U.S. DEPARTMENT OF ENERGY

Pathways to Commercial Liftoff

And Future Analysis

2023 H2 AMR

Disclaimer

As DOE is actively engaged in financial assistance planning, we are subject to constraints during this period to ensure fairness of the process:

- **DOE can only communicate public and non-privileged information during this meeting or event.**
- **DOE cannot discuss the details of active or planned financial assistance matters [e.g., Requests for Information (RFI), Notices of Intent (NOI), Funding Opportunity Announcements (FOA)] or entertain requests for a specific outcome or benefit related to a financial assistance activity.**

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 move use cases into the money that would otherwise not take-off

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

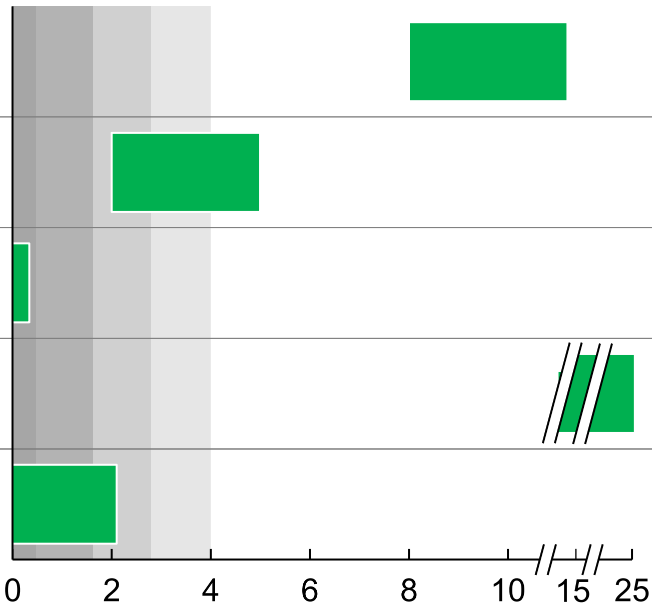
Without sustained long-term offtake or merchant markets, domestic market acceleration could be slowed

A Production: SMR with CCS and electrolysis from clean energy have highest potential for low-cost clean hydrogen supply, but cost-downs and scale-up are needed

Capex | Opex

Comparison of domestic hydrogen production pathways

PTC value, $/kg: $3.00 | $1.00 | $0.75 | $0.60

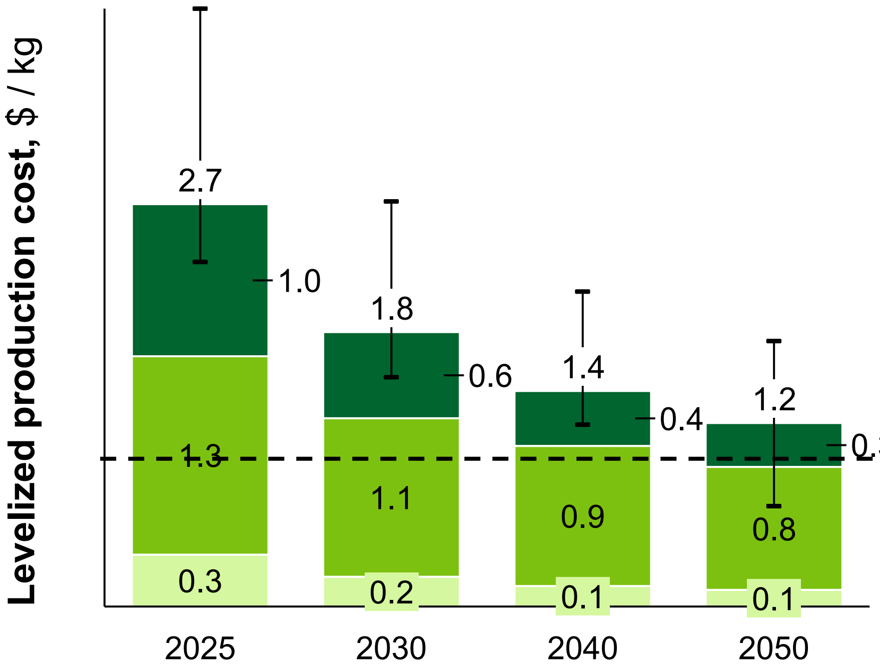
Production method	Carbon intensity[1], kg CO2e/kg H2	% 2022 US production	Projected unit costs current & 2030, $/kg H2 (without PTC)	Projected cost decline by 2030, %
Reformation (SMR or ATR) without CCS[2]		~95%	1.3; 1.0	~25%
Reformation (SMR or ATR) with >90% CCS[3]		~5%	1.6; 1.2	~25%
Electrolysis (from renewables and nuclear)[4]		<1%	3.6; 1.6	~50%
Electrolysis (from grid electricity)[5]		<1%	4.2; 3.4	~20%
Pyrolysis		<1%	*Estimates not available*	

1.Excludes renewable natural gas feedstocks that would result in negative carbon intensities
2.Capex: SMR facility capex (100k Nm3/h capacity): $215 million (current and 2030); reference case natural gas: $4.8/MMBtu (current), $3/MMBtu (2030); high case natural gas: $4.8/MMBtu (current), $3.3/MMBtu (2030); high case based on EIA Advanced Energy Outlook 2022 high oil price scenario. Range for current reformation costs based on +/- 25% natural gas price.
3.Unit costs assumptions are the same as (1), plus CCS capex (for 100k Nm3 / h SMR facility): $145 million (current), $135 million (2030)
4.Assumes alkaline electrolyzer with installed capex: $1400/kW (current, 2MW electrolyzer, 450 Nm3/h), $425 / kW (2030, ~90MW electrolyzer, 20,000 Nm3/h); reference case based on NREL ATB Class 5 onshore wind: capacity factor: 42% (current), 45% (2030), LCOE: $31/MWh (current), $22/MWh (2030); low case based on NREL ATB Class 1 onshore wind: capacity factor: 48% (current), 54% (2030), LCOE: $27/MWh (current), $18/MWh (2030); high case based on NREL ATB Class 9 onshore wind: capacity factor: 27% (current), 30% (2030), LCOE: $48/MWh (current), $33/MWh (2030)
5.Electricity unit costs are based on median, top quartile, and bottom quartile 2030 grid LCOE by census region from EIA Advanced Energy Outlook 2022; assumes the same electrolyzer installed capex as (5); median LCOE: $68/MWh (current), $63/MWh (2030); top quartile LCOE: $66/MWh (current), $62/MWh (2030); bottom quartile LCOE: $89/MWh (current), $80/MWh (2030); Grid carbon intensities are based on data from the Carnegie Mellon Power Sector Carbon Index as well as national averages in grid mix carbon intensity – in some states, grid carbon intensity can be as high as 40 kg CO2e / kg H2 (absent power import / export across sate lines that can lower the carbon intensity of consumption, relative to generation)
Sources: Hydrogen Council, NREL Annual Technology Baseline 2022, EIA Advanced Energy Outlook 2022

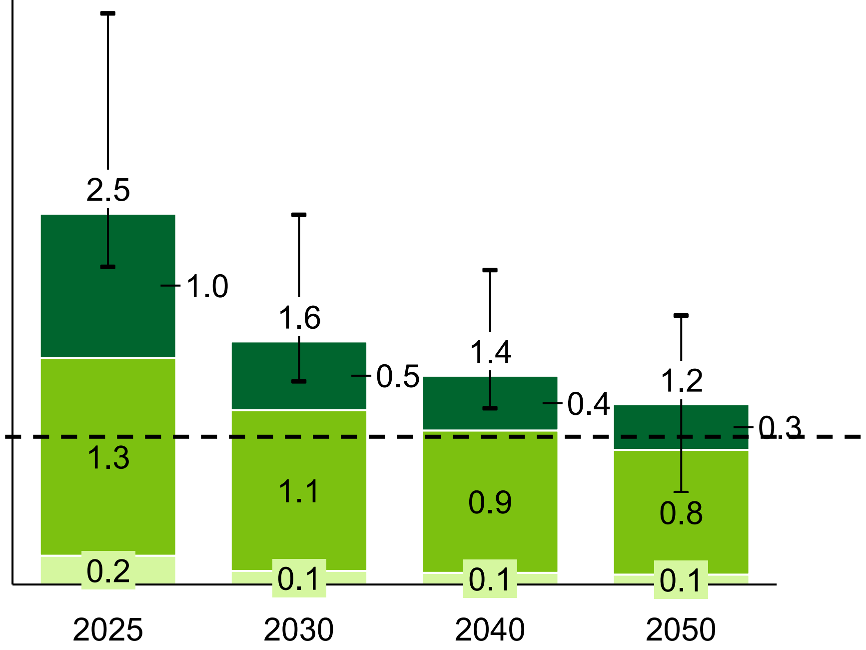
A Production: Low-cost clean energy is the largest cost driver of hydrogen production costs and the primary lever to reach the Hydrogen Shot, however, the PTC removes near-term unit cost pressure, supporting lift-off as R&D advances are developed.

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

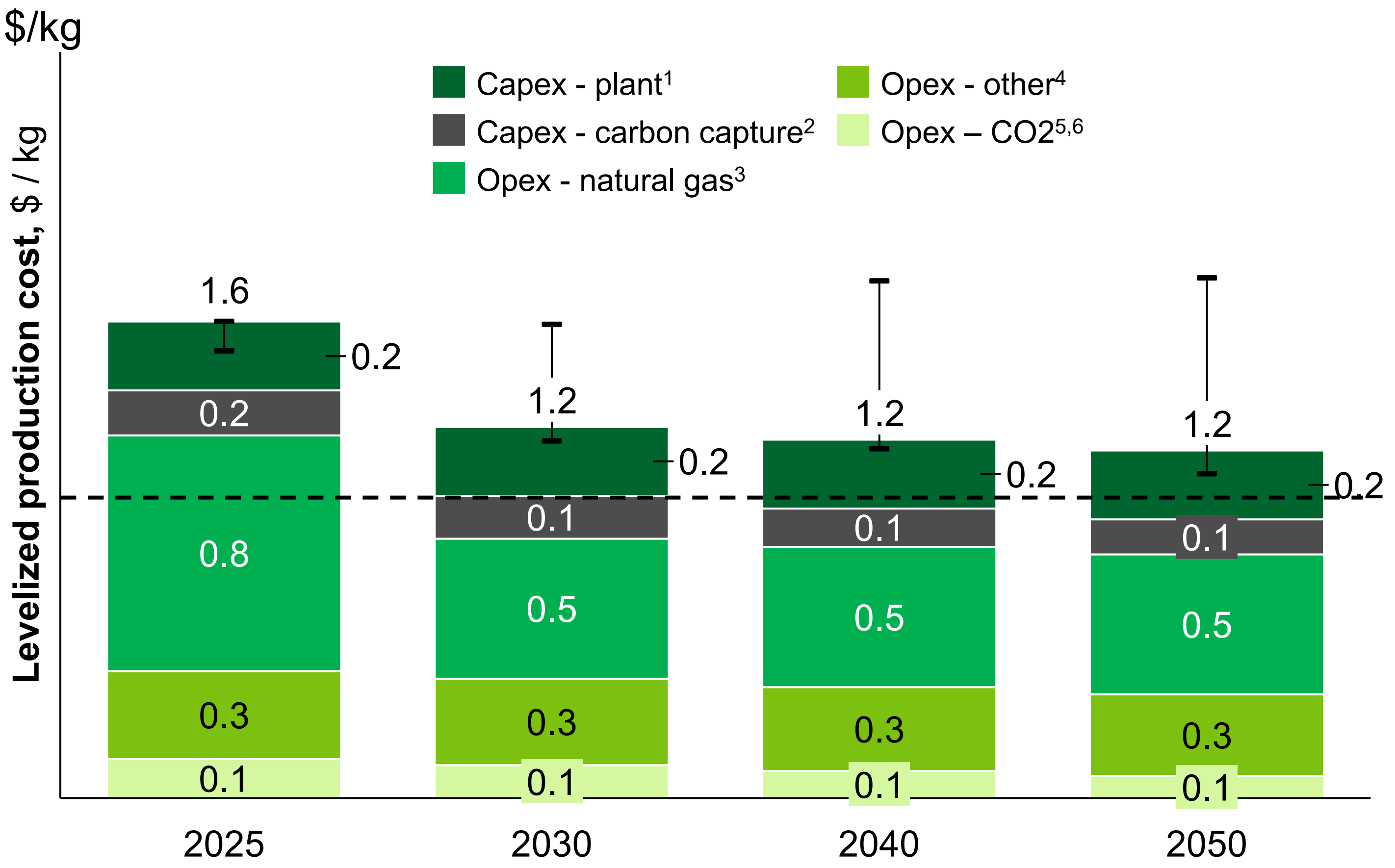
At equivalent production costs, delivered costs for electrolytic hydrogen will be higher than reformation-based hydrogen due to higher storage costs

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 Nm^3/h) in 2025, ~90MW electrolyzer (20,000 Nm^3/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 Nm^3/h) in 2025, ~90MW electrolyzer (20,000 Nm^3/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: 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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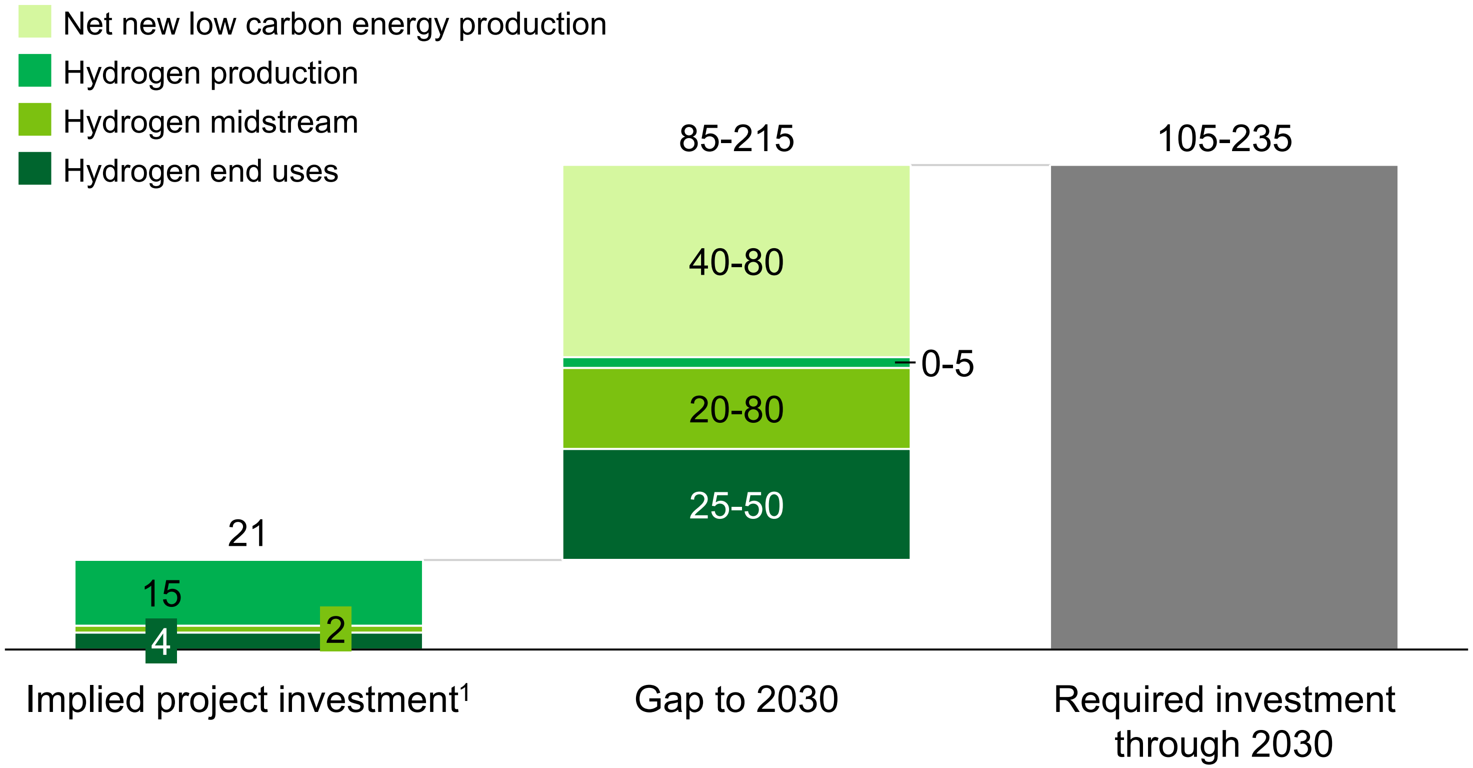
A Production: Announced hydrogen production investments are on track to meet 2030 requirements if projects pass final investment decision. However, an $85–215B capital gap currently exists across midstream (distribution, storage) and end-use infrastructure, low carbon energy production.

Investments into hydrogen value chain, $ B



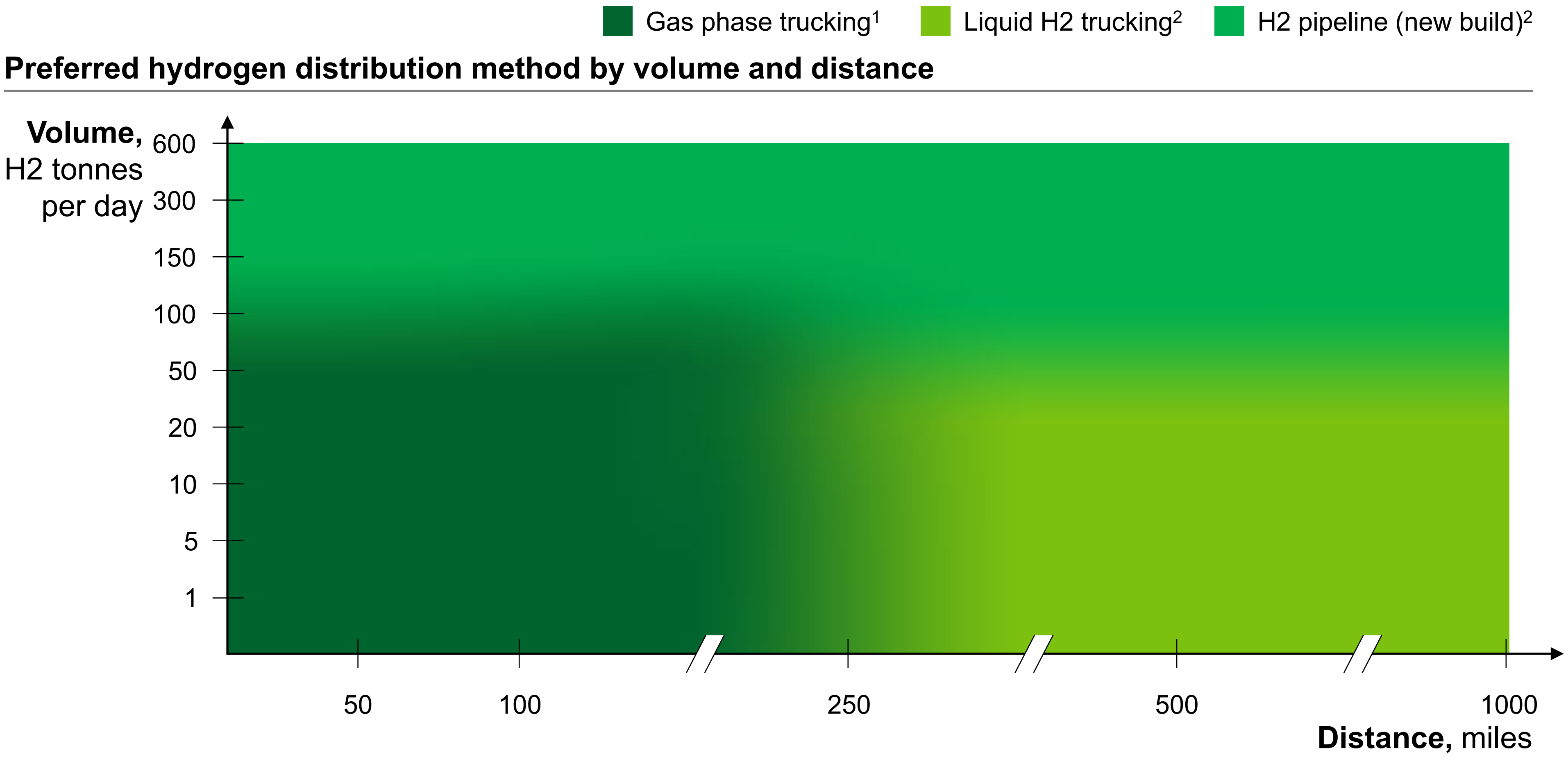
Range based on the Net zero 2050 and hydrogen tech spike cases

1. Excludes pre-feasibility study production projects

Source: Hydrogen Council, McKinsey Hydrogen Investment Model

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

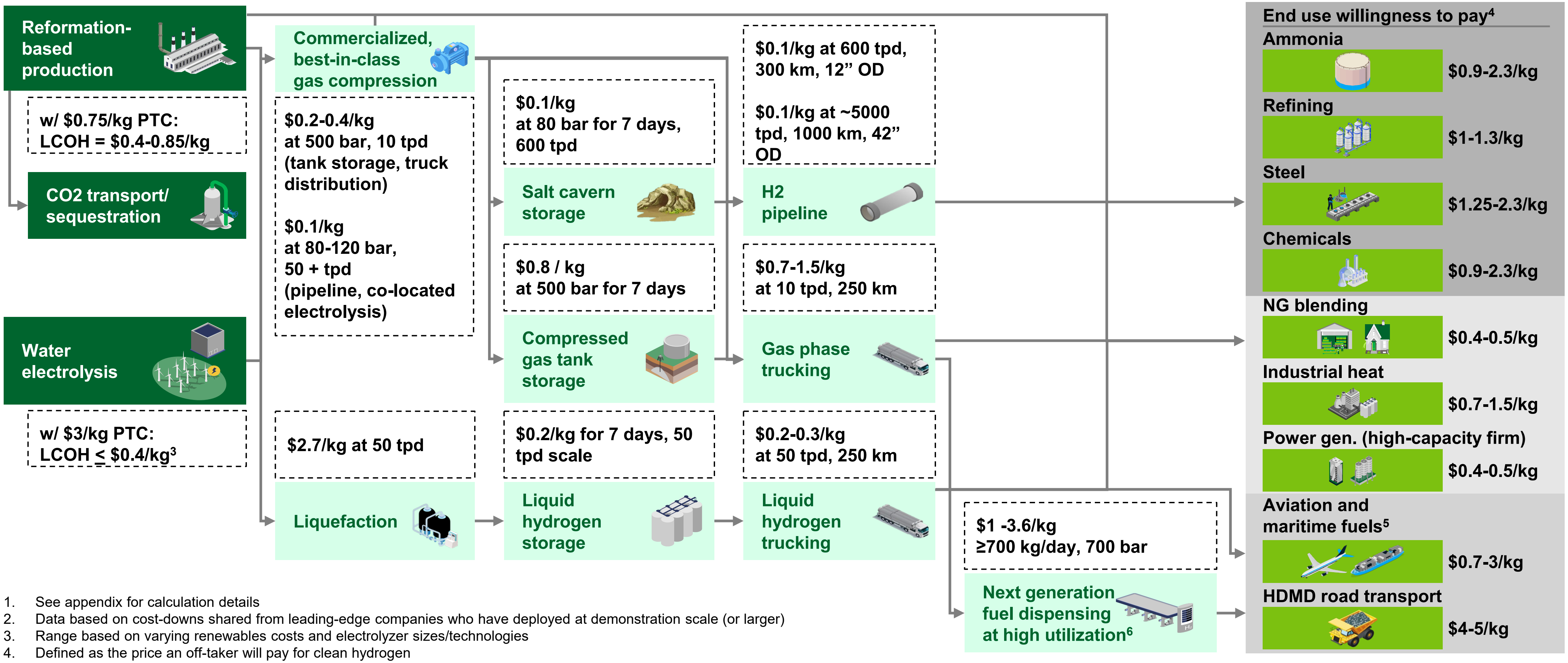
Source: Heatmap is based on data from the Hydrogen Council and the Hydrogen Delivery Scenario Analysis Model at Argonne Natio nal Laboratory, but left qualitative to highlight uncertainty in distribution methods and case-by-case variability

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

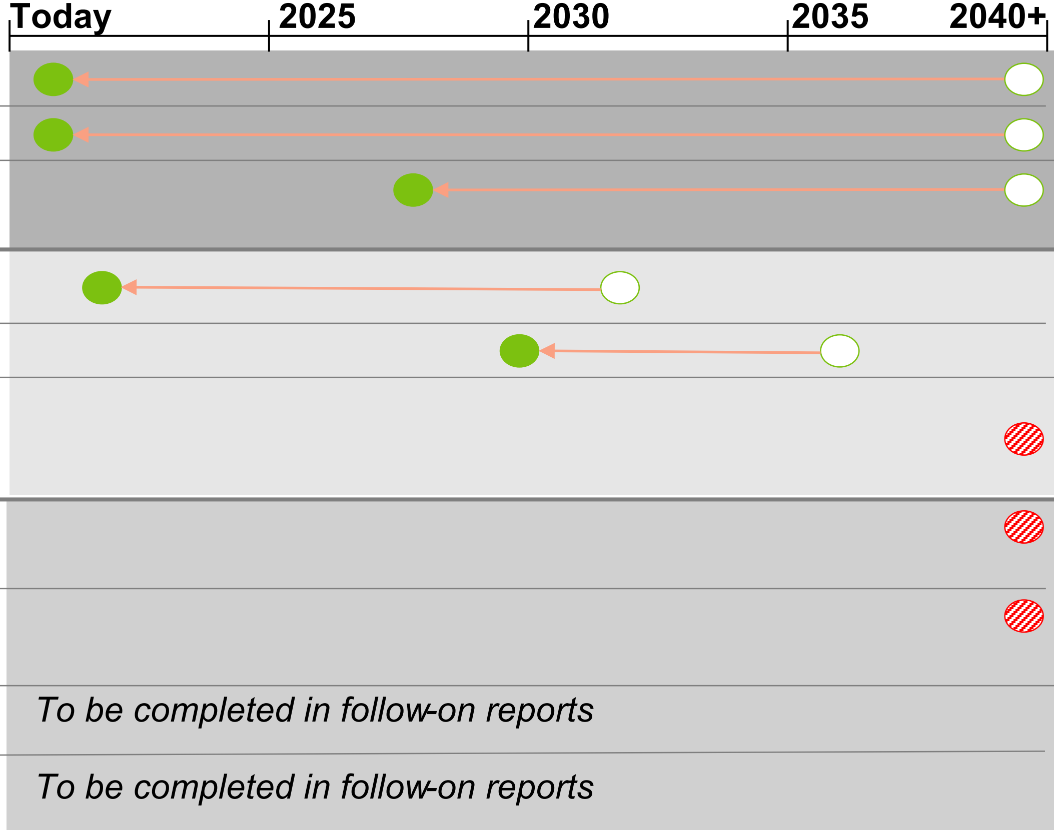
Sources: HDSAM, Argonne National Laboratory; DOE National Hydrogen Strategy and Roadmap, Hydrogen Council

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: 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	Use cases require successful, scaled H2 Hub with open pipeline access
Long duration energy storage	

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.

OCED, H2Hubs, and Pathways

H2Hubs learnings and best practices will inform Pathways and Other Updates for public dissemination

OCED Mission

"Deliver clean energy technology **demonstration projects at scale** in partnership with the **private sector** to **accelerate deployment**, **market adoption**, and the **equitable transition** to a decarbonized energy system."

Thank you!

Download the report: liftoff.energy.gov

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