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European Union Agency for the Cooperation of Energy Regulators

European hydrogen markets

2026 Monitoring Report

13 November 2026

Report in PPT format

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Overview of key findings

Regulatory framework	**1 of 27** Member States has fully transposed the Gas Directive (11 partially)	• Core EU framework largely in place: REDIII, RFNBO and low-carbon rules and the H2 and Gas Package • Transposition and enforcement lag on the national level → **Transpose, certify HNOs, clarify NRA roles, coordinate national rules, provide post-2030 certainty**
Supply	**4.2 GW** committed electrolysis vs 30–58 GW in 2030 scenarios and strategies	• 490 MW of operating electrolysis by end of 2025: 5.7x since 2020, below 1% of supply capacity → **Recalibrate targets in strategies and modelling scenarios**
Infrastructure	**622 km** of pipelines commissioned since 2025; 555 km under construction	• An enabler: 8 out of 15 largest committed projects rely on hydrogen infrastructure • Progress is slow and concentrated; uncertain demand holds back network, storage and terminal FIDs → **Build networks incrementally on updated demand; agree corridor risk and cost sharing**
Demand	**7.3 Mt** EU hydrogen demand in 2025, down 3% since 2022	• Electrolytic investment follows bankable demand: electrolysers for refining lead, backed by penalties • Electrolysers for ammonia, methanol, eSAF and steel lag; lead markets could help → **Industrial policy should set these value chains' role and scale, and the balance with imports**
Public support	**15 of 15** largest electrolytic FIDs received EU or national support	• Electrolytic hydrogen remains costlier than fossil alternatives, so public funding is an enabler • An award is not an investment: a third of Innovation Fund hydrogen grant value has been cancelled → **Public support should target mature projects**

The future of renewable and low-carbon hydrogen in EU depends on industrial policy decisions about the future of hydrogen-consuming industries balancing decarbonisation, competitiveness and resilience.



This publication is rich in technical language. Acronyms, abbreviations and terminology are listed at the end of the report. See also the disclaimer on data at the end of this report.

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Slower than expected growth with uncertain future



Progress, but hydrogen deployment remains far behind plans

- **~4.2 GW** of electrolysis (a technology used to produce hydrogen from electricity) is under construction, at FID or operational (almost 50x since 2020) representing 6% of EU hydrogen demand once online.
- Significantly lower than 30–58 GW in 2030 scenarios and strategies.

Investments are mostly driven by mandates

- Refining accounts for **~49%** of committed electrolyser capacity, supported by REDIII transport obligations and penalties.
- REDIII Industry and ReFuelEU mandates have not yet triggered major investment.
- Industries without enforceable mandates struggle to pass through the green premium to final consumers.



Funding and infrastructure are enablers, but cannot create the market alone

- **All 15** large electrolytic FIDs received public support.
- **8 out of 15** large electrolytic FIDs rely on pipeline infrastructure.
- Infrastructure build-out remains concentrated in a few Member States.

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Key findings 1/2

REGULATORY FRAMEWORK

The EU hydrogen regulatory framework is largely complete, but deployment does not align with the stated ambitions and clear post-2030 policy framework needs to be established. At national level implementation lags: *REDIII and hydrogen and decarbonised gas package transposition and implementation should be completed,* with credible enforcement, clear national regulators' responsibilities, certified hydrogen network operators and coordinated national rules for hydrogen network access and operation.

SUPPLY

Despite sixfold growth since 2020, electrolyser capacity stood at 490 MW by end of 2025 and remains less than 1% of EU hydrogen supply capacity. Only 4.2 GW of electrolysis is committed, meaning operational, under construction or with a final investment decision (FID), against 30–58 GW foreseen by 2030 in EU studies and national strategies. The first large-scale project producing hydrogen from fossil fuels with carbon capture and storage was inaugurated in 2026; more are planned to start in 2027. Imports do not close the gap: binding EU import offtake agreements reach 0.2 Mt H_2eq/y by 2030, about 2% of total current hydrogen demand. The resulting gap between ambitions and committed supply feeds into infrastructure planning. The *European Commission and Member States should recalibrate deployment ambitions through the forthcoming revision of the EU Hydrogen Strategy and updates of national hydrogen strategies. Member States and national regulators should integrate electrolysers efficiently into the power system* by removing barriers for technology-neutral demand-side flexibility, supported by cost-reflective tariff structures and connection incentives that encourage efficient operation and location.

INFRASTRUCTURE

Deployment concentrates in a few Member States supporting industrial demand clusters or building export capacity. Between January 2025 and June 2026, 622 km of new or repurposed pipelines were commissioned in the EU, and currently 555 km are under construction; network, storage and import terminal FIDs mostly wait for demand. Similarly, the network access framework evolves in few frontrunner Member States. *Hydrogen networks should be developed incrementally*, based on realistic and regularly updated demand and supply assumptions. Strategic cross-border corridors may require coordinated commitments and clear arrangements for risk allocation and cost sharing. These arrangements are still at an early stage.

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Key findings 2/2

DEMAND

EU hydrogen demand was 7.3 Mt in 2025, 3% lower than in 2022, with the decline concentrated in methanol and chemicals. Renewable hydrogen remains more costly than its fossil alternative, so investment depends on bankable demand. This can be created, often in combination, through binding targets and enforceable penalties, public support that narrows the cost gap or customers willing to absorb the premium commercially through the value chain. Lead markets, supported by measures such as public procurement and downstream obligations, could stimulate demand for low-emission products and, where hydrogen is part of the production pathway, support hydrogen uptake. Refining holds half of committed electrolyser capacity (2.1 GW), supported by REDIII obligations, penalties and straightforward substitution of fossil hydrogen. Electrolyser investments for ammonia, methanol, synthetic aviation fuel (eSAF) and steel lag where obligations are absent or weakly implemented or enforced, or where the cost premium cannot be passed on or secured through long-term contracts. The future pace of hydrogen deployment remains uncertain and depends on policy choices affecting hydrogen-consuming industries exposed to global competition. EU and national industrial policy therefore needs to *set out the role and scale of hydrogen-consuming value chains in Europe*, including the balance between EU production and imports of hydrogen, intermediates and final products, while balancing competitiveness, resilience and decarbonisation.

PUBLIC SUPPORT

Public funding is an enabler of investments as 15 largest committed electrolytic projects, representing 3 GW out of the 4.2 GW total committed capacity, have all secured EU or national funding. Most (15) Member States provide support via grants, premiums or indirect support such as tax and grid-fee exemptions. Yet, funding awards do not always lead to investments. *The European Commission and Member States should target EU and national funding at mature projects and sectors where support can cost-effectively create firm, long-term demand*.

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Market status

Hydrogen retains a material but targeted role in EU decarbonisation pathways. Market deployment remains at an early stage, with fossil routes over 90% of hydrogen production capacity. Over 4 GW of electrolysis is committed, compared with 30–58 GW in 2030 scenarios and strategies. Early investments have relied on captive demand, public support or credible infrastructure commitments. Network, storage and import commitments remain limited, and a liquid, multi-buyer hydrogen market has yet to develop.

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Climate pathway points to a targeted 2050 role for hydrogen

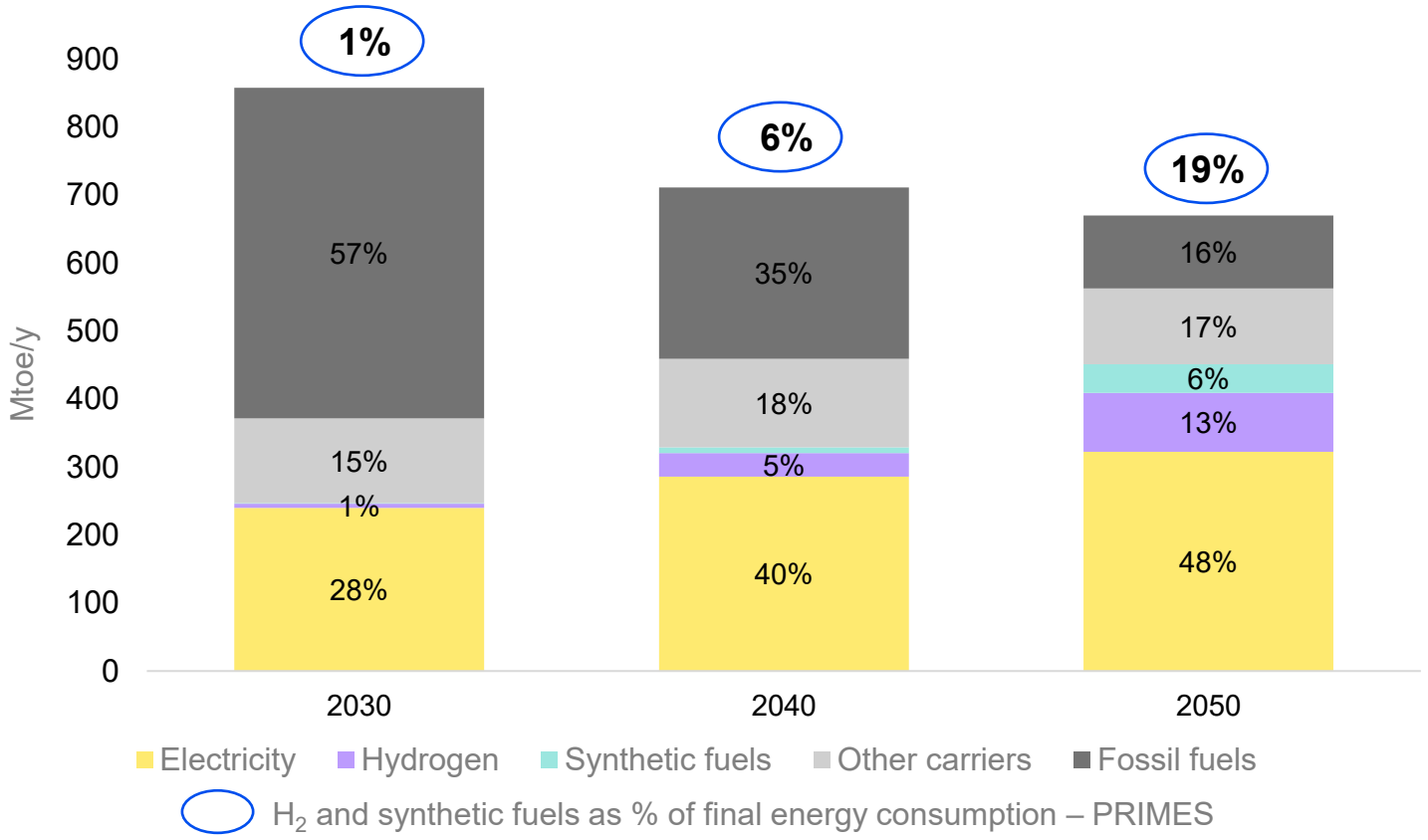
EU climate pathway expects hydrogen and synthetic fuels to constitute 19% of final energy consumption in 2050.

PRIMES S2, the pathway behind the 2040 GHG target impact assessment, shows final energy and industrial feedstock consumption falling by around 22% between 2030 and 2050. Fossil fuel consumption declines by almost 80%, while electricity becomes the largest carrier at 48% of consumption by 2050.

Hydrogen and synthetic fuels grow from about 1% of consumption in 2030 to 6% in 2040 and 19% in 2050, 13% hydrogen and 6% synthetic fuels. The report examines hydrogen in refining, ammonia for fertilisers, methanol for chemicals, steel and synthetic fuels: eSAF in aviation and e-ammonia and e-methanol in maritime. Their role remains complementary to electrification.

The scale, however, remains uncertain. PRIMES S2 is a climate-target pathway rather than a market forecast. S&P's December 2025 Planning Case reaches only ~7% by 2050,[1] showing how strongly the long-term role of hydrogen and synthetic fuels depends on policy delivery, costs and market development. The divergence widens after 2040, underlining uncertainty over the pace of deployment.

Figure 1: Final energy consumption in EU-27 by 2050 and share of hydrogen and synthetic fuels (Mtoe/y; shares in %)



Sources: European Commission, 2040 Climate Target impact assessment, Annex 8 data (PRIMES S2); S&P Global Energy, ©2026 by S&P Global Inc., European Long-Term Energy Demand Balance, Planning Case (December 2025).
Notes: Final energy consumption includes final energy and industrial non-energy use. Fossil fuels comprise coal, oil and gas. Other carriers comprise direct renewables and district heat. Synthetic methane is excluded from PRIMES non-energy consumption. [1]The S&P comparison is indicative because model definitions differ.

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EU hydrogen demand has declined modestly since 2022

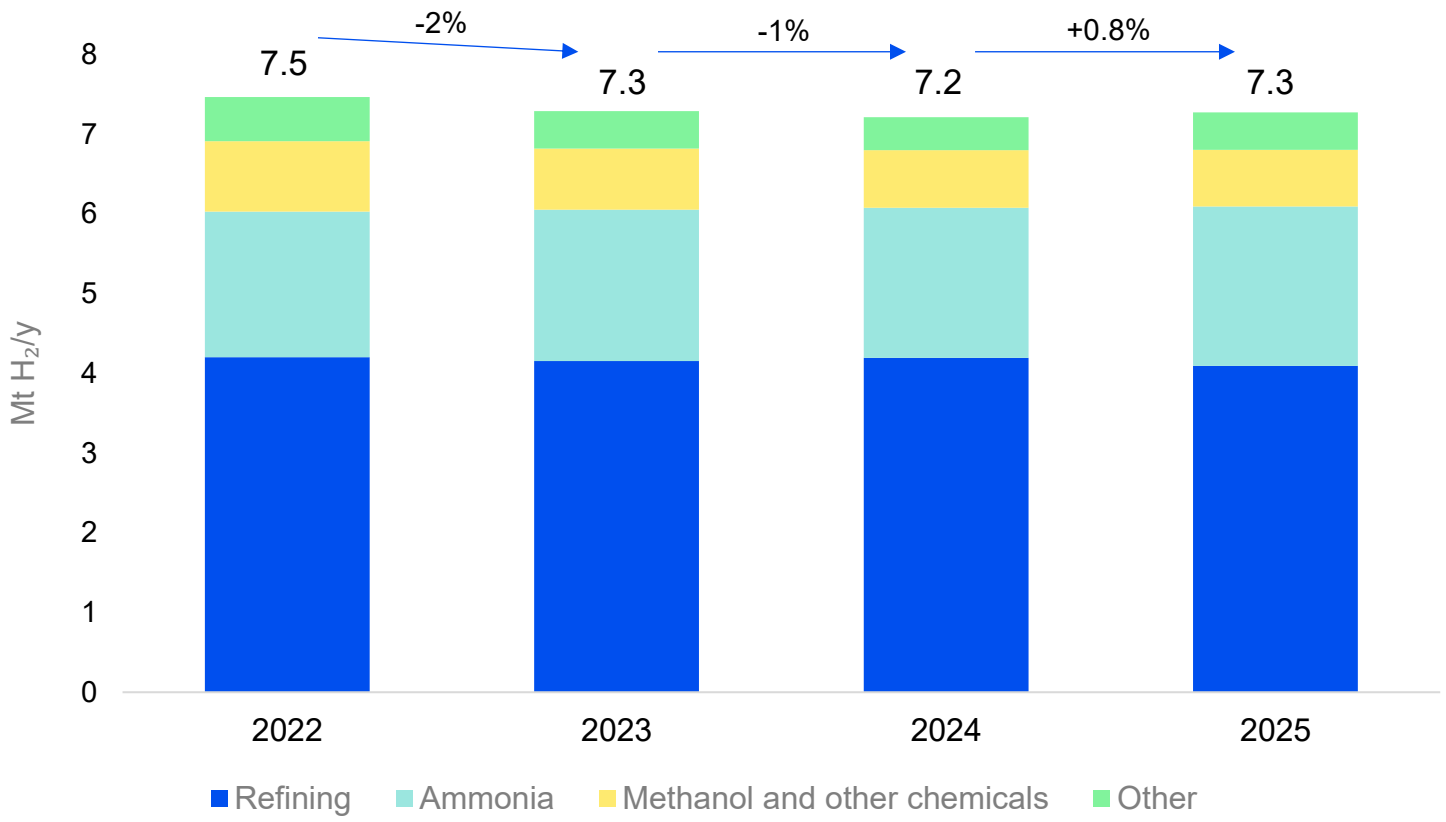
Demand rose slightly in 2025 but remained 3% below 2022, with the largest decline in methanol and other chemicals.

Since 2022, EU hydrogen demand has decreased by around 3%, from 7.5 Mt to around 7.3 Mt in 2025. This relatively small net decline reflects lower consumption in refining, methanol and other chemicals, and other uses, partly offset by increased ammonia demand.

Hydrogen use in ammonia production increased by 10% compared with 2022, when consumption was already depressed by elevated gas prices. High and volatile gas prices drove repeated curtailments and closures, while rising lower-cost fertiliser imports, including from Russia, added pressure on EU producers. Hydrogen use in methanol and other chemicals fell 20%, consistent with weaker EU chemicals production, high energy costs and plant rationalisation. Part of the decline may be structural.

Growing electrolysis capacity has so far supplied little additional hydrogen demand: it remains small, and much of its output replaces fossil-based hydrogen in existing uses. New applications, such as hydrogen-based steelmaking, have yet to add substantial demand.

Figure 2: EU hydrogen demand by end-use, 2022-2025 (Mt H_2/y)



Sources: European Hydrogen Observatory, Hydrogen demand.
Notes: 2025 data are not available on EHO at the time of the publication of this report.

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Electrolysis is emerging rapidly but still marginal

Water electrolytic capacity grew sixfold since 2020 to 490 MW in 2025, yet remains only 0.9% of the total EU hydrogen production capacity.

EU hydrogen production capacity stood at 10 Mt H_2/y in 2025, with unabated reforming accounting for 89% and by-product routes for a further 10%. Capacity exceeds consumption by around 3 Mt H_2/y, with EU hydrogen demand at 7.3 Mt in 2025 (Figure 2). New electrolytic capacity enters a market where aggregate production capacity already exceeds demand, largely replacing conventional hydrogen in existing uses.

Water electrolysis reached 490 MW by end-2025, 5.7 times the 2020 level, but 0.9% of the total hydrogen production capacity, up from 0.5% in 2024. As of writing of this report, Germany and Denmark hold the largest installed capacity, at 219 MW and 100 MW. Average installation size rose from 0.9 MW in 2020 to 2.9 MW, the largest unit being BASF's 54 MW electrolyser in Ludwigshafen.[1]

Reforming with carbon capture capacity remained stable, with no commissioning in 2025. It grew in 2026 with commissioning in the Netherlands and is expected to further do so as capture retrofits at existing Rotterdam reforming units connect to the Porthos network.

Figure 3: EU hydrogen production capacity by process, 2025 (Mt H_2/y)

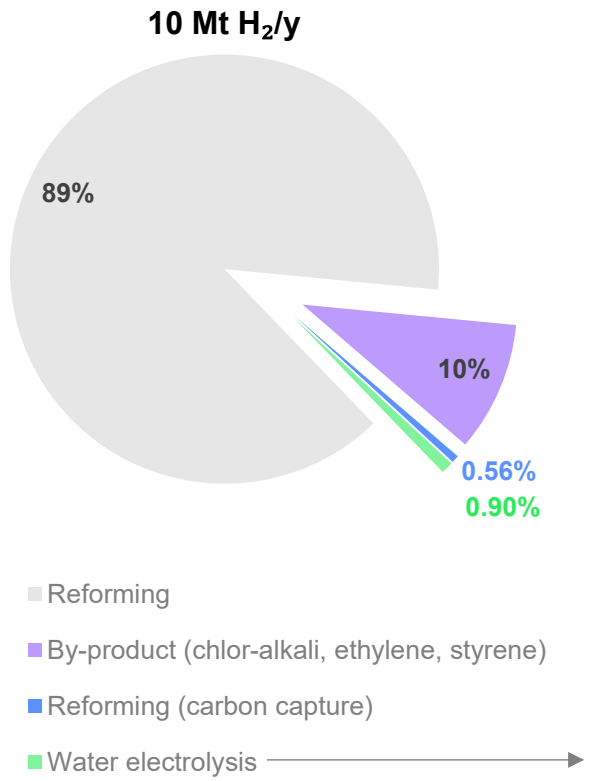
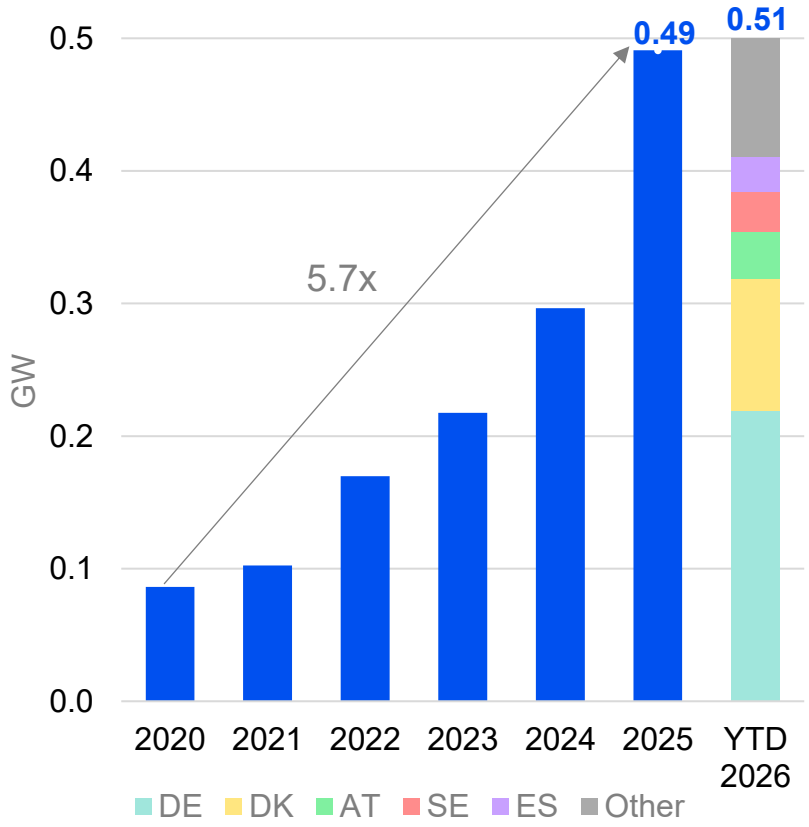


Figure 4: Operational water electrolysis capacity in EU-27, September 2026 (GW)



Sources: European Hydrogen Observatory, hydrogen production capacity; S&P Global Energy, ©2026 by S&P Global Inc., Hydrogen Production Assets Database (operational electrolysis); BASF, Ludwigshafen electrolyser (2025); European Commission, Fertiliser Action Plan (2026).
Notes: Reforming includes by-product hydrogen from refinery off-gases. [1]BASF's electrolyser can supply up to 8,000 t H_2/year to the site's existing hydrogen network; 2025 data are not available on EHO at the time of the publication of this report.

CO_2 storage enables fossil hydrogen with carbon capture

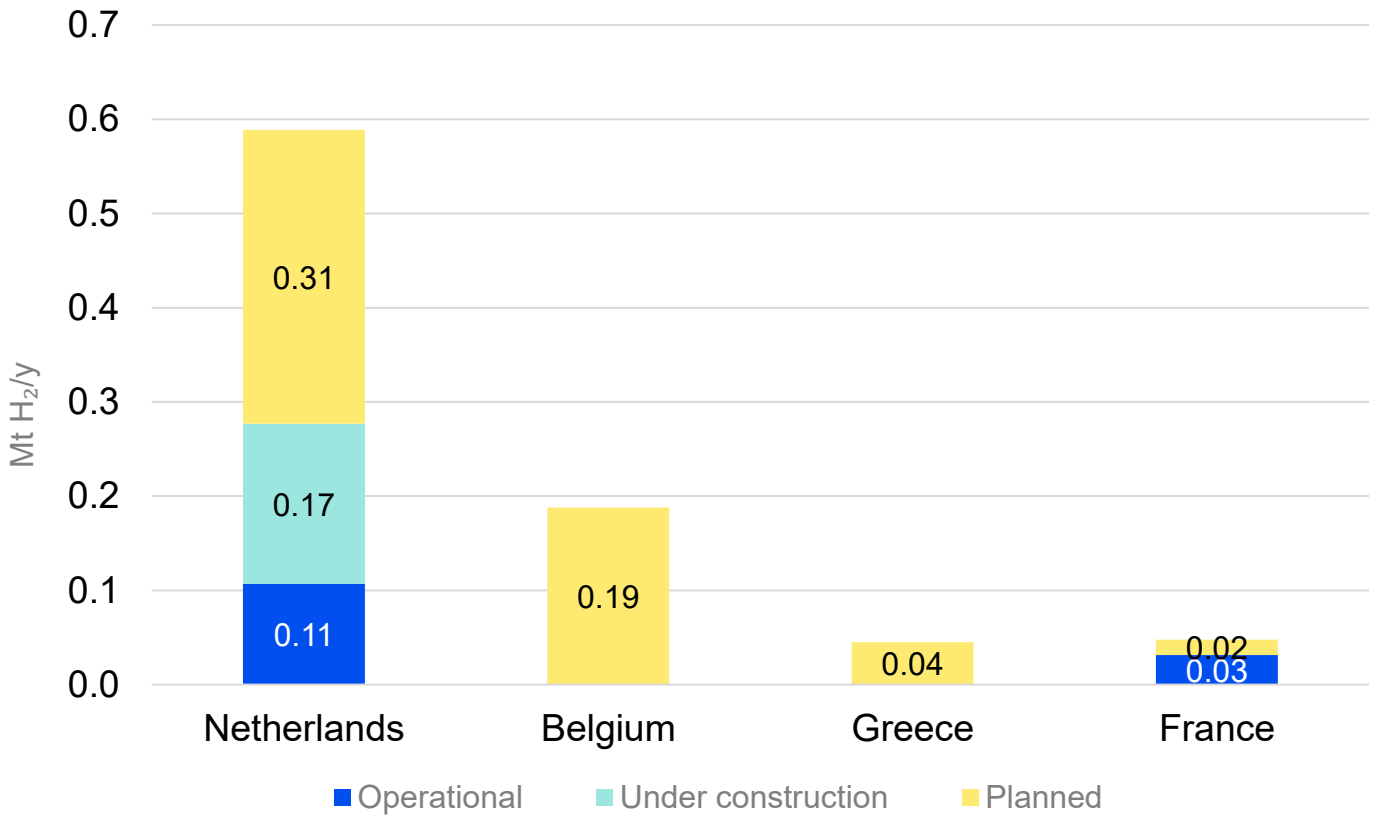
… but continued gas dependence, upstream emissions and exclusion from key H_2 mandates constrain its longer-term role.

Fossil hydrogen with carbon capture is advancing in industrial clusters where natural gas and CO_2 transport and storage are available, supporting favourable economics. Most planned capacity remains under development. Near-term deployment centres on Dutch retrofits: Yara's Sluiskil ammonia project started in September 2026 while two Rotterdam projects expected to become operational in 2027.

The production route nonetheless carries structural risks: continued gas dependence and carbon lock-in, reliance on still-limited CO_2 transport and storage infrastructure and residual upstream methane emissions.

Whether projects qualify as low-carbon hydrogen will depend on their life-cycle GHG emissions, including upstream methane emissions and actual capture rates, meeting the EU's 70% emissions-saving threshold. Certified low-carbon fossil hydrogen cannot meet REDIII RFNBO-specific quotas, but can contribute under technology-neutral instruments such as FuelEU Maritime.

Figure 5: EU-27 fossil hydrogen with carbon capture project pipeline (Mt H_2/y)[1]



Sources: S&P Global Energy, ©2026 by S&P Global Inc., Hydrogen Production Assets Databas; Yara.
Notes: EU-27 SMR/ATR projects with carbon capture; excludes cancelled, decommissioned/offline and on-hold projects. "Under development" covers stages from concept to FEED before construction.
[1]Available emissions data do not establish whether these projects meet EU low-carbon hydrogen criteria.

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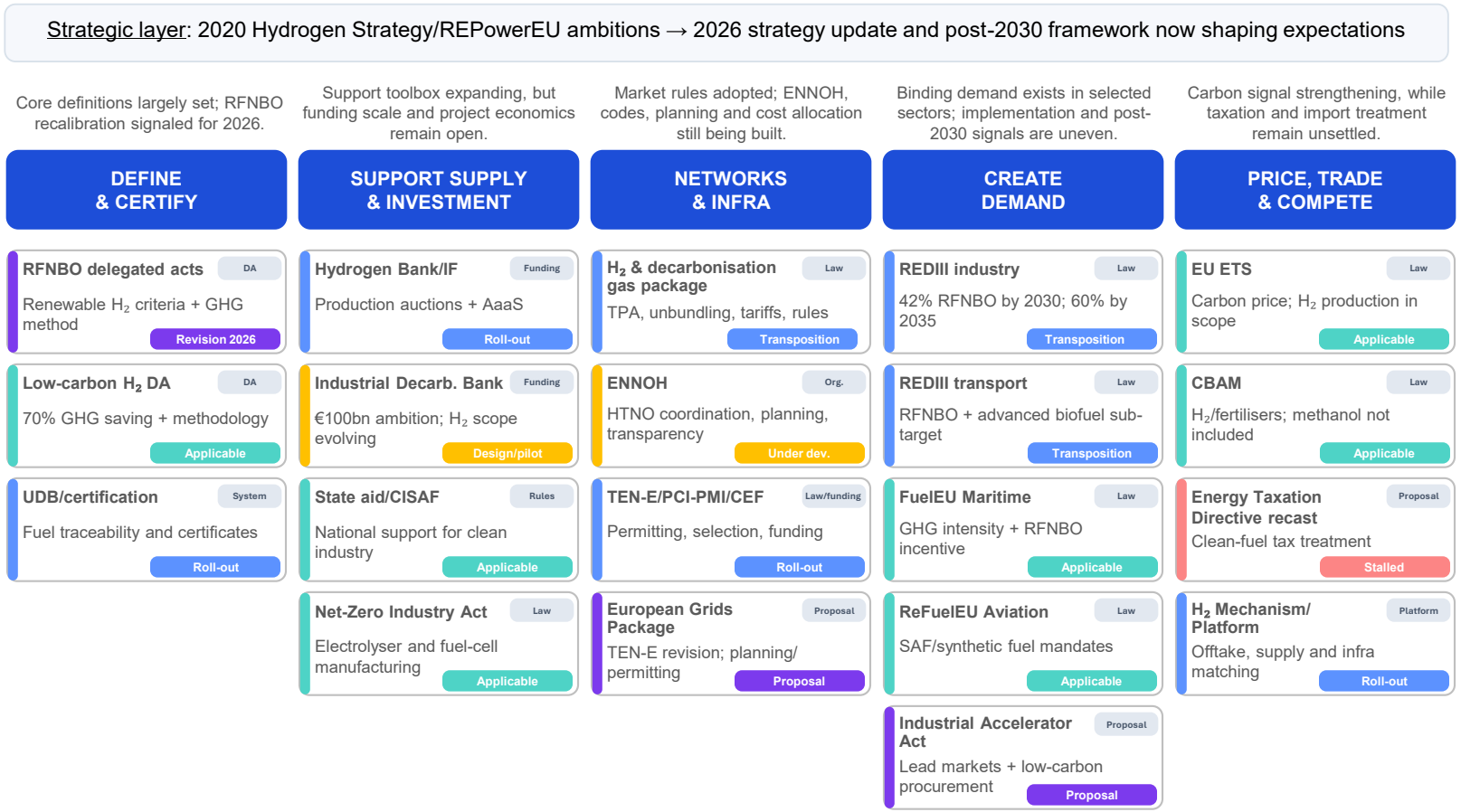
The EU framework is largely set, but implementation lags

Definitions, mandates and rules are largely set, while transposition, infrastructure implementation and post-2030 certainty remain open.

The EU hydrogen regulatory framework is largely in place. REDIII sets binding RFNBO 2030 consumption targets in industry and transport, the RFNBO Delegated Acts and the low-carbon hydrogen DA define renewable and low-carbon hydrogen, and Hydrogen and Decarbonised Gas Package sets market and network rules. The Hydrogen Strategy and the RFNBO DA review are expected by end-2026.

Regulatory uncertainty persists, among others, amid limited REDIII industry target transposition and calls from some airlines to postpone the ReFuelEU Aviation eSAF mandate. Whether the framework will deliver renewable and low-carbon hydrogen deployment and cost-effective decarbonisation at scale remains uncertain. The Commission is preparing the post-2030 framework; clear long-term hydrogen demand signals will be key for investment certainty.

Figure 6: Non-exhaustive selection of the most relevant EU-level hydrogen policy files



Sources: EU hydrogen legislation and European Commission policy documents; Airlines for Europe, CEO declaration.

Different project types reach investment as enablers emerge

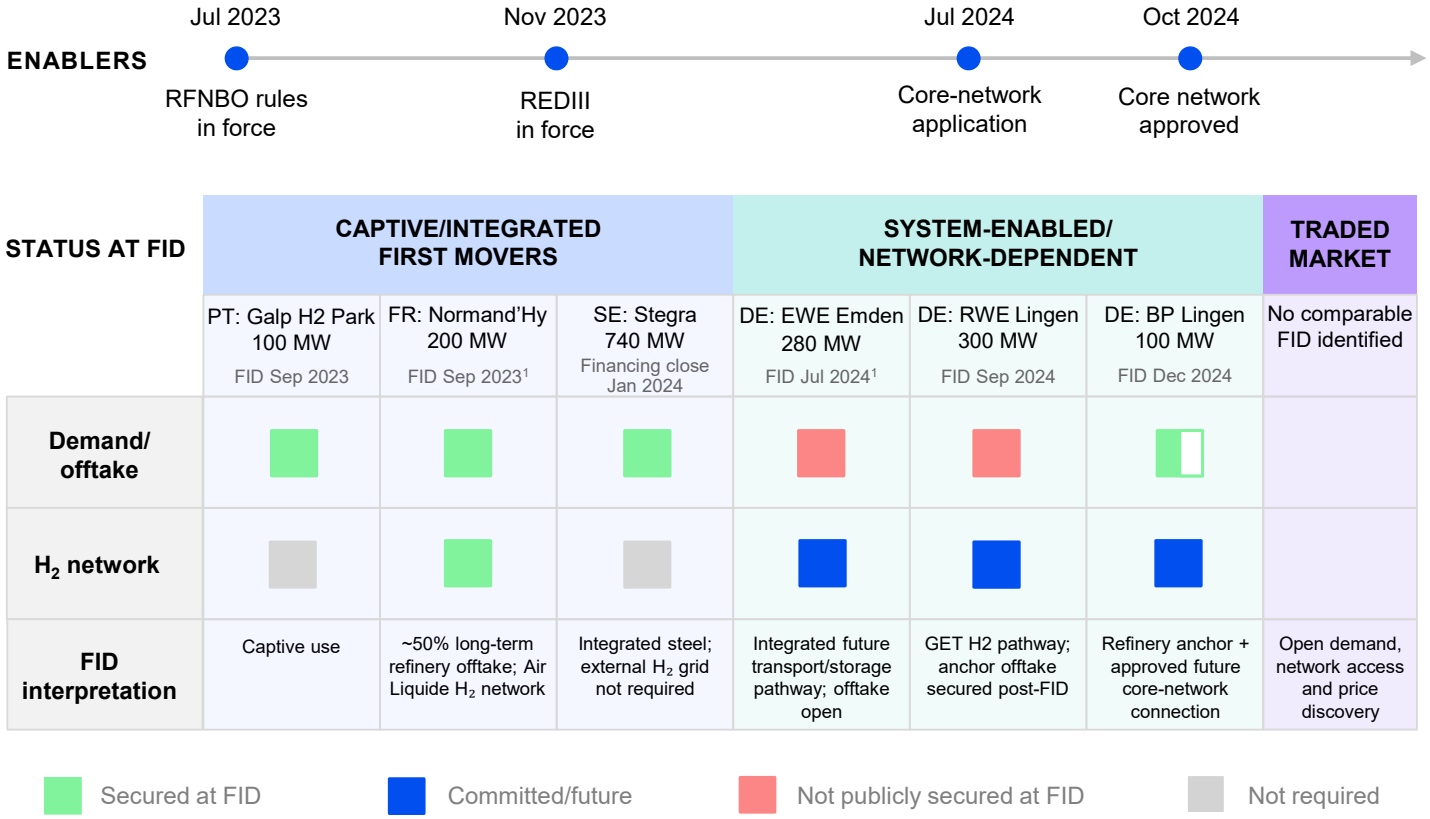
Captive projects moved first; infrastructure commitments enabled network-dependent projects; no comparable traded-market final investment decision (FID) yet.

Early FIDs were concentrated in captive or integrated projects that could control key risks within the project structure. Galp H2 Park relied on captive refinery demand, while Normand'Hy[1] combined an anchor customer with Air Liquide's local network, and Stegra integrated hydrogen production directly into steelmaking. These projects therefore did not depend on a mature, open hydrogen market.

By 2024, public funding and increasingly credible network-development plans enabled a second group of projects. EWE Emden[1] and RWE Lingen proceeded after receiving major funding commitments and with defined transport and storage pathways, although shared infrastructure was not yet operational and external offtake remained partly unresolved. BP Lingen followed after approval of Germany's hydrogen core network, combining captive refinery demand with future network access.

These selected cases suggest a progression from sponsor-controlled value chains towards network-connected projects. No comparable FID has yet relied primarily on a liquid, multi-buyer hydrogen market.

Figure 7: Selected captive and system-enabled hydrogen projects and their conditions at FID



Sources: Galp, H2 Park; Air Liquide, Normand'Hy; Stegra, financing; EWE, Emden; RWE, GET H2; bp, Lingen; RFNBO Delegated Regulations (EU) 2023/1184 and 2023/1185; REDIII; BNetzA, hydrogen core network.
Notes: Conditions reflect publicly available evidence at FID. [1]FID dates for EWE Emden and Normand'Hy are inferred from announcements of project steps requiring FID.

Hydrogen planning needs realistic deployment pathways

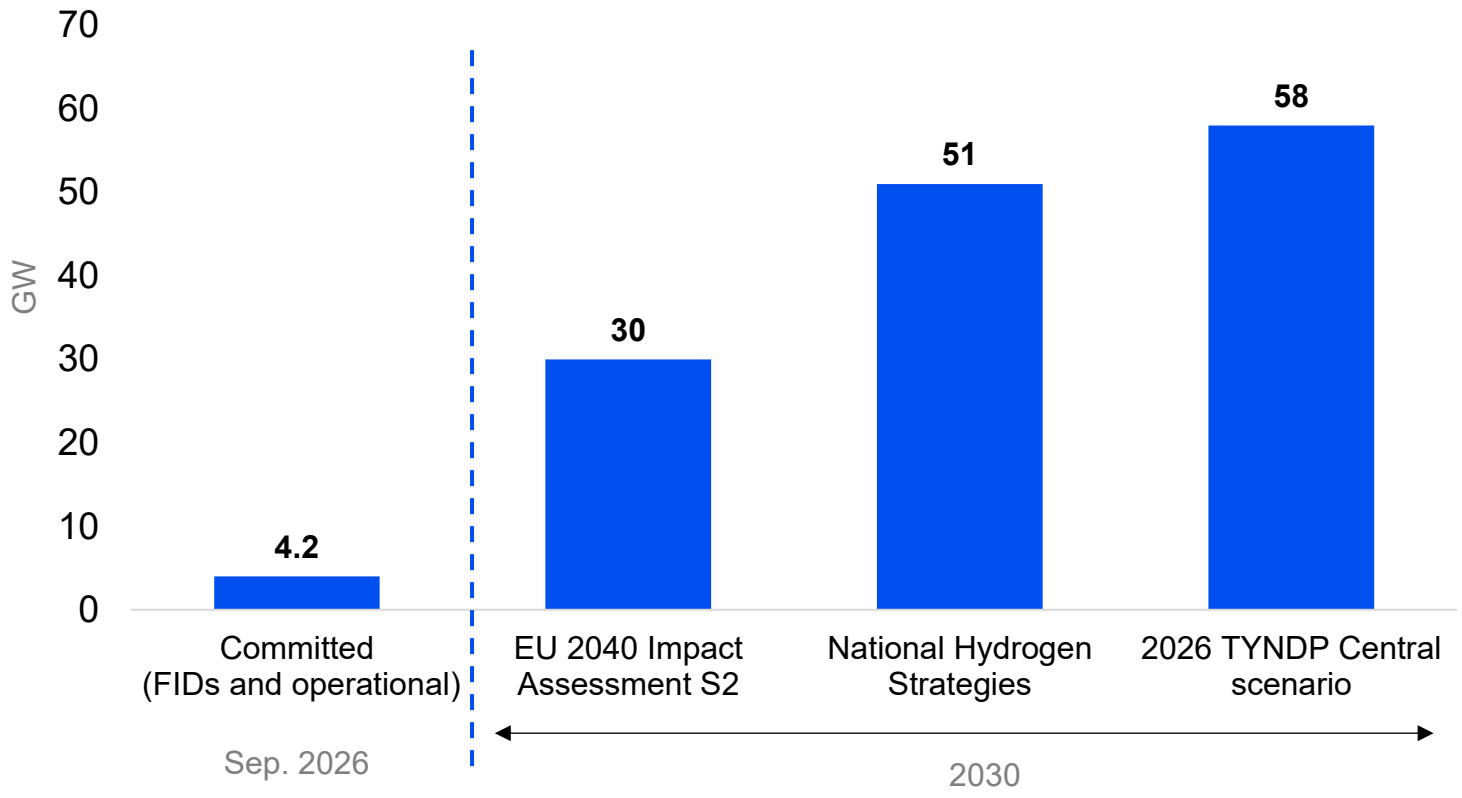
Only 4 GW of electrolysis is committed against 30 to 58 GW in 2030 modelled scenarios and national strategies, feeding uncertainty into infrastructure plans.

Observed electrolytic hydrogen deployment remains well below policy ambitions and scenario assumptions. Only around 4.2 GW has reached FID or operation, indicating limited progress from announced projects to realised investment decisions. The higher 2030 benchmarks reflect different sources: an EU decarbonisation scenario, national strategies and a TYNDP scenario largely based on NECP-reported targets, but all show deployment far beyond the committed pipeline.

The divergence points to a disconnect between policy objectives and implementation on the ground.

The gap calls for action on both delivery and planning. Hydrogen strategies should reassess near-term deployment targets and trajectories, alongside the measures needed to deliver them. System planning should complement target-aligned pathways with additional sensitivities and at least one regularly updated scenario as projects, demand and infrastructure commitments mature. This would make planning more robust to deployment uncertainty while remaining consistent with longer-term policy objectives.

Figure 8: Electrolytic deployment in EU-27 versus national strategies and EU scenarios for 2030 (GW)



Sources: S&P Global Energy, ©2026 by S&P Global Inc., Hydrogen Production Assets Database for committed capacity; European Commission, 2040 Climate Target impact assessment; ACER, European hydrogen markets 2025; ENTSO-E/ENTSOG, TYNDP 2026 draft scenarios.
Notes: National strategies: midpoint (51 GW) of the 48–54 GW range reported in ACER's 2025 Hydrogen MMR; Committed reflects operational, under construction and FIDs).

Investments need enforceable mandates, funding or premia

Half of committed electrolyser capacity is linked to refining supported by Renewable Energy Directive: transport targets (REDIII transport); other sectors struggle with bankable demand.

Refining illustrates how regulatory obligations can support investment, with 2.1 GW of EU electrolyser capacity committed to refinery demand. Adopted and proposed REDIII transport measures, together with ReFuelEU Aviation, could require 1.4 Mt of RFNBO hydrogen by 2030.

Other sectors lag in electrolyser deployment. Electrolyser FIDs for steel emerge where customers pay a premium or governments support domestic plants. Fertilisers and chemicals fall under REDIII industry targets, but weak transposition and penalties limit offtake certainty. Aviation faces a binding eSAF mandate and high penalties, but long-term offtake remains difficult to secure. FuelEU Maritime does not set a near-term RFNBO sub-target.

Bankable demand supports investment across sectors. Penalty-backed mandates can help secure it, as in refining. Public funding can narrow the cost gap, while willing buyers may absorb the green premium. Lead markets can support hydrogen demand through low-emission products. Post-2030 clarity supports long-term commitments.

Figure 9: Committed electrolytic capacity in the EU by end-use, 100%: 4.2 GW

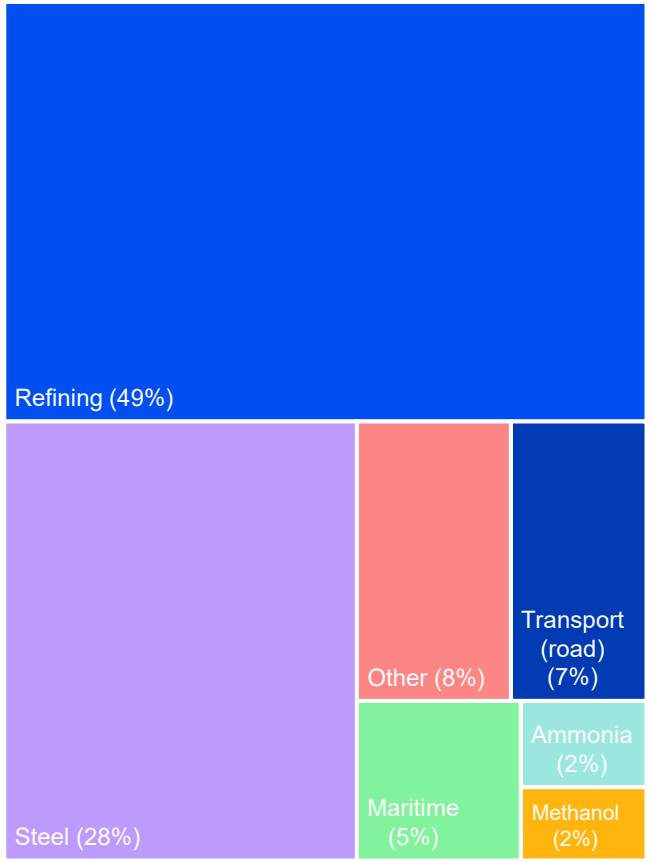
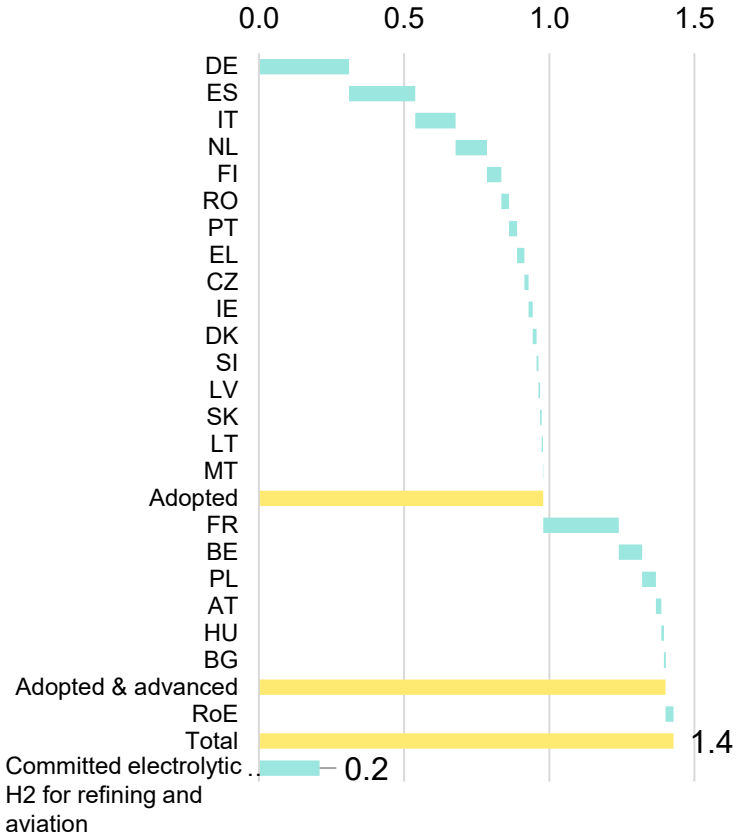


Figure 10: Estimated RFNBO H_2 demand to meet REDIII transport and ReFuelEU Aviation obligations in 2030, based on adopted and draft national measures, August 2026 (Mt H_2/y)



Sources: S&P Global Energy, ©2026 by S&P Global Inc., Hydrogen Production Assets Database for committed capacity; Hydrogen Europe, REDIII transport-demand estimates from August 2026.
Notes: Electrolytic capacity only; each project assigned once to its primary declared offtake. Ammonia/methanol: industrial feedstock and fertilisers; bunkering: Maritime; eSAF: synthetic fuels/PtL primarily serving aviation; refinery H_2 for biofuels/HEFA: Refining. RoE: rest of EU-27.

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Regulation and infrastructure progress slowly

Infrastructure build-out moves from planning to implementation, but progress is concentrated in frontrunner Member States.

Europe's hydrogen market is gradually moving from policy design to implementation, but efforts are currently concentrated in few Member States.

Most of the Member States have been developing national hydrogen network development plans (NDPs) either as stand-alone plans or as part of their gas NDPs.[1] Integrated or coordinated planning with electricity and/or gas is also emerging[2]. Future demand expectations have been revised downward in some national NDPs (DE) and in the TYNDP 2026 scenarios, reflecting the sector's slower than expected development pace and the underlying uncertainties.

While first pipelines are entering operation and cross-border corridors advance, albeit slowly, frontrunner Member States (BE, DE, DK, ES, NL, LU, PL) are developing the necessary regulatory frameworks. Most storage and import terminal projects still lack FIDs and need stronger demand signals and commercial viability.

The transition from planning to large-scale market development is moving slowly and unevenly across the EU. Progress towards FID requires coordination on financing, market development and regulation. Additional de-risking measures should be assessed for their added value and allocation of risks.

REGULATORY FRAMEWORK & PLANNING

Regulation and network planning are gradually emerging across Europe, but implementation remains uneven across Member States.

- 1 Member State has notified full transposition, and 11 have partially transposed the Hydrogen and Decarbonised Gas Directive
- 10 Member States have (some) national market rules in place; 2 have a certified HTNO
- 14 Member States with common gas/hydrogen NDPs – 4 with separate hydrogen NDPs

PIPELINES & CORRIDORS

First regulated hydrogen pipelines commissioned, and cross-border corridors are advancing. Absence of binding commitments increase the risks.

- 622 km of hydrogen pipelines commissioned in the EU until October 2026
- 555 km currently under construction in AT, BE, DE, NL
- 42,259 km of transmission projects planned – 24,352 km by 2030
- South-West and Southern corridors advance faster, but FIDs not taken yet

STORAGE & TERMINALS

Most projects remain at an early stage; implementation depends on demand prospects, technological developments and global trade patterns.

- 11 kt H_2 eq. of storage capacity under construction and 0.7 Mt eq. H_2 planned
- 0.6 Mt H_2 eq./year "clean" ammonia import capacity added in 2025 – 4.4 Mt H_2 eq./year more is planned
- 6.2 Mt H_2 eq./year of liquid hydrogen and hydrogen-derivative imports planned

Sources: NRAs; ACER, Opinion 17/2026; ENTSO-E/ENTSOG, TYNDP 2026 scenarios; S&P Global Energy, ©2026 by S&P Global Inc., hydrogen infrastructure data as reported in the infrastructure chapter.
Notes: "Planned" covers stages from concept to FEED before construction; [1]Only six of these plans are prepared by nationally designated HNOs. [2]Joint electricity–gas–hydrogen scenarios: BE, DK, DE, LT; gas–hydrogen scenarios: AT, FR, HU, RO. Integrated gas–hydrogen NDPs: DK, DE, HU.

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Large electrolytic investments depended on public support

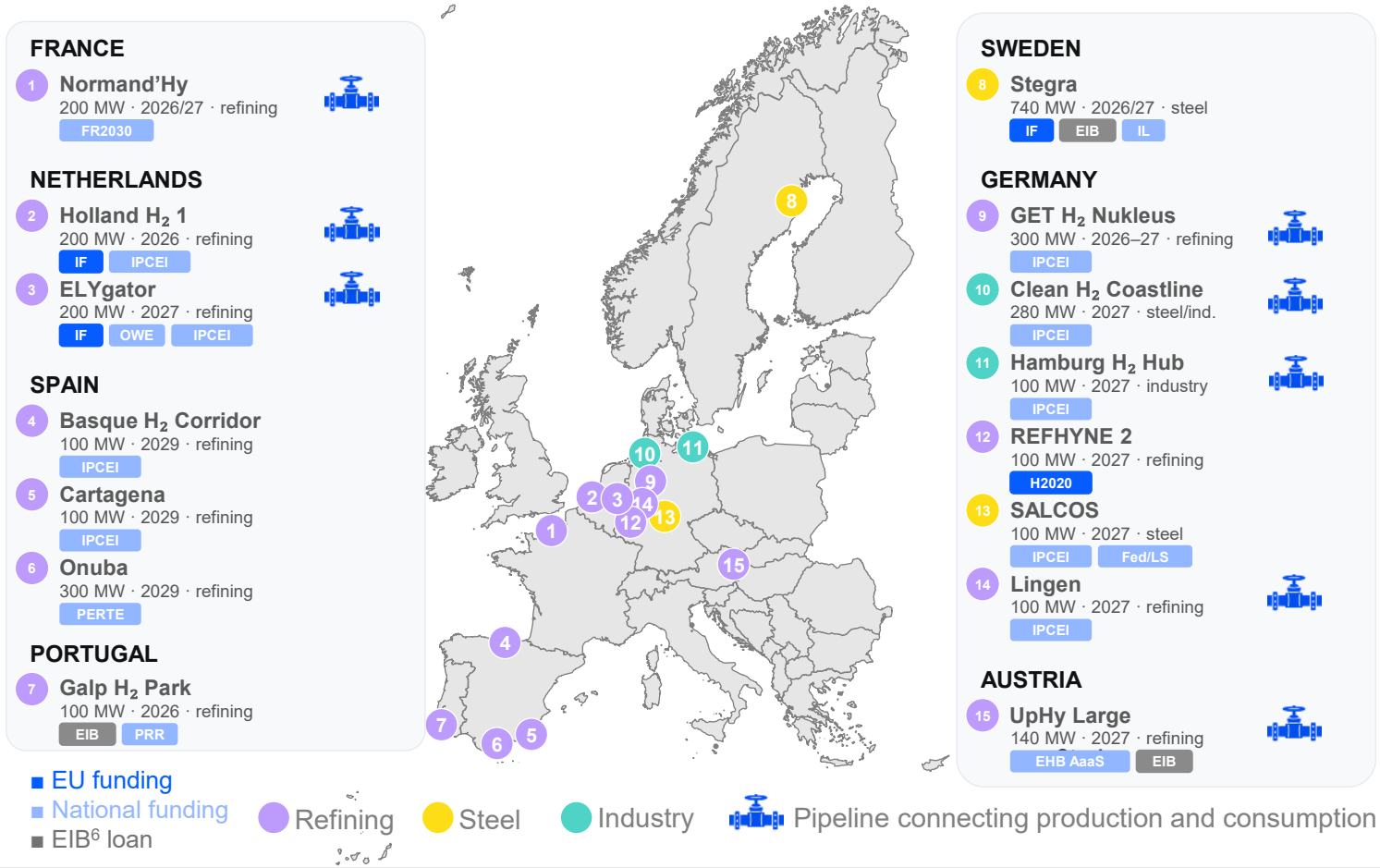
Over 3 GW of large electrolytic final investment decisions (FIDs) benefited from CAPEX grants, premiums, public loans or other instruments to narrow the cost gap; 8 out of 15 largest production projects rely on a pipeline connection

Public funding has supported the largest electrolytic hydrogen FIDs in the EU. The largest 15 FIDs shown on the map, over 3 GW of capacity, all secured EU or national support. Support varies by stage and risk. CAPEX grants such as IPCEI and the Innovation Fund reduce upfront costs, while production support such as the Hydrogen Bank or OWE reduces operating and revenue gaps. Different instruments address different risks, reducing the gap that must be covered by offtake; projects may combine them where available.

An award, however, is not an investment decision. Only a minority of invited/supported projects have reached FID, around a fifth of hydrogen IPCEI projects by 2025, and the Hydrogen Bank's second auction shed most of its selected capacity. Funding can help narrow the cost gap, but firm offtake often remains the next binding constraint, with infrastructure sometimes critical to securing it.

Eight out of these 15 projects rely on pipeline infrastructure, so it is also an investment enabler.

Figure 11: 15 largest electrolytic FIDs in EU, their end-uses, public support and infrastructure connection



Sources: EC/CINEA, Innovation Fund/EHB; RVO, OWE; EIB, Galp, Stegra and OMV financing; company disclosures: Air Liquide, Shell, Repsol, Moeve, Galp, EWE, RWE, bp, OMV, Stegra and Salzgitter; Hydrogen Europe.
Notes: Announced electrolyser capacities and target commissioning dates; Funding coverage is non-exhaustive; Other labels identify EU or national support programmes; Pipeline connection reflects connection of a production asset to the place of consumption

Binding import commitments for 2030 remain limited

Only 0.17 MtH_2eq/yr of extra-EU imports is binding or committed versus 4.1 Mt in TYNDP National Trends+.

Binding agreements cover an estimated 0.17 Mt H_2eq/yr of extra-EU imports from projects expected to start by 2030.[1] Import needs vary widely. The Commission's PRIMES S2 climate-target pathway shows little extra-EU hydrogen imports around 2030, with imports increasing only after 2035. The TYNDP National Trends+ assumes 4.1 MtH_2eq/yr of hydrogen and derivative imports in 2030, although the models use different assumptions and coverage.

Binding agreements are concentrated in renewable ammonia, particularly from India, with additional volumes from China, Norway, Egypt and other countries. A further 0.33 MtH_2eq/yr of non-binding renewable imports is largely destined for Germany as ammonia.

National import strategies also point to substantial import needs. Germany expects imports to cover 50–70% of hydrogen demand by 2030, while Belgium foresees around 0.6 Mt/yr of imports, roughly half for transit. The Netherlands is developing ammonia import infrastructure at Rotterdam and Eemshaven.

Figure 12: Estimated extra EU import offtake for projects starting by 2030 versus TYNDP National Trends+ scenario, September 2026 (Mt H_2eq/yr)



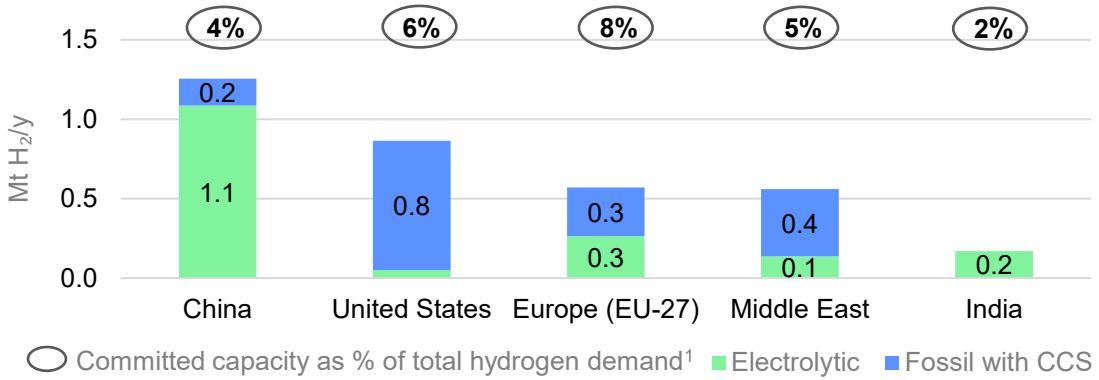
Sources: S&P Global Energy, ©2026 by S&P Global Inc., hydrogen offtake data; ENTSO-E/ENTSOG, TYNDP 2026; EC, 2040 impact assessment; German and Belgian hydrogen strategies; Port of Rotterdam; Groningen Seaports.
Notes: H_2-equivalent volumes; intra-EU trade excluded; TYNDP includes derivatives; model scopes differ; National strategies express expectations, not contracts; Project start does not guarantee delivery.

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Global projects advance under different deployment models

Cost advantages matter, but demand, finance, state coordination, infrastructure buildout and execution also shape project progress in different regions

Figure 13: Committed electrolytic and fossil with CCS hydrogen production capacity by region (Mt H_2/y)



The EU has tools, but project costs and weak offtake still delay FIDs

The EU already has binding RFNBO demand obligations, available public support, existing H_2 demand and a common certification framework. Project development remains constrained by implementation challenges and project economics, while stricter RFNBO electricity-sourcing rules can raise costs versus other markets.

IEA estimates Europe has <20% of committed electrolytic capacity but almost 45% of investment, versus >60% and <25% in China, indicating higher capital costs per unit of electrolyser capacity.[2]

What drives deployment elsewhere?

China

Low-cost, state-coordinated scale

- Low whole-project costs: power, CAPEX, finance
- Industrial demand and strong state coordination
- Manufacturing scale, integrated supply chains and fast execution
- Support increasingly linked to actual hydrogen use

Constraints: OEM overcapacity, below-cost competition, cases of equipment under performance.

United States

Gas and CCUS with incentives

- Cheap gas, CO2 infrastructure and industrial clusters
- 45Q supports CCUS; 45V supports eligible clean-H_2 production
- Export projects can combine US supply support with foreign demand support

Constraints: Limited domestic demand pull; cheap conventional H_2; some projects rely on exports and time-limited policy support.

Middle East

Resource + integrated industrial base

- Strong renewable resources and low-cost gas
- Existing industrial/port infrastructure, often coordinated through state-backed integrated value chains
- Some anchor projects have secured long-term offtake; the wider pipeline remains dependent on external demand

Constraints: Limited domestic demand; reliance on securing export offtake.

India

Demand-backed substitution

- Good renewables, costly imported gas and flexible electricity-sourcing rules improve electrolytic vs fossil-based H_2 economics
- Long-term refinery tenders and aggregated fertiliser procurement create firm demand
- Production support and substantial public/DFI finance

Constraints: Some awarded bids rely on regional incentives that may not materialize.

Sources: S&P Global Energy, ©2026 by S&P Global Inc., Hydrogen Production Assets Database for committed production capacity by country/region; IEA, Global Hydrogen Review 2026; EC, renewable hydrogen framework; ACER, Hydrogen MMR 2025; MNRE/SECI, hydrogen mission; MIIT/MOF/NDRC, application pilots; IRS, 45Q/45V; DOE, H_2 Hubs; Hydrom.
Notes: Committed: operational, under construction or FID. DFI: development finance institution. [1]Committed output as a share of current H_2 demand; indicative and rounded, with differing regional coverage. [2]IEA investment shares cover committed electrolysis, including installation (2026 estimate).

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Focus: Demand

Renewable hydrogen cannot yet compete with fossil alternatives on price alone. Refining holds the largest share of electrolyser investments, because REDIII transport obligations, enforceable penalties and relatively straightforward substitution create bankable demand; ammonia and methanol for chemical uses, eSAF, maritime fuels and steel lag because mandates are absent, weakly implemented or enforced or green premiums cannot be passed through or contracted long term. Industrial policy decisions will shape the role and scale of hydrogen-consuming value chains in Europe, including the balance between EU production and imports of hydrogen, intermediates and final products, while balancing competitiveness, resilience and decarbonisation.

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Electrolytic hydrogen cost gaps vary, but premium remains

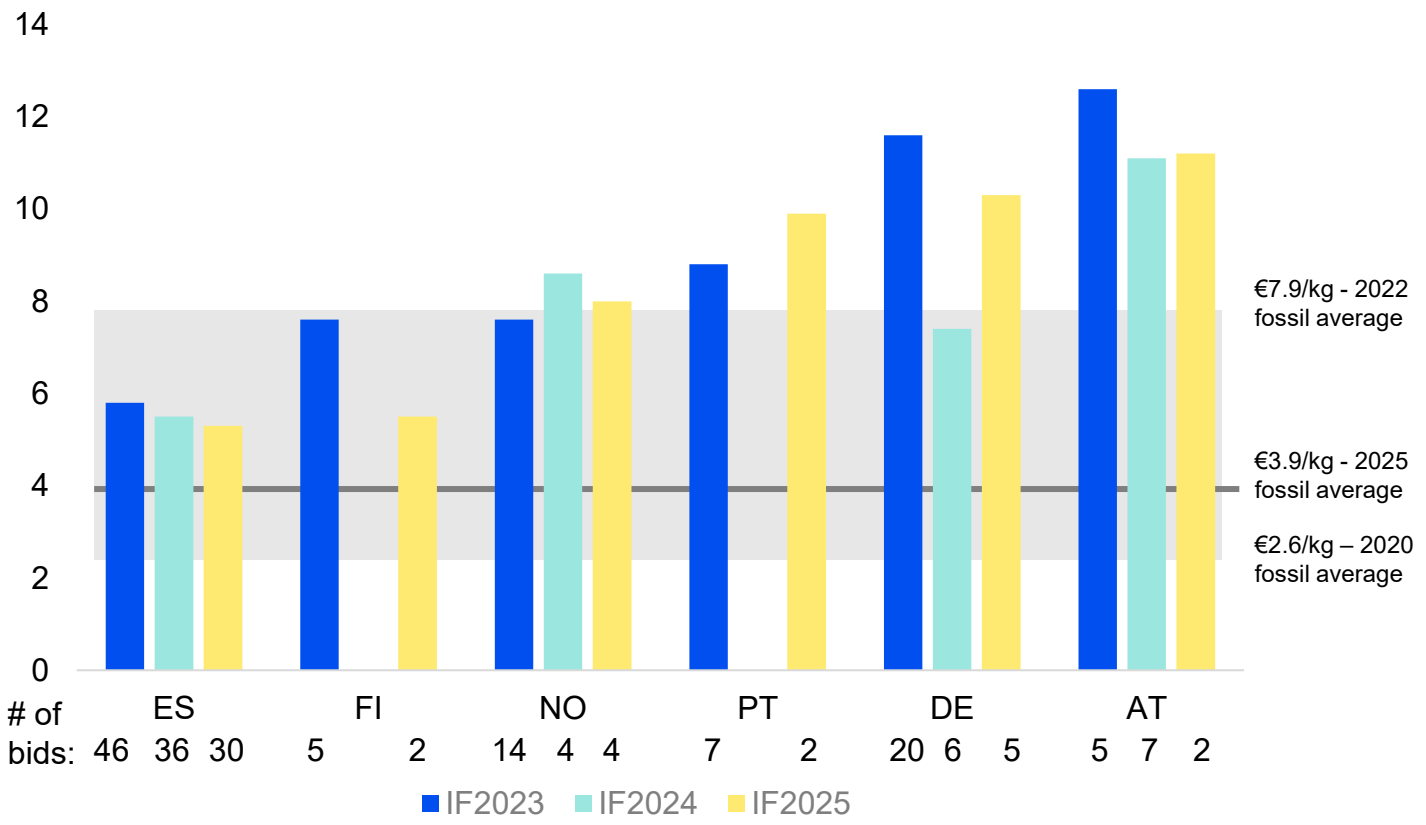
Even Spain's low levelized cost of electrolytic hydrogen (~€5.3/kg) exceeds the ~€3.9/kg fossil H_2 average (2025).

Hydrogen production costs reported by European Hydrogen Bank applicants exceed the 2025 conventional hydrogen average in all countries shown. Country averages and medians range from €5.3/kg in Spain to €12.6/kg in Austria, with Spain consistently at the lower end and attracting the most bids.

The first two auction rounds are presented as country averages, while the third round is shown as country medians. As a benchmark, fossil hydrogen from reforming without CCS averaged €3.9/kg in 2025, with annual averages over 2020–2025 ranging from €2.6/kg in 2020 to €7.9/kg in 2022, when European gas prices surged following Russia's invasion of Ukraine. Under lower gas-price conditions, the cost gap is substantially wider.

Even when high gas prices narrow the cost gap, such periods do not provide the long-term certainty needed to secure bankable RFNBO offtake. Investment still depends on enforceable obligations, public support or customers willing to contract a green premium.

Figure 14: LCOH from IF auctions (European Hydrogen Bank) and conventional H_2 cost benchmark (€/kg H_2)



Sources: Hydrogen Bank auctions (IF23, IF24, IF25); S&P Global Energy, ©2026 by S&P Global Inc., fossil hydrogen prices.
Notes: Applicant estimates: IF23–24 country averages; IF25 country medians, including topics open to low-carbon electrolysis. Fossil benchmark from S&P Global Energy: historical SMR without CCS, including CAPEX, OPEX and carbon costs. Shading: range of annual averages, 2020–25; line: 2025 annual average.

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Refining leads electrolytic uptake, chiefly driven by policy

Obligations and high penalties can bridge the cost gap; replacement of fossil hydrogen eases deployment; uptake remains mandate-led.

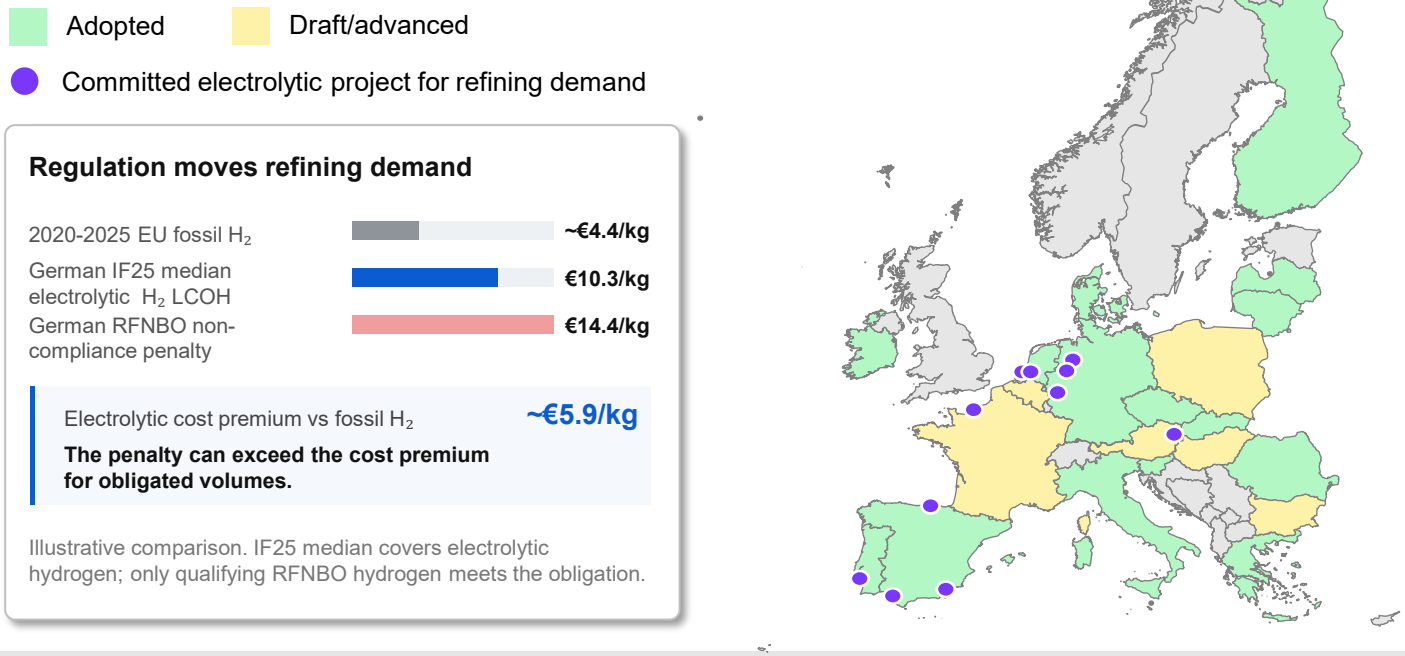
Deployment of electrolytic hydrogen is most advanced in refining, which accounts for 2.1 GW, around 49% of committed EU electrolytic capacity. These projects could produce around 0.21 Mt H_2/year, equivalent to around 5% of EU refinery hydrogen demand.

REDIII transport obligations drive uptake by crediting RFNBO hydrogen used in fuel production, with high non-compliance penalties helping bridge the cost gap. Interim targets would support near-term uptake; post-2030 clarity would support long-term offtake. Technical substitutability supports deployment: electrolytic hydrogen can replace existing hydrogen molecule-for-molecule, particularly at low substitution shares. Even with significantly higher hydrogen costs, impact on final product prices remains limited.

Beyond mandated volumes, demand remains constrained by the cost gap with conventional hydrogen. At higher substitution shares, storage, backup supply or other balancing solutions may also be needed, adding further cost.

EU committed	Supporting factors	Constraints
2.1 GW	• REDIII transport obligation with penalties • Technical feasibility • Low impact on final product price	• Limited refinery presence in some Member States • Demand concentrated in compliance volumes • Grid capacity and land constraints near refineries • Balancing variable electrolyser output

Figure 15: Selected European committed electrolytic production projects for refining and REDIII transport transposition status, August 2026



Sources: S&P Global Energy, ©2026 by S&P Global Inc., Hydrogen Production Assets Database for EU committed and fossil hydrogen prices for 2020-2025 EU fossil H2; European Hydrogen Observatory, hydrogen demand; Hydrogen Europe, Clean Hydrogen Monitor 2025 and REDIII implementation tracker; EC, hydrogen auctions; ACER, hydrogen markets (2025); Germany, BImSchG §37c; REDIII; company announcements for map locations. Notes: Output assumes 5,500 full-load hours/year and 55 kWh/kg H_2; share uses 2024 refinery demand (4.195 Mt). Costs: German IF25 median, all topics, versus 2020–25 fossil average; excludes storage, backup and balancing. Penalty: €120/GJ = €14.4/kg H_2 (LHV).

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Hydrogen-ready steel projects advance, some on gas first

Projects that progress have cheap clean power, funding, infrastructure or green premia; some defer hydrogen use.

Steel differs from existing hydrogen uses: hydrogen-based direct reduction replaces coking coal and requires new production assets. Without mandates to switch to hydrogen and non-compliance penalties, the economics depend on low-cost clean power, hydrogen availability, ore quality and customers willing to pay a green premium.

ETS free-allocation phase-out and CBAM inclusion improve low-emission steel's relative economics but do not alone secure European steel competitiveness. EU trade rules from July 2026 cut tariff-free quotas by 47% relative to 2024 and raise out-of-quota duties to 50%. The Steel and Metals Action Plan and proposed Industrial Accelerator Act seek to create lead markets, including through low-carbon public procurement requirements and a voluntary carbon-intensity label.

If all selected DRI projects ran on hydrogen, they could create over 1 Mt/y of hydrogen demand. Four are under construction. Stegra plans hydrogen-based production from the outset. SALCOS, Power4Steel and tkH_2Steel plan substantial initial natural gas use, with SALCOS also producing hydrogen on site.

EU committed	Supporting factors	Constraints
1.2 GW[1]	• ETS free allowances phase-out and CBAM • WtP in some sectors (some automotive, and selected others) • Lead markets and public procurement	• No mandate to switch to H_2 • Limited WtP in cost-sensitive sectors • Economics only work in specific regions • Flexible NG-H2 DRI default – hydrogen deferred • Reduced iron (HBI) can be imported; no EU-origin requirement

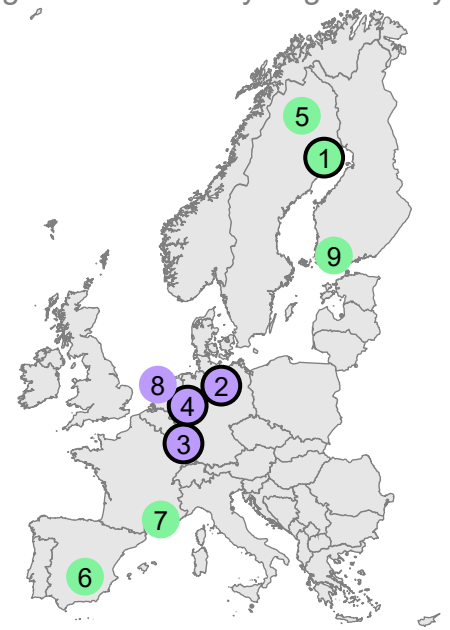
Figure 16: Selected European hydrogen-based and hydrogen-ready steel projects

1 Stegra
Stage: Under construction;
Scale: 2.5 Mtpa steel · 740 MW
H_2 route: Integrated on-site H_2 production

2 Salcos (Salzgitter)
Stage: Phase 1 construction; 2027
Scale: 2.1 Mtpa DRI · 100 MW
H_2 route: On-site, NG, external H_2 from 2030

3 Power4Steel (Stahl Holding Saar)
Stage: Under construction; 2028/29
Scale: ~2 Mtpa DRI
H_2 route: NG at first ; limited h2 contracted

4 tkH2Steel
Stage: Under construction; ~2027
Scale: 2.5 Mtpa DRI
H_2 route: NG first; H2 tender paused



100% H2
Mostly natural gas initially
Construction

5 HYBRIT/LKAB
Stage: Permitted; pre-FID
Scale: 1.3 Mtpa DRI
H_2 route: Integrated on-site H_2 production

6 HyDnum Steel
Stage: Pre-FID · 2026 target
Scale: 1.5 Mtpa flat steel
H_2 route: Integrated on-site H_2 production

7 GravitHy
Stage: Pre-FID
Scale: 2 Mtpa DRI/HBI · 720 MW
H_2 route: Integrated on-site H_2 production

8 Heracless (Tata Steel)
Stage: Pre-FID
Scale: N/A
H_2 route: NG first; H_2-ready

9 Blastr Green Steel
Stage: Pre-FID; Environmental permitting
Scale: N/A
H_2 route: Integrated on-site H_2 production

Sources: LKAB (HYBRIT); Tata Steel; GravitHy; Hydnum Steel; Stegra; Blastr; Salzgitter (SALCOS); SHS (Power4Steel); EUROMETAL (tkH_2Steel); EC, Steel and Metals Action Plan, Industrial Accelerator Act and steel safeguards; Other company announcements
Notes: Capacities refer to the stated product and are not directly comparable; MW denotes electrolyser capacity; [1]The 1.2 GW includes EWE Clean Hydrogen Coastline's full 280 MW, allocated to steel as its primary offtake sector despite supplying other users.

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ReFuelEU mandates eSAF demand; EU projects lag

High penalties have not unlocked commercial EU investment; global committed capacity falls short of 2030 ReFuelEU demand.

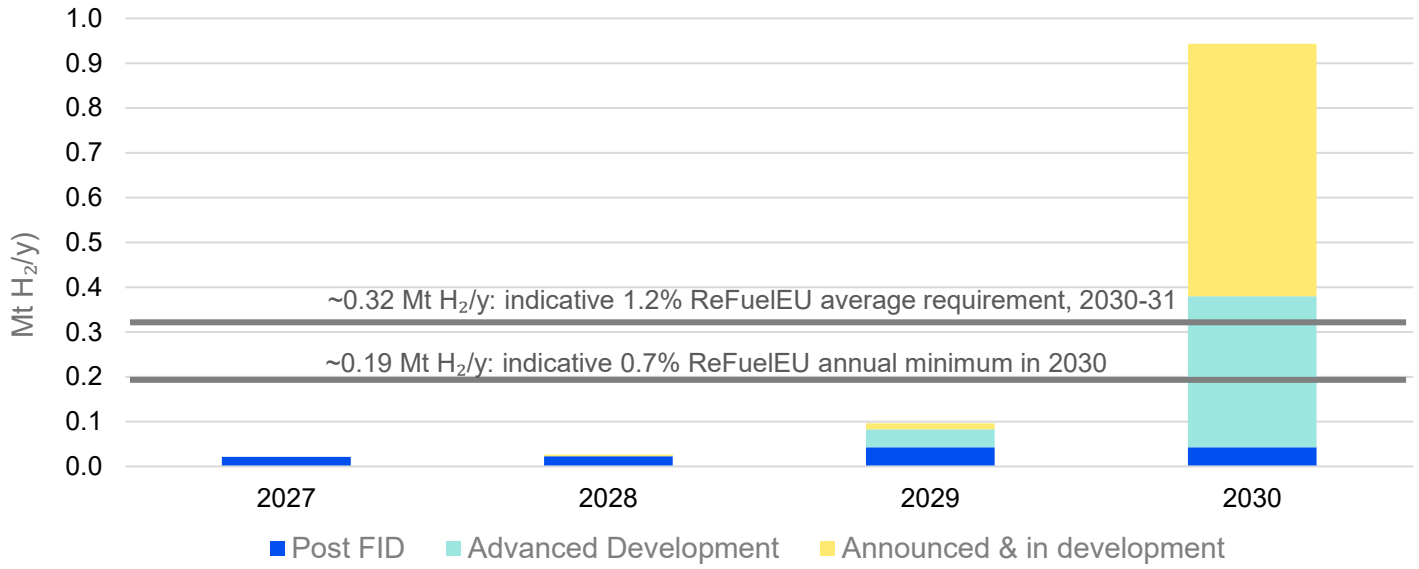
E-kerosene (eSAF) is a synthetic aviation fuel made from renewable hydrogen and CO_2. Under ReFuelEU Aviation, it must account for an average of 1.2% of aviation fuel in 2030–31, rising to 35% by 2050, creating substantial long-term hydrogen demand. Bio-SAF cannot meet this sub-target, long-haul aviation has limited alternatives and shortfalls trigger high penalties and carry-over obligations.

Yet no commercial EU eSAF project has reached FID. Producers need 10–15-year offtake contracts, but airlines buy on shorter terms. Obligated fuel suppliers have not bridged this gap, while some airlines press to postpone the sub-target in the 2027 review. Prospective penalties of ~€13,800/t[1] have not unlocked FIDs, and 13 Member States face infringement over missing penalty rules.

EU ETS SAF allowances partly cover airlines' fuel price premium, while the Sustainable Transport Investment Plan's pooled double-sided pilot auction will test revenue certainty in time for 2030 commissioning. If EU projects do not progress, much of this demand may be met through imports.

EU committed	Supporting factors	Constraints
0 GW (Commercial)	• Binding ReFuelEU Aviation sub-target • Penalty floor of 2× price gap and carry-over obligations • ETS SAF allowances • STIP pilot double-sided auction; EU-wide mechanism under assessment	• 2027 review uncertainty as window closes for 2030/31 compliance • Offtake mismatch: projects need 10–15y, buyers sign short-term • ~12× cost (e-kerosene vs regular) • 13 Member States under infringement for missing penalty rules (June 2026) • CO_2 cost and eligibility constraints

Figure 17: Global eSAF project pipeline by stage, cumulative capacity (Mt H_2/y)



Sources: Public project announcements; IEA Hydrogen Production and Infrastructure Projects Database; ReFuelEU Aviation (2023/2405); IFRI (June 2026); T&E (March 2026); EASA, 2025 fuel reference prices; EASA, ReFuelEU Aviation Annual Technical Report 2026; EC, June 2026 infringements and STIP (2025).
Notes: Full capacity allocated to primary end-use; synthetic eSAF/PtL only; HEFA refinery H_2 under Refining. [1]Indicative Article 12(5) minimum: 2 × (€7,520 − €640) = €13,760/t of synthetic fuel, using EASA's 2025 prices. Actual 2030 fines depend on future prices and national rules; EU reference lines assume 44.385 Mt aviation fuel/y and an indicative conversion factor of 0.60 t H_2/t eSAF.

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Ammonia faces a strategic import trade-off

Low-emission imports compete on price, but limited premium pass-through along the value chain constrains uptake.

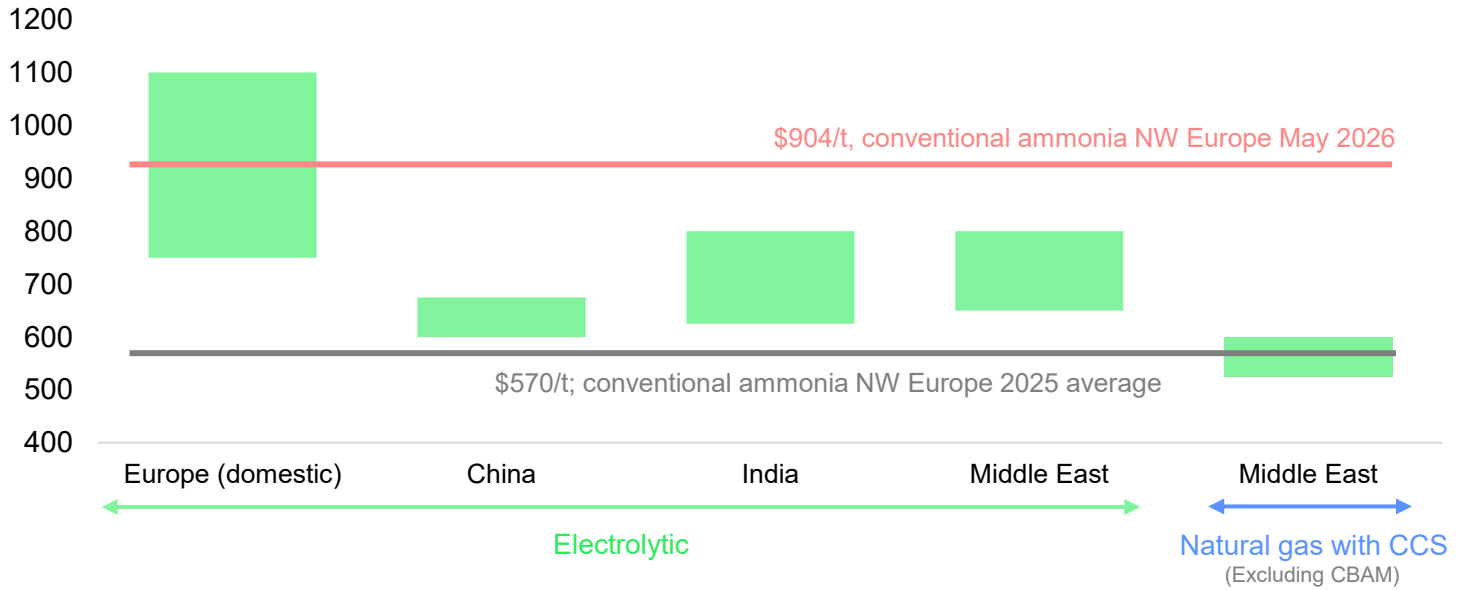
Ammonia is a major hydrogen use and a strategic input to fertilisers and chemicals; the EU makes about 5% of global output and imports around 15% of its ammonia. E-ammonia for bunkering is covered on page 25. EU production faces gas and carbon costs, and 9% of EU capacity has closed permanently since 2023, linking hydrogen policy to food security and industry resilience.

Announced ammonia capacity is largely low emission: natural gas with CCS in the US and Middle East, electrolytic in China, India and Saudi Arabia. Indicative low-emission import prices ($525–800/t) overlap the 2025 conventional NW Europe benchmark ($570/t) and are below its May 2026 level ($904/t).

Under REDIII, ammonia production falls within REDIII's 42% industrial RFNBO target, but transposition is uneven and non-compliance penalties are rare. As producers struggle to pass the green premium to customers, FIDs are limited. The Chemicals Industry Action Plan lists ammonia as an essential chemical to safeguard, and the Fertiliser Action Plan signals intent to retain domestic production, but their impact is yet to be seen.

EU committed	Supporting factors	Constraints
0.08 GW	• REDIII 42% industry RFNBO target (if adhered to) • ETS free-allowance phase-out + CBAM • Fertiliser security/strategic autonomy	• Slow, uneven REDIII transposition • Limited willingness to pay (unable to pass through the premium) • Competitive conventional and low-emission imports • RFNBO imports can meet the target; leakage risk

Figure 18: Indicative low-emission ammonia price ranges, delivered to Europe and domestic production, 2026 (USD/t NH_3)



Sources: S&P Global Energy, ©2026 by S&P Global Inc for price ranges, conventional ammonia prices and EU committed; McKinsey, From Tight Markets to Green Horizons: The New Era of Ammonia (2026), using Fertecon Ammonia Outlook 2026.01; EC, Fertiliser Action Plan and Chemicals Industry Action Plan; OIES, Decarbonising Europe's ammonia industry (2025).
Notes: Conventional ammonia: Platts CFR NW Europe benchmark. Full capacity allocated to primary stated end-use/offtake: fertiliser and chemical feedstock under Ammonia; bunkering under Maritime.

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REDIII industry target may deepen methanol import reliance

EU methanol is import-dependent and outside CBAM; over 95% of committed e-methanol capacity for industry is in China.

Methanol is used mostly as a chemical-industry feedstock; e-methanol is produced from electrolytic hydrogen and CO_2. Aviation and maritime uses are covered on pages 22 and 25. The EU is a small, import-dependent buyer: its ~6.7 Mt apparent consumption is ~ 7% of the global market, with domestic production covering only ~12%. EU production faces gas and supply shocks and, unlike ammonia, import competition without CBAM coverage. Methanol has followed the wider EU chemical-industry downturn, marked by curtailments and closures.

Indicative import costs and offers suggest that electrolytic methanol from abroad could undercut European production although a substantial premium over conventional methanol remains. Over 95% of committed e-methanol capacity for industry is in China. REDIII demand may deepen import dependence without anchoring EU supply. The Chemicals Industry Action Plan (2025) recognises methanol's strategic importance, but pricing, trade dynamics and CBAM exclusion leave EU production uncertain; rebuilding it would require a deliberate policy choice.

EU committed	Supporting factors	Constraints
0.07 GW	• REDIII 42% industry RFNBO target (if adhered to) • Strategic role in chemicals	• No CBAM coverage • High EU production costs relative to imports, conventional and electrolytic • RFNBO imports can meet REDIII demand; mandates do not anchor EU supply • Slow, uneven transposition and limited willingness to pay

Figure 19: 2024 EU Methanol balance (Mt methanol)

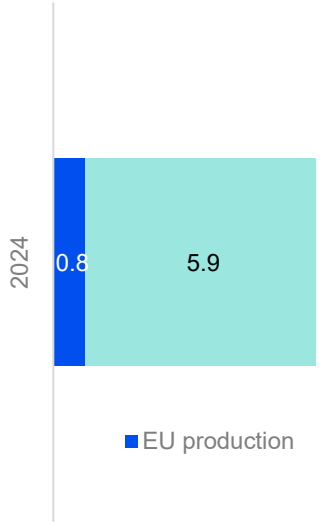
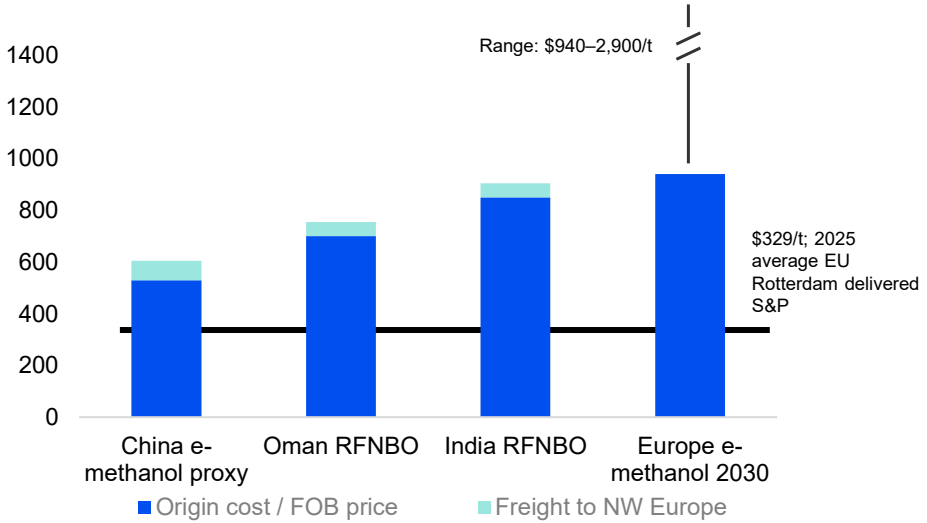


Figure 20: Indicative e-methanol costs and offers delivered to NW Europe (USD/t methanol)



Sources: S&P Global Energy, ©2026 by S&P Global Inc. for EU committed, for Oman and India costs and Platts prices for methanol and Hydrogen Transportation Cost Analysis v4.2 for freight to NW Europe; IEA, Global Hydrogen Review 2026; China Energy News; Eurostat, Prodcom and trade; EC, Chemicals Industry Action Plan (2025); Argus (Dec. 2024); ECB, exchange rates.
Notes: Indicative comparison across years and cost/price bases: India/Oman, 2026 prices; China, production-cost proxy; Europe, IEA 2030 range. RFNBO compliance unverified for China/Europe; freight modelled by S&P. Full capacity allocated to primary end-use: feedstock here, bunkering under Maritime, methanol-to-jet under Aviation.

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FuelEU compliance does not yet lead to RFNBO demand

Biofuels and LNG support near-term compliance, while vessel orders alone do not establish RFNBO demand.

Maritime can create renewable hydrogen demand through e-methanol, e-ammonia, and e-LNG. Uptake depends on vessel and fuel costs, and the value of emissions reductions under EU rules.

FuelEU Maritime requires lifecycle GHG-intensity cuts of 2% from 2025 and 6% from 2030. It rewards RFNBOs through a multiplier until 2033, with a conditional 2% RFNBO sub-target from 2034. EU ETS adds an incentive to reduce fossil fuel use. Delayed adoption of the IMO Net-Zero Framework leaves uncertainty over a global fuel standard and emissions pricing. Competing fuels and pooling can meet near-term FuelEU obligations. More than 90% of ships covered by FuelEU used pooling in 2025, allowing surplus compliance to cover deficits elsewhere. Pooling can support e-fuels, but RFNBO suppliers compete with other sources of surplus. Compatible vessels create a potential market rather than assured RFNBO demand. Fuel choice depends on price and availability; investment requires confidence in future costs and revenues. Bunker fuels are globally sourced, so EU obligations do not reserve demand for EU-produced RFNBOs.

EU committed	Supporting factors	Constraints
0.2 GW	• FuelEU Maritime GHG-intensity target, RFNBO multiplier and conditional 2034 sub-target • EU ETS coverage of maritime since 2024 • National maritime RFNBO quotas emerging in FR, BE and NL • EHB maritime auction basket and STIP measures	• EU-wide near-term compliance does not require RFNBOs • IMO framework delayed • RFNBO supply remains scarce and costly

Figure 21: Maritime fuel pathways and implications for RFNBO demand

Fuel pathway	Current use and fleet access	Fuel capable fleet by 2030[1]	Implications for RFNBO demand
Biodiesel	Leading reported renewable and low-carbon energy source for FuelEU compliance. Suitable blends can use existing oil-fueled ships.	Broad existing fleet[2]	Compliance without RFNBOs and with limited vessel adaptation. Sustainable feedstock supply constrains growth.
Methane LNG, bio-LNG and e-LNG	LNG and bio-LNG already support compliance, with established vessels and bunkering infrastructure.	~8% of global DWT	E-LNG can use the same fleet, but competes with LNG and bio-LNG. Methane slip affects compliance value.
Methanol, Biomethanol and e-methanol	Commercial vessel deployment, with further ships on order.	~1% of global DWT	E-methanol competes with biomethanol and other compliance routes. Vessel orders do not determine the RFNBO share.
Ammonia Including e-ammonia	Earlier deployment stage. Requires dedicated vessels and fuel supply.	~0.13% of global DWT	Uptake depends on vessel deployment, competitive fuel supply and buyers willing to commit.

Sources: DNV, shipping biofuels (2025); IEA, Global Hydrogen Review 2026; EC, FuelEU and maritime ETS FAQs, Hydrogen Bank; IMO, Net-Zero talks; Mærsk Mc-Kinney Møller Center, FuelEU year one; S&P Global Energy, ©2026 by S&P Global Inc. for EU committed.
Notes: [1]Global DWT in 2030: existing fleet plus May 2026 orderbook; fully fuel-capable vessels only, excluding conversion-ready ships. DWT measures carrying capacity, not fuel use. [2]Biodiesel compatibility depends on blend and equipment. Fleet capability does not establish RFNBO use. Methane slip: unburned methane from engines; varies by engine and operation.

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Bankable hydrogen demand remains sector-specific

Investment responds to different combinations of policy, economics and offtake; EU demand does not necessarily lead to EU production.

Demand sector *intended final use*	**Policy support** *do rules create credible demand?*	**Cost recovery** *can the premium be recovered?*	**Demand and offtake** *is demand secure enough to invest?*	**EU production link** *does EU demand support EU H_2 supply?*	**EU deployment and barriers** *committed electrolyser capacity (GW) and main barrier*
REFINING Replacement of fossil H_2	+ REDIII transport obligations and high penalties in some Member States. – Post-2030 requirements remain uncertain.	+ Small final-fuel price impact at low substitution. – Recovery relies on compliance incentives; demand beyond mandated volumes remains limited.	+ Existing refinery demand supports on-site or contracted supply.	+ Refinery demand favours nearby H_2 supply while import infrastructure remains limited.	**2.1 GW: mandate-led deployment** – **Policy support:** limited post-2030 demand visibility.
STEEL H_2-based ironmaking	+ ETS, CBAM and proposed IAA low-carbon rules for public procurement. – No mandate for low-emission steel or for H_2 use.	+ Avoided CO_2 costs and automotive premiums improve economics. – Limited commercial willingness to pay constrains wider uptake.	+ Integrated projects link H_2 production and use. – Gas-based operation allows mills to defer H_2 purchases.	+ Trade measures support continued EU steelmaking. – No requirement that H_2 or reduced iron (HBI) be EU-produced.	**1.2 GW: linked to initial DRI projects** – **Cost recovery:** High H_2 cost and limited availability; H_2 use can be deferred for gas.
eSAF Aviation: Fischer-Tropsch and methanol-to-jet	+ Binding mandate, high penalties and targets extending to 2050. – Calls to postpone the sub-target create uncertainty ahead of the 2027 review.	– At ~12× fossil jet cost, the premium falls on passengers or ETS SAF allowances.	– Projects seek 10–15-year offtakes; buyers favour shorter terms. + Planned double-sided auctions seek to bridge long-term producer and short-term buyer contracts.	– Origin-neutral mandate: imported compliant eSAF, including fuel made via methanol, can meet EU obligations.	**0 GW (commercial): no EU FID** – **Demand and offtake:** difficulty securing bankable long-term revenues.
AMMONIA Fertiliser and chemical feedstock	+ REDIII industry RFNBO target of 42% in 2030. – Uneven transposition and few penalties weaken demand certainty.	– Commodity pricing and limited cost pass-through constrain recovery of the RFNBO premium	+ Plants provide large, existing H_2 demand. – Securing long-term contracts that cover the RFNBO premium remains difficult.	+ CBAM seeks to level carbon costs; EU action plans aim to retain domestic ammonia production. – Competitive low-emission imports; RFNBO imports can meet the target.	**0.08 GW: few FIDs** – **Cost recovery:** limited ability to pass higher fertiliser costs through farmers to final food prices.
METHANOL Chemical feedstock	+ REDIII industry RFNBO target applies to chemical feedstock uses. – Uneven transposition and few penalties weaken demand certainty.	– Competition with conventional methanol limits recovery of the RFNBO premium; H_2 and CO_2 dominate cost.	+ Established chemical uses provide an existing market. – Contracts covering the premium remain scarce.	– Imports cover ~88% of EU demand, methanol is outside CBAM and over 95% of committed e-methanol for industry is in China.	**0.07 GW: deployment concentrated outside the EU** – **EU production link:** import competition and methanol outside CBAM.
MARITIME Shipping fuels, mainly e-methanol and e-ammonia	+ FuelEU GHG-intensity cuts; national RFNBO quotas emerging (FR, BE, NL). – The EU-wide RFNBO sub-target starts only in 2034 and is conditional.	– LNG and biofuels offer cheaper near-term compliance than e-fuels, including through pooling.	+ Dedicated EHB maritime/aviation auction support. – Fuel-capable vessels do not commit owners to RFNBOs; delayed IMO framework limits long-term contracts.	– Bunker fuels are globally sourced; FuelEU sets no EU-origin requirement.	**0.2 GW: limited committed capacity** – **Policy support:** no near-term EU-wide RFNBO requirement.

Assessment: supportive mixed constraining | + and – mark individual factors

Sources: ACER assessment, sector analysis on pages 20–25; steel project disclosures (page 21).
Notes: Committed: operational, under construction or post-FID electrolyser capacity. Shading: qualitative assessment. Each project allocated to one sector by intended final use. The six sectors do not cover the full EU total; unknown end-use remains unallocated; eSAF excludes pilots.

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System and market conditions define electrolyser flexibility

Plant capabilities, hydrogen delivery requirements and electricity-market and regulatory conditions shape the flexibility electrolysers can provide.

Electrolysers can contribute to power-system flexibility over different timescales. In the short term, they can adjust electricity consumption within seconds or hours, supporting balancing and shifting production away from high-price periods. Over longer periods, hydrogen can enable energy shifting across days or seasons, but this increasingly depends on pipelines, storage and flexible end-use. It is therefore a capability of the wider hydrogen system.

Any change in electrolyser load also changes hydrogen output. The full facility, not only the stack, must respond, while hydrogen delivery is maintained through buffering, alternative supply or flexible demand. Flexible operation may also reduce utilisation and increase unit hydrogen costs unless this is offset by lower electricity costs or additional revenues. Current constraints include limited hydrogen infrastructure, uncertain remuneration, barriers to participation in flexibility markets and grid-connection delays. PPA structures, hourly RFNBO matching and differing network-tariff incentives may also limit response to market signals.

Possible power-system applications across increasing durations

SECONDS TO MINUTES

Fast response

Short-lived modulation of electricity demand; the associated hydrogen-output deviation must still be absorbed.

HOURS TO DAYS

Production shifting

Move electricity consumption between periods using buffering, flexible demand, alternative supply or network access.

WEEKS TO SEASONS

Long-duration shifting

Separate hydrogen production and use over longer periods through transport and larger-scale storage.

Hydrogen-side accommodation increases with the duration and scale of the response

Limited, short-lived accommodation → **Large and sustained accommodation**

Delivered flexibility depends on three project-specific factors

Plant configuration

Complete facility performance determines how rapidly and how far electricity consumption can change.

Examples: Stack and balance of plant; current load and available operating range.

Hydrogen-side flexibility

The hydrogen system must absorb every deviation between planned and actual production.

Examples: Buffer storage; flexible demand; alternative supply, network access or storage.

System and market signals

Technical flexibility creates value only where the project can respond to relevant signals.

Examples: Location in the electricity system; electricity-price exposure; access to flexibility markets.

Sources: ENTSO-E, Market design and regulatory framework for electrolysers (2025); ACER/EEA, Flexibility solutions for a decarbonised and secure EU electricity system; Hydrogen Europe, Hydrogen: a ready-made solution for Europe's flexibility needs (2026) and flexibility workshop (30 June 2026).

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Focus: Infrastructure

Hydrogen infrastructure is progressing slowly from planning to implementation. Development remains concentrated in a small group of frontrunner Member States. Although the first infrastructure projects are advancing, limited commercial viability constrains broader market deployment, with few projects reaching final investment decisions. This highlights the need for stronger coordination on financing, market creation, regulatory frameworks and de-risking measures.

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Hydrogen network build-out progresses in a slow pace

First hydrogen pipelines commissioned but slow progress reflects market uncertainties.

A plethora of hydrogen network projects, totalling some 42 thousand km are currently at various development stages.[1] The transition from planning to implementation, however, moves slowly, led primarily by Germany, the Netherlands, Belgium and Austria.

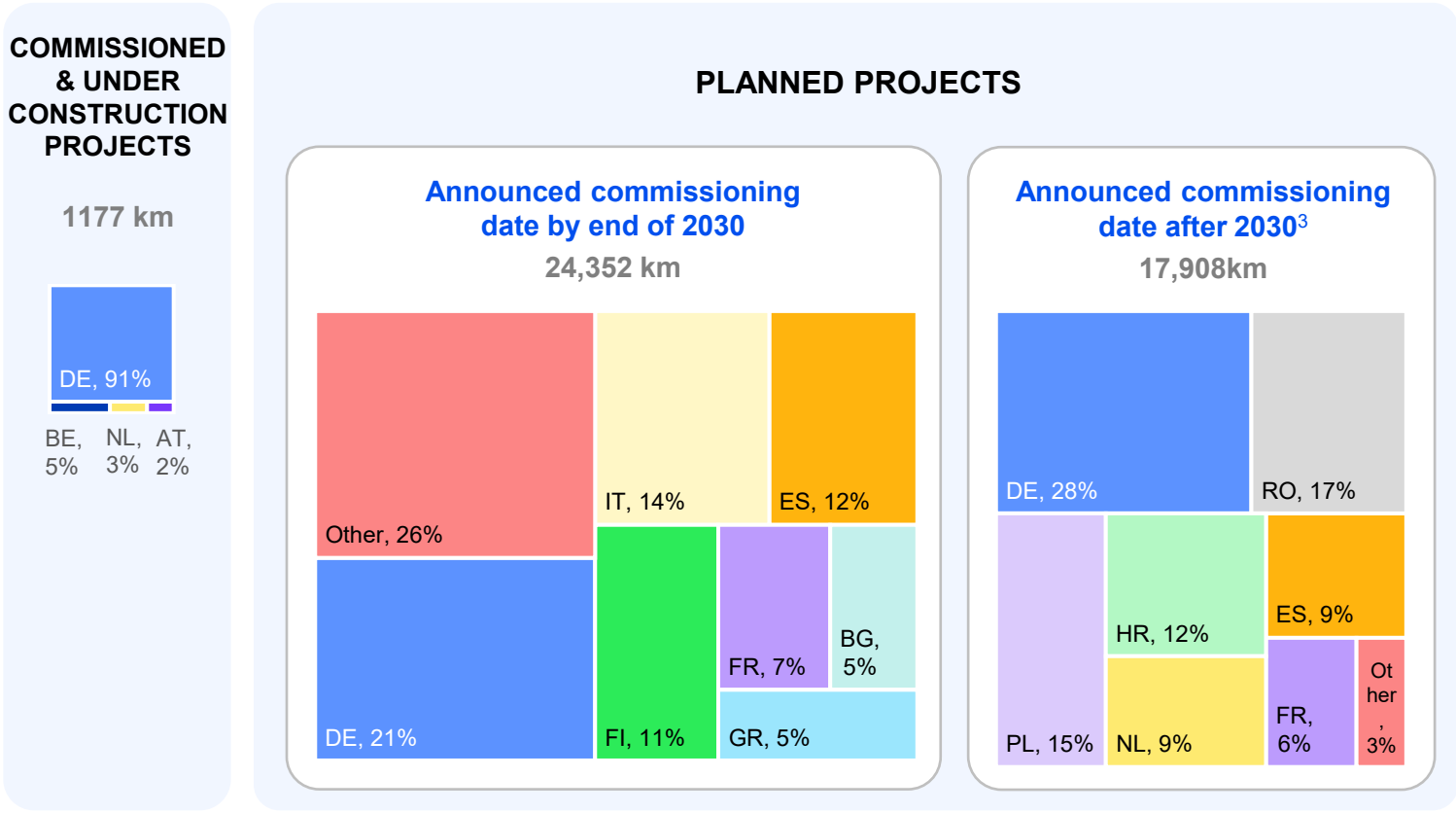
In Germany, around 590 km of hydrogen pipelines were commissioned in 2025-2026, with roughly 480 km currently under construction[4]. In March 2026, the German network operators launched a capacity reservation round to identify demand for the next 7-15 years. As of May 2026, a total of 32 requests of approximately 3.5 GW have been submitted.

In the Netherlands, the first, 32 km long hydrogen pipeline was commissioned in January 2026, linking the port of Rotterdam with the Pernis industrial site.

In Belgium, the designated hydrogen operator began construction of the first 52 km section of the hydrogen backbone in the area of Ghent and Antwerp in spring 2025.

In Austria, construction of a 23 km long pipeline connecting an electrolyser in Bruck an der Leitha to the Schwechat refinery near Vienna started in winter 2025.

Figure 22: Commissioned & under construction, and planned hydrogen networks in the EU (excluding existing non-regulated network), June 2026 (% of km)[2]



Sources: S&P Global Energy, ©2026 by S&P Global Inc., infrastructure database for planned projects; ENTSOG/ENTSO-E, TYNDP 2026 scenarios; Fluxys, Hydrogen NDP 2025–2034; Gasunie, market meeting (May 2026); JRC, Hydrogen delivery options (2022); NRA information and company announcements for commissioned and under construction projects. Notes: [1]According to ENTSOG/ENTSO-E, TYNDP 2026 scenarios around 39,000 km of hydrogen network is planned in the EU, 2,355 km of which are with an FID; [2] "Planned" covers stages before construction; the Figure excludes pre-existing hydrogen pipelines outside the regulatory framework; [3]Includes projects without a declared online date; [4]Includes the Vlieghuis-Ochtrup pipeline (NL-DE).

Storage: how much and when depends on market growth

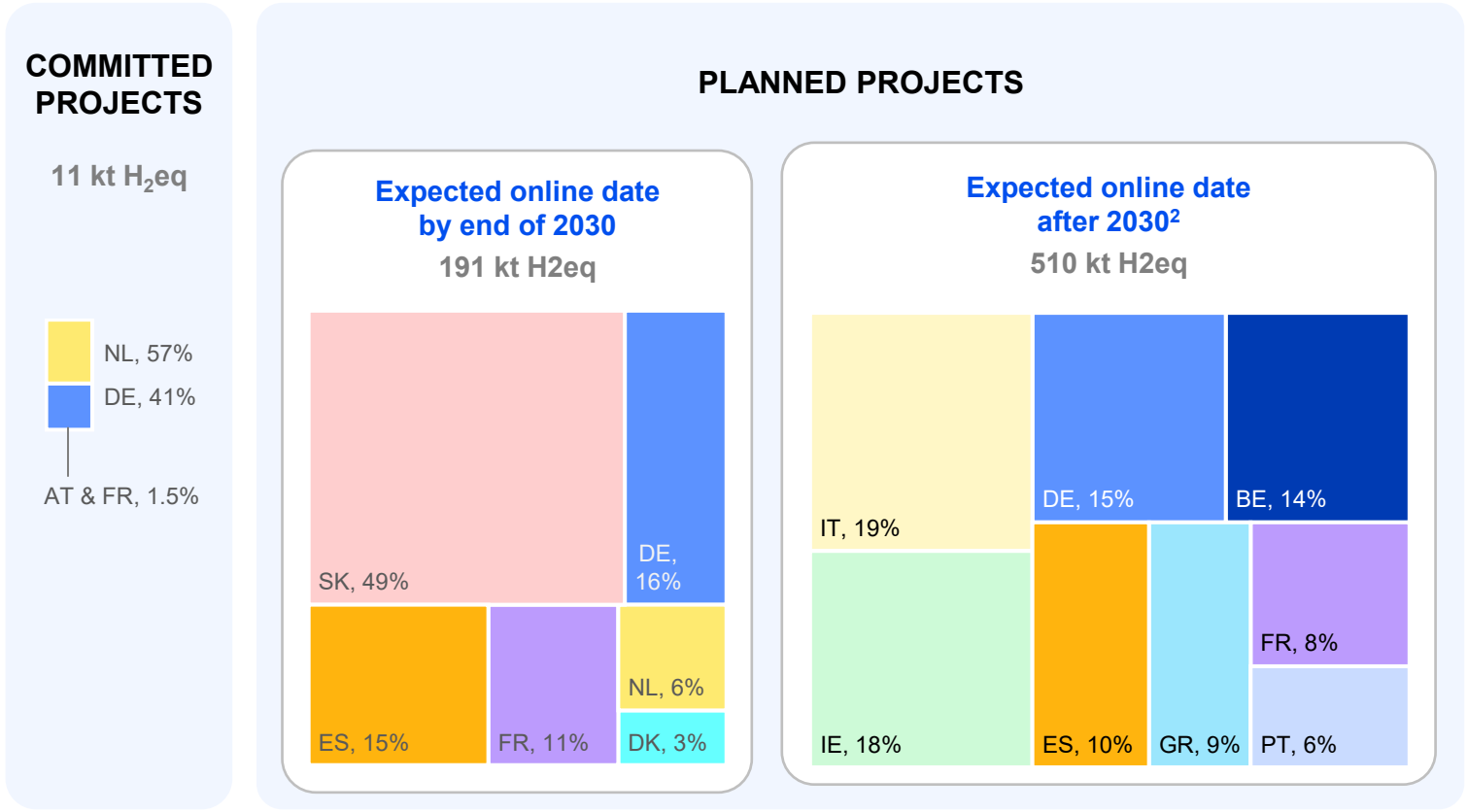
Planning for storage is challenging, adding to the complexities of the hydrogen market development.

Storage is a critical element of the future hydrogen network. It provides the flexibility needed to balance variable production and demand and optimise network utilisation. In the longer-term, it is also expected to strengthen security of energy supply, especially during extended periods of low renewable energy generation.

To date, hydrogen storage deployment remains limited to a handful of pilot projects commissioned in Austria, Germany, France and Hungary, totalling just 266 tonnes of hydrogen. Another 6 projects with a capacity of 11 kt are currently under construction in Germany, France and the Netherlands, while overall, a total capacity of 0.7 Mt is planned.[3]

At the current pace of market development, the need for significant storage capacity is expected to emerge after 2030 and increase extensively towards 2050. Planning remains challenging due to long lead times, the uneven geographical distribution of suitable storage sites, interdependencies with the gas sector (security of supply) and technical considerations like cycling, ramping and hydrogen quality. Storage cost estimates are quite uncertain, too, potentially exceeding €1/kg H_2, adding an additional challenge to storage deployment.[4]

Figure 23: Committed (commissioned, under construction and with FID) and planned hydrogen storage projects in the EU, June 2026 (% of H_2 equivalent tonnes)[1]



Sources: S&P Global Energy, ©2026 by S&P Global Inc., infrastructure database for planned and committed; European Hydrogen Observatory; NRA information. Notes: "Planned" covers stages from concept to FEED before construction; [1]The Figure shows planned projects not necessarily approved by a network development plan; [2] Includes also projects without a declared online date; [3]Data from S&P Global Energy infrastructure database; in contrast, the TYNDP 2026 draft project list includes 73 hydrogen storage projects with a total capacity of 1 million tonnes; [4]de Maigret et al.

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Import and terminals are still in early developing stages

Cost considerations and global trade could make terminals critical for EU's hydrogen market.

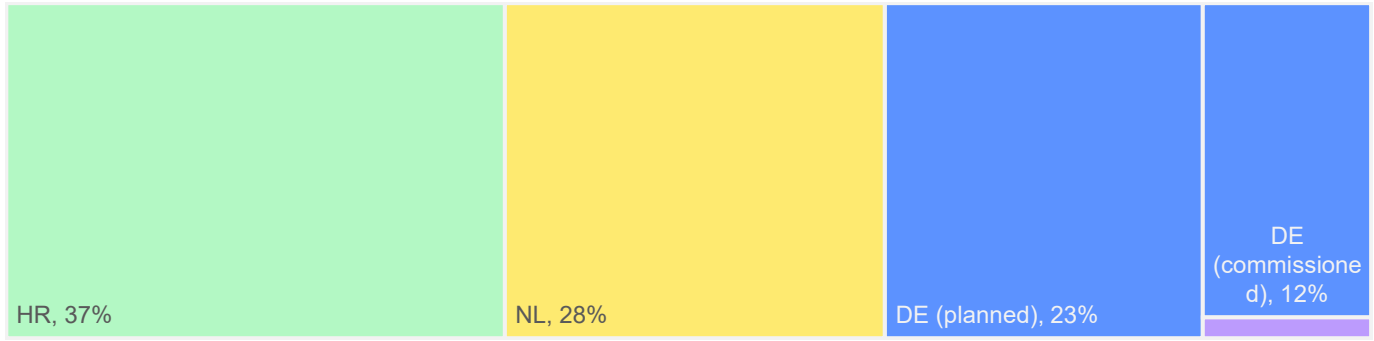
Imports are anticipated to cover around 15-18% of hydrogen demand in the longer-term (TYNDP 2026 scenarios), in which case terminals could become a crucial element of the supply chain. There are currently 31 operational ammonia terminals in the EU with a storage capacity of 0.7 Mt of ammonia[2]. So far, one additional "clean" ammonia terminal has been commissioned in Germany and 12 more are currently in various planning stages (but without an FID). Together they total around 4.9 Mt H2eq/y import capacity[3].

In addition, 16 ammonia cracking projects are also planned. Ammonia re-conversion to hydrogen, however, remains challenging[4]. Industrial scale cracking is still not commercialised and needs significant amount of energy[5]. If technology matures and clean ammonia cost drops globally, ammonia could potentially become an important hydrogen supply carrier.

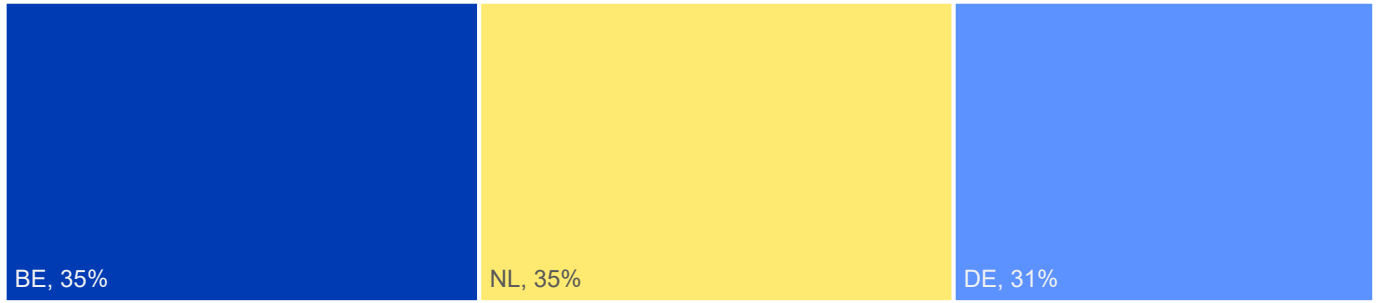
In addition to ammonia terminals, 4 import liquid hydrogen and 6 hydrogen derivatives (liquid organic hydrogen carriers, e-methane) import facilities are also planned, adding another 6.2 H2eq/y import capacity.

Figure 24: Planned and commissioned "clean" ammonia terminals and ammonia cracking projects in the EU, June 2026 (% of H_2 equivalent tonnes)[1]

Ammonia terminals: 13 projects, 4.9 Mt H_2eq/y (2.6 Mt H_2eq/y planned by 2030)



Ammonia cracking: 16 projects, 3.5 Mt H_2eq/y (1 Mt H_2eq/y planned by 2030)



Sources: S&P Global Energy, ©2026 by S&P Global Inc., infrastructure database; ENTSOG/ENTSO-E, TYNDP 2026 scenarios; IEA, infrastructure database. Notes: "Planned" covers stages from concept to FEED before construction; [1]The Figure shows planned projects not necessarily approved by a network development plan; [2]Based on IEA; [3]Based on S&P Global Energy; its database includes another 19 planned projects without capacity figures. The IEA database includes 22 projects in concept, feasibility or design status; TYNDP 2026 draft project list includes 13 ammonia terminals in advanced stage with 3.5 Mt of hydrogen import capacity (ACER calculation from daily import capacity considering 90% annual utilisation factor and based on NCV); [4]H_2 can be derived from ammonia via cracking; [5]See for example JRC (2022).

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Member States start establishing national market rules

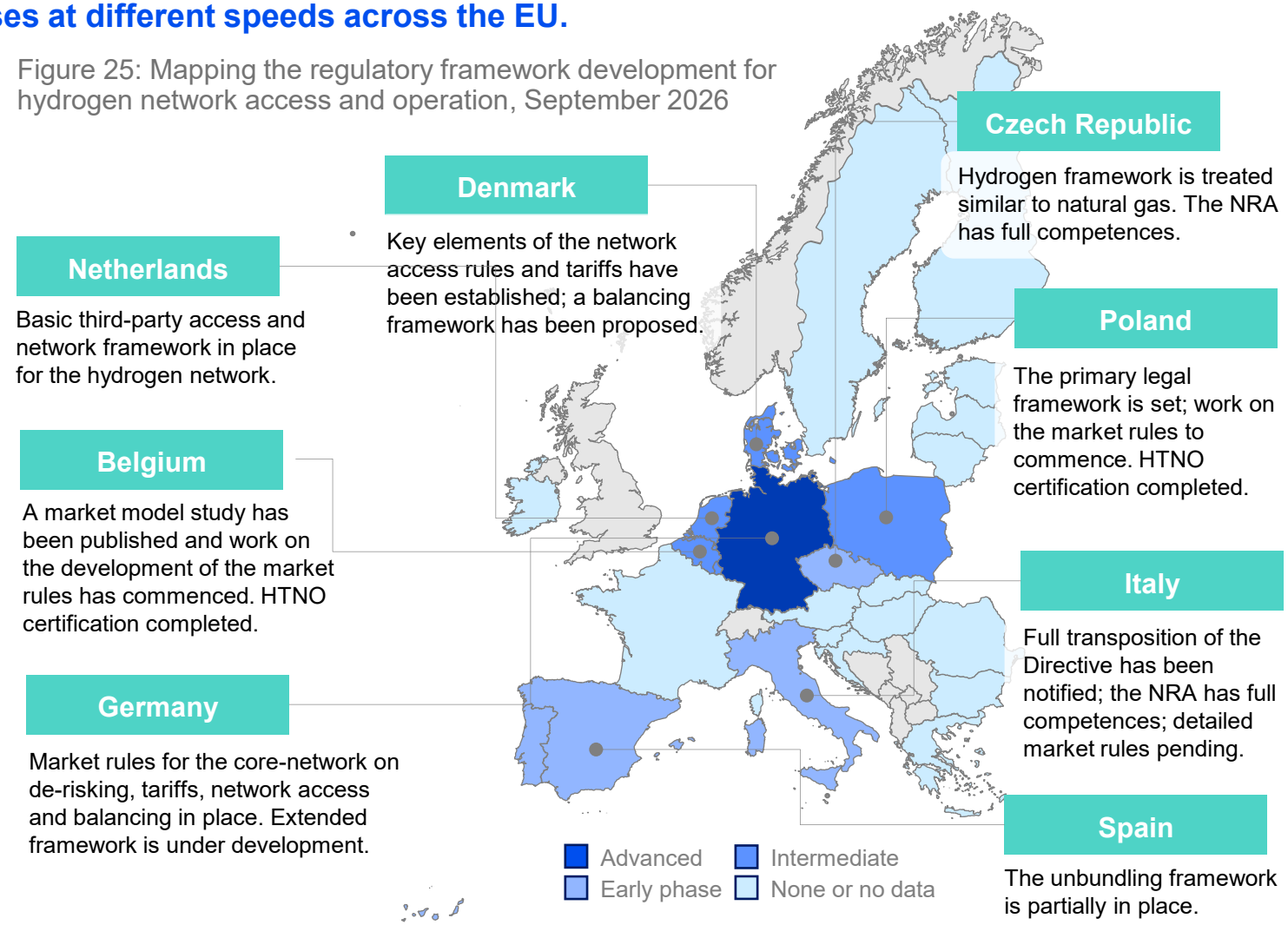
The EU framework implementation progresses at different speeds across the EU.

The transposition of the Hydrogen and Decarbonised Gases Directive (Directive) is generally pending, yet some Member States are progressing faster. Italy has notified the EC about full transposition of the Directive, while Austria, Belgium, Bulgaria, Lithuania, Portugal, Slovakia and Spain have notified separate measures. Czech Republic, Germany, Hungary and Poland have also transposed certain Directive provisions. In Denmark, Finland, Latvia, Netherlands and Slovenia the draft legislation's public consultation is concluded or ongoing, while in Sweden the legislative proposal is being drafted.

In the meantime, national market frameworks and rules have already been established in Germany, where comprehensive market rules for the core-network are already in place, and to a lesser extent in Belgium, Luxembourg and Poland. In the Netherlands, basic network access rules, including network tariffs, have been set by the Ministry on the basis of a Service of General Economic Interest. In the Czech Republic, hydrogen is treated similarly to natural gas.

Belgium, Czech Republic, Germany, Italy, Luxemburg and Poland have already extended the NRA competences over the hydrogen market.

Figure 25: Mapping the regulatory framework development for hydrogen network access and operation, September 2026



Sources: Information from the European Commission and NRAs.
Notes: The mapping is based on the information regarding the existence of frameworks about unbundling, HNO certification, network access and tariffs, congestion management, balancing, interoperability, network planning, monitoring, dispute settlement, consumer protection and NRA competences; see Annex for more details.

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Highlight: The German core-network framework

Amid uncertain hydrogen demand growth, Germany sets the market framework to enable scale-up.

Germany's hydrogen core-network aims to solve the classic infrastructure challenge: industrial users need reliable transport before switching to hydrogen, while network operators need firm demand before building pipelines. The German approach combines a gradual network expansion with an inter-temporal cost allocation derisking regime, supported by State-backed financing and guarantees.

Germany has already developed an already applicable network tariff framework, and access, and balancing rules that will apply from 2028. The core regulatory pillars are:

- WANDA, establishing the tariff methodology and the initial postage-stamp approach;
- WaKandA, defining capacity products and access rules;
- WasABi, governing balancing and operational processes; and
- KOSMO, refining tariff differentiation for different transport services and capacity types.

Additional developments include the establishment of the integrated gas-hydrogen network planning (see page 35), and further alignment with the European framework.

Key acts of the German hydrogen market framework, June 2026

Framework	Primary purpose	Key features
WANDA	Tariff methodology: creates investment certainty and smoothens early costs	Uniform initial "postage-stamp" tariff; supports long-term cost recovery and affordable market ramp-up
WaKandA	Capacity allocation: standardises how users reserve transport rights	Defines hydrogen capacity products, booking rules and network access arrangements
WasABi	Balancing rules: supports reliable day-to-day network operation	Establishes balancing and operational procedures for hydrogen system management
KOSMO	Tariff refinement: aligns tariffs with actual capacity products and usage patterns	Introduces differentiated pricing (multipliers) for shorter-term capacity products, and discounts for interruptible/storage-related services

Key features of the German inter-temporal cost allocation mechanism

Duration	Tariff	Review	Liquidity	Risk Sharing	Early Exit
2025-2055 (31-year payback period).	NRA sets ramp-up tariff; indexed to inflation.	Review every 3 years from 2028; tariff adjusted if cost recovery is at risk.	KfW financing covers early revenue shortfalls; repaid as network demand increases.	Residual deficit in 2055: State 76% - HNOs 24%	Government may terminate the scheme if demand is insufficient; HNOs retain a 16-24% deductible.

Sources: BNetzA, WANDA; WaKandA; WasABi; KOSMO.

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National hydrogen network plans are growing in number

Implementation of hydrogen Network Development Plans (NDPs) is progressing unevenly across the EU

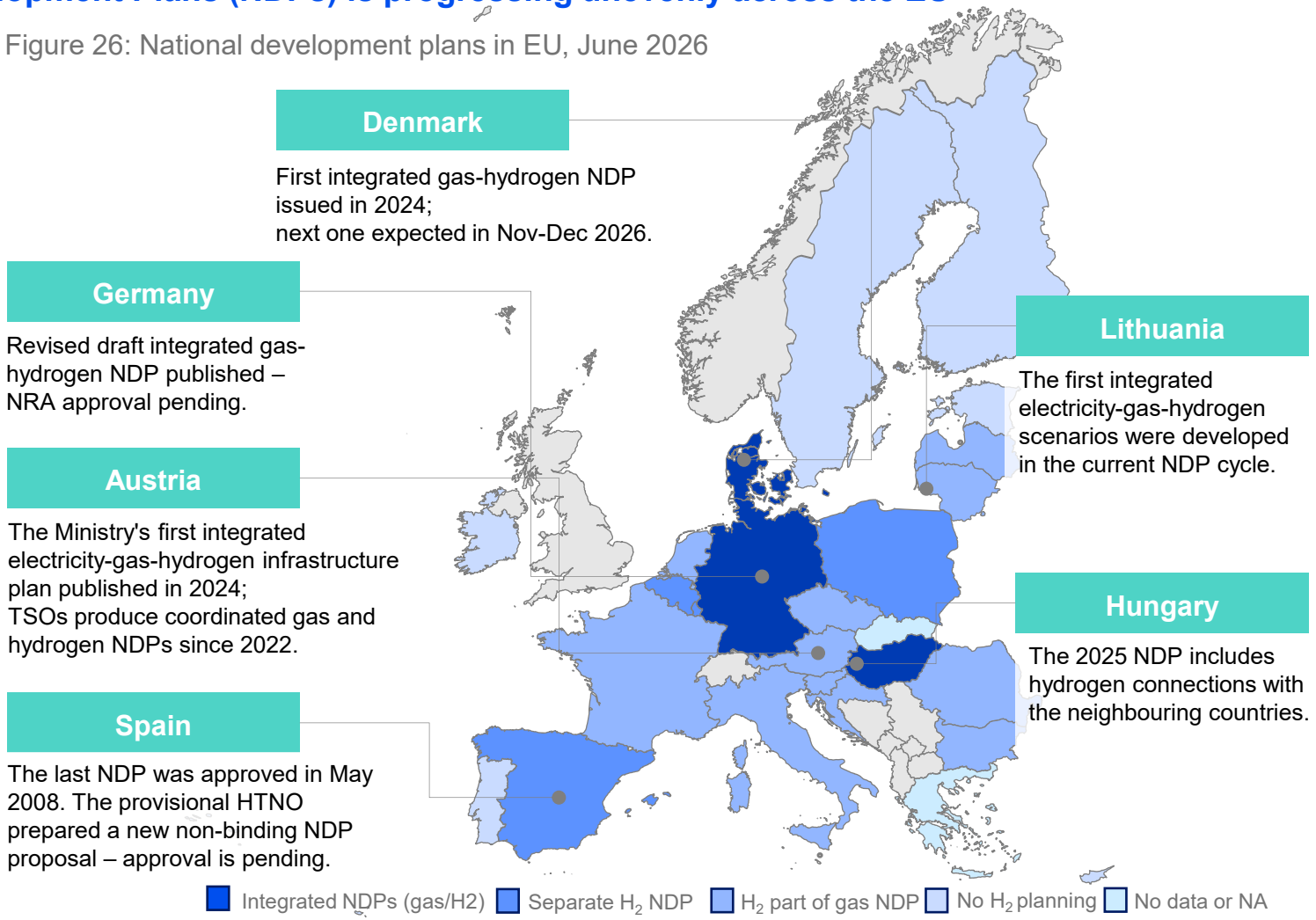
Currently, hydrogen network development planning progresses somehow unevenly across the EU due to evolving national regulatory frameworks. Coordinated network planning is, however, gradually expanding.

Belgium, Denmark, Germany and Lithuania develop joint electricity-gas-hydrogen scenarios, while Austria, France, Hungary and Romania develop joint gas-hydrogen ones. Most Member States develop hydrogen NDPs either as integrated gas-hydrogen NDPs (3 Member States), stand-alone ones (4 Member States) or as part of their gas NDP (11 Member States).

NRA's involvement in NDPs' preparation, assessment, amendment and implementation remains uneven across Member States. For example, while in Hungary the TSO develops an integrated gas and hydrogen NDP, the NRA cannot assess hydrogen projects due to lack of the relevant mandates. Notably, only a share of the projects included in the national NDPs and the EU-wide TYNDP-2026 are being scrutinised by NRAs.

For further information on the topic read **ACER's Opinion on gas and hydrogen NDPs.**

Figure 26: National development plans in EU, June 2026



Sources: NRA information; ACER, Opinion 17/2026 on gas and hydrogen NDPs.

Highlight: German gas/hydrogen network development plan

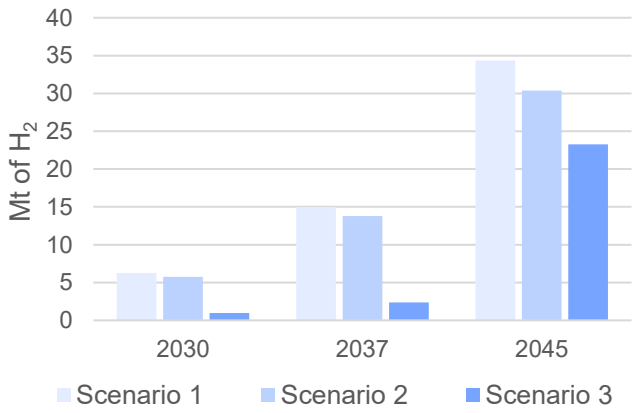
Low demand scenarios in the German NDP lead to reduced network needs highlighting the need for cautious planning.

Germany's hydrogen strategy centres on developing a hydrogen core-network to support industrial decarbonisation, power generation and cross-border trade. The 9,040 km long core-network, approved in 2024, forms the backbone of the biennial integrated gas and hydrogen NDP, which assesses infrastructure needs through multiple future scenarios.

The 2025 Scenario Framework defines three hydrogen pathways to 2037: Scenario 1 assumes lower electrification and the highest hydrogen demand across most sectors, Scenario 2 features stronger electrification with hydrogen used mainly for power generation and Scenario 3 envisages a slower transition with lower hydrogen uptake in the initial phase until 2037, restricted to the industrial and power sectors.

With a starting hydrogen network of 2,201 km already under development or in advanced stage the revised draft of the NDP proposes an expansion of 7,041 km by 2037. The total network is largely aligned with the approved core-network but incorporates targeted technical and planning adjustments to improve cost-effectiveness.

Figure 27: ACER estimates[1] of annual hydrogen exit volumes of the revised draft German gas and hydrogen NDP 2025



Starting network (already under development or in advanced stage)	2,201 km
Network expansion results	Scenario 1: 8,229 km Scenario 2: 7,998 km Scenario 3: 5,232 km
Network expansion proposal	7,041 km
Total proposed hydrogen network	9,241 km

Figure 28: Hydrogen network expansion final proposal for 2037 based on the revised draft German gas and hydrogen NDP 2025



Sources: Germany's Gas and Hydrogen Scenario Framework 2025–2037/2045; Gas and Hydrogen NDP 2025, revised draft.
Notes: [1]The revised German NDP draft provides exit capacities in GWh/h in 2037 and 2045. These were used to derive the estimates of annual demand in Figure 27 assuming an average capacity factor of 50% and excluding storage. Estimates for 2030 use interpolation. Conversion from TWh to Mt was done using the Low Heating Value of hydrogen (33.3 kWh/kg).

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The draft TYNDP-2026 recalibrates demand assumptions

European network planning adopts more conservative demand growth scenarios, yet requests for infrastructure persist.

The TYNDP 2026 scenarios[1] project a substantially lower hydrogen demand in 2050 - 1,661 TWh (50 Mt) [2] compared with the 2,300-3,100 TWh (69-93 Mt) in TYNDP 2024. The largest reduction occurs in industry and transport, reflecting a shift from exploratory net-zero pathways to policy-based scenarios grounded in the updated NECPs, and stronger direct electrification. In contrast, the role of hydrogen for e-fuels remains significant, with synthetic aviation and maritime fuels continuing to be one of the main drivers of hydrogen demand growth towards 2050. The shorter-term projections are still optimistic foreseeing 260 TWh (8 Mt) of hydrogen demand by 2030 (excluding onsite captive use). Complementary sensitivity analysis, depicting the sector's uncertainties is thus recommended.

Despite the recalibrated hydrogen demand, request for infrastructure remains strong, with nearly 39 thousand km of transmission network, 44 ammonia and hydrogen derivatives terminals and 73 storage facilities included in the TYNDP 2026 project list.

Further reading on the topic in ACER's Opinion on the draft TYNDP 2026 Scenario Report.

Figure 29: EU hydrogen demand projections in the 2022, 2024 and 2026 TYNDPs, 2030-2050 (TWh)[3]

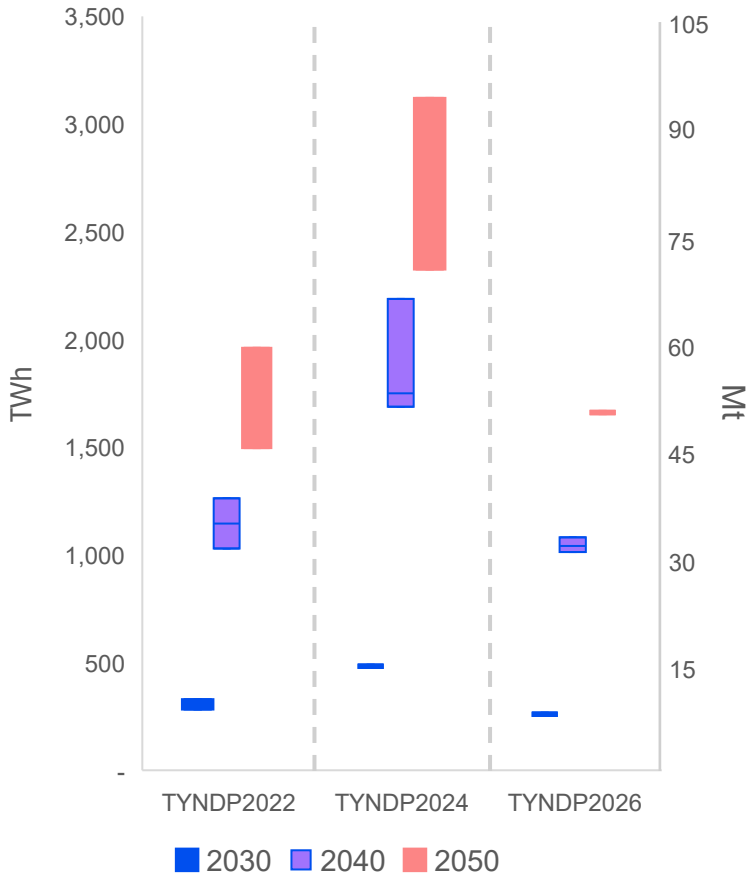
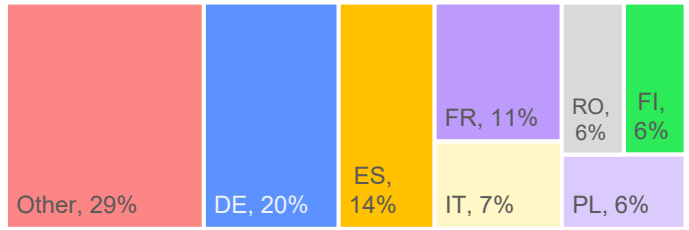
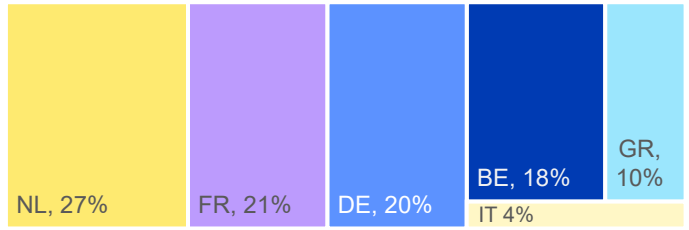


Figure 30: Infrastructure in TYNDP 2026 draft project list

Transmission: 38,779 km



Terminals: 44 projects, 14 Mt import capacity[4], 0.35 Mt storage capacity



Storage: 73 projects, 1 Mt storage capacity



Sources: ENTSOG/ENTSO-E, TYNDP scenarios (2022, 2024, 2026); ENTSOG, TYNDP 2026 project list.
Notes: [1]The TYNDP 2026 scenarios are not final; [2] Including demand for conversion; [3]The ranges reflect the variants of the TYNDP scenarios; [4]ACER calculation from daily import capacity considering 90% annual utilisation factor. Conversion from TWh to Mt was done using the Low Heating Value of hydrogen (33.3 kWh/kg).

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Corridors face financing and risk-sharing challenges

Market consultations indicate non-binding commitments and stakeholders' interest in additional de-risking tools.

The 2nd PCI/PMI list includes projects related to the potential hydrogen corridors identified in the REPowerEU plan. Various market tests demonstrated potential interest, but binding commitments are pending. The proposed Grids Package prioritised the South and Southwest corridors potentially opening regulatory, financial and administrative support options. Discussions between project promoters, relevant Ministries, NRAs and financing institutes are progressing for the South-West and the Southern corridors. The former is at a more mature stage; however, FID is still pending. The Nordic-Baltic and South-Eastern corridor are less mature but still progressing, while the Northern-Sea corridor is technically more challenging and dependents on the progress of individual offshore-wind projects.

Cross-border network projects face increased market and regulatory risk, especially in transit countries. Stakeholders (e.g. network operators, project promoters) request enhanced coordination on project financing, including potential de-risking mechanisms, market creation and network regulation to help projects reach FID. Proposed additional de-risking measures should be assessed for their added value, contribution to market development and impact to public budgets.

Figure 31: Cross-border hydrogen networks included in the PCI/PMI list and key corridors, June 2026

Northern-Sea corridor

Less advanced; dependent on demanding off-shore hydrogen projects.

Nordic-Baltic corridor

2026 call for interest results indicate **2.4 Mt of demand by 2040** or 87% of planned capacity.

South-West corridor

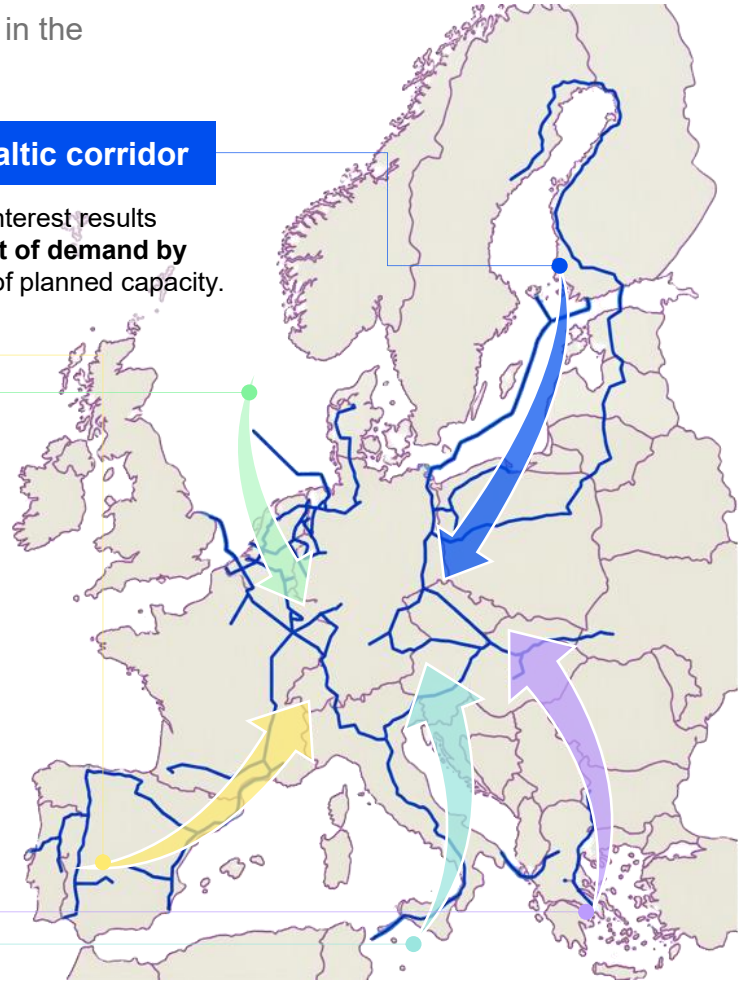
The November 2024 call for interest, indicated export potential from Iberia peninsula of **1.6 Mt/year by 2030 and 2 Mt/year (100% capacity) by 2032.**

Southern corridor

No market test yet; industry endorsement for **2.5 Mt of renewable H_2 per year** from North Africa supporting the projected **import capacity** of **4 Mt/year.**

South-Eastern corridor

Various non-binding market tests during 2024–2025 by participating TSOs underpin an initial design capacity of **1 Mt/year.**



Sources: CINEA, PCI/PMI map; Nordic-Baltic Hydrogen Corridor market consultation results; SoutH$_2$Corridor; H2Med call for interest results; SeeHyC.

Highlight: The 7-tallet DK-DE interconnector

Political support and DK-DE coordination advance the corridor ahead of FID.

The planned Danish Hydrogen Backbone 1 ("7-tallet") corridor from Esbjerg to Frøslev comprises a new 45 km pipeline and a re-purposed gas pipeline to the German border. It is the first phase of the planned Danish Hydrogen Backbone, connecting electrolysis clusters in western Denmark with domestic demand centres and export markets in Germany.

In January 2026, Energinet launched an open season followed by a binding capacity allocation, offering approximately 2.7 GW of capacity against a minimum booking threshold of 0.5 GW. Six pre-construction agreements have already (June 2026) been signed with potential network users. FID decision is expected in 2027.

To address demand uncertainty, Denmark is developing a de-risking framework combining direct state support and inter-temporal cost allocation to lower tariffs for early users.

The project is closely coordinated with Germany through cross-border infrastructure planning and regulatory cooperation (the CBCA[1] requests have been submitted by HNOs and approved by the relevant NRAs), and German funding targeting renewable hydrogen production in Denmark, earmarked on the 2025 European Hydrogen Bank Auction.

Figure 32: The Danish hydrogen backbone 1, "7-tallet" pipeline project (solid line).



- Total length: **133 km**
  Of which repurposed**: 88 km**
- Total capacity offered: **2.7 GW**
- Total cost: **EUR 950 million**
- **State support**: soft loan and de-risking
- **EUR 1.3 billion**: related German support for H_2 production in Denmark through European Hydrogen Banks, auction as a service

Sources: Information from the Danish NRA (DUR); Energinet, hydrogen website, Danish Hydrogen Backbone business case and market meeting (May 2026).
Notes: [1]Cross Border Cost Allocation

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Focus: Public support

Public support has been central to large electrolyser investments, but a funding award does not guarantee delivery. Member States are using a wide mix of investment, operating and enabling measures, but support remains uneven. All of the more than 3 GW of large electrolytic investments mapped in this report received EU or national financial support, while Innovation Fund terminations and Hydrogen Bank withdrawals show that grants and premiums can narrow the cost gap but cannot alone secure bankable demand or guarantee project delivery.

1/3 of Innovation Fund hydrogen grant value was cancelled

Calls signed €3.1 billion across 47 hydrogen and derivative-production projects; the terminated share is over twice the fund-wide level.

The Innovation Fund has become a major source of EU support for hydrogen. Excluding auctions, 47 hydrogen and hydrogen-derivative production projects account for €3.1 billion in original grant-agreement value since 2020, around one-fifth of the grant portfolio.

Delivery has been harder with fifteen agreements worth €987 million having been terminated, 32% of hydrogen grant value against 14.4% across the Fund. Attrition is not confined to the oldest calls: two IF23 awards account for €269 million of its value.

The European Court of Auditors cites absent offtake and prices above market as evidence of insufficient maturity at selection. The Court's fund-wide analysis points to project maturity, financing, costs, partnerships and market conditions as common causes of termination. These findings are consistent with the delivery challenges observed in the hydrogen portfolio, although they do not provide a hydrogen-specific breakdown of cancellation reasons.

Figure 33: Original grant value for Innovation Fund hydrogen and derivative-production projects by call (EUR million)

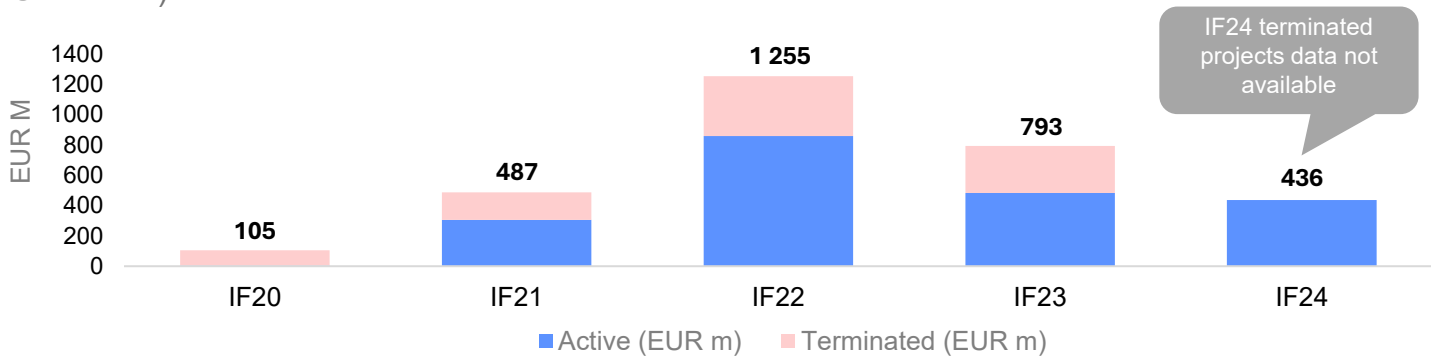


Figure 34: Reasons cited for terminated Innovation Fund grant agreements, June 2025

Reason citations across 20 terminated Innovation Fund grant agreements, all sectors. Total 45 citations with multiple citations per project.

Financial and market viability	19	Project execution and partnerships	19	Regulatory and enabling conditions	7
Additional funding not secured	7	Partnership changes	5	Legislative changes or lack thereof	3
Costs higher than expected	5	Design, site, permitting or technical	5	EU sanctions	1
No off-taker	3	Supply-chain delays	4	Regulatory non-compliance	1
Product price too high	2	Milestones not achieved	3	Missing infrastructure	1
Negative or uncertain profitability	2	Bankruptcy	1	Environmental constraint	1
		Replaced by a new project	1		

Grouping is ACER analysis of ECA Figure 5. The Court classifies 33 of the 45 citations as ultimately related to project maturity; 18 of the 20 terminations occurred before financial close.

Sources: CINEA, Innovation Fund dashboard and country factsheets (August 2026); ECA, Special Report 11/2026, Figure 5.
Notes: IF20–IF24 denote call rounds. Hydrogen portfolio excludes auctions, manufacturing, steel and hydrogen-use projects; integrated derivative projects counted at full grant value. Values and termination shares use original signed grant amounts; pre-signature withdrawals excluded. IF24 attrition not comparable. ECA reasons cover 20 fund-wide terminations to 30 June 2025; multiple reasons per project.

Hydrogen Bank: strong interest, uneven grant conversion

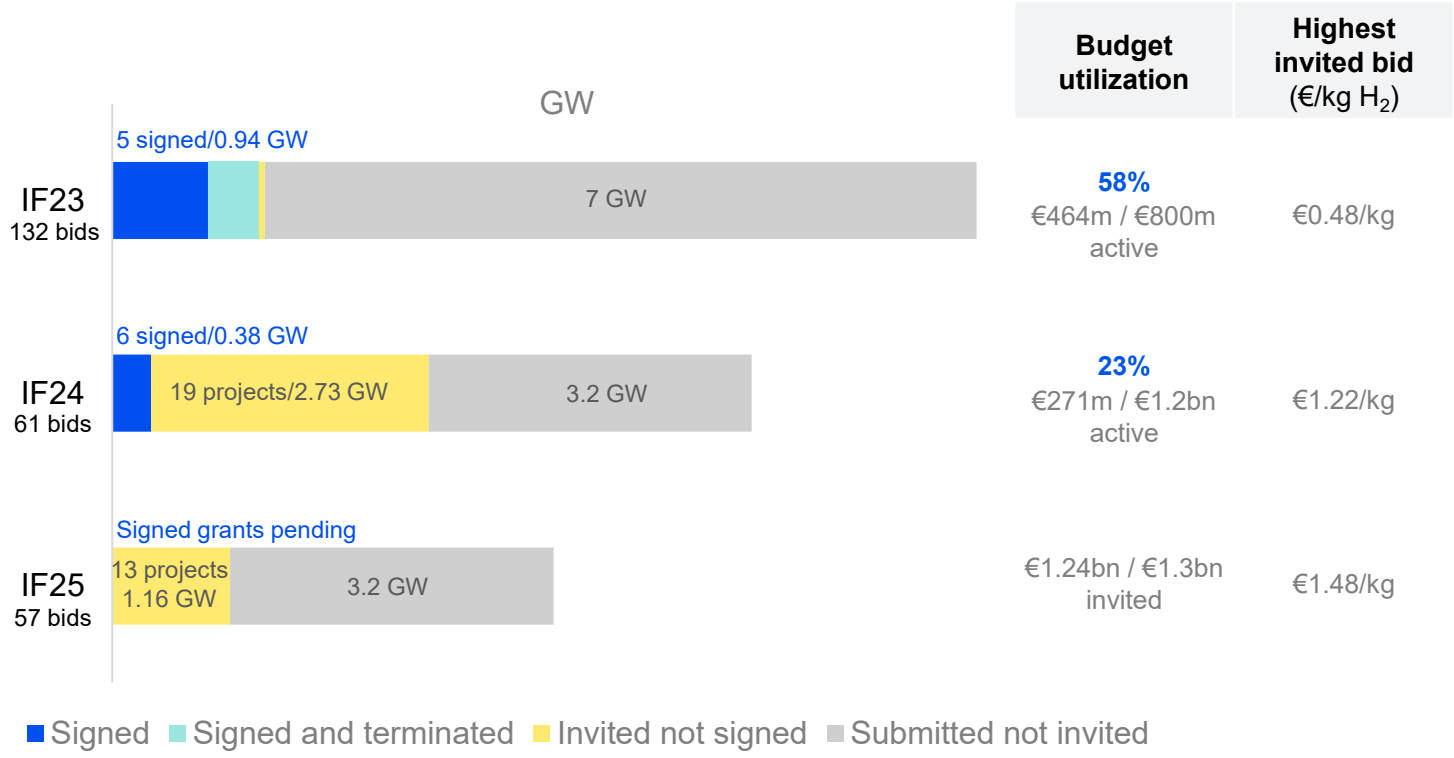
Auctions are oversubscribed, but project conversion is uneven and signed capacities remain small relative to EU demand.

Despite all three auctions being oversubscribed, participation has declined, likely reflecting developers reassessing project economics after the very low pilot premiums. Meanwhile, support levels among invited projects have increased. Competition is geographically concentrated, with Spanish projects accounting for over half of bids in IF24 and IF25.

Conversion from selection to signed grants has been uneven. IF24 withdrawals reflected insufficient or uncertain offtake, delayed REDIII implementation and hydrogen infrastructure, as well as project maturity, the completion guarantee and delivery deadlines. Low budget utilization shows that auction demand does not automatically translate into deployable projects.

To strengthen market creation, future rounds could better screen deliverability and offtake, recycle funding rapidly, provide predictable multiannual auctions and coordinate support with demand and infrastructure. The Industrial Decarbonisation Bank could complement production support by enabling downstream industrial investment and hydrogen demand.

Figure 35: Project numbers and electrolyser capacity by application and grant status in Innovation Fund hydrogen auctions (IF2X), August 2026



Sources: EC, IF23 auction (April 2025); IF24 auction and results (January 2026); IF25 auction and results (June 2026); Innovation Fund projects (July 2026).
Notes: IF23 signed grants exclude terminated Catalina. IF24 invitations are cumulative; signed projects shown separately. IF25 projects remain in grant preparation. Budget coverage: maximum support for active/invited projects, not disbursements. Highest invited bid: general RFNBO topic.

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Member States support electrolysis in various ways

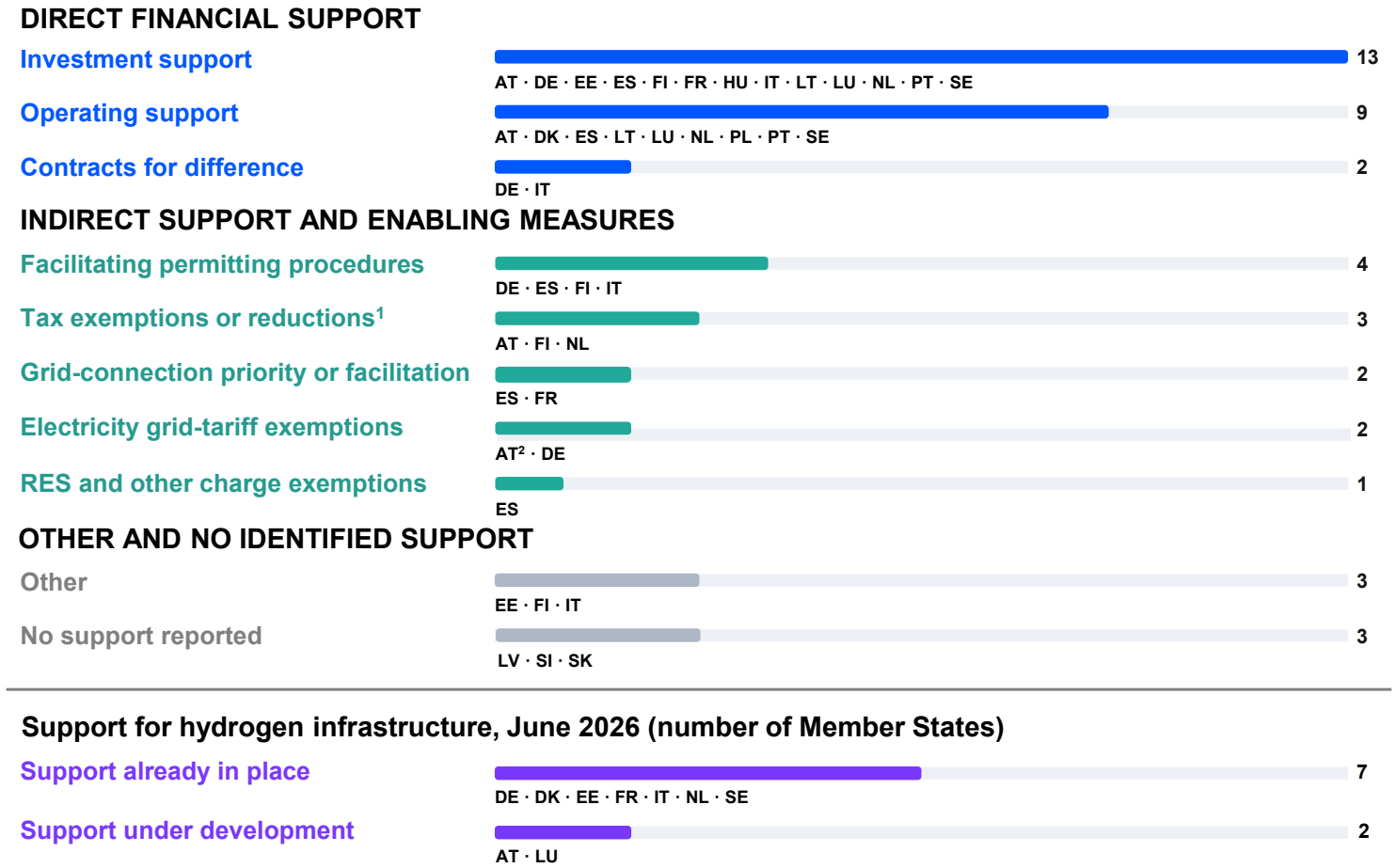
Indirect economic incentives complement direct financial support for electrolysers.

Most Member States provide support for electrolysers, although approaches differ significantly. Direct financial support is in place in 15 countries, mainly through capital grants and operating support. Germany has adopted CCfDs; Italy's hydrogen CfD scheme has EU approval. In a smaller number of cases direct financial support is complemented with tax exemptions or reductions (Finland, Austria, and the Netherlands), exemptions from electricity grid tariffs for eligible electrolysers (Austria, Germany) and exemptions from other system charges like RES levies (Spain).

Administrative and regulatory support is also provided. Germany, Spain, Finland and Italy facilitate permitting procedures, including via streamlined environmental assessments, accelerated approval processes and priority treatment for hydrogen-related projects. Spain and France have also adopted measures that facilitate grid access.

Support for infrastructure is less frequent, with only 7 Member States providing soft loans or grants (e.g. via IPCEI) or de-risking support (such as intertemporal cost allocation).

Figure 36: Support for electrolysers, June 2026 (number of Member States)



Sources: Information provided by national regulatory authorities (June 2026); Austria, EIWG §127(3).
Notes: [1]Excludes differentiated electricity tax rates for electrolysers. [2]Austria: 20-year relief from grid-use and grid-loss charges applies to electrolysers qualifying as system-beneficial storage, replacing the earlier ≥1 MW exemption.

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National hydrogen subsidies vary in size, scope and form

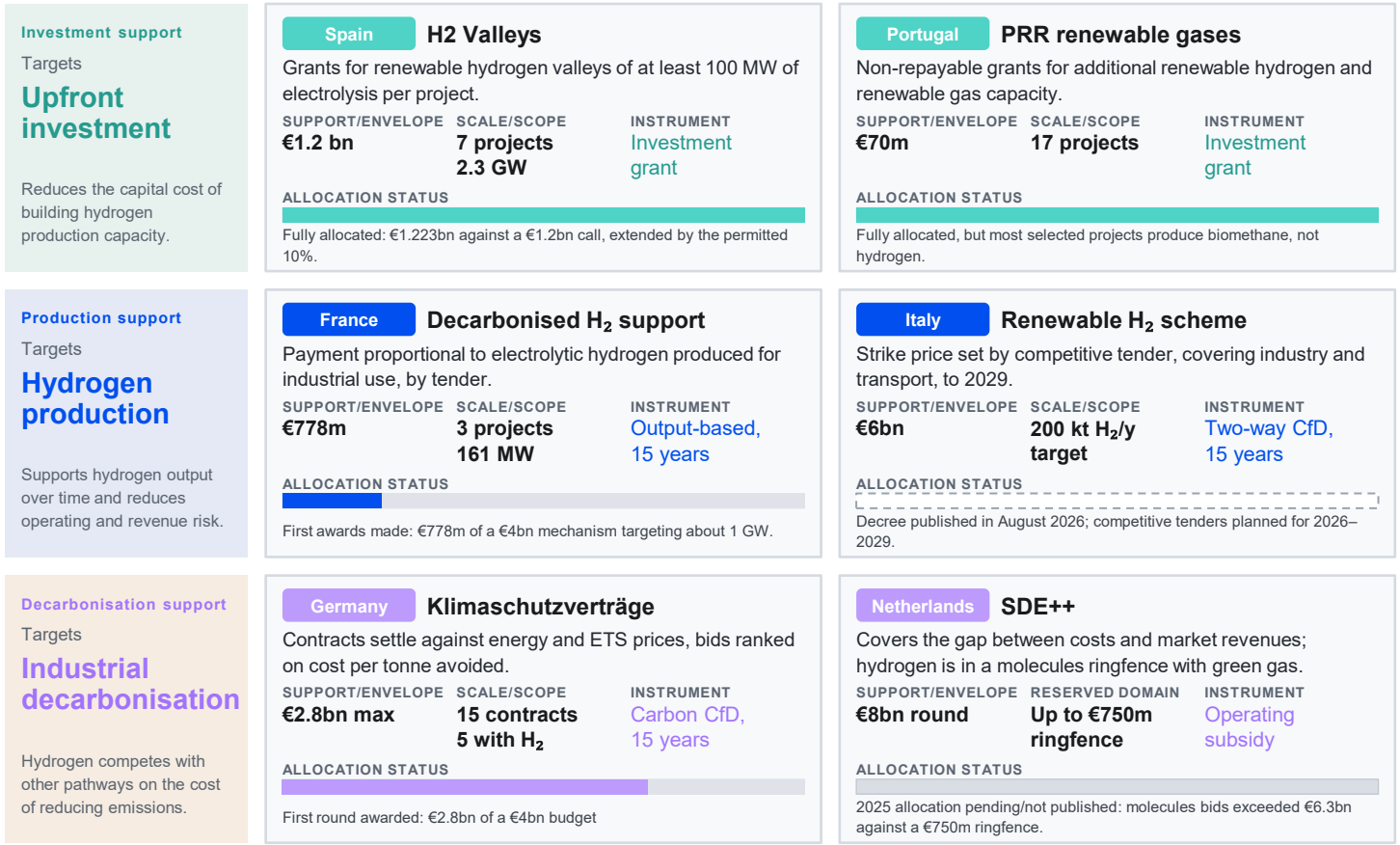
National schemes support upfront investment, hydrogen output or broader decarbonisation, with very different allocation models.

Both national funding schemes and EU programmes such as the European Hydrogen Bank auctions and the Innovation Fund contribute to bridging the cost gap in the hydrogen markets, but they differ in what they pay for, and the payment basis determines which project risk is reduced.

Spanish and Portuguese grants among others, paid against eligible investment expenditure, reduce capital cost but leave producers exposed to operating costs and offtake risk. Both envelopes are fully allocated, although most Portuguese awards support biomethane rather than hydrogen.

The French and Italian schemes pay against hydrogen produced and address the operating cost gap directly. France has awarded around a fifth of its mechanism and Italy has adopted its implementing decree. In broader decarbonisation schemes, such as the German Klimaschutzverträge and Dutch SDE++, hydrogen competes with electrification, biomass, and carbon capture for the same budget, and only five of fifteen German first-round contracts involve hydrogen.

Figure 37: Selection of national schemes supporting hydrogen deployment, August 2026



Sources: MITECO and BOE, H_2 Valleys (Spain); Fundo Ambiental and Government of Portugal, PRR renewable gases; DGE and Ministry of Economy, H_2 production support (France); EC, SA.118992 (Italy); Klimaschutzverträge and BMWE (Germany); RVO and parliamentary letters, SDE++ (Netherlands).
Notes: Selected schemes; ACER categorisation. Bars show awards relative to each scheme's own envelope, not absolute scheme sizes. Portugal includes other renewable gases; German and Dutch envelopes cover multiple technologies, not hydrogen alone.

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Acronyms and abbreviations

AaaS: Auctions-as-a-Service
ACER: EU Agency for the Cooperation of Energy Regulators
AFIR: Alternative Fuels Infrastructure Regulation
ATR: autothermal reforming
BNetzA: Bundesnetzagentur (German NRA)
CAPEX/OPEX: capital/operating expenditure
CBAM: Carbon Border Adjustment Mechanism
CBCA: cross-border cost allocation
CCS: carbon capture and storage
CCUS: carbon capture, utilisation and storage
CEF: Connecting Europe Facility
CfD/CCfD: (carbon) contract for difference
CFR: cost and freight
CINEA: European Climate, Infrastructure and Environment Executive Agency
CISAF: Clean Industrial Deal State Aid Framework
DA/IA: delegated/implementing act
DRI: direct reduced iron
DUR: Danish Utility Regulator
DWT: deadweight tonnage
eSAF: synthetic aviation fuel
EASA: EU Aviation Safety Agency
HB: European Hydrogen Bank
EIB: European Investment Bank
ENNOH: European Network of Network Operators for Hydrogen
ENTSO-E/ENTSOG: EU TSO networks for electricity/gas
ETS: Emissions Trading System
FEED: front-end engineering design
FID: final investment decision
FOB: free on board
FuelEU: FuelEU Maritime Regulation
GHG: greenhouse gas
HBI: hot briquetted iron
HEFA: hydroprocessed esters & fatty acids
HNO: hydrogen network operator
HTNO: hydrogen transmission network operator
IEA: International Energy Agency
IF: Innovation Fund (IF20-IF25: call year)
IMO: International Maritime Organization
IPCEI: Important Project of Common European Interest
KOSMO: German hydrogen tariff differentiation regulation
LCOH: levelised cost of hydrogen
LHV: lower heating value
LNG: liquefied natural gas
MEPC: Marine Environment Protection Committee (IMO)
NDP: network development plan
NECP: National Energy and Climate Plan
NG: natural gas
NRA: national regulatory authority
OWE: Opschaling Waterstof Elektrolyse (Dutch scheme)
PCI/PMI: Project of Common/Mutual Interest
PERTE: Spanish recovery and transformation scheme
PPA: power purchase agreement
PRIMES: EU energy system model
PRR: Plano de Recuperação e Resiliência (Portugal)
PtL/PtX: power-to-liquid/power-to-X
REDIII: Renewable Energy Directive (EU) 2023/2413
ReFuelEU: ReFuelEU Aviation Regulation
RFNBO: renewable fuel of non-biological origin
SAF: sustainable aviation fuel
SDE++: Dutch sustainable energy and climate scheme
SMR: steam methane reforming
STIP: Sustainable Transport Investment Plan
TEN-E: Trans-European Networks for Energy
TPA: third-party access
TSO: transmission system operator
TYNDP: Ten-Year Network Development Plan
UDB: Union Database
WaKandA: German hydrogen capacity and access rules
WANDA: German hydrogen tariff methodology regulation
WasABi: German hydrogen balancing rules
WtP: willingness to pay

Units

t: tonne (1,000 kg)
kt: thousand tonnes
Mt: million tonnes
Mtoe: million tonnes of oil equivalent
MW: megawatt
GW: gigawatt
TWh: terawatt-hour
H_2-eq: hydrogen equivalent (conversion basis specified in the relevant figure notes)
/y: per year
Mt H_2/y: million tonnes of hydrogen per year
Mt H_2-eq/y: million tonnes of hydrogen equivalent per year

Terminology

Hydrogen categories and production

- **Renewable fuels of non-biological origin (RFNBOs).** Liquid and gaseous fuels whose energy content derives from renewable sources other than biomass. This category includes hydrogen and qualifying hydrogen-derived fuels. Counting RFNBOs towards RED targets requires at least 70% lifecycle greenhouse gas emissions savings.
- **Renewable hydrogen (report usage).** Hydrogen qualifying as an RFNBO and meeting the applicable EU requirements for renewable-electricity sourcing and lifecycle emissions savings.
- **Low-carbon hydrogen.** Hydrogen whose energy content derives from non-renewable sources and which achieves at least 70% lifecycle greenhouse gas emissions savings against the prescribed fossil fuel comparator, calculated under the EU methodology for low-carbon fuels.
- **Electrolytic hydrogen.** Hydrogen produced by splitting water through electrolysis, irrespective of the electricity source. The term does not imply renewable or low-carbon status and excludes hydrogen produced as a by-product of chlor-alkali electrolysis.
- **Low-carbon electrolytic hydrogen.** Hydrogen produced by water electrolysis that meets the EU definition and emissions-saving requirements for low-carbon hydrogen.
- **Fossil-based hydrogen with CCS.** Hydrogen produced from fossil fuels through reforming, partial oxidation or gasification, with CO_2 capture and permanent geological storage. Compliance with the EU low-carbon threshold depends on lifecycle emissions, including upstream emissions and the proportion of CO_2 captured.
- **Unabated fossil-based hydrogen.** Hydrogen produced from fossil fuels without CO_2 abatement. In this report, “conventional hydrogen” and “fossil hydrogen” refer to this category and are used interchangeably. Fossil-based production with CCS is always named as such.
- **By-product hydrogen.** Hydrogen generated alongside the main products of another industrial process, such as catalytic reforming, steam cracking or chlor-alkali production. The term does not specify emissions intensity.

Demand and economics

- **Bankable demand.** Demand for hydrogen or its derivatives with sufficient certainty over volumes, duration and cost recovery to support an investment decision.
- **Mandated demand.** Demand arising from a binding regulatory requirement. It may also be contracted.
- **Contracted demand.** Demand backed by binding purchase commitments. Excludes non-binding memoranda of understanding.
- **Captive use/merchant supply.** Consumption within the producing company or group/sales to independent third parties.
- **Lead markets.** Markets in which policy measures or buyer commitments stimulate early demand for low-emission products, potentially supporting hydrogen uptake where hydrogen is used in production.
- **Levelised cost of hydrogen (LCOH).** Discounted lifetime production costs divided by discounted lifetime hydrogen output. Cost boundaries and assumptions follow the cited source.
- **Willingness to pay.** The maximum delivered price a buyer would accept under specified conditions.
- **Cost gap.** The difference between hydrogen cost and a stated comparator, such as conventional hydrogen cost or willingness to pay.
- **Green premium.** The price increment over the conventional equivalent that a buyer pays for a product made with renewable or low-carbon hydrogen. It is the commercial route to recovering the cost gap. Used as market shorthand, not as a colour/type classification.

Project status

- **Final investment decision (FID).** Investors’ decision to commit capital and proceed with project execution. Completion is not guaranteed.
- **Committed capacity.** Capacity at FID, under construction or operational, unless the source specifies a different scope.
- **Operational capacity.** Capacity commissioned and in service. This does not imply full utilisation.

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Furthermore, it is important to note that the underlying data used by ACER for the creation of the data presented in the Market Status, Demand, Infrastructure and Public support chapters were sourced from June to October 2026, and they may have been updated afterwards.

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