INDEPENDENT POLICY SUBMISSION · 10 NOVEMBER 2026

Europe’s Hydrogen Strategy After Competition

A demand-led approach to decarbonisation, industrial competitiveness and infrastructure

Michael Barnard | Chief Strategist, TFIE Strategy Inc. | 10 November 2026

Correspondence: michael@tfie.io

Interactive dashboard: https://tfie.io/euhydrogen

Supporting files: select “Download research package (ZIP)” on the dashboard.

Prepared for the European Commission, Directorate-General for Energy | Renewed EU Hydrogen Strategy consultation

1. Add industrial and transport-fuel competition to TYNDP 2028

The European Commission should add an industrial-product, transport-fuel and production-location sensitivity to the TYNDP 2028 scenarios. ENTSO-E, ENTSOG and ENNOH should develop it with industrial and transport specialists, DG MOVE participation and ACER oversight. Compare routes delivering equivalent industrial products, transport services and climate outcomes, including electrification, domestic production, imported inputs, sustainable biofuels and hydrogen-derived fuels. Assess each proposed network or support measure unchanged under both the policy-aligned reference and the competition-led sensitivity.

This comparison would show which investments remain justified when lower-cost industrial and fuel pathways reduce EU hydrogen demand. Project sponsors should disclose delivered prices, binding demand, expected utilisation, public support and the costs of smaller or staged alternatives. Strategic capacity may still be justified, but its security or resilience benefit and financial exposure must be explicit.

TFIE examines selected EU industrial and transport markets in 2030, 2040 and 2050. The analysis draws on a 2024 hydrogen-use register, industrial and fuel-route costs, and competition among domestic production, imports, process substitution and residual marine and aviation fuels. Six specified industrial markets and the transport services are allocated first. A further cost screen assesses hydrogen requirements for other chemicals within the remaining supply capacity. The Python model calculates the results, the evidence workbook records assumptions, and the interactive dashboard tests sensitivities (TFIE Strategy Inc., 2026a–c).

In the long-term central case, the specified industrial products and transport services are supplied, while the other-chemicals reference activity is met through cost-ranked alternatives. Imported green industrial inputs and process substitution reduce hydrogen production inside the EU. The results test economic competition in selected markets without hydrogen-specific uptake mandates. They are neither an EU-wide forecast nor evidence of compliance with current law. Infrastructure decisions must also account for emissions, security and European industrial value.

In 2024, the European Court of Auditors urged the Commission to reassess its hydrogen ambitions against the industries Europe intends to retain and the costs of doing so. TYNDP scenarios already vary industrial demand, economic activity, technology and hydrogen supply, while ACER has called for stronger alternatives (2026). What remains missing is a comparison of the processes and locations that can supply the same products and transport services, followed by an assessment of the resulting infrastructure needs.

DG ENER should commission this sensitivity through TYNDP 2028. Appraisals must cover electricity networks and flexibility, sustainable feedstock limits, lifecycle emissions of imports and supply risks. Hydrogen-specific mandates should not predetermine the economic result; a separate comparator should show the consequences of existing legal obligations. Where a project remains unattractive commercially, its sponsor must quantify the public benefit, cost and risk of proceeding.

2. Start with Europe’s existing industrial economy

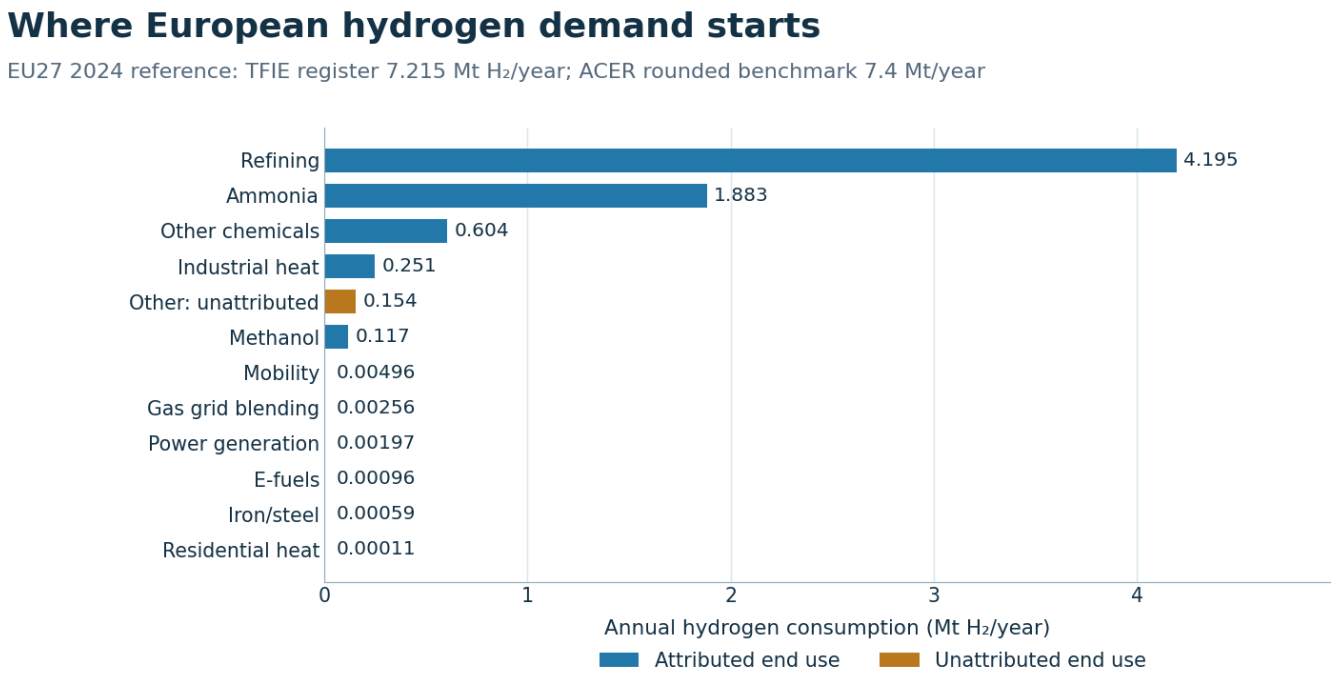


Figure 1. EU27 hydrogen use in 2024 (Mt H₂/year). The 0.154 Mt Other category is end-use unattributed. TFIE's twelve-sector register totals 7.215 Mt, compared with ACER's rounded 7.4 Mt benchmark. Source: TFIE Strategy Inc. (2026a); ACER (2025).

Hydrogen in Europe is used mainly as an industrial input. ACER estimates EU consumption at about 7.4 Mt H₂/year in 2024, including 4.2 Mt in refining and 1.9 Mt in ammonia. TFIE's independently compiled twelve-sector register totals 7.215 Mt H₂/year. The records differ in coverage and classification, and their underlying categories have not been reconciled one to one (ACER, 2025; TFIE Strategy Inc., 2026a).

Today's industrial hydrogen volumes will change with the products and facilities that use them. Reduced petroleum refining lowers demand for upgrading and treatment. Demand for ammonia as an industrial feedstock, principally for fertilisers and chemical manufacturing, can remain while some production moves to regions offering cheaper clean electricity. This comparison does not assume ammonia demand as a fuel or energy carrier. Ironmaking can draw on scrap, imported green iron and new processes alongside hydrogen-based reduction. Chemical plants may retain valuable downstream activities while purchasing intermediates produced elsewhere.

Hydrogen quantities use metric mass units, with annual demand in Mt H₂/year and prices in €/kg H₂. Electricity, equipment capacity and useful services retain their respective units. Alternative routes compete to supply the same product or service.

The decline in refining has the largest direct effect on current hydrogen use. Other chemicals accounted for 0.604 Mt H₂/year in the 2024 register. The model tests how this activity could be supplied through substitution, imported finished products, imported feedstocks and physical hydrogen. Under Strong/central assumptions, hydrogen supplied to other chemicals is 0.513 Mt in 2030, 0.362 Mt in 2040 and 0.211 Mt in 2050. These estimates depend on illustrative route prices and capacities, not verified chemical-product bids. Hydrogen embodied in imported products and feedstocks is excluded from EU physical hydrogen consumption.

3. Delivered hydrogen cost limits the competitive market

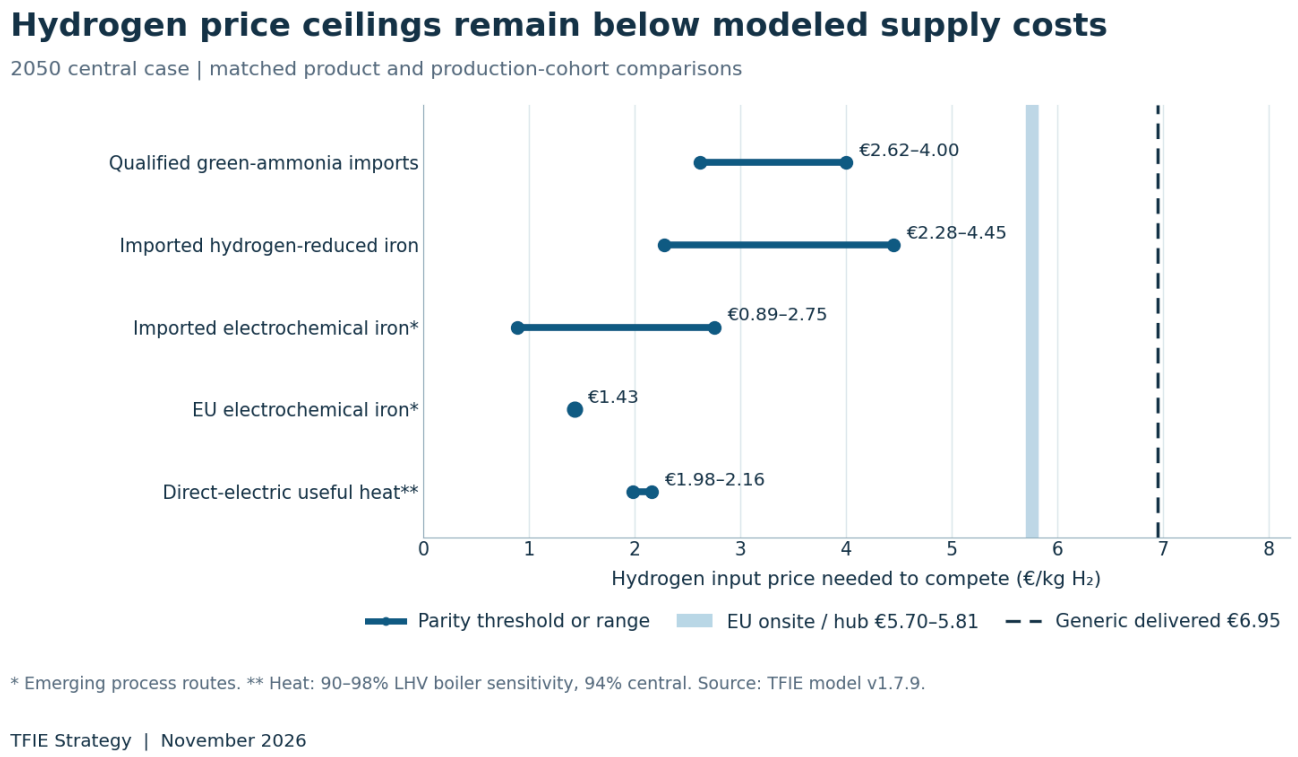


Figure 2. Maximum hydrogen input prices (€/kg H_2) at which specified industrial routes compete with alternatives in 2050, compared with modelled hydrogen supply costs. The range endpoints reflect different routes and production cohorts. Source: TFIE Strategy Inc. (2026b).

Producing hydrogen at 55 kWh electricity/kg H_2 costs €5.50/kg H_2 in electricity alone when power costs €100/MWh, or €3.30/kg H_2 at €60/MWh. Capital, financing, maintenance and delivery come on top. Producing 1 Mt H_2/year at this efficiency requires 55 TWh of electricity annually. Low electricity prices and high operating hours must be achievable at the same site.

ACER estimates average EU renewable hydrogen production costs of about €8/kg H_2 in 2024 (ACER, 2025). TFIE's central delivered-cost cases are €9.32/kg in 2030, €7.84/kg in 2040 and €6.95/kg in 2050. The favourable 2050 cost of €3.46/kg depends on cheap electricity, inexpensive equipment and low delivery costs occurring together. The IEA also finds a gap between hydrogen supply costs and prices many customers can afford (IEA, 2026).

In the 2050 central case, on-site hydrogen costs about €5.70/kg H_2, and supply from a hub with pipeline delivery costs €5.81/kg H_2. Several ammonia, iron and industrial-heat routes in Figure 2 require still lower hydrogen prices to compete. The generic €6.95/kg H_2 benchmark includes a different delivery allowance, so these figures are not interchangeable (TFIE Strategy Inc., 2026a).

A threshold below the modelled hydrogen supply price means the competing route is cheaper under those assumptions. Thresholds differ across ammonia and iron suppliers and production cohorts, while industrial heat is compared on useful heat delivered. Scrap quality, iron ore, equipment maturity and product specifications also affect which alternatives are available. Even the favourable hydrogen cost case requires electricity prices, operating hours and delivery costs that can be achieved together.

4. Allow competing routes to win

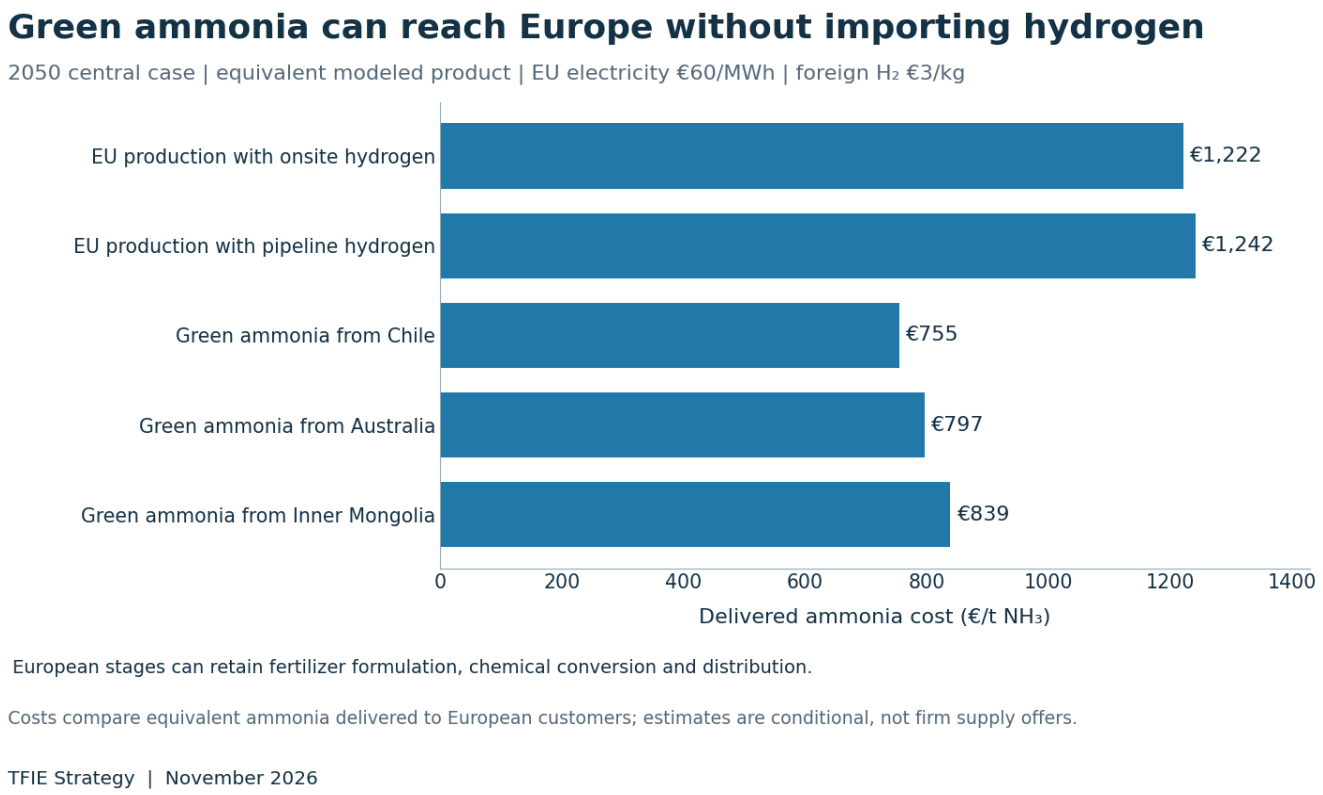


Figure 3. Example of industrial-geography competition: European and imported green ammonia costs in the 2050 central scenario (€/t NH_3). The wider comparison of industrial production locations and green-product trade appears in Technical Annex A, Section F. Source: TFIE Strategy Inc. (2026b).

Figure 3 compares two ways to supply an industrial feedstock. European green ammonia synthesis with central-case on-site hydrogen costs about €1,222/t NH_3, against €755–839/t NH_3 for qualifying imports. That ammonia serves fertiliser and chemical manufacturing, not an assumed fuel market. Producing the input abroad avoids the corresponding hydrogen production in Europe (TFIE Strategy Inc., 2026a).

Qualifying imported green hot briquetted or direct-reduced iron costs about €605 per tonne of equivalent iron input, compared with €733 for EU hydrogen-based production in the central case. Product grade and yield must match. Scrap availability and quality constrain one alternative; electrochemical iron faces technology and capacity risks.

Electric boilers avoid hydrogen conversion losses for suitable industrial heat, while batteries and electric drives do so for road transport, rail and much inland shipping. Long-distance shipping and aviation retain liquid-fuel needs after electrification and efficiency change the denominator. Biomethanol, marine biofuels, bio-SAF and hydrogen-derived fuels then compete to supply the remaining energy service. Their feedstocks, delivered costs, emissions and production locations determine the European hydrogen requirement.

These results put the choice of industrial process ahead of the choice of hydrogen supplier. On-site production, shared pipelines and molecule imports remain available where their costs and service requirements justify them.

5. Compare domestic production with imported green inputs

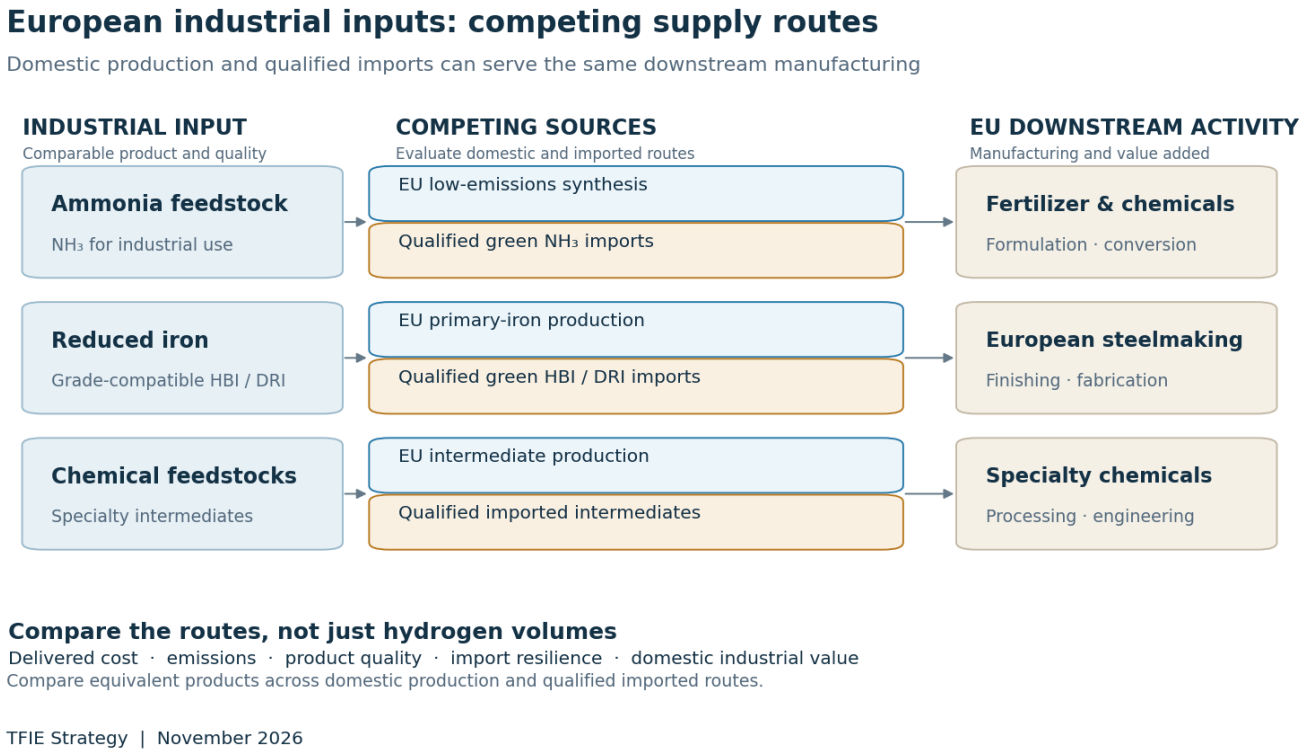


Figure 4. Domestic and qualified imported supplies of ammonia, reduced iron and chemical intermediates for European manufacturing. The routes are compared on delivered cost, emissions, quality and supply security. Source: TFIE Strategy Inc. (2026b).

Production costs and resources vary across regions. Qualifying imported green ammonia could support European fertiliser and chemical manufacturing; imported reduced iron could feed steelmaking and fabrication; and green chemical intermediates could support downstream specialty production. These are industrial inputs, not fuels. Domestic supply remains valuable where its cost, quality, resilience or strategic importance warrants it.

Relocating primary production affects employment, regional investment and strategic capabilities as well as input costs. The Commission's industrial appraisal should weigh potential gains for downstream manufacturing against the value of retaining upstream skills and capacity, and assess whether each sourcing combination strengthens European value creation.

Import dependence carries risks involving supplier concentration, water and environmental standards, verified emissions, product quality and contingency capacity. Existing RFNBO rules may treat industrial-product imports differently from imported hydrogen molecules. The proposed sensitivity would reveal the economic implications without assuming a change in EU law.

6. Hydrogen demand after industrial competition

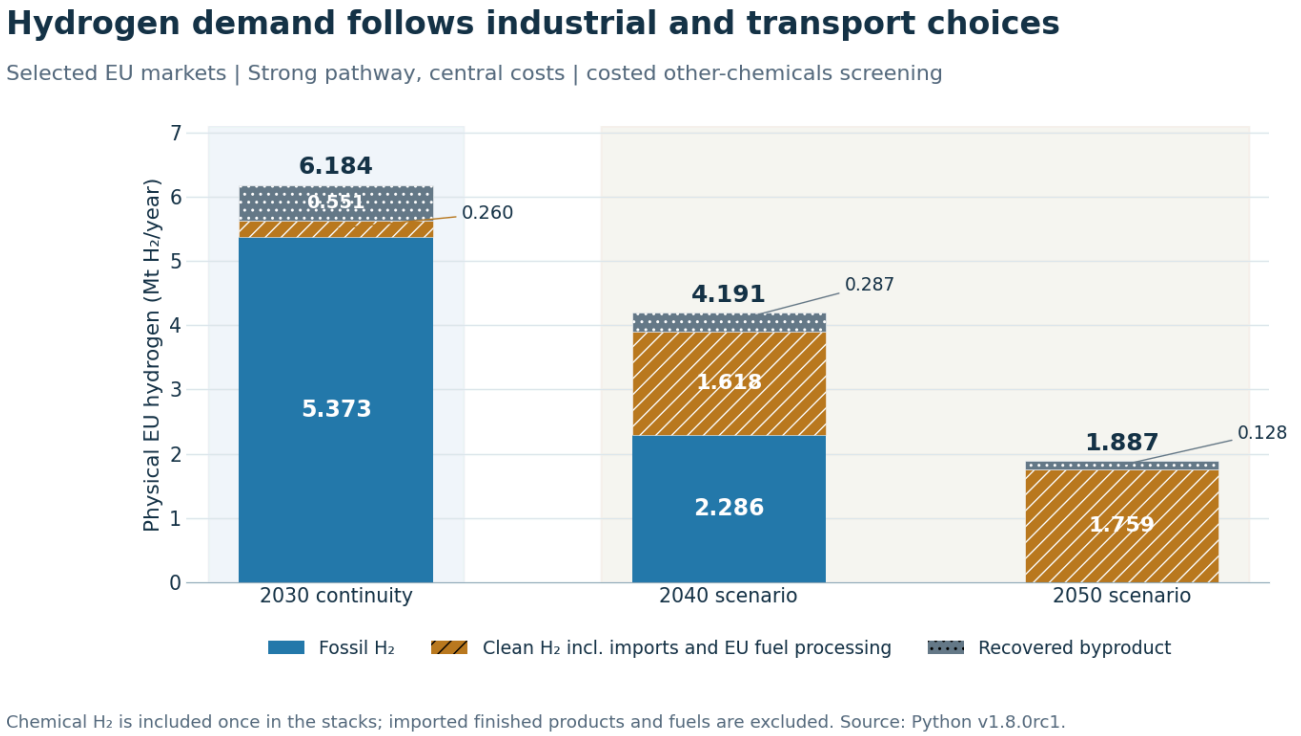


Figure 5. Physical EU hydrogen supply in selected markets under the Strong pathway with central costs in 2030, 2040 and 2050 (Mt H₂/year). Totals include hydrogen supplied to other chemicals and European transport-fuel processing but exclude hydrogen embodied in imported products and finished fuels. Source: TFIE Strategy Inc. (2026a, 2026b); Python v1.8.0rc1.

Under the Strong pathway with central costs, physical EU hydrogen use is 6.184 Mt in 2030: 5.373 Mt fossil, 0.260 Mt clean (including imported molecules and European fuel processing) and 0.551 Mt recovered byproduct. In 2040 the total is 4.191 Mt: 2.286 Mt fossil, 1.618 Mt clean and 0.287 Mt byproduct. By 2050 it is 1.887 Mt: 1.759 Mt clean and 0.128 Mt byproduct. Hydrogen for other chemicals accounts for 0.513, 0.362 and 0.211 Mt of those totals. These figures describe the selected markets, not all EU hydrogen demand.

Industrial demand is served by domestic production and imports according to route costs and capacities. Maritime and aviation fuel demand reflects remaining service needs after electrification, efficiency and changes in activity. By 2050, biomethanol supplies most of the modelled maritime service and bio-SAF most aviation fuel demand; hydrogen used to process those fuels in Europe enters EU hydrogen consumption. For other chemicals, the model then compares substitution, imported products and feedstocks, and physical hydrogen against remaining supply capacity. This final chemical allocation is sequential, not a joint optimisation of all industrial markets.

The 2050 central result is sensitive to trade, technology and fuel availability. Halving product-import capacity raises physical EU hydrogen use from 1.887 to 3.206 Mt/year; excluding electrochemical iron raises it to 2.547 Mt/year; and foreign plant-gate hydrogen at €6/kg raises it to 3.055 Mt/year. Combining all three constraints yields 3.899 Mt/year. Halving sustainable biofuel availability raises demand to 3.085 Mt/year, or 5.119 Mt/year when all four constraints apply. The chemical-activity and import-cost cases have smaller effects. Annex H reports the full set.

These comparisons depend on assumed prices, technologies and supply capacities. The other-chemicals routes are screening estimates, not verified industrial bids. Electricity needs for future direct chemical substitution, matched lifecycle emissions and complete EU system costs remain unmeasured. Because the competition case excludes hydrogen-specific mandates, it cannot establish compliance with existing hydrogen or synthetic-fuel obligations.

7. Specify the industrial and transport-fuel sensitivity

TYNDP 2026 already considers changes in industrial demand, National Trends Plus, economic variants and hydrogen supply (ENTSO-E and ENTSOG, 2026a, 2026b). ENTSO-E, ENTSOG and ENNOH launched work on the TYNDP 2028 scenarios in 2026. The proposed addition would compare production routes and sourcing locations for equivalent products and transport services, filling a gap in the existing scenarios.

Hold industrial product specifications and transport-service requirements comparable, while allowing electrification, efficiency, modal shift and changes in travel and freight to alter the residual fuel denominator. Compare domestic and imported production on delivered costs, lifecycle emissions, sustainable feedstocks, product quality, reliability and security. Report EU hydrogen and electricity demand, trade, infrastructure utilisation, import exposure and the distribution of costs and risk. ACER's 2026 assessment provides a basis for testing infrastructure need under differing demand configurations.

Apply the same climate ambition, economic boundaries and cost conventions to each pathway. Include grid and flexibility costs for electrification; include transport, qualification, embodied emissions and supply risk for imports. Test favourable assumptions for overseas hydrogen and emerging iron processes as carefully as favourable domestic supply. Combined constraints can be more material than one-at-a-time sensitivities.

The economic-competition case excludes hydrogen-specific uptake and RFNBO volume mandates so that prescribed hydrogen shares do not determine the result. Existing EU obligations remain in force. A separate current-law case should quantify the costs and effects of complying with them.

For each proposed investment, first hold the network, subsidy or policy design fixed across the cases. Publish served output, costs, hydrogen and electricity needs, emissions, utilisation, tariffs and financial exposure. Only then compare smaller, deferred or alternative investments. Reoptimising the network for every scenario at the outset would conceal the downside of the actual proposal.

8. Size infrastructure against paying demand and public value

Hydrogen networks may earn their cost in chemical clusters with durable demand. Before projecting pipeline, terminal or storage throughput, compare on-site production, direct electrification, process substitution and imported green industrial inputs. These alternatives determine which customers need hydrogen and how much infrastructure they can support.

TFIE's 2050 central hub-and-pipeline hydrogen cost is about €5.81/kg H_2. Actual networks also depend on distance, compression, storage, utilisation and tariffs. Model production-capacity ceilings are not evidence that any specific project has contracted supply.

Distinguish nonbinding expressions of interest and pipeline reservations from enforceable purchase agreements. Commercial investments require credible paying demand; anticipatory strategic capacity may proceed earlier only with a stated public rationale, financing plan and explicit bearer of underutilisation risk.

Identify the customers whose competitive industrial processes require hydrogen, then size production, transport and storage against contracted demand and justified contingency. Compare cluster networks and cross-border connections with smaller projects, on-site supply and imported-product alternatives.

Outcome-based support, including carbon contracts for difference where appropriate, should compare the cost of qualified routes per ton of emissions avoided, rather than rewarding hydrogen volumes as such.

Backbone proposals should disclose binding offtake, expected utilisation, tariffs, public exposure and the additional security or resilience value of any oversizing. After commissioning, report actual demand, delivered prices and emissions so subsequent investment decisions can adjust to evidence.

9. Require the comparison, then justify the choice

The Commission should require ENTSO-E, ENTSOG and ENNOH to add this industrial-product and transport-fuel competition test to TYNDP 2028, with industrial and transport expertise, DG MOVE participation and ACER oversight. Compare each proposed investment unchanged under both a

policy-aligned case and a mandate-free economic case. Report the cost of current-law obligations separately, then examine smaller, staged or alternative investments.

The decision record should identify the products and services delivered, emissions, EU hydrogen and electricity requirements, reliance on qualified imports, binding demand, project utilisation and who bears the financial risk. Where infrastructure remains worthwhile despite weak competitiveness, the sponsor should state the specific security, resilience or industrial benefit that warrants its premium. Contracts, delivered prices and observed utilisation should inform subsequent planning cycles.

Funding and conflicts of interest

This research and submission were funded by TFIE Strategy Inc. TFIE Strategy Inc. and Michael Barnard have no commercial interests that constitute a conflict of interest in this submission.

Copyright © 2026 TFIE Strategy Inc. Attributed non-commercial circulation, quotation and reasonable reproduction are permitted for policy evaluation, teaching, academic study and government consultation, provided substantive caveats are retained. Private modifications of the model or dashboard are permitted for those purposes; published modifications must be identified and must not imply TFIE endorsement. Third-party rights, standalone branding and commercial republication remain reserved. Full usage terms accompany the research package.

TECHNICAL ANNEX A · INDEPENDENT RESEARCH

Europe’s Hydrogen Strategy After Competition

Methods, assumptions, competitiveness tests and reproducibility

Michael Barnard | Chief Strategist, TFIE Strategy Inc. | 10 November 2026

Correspondence: michael@tfie.io

Interactive dashboard: https://tfie.io/euhydrogen

Supporting files: select “Download research package (ZIP)” on the dashboard.

Supporting evidence for the independent policy submission to the European Commission, Directorate-General for Energy.

Python industrial and transport model v1.8.0rc1 | Evidence workbook v1.8.1 | Dashboard v0.45rc1 | Units schema 2.0

A. Purpose, interpretation and system boundary

The model evaluates how industrial processes, energy prices, transport activity and trade determine hydrogen consumption in selected EU markets. It compares production routes serving equivalent industrial products, marine energy services and residual aviation liquid-fuel demand across the Slow, Strong and Rapid pathways. Maritime demand accounts for cargo, efficiency and electrification; aviation incorporates short-route electric substitution, travel-demand changes and the remaining liquid-fuel requirement. Section K describes the proposed decision protocol for infrastructure and support.

Physical EU hydrogen use comprises domestic fossil hydrogen, clean hydrogen including imported molecules and European fuel-processing demand, and recovered byproduct hydrogen. Hydrogen embodied in industrial inputs or finished fuels produced abroad is recorded separately. The other-chemicals screen assigns physical hydrogen only where that route supplies domestic chemical activity. It follows the allocation of the six specified industrial markets and transport services and uses remaining supply capacity.

The analysis covers 2030, 2040 and 2050, three transition pathways, favourable, central and adverse costs, and differing levels of product-import capacity. Across the 81 tested combinations, domestic production and imports meet all six covered industrial product requirements. These deterministic cases use stated assumptions for technology availability, production capacity and trade.

B. 2024 baseline and market coverage

The TFIE register records annual hydrogen consumption of 7.215 Mt H_2/year in 2024: refining 4.195, ammonia 1.883, other chemicals 0.604 and methanol 0.117 Mt H_2/year, plus smaller uses. ACER's separate rounded benchmark is about 7.4 Mt H_2/year. The approximately 0.2 Mt H_2/year difference reflects source coverage and classification differences; it is not reallocated across industries.

2024 evidence	Mt H_2/year	Status / interpretation
TFIE 12-sector reference	7.215	Observed 2024 consumption
ACER EU27 rounded	~7.4	Independent published benchmark
Difference (ACER − TFIE)	~0.2	Source coverage and classification difference
Other chemicals within TFIE	0.604	Chemical route screen; physical H_2 supplied
2024 uses outside scenario coverage	0.165	Recorded separately from scenario

2024 evidence	Mt H_2/year	Status / interpretation
		totals

The register attributes 0.604 Mt H_2/year in 2024 to other chemicals. For future scenarios, this volume serves as a hydrogen-equivalent reference for chemical activity, not a forecast of particular products. Under Strong/central assumptions, physical hydrogen supplied to other chemicals is 0.513 Mt in 2030, 0.362 Mt in 2040 and 0.211 Mt in 2050. Substitution and imported products or feedstocks meet the balance, subject to assumed route constraints. A further 0.165 Mt of 2024 hydrogen use lies outside the forward scenarios: 0.154 Mt of unattributed end use and about 0.011 Mt across five small categories. Future demand in those categories is unknown.

C. Route competition and accounting rules

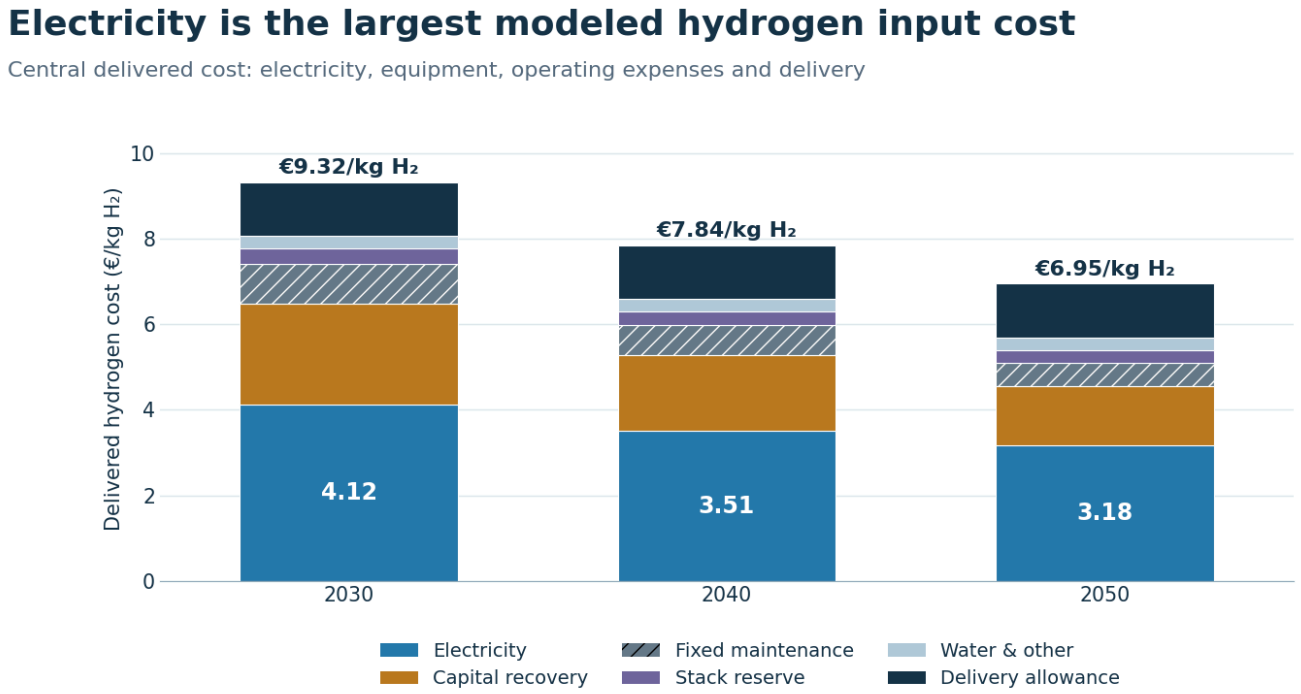
Equivalent industrial output or useful service defines each comparison, whether ammonia, an iron input of specified quality or useful heat. Modelled route costs include materials, energy, operating charges and capital. Sector-specific capacity, product standards and technology-qualification constraints limit movement to cheaper routes.

Industrial production routes and imports compete within their modelled costs and capacity limits, with conventional industrial supply available at specified costs and carbon charges. Marine fuels compete through biomethanol, other biofuels, e-methanol and e-ammonia, with domestic and imported production separately identified. Aviation compares HEFA bio-SAF, biomass-to-jet and e-SAF. Sustainable feedstock pools limit supply; hydrogen used in European fuel processing adds to EU consumption, while processing hydrogen abroad stays in the imported-fuel account. These rules apply across the three transition pathways.

Existing fossil-hydrogen facilities operate within their installed capacity. Their operating life depends on industrial demand and the availability of replacement supply. New fossil-hydrogen production incurs a separate capital charge, and its output and direct CO_2 emissions are identified. Recovered byproduct hydrogen is counted once as a separate physical supply. Imported industrial products enter their respective product balances rather than the EU hydrogen-consumption total.

The model assumes electrolyser capacity ceilings of 5, 25 and 75 GW electrical input in 2030, 2040 and 2050. Annual hydrogen output depends on operating hours and specific electricity consumption. Supply is allocated across sectors, with limits on transferring unused capacity between sites. Product and useful-service balances are checked sector by sector.

D. Delivered hydrogen production and distribution cost



Annex Figure A1. Central delivered-hydrogen costs (€/kg H₂), 2030–2050, comprising electricity, capital recovery, maintenance, stack allowance, other expenses and delivery. Source: TFIE Strategy Inc. (2026b).

Delivered hydrogen cost uses €/kg H₂. Its electricity component is kWh electricity/kg H₂ multiplied by €/MWh electricity and divided by 1,000. Annualised equipment charges, in €/kW electrical input/year, are divided by annual hydrogen production per kW electrical input. Water, other operating costs and delivery are then added. Domestic electric alternatives face the same electricity tariff; foreign product routes retain their stated foreign input costs.

Delivered cost (€/kg H₂) = electricity cost per kg H₂ + annualised equipment and fixed costs divided by annual kg H₂ output + water, other operating costs and delivery per kg H₂. Annual output (Mt H₂/year) = GW electrical input × full-load hours/year ÷ [1,000 × kWh electricity/kg H₂].

Year	Case	Electricity price €/MWh electricity	Hours/year	CAPEX €/kW electrical input	Delivered €/kg H₂
2030	Favourable	35	4,500	1,050	4.50
2030	Central	75	3,800	1,600	9.32
2030	Adverse	110	3,000	2,400	16.99
2040	Favourable	30	4,700	850	3.84
2040	Central	65	4,200	1,350	7.84
2040	Adverse	100	3,300	2,100	14.60
2050	Favourable	28	4,800	700	3.46
2050	Central	60	4,500	1,150	6.95
2050	Adverse	95	3,500	1,850	13.09

Each case combines an electricity tariff, operating hours, electrolyser capital costs and delivery assumptions. The favourable case requires low power prices and high operating hours at the same site. Project appraisals must establish whether electricity procurement, certification and local delivery conditions make that combination achievable.

The 2050 central generic benchmark is €6.95/kg H_2. The on-site route costs €5.70/kg H_2, and hub supply with pipeline handling costs €5.81/kg H_2. These supply boundaries remain distinct. The pipeline allowance does not replace a route-specific assessment of distance, compression, storage, tariff recovery and utilisation.

Transport assumptions in the Python file transport_routes.py (FUEL_ASSUMPTIONS) include illustrative liquid biofuel resource budgets of 120, 225 and 300 TWh in 2030, 2040 and 2050; a 70% lignocellulosic-residue and 30% waste-lipid resource allocation; a 60% ceiling on imported finished fuel; and a 5% e-SAF share limit for residual aviation demand. These are scenario limits, not verified sustainable biomass supplies, binding contracts or regulatory requirements.

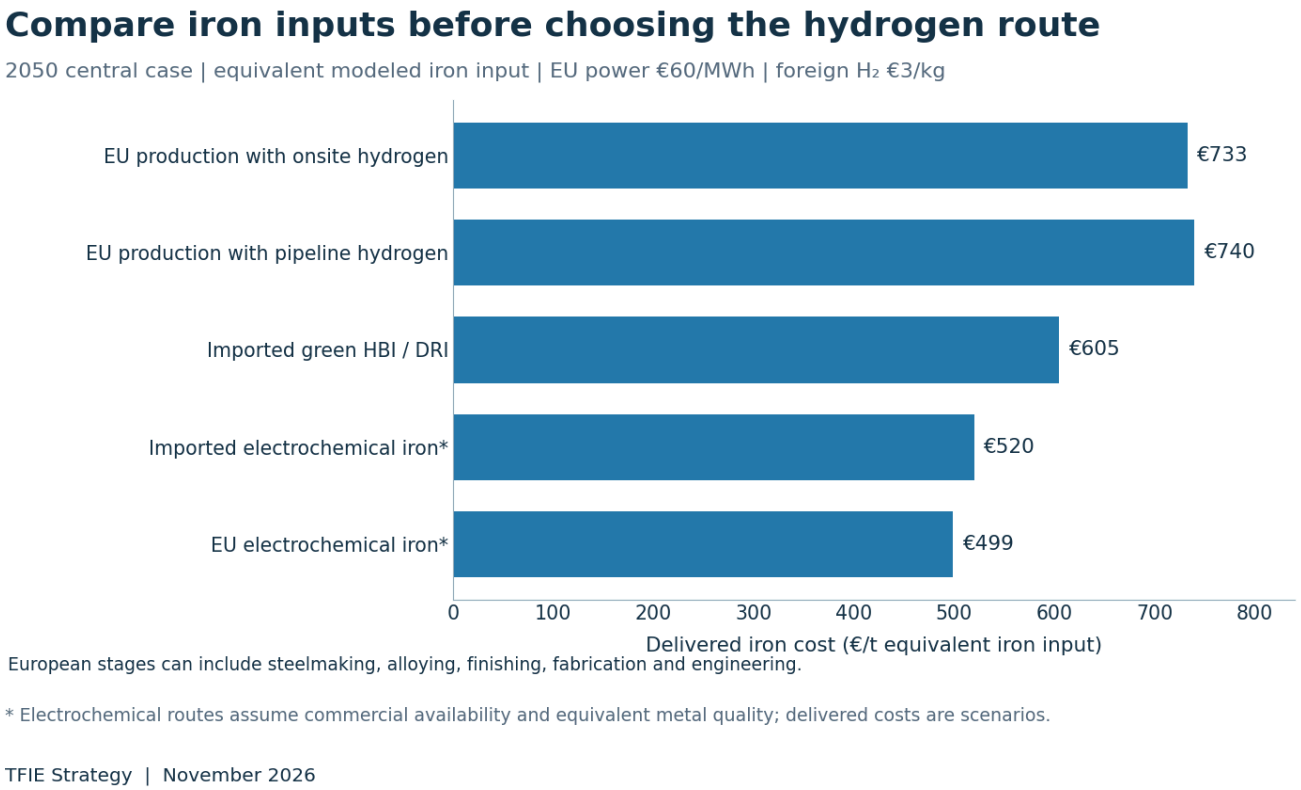
E. Parity methodology and industrial process alternatives

Hydrogen price parity is the highest hydrogen input price at which a production route remains competitive with an eligible alternative. It is calculated by subtracting the hydrogen route's non-hydrogen costs from the alternative's total cost, then dividing the difference by the kilograms of hydrogen needed to produce one comparable unit of output. Each production-cohort result is checked numerically. Capacity limits and product specifications can constrain adoption, so parity differs across routes and cohorts.

For European ammonia production to compete with qualifying imported green ammonia in the 2050 central case, its hydrogen input would need to cost €2.62–€4.00/kg H_2 or less, depending on the supplier and production route. European hydrogen-based ironmaking would need hydrogen at €2.28–€4.45/kg H_2 or less to compete with imported green reduced iron. Electrochemical iron could impose lower ceilings, subject to technology and feedstock availability. Marine biomethanol and e-methanol are distinct fuel routes; their comparison follows delivered marine energy service, rather than treating methanol as a generic industrial hydrogen input.

The industrial-heat comparison uses 94% efficiency on a lower-heating-value (LHV) basis, with sensitivities from 90% to 98%. At 33.33 kWh chemical energy/kg H_2, the central route needs 31.9 kg H_2/MWh useful heat. In the central 2050 case, hydrogen must cost €2.07/kg or less to compete with direct-electric industrial heating, with a range of €1.98–€2.16/kg depending on heating efficiency. Hydrogen equipment and other nonfuel costs are excluded, making the threshold favourable to hydrogen. Other service routes use their specified conversion efficiencies.

F. Industrial geography: delivered green products

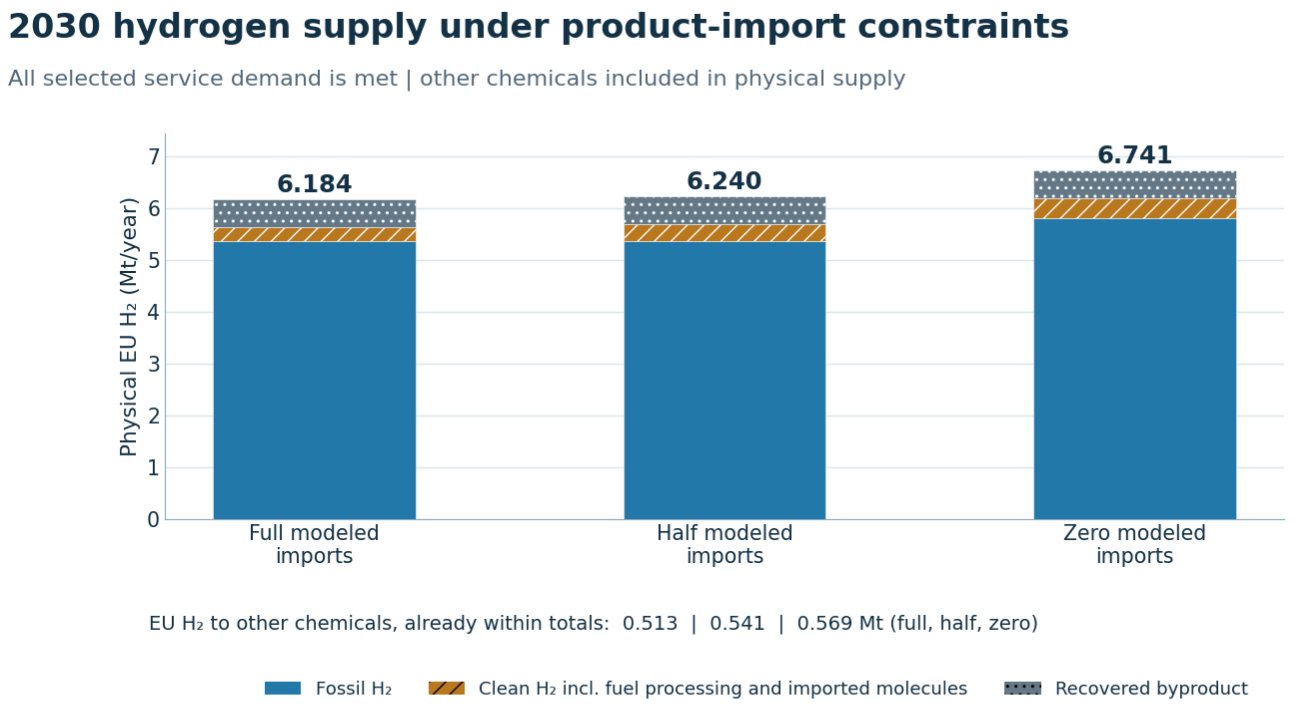


Annex Figure A2. Green iron delivered-product costs in the 2050 central case (€/t equivalent iron input), including hydrogen-based and electrochemical routes in European and overseas production locations. Source: TFIE Strategy Inc. (2026b).

Industrial trade is compared using the cost of the same industrial input delivered to European customers. In the 2050 central case, qualifying imported green ammonia costs €755–839/t NH_3, compared with about €1,222/t NH_3 for European synthesis using modelled on-site hydrogen. Imported green HBI or DRI costs about €605/t equivalent iron input, compared with €733/t for European hydrogen-based production. Imports are cheaper in these cases, provided product grade and yield match and the assumed trade capacity is available.

In the 2050 case, imported green intermediates compete with domestic upstream production and can supply European steelmaking, finishing, fabrication and chemical conversion. Industrial appraisal should assess the implications for employment and strategic autonomy alongside delivered costs. Supplier concentration, certification, water impacts, product quality, domestic capability and contingency costs require consistent treatment across sourcing options.

G. Hydrogen consumption and industrial supply



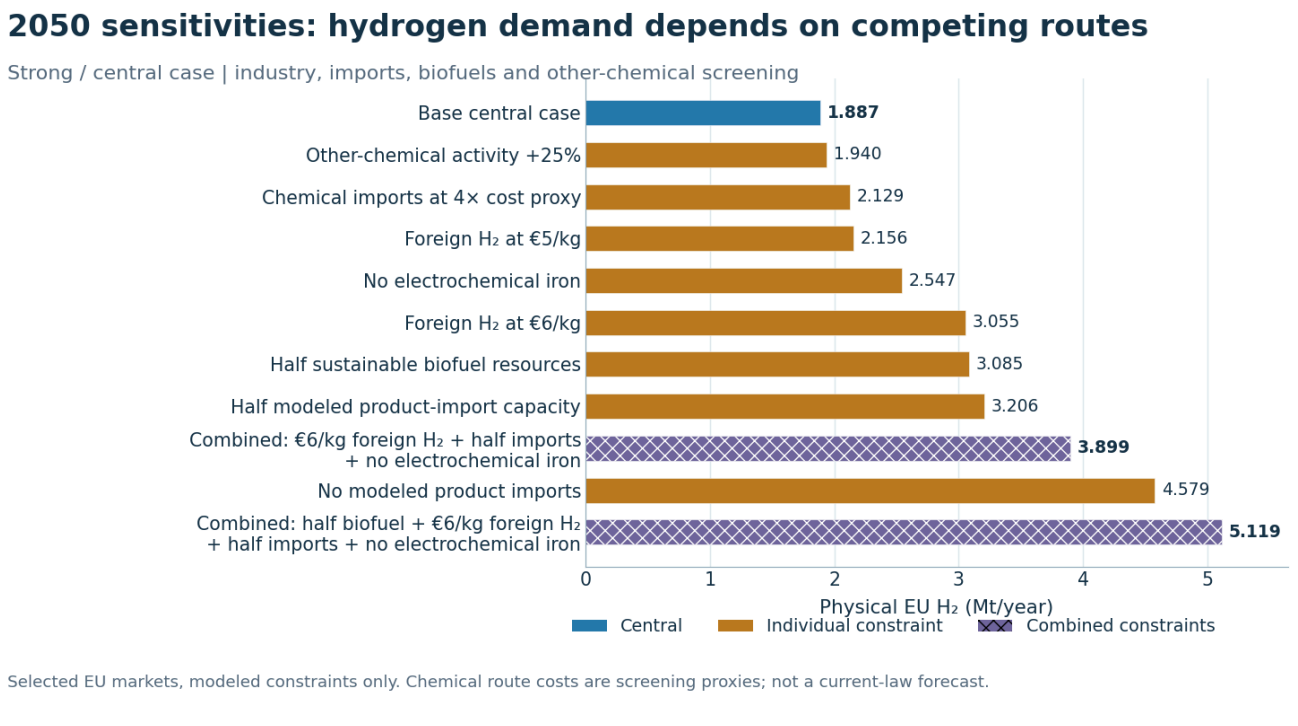
Annex Figure A3. Physical EU hydrogen supply in the Strong/central 2030 case with full, half and zero modelled product-import capacity (6.184, 6.240 and 6.741 Mt H₂/year). The stacks include hydrogen supplied to other chemicals; all specified industrial and transport output is served. Source: TFIE Python v1.8.0rc1.

Under the Strong pathway with central costs, physical EU hydrogen use is 6.184 Mt H₂/year in 2030, 4.191 Mt/year in 2040 and 1.887 Mt/year in 2050. Fossil hydrogen contributes 5.373, 2.286 and 0 Mt/year; clean hydrogen, including European fuel processing and imported molecules, contributes 0.260, 1.618 and 1.759 Mt/year; and recovered byproduct contributes 0.551, 0.287 and 0.128 Mt/year. Hydrogen supplied to other chemicals accounts for 0.513, 0.362 and 0.211 Mt/year of these totals. The six specified industrial markets and transport services are supplied. Hydrogen embodied in imported products and fuels does not enter EU physical consumption.

Year	Fossil Mt H₂/year	Clean Mt H₂/year	Byproduct Mt H₂/year	Physical Mt H₂/year	Other-chemical H₂ included Mt/year
2030	5.373	0.260	0.551	6.184	0.513
2040	2.286	1.618	0.287	4.191	0.362
2050	0	1.759	0.128	1.887	0.211

In 2030, the model includes about 1.170 Mt/year of conventional ammonia imports at €0.748 billion/year and 3.743 Mt/year of conventional blast-furnace iron inputs. The ammonia imports carry 2.574 Mt/year of modelled gross process CO_2 outside Europe. European transport-fuel processing uses 0.033 Mt H_2 in 2030, 0.059 Mt in 2040 and 0.076 Mt in 2050. A further 0.114 Mt/year of hydrogen embodied in imported aviation fuels in 2050 is recorded outside EU physical hydrogen use. Hydrogen embodied in imported chemical products and feedstocks is treated the same way.

H. Sensitivity to imports, fuel resources, prices and technology



Annex Figure A4. Strong/central 2050 EU hydrogen-consumption sensitivities (Mt H₂/year), comparing chemical activity and import prices with product-import capacity, ironmaking technology, foreign hydrogen prices and biofuel resources. The central result is 1.887 Mt/year; the most constrained combined case reaches 5.119 Mt/year. Source: TFIE Python v1.8.0rc1.

2050 Strong central assumption	**Physical EU H₂ Mt H₂/year**
Central case	1.887
Other-chemical activity +25%	1.940
Chemical imports at 4× assumed cost	2.129
Foreign plant-gate cost €5/kg H₂	2.156
Foreign plant-gate cost €6/kg H₂	3.055
Half modelled product-import capacity	3.206
No electrochemical iron	2.547
€6/kg foreign H₂ + half imports + no electrochemical iron	3.899
Zero modelled product-import capacity	4.579
Half sustainable biofuel resources	3.085
Half biofuel + €6/kg foreign H₂ + half imports + no electrochemical iron	5.119

Annex Figure A4 and the table show how 2050 hydrogen consumption changes with import capacity, foreign hydrogen prices, ironmaking technology, biofuel resources and chemical activity. The central result is 1.887 Mt/year. Cutting modelled product-import capacity in half raises it to 3.206 Mt/year; eliminating imports raises it to 4.579 Mt/year. Without electrochemical iron, it rises to 2.547 Mt/year, and at a foreign hydrogen price of €6/kg it reaches 3.055 Mt/year.

The combined case of half product imports, €6/kg foreign hydrogen and no electrochemical iron requires 3.899 Mt/year. Halving sustainable biofuel resources raises the result to 3.085 Mt/year on its own and 5.119 Mt/year when combined with those three constraints. Higher chemical activity and chemical import prices have smaller effects. Import constraints also matter earlier: half and zero product imports raise 2040 consumption to 4.571 and 5.489 Mt/year, while zero imports raise the 2030 result to 6.741 Mt/year.

I. Official planning and the additional scenario test

Year	NT hydrogen energy TWh/year as reported	H_2 mass equivalent NCV/LHV basis
2030	212	6.36 Mt H_2/year
2040	700	21.00 Mt H_2/year
2050	1,071	32.13 Mt H_2/year

The table reports National Trends (NT) final hydrogen demand, not the broader NT+ total-system hydrogen consumption. TYNDP 2026 uses net calorific value (NCV), equivalent to lower heating value (LHV), as specified in ENTSOG TYNDP 2026 Annex D2, p. 4, footnote 4. Converting the reported 212, 700 and 1,071 TWh/year at 33.33 TWh/Mt H_2 gives 6.36, 21.00 and 32.13 Mt H_2/year. The energy and mass columns describe the same demand. Comparing these values with TFIE results requires common sector and geographic boundaries. TYNDP already includes industrial-demand, technology, economic and hydrogen-supply variations. The proposed 2028 scenario would also compare the locations and processes supplying equivalent products and transport services (ENTSO-E and ENTSOG, 2026a, 2026b).

A direct comparison requires common industrial output, service, geography, emissions and cost boundaries. Differences in hydrogen volumes should be traced to those boundaries and to the production choices within them. ACER's 2026 assessment calls for economic variants that operate as genuine alternatives, and the Commission's Better Regulation toolbox sets out the treatment of baselines, policy choices and uncertainty (ACER, 2026; European Commission, n.d.).

J. Reproducibility, audit tests and limitations

The Python v1.8.0rc1 code and packaged inputs reproduce the physical hydrogen supply results, including the other-chemicals allocation. Regression testing includes 505 checks, of which 111 address chemical integration. Dashboard v0.45rc1 passed 52 JavaScript tests and matched 102 independently generated Python scenarios. The six specified industrial markets and transport-fuel services are allocated before the chemical screen. Test agreement does not establish the accuracy of illustrative chemical prices or future supply capacities.

Hydrogen and direct-electric routes use comparable scenario electricity tariffs, with explicit efficiency and operating-hour assumptions. Fossil, clean, byproduct and physically imported hydrogen are accounted for separately from imported products. The economic-competition case excludes RFNBO and synthetic-fuel volume mandates; compliance must be tested against current law in a separate case.

Scenarios vary industrial and finished-fuel imports, maritime and aviation fuels, sustainable feedstocks, foreign hydrogen prices and emerging iron processes. The chemical screen applies assumed prices and capacities to each unit of 2024 hydrogen-equivalent activity, using supply left after the other markets have been served. Modelled electricity consumption includes hydrogen supplied to chemicals but not the unmeasured electricity for chemical substitution. Lifecycle emissions, employment, welfare and network finance require further analysis.

The 2024 hydrogen-use register compiles published observations, but its source categories have not been reconciled one to one. Future costs, process substitution and import capacities are assumptions, not established outcomes. The chemical-screen prices do not represent confirmed bids for identifiable products and cannot establish a least-cost result for the whole EU chemical industry. The Python code, workbook and dashboard make the results reproducible within these limits.

K. Scenario specification and decision protocol

ENTSO-E, ENTSOG and ENNOH should develop the TYNDP 2028 sensitivity with DG MOVE, DG ENER, industrial and transport specialists, and ACER oversight. Define a policy-aligned reference and a distinct economic-competition case without hydrogen-specific uptake mandates. Test the same infrastructure proposal under both before changing its scale or timing.

Specify identical climate objectives, equivalent industrial products and transport services, geographic coverage and time horizons; disclose changes in demand, efficiency, technology and location. Report a separate current-law comparator rather than treating mandate-constrained choices as economic optima. The analysis must identify served output, lifecycle emissions, electricity requirements and infrastructure demand without conflating imported products with EU hydrogen molecules.

Price qualifying domestic and imported routes at comparable product grades and delivered boundaries. Account for electricity and grid flexibility, transport, capital, finance, equipment lives, operating hours, processing yields, environmental qualification, sustainable feedstocks and strategic import exposure. Compare favourable assumptions for foreign green products and new technologies with the same scrutiny applied to domestic hydrogen.

Test plausible interacting constraints: lower import availability with higher prices, limited scrap with delayed electrochemical iron, and constrained grids with lower electrolyser utilisation. Include a strong-hydrogen case with competitive electricity and equipment costs where achievable. Distinguish modelled sensitivities from verified supplier capacity, certification and financing.

For each network, subsidy or investment under review, publish the performance of the unchanged proposal across scenarios: served products and services, hydrogen and electricity demand, cost, tariffs, emissions, utilisation, binding purchases and financial exposure. Then compare deferral, staging, downscaling and substitute investments. This sequence reveals stranded-asset exposure that separate scenario-by-scenario optimisations could mask.

If a project underperforms commercially, decision-makers may still justify it through measurable security, resilience or learning benefits. Specify the premium, the risk bearer, and review or exit triggers linked to contracts, costs, utilisation and available competing routes. Wider Commission assessment should integrate electricity networks, welfare, lifecycle emissions and industrial investment.

References and reproducibility

External sources

ACER (2025). European hydrogen markets: 2025 monitoring report. Agency for the Cooperation of Energy Regulators. https://www.acer.europa.eu/monitoring/European-hydrogen-markets-2025

ACER (2026). ACER calls for transparent EU infrastructure scenarios, aligned with energy and climate targets. News release, 9 July 2026. https://www.acer.europa.eu/news/acer-calls-transparent-eu-infrastructure-scenarios-aligned-energy-and-climate-targets

ENTSO-E and ENTSOG (2026a). TYNDP 2026 scenario framework. Joint TYNDP 2026 Scenarios, June 2026. https://2026.entsos-tyndp-scenarios.eu/tyndp-2026-scenario-framework/

ENTSO-E and ENTSOG (2026b). TYNDP 2026 scenario results: Demand. Joint TYNDP 2026 Scenarios, June 2026. https://2026.entsos-tyndp-scenarios.eu/tyndp-2026-scenario-results-demand/

European Commission (n.d.). Better regulation guidelines and toolbox. Accessed 6 November 2026. https://commission.europa.eu/law/law-making-process/better-regulation/better-regulation-guidelines-and-toolbox/better-regulation-toolbox_en

European Court of Auditors (2024). The EU's industrial policy on renewable hydrogen: Legal framework has been mostly adopted – time for a reality check. Special Report 11/2024, Luxembourg, 16 July 2024; doi:10.2865/882. https://www.eca.europa.eu/en/publications/SR-2024-11

European Hydrogen Observatory (n.d.). Hydrogen demand. Hydrogen Landscape; accessed 6 November 2026.

European Commission (2025). Commission guidance on Articles 22a and 22b of Directive (EU) 2018/2001 concerning industrial renewable fuels of non-biological origin. Official Journal C/2025/2983; https://eur-lex.europa.eu/eli/C/2025/2983/oj/eng.

Council of the European Union (2026). Council Regulation (EU) 2026/1181 of 22 May 2026 on autonomous tariff quotas for certain fertilisers. Recital 1 reports EU imports of 2 Mt ammonia in 2024; https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32026R1181.

IEA (2026). Global Hydrogen Review 2026. International Energy Agency, Paris, 18 June 2026. https://www.iea.org/reports/global-hydrogen-review-2026

ENTSO-E, ENTSOG and ENNOH (2026). TYNDP 2028 Scenarios Kick-off Workshop, 1 October 2026. https://www.entsos-tyndp-scenarios.eu/.

ENTSOG (2026). Scenarios: ENNOH involvement in TYNDP 2028 joint planning. https://www.entsog.eu/scenarios.

TFIE model and research assets

TFIE Strategy Inc. (2026a). EU Hydrogen Python Model v1.8.0rc1, covering industrial production, residual transport fuels and illustrative chemical-route screening. Source code, scenario assumptions, datasets and 505 software regression checks.

TFIE Strategy Inc. (2026b). EU Hydrogen Evidence and Assumptions, Supporting Workbook v1.8.1. Physical hydrogen supply, chemical screening costs and capacities, industrial and transport route evidence, and sensitivity analyses.

TFIE Strategy Inc. (2026c). EU Hydrogen interactive dashboard v0.45rc1, matched to Python v1.8.0rc1. Exploratory controls for industrial processes, chemical activity, import capacity, fuel resources and hydrogen prices. Live dashboard and research-package download: https://tfie.io/euhydrogen