D
- Further development of distributed generation and community-ownership models for renewable power

Beyond hydrogen transport: over longer distances, transport of electrons from areas of favourable renewables via high-capacity HVDC cables is increasingly competitive with new hydrogen pipelines

All-in delivered cost of hydrogen including production, transport and storage, 2050
$/kg H_2

See technical Annex for further information



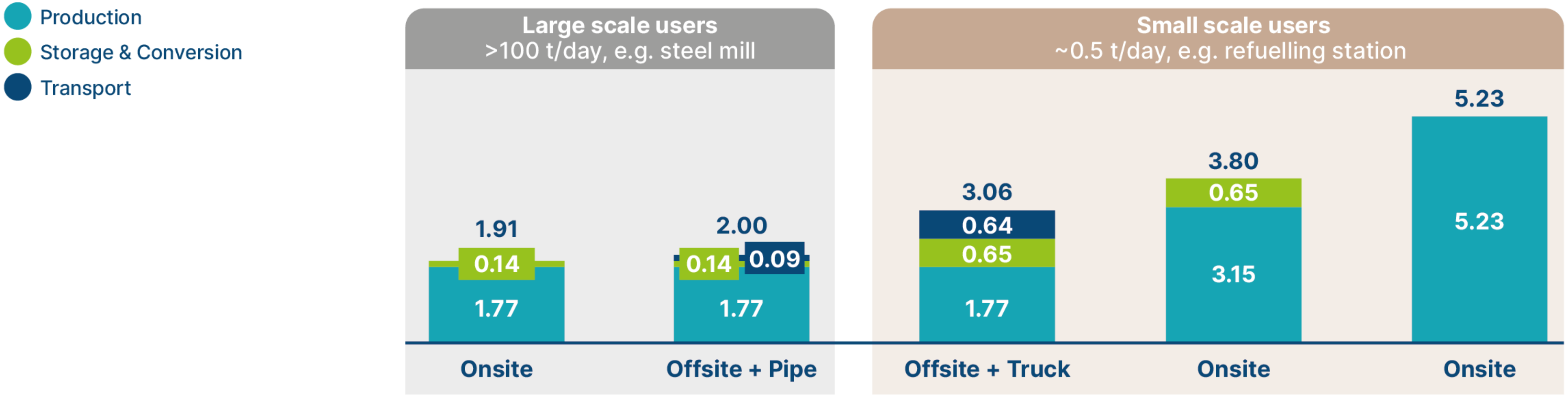
NOTES: [1] Green hydrogen production + low-cost rock cavern storage. LCOE $13/MWh (mid), $10/MWh (low), $29/MWh (high). CAPEX: $140/kW; [2] Green hydrogen production takes storage costs of 50% annual demand into account. [3] Capacity utilization factor for pipelines: 57% and 50% for HVDC.

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

Distributed, onsite production of hydrogen at small-scale users more expensive than offsite production and transport; but large-scale, co-located production cheapest

"All-in" cost of delivered hydrogen including production, transport and storage, 2030

LCOH, $/kg



			Onsite (large scale)	Offsite + Pipe (large scale)	Offsite + Truck (small scale)	Onsite (small scale)	Onsite (small scale)
Production	Electricity source		PV (large-scale)	PV (large-scale)	PV (large-scale)	PV (small-scale)	Continuous grid
	Electricity cost[1]	$/MWh	24	24	24	40	100
	Electrolyser CAPEX[2]	$/kW	290	290	290	580	580
Storage	Mode[3]		Rock cavern	Rock cavern	Pressurised tank	Pressurised tank	N/a
Transport	Mode[4]		N/a	Pipe (13cm)	Truck	N/a	N/a
	Distance	km	N/a	50	200	N/a	N/a

NOTES: [1] Electricity cost estimated higher for small scale user with onsite production due to smaller VRE plant size. [2] Electrolyser CAPEX for large scale (20 MW) alkaline electrolyser according to conservative scenario in Exhibit 1.10. Electrolyser CAPEX ca. 2x for 1 MW size according to IRENA. Similarly, higher costs would be expected for PEM electrolyser with smaller foot-print due to space constraints. [3] Small scale users would likely use small scale pressurized tank storage. No storage assumed for grid connected electrolysis, as hydrogen could be produced "on-demand". [4] Pipe would require 10-100 t/day to justify the infrastructure. A large refuelling station today has a capacity of less than 1 t/day and would therefore not qualify for a distribution pipeline in most cases.

SOURCES: BloombergNEF (2020), *Hydrogen – the economics of storage*; IRENA (2020), *Green hydrogen cost reduction*

Accelerating clean hydrogen in the 2020s:
2030 targets

SUPPLY

50 Mt — Clean hydrogen production

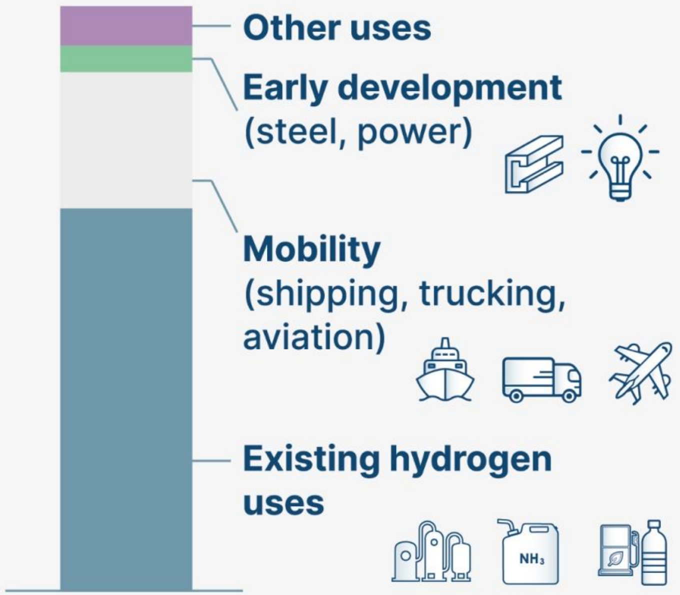
<$2/kg — Average clean hydrogen production cost

DEMAND

> 60% — Clean hydrogen demand from existing hydrogen use

> 30% — From new mobility and industry use-cases

HYDROGEN USE



National hydrogen strategy – Best practices I

1 Long-term vision

- **Net-zero targets:** Implementation of hydrogen strategy as pillar of legally binding national net-zero target
- **Import/Export:** Clear long-term vision on national energy supply & security (electricity & hydrogen import /export)
- **Infrastructure:** National infrastructure vision (e.g. hydrogen pipelines, electricity grid developments, refuelling stations)
- **Production technology:** Clarify expected roles of different clean hydrogen technologies within national context, i.e. given national resources, existing assets (production, transportation) and relevant off-take sectors

2 Concrete goals

- **Supply side aims:**
  - **Clean hydrogen target:** Share of national hydrogen demand that must be clean in what timeframe
  - **Electrolyser capacity target:** Derived from clean hydrogen targets and national import / export plans
- **Demand side aims:**
  - **Emission targets:** Per industry (e.g. steel, refining, fertiliser) quantitative targets, increasing over time
  - **Technology commitments:** Which / how hydrogen end-use sectors will be publicly supported considering local economy (e.g. focus on heavy industry, long distance transport and energy storage)

National hydrogen strategy – Best practices II

3 Underpinning incentives

- **Carbon pricing: Implement meaningful and increasing** national carbon pricing mechanisms (international collaboration and alignment ideal)
- **Deploy sector specific mechanisms** to create demand and to bridge the green cost premium in the next decade:
  - **Mandates** (e.g., fuel mandates, bans of fossil technology), **product carbon standards** and public procurement standards to help accelerate demand growth
  - Address the cost premium via **sector specific contracts for difference**
  - Foster creation of **voluntary green premium markets** through supporting traceability mechanism development
- **Investment support** of business cases for early industrial clusters including direct investment support and access to low cost capital for hydrogen production and end-use.
- **Innovation support:** Identification of areas that require further development coupled with specific research funding (basic research through to applied – pilot, demonstration and commercial plant)

4 Infrastructure planning

- **Support of early projects for both green and blue hydrogen** via simplified permitting procedures for zero-carbon electricity deployment (one-stop shop) and CCS infrastructure development
- **Power market design:** Role for grid-connected green hydrogen production in energy storage & system balancing

National hydrogen strategy – Best practices III

5 Safety and regulation

- **Safety:** Commitment to international cooperation for hydrogen and ammonia handling
- **Purity:** Set clear national standards on hydrogen purity for different end-uses
- **Certification:** National clean hydrogen definition (kg CO_{2e}/kg H_2) alongside traceability mechanisms, in addition to international collaboration

6 Accountability

- **Advisory board:** Implement board of independent advisors (with representation of the entire value chain + local governance) to keep track of progress, propose key actions and ensure accountability

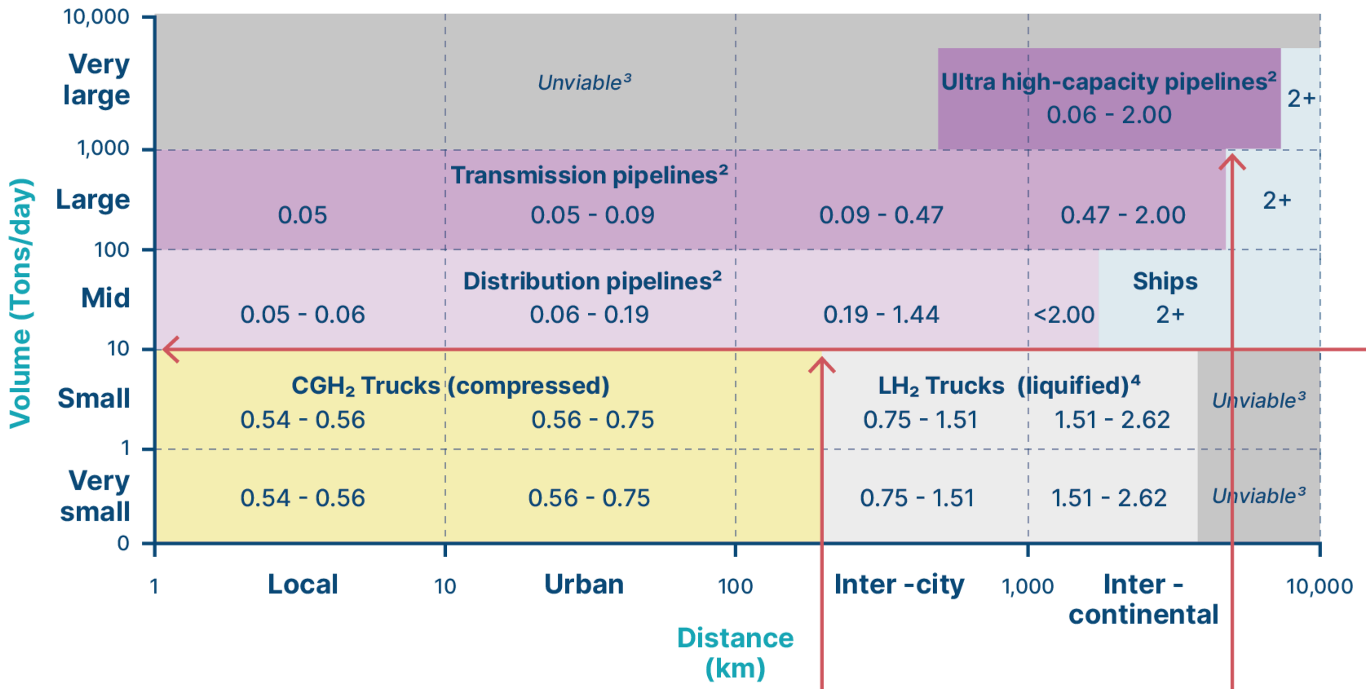
Certification schemes must incorporate full lifecycle emissions, including, in the case of blue hydrogen, residual CO_2 emissions not captured by CCS and methane leakage occurring before and during production – total carbon intensity of ca. 1.2 kg_{CO2}/kg_{H2}

- Minimal methane leakage of 0.05 % should be targeted (0.1 kg_{CO2}/kg_{H2})
- Minimal 90 % CO_2 capture rate in blue hydrogen production (1.1 kg_{CO2}/kg_{H2})

Current EU taxonomy policy proposal suggests a near term target of 3 kg_{CO2}/kg_{H2} (previous suggestion 2.26 kg_{CO2eq}/kg_{H2}) – note: excludes green from grid electricity at current grid intensities of several EU member states

Three key volume / distance tipping points for moving hydrogen, making different modes and / or states competitive

Lowest cost form of hydrogen transportation[1] based on volume and distance
$/kg H_2



Tipping point #1

Distribution pipelines (gas): > 10t / day
Required to justify the expensive infrastructure

Tipping point #3

Trucks (liquid H2 gas): > 300-400km
Compressed hydrogen cheaper at shorter distances due to lower conversion costs; higher volume per truck means liquid hydrogen is cheaper over long-distance

Tipping point #2

Ammonia ships: > 5,000km
Long-distance required to make up for high storage & conversion costs; low unit cost of transport

NOTE: [1] Including conversion and storage; [2] Assumes salt cavern storage for pipelines; [3] Ammonia assumed unsuitable at small scale due to its toxicity; [4] While LOHC (liquid organic hydrogen carrier) is cheaper than liquid hydrogen for long distance trucking, it is unlikely to be used as it is not commercially developed.

SOURCE: Adapted from BloombergNEF (2019), *Hydrogen: The Economics of Transport & Delivery*, Guidehouse (2020), *European Hydrogen backbone*

Storage of hydrogen: Large-scale geological storage is cheapest, although costs for small-scale storage expected to decline significantly

	Storage option	Capacity[1] (t H_2)	Cost of storage ($/kg)	TRL	Example applications
Gaseous state	Salt caverns	300 – 10,000	0.23 / 0.11	9	Large volume storage, medium term (weeks-months)
Gaseous state	Rock caverns	300 – 2,500	0.71 / 0.23	2 – 3	Lage volume storage, medium term (weeks-months)
Gaseous state	Depleted gas fields	300 – 100,000	1.90 / 1.07	2 – 3	Lage volume storage, long term (seasonal)
Gaseous state	Pressurized containers	0.005 – 1.1	0.19 / 0.17	9	Pipelines, short-distance trucking
Liquid state	Liquid hydrogen	0.0002 – 0.2	4.57 / 0.95	7 - 9	Long-distance trucking
Liquid state	Ammonia	0.001 – 10,000	2.83 / 0.87	9	Long-distance shipping
Liquid state	LOHCs	0.0002 – 4,500	4.50 / 2.86	7 - 9	Long-distance shipping
Solid state	Metal hydrides	0.0001 – 0.002	Not evaluated	7 - 9	Trucking

Storage type: Geological (Salt caverns, Rock caverns, Depleted gas fields); Tanks (Pressurized containers, Liquid hydrogen, Ammonia, LOHCs, Metal hydrides)

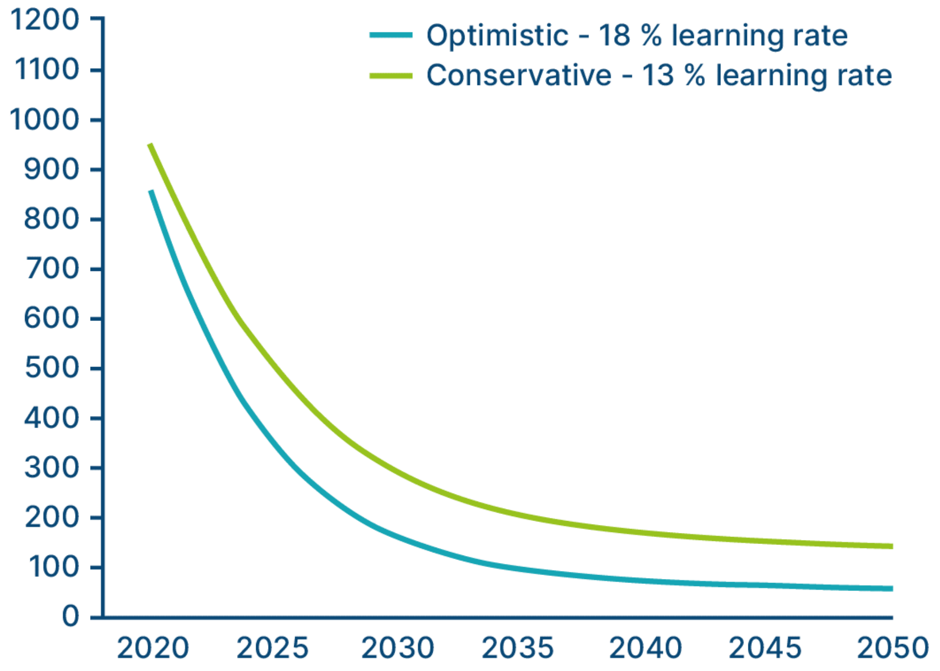
Forecast period: 2019 (first value); Future (c. 2050) (second value)

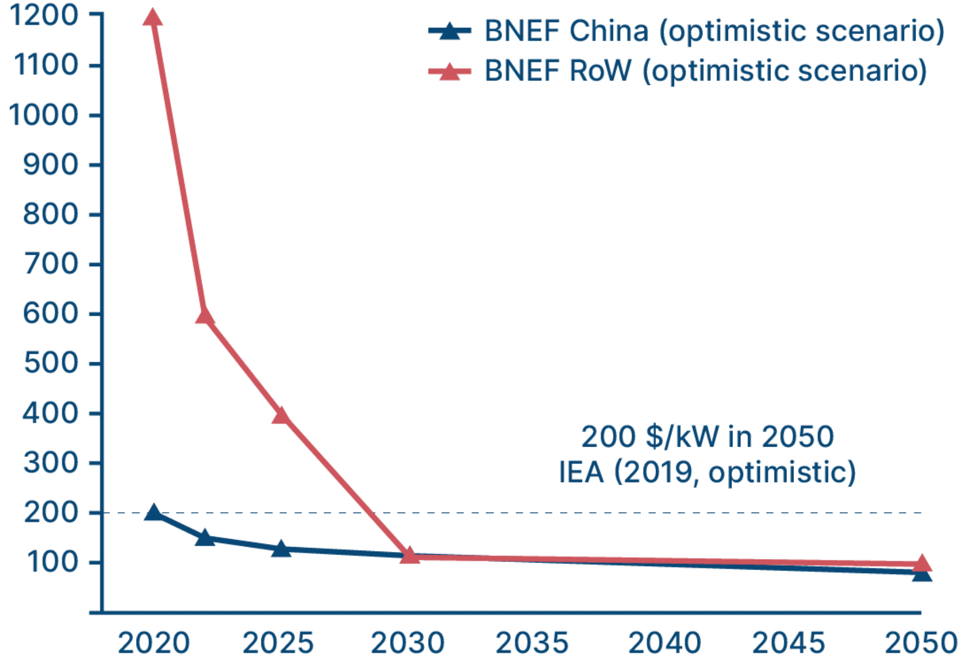
NOTES: [1] Capacity is "per unit" – ie. one salt cavern. Costs of hydrogen storage depends significantly on cycle rate (ie. how often the gas is filled and withdrawn). Geological storage of hydrogen is limited in how fast gas can be withdrawn (ca. 1 month for salt cavern).

SOURCE: IEA (2019), *Future of Hydrogen*; BloombergNEF (2019), *Hydrogen – the economics of storage*

Green hydrogen production costs are expected to fall driven by both falling costs of electrolysers and continued declines in renewable electricity prices

Fully installed system capex forecast of large alkaline electrolysis projects
US$/kW





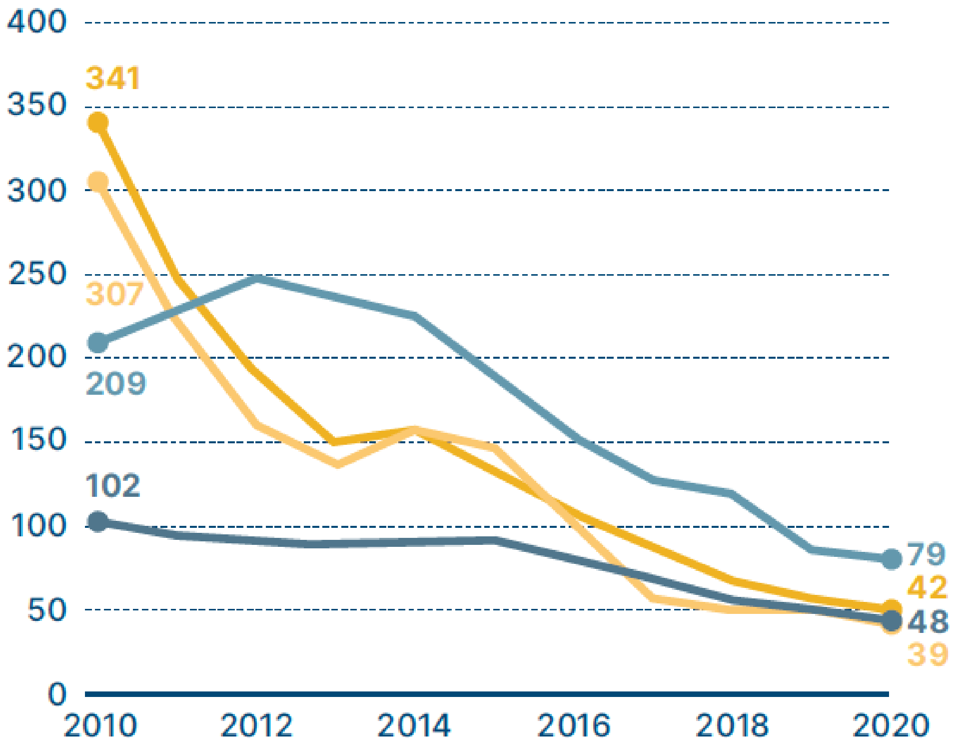
Electrolyser capacity (GW)	15	225	1300	3300	5500	7800

NOTES: CAPEX figures include full installation costs for a large scale (>20 MW) alkaline electrolyser including stack, balance of plant (power electronics for voltage transformation, hydrogen purification and compression), construction and mobilisation and soft costs (project design, management, overhead, contingency and owners cost). There are significant differences in electrolyser CAPEX forecasts likely related to differences in definitions of what is included/excluded in quoted figures and differences in system size (costs decline significantly with order and module size). Hydrogen Council suggests electrolyser CAPEX could drop to about $200-250/kW (IRENA: $360/kW in Transforming Energy Scenario) by 2030 at the system-level but do not include installation and assembly, building, indirect cost.

SOURCES: BloombergNEF (2019), *Hydrogen – Economics of production from renewables*; BloombergNEF (2021), *1H2021 Hydrogen Market Outlook*; Hydrogen Council (2021), *Hydrogen Insights*; IRENA (2020), *Green hydrogen cost reduction*; Expert interviews.

Wind and solar LCOE have dramatically decreased in the last 10 years with latest lowest auction prices for solar PV below $20/MWh

PV and wind LCOE global benchmarks
LCOE, $/MWh, 2019 real



Lowest auctions prices

Portugal: $13.2/MWh (lowest offer) (Aug 2020)
India: $38/MWh for Solar + batteries delivering 80% of hours per year (June 2020)
Abu Dhabi: $13.5/MWh (lowest offer) for 2 GW (April 2020)
Qatar: $15.7/MWh for 800 MW (Jan 2020)
Saudi Arabia: $16.9/MWh for 900 MW (2019)
Portugal: $16/MWh for 1.4 GW (July 2019)

UK: $51/MWh (£39.7/MWh) for 6 GW (2019)
France: $48/MWh for 600 GW (2019)

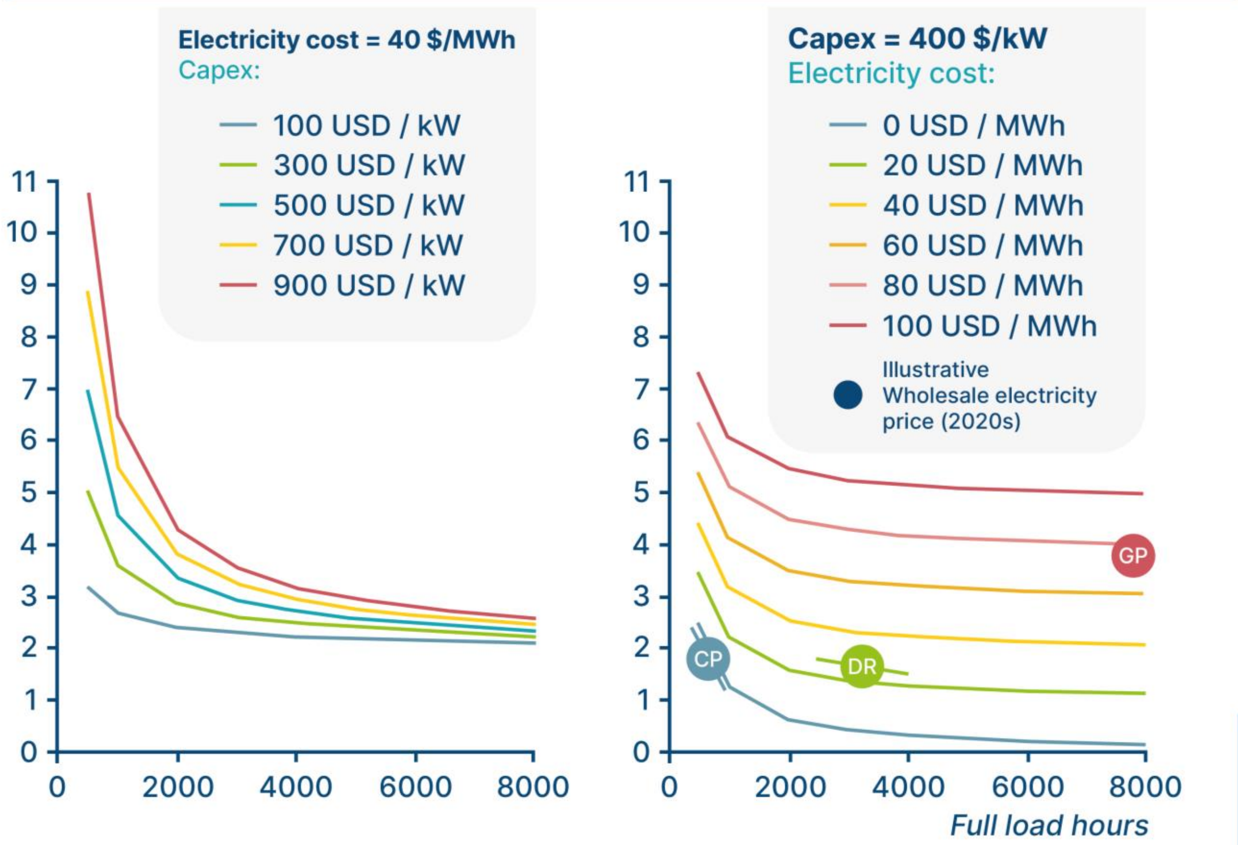
Chile: $32.5/MWh for 240 MW (mixed with solar and geothermal)
US: average wind price at $20/MWh (2017)
Mexico: $20.6/MWh for 250 MW (2017)

LEFT-HAND SIDE: the global benchmark is a country weighted-average using the latest annual capacity additions.
RIGHT-HAND SIDE: economics of auction prices may be favoured by local tax treatments and other implicit subsidies.

SOURCE: Press research, BloombergNEF (2020), *2H 2020 LCOE update*

Electricity cost is key determinant of green hydrogen cost above ca. 2000 hours annual electrolyser utilisation; dedicated renewables likely best source of zero-carbon power

Green hydrogen production costs
$/kg



Electricity sources for green hydrogen production – commentary

DR **Dedicated renewables: reasonable load hours (> 2k)** and **competitive electricity cost** (below $20/MWh in future), likely H_2 market price for will be set by H_2 price when produced with dedicate renewables

CP **Curtailed power volumes will develop if electrolyser CapEx declines considerably** (e.g., to $200/kW)

Increased variable renewables results in higher number of hours with cheap power (curtailment)

GP Given **higher average electricity price, grid power** would likely not be used Load hour advantage (100%), but minimal costs benefits above ~2k hours

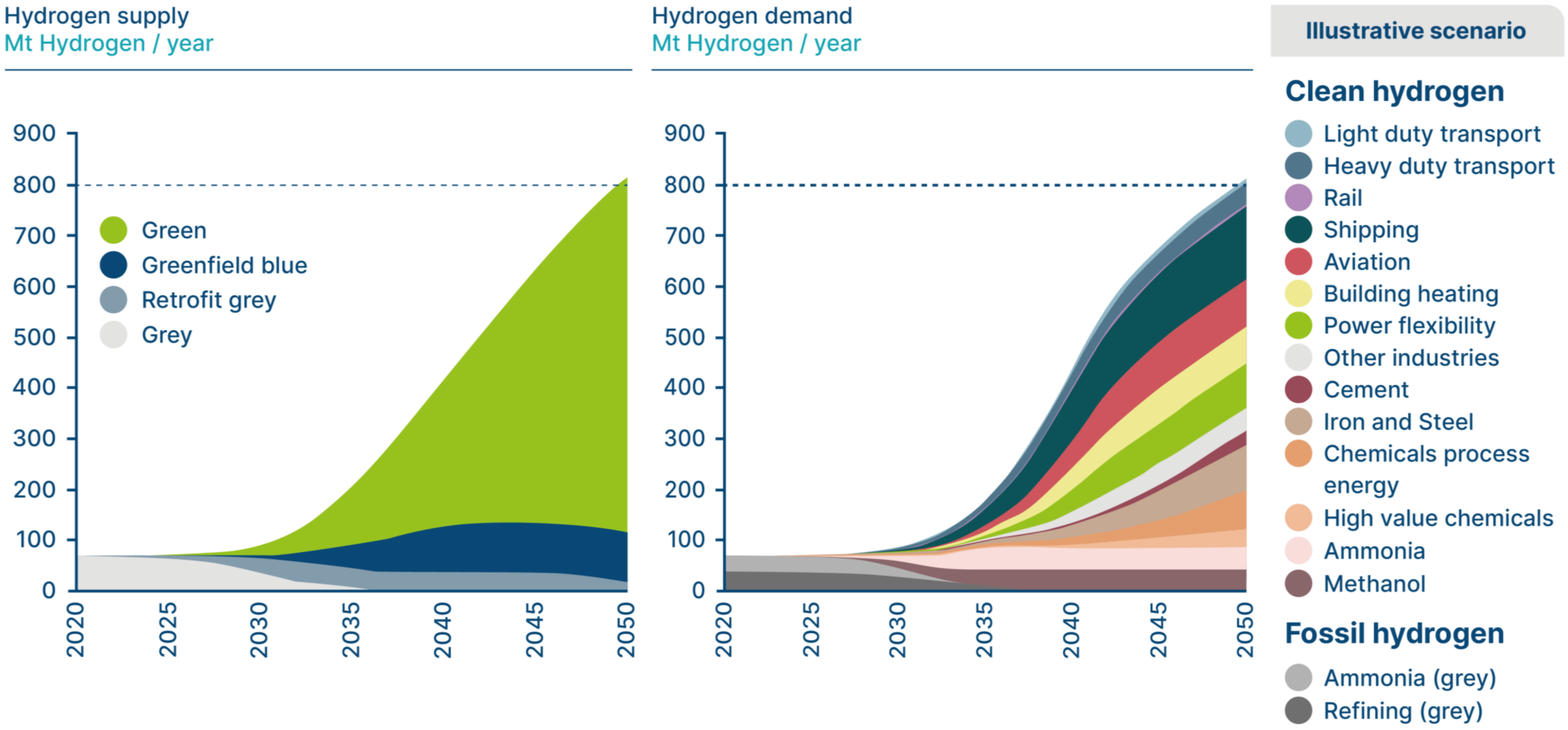
Note, in a renewables dominated power system (as discussed in the ETC's clean electrification report) **curtailed power** and **grid power** will start to overlap and merge, with electrolysers able to support grid balancing by **offering flexible demand** at times of over-supply

NOTES: Electricity consumption 48 kWh/kg, Electrolyser lifetime = 25 years, Discount rate = 8%

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2020) based on IEA (2019), *The Future of Hydrogen*

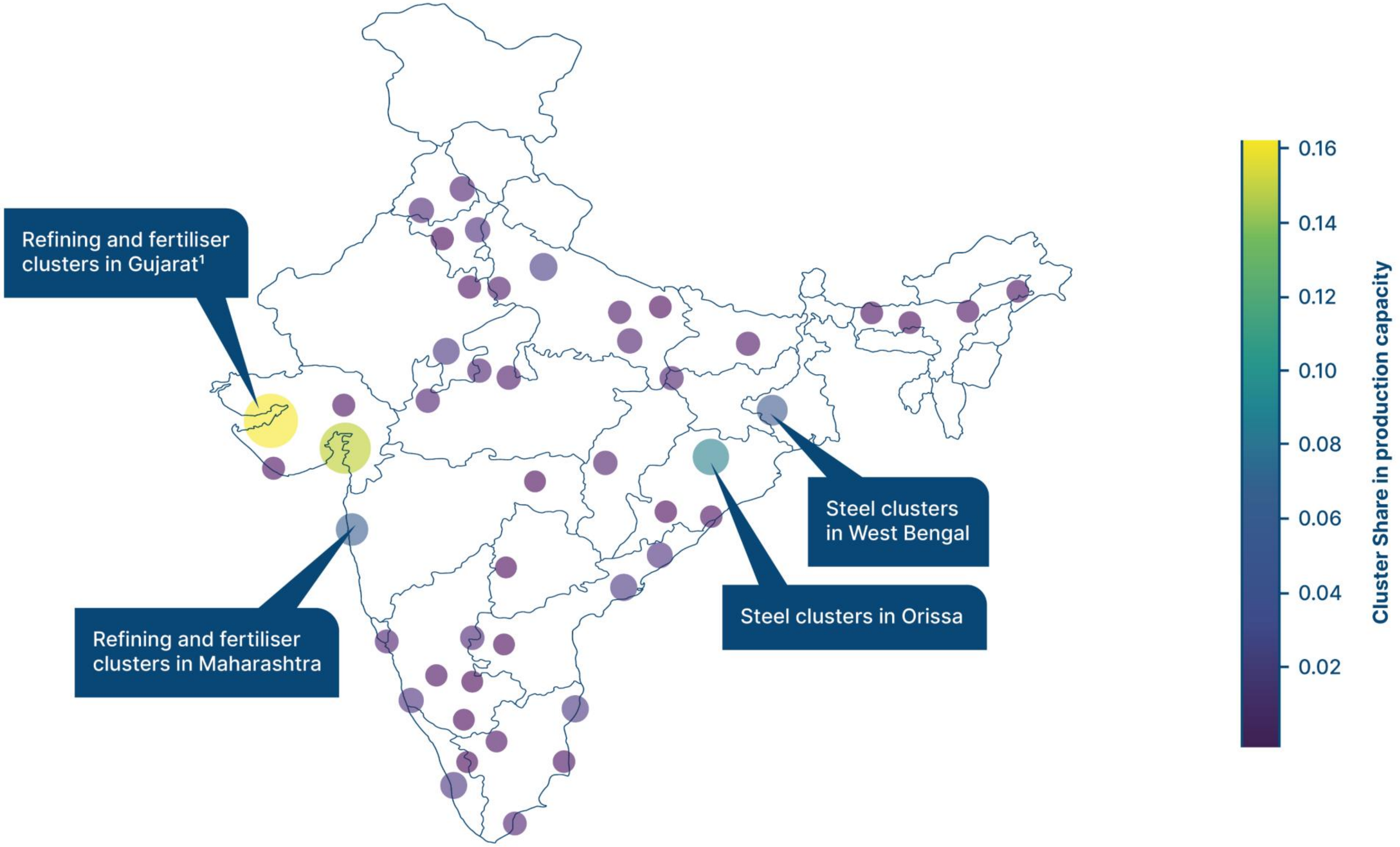
In a mass-electrification scenario, what could the scale-up of the hydrogen economy look like?

Scenario 2: ~85% 2050 supply green, ~15% blue



SOURCE: SYSTEMIQ analysis for Energy Transitions Commission (2021)

India 'clusters' example – spatial analysis identified 46 favourable clean hydrogen industrial cluster locations



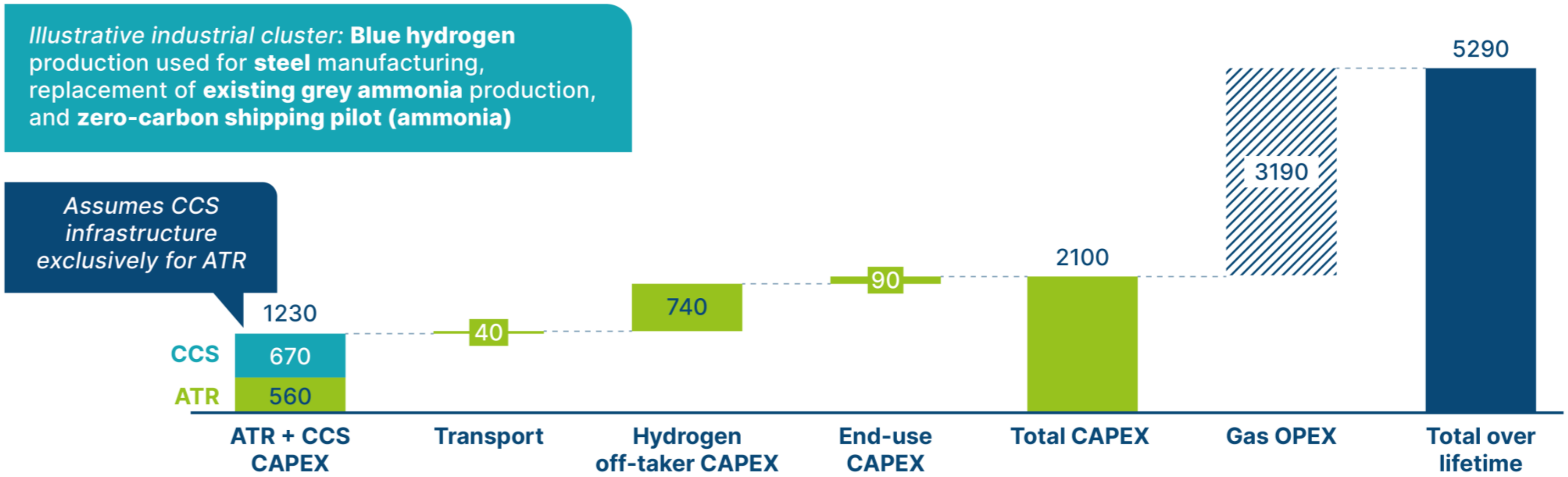
NOTES: [1] There is also a significant chlor-alkali industry in Gujarat which may offer by-product clean hydrogen for these clusters.

SOURCE: TERI/ETC India analysis published in TERI (2020), *The Potential Role of Hydrogen in India*

Lower CAPEX investments in blue hydrogen industrial cluster are balanced by higher OPEX from natural gas feedstock

Total investment cost for greenfield blue hydrogen industrial cluster excl. financing costs (2020s)
$ million

Blue H_2



	ATR + CCS CAPEX	Transport	Hydrogen off-taker CAPEX	End-use CAPEX	Total CAPEX	Gas OPEX	Total over lifetime
Industrial cluster description	625 MW ATR+ CCS (greenfield)	100 km distribution pipe	1 Mt steel plant + 0.23 Mt ammonia plant (1/3 for shipping)	Ammonia storage, bunker vessel and 3 retrofitted carriers		30 years natural gas at $5/MMBtu	
Potential bottlenecks	Lack of long term carbon storage (CCS infrastructure)		Significant investment for industry players with highly leveraged balance sheets	Ship retrofitting			

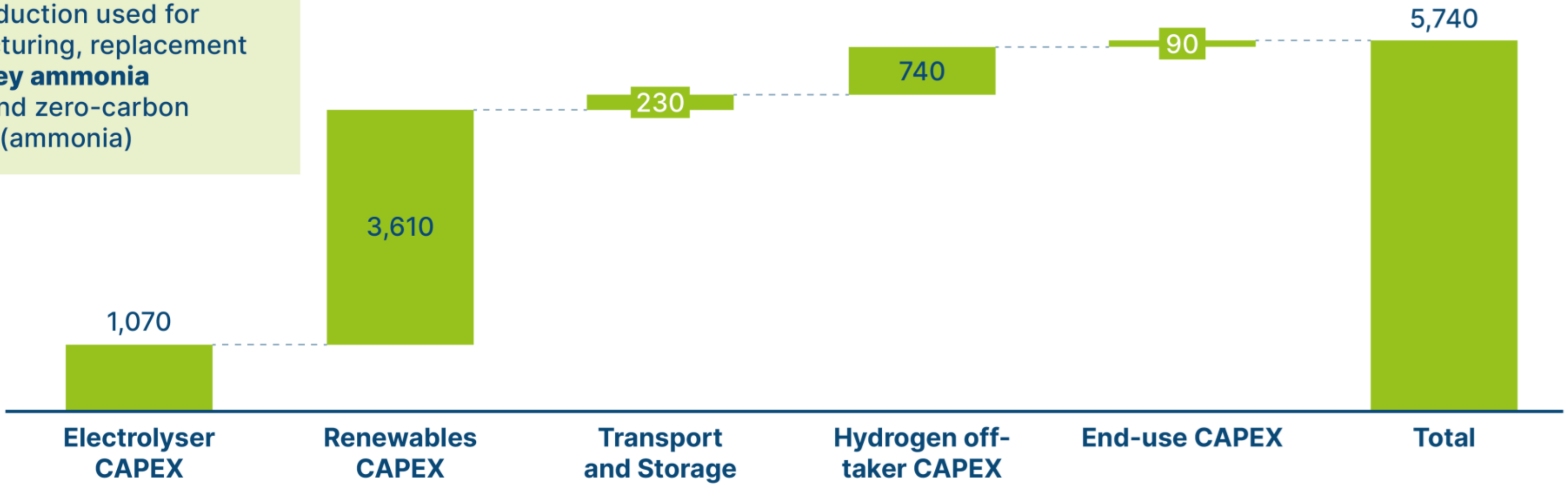
SOURCES: SYSTEMIQ analysis for the Energy Transitions Commission (2021); Element Energy and Jacobs (2018), *Hydrogen supply chain evidence base*; BloombergNEF (2019), *Hydrogen - the economics of storage and Hydrogen - the economics of transport & delivery*

Renewables and electrolyser for hydrogen production ~80% of investment for a green hydrogen industrial cluster

Total investment cost for greenfield green hydrogen industrial cluster excl. financing costs (early 2020s)
$ million

Green H_2

Illustrative industrial cluster: **Green hydrogen** production used for **steel** manufacturing, replacement of **existing grey ammonia production**, and zero-carbon shipping pilot (ammonia)



	Electrolyser CAPEX	Renewables CAPEX	Transport and Storage	Hydrogen off-taker CAPEX	End-use CAPEX
Industrial cluster description	1.3 GW electrolyser ($850/kW)[1]	1.9 GW renewables (PV+wind)[2]	100 km distribution pipe + 2,500 t salt cavern	1 Mt steel plant + 0.23 Mt ammonia plant (1/3 for shipping)	Ammonia storage, bunker vessel and 3 retrofitted carriers
Potential bottlenecks		VRE space requirements	Lack of geological hydrogen storage	Significant investment for industry players with highly leveraged balance sheets	Ship retrofitting and engine availability

NOTES: Total investment would be $2,130 million if renewables CAPEX were not considered. Power OPEX for corresponding levelized cost of electricity ($27/MWh) would amount to ca. $4.470 million corresponding to ca. 2x the total CAPEX investments. [1] Assumptions: 53 kWh/kg hydrogen, 50 % capacity utilisation factor; [2] Assumption: 33 % photovoltaics, 53% onshore wind, 13% offshore wind.

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021); BloombergNEF (2019), *Hydrogen - the economics of storage* and *Hydrogen - the economics of transport & delivery*

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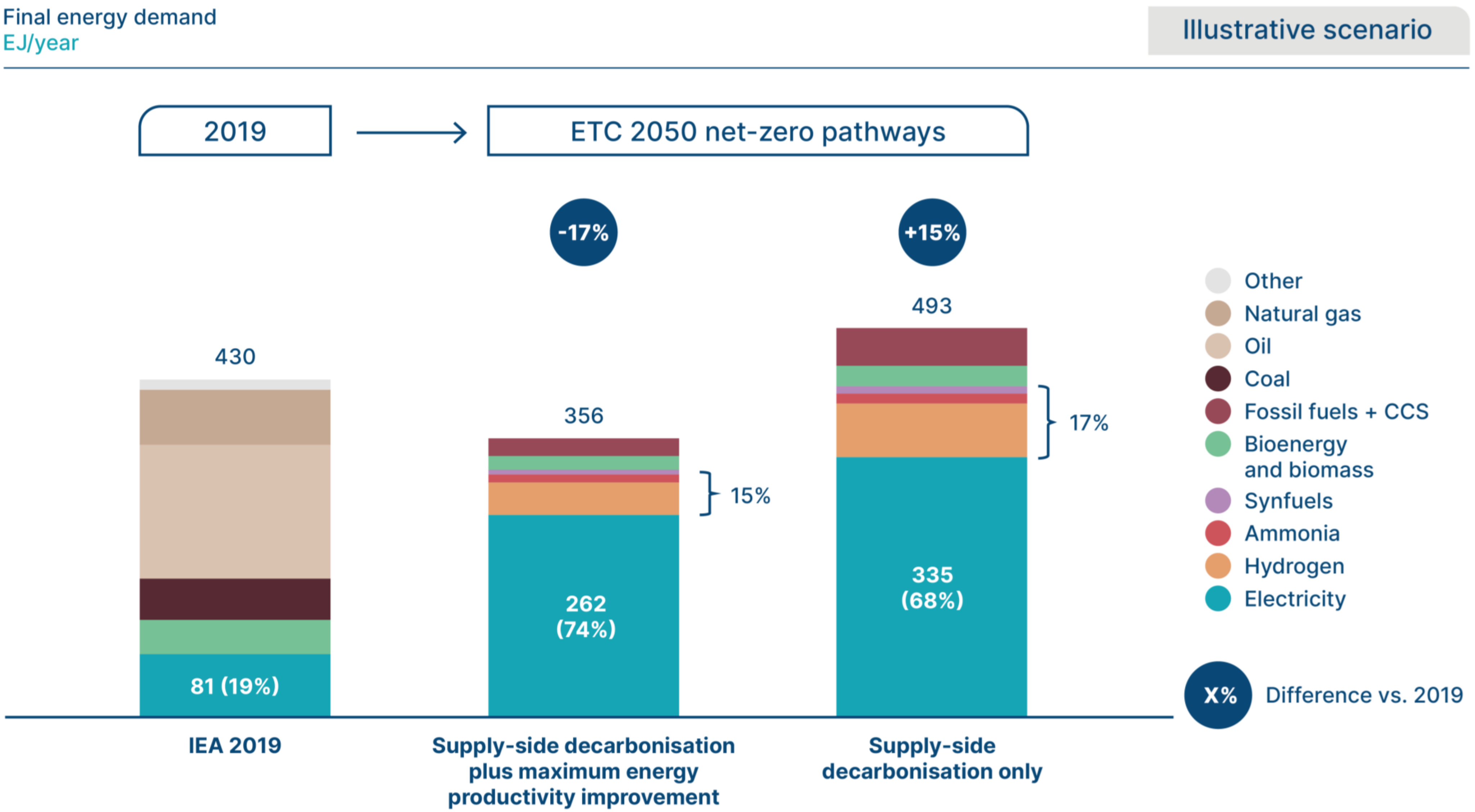
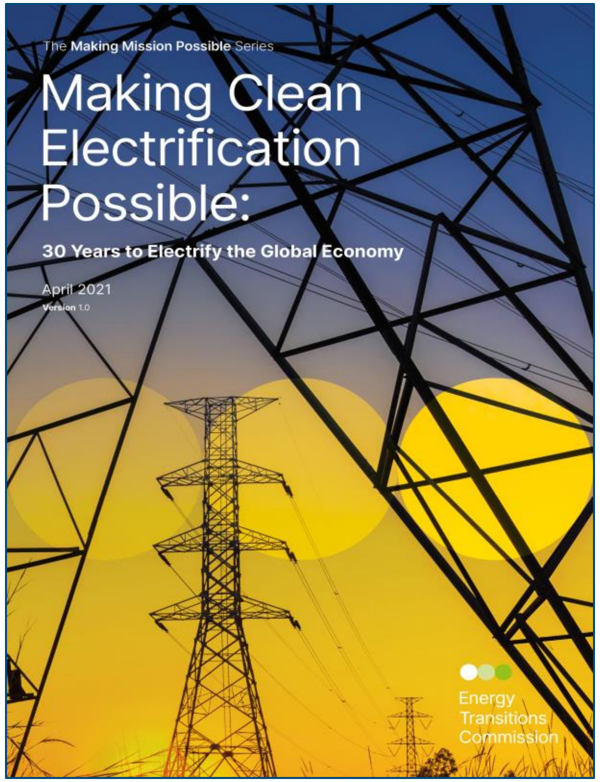
A net-zero global economy is technically and economically possible by mid-century, but we need to act in the 2020s to put mid-century targets within reach.

Final energy mix in a zero-carbon economy: electricity will become the dominant energy vector, complemented by hydrogen and fuels derived from it

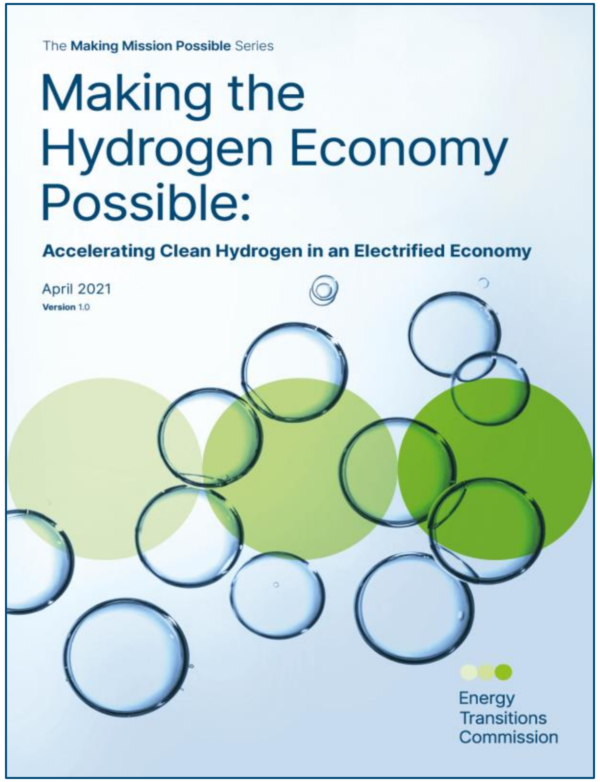


Source: SYSTEMIQ analysis for the Energy Transitions Commission (2021); IEA (2020), *World Energy Outlook*

Global energy programme: Three reports exploring how to scale zero-carbon energy systems and a consultation paper exploring the role of carbon dioxide removals



April



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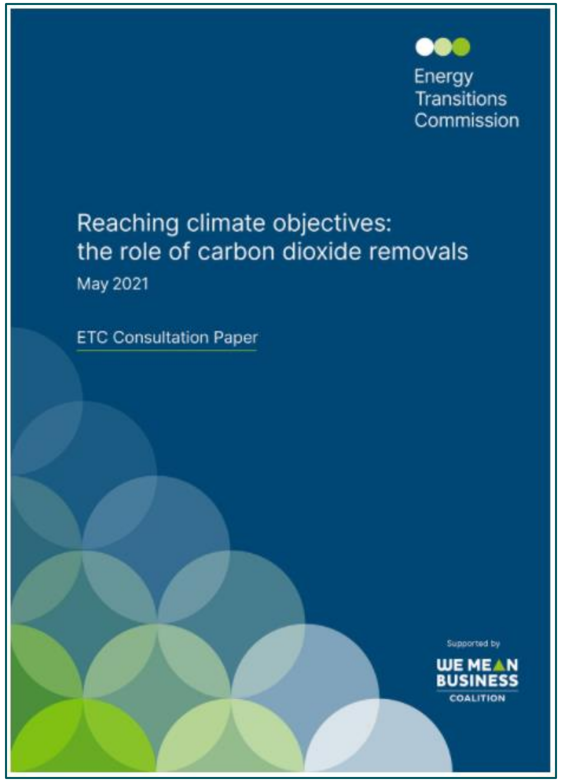

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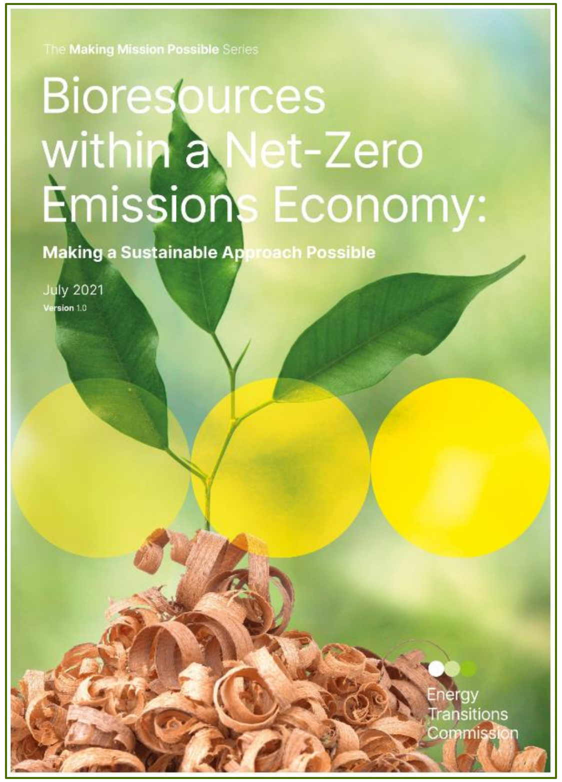
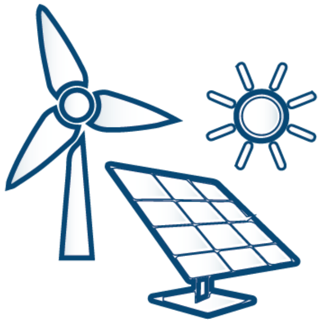


July

The Making Mission Possible Series

Scaling the underlying decarbonisation technologies to meet mid-century net-zero economy needs



Clean electrification

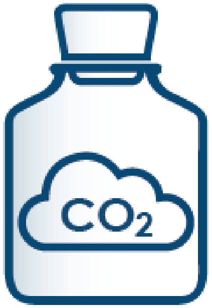
Massive clean electrification at the heart of a net-zero emissions economy: global power system growing 3.5-5x and simultaneously decarbonising

Hydrogen

Major, complementary role for clean hydrogen alongside clean electrification, with 5-7x increase in global hydrogen production

Bio-energy

Prioritised, and tightly regulated use of constrained supply of sustainable, low-carbon bio resources



Fossil + CCU/S

Essential but limited role for fossil energy combined with carbon capture and storage (c.5-8 GtCO_2 p.a.)

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

Hydrogen

Major, complementary role for clean hydrogen alongside clean electrification, with 5-7x increase in global hydrogen production

1. **A vision for 2050: Hydrogen’s role in a zero-carbon, deeply electrified economy**
2. **Scale-up challenges, required actions and investments**
3. **Critical policy and industry actions in the 2020s**

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

Hydrogen

Major, complementary role for clean hydrogen alongside clean electrification, with 5-7x increase in global hydrogen production

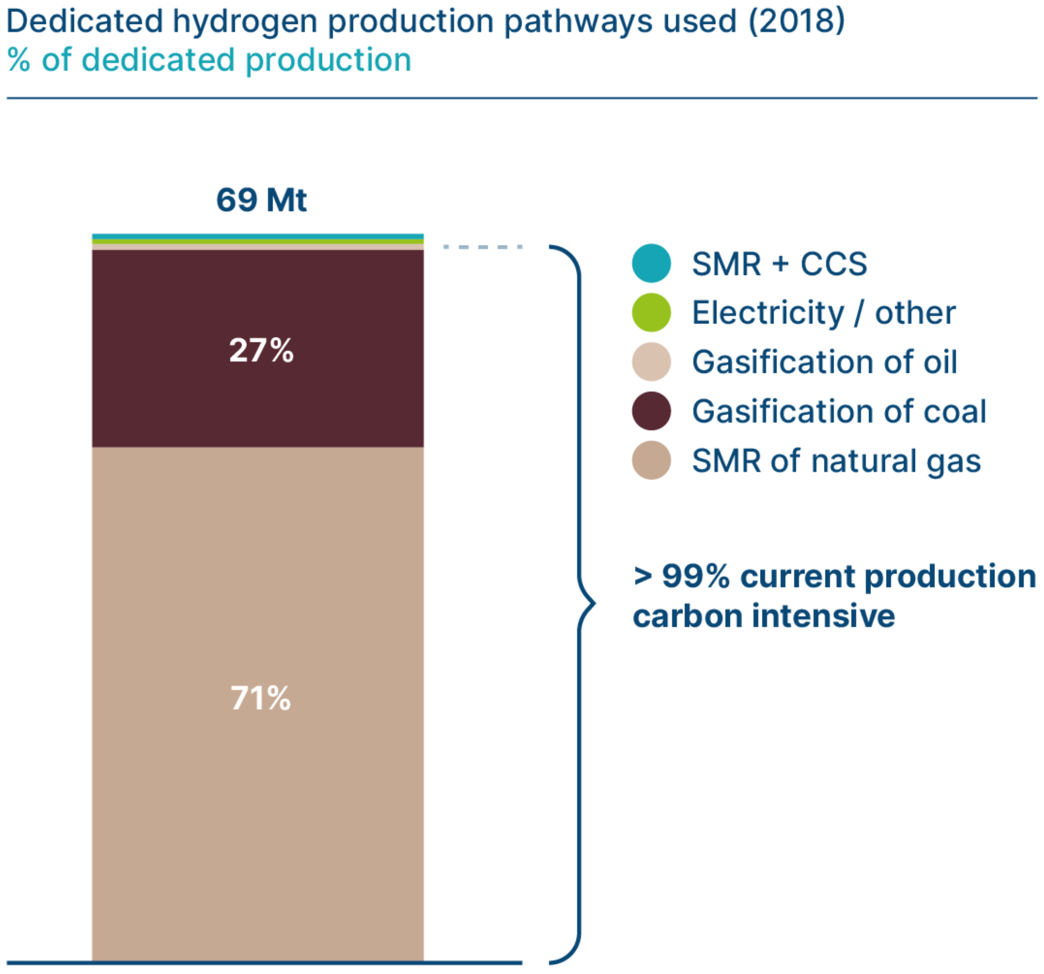
1 A vision for 2050: Hydrogen's role in a zero-carbon, deeply electrified economy

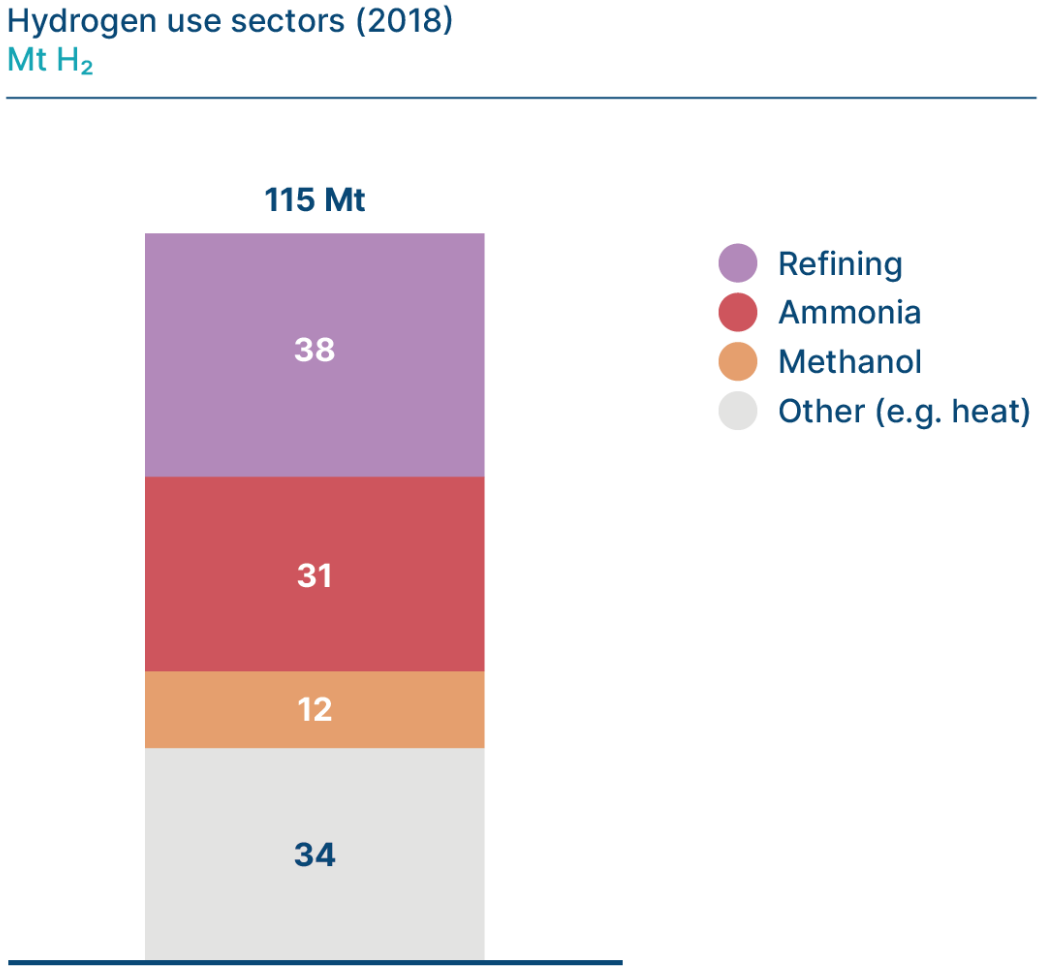
- The situation today and potential demand growth
- Falling production costs and implications for the cost of decarbonisation
- Transport, storage and international trade of hydrogen

2 Scale-up challenges, required actions and investments

3 Critical policy and industry actions in the 2020s

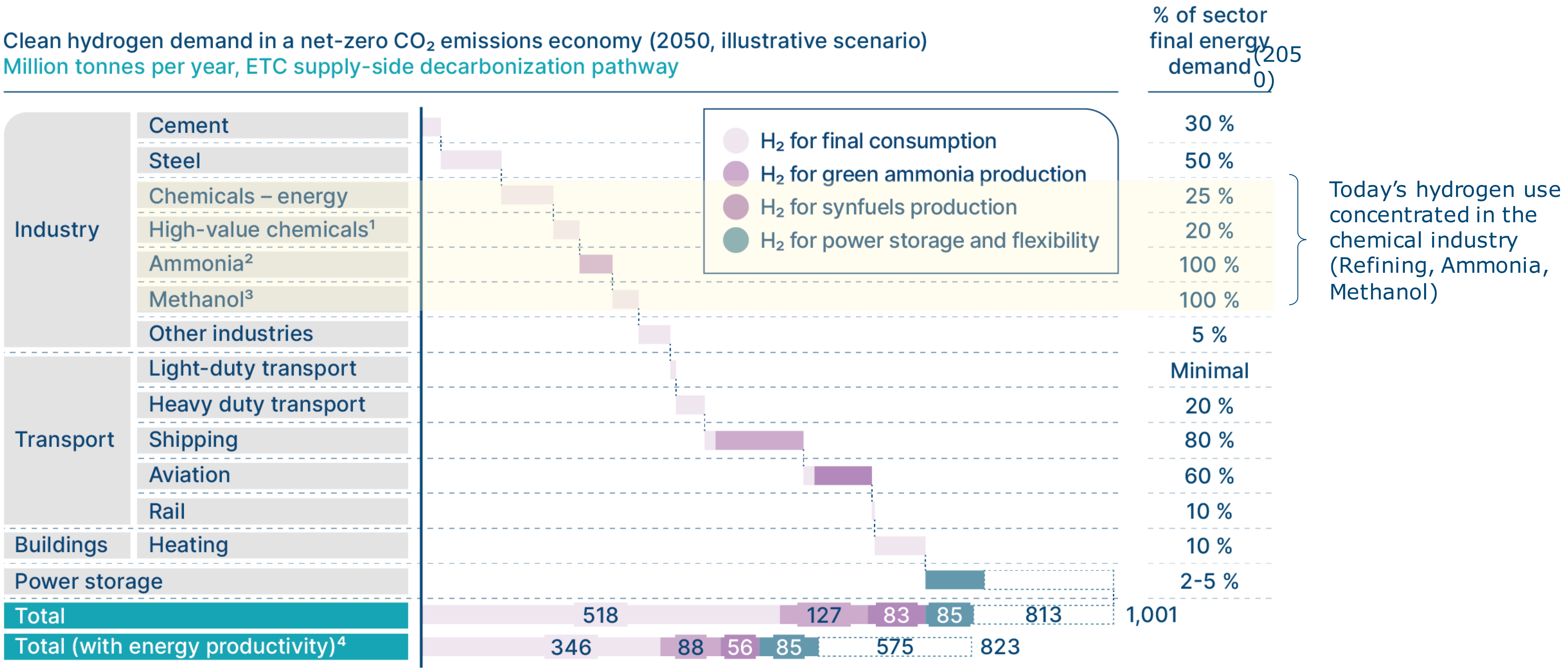
Today's production of hydrogen is via carbon-intensive processes; use of hydrogen concentrated in the chemical industry (Refining, Ammonia, Methanol)





SOURCE: IEA (2019), *The Future of Hydrogen*

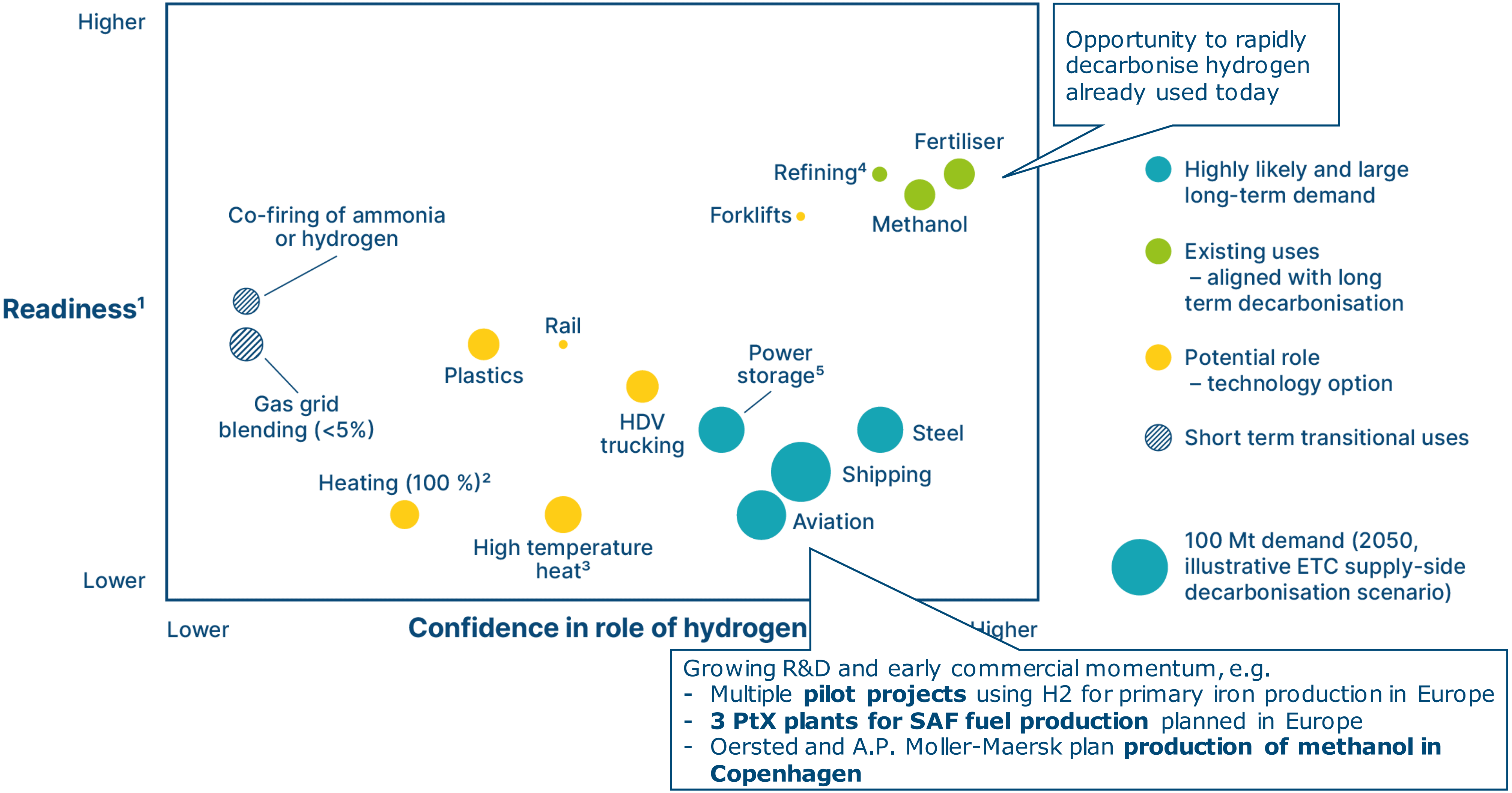
Clean hydrogen will play a growing role across the economy as the world transitions towards net-zero



NOTES: [1] High value chemicals predominantly used to produce plastics, which could potentially be produced via Hydrogen and CO_2 in the future (via methanol and MTO process); [2] Around 80% of ammonia (excl. shipping) is used to produce fertilisers; [3] Methanol is used as intermediate in numerous chemical processes, including plastics production. [4] ETC scenario including maximum energy productivity improvements.

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

Beyond existing uses: multiple potential uses of hydrogen in a low carbon economy, could reach 500-800 Mt of p.a. by mid-century



NOTES: [1] Readiness refers to a combined metric of technical readiness for clean hydrogen use, economic competitiveness and ease of sector to use clean hydrogen. [2] 'Heating (100%)' refers to building heating with hydrogen boilers via hydrogen distribution grid, [3] 'High temperature heat' refers to industrial heat processes above ca. 800°C [4] Current hydrogen use in refining industry is higher due to greater oil consumption. [5] Long-term energy storage for the power system.

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

Multiple potential clean hydrogen production pathways; however, two pathways likely to dominate hydrogen scale-up in coming decade

Clean H_2 production pathways:

Priority production pathways: Green Blue

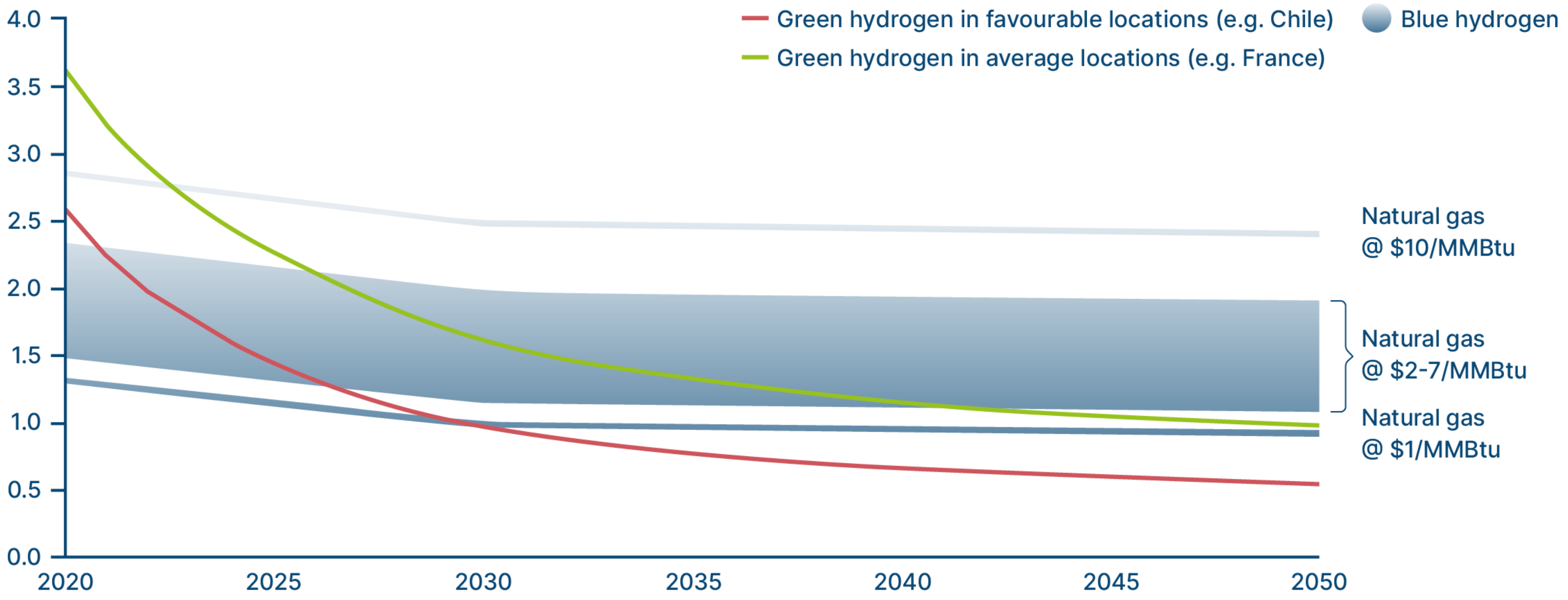
See technical annex for further information

H_2 Source input	Additional inputs	Process	CCS required? (*neg. emissions)	Reason for prioritization / de-prioritization
Natural Gas +	Power[1] + water	Steam methane reforming (SMR)	+ CCS	Commercially available and deployed in pilots/few commercial plants (<5); commonly employed with only 60 % capture rate today; higher capture rates more expensive
	Power[1] (heat produced in reformer) + water	Autothermal reforming (ATR)	+ CCS	Commercially available and deployed in pilots; typically larger plant scale, high CO_2 recovery rates & lower CCS costs due to concentrated CO_2
	Power[1] + oxygen (no combustion)	Chemical looping	+ CCS	Low TRL (~100kW); no investment from industry
	Power[1] + oxygen	Partial oxidation (POX)	+ CCS	Similar to ATR, commercially available, high CO_2 capture & lower CCS costs, more flexible on feedstock, lower purity hydrogen product
	Power[1] (no oxygen)	Pyrolysis (methane splitting)		Some promising technology at lab/pilot scale; lower TRL; no CO_2 emissions during process; option to sell by-product 'carbon-black'
Liquid hydro-carbons +	Power[1] + oxygen	Partial oxidation	+ CCS	Upgrading of residual refinery hydrocarbons to hydrogen. Overall smaller volumes with declining role towards mid-century
Coal +	Power[1] + oxygen + water (partial combustion)	Coal gasification	+ CCS	Lower process efficiency than SMR; higher carbon emissions per kg hydrogen therefore CCS more expensive
Biomass +	Power (no oxygen)	Pyrolysis	+ CCS*	Constrained by limited sustainable, low-lifecycle carbon bio-resources
	Power + oxygen + water (partial combustion)	Biomass gasification	+ CCS*	Complex processing, more expensive than alternative routes (especially given high biomass collection costs), with low TRL
	Microorganisms (no oxygen)	Bio-chemical		Biomass has lowest hydrogen to carbon ratio from all feedstocks, hence highest CO_2/H_2 emissions
Biogas +	Power + water	Biomethane reforming	+ CCS*	However combined with CCS could create "negative emissions" – may have a long-term local role where sustainable biomass available
Water +	Power	Electrolysis		Declining costs of renewable power, and equipment costs decline with scale - 'zero-carbon hydrogen' feasible
	Nuclear power	Thermochemical water splitting		Low TRL (lab-scale), large advancements in tech required, high cost uncertainty
	Solar power	Solar-chemical water splitting		

NOTE: [1] Power input depends on plant design and CO_2 capture. Power often provided through combustion of fossil input.

Green hydrogen from electrolysis likely to become cheapest clean production route in the long-term, in favourable locations it could be competitive with blue in the 2020s

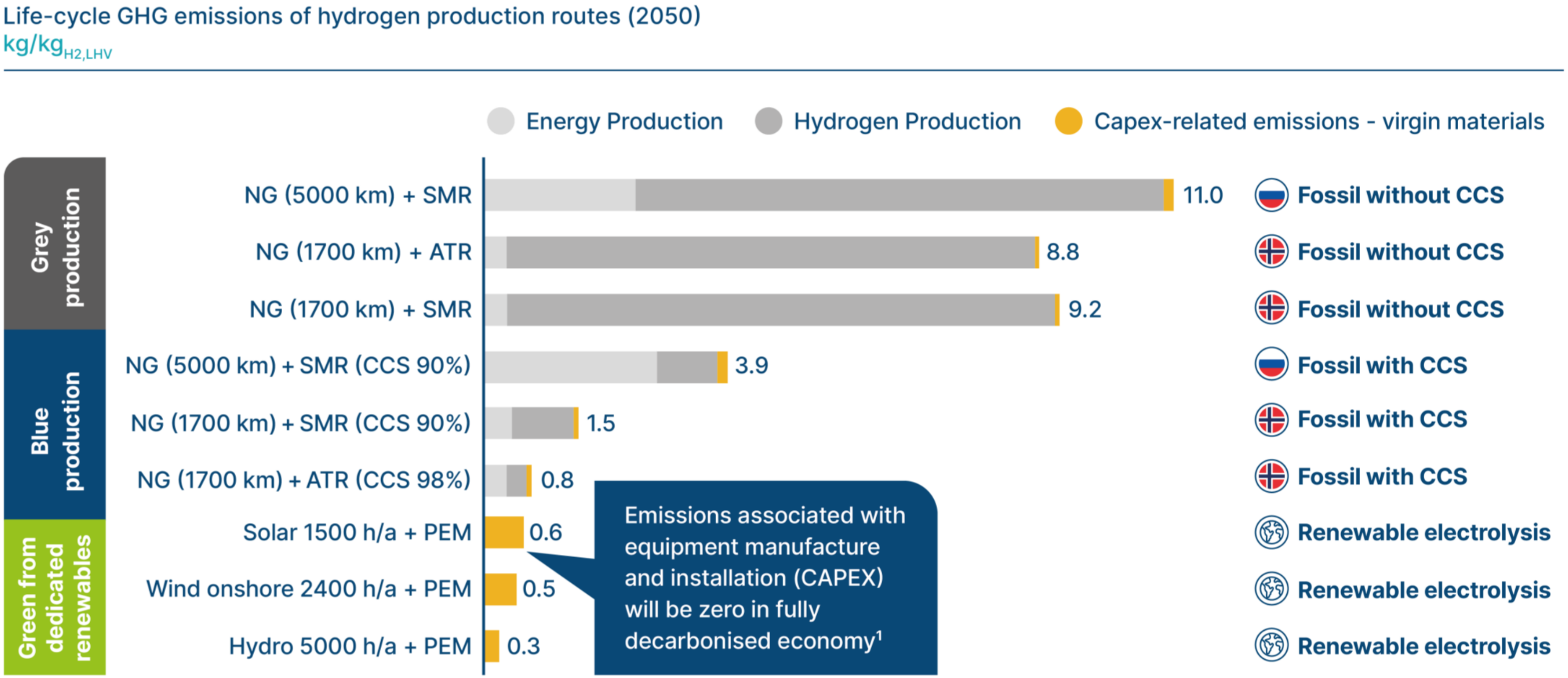
Cost of hydrogen production from different production routes (excluding transport & storage costs)
$/kg H_2



NOTES: Blue hydrogen production: i) forecast based on SMR+CCS costs (90% capture rate) in 2020 transitioning to cheaper ATR+CCS technology in the 2020s; Green hydrogen production: i) favorable scenario assumes average LCOE of PV and onshore wind of lowest 33% locations (falling from $22/MWh in 2020 to $10/MWh in 2050) and average scenarios assumes median LCOE from lowest 75% locations (falling from $39/MWh in 2020 to $17/MWh in 2050) from BloombergNEF forecasts, ii) additional 20% (favorable) and 10% (average) LCOE savings included due to directly connecting dedicated renewables to electrolyser, iii) 18 % learning rate for favorable & 13 % for average scenario. Electrolyser capacity utilization factor: 45%. Comparison to BloombergNEF most favorable ($0.55/kg) and average ($0.86/kg) and Hydrogen Council favorable (ca. $0.85/kg) and average (ca. $1.45/kg) in 2050.

SOURCE: BloombergNEF (2021), *Natural gas price database* (online, retrieved 01/2021), BloombergNEF (2020), *2H 2020 LCOE Data Viewer*; BloombergNEF (2021), *1H2021 Hydrogen Levelised Cost Update*; Hydrogen Council (2021), *Hydrogen Insights*

Beyond costs, it is essential that 'clean' hydrogen is truly clean: for blue, upstream natural gas production, methane 'leakage', and capture rates drive bulk of emissions; for green, emissions are associated with electricity generation

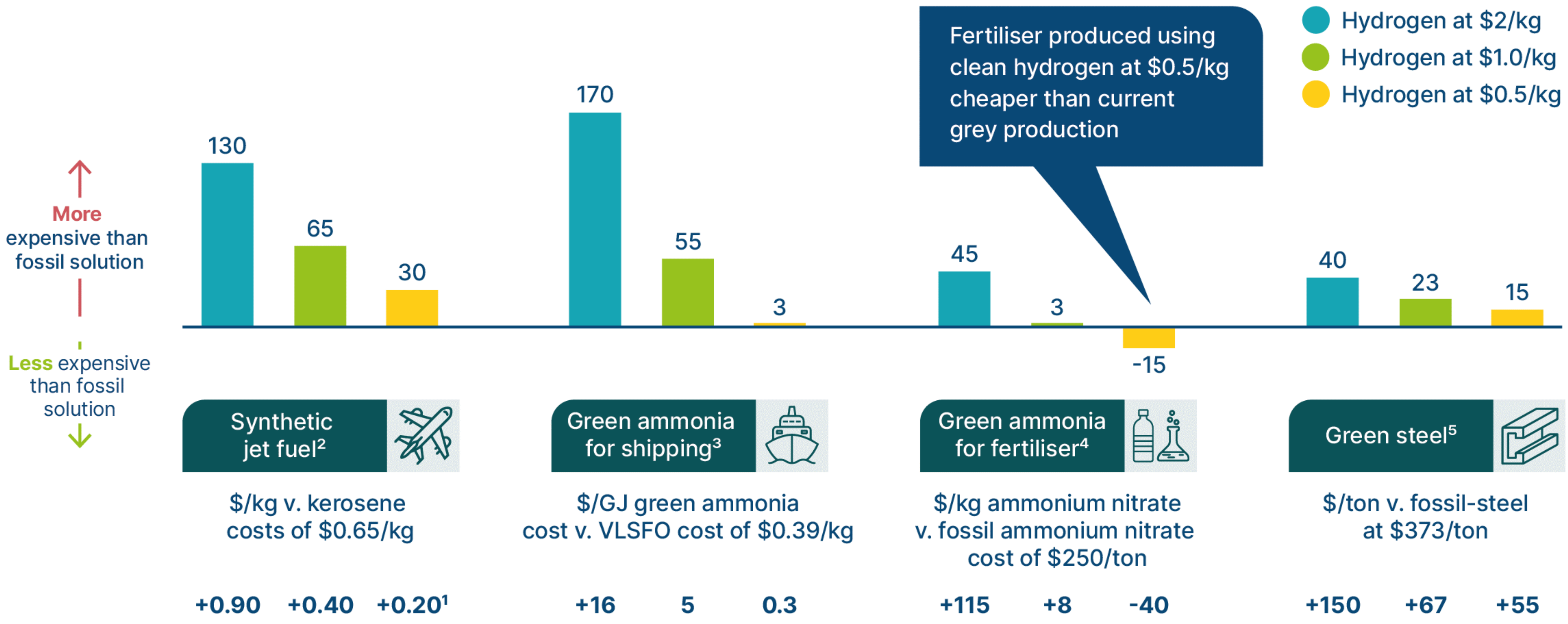


NOTE: Energy production category includes upstream methane emissions; equals leakage rates of ca. 0.15-1.2 % based on natural gas source and transport distance; H_2 production refers to process emissions from SMR/ATR; [1] GHG emissions for CAPEX due to carbon emissions associated with grid electricity used to manufacture equipment.

SOURCE: Adapted with permission from Hydrogen Council and LBST(2021), *Hydrogen decarbonization pathways – A life-cycle assessment*

Even at very low clean hydrogen costs (e.g. $0.5/kg), majority of hydrogen technologies more expensive than current fossil technologies

'Low carbon' premium for products produced with clean hydrogen vs. existing fossil solution[1]
%, increase/decrease compared with fossil solution



NOTES: [1] Cost premium calculated with illustrated delivered hydrogen cost. If close to 0, no premium would be required. [2] CO_2 feedstock cost of $215/ton. SAF production cost compared to kerosene market price. [3] Green ammonia production cost compared to very low sulphur fuel oil (VLSFO) market price. [4] Compared to ammonium nitrate production cost.
[5] Hydrogen-DRI combined with electric arc furnace compared to production cost of coke-fired blast-furnace with basic oxygen furnace fossil steel.

SOURCES: World Economic Forum and McKinsey for Clean Skies for Tomorrow (2020) - *Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation*; Expert interviews

However, while use of clean hydrogen would have a significant impact on the price of intermediate products, but a negligible impact on final product prices in most sectors

Hydrogen technology at $2/kg H_2	Impact on intermediate product 1 US$ / % price increase	Impact on intermediate product 2 US$ / % price increase	Impact on end product US$ / % price increase
Steel	**+40%** Increase on a ton of steel	n/a	**+0.7%** increase on retail price of automobile
Shipping	**+160%** compared to ton of VLSFO	**+3%** increase per ton of imported soybean	**+0.8%** increase per litre of dairy milk
	+160% compared to ton of VLSFO	**+60%** increase in container freight rate	**+0.7%** increase on retail price of flat screen TV
	+160% compared to ton of VLSFO	**+60%** increase in container freight rate	**+0.4%** increase on retail price of pair of shoes
Fertiliser	**+45%** compared to ton of ammonium nitrate	**+3%** increase per ton of soybean	**+0.8%** increase per litre of dairy milk
	+45% compared to ton of ammonium nitrate	**+5%** increase per ton of wheat	**+0.6%** increase on price of loaf of bread
	+45% compared to ton of ammonium nitrate	**+9%** increase per ton of corn	**+3.2%** Increase in price of pork
Aviation	**+130%** compared to ton of kerosene	n/a	**+18%** increase on long-haul flight ticket price

NOTE: Calculated for 2 $/kg delivered hydrogen cost.

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

Transport, storage and international trade of hydrogen

Transport of hydrogen

- Many carrier forms (e.g., **gas, liquid, ammonia**) and technology options (**truck, pipeline, ship**)
- Most economic format depends on **volumes & distances**; **gas pipelines preferred** in most cases

Storage of hydrogen

- **Large-scale geological storage** (e.g. salt caverns) cheapest but **uneven geographical distribution** and further development needed (esp. rock caverns and depleted oil & gas fields)
- **Rapid build out required** to support growing hydrogen economy

Alternatives to hydrogen transport

- **Moving electrons**: Over long distances (>1000km) transporting electrons via HVDC transmission lines may be competitive – partly dependant on location of geological hydrogen storage
- **Moving natural gas**: Where very cheap natural gas is available, transport via existing pipelines to areas with CCS infrastructure cheaper than transport of blue hydrogen

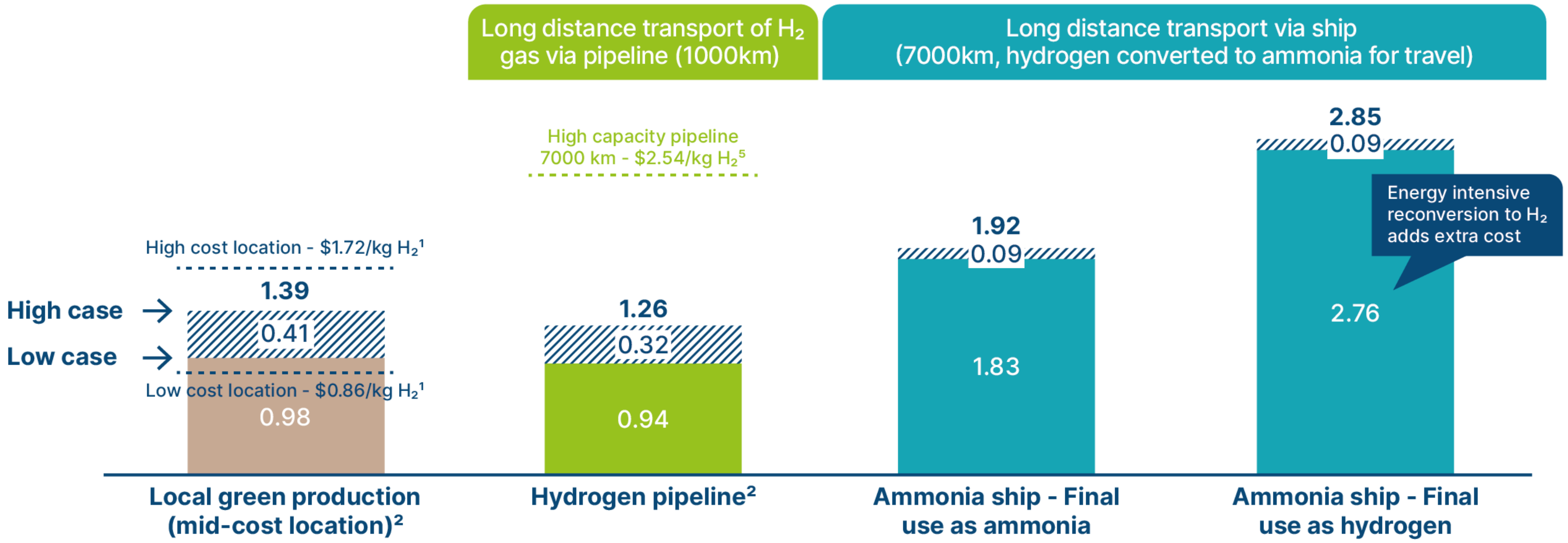
International trade of hydrogen / energy

- **Cost differential between production locations may drive trade of hydrogen**, but cost differential between low/high cost production regions decreases over time
- International trade opportunities in long-term likely limited to:
  - **Cheap high-capacity pipeline** (4000t/day), especially retrofitted
  - **Ammonia transport via ship** with ammonia end-use
  - **Renewable resource constrained** countries
- In the long-term, **shift of production sites for energy intensive processes** also likely

Example: Pipeline transport of hydrogen cheaper than shipping, in particular when end-use is hydrogen (high reconversion costs), but local green production often competitive

All-in delivered cost of hydrogen including production, transport and storage, 2050
$/kg H_2

See technical Annex for further information



	Local green production (mid-cost location)[2]	Hydrogen pipeline[2]	Ammonia ship - Final use as ammonia	Ammonia ship - Final use as hydrogen
Low case	Rock cavern storage	High capacity retrofitted pipeline (4000 t/day, 48 inches)[3]	Green production in favourable region	Green production in favourable region
High case	Tanked storage	Transmission pipeline (<1000 t/day, 13 inches)	Blue production in favourable region[4]	Blue production in favourable region[4]

NOTE: [1] Green hydrogen production + low-cost rock cavern storage; [2] Green hydrogen production takes storage costs of 50% annual demand into account. [3] Lowest cost retrofitted natural gas pipeline according to European Hydrogen backbone report. [4] Blue hydrogen production via ATR + CCS (90%+ capture rate). [5] Assuming medium levelized cost of greenfield high-capacity pipeline according to European Hydrogen backbone report.

SOURCE: BloombergNEF (2019), Hydrogen – The Economics of Transport & Delivery, Guidehouse (2020), European Hydrogen backbone. Industry interviews.

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Major, complementary role for clean hydrogen alongside clean electrification, with 5-7x increase in global hydrogen production

1 A vision for 2050: Hydrogen's role in a zero-carbon, deeply electrified economy

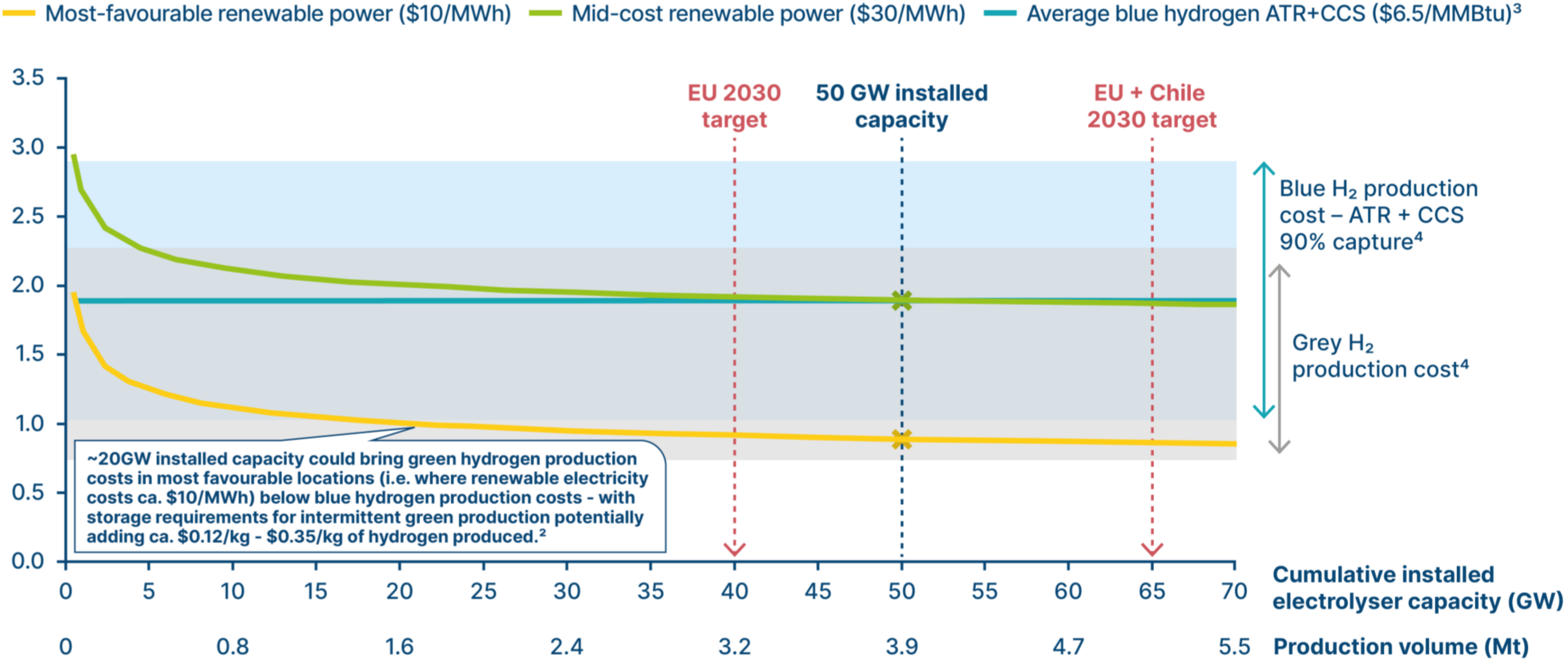
2 Scale-up challenges, required actions and investments

- Critical scale and pace of cost declines
- Feasible paths to 2050 – the need to accelerate demand growth
- Key actions to enable production ramp-up
- Developing hydrogen clusters
- Total investment needs

3 Critical policy and industry actions in the 2020s

Ca. 50 GW electrolyser capacity would unlock green production costs of $2/kg or less in ‘average’ locations, making it competitive with blue & even some grey

Green hydrogen production costs[1] (excluding storage costs[2], 2020s)
$/kg



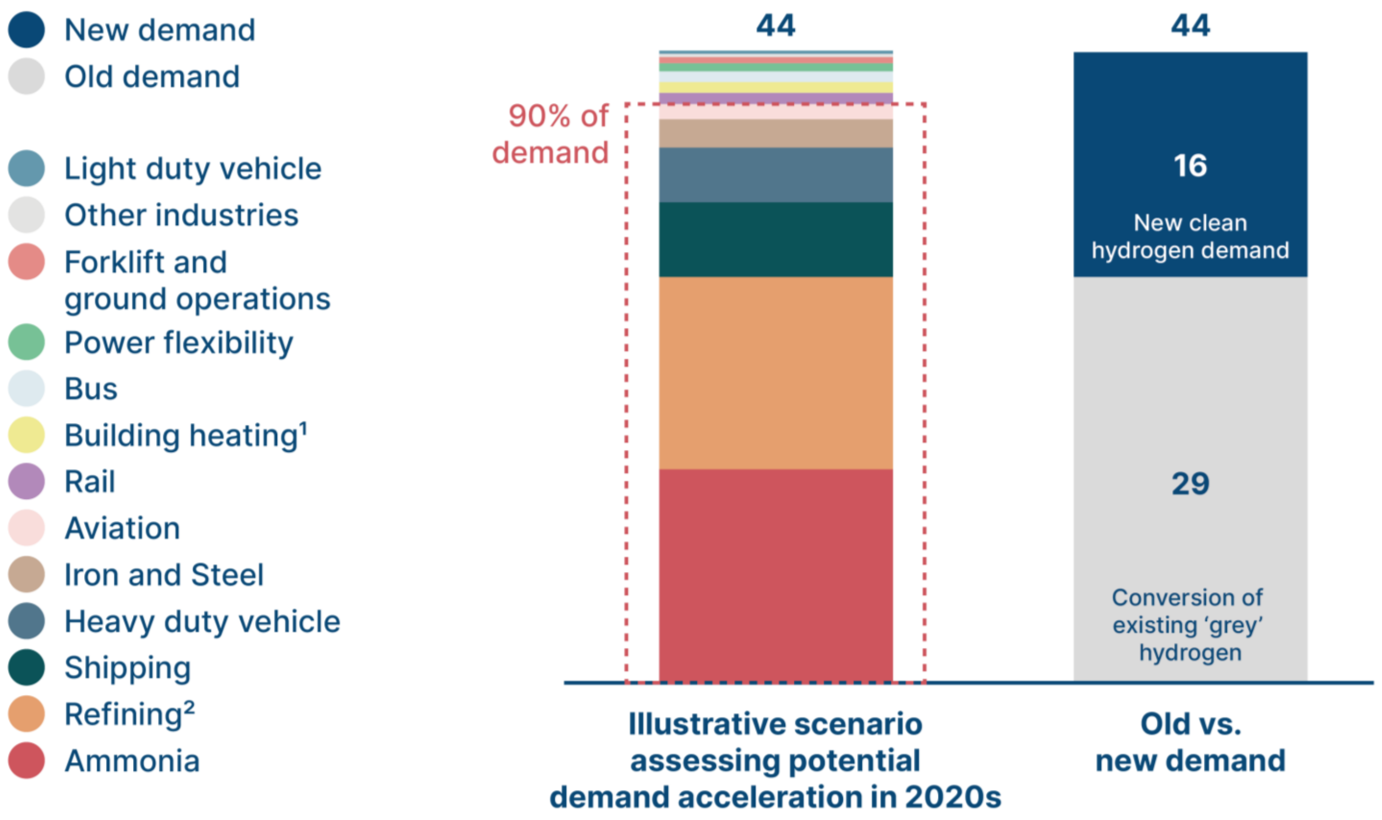
NOTES: [1] Assumptions for green hydrogen production: i) LCOE mid-cost: $30/MWh, LCOE most favourable: $10/MWh (assuming dedicated renewable power generation), 50% capacity utilisation factor, Electricity consumption: 50 kWh/kg; ii) Electrolyser CAPEX cost decline calculated based on a 18% learning rate, iii) Starting capacity in 2020: 200 MW, iv) CAPEX in 2020: $1200/kW; [2] Storage costs for intermittent green hydrogen production could add ca. $0.12/kg (salt cavern) - $0.35/kg (rock cavern) assuming 50% of the produced hydrogen would need to be stored at some point; [3] Blue line represents ATR+CCS (90% CO_2 capture) at $6.5/MMBtu natural gas price illustrated as an approximate global average natural gas price such as seen in parts of Europe, India and China. [4] Band refers to gas prices: $1.1-10.3/MMBtu.

SOURCES: BloombergNEF (2019), *Hydrogen – the economics of production from fossil fuels, Hydrogen – the economics of production from renewables and Hydrogen – the economics of storage*

An illustrative scenario assession potential demand acceleration in 2020s reaches ca. 45 Mt clean hydrogen demand in 2030 & requires mobilisation across 5 key sectors

Illustrative scenarios

Illustrative demand scenario for clean hydrogen in 2030
Mt / year, 2030



Sectors with most rapid demand acceleration

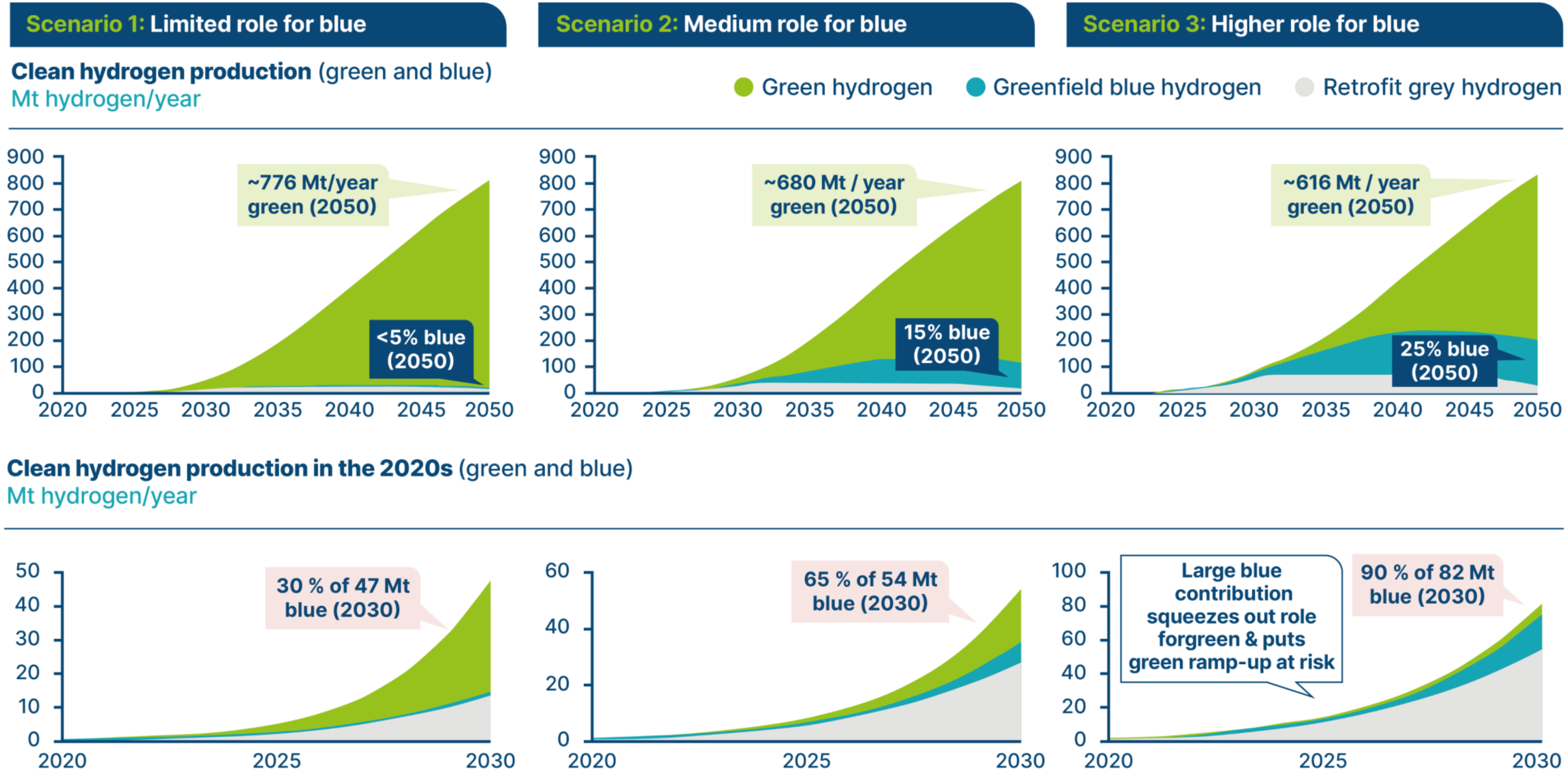
- **Ammonia:** ca. 50% of ammonia production switches to clean hydrogen[3]
- **Refining:** ~1/3 of dedicated grey hydrogen production facilities in refineries transition to clean hydrogen
- **Shipping:** 5 % of total shipping demand decarbonised[4] (corresponds to ~900 small container ships)
- **HDV:** 10% new heavy duty trucks from 2027 are FCEV
- **Steel:** 15-20 plants using 100% hydrogen-DRI (32 Mt/year green steel)

NOTES: [1] Illustrates use of hydrogen in residential and commercial building heating. The dominant form of this in the 2020s is likely gas grid blending. [2] Clean hydrogen demand in the refining category summarises existing uses in desulphurisation and in hydrocracking of crude oil. In addition, methanol production, heat provision in chemical industry and production of high value chemicals was also included in this category for this analysis. [3] Ammonia production for use in the chemical industry and ammonium and nitrate based fertiliser production can transition to clean hydrogen without significant retrofit. Urea production (50%+ of today's fertiliser production) is more challenging to convert to clean hydrogen. See appendix for more details.
[4] This demand would correspond to ca. 900 small container ships.

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

Rapid ramp-up of blue production in the 2020s would see blue taking a greater share of supply in next decade, and green ramping up faster in the 2030s to compensate

Illustrative scenarios



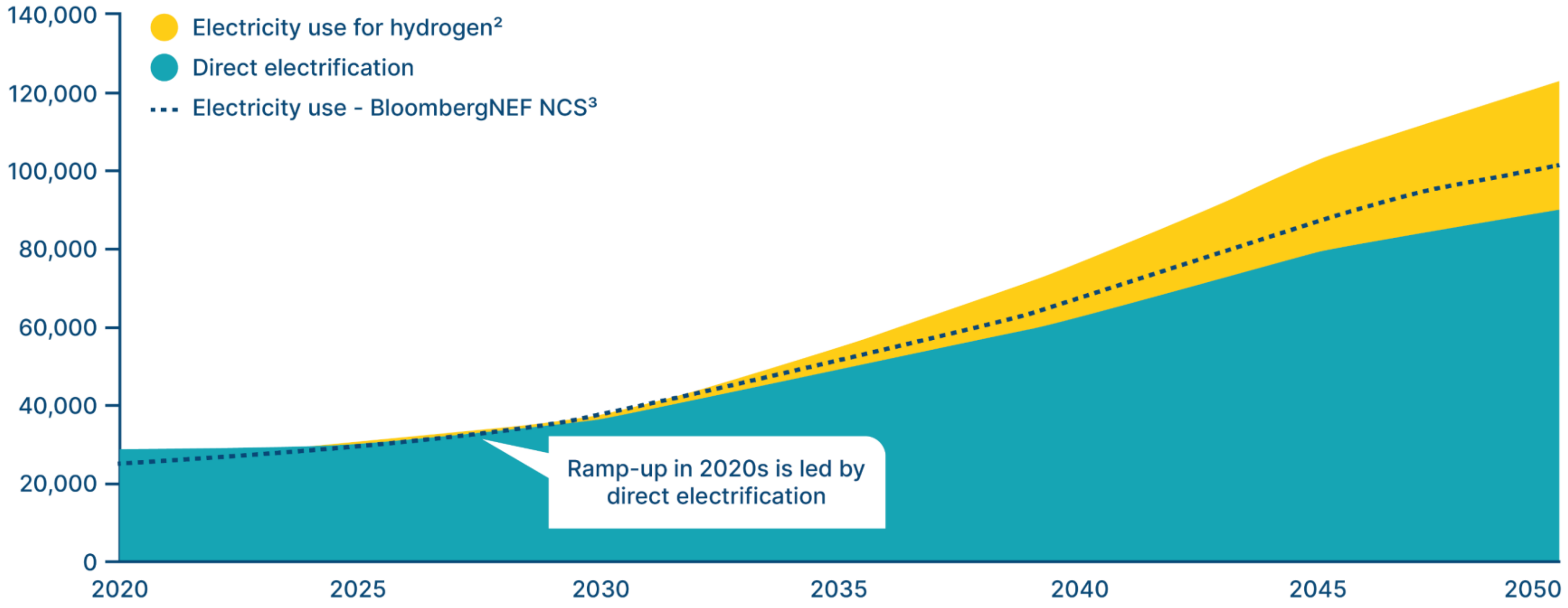
NOTES: Details on the models methodology describing these scenarios can be found in the appendix. Historical build rates for green and blue projects were based on public databases. Size of plant: 1) 500 2) 700, 3) 800 tons of hydrogen/day

SOURCES: SYSTEMIQ analysis for the Energy Transitions Commission (2021); IEA (2020), *Hydrogen Projects Database; IEA (2020), World large-scale CCUS facilities operating and in development, 2010-2020*

Green hydrogen ramp-up will require major increase in green electricity generation post 2030 (ca. 25% of total TWh in 2050)

Electricity use for green ramp-up
TWh, ETC supply-side decarbonization pathway[1]

Illustrative scenario



NOTES: [1] Total hydrogen demand of 800 Mt with 85% derived from green hydrogen assumed. Lower-end of hydrogen demand for power storage used. [2] Electricity use for hydrogen includes hydrogen and hydrogen derived (ammonia, synfuel) end-uses. [3] BloombergNEF *New Energy Outlook* Climate Scenario.

SOURCE: BloombergNEF (2020), *New Energy Outlook;* SYSTEMIQ analysis for the Energy Transitions Commission (2021)

Significant power production ramp-up required

- Total electricity demand will grow by 3.5-5x by 2050, from 27,000 TWh today up to 90-130,000 TWh

No inherent barriers:

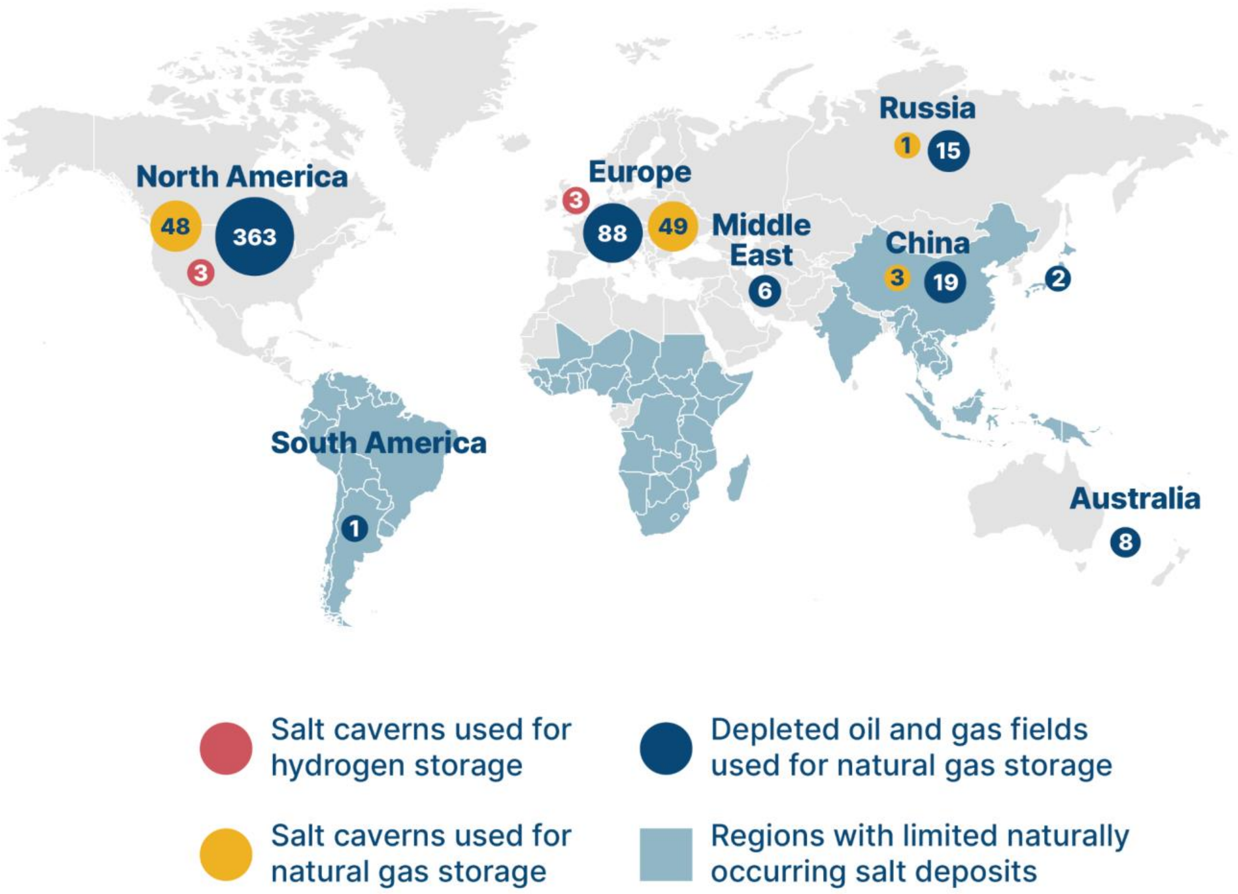
- Reserves of lithium, cobalt, nickel sufficient to meet demand
- 100,000 TWh produced entirely from solar would require only 1-1.2% of global land area

However, planning and incentives required:

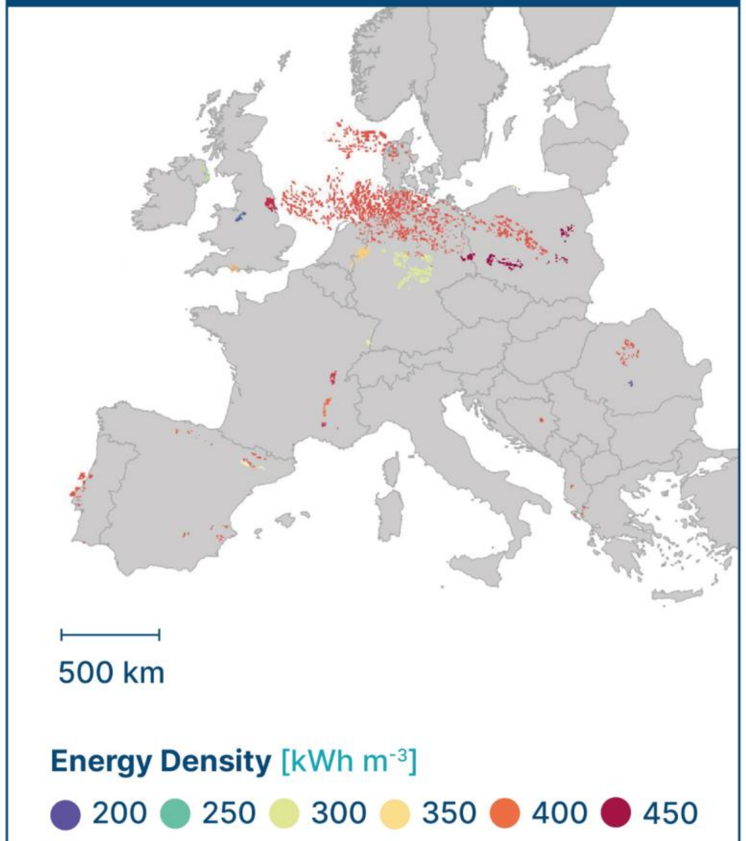
- Optimal power market design to attract sufficient low-cost capital
- Planning for scaling supply chain and new skills development
- Streamlined permitting processes to build at pace and scale

Availability of large-scale storage differs by region, those without salt caverns access (e.g., China, India) will have to rely on costly or unproven tech

Current number of geological storage sites for natural gas and hydrogen (2018)



European map on potential salt cavern storage sites



SOURCES: BloombergNEF (2019), *Hydrogen – The economics of storage*; Preprints (2019), *Technical Potential of Salt Caverns for Hydrogen Storage in Europe*

Early demand for clean hydrogen offtake likely to focus around clusters with co-located and shared production, transport & storage and end-use infrastructure - Four archetypes

1 Port

Ports[1] as infrastructure hubs for import/export of feedstocks and goods.

Core off-taker:

- **Shipping (Ammonia)**

Often co-located with:

- **Refining & Fertiliser**
  Import/export of LNG for these industries
- **Steel**
  Import/export of feedstocks and products
- **Road Transport**
  Container transport
- **Aviation**
  Coastal transport hub
- **Forklifts & Ground Operations**
  Container/goods handling
- **Option for blending**
  dependant on trade-offs (see Box B)
  Coincide with LNG storage

2 City

Continental cities serve as non-coastal hub for transport and are often well connected to gas grid infrastructure.

Core off-takers:

- **Aviation**
- **Long-haul trucking & buses**
- **Option for low % H_2 blending** into natural gas grid dependant on trade-offs (see Box B)

Often co-located with:

- **Refining & Ammonia**
  As large natural gas demand sites commonly close to gas storage/import sites
- **Forklifts & Ground Operations**
  Heavy transport in mines

3 Refining & Fertiliser

Refineries and fertiliser production are frequently co-located and require large amounts of hydrogen.

Core off-taker:

- **Refining & Fertiliser**

Often co-located with:

- **Ports**
- **Gas storage facilities** – option for low % H_2 blending into natural gas grid dependant on trade-offs (see Box B)

4 Steel

Hydrogen-DRI steel production as major hydrogen off-taker (medium sized steel site requires approximately ~120 kt H_2/year).

Core off-taker:

- **Hydrogen-DRI steel production**

Often co-located with:

- **Ports**

- **Refining, Fertiliser and Steel** offer sufficient off-take to operate on stand-alone basis, but co-location enables shared off-take

- **Road Transport**
  Dependant on long-term role of hydrogen in road transport & hydrogen refuelling infrastructure network requirements

Examples across the four archetypes already starting to appear

1 Port

Port of Amsterdam:

- Partners: Nouryon, Tata Steel
- 100 MW electrolysis
- Oxygen bi-product from electrolysis will be used in steel production

Port of Rotterdam:

- 1.2 Mt clean hydrogen production via green and blue route by 2030
- Wide variety of end-uses targeted in several consortia and pilots including shipping, trucking and aviation

North Sea Port[2]:

- Partners: 500 MW electrolysis
- End-users include refinery, ammonia and steel plant in proximity to port

2 City

Aberdeen Hydrogen Hub, Scotland:

- Hydrogen refuelling stations and deployment of hydrogen powered L/M/HDV
- Feasibility study to expand to building heating and industry

Hydrogen Cities, South Korea:

- 4 cities as candidate cities for the hydrogen economy
- Road transport refuelling infrastructure
- Hydrogen grid for building heating/cooling

Liverpool & Manchester, UK:

- Partners: Consortium lead by Cadent and Progressive Energy
- Blue hydrogen for gas grid blending combined with local industry and transport

3 Refining & Fertiliser

Puertollano, Spain[3]:

- Partners: Iberdrola and Fertiberia
- 20 MW electrolysis (2021)
- Green hydrogen used to co-feed (10%) into existing ammonia plant

Lingen, Germany[3]:

- Partners: BP and Oersted
- 50 MW electrolysis
- Green hydrogen to replace 20% of grey hydrogen in refinery

Antofagasta, Chile[3]:

- Partners: Engie and Enaex
- 1600 MW electrolysis
- For local ammonium nitrate plant and export market

Large projects such as Australian Renewable Energy Hub[4] and NEOM[5] are in early planning stages

4 Steel

Lulea, Sweden:

- Partners SSAB, Vattenfall, LKAB
- Pioneering hydrogen-direct reduction (DRI) technology
- Commencing early commercial production in 2026

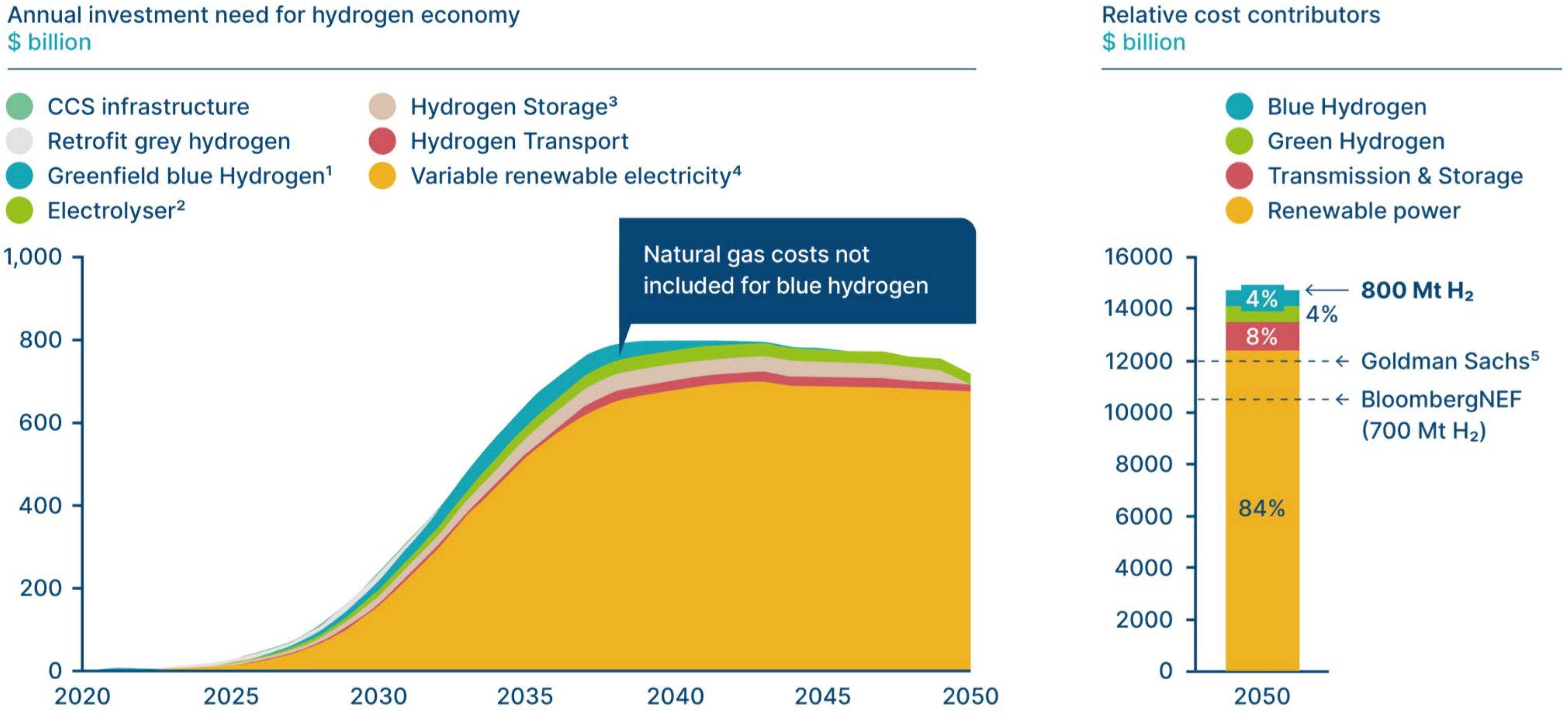
Duisburg, Germany:

- Partners: Thyssenkrupp, RWE
- 100 MW electrolysis
- Co-feed of hydrogen into coal-powered blast-furnace as first step prior to conversion to DRI plants

Dunkirk, France:

- Partners: AcelorMittal, Air Liquide
- Development of hydrogen-DRI and hybrid BF/DRI technology

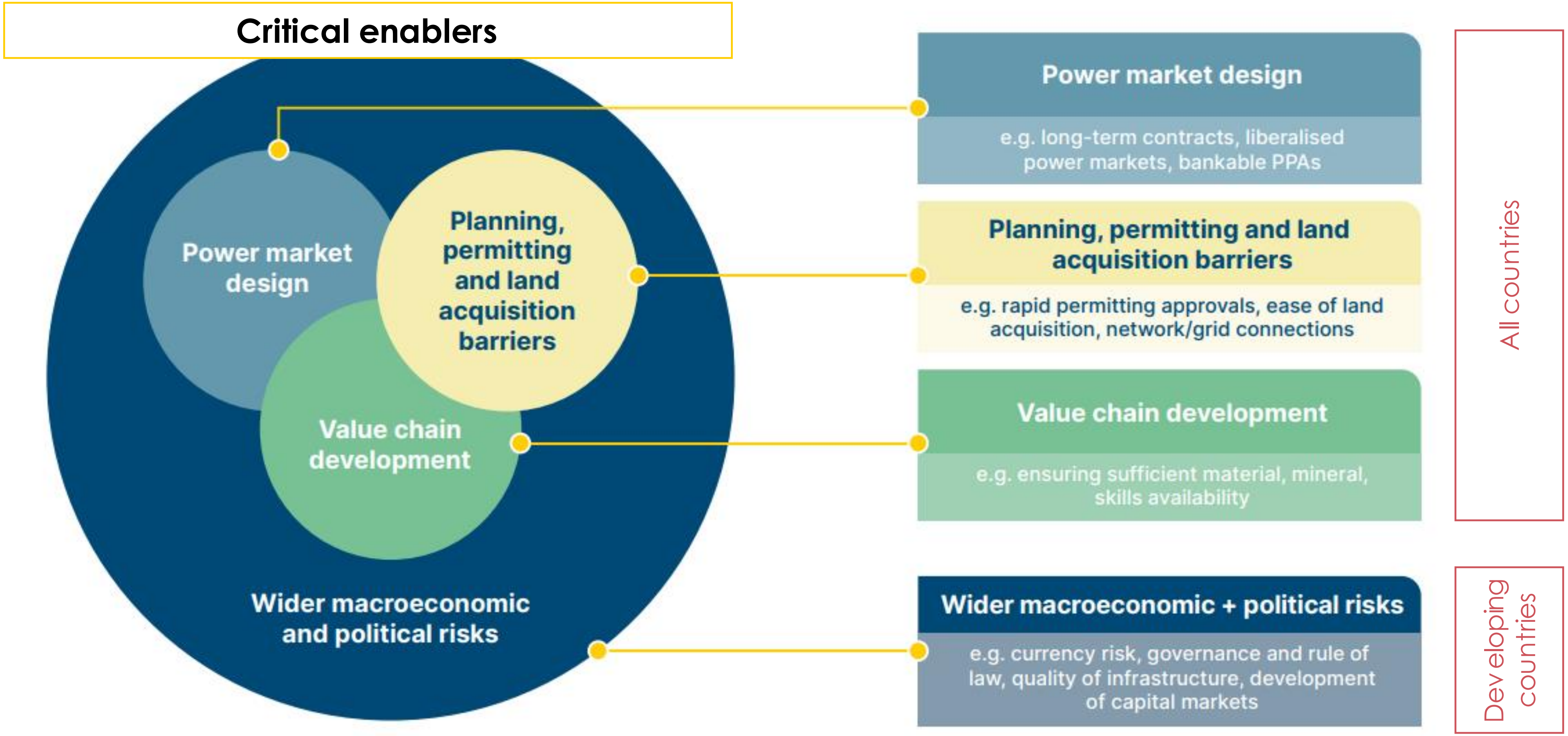
Cumulative investment needs amount to ~$15 trillion until 2050 for supply ramp-up with peak at $800 billion per year, dominated by renewable electricity production (~85%)



NOTES: The investment is assumed to take place in the year the plant is going in operation. Used middle ramp-up scenario with 85 % green and 15 % blue hydrogen.
[1] Blue hydrogen cost: $ 0.1 billion/TWh.
[2] Learning rate model for electrolyser CAPEX assuming 18% learning rate, 200 MW cumulative installed capacity (2020), 1200 $ / kW CAPEX (2020). Average utilisation factor: 50%.
[3] Assume 20% of global hydrogen demand needs to be stored.
[4] Assumed capacity split (in terms of GWh produced) of 33 % PV, 53 % onshore wind, 13 % offshore wind. Used BloombergNEF cost predictions for VRE production (median cost of lowest 1/3 globally in terms of cost) with global average fleet load factors.
[5] Hydrogen demand volume in 2050 unknown.

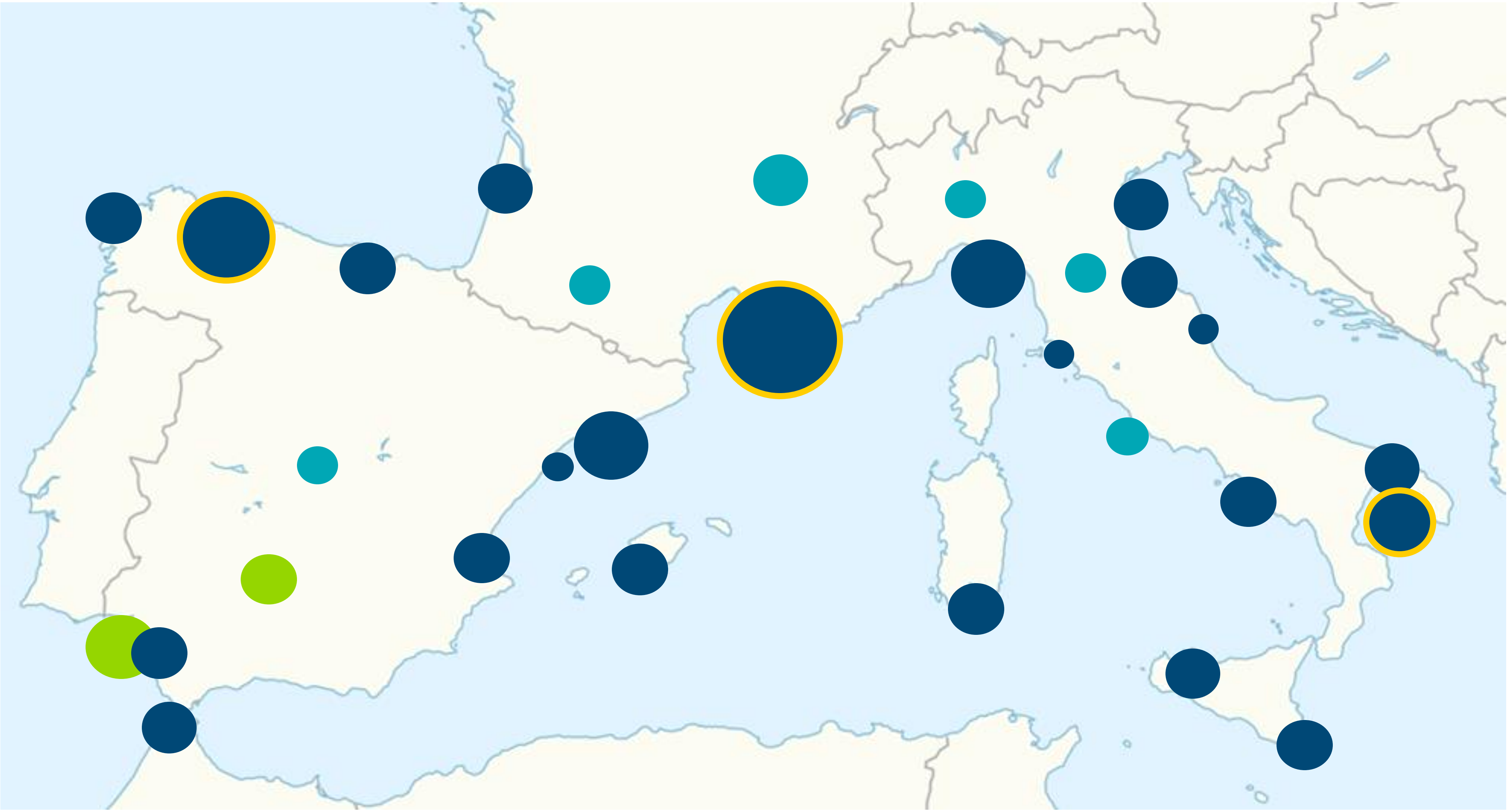
SOURCE: Goldman Sachs (2020), *Green Hydrogen - The next transformational driver of the Utilities industry*; BloombergNEF (2020), *Hydrogen Economy Outlook*. Element Energy (2019), *Hydrogen production with CCS and bioenergy*

Achieving the build and investment at the pace and scale required will necessitate critical enablers



Source: Industry interviews, SYSTEMIQ analysis for the Energy Transitions Commission (2021).

Location of potential hydrogen clusters in southern Europe



ILLUSTRATIVE SIZING

Port

Port with co-located steel

City

Refining & Fertiliser

Scale:

250-1000 t/day H_2 Demand

Overcoming the chicken and egg issue for hydrogen by bringing forward initial demand through clusters

Why clusters?

- **Regional industrial clusters provide** a mechanism for securing coordinated early demand and supply over the next decade
- **Increasing number of cluster projects** coming forward especially in Europe and Australia
- **Clusters are attractive to key decision markers** in both industry and policy
  - **Economics are improved** (e.g. shared transport and storage costs at higher volume)
  - **Risks are shared** (e.g. multiple H2 off-takers)
  - **Public support shared** across multiple sectors and companies

What could be the profile and location of early clean hydrogen clusters?

- **What is the most appropriate combination of sectors to for cluster and how does this differ across locations?**
- **What is the minimum viable size for a hydrogen cluster? What are the relative advantages of additional scale?**
- **What are favourable regions / areas for locating hydrogen clusters?** E.g.

– **Supply:** Access to low cost renewables; CCS availability, low cost CAPEX

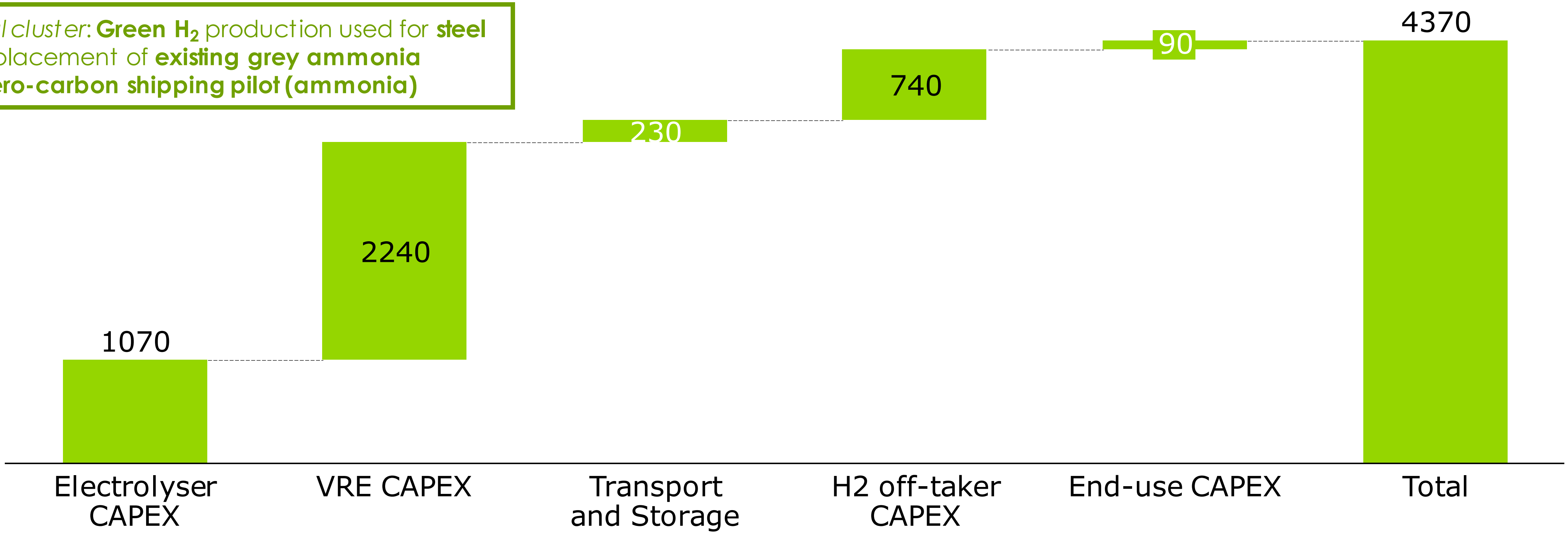
  - **Demand:** Broad combination of off-take sectors, access to gas grid, location of existing industrial production
  - **Enabling conditions:** Government commitments to support (supply / demand / T&S) and customer pressure / support

Renewables and electrolyser for hydrogen production ~80% of investment for a green hydrogen industrial cluster

GREEN H_2

Total investment cost for greenfield green hydrogen industrial cluster excl. financing costs (early 2020s)
$ million

Illustrative industrial cluster: **Green H_2** production used for **steel** manufacturing, replacement of **existing grey ammonia** production, and **zero-carbon shipping pilot (ammonia)**



	Electrolyser CAPEX	VRE CAPEX	Transport and Storage	H2 off-taker CAPEX	End-use CAPEX
Industrial cluster description	1.3 GW electrolyser (850 $/kW)	1.9 GW VRE	100 km distribution pipe + 2500 t salt cavern	1 Mt steel plant + 0.2 Mt ammonia plant (1/3 for shipping)	NH_3 storage, bunker vessel and 3 retrofitted carriers
Potential bottlenecks		VRE space requirements	Lack of geological H2 storage	Significant investment for industry players with highly leveraged balance sheets	Ship retrofitting and engine availability

Global annual installations of wind and solar will rise by 5-7 times compared with current levels; pace of solar and wind deployment in the EU will also need to increase