U.S. DEPARTMENT OF ENERGY

Pathways to Commercial Liftoff

Clean Hydrogen | March 2023

Agenda

Report summary

Community benefits & jobs implications

Deep-dive: Select analysis

Clean Hydrogen – Executive Summary

Production

Domestic market poised for growth

- **Today:** ~0 MMTpa clean H2
- **2030:** ~10 MMTpa clean H2
- **2050:** ~50 MMTpa clean H2

Post-IRA project announcements accelerating

Supply chain scale-up has begun

Growth along value chain is required (midstream, long-term offtake)

Midstream

Distribution & storage costs

DOE Regional Clean Hydrogen Hubs

Open access

Collocated vs. Distributed use cases

Downstream

Market unlocks in phases

- Near-term
- Medium-term
- Long-term

Long-term offtake is critical

Market-specific challenges & opportunities

Export opportunity

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Energy and Environmental Justice and Community Benefits

Common EEJ considerations for H2

- **Safety** of production and midstream H2 and CO2 infrastructure (e.g., pipelines)
- **Health impacts** of certain production and end use technologies (e.g., criteria air pollutants)
- Continued **operation of polluting facilities**, especially in overburdened communities
- Use of H2 where **electrification** is preferred by communities
- **Entrenchment of fossil fuel** use and/or infrastructure; continued revenue to fossil fuel companies
- **Increased costs** compared to other clean energy options

Why does EEJ matter for early- or first-of-a-kind H2 projects?

- Determine social acceptance, adoption, and **market liftoff**
- **Mitigate social risk** (delays, cancelation)
- **Set the standard** for follow-on projects
- **Influence** health, livelihoods, economy, environment of surrounding communities
- Determine whether projects **exacerbate or help address harms** or injustices

What role do developers and investors play?

Engage impacted communities, Tribes, and labor unions

Create **quality jobs** and invest in workforce development

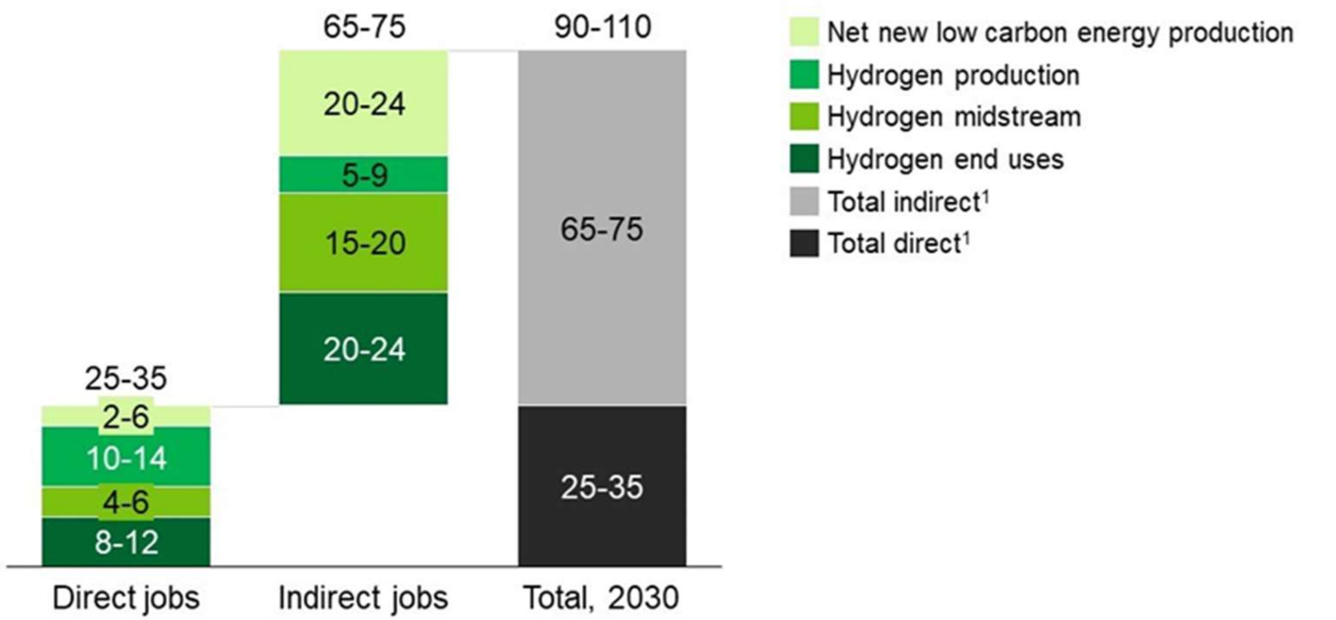
Address energy and **environmental justice** concerns and opportunities

Support **diversity, equity, inclusion, and accessibility**

Quality Jobs and Investing in the American Workforce

- **~100,000 net new direct and indirect jobs** related to new capital projects and clean hydrogen infrastructure in 2030 (~450,000 cumulative job-years)
- ~120,000 direct and indirect jobs in operations and maintenance of hydrogen assets
- **U.S. currently lacks sufficient, appropriately skilled workforce** to manufacture, construct, or operate the volume of hydrogen infrastructure required to meet projected demand

New hydrogen asset install, OEM & capex-driven jobs, by value chain step in 2030, thousands



1. Direct jobs include roles related to installing new assets while indirect jobs are roles that support asset installations (e.g., OEM and other supply chain jobs)

Source: Vivid Economics

- **Just transition:** attract and train labor from adjacent industries, minimize worker displacement
- **Quality jobs:** to attract and retain a quality workforce, jobs must be high paying, have strong labor protections, offer training/placement opportunities, and build pathways for long-term career growth (facilitated through Project Labor Agreements and other collective bargaining agreements)
- **Economic growth:** opportunities for enterprise creation in minority-, women-, Veteran-owned businesses and Minority Serving institutions; create industrial clusters with wide impact; replace revenue and project jobs in communities where fossil tax revenues might decline

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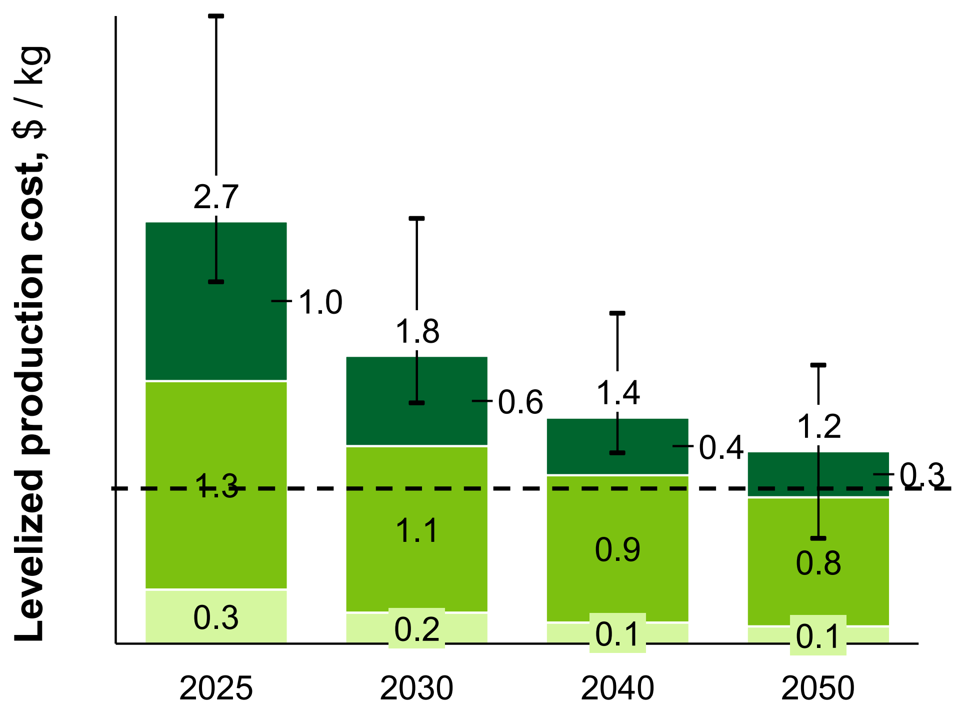
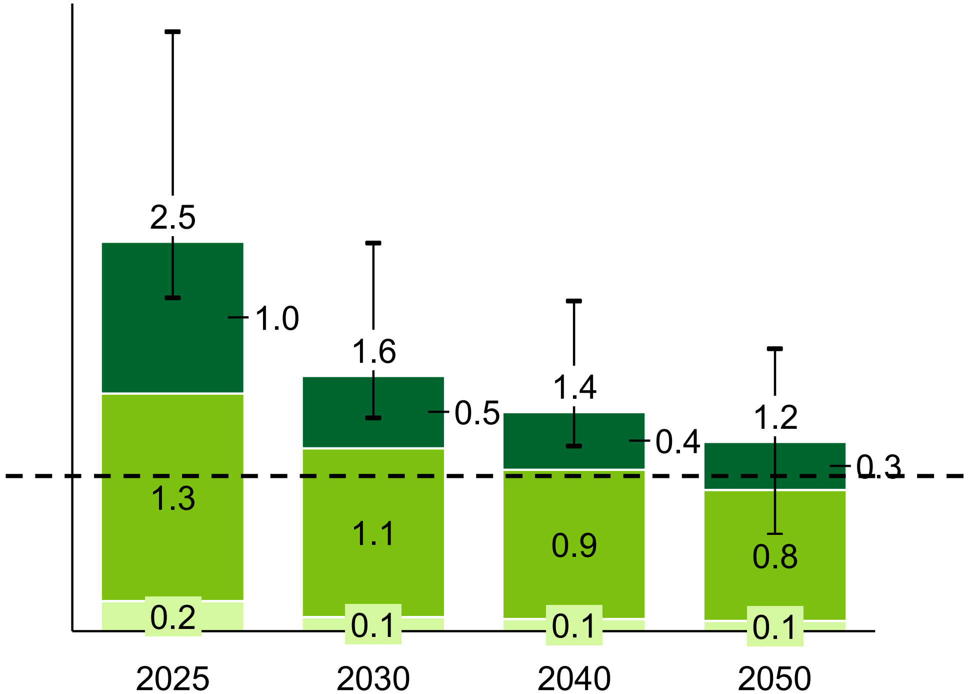
A Production: Low-cost clean energy is the largest cost driver of hydrogen production costs and the primary lever to reach the Hydrogen Shot, however, the PTC removes near-term unit cost pressure, supporting lift-off as R&D advances are developed.

Capex - electrolyzer | Opex - electricity | Opex - other

PEM electrolysis levelized hydrogen production cost (without PTC)[1,2,3], $/kg



Alkaline electrolysis levelized hydrogen production cost (without PTC)[1,4], $/kg



Hydrogen Shot target: $1/kg in 2031 (without PTC)

Would require additional R&D compared to what industry players are building into their current forecasts

At equivalent production costs, delivered costs for electrolytic hydrogen will be higher than reformation-based hydrogen due to higher storage costs

1. These levelized costs use industry estimates for electrolyzer capex costs developed in 2020 using 2020 USD. Forecasted electrolyzer capex values are rapidly evolving and may differ between sources
2. Assumes ~18MW electrolyzer (4,000 Nm³/h) in 2025, ~90MW electrolyzer (20,000 Nm³/h) for 2030 onwards; electrolyzer installed capex: $900/kW (2025), $540/kW (2030), $350/kW (2040), $300/kW (2050); error bars also include reported LCOH values from Bloomberg New Energy Finance: $1.8/kg (2030), $0.7/kg (2050)
3. Assumes onshore wind power: Class 5 – Moderate (reference case), Class 1 – Moderate (low-cost case), Class 9 – Moderate (high-cost case); Class 1 – Moderate capacity factors: 51% (2025), 54% (2030), 55% (2040), 55% (2050); Class 5 – Moderate capacity factors: 44% (2025), 45% (2030), 46% (2040), 47% (2050); Class 9 – Moderate capacity factors: 28% (2025), 30% (2030), 31% (2040), 31% (2050); Class 1 – Moderate LCOE: $22/MWh (2025), $18/MWh (2030), $16/MWh (2040), $15/MWh (2050); Class 5 – Moderate LCOE: $26/MWh (2025), $22/MWh (2030), $19/MWh (2040), $17/MWh (2050)
4. Assumes ~18MW electrolyzer (4,000 Nm³/h) in 2025, ~90MW electrolyzer (20,000 Nm³/h) for 2030 onwards; electrolyzer installed capex: $850/kW (2025), $425/kW (2030), $350/kW (2040), $300/kW (2050); error bars also include reported LCOH values from Bloomberg New Energy Finance: $1.7/kg (2030), $0.6/kg (2050)

Includes data from external sources – to be updated upon publication of DOE Working Group papers

A

Production: Industry estimates related to electrolyzer capex cost-downs. Figure to be updated when DOE internal numbers are available for publication. Electrolytic hydrogen production will likely come from a range of technologies; AWE is most mature and certain to scale for near-term industrial uses due to low-cost and absence of PGM catalysts. PEM must overcome challenges to increase scale up, while SOEC is unproven at scale

High / Low

Technology	Applications	Degree of maturity	Industry forecasts for system capex excluding installation[1,2,3], $/kW	Advantages	Disadvantages
Alkaline Water Electrolysis (AWE)	Industrial applications (e.g., ammonia, refining, steel, chemicals)	Established technology; commercial stage	Current: 760-1,000; 2030: 230-400; -60%	Cost-effective, mature technology No PGM[4] catalysts	Low current density Corrosive electrolyte
Proton Exchange Membrane (PEM)	Diverse use cases, including road transport Distributed hydrogen production Grid balancing	Increasing scale-up; commercial stage	Current: 975-1,200; 2030: 380-450; -60%	Simple cell design and small footprint High current density Differential pressure operations High dynamic response	Scale-up constrained by PGM supply and PFAS[5] usage Less demonstration of long-term durability vs. AWE
Solid Oxide Electrolysis Cell (SOEC)	Low purity industrial use cases Co-location with high temperature steam	Laboratory / early commercial stage	Current: 2,000-2,500; 2030: 300-500; -80%	Low electricity demand using steam (high efficiency) No PGM catalysts	Heat / steam source required Limited dynamic response Durability challenges with high-temperature operations
Anion Exchange Membrane (AEM)	Distributed hydrogen production Grid balancing	Latest technology, limited deployment; laboratory stage	*Estimates not available*	Potential for: — No PGM catalysts — High current density — Differential pressure operations — High dynamic response	Limited performance and lifetime with current material systems

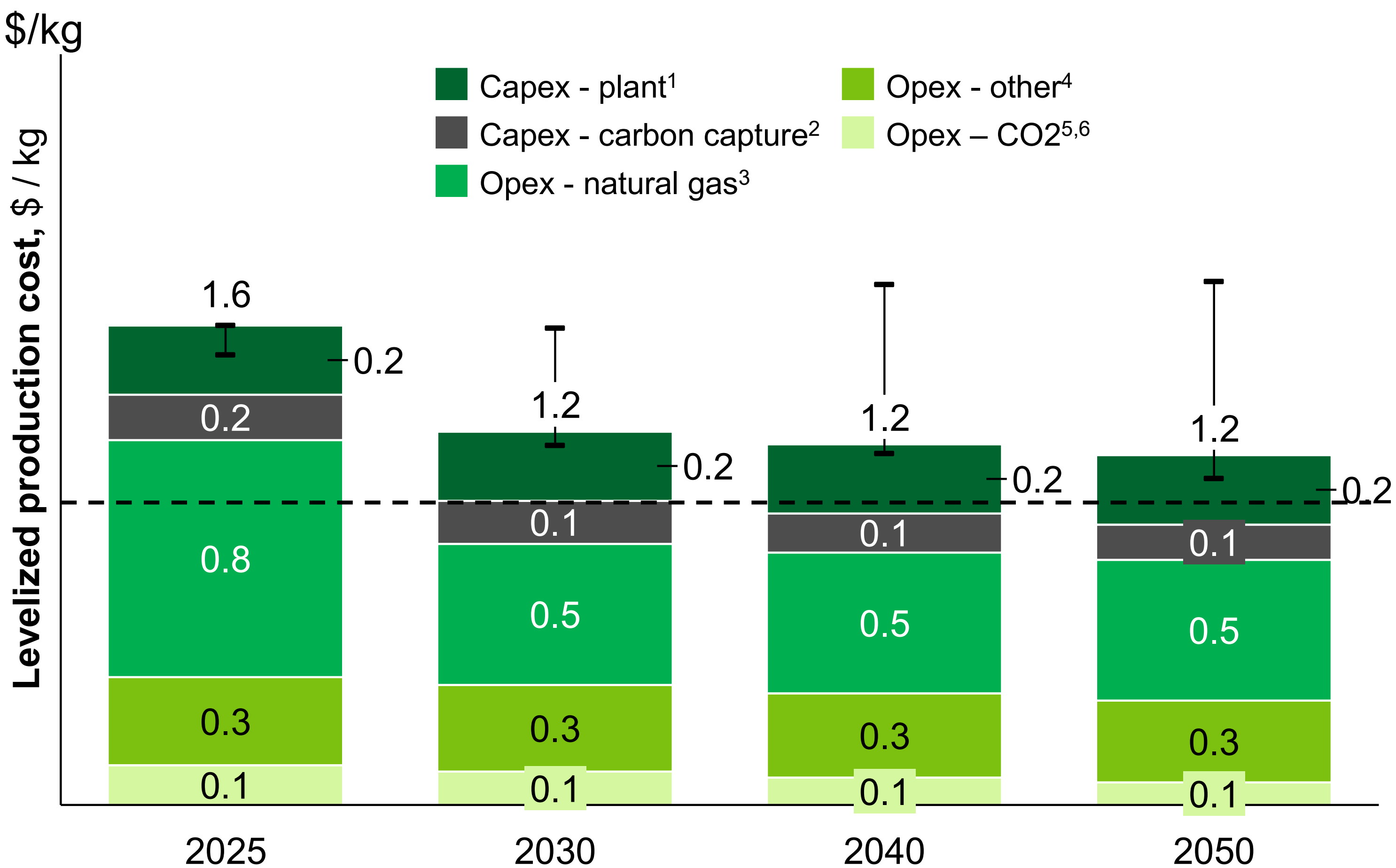
1. System capex incl. stack, transformer and rectifier, compressor for 30 bar compression, purification/drying for 99.9% purity. 2022 for 2 MW system, 2030 for 80 MW system; range based on median and top quartile performance
2. These levelized costs use industry estimates for electrolyzer capex costs developed in 2020 using 2020 USD. Forecasted electrolyzer capex values are rapidly evolving and may differ between sources; ranges have been expanded to include both Hydrogen Council and Bloomberg New Energy Finance data for AWE and PEM electrolyzers
3. Electrolyzer installed capex values: AWE, 2022: $1,380-1,420/kW (2 MW); AWE, 2030: $400-550/kW (80 MW); PEM, 2022: $1,700-1,800/kW (2 MW); PEM, 2030: $500-600/kW (80 MW); SOEC, 2022: $3,500/kW (2 MW); SOEC, 2030: $700-800/kW (80 MW). Installed capex also includes assembly, transportation, building, and installation costs
4. Platinum group metals
5. Per- and Polyfluorinated Substances

Source: Bloomberg New Energy Finance, Hydrogen Council

Data from external sources – to be updated upon publication of DOE Working Group papers

A Production: Reformation-based H2 with CCS has a lower initial unsubsidized LCOH than electrolysis, but is expected to have limited cost-downs and is sensitive to natural gas prices

Levelized hydrogen production cost for SMR with >90% CCS (without PTC)[1]



Hydrogen Shot target: $1/kg in 2031 (pre-PTC)

Would require additional R&D compared to what industry players are building into their current forecasts

1. These levelized costs use industry estimates for capex costs developed in 2020 using 2020 USD. Forecasted capex values may differ between sources
2. SMR facility capex (100k Nm^3/h capacity): $215 million (2025 onwards)
3. CCS capex (100k Nm^3/h capacity facility): $140 million (2025), $135 million (2030), $120 million (2040), $110 million (2050)
4. Natural gas reference case: $4.3 / MMBtu (2025), $3 / MMBtu (2030 onwards); assumes non-renewable natural gas; natural gas high case based on EIA Annual Energy Outlook 2022 high oil price scenario; natural gas low case based on EIA Annual Energy Outlook 2022 low oil price scenario
5. Includes O&M, catalyst replacement, electricity, and water costs
6. CO2 transport and storage: $48/tonne CO2 (2025), $44/tonne CO_2 (2030), $39/tonne CO2 (2040), $35/tonne CO2 (2050)

Source: Hydrogen Council, EIA Annual Energy Outlook 2022

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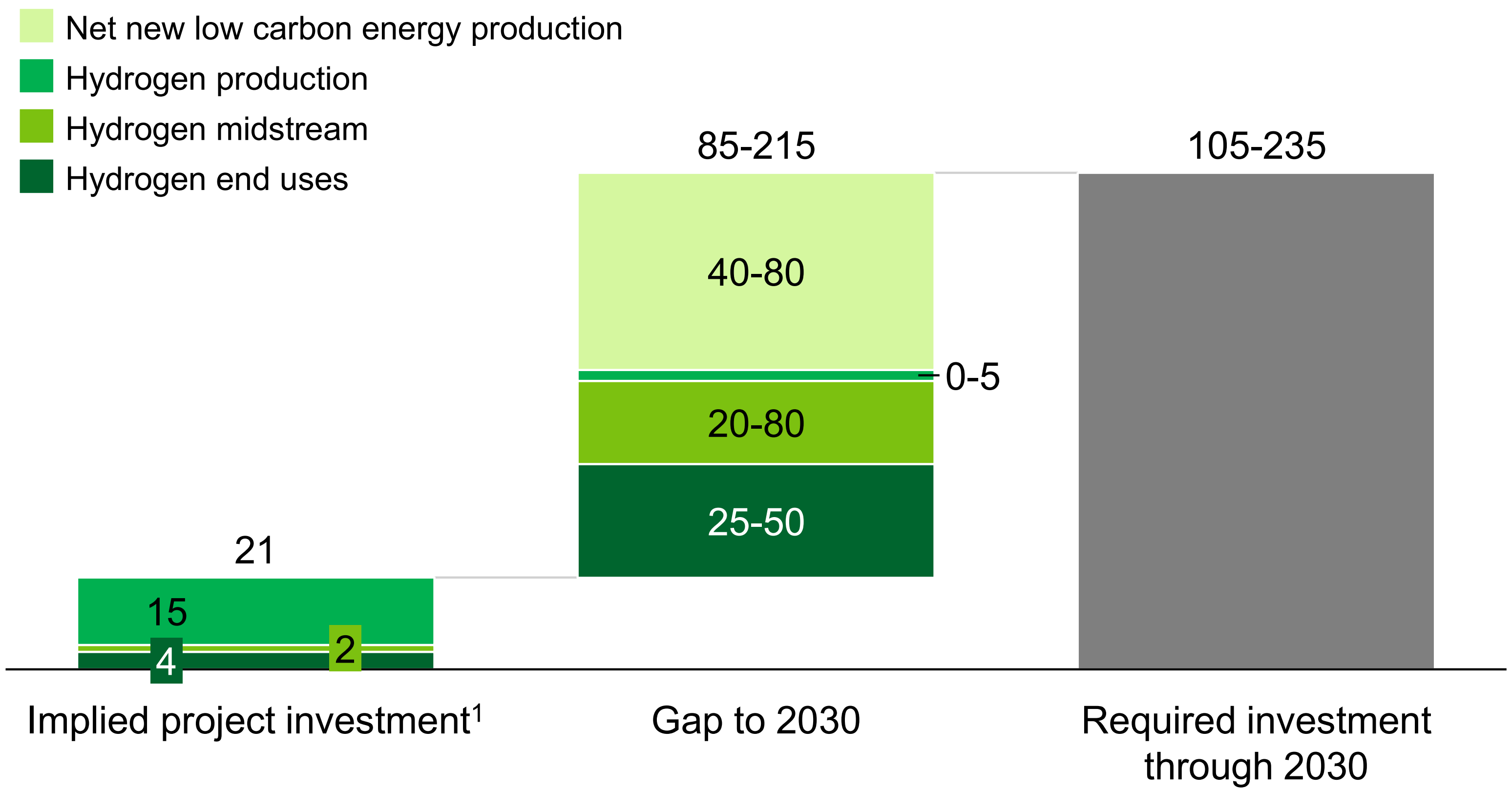
A Production: Announced hydrogen production investments are on track to meet 2030 requirements if projects pass final investment decision. However, an $85–215B capital gap currently exists across midstream (distribution, storage) and end-use infrastructure, low carbon energy production.

Investments into hydrogen value chain, $ B



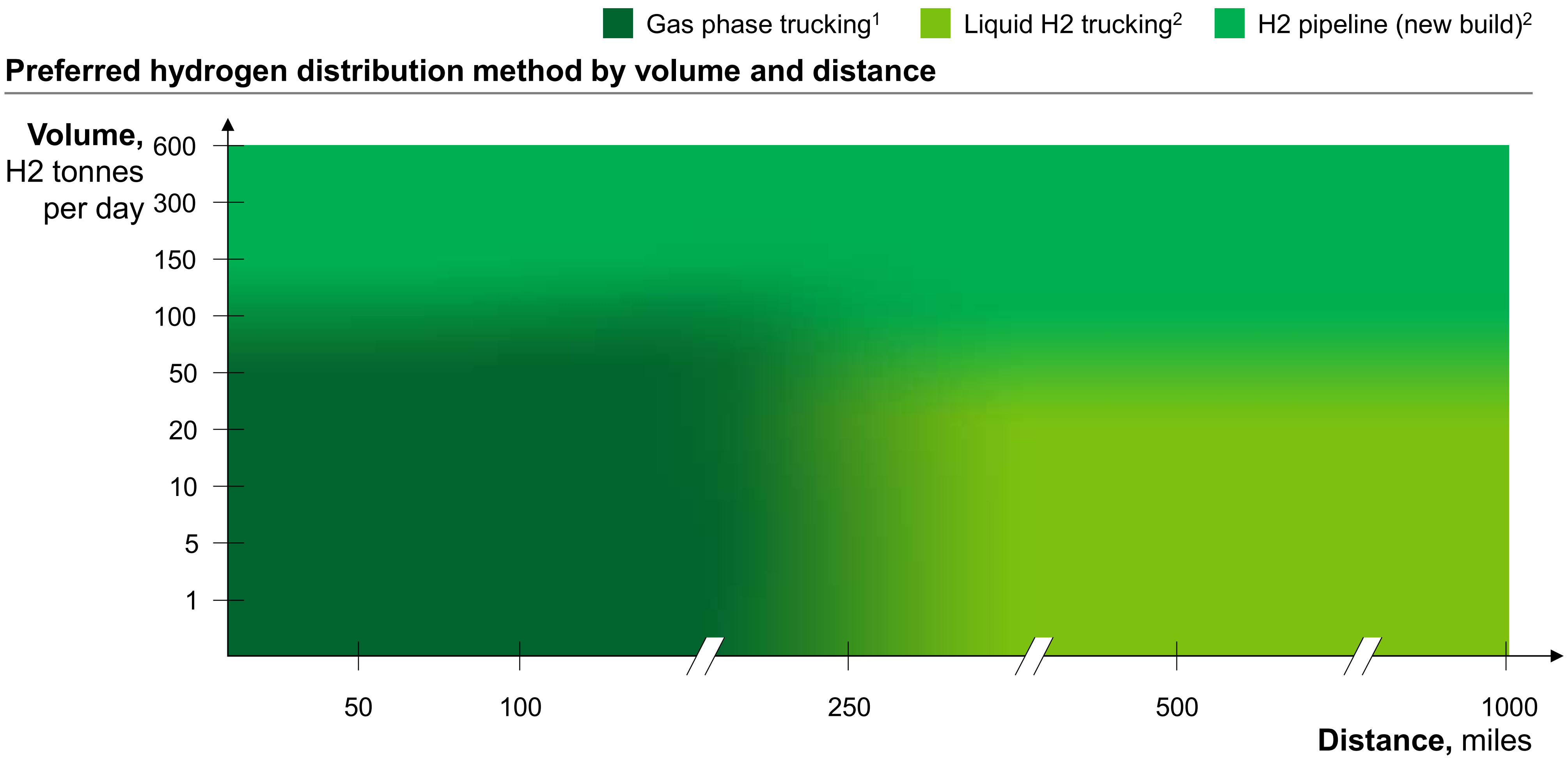
Range based on the Net zero 2050 and hydrogen tech spike cases

1. Excludes pre-feasibility study production projects

Source: Hydrogen Council, McKinsey Hydrogen Investment Model

B Midstream: For production and distribution networks, pipelines are the economic solution at large volumes, and will be needed when off-take scales beyond co-located production

Preferred hydrogen distribution method by volume and distance



1. Assumes hydrogen is compressed to 500 bar and transported in 1100 kg truck
2. Includes liquefaction and liquid transport (fuel and labor)
3. Assumes hydrogen is compressed to 80 bar and transported in a newly built, dedicated H2 pipeline. These results do not consider leveraging existing pipelines

Source: Heatmap is based on data from the Hydrogen Council and the Hydrogen Delivery Scenario Analysis Model at Argonne National Laboratory, but left qualitative to highlight uncertainty in distribution methods and case-by-case variability

B Midstream: Industry-informed distribution costs. Gas trucking is suitable for short distance/small volume transport while liquid trucking is preferred for higher throughput use cases over longer distances when pipelines are not available or practical

Distribution method	**Key characteristics**	**2030 levelized cost, including compression / liquefaction,** $/kg
Gas phase trucking[1]	• H2 **gas is compressed at ambient temperature** to 300 – 500 bar • **Ideal for short distances and small volumes** (≤ 20 TPD) due to lower capex costs for compressors and tube trailers vs. liquid and pipeline transport • **Lower transport capacity** due to the low volumetric density of H2	0.9-1.9
Liquid hydrogen trucking[2]	• **Cryogenic cooling to liquefy hydrogen**, followed by storage in cryogenic tankers • **Ideal for larger volumes where pipelines are not feasible** and longer distances to minimize the number of trips and driver labor cost • **Higher capex costs than gas phase trucking** but lower than pipelines	2.7-3.2
Dedicated hydrogen pipeline transport[3]	• **Underground pipeline** transporting compressed gas phase hydrogen • **Lowest levelized cost at high volumes** (50+ TPD) **and long distances** due to low opex costs; not commonly used for lower volumes • **Requires permitting approval and high upfront capex costs** ($2-10 million per (inch-mile) for 6–14-inch diameter pipes)	0.2-0.5
Hydrogen / natural gas blended pipeline	• **Blending of up to ~20% hydrogen by volume into natural gas pipelines** for use in the power and heating sectors • **Blending rates are limited** due to leakage and required compressor modifications, but work is underway to refine volume threshold • **Separation** of hydrogen from natural gas **can be very expensive**	*Dependent on blending volume and retrofit costs*

1. Assumes hydrogen compressed to 500 bar and transported 250 km; 50 TPD compression capacity; Source: Hydrogen Council
2. Assumes hydrogen liquefied and transported 250 km; 50 TPD compression capacity; Source: Hydrogen Council. Range based on increased leak rate and liquefaction costs.
3. Assumes 600 TPD hydrogen compressed to 80 bar and transported 300 km; range represents difference between high-cost region (New England) and low-cost region (Great Plains); Source: Hydrogen Delivery Scenario Analysis Model, Argonne National Laboratory

B Midstream: Industry-informed storage costs. Hard rock and salt cavern storage are geographically constrained but represent the largest scale and lowest-cost storage options. Large-scale production and off-take likely to be built near these natural resources.

Storage method	Key characteristics	2030 levelized cost[1], $/kg
Compressed gas tank storage[2]	• H2 **gas is compressed at ambient temperature** to 300 – 700 bar • **Storage capacity is limited** due to the low volumetric density of H2 at room temperature • **Highest unit cost** option, but **lower total capex** cost due to smaller scale • **Storage capex costs** expected to decline from ~$550/kg to ~$400/kg in 2030	0.8-1.0
Liquid hydrogen storage[3]	• **Cryogenic cooling** to liquefy hydrogen, followed by storage in insulated tanks • **Allows storage of large volumes** of hydrogen, but requires large total capex investment • Hydrogen liquefaction **uses >30% of the hydrogen energy content** • Liquid hydrogen is **not viable for long-term storage** (>10 days) • **Storage capex costs** expected to decline from ~$120/kg to ~$100/kg in 2030	0.1-0.3
Salt cavern storage[4]	• **Geologic formations created by salt deposits** that can store gaseous hydrogen at elevated pressure (70-190 bar) • **Large-scale storage and low capital costs**, but also **limited availability** (~2000 salt caverns in North America with an average capacity of 10^5-10^6 m^3) • Salt caverns **can also store other gases** (e.g., natural gas), so there is **competition for cavern usage** • **Storage capex costs** expected to remain stable through 2030	0.05-0.15
Lined hard rock storage[5]	• **Underground cavern is surrounded by hard, low permeability rock**, which can be lined to hold pressurized hydrogen • **Earlier stage technology than salt caverns**, with limited hydrogen demonstrations but **expected to allow higher storage pressures** (up to 300 bar) • Storage capex costs expected to remain stable through 2030	0.1-0.3

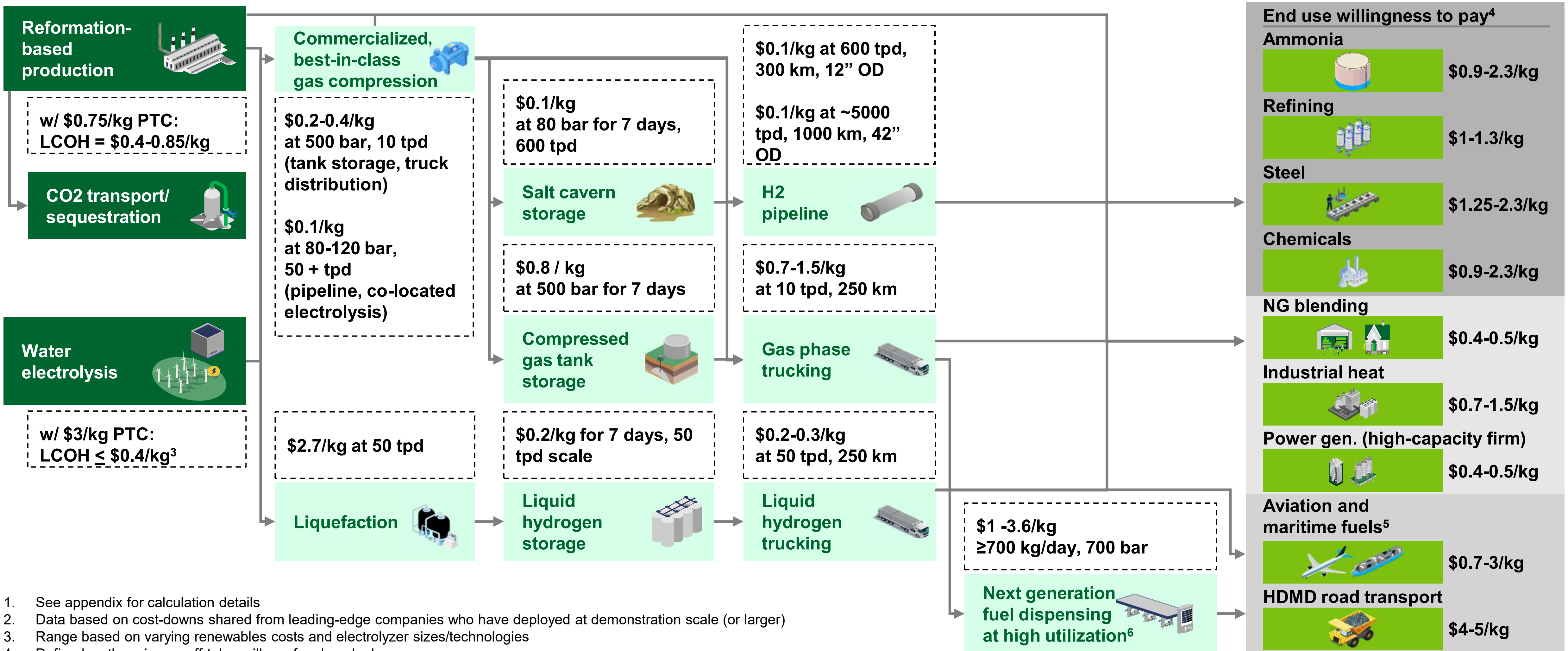
1. Does not include cost of compression or liquefaction (included in transport costs)
2. Assumes 950 kg stored at 500 bar with 1 cycle per week; Source: Hydrogen Council
3. Assumes 1 cycle per week and 50 TPD volume, Range based on 0.5-2 cycles per week. Source: Hydrogen Council
4. Assumes capacity to store 600 TPD pipeline throughput for 7-days at 80 bar; cushion gas is ~40% of volume; Range based on 50-2000 TPD; Argonne National Laboratory
5. Assumes 150 bar storage with 1 cycle per week. Range based on 0.5-2 cycles per week. Source: Argonne National Laboratory

B Midstream: Industry-informed estimates of 2030 upstream and midstream costs. By 2030, industry estimates that multiple methods of hydrogen distribution and storage can become affordable if state-of-the-art technologies are commercialized at scale.

2030 costs across the value chain if advances in distribution and storage technology are commercialized[1]

Industry | Gas replacement | Transport

Upstream: Hydrogen production | **Midstream: Hydrogen distribution and storage assuming state-of-art technology at scale[2]** | **Downstream: End use applications**



1. See appendix for calculation details
2. Data based on cost-downs shared from leading-edge companies who have deployed at demonstration scale (or larger)
3. Range based on varying renewables costs and electrolyzer sizes/technologies
4. Defined as the price an off-taker will pay for clean hydrogen
5. Represents delivery of hydrogen to aviation and maritime fuel production facilities
6. Greater than or equal to 70% utilization, assumes line fill at high pressure

Sources: HDSAM, Argonne National Laboratory; DOE National Hydrogen Strategy and Roadmap, Hydrogen Council

Readers should sum (1) Upstream costs and (2) Midstream costs to arrive at a potential delivered cost of clean hydrogen, based on production pathway and storage/distribution method selected. Hydrogen production costs shown take an upper bound of production costs (~2MW (450 Nm3/h) PEM electrolyzer with Class 9 NREL ATB wind power) and then subtract the PTC at point-in-time. A wider range of LCOH values, without the PTC credit applied, are described in Figures 11 and 12 in the Clean Hydrogen Liftoff report.

C End use: Hydrogen is a large and growing domestic market, from $80-150B by 2050. The largest markets are for hydrogen in industrial use cases, medium and heavy-duty road transport, and liquid fuels that use hydrogen feedstock.

Largest long-term H2 feedstock TAM **Role in decarbonization:** Strong potential — Low potential

New Liftoff reports kicking off this month related to Steel, Chemicals, Cement

Sector	End-use	Role of H2 in decarb.	Description of switching costs	H2 feedstock TAM[1], $ billion 2030	2040	2050	H2 market size with full adoption[2], $ billion 2030	2040	2050
Industry	Ammonia		**Low:** Process currently uses fossil-based H2, hydrogen supply feed in place	4-10	4-11	5-12	4-10	4-11	5-12
	Refining		**Low:** Hydrogen supply feed in place	6-8			6-8		
	Steel		**Variable:** Highly dependent on current plant configuration and feedstock, may also include hydrogen distribution infrastructure		4-7	4-8	15-30	18-35	20-40
	Chemicals-methanol		**Variable:** Can limit switching costs by adding CCS to SMR, other approaches more costly with higher unit cost savings		2-6	3-7	5-12	5-12	6-14
Transport[1]	Road[3]		**High:** New vehicle power trains with fuel cells, refueling stations & distribution infrastructure	0	25-30	40-55	90-125	110-140	120-160
	Aviation fuels		**Moderate:** Fuel conversion / production facilities		5-15	10-30	8-20	10-25	10-30
	Maritime fuels[4]		**High:** New ship engines, port infrastructure & local storage, and fuel supply, storage, and bunkering infrastructure in ports	< 1	4-10	8-20	5-15	5-15	8-20
Heating	NG blending for building heat[5]		**Variable:** Will depend on pipeline material, age, and operations (e.g., pressure); requires testing for degradation and leakage	0	0	0	2-3	2-3	2-3
	Industrial heat		**Variable:** Dependent on extent of furnace retrofits required	0	1-3	2-5	7-10	7-10	7-10
Power	Power – 20% H2 (Combustion)[6]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	< 0.2	< 0.1	< 0.1	4-6	5-8	8-12
	Power – LDES[7]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	0	4-6	8-11	*Varies based on cost-downs in other LDES technologies and composition of grid*		

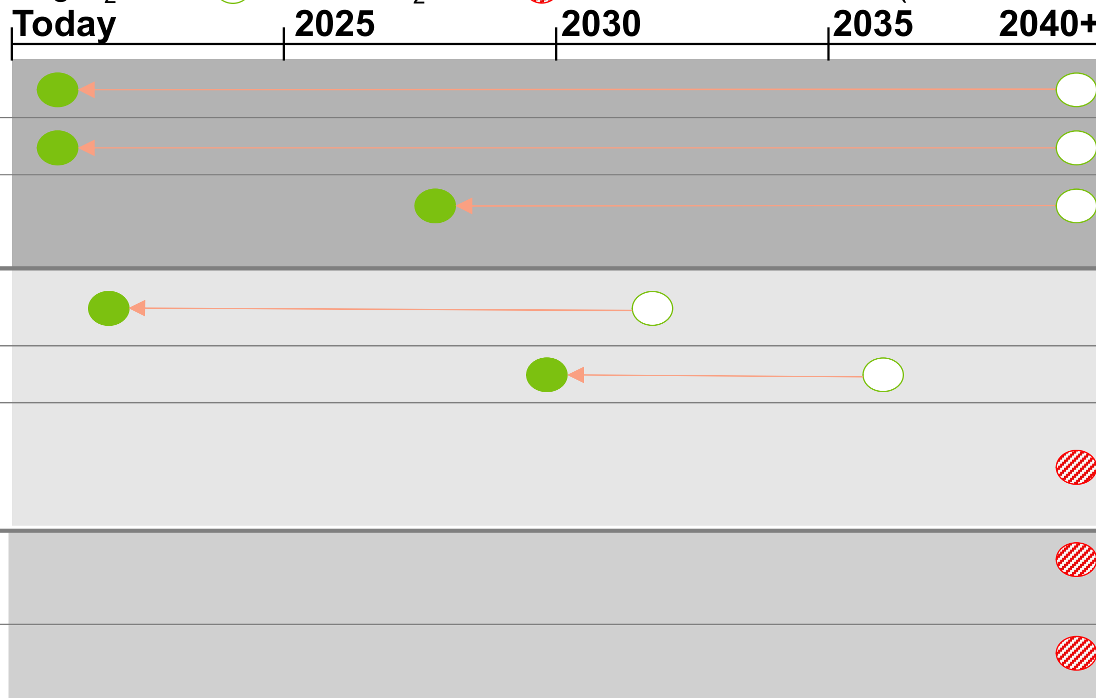
Some end-use segments were not analyzed in this iteration of the Liftoff report. End-uses not analyzed include (1) clean hydrogen combustion for lower-capacity factor power and (2) clean hydrogen combustion for intermediate range capacity factor turbines. In the presence of carbon constraints or other regulatory drivers, these use cases (1) and (2), may have a higher potential in the power sector than high-capacity use cases detailed above (Figure 7 in report).

1. Represents the market size for clean hydrogen feedstocks in each end use; calculated by multiplying the clean hydrogen in the "Net zero 2050 – high RE" scenario by range of willingness to pay by end use reported in the DOE National Hydrogen Strategy and Roadmap; dispensing costs are subtracted from the road transport TAM and market size with full adoption

C End use: When evaluating best-in-class projects, the PTC pulls forward breakeven for clean hydrogen versus traditional, fossil alternatives to within the next 3-5 years for most end uses.

Breakeven timing for hydrogen vs. conventional alternative[1]

Adoption scenario: With \$3 / kg H_2 PTC; Without H_2 PTC; Post-2040 breakeven (both scenarios) **Sector:** Industry[4]; Transport[5]; Gas replacement/ Power



		Other considerations
Refining		Long-term supply stability, breakeven highly sensitive to future natural gas price
Ammonia (via electrolysis)		
Steel – new build DRI[2]		Geographic considerations, post-PTC breakeven, H_2 pipeline infra availability
Heavy-duty truck with LCFS		Refueling infra availability, truck availability, cost and uptime / range constraints, long-term LCFS value
Heavy-duty truck		
Container ships[3]		Refueling infra availability, new / retrofitted ship availability and cost
Firm power generation – 100% H_2 (Combustion)[3]		Blending limits, end use and pipeline retrofits, pipeline infra, lower energy density, breakeven highly sensitive to future natural gas price
Firm power generation – 20% H_2 (Combustion)[3]		
Peaking power – H2 fuel cell	*To be completed in follow-on reports*	Use cases require successful, scaled H2 Hub with open pipeline access
Long duration energy storage	*To be completed in follow-on reports*	

Off-takers may hesitate to switch to clean hydrogen given uncertainty over pace of hydrogen supply scale up, switching costs, performance, and lack of cost-effective mid- and downstream infrastructure. Existing and new regulatory drivers may help to overcome these challenges

1. Assumes 'average" hydrogen production from electrolysis and \$3/kg PTC; assumes a production cost floor of \$0.40/kg. No carbon pricing for business as usual
2. Within 5% of breakeven during PTC term, but costs do not cross. Once the PTC sunsets, TCO is >5% of breakeven. Breakeven timing shown as the mid-point of the PTC term.
3. Use cases do not breakeven without additional carbon tax, higher willingness to pay, or lower H2 cost floor
4. Assuming hydrogen production is co-located with demand, avoiding distribution costs
5. Assumes 300km between hydrogen production and refueling station

Source: Hydrogen Council, McKinsey Hydrogen Insights Analysis

Best-in-class refers to projects in areas with favorable renewables (e.g., NREL ATB Class 1 Wind); less competitive projects will have a later breakeven timeline. Appendix Figure 27 shows these ranges.

In conclusion, overcoming the challenges below will help accelerate commercial lift-off of the clean hydrogen economy

Challenges	Solutions
Hesitancy to commit to long-term, scaled offtake	**Invest in the development of midstream infrastructure**
Limited cost-effective midstream infrastructure	**Secure supply chain investments**
Limited availability of specialized hydrogen workforce	**Expand and accelerate the capital base**
Capacity-spike required for U.S. electrolyzer production	**Develop regulations for a scaled industry**
Development of regional CO_2 transport & storage	**Standardize processes and systems across the clean hydrogen economy**
Credit risk constraining widespread debt financing	**Accelerate technical innovation through R&D**
Competition for clean electricity	**Expand the clean hydrogen workforce**
Raw materials constraints	
Conversion and scale-up challenges for specific end uses	
Long-term cost competitiveness upon credit expiration	

Key messages of the Clean Hydrogen Liftoff report

PTC reduces production costs to kick-start the transition from high carbon intensity (CI) to low CI hydrogen for existing uses

DOE H2Hubs and open access infrastructure will bolster the project economics for more nascent use cases

In addition to industrial/chemicals use cases, transportation use cases will be critical for market lift-off

Without sustained long-term offtake or merchant markets, domestic market acceleration could slow

Foregrounding energy and environmental justice mitigates project risk, improves health and safety in surrounding communities, and generates social acceptance

Providing quality jobs and investing in worker development is essential to recruit and retain a sufficient, appropriately skilled hydrogen workforce

Thank you!

Download the report: liftoff.energy.gov

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