

Rethinking Germany's hydrogen- led transition

Demand shortfalls, infrastructure risk and the
public cost of overbuilding

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Key findings

Germany's hydrogen demand is likely to fall at or below the bottom of official projections, as direct electrification offers a more cost-competitive path across heating, transport and power.

The financing model for Germany's hydrogen core network shifts costs to taxpayers as uptake falls short. This pressures policymakers to sustain pipeline utilisation rather than resize the network to match demand.

Failure to meet optimistic hydrogen demand projections could require around €45 billion in additional public funding — roughly €1,000 per German taxpayer.

Prioritising imports of hydrogen derivatives for hard-to-electrify sectors can cut infrastructure needs, lower system costs and protect Germany's long-term industrial competitiveness.



Executive summary

Germany faces a uniquely challenging net-zero balancing act. Unlike peers with smaller industrial footprints, Germany must not only meet legally binding climate targets and rebuild energy security, but also preserve energy-intensive manufacturing and export competitiveness. The central challenge is therefore how to decarbonise without hollowing out the industrial base that underpins its economic model.

Green hydrogen, produced from renewable energy, has been presented as a bridge between these objectives. It promises deep emissions reductions in sectors such as steel and chemicals while preserving industrial production that cannot easily electrify. At the same time, the German government expects that hydrogen produced domestically or imported from a diverse group of international partners will strengthen energy security in the wake of Russia's full-scale invasion of Ukraine.

The logic is compelling, but delivering hydrogen at scale requires costly infrastructure be built ahead of confirmed demand. The centrepiece of the infrastructure buildout is Germany's hydrogen core network, a pipeline system connecting demand centres with domestic production and import terminals. Public debate often describes this as a €19.8 billion construction project, yet the true cost is substantially higher. Regulatory modelling suggests the total commitment optimistically approaches €50 billion, once financing, repurposed assets and maintenance are included.¹ Recent reports suggest this figure already needs revising upwards. With just 4% of the pipeline completed, network operators project that procurement overspends will add at least €5 billion to the final bill.²

The scale of that commitment would be manageable if hydrogen were on a credible path to economic competitiveness. Demand would follow organically, the pipeline would fill, transport fees would recover costs, and public backstops would remain theoretical. But green hydrogen remains persistently expensive — a fact that is increasingly recognised. Less well understood is the true cost of the infrastructure required to deliver it, and who will ultimately foot the bill. To answer that, we must examine the financial architecture.

A state-backed credit facility known as the amortisation account supports the hydrogen core network. The facility absorbs early revenue shortfalls with the expectation that balances will be repaid over time through transport fees. If hydrogen demand grows as regulators plan, costs can be gradually recovered from network users. If uptake remains weak, paying the accumulated credit balance falls on public backstops, transferring the burden onto taxpayers. The state is legally obligated to cover at least 76% of any unrecovered balance by 2055. Who pays for the pipeline therefore depends on a single variable: utilisation.

¹ Fraunhofer-Einrichtung für Energieinfrastrukturen und Geotechnologien IEG. [Hintergrundscenarien zur Festlegung des Hochlaufentgelts im Wasserstoff-Kernnetz](#). 15 March 2025. See page 63.

² Clean Energy Wire. [German utilities call for hydrogen law as grid cost estimates rise](#). 4 March 2026.

In practice, this means whether Germany's hydrogen demand meets optimistic targets. Pipeline financing is calibrated for hydrogen achieving system-wide relevance by 2040. This would require hydrogen penetrate district heating, baseload power generation, low-temperature industrial processes and potentially even large parts of the transport sector. In each of these areas, electrification and established technologies already offer more cost-effective decarbonisation pathways. IEEFA's sectoral analysis of Germany's hydrogen demand outlook suggests the true picture is far more constrained than official projections acknowledge. Setting aside transport, heating and most power generation as unsuitable, demand in 2045 is much more likely to fall at or below the very bottom of official scenario ranges.

Early market developments point in the same direction, suggesting hydrogen is unlikely to achieve universal relevance. Germany's 2030 target of 10 gigawatts of domestic electrolyser capacity looks distant, with only around an eighth of that having reached final investment decision. Sections of pipeline built so far also sit largely unused, with no customers connected and no supply contracted.

The fiscal implications are jarring. Across the expenditure channels this report examines, the difference between a rapid and limited hydrogen rollout conservatively amounts to €45 billion in additional public funding requirements, or €1,000 per German taxpayer, driven primarily by €34.7 billion in unrecovered pipeline costs. The remainder reflects support for hydrogen-ready power plants and extended reliance on liquefied natural gas infrastructure as an insurance mechanism.



The greater fiscal risk is arguably not stranded infrastructure, but infrastructure that works just well enough to lock in economy-wide, open-ended demand subsidies.

Yet a potentially greater long-term risk to public finances exists. As the cost realities of green hydrogen come into focus, blue hydrogen is quietly being positioned as a fallback. Produced from methane with carbon capture, it appears cheaper on paper, ostensibly offering policymakers a way to sustain demand and protect network utilisation. In practice, however, blue hydrogen would layer a second infrastructure bet on top of the first while re-anchoring hydrogen production in the same volatile gas markets Germany seeks to move away from.

Blue hydrogen also remains structurally more expensive than direct electrification and struggles to compete with incumbent fossil fuels absent prolonged policy support. If switching to blue still fails to close the competitiveness gap, policymakers must then choose between accepting dual stranded infrastructures and intervening to sustain demand. The former would be a large but finite fiscal shock, the latter a slower but indefinite drain on public finances.

The greater fiscal risk is arguably not stranded infrastructure, but infrastructure that works just well enough to lock in economy-wide, open-ended demand subsidies — tying public finances to the uncertain path of hydrogen prices.

Germany's hydrogen strategy — a reset in progress

Key findings

- Germany's 2045 hydrogen demand is likely to be at or below the lower end of official scenario ranges.
- Green hydrogen is failing to achieve the cost reductions needed to be competitive, while blue hydrogen costs will always depend on volatile gas prices.
- Vested interests played a documented role in shaping Germany's oversized hydrogen ambitions.
- To reduce costs and compete in the long term, German industrial sectors may need to import clean hydrogen derivatives rather than hydrogen itself — further reducing the need for hydrogen pipelines.

Germany has the largest and most ambitious national hydrogen strategy in Europe. It aims to deliver not only decarbonisation, but industrial growth, technological leadership and energy system resilience. Green hydrogen sits at the centre of this vision, though the strategy increasingly allows for low-carbon alternatives, including blue hydrogen, to support scale-up.³ The challenge lies in building supply, demand and transport infrastructure simultaneously. Costs remain higher than the current willingness to pay, while supply volumes are still limited. To bridge this gap, Germany has deployed a range of regulations and public finance mechanisms to build the market in parallel. But the strategy rests on two key assumptions: broad cross-sector adoption and substantial cost declines. Both are becoming increasingly uncertain.

Supply push becomes demand pull

Germany announced its initial hydrogen strategy in 2020. It updated it in 2023 to target 10 gigawatts (GW) of domestic electrolyser capacity and 95–130 terawatt-hours (TWh) of annual hydrogen demand by 2030, of which 50–70% is expected to be supplied by imports. Since 2023, there has been a further shift in approach, with the original, larger-scale supply-push build out of production and transport capacity swapped for a more cautious demand-pull approach. This is in response to slow implementation, with an insufficient number of announced hydrogen production projects reaching final investment decision. Developers' constraints include high project costs, strict EU definitions (renewable fuels of non-biological origin) for green hydrogen and investors seeking long-term offtake agreements.

³ Green hydrogen is produced from water using renewable energy. Blue hydrogen is produced from natural gas with carbon capture. Other potential low-carbon colours are referenced in Germany and the EU, but this remains an evolving area. Clean hydrogen refers to renewable and low-carbon hydrogen.

Official acknowledgement

In September 2025, the Federal Ministry for Economic Affairs and Energy (BMWE) commissioned a monitoring report on Germany's energy transition.⁴ The section on hydrogen is a meta-study of existing modelled scenarios and further updates the shift towards more flexible targets, widening beyond green hydrogen to include blue and other types of hydrogen. At the report's launch, Energy Minister Katherina Reiche emphasised the need to focus on sectors with a high willingness to pay for hydrogen and a need to build out infrastructure "step by step", alongside bankable demand.⁵ The monitoring report acknowledges that currently there is "hardly any market demand" and the 10GW domestic target seems "hardly achievable given the current project pipeline". It also reiterates the high uncertainty in future hydrogen demand. Hanna Schumacher, head of the hydrogen and gas infrastructure department in the economy ministry, said in October 2025 that "the hydrogen ramp-up has not worked as well as we had hoped so far", adding: "It may also make sense not to do things quite so quickly and not quite so much."⁶

What is Germany's Hydrogen Acceleration Act?

Germany's strategy previously focused on hydrogen made from renewable energy (green hydrogen). But high costs and uncertain supply have opened the door to blue hydrogen, produced from natural gas with carbon capture and storage (CCS). Germany's Hydrogen Acceleration Act, passed by parliament in February 2026, has formalised this shift. The legislation designates blue hydrogen as being in the "overriding public interest", effectively giving such projects equal access to accelerated permitting as green hydrogen.

But this strategy deepens Germany's infrastructure exposure, adding a network of carbon dioxide pipelines to the planned hydrogen backbone. It also expands reliance on CCS, a technology with prohibitive costs and historical underperformance.⁷ Most worryingly for Germany's energy security, the legislation could lock in natural gas to create blue hydrogen. This would increase the country's vulnerability to supply shocks and volatile gas prices.

⁴ German Federal Ministry for Economic Affairs and Energy. [Monitoring report on the status of the energy transition](#). 23 September 2025.

⁵ H2 International. [German energy minister plans shaping hydrogen ramp-up "based on demand"](#). 17 September 2025.

⁶ Hydrogen Central. [Germany to revise hydrogen subsidies, increase focus on imports – official](#). 9 October 2025.

⁷ IEEFA. [The carbon capture crux: Lessons learned](#). 1 September 2022.

In February 2026, the German parliament passed the Hydrogen Acceleration Act to speed up deployment of hydrogen production and supply infrastructure (such as electrolyzers, import terminals, storage facilities and pipelines). It grants priority status to qualifying projects based on “overriding public interest” and defines binding deadlines, digitalisation requirements and fast-track legal procedures. The bill had been delayed for months amid intense lobbying pressure to expand its scope. Amendments to look beyond solely green hydrogen were accepted, meaning blue (and natural) hydrogen, renewable fuels of non-biological origin and power-to-liquid projects will qualify. However, the government rejected proposals to include industrial hydrogen usage (such as steel furnaces) on the basis that downstream project support was not the intention of this bill.^{8,9}

The case for importing derivatives

With the size of the hydrogen economy increasingly uncertain, focus should shift from marginal production costs to total system costs. IEEFA recommends focusing less on importing green hydrogen and more on its derivatives, which are needed to decarbonise certain industrial manufacturing processes. These include e-methanol (for plastics, fuel and other chemicals), e-ammonia (for fertilisers and fuel) and green hot briquetted iron (for steel).¹⁰ By importing these products instead of producing them domestically, Germany could decarbonise parts of its industry at lower overall system cost while preserving industrial activity in the long term.¹¹ This may be politically sensitive and could be framed as ceding German industry. But where jobs are already being lost to global competition despite substantial subsidies, the trade-off merits serious examination. Hanna Schumacher, head of the hydrogen and gas infrastructure department in the economy ministry, said in October 2025: “We will focus on imports, perhaps even more so than the last government because it is more cost-effective overall.”¹²

The Thyssenkrupp case illustrates the challenge. In 2023, the EU approved up to €2 billion in German state aid for the company to develop a new hydrogen-ready direct reduction plant.¹³ Yet in 2024, the company still announced that it would cut 11,000 jobs.¹⁴ Today the plant is delayed and will run on natural gas rather than green hydrogen when it finally comes online. A recent study by Agora Industry found that integrating green iron imports could cut steelmaking costs in Europe by 12–15% by 2040.¹⁵

⁸ Hydrogen Insight. [Germany passes Hydrogen Acceleration Act, designating green and blue H2 infrastructure as being of ‘overriding public interest’](#). 26 February 2026.

⁹ German Federal Law Gazette. [Gesetz zur Beschleunigung der Verfügbarkeit von Wasserstoff und zur Änderung weiterer rechtlicher Rahmenbedingungen für den Wasserstoffhochlauf und weiterer energierechtlicher Vorschriften](#). 1 April 2026.

¹⁰ The precursor for steel production is known as hot briquetted iron, which is processed from iron ore. When green hydrogen is used instead of fossil fuel in this process, its by-product is water instead of carbon dioxide, substantially reducing carbon footprint.

¹¹ IEEFA. [European steel technology transition in danger of slowing but carbon capture is not the answer](#). 23 January 2025.

¹² Hydrogen Central. [Germany to revise hydrogen subsidies, increase focus on imports – official](#). 9 October 2025.

¹³ Thyssenkrupp. [EU Commission approves German federal and state government funding for thyssenkrupp Steel's "tkH2Steel" decarbonization project](#). 20 July 2023.

¹⁴ Reuters. [Thyssenkrupp to cut 11,000 jobs at steel division in major corporate shakeup](#). 25 November 2024.

¹⁵ Agora Industry. [The role of green iron trade in accelerating competitive steel transformation](#). 17 September 2025.

Lower costs would stem from three factors:

1. Reduced need for a new network of costly hydrogen pipelines and storage facilities within Germany, lowering capital needs and limiting utilisation risk.^{16,17}
2. Decreased domestic electricity demand, which — in a marginal pricing system where gas often sets the price — could lower electricity costs economy-wide.
3. Some countries can produce hydrogen-based products more cheaply than Germany can domestically, though transport costs still matter.

The downside is less upstream economic activity located in Germany and a greater reliance on international supply chains. Risk is mitigated, however, by the fact that production is viable anywhere with strong renewables resources, making meaningful supply diversification more achievable than with conventional energy imports. Collaboration at the EU level could also help to structure and secure those partnerships.

This shift reflects an inevitable economic trend — energy-intensive upstream production processes are naturally pulled towards centres with cheaper input costs. Whereas in the past this meant geographies with vast fossil fuel reserves, now and going forward it means countries with more abundant renewables resources. In IEEFA's view, a recalibrated strategy that acknowledges and pre-emptively adapts to this reality is more likely to protect the future competitiveness of German industry than one that resists it.

Vested interests and a long-overdue reset

Germany's difficulties are not entirely unique. A parallel reset of hydrogen expectations and plans has been taking place across the EU. A July 2024 report from the European Court of Auditors called for a hydrogen reality check and for the European Commission to “make strategic choices on the way ahead without creating new strategic dependencies”.¹⁸

What EU institutions are now acknowledging has been argued for years by analysts, academics and civil society groups. Their concerns centre on two related problems — the lack of robust scientific assumptions around hydrogen, and the role of lobbying from vested interests (including gas and petrochemicals companies) in inflating hydrogen expectations.

¹⁶ Seibold et al. [Balancing Cost Savings and Import Dependence in Germany's Industry Transformation](#). 1 October 2025.

¹⁷ Glaum et al. [The Minimal Methanol Economy as a Gap-Filler for High Electrification Scenarios](#). 14 May 2025.

¹⁸ European Court of Auditors. [Special report 11/2024: The EU's industrial policy on renewable hydrogen – Legal framework has been mostly adopted – time for a reality check](#). 16 July 2024.

Table 1: The growing gap between hydrogen ambition and reality

Economic and technical limits	A growing body of analysis shows that hydrogen struggles to compete with direct electrification in several proposed end uses. Since 2021, the Hydrogen Science Coalition has published numerous briefings demonstrating this in domestic heating and passenger vehicles. ¹⁹ IEEFA has also highlighted the limited competitiveness of hydrogen in areas such as gas blending and power generation, where efficiency losses and cost differentials remain substantial. ^{20,21}
Policy drivers and vested interests	Concerns have also been raised about the drivers of hydrogen policy. A 2023 report by Corporate Europe Observatory pointed to significant corporate influence, arguing that inflated demand projections are being used to justify continued investment in fossil-linked infrastructure, including blue hydrogen. ²² The report also points to the scale of lobbying activity, noting that “Germany’s hydrogen lobby employs hundreds of lobbyists and spends millions on influencing German politics”.
The misaligned outcome	The result is a strategy that appears calibrated for a hydrogen economy that will not materialise at the scale or speed assumed. As analyst Michael Liebreich observed in 2025, there remains “a big disconnect between the physics of what a solution can deliver, and the politics of what’s being asked of it”. ²³

The misalignment between hydrogen ambition and reality is most visible in demand projections, where assumptions about future uptake often run ahead of current economic and technical realities.

¹⁹ Hydrogen Science Coalition. [What does science say about hydrogen's role in the energy transition?](#)

²⁰ IEEFA. [Hydrogen gas does not belong in your home: Hydrogen faces a diminishing future as a heating and cooking fuel](#). 21 January 2025.

²¹ IEEFA. [Hydrogen: Not a solution for gas-fired turbines](#). 1 August 2024.

²² Corporate Europe Observatory. [Germany's great hydrogen race](#). 23 March 2023.

²³ BloombergNEF. [Liebreich: The Pragmatic Climate Reset – Part II: A Provocation](#). 11 September 2025.

Demand projections: Outdated, oversized and uncertain

Germany currently uses hydrogen in petrochemical refining and the production of hydrogen derivatives, mainly ammonia (for fertiliser) and methanol (for chemicals and fuel). BMW's monitoring report estimates that Germany's current hydrogen demand is as much as 60TWh per year, almost entirely from fossil fuel production.²⁴ Germany's 2024 hydrogen production of around 1.7 million tonnes generated approximately 20 million tonnes of carbon dioxide, or about 3% of the country's total annual greenhouse gas emissions.²⁵

The monitoring report is direct about where the market stands today: "There is virtually no market-driven demand for renewable or low-carbon hydrogen in Europe. Market ramp-up is being managed at the national and EU levels through regulatory requirements and support instruments." As well as the Emissions Trading System and Carbon Border Adjustment Mechanism, other EU measures to stimulate hydrogen demand include quotas for minimum use of renewables in the Renewable Energy Directive (RED II and RED III) and financial support for certain sectors under the Important Projects of Common European Interest. German measures include federal funding for industrial decarbonisation (Dekarbonisierung der Industrie & Bundesförderung Industrie und Klimaschutz) and climate protection agreements (Klimaschutzverträge). While these measures can help to stimulate demand to an extent, sustainable market-driven demand will ultimately require improved fundamentals.

²⁴ This section draws significantly from BMW's monitoring report, which references numerous scenarios of hydrogen demand to give a very wide range of Germany's possible hydrogen demand in 2045, highlighting the high uncertainty of adoption across different sectors. The report includes exploratory trend scenarios, which may not achieve climate targets, alongside so-called normative scenarios, which do. The report notes that discrepancies between the two are growing and that this generally indicates a "risk of failing to meet the targets if no [corrective] action is taken".

²⁵ IEEFA estimate based on data from the Fraunhofer Institute, the International Energy Agency and German Environment Agency.

Will Germany's hydrogen demand fall short of government forecasts?

Germany still plans a system-wide role for hydrogen. But analysing potential demand across sectors suggests that government forecasts are overoptimistic. IEEFA expects that hydrogen will not play a meaningful role for heating and transport. Germany will also likely use hydrogen power plants less than anticipated because of their high expense and low efficiency. This leaves industrial applications. A report from the Federal Ministry for Economic Affairs and Energy suggests uncertainty about industrial demand.²⁶ IEEFA therefore estimates that Germany's 2045 hydrogen demand will likely be at or below the lower end of official scenario ranges.

There is recognition within Germany that the country's hydrogen forecasts are unrealistic. A member of the German government's National Hydrogen Council warned last year that the country's hydrogen targets will likely be missed.²⁷ Both supply and demand are falling well below expectations, the president of Germany's Federal Court of Auditors said in October 2025.²⁸ To avoid overburdening the federal budget, he called on the government to "act now and fundamentally revise its hydrogen strategy".

Where hydrogen will and won't scale

Hydrogen is no longer expected to play a significant role in transport or buildings. This has been clear since 2020, as electric vehicles and heat pumps (in particular) have demonstrated falling costs, superior efficiency and strong growth. Any demand that does materialise in these sectors will likely be driven by regulatory quotas — for shipping and aviation fuels, for example — or exceptional cases such as off-grid heating.

In the power sector, hydrogen-ready plants have been touted as a solution to "dunkelflaute" periods of extended low solar and wind output, when the grid needs firm backup (typically in winter). However, hydrogen power plants will likely play a [smaller role](#) than originally planned and should not be expected to provide baseload generation. Their high expense and low efficiency, as well as the development of alternatives over the coming decades (more energy storage, stronger grid

²⁶ German Federal Ministry for Economic Affairs and Energy. [Monitoring report on the status of the energy transition](#). 23 September 2025.

²⁷ Der Tagesspiegel. [Unternehmen sind alarmiert: Verpasst die Regierung den Wasserstoffhochlauf?](#) 11 July 2025.

²⁸ German Federal Court of Auditors. [Umsetzung der Wasserstoffstrategie stockt: Erhebliche Risiken für Energiewende, Industriestandort und Bundesfinanzen](#). 28 October 2025.

interconnections, demand-side management and increased system flexibility) significantly constrain their realistic contribution.

That leaves industrial applications such as chemicals production, steel and process heat generation. These sub-sectors currently rely on fossil fuels or grey hydrogen and could potentially switch to low-carbon hydrogen-based processes.²⁹ The monitoring report scenarios suggest significant uncertainty about the extent of hydrogen demand here. Process heat could largely be decarbonised at lower cost through electrification, except in the highest temperature cases. The final result will depend largely on the future affordability and availability of clean hydrogen supply, as well as regulatory incentives supporting investment.

A blind spot also exists. The novel approach outlined previously, of importing green hydrogen derivatives (e-methanol, e-ammonia and green iron) rather than producing them domestically, would mean the associated hydrogen gas demand is swapped out and replaced with demand for the derivatives themselves. This has not yet been modelled in detailed scenarios for the industrial sector because the prevailing assumption has been that sufficient domestic clean hydrogen supply would make it unnecessary. However, this assumption is now hard to reconcile with auditor warnings. If it breaks down, hydrogen gas demand projections across the industrial sector may be substantially overstated, significantly weakening the case for pipeline infrastructure.

IEEFA's adjusted demand estimates

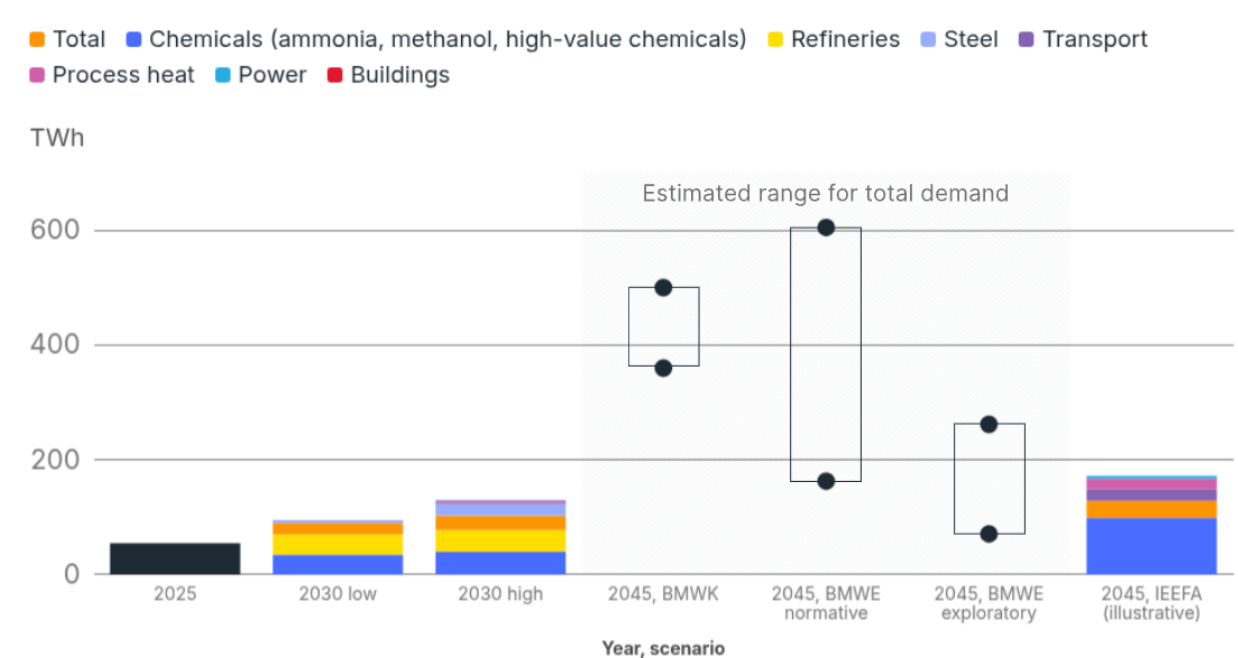
Many of the existing scenarios do not reflect the above findings, meaning that projected green hydrogen demand is often unrealistically high. By applying these simple findings to existing projections, IEEFA estimates that Germany's 2045 hydrogen demand is far more likely to sit at the bottom end of the monitoring report's normative scenarios range (163–605 TWh), near the midpoint of the exploratory scenarios range (71–262TWh) and well below the range in the Federal Ministry for Economic Affairs and Climate Action's 2024 system development strategy (360–500TWh).



Germany needs to rethink and downsize its hydrogen infrastructure plans around a substantially lower demand baseline.

While more detailed analysis is required to test and refine assumptions, it is clear that Germany needs to rethink and downsize its hydrogen infrastructure plans around a substantially lower demand baseline. Failure to do so risks overspending on hydrogen infrastructure, pushing up energy prices and locking in natural gas through blue hydrogen or hydrogen-ready gas plants that fail to switch to hydrogen. This would undermine Germany's energy security and climate commitments and have sizeable [fiscal consequences](#).

²⁹ Grey hydrogen is produced from unabated natural gas.

Figure 1: Germany hydrogen demand projections by sector

Sources: German Federal Ministry for Economic Affairs and Energy (BMWE), German Federal Ministry for Economic Affairs and Climate Action (BMWK), IEEFA analysis.

Notes: IEEFA's 2045 illustrative scenario assumes the following relative to official projections. To reduce costs and stay competitive, Germany imports significant volumes of hydrogen derivative industrial precursors rather than producing them domestically, reducing demand for hydrogen gas by a third for chemicals and a half for steel production (to 99TWh and 30TWh, respectively). Germany only burns hydrogen gas for 5% (20TWh) of process heat energy demand and a fifth (18TWh) of projected power sector demand. It uses minimal amounts of hydrogen gas in transportation and buildings (5TWh), instead relying mainly on electrification and imported liquid e-fuels.

Hydrogen supply

Although Germany's hydrogen demand outlook remains uncertain, it is clear that the country will meet most of it with imports, whether of hydrogen gas or hydrogen derivatives. This requires international supply chains, as well as terminals, pipelines and trucks in Germany. Under the EU's hydrogen strategy, Germany, Belgium and the Netherlands will account for around 60% of the bloc's hydrogen imports.³⁰ The strategy identifies five possible supply corridors: South2, via North Africa and Southern Europe; H2Med, via Southwest Europe and North Africa; the North Sea; the Nordic and Baltic regions; and the Central European Hydrogen Corridor, via East and Southeast Europe.

While imports are expected to be cheaper, Germany aims to retain some domestic production for resilience, flexibility and technological know-how. The monitoring report notes that this trade-off is

³⁰ German Federal Ministry for Economic Affairs and Climate Action. [Hydrogen in Germany Recent Developments Presentation](#). February 2025.

“also a political decision”. Its analysed scenarios vary widely, with imports accounting for 26–92% of hydrogen supply in 2045.

Domestic production

Germany's target of 10GW of electrolyser capacity by 2030 is towards the top of the range of analysed scenarios in the monitoring report (2–12GW). As of 2025, only 1.2–1.3GW of projects were at financial investment decision stage and another 7–12 GW were in planning, according to the monitoring report. On any reasonable construction timeline, the 10GW target is no longer credible. In October 2025, the German Federal Court of Auditors highlighted that according to the German Energy Agency, “less than 5GW of projects have a high to medium probability of being implemented by 2030”.³¹

International supply

Germany has allocated €4.4 billion to using the H2Global mechanism for procuring imports of green hydrogen and derivatives.³² The mechanism uses a double auction model to first buy internationally at the lowest possible price, then sell domestically to the highest bidder. Public funds initially cover the gap between these two prices, stimulating the market. In 2024, Germany awarded its first green hydrogen tender to fertiliser producer Fertiglobe. The company will supply Germany with at least 259,000 tonnes of green ammonia from Egypt between 2027 and 2033 for a total cost of €397 million. H2Global operator Hintco is now progressing a larger second auction round, partly jointly funded by the German and Dutch governments, with five lots totalling €2.9 billion.³³

Germany is pursuing bilateral green hydrogen tenders with both Canada and Australia.^{34,35} In January 2026, German utility Uniper announced a binding offtake agreement to purchase up to 500,000 tons of green ammonia per year from AM Green in India, certified for European use as a renewable fuel of non-biological origin, though commercial terms remain confidential.

The overall picture of international supply is one of tentative, early-stage commitments. Downsizing and cancellations have also started to creep in. Namibia's Hyphen Hydrogen Energy project was one of the more advanced green ammonia supply projects targeting Germany. In September 2025, however, German utility RWE withdrew from the project entirely, having initially planned to import 300,000 tonnes of ammonia per year from 2027.³⁶ The withdrawal signals how even committed players with established supply plans are stepping back, reflecting a broader reluctance to lock in long-term hydrogen offtake without greater demand certainty.

³¹ German Federal Court of Auditors. [Implementation of the Federal Government's Hydrogen Strategy](#). 28 October 2025.

³² [H2Global Foundation](#).

³³ Hintco. [Tender 2](#).

³⁴ German Federal Ministry for Economic Affairs and Energy. [Evaluation of the market consultation for the bilateral window with Canada as part of the H2Global hydrogen program](#). 26 November 2025.

³⁵ German Federal Ministry for Economic Affairs and Climate Action. [Hydrogen in Germany: Recent developments](#). February 2025.

³⁶ Reuters. [RWE withdraws from \\$10 billion Namibia green hydrogen project](#). 29 September 2025.

Import infrastructure

Germany plans to build or adapt its existing import terminals to be ammonia-ready. It has already made meaningful progress:

- Stade: Hanseatic Energy Hub is constructing a terminal to import liquefied natural gas (LNG) and later ammonia, targeting operation by 2027.³⁷
- Wilhelmshaven: Uniper is planning an ammonia import terminal and cracker plant.³⁸
- Hamburg: Mabanaf and Air Products are planning New Energy Gate Hamburg, an ammonia import terminal and cracker facilities at the Port of Hamburg, targeting 2028 operation.³⁹
- Brunsbüttel: The German LNG Terminal is constructing an ammonia-ready LNG terminal to be operational (importing LNG) from 2027.⁴⁰

Germany has had less success in developing hydrogen import pipelines, which fall within scope of the European Network of Transmission System Operators for Gas's European Hydrogen Backbone project:

- In September 2024, Equinor halted its plans for a (blue) hydrogen export pipeline from Norway to Germany. "The hydrogen pipeline hasn't proved to be viable. That also implies that hydrogen production plans are also put aside," a spokesperson said at the time, citing a lack of firm long-term commitments from European buyers to import hydrogen.⁴¹
- The H2Med pipeline via Portugal, Spain and France to Germany is progressing as an EU Project of Common Interest, targeting operation from 2030 at the earliest.

Hydrogen cost projections

Prices have failed to come down as projected since 2020. Germany's strategy originally envisioned green hydrogen as the energy carrier of the future, economically competitive with alternative decarbonisation solutions in time to justify the infrastructure that is already being built. But the cost gap has proven persistent, leading Germany to broaden its targets and include blue hydrogen alongside green — a decision that carries its own [set of risks](#).

The delivered price in Germany reflects several stacked cost layers, each of which adds to the competitiveness gap between clean hydrogen and the incumbent fossil fuels it needs to displace or electrified alternatives it competes with:

³⁷ [Hanseatic Energy Hub](#).

³⁸ Uniper. [Global hydrogen market: Uniper and thyssenkrupp Uhde sign framework agreement on the use of ammonia cracking technology](#). 26 November 2025.

³⁹ MB Energy Holding. [New Energy Gate Hamburg](#).

⁴⁰ [German LNG Terminal](#).

⁴¹ Reuters. [Norway's Equinor scraps plans to export blue hydrogen to Germany](#). 21 September 2024.

- (i) Production costs (highly variable, depending on method; see Table 2)
- (ii) Transport and storage costs (infrastructure such as pipelines, terminals, tanks)
- (iii) Any other levied taxes and charges (such as grid fees)

These costs may be partly offset by any subsidies or contract for difference payments offered to producers/consumers at either a national or EU level.

The monitoring report references recent modelling from the Institute of Energy Economics (EWI) at the University of Cologne, which puts the cost of domestic green hydrogen production in Germany at approximately €244/megawatt-hour, or around €7.30/kg. EWI projects this will fall to around €200/megawatt-hour in 2030, or roughly €6/kg. For context, grey hydrogen currently costs around €3/kg. Although the outlook for green hydrogen improves by 2050, it is unlikely to reach parity with the current cost of hydrogen produced using fossil fuels.⁴²

Table 2 summarises the cost components and projected ranges for grey, blue and green hydrogen production. The blue hydrogen data illustrate why it seems increasingly attractive to policymakers facing green hydrogen's cost persistence. At best around €4/kg in Europe today, it appears closer to the grey baseline. But blue hydrogen costs remain sensitive to gas prices, carbon capture performance/costs and carbon pricing for uncaptured emissions, meaning its 2050 trajectory is highly uncertain. For example, a meaningful carbon price at that point in time could erode much of blue hydrogen's apparent advantage.

⁴² Institute of Energy Economics at the University of Cologne. [EWI Global PtX Cost Tool](#). June 2025.

Table 2: Hydrogen types and their corresponding production cost components

Hydrogen type	Production method	2025 levelised cost of hydrogen (€/kg)	Key cost variables	2050 projected levelised cost of hydrogen (€/kg)
Grey hydrogen	Steam methane reforming	~3	Natural gas price, CO ₂ prices, operational efficiency, financing	Highly dependent on natural gas and CO ₂ prices (once free EU allowances are phased out)
Blue hydrogen	Steam methane reforming with carbon capture and storage (CCS)	~4	Natural gas price, CCS capex, CO ₂ transport/storage costs, carbon pricing for uncaptured carbon, financing	~2.5–4
Green hydrogen	Electrolysis of water	>6	Electricity price (renewables power purchase agreement or wholesale electricity, for example), electrolyser capex, balance of plant costs, grid fees (if applicable), financing	~2–6

Sources: IEEFA, Oeko-Institut, Institute of Energy Economics at the University of Cologne.

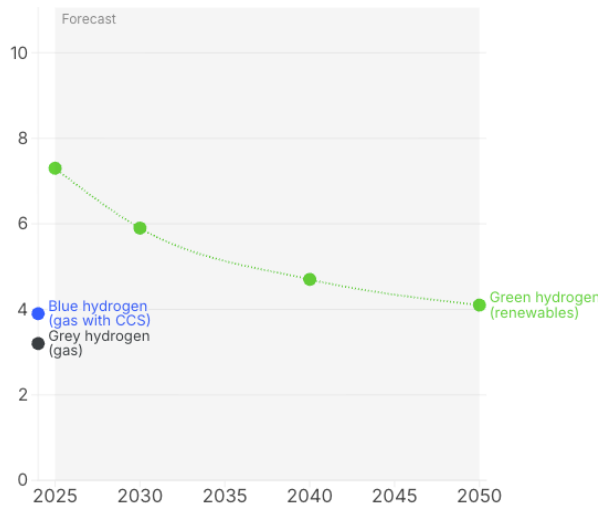
Imports could offer partial relief. By 2030, EWI estimates that green hydrogen pipeline imports from Morocco, Spain or Finland will likely be cheaper than domestic production. Shipped imports from countries like Canada, Mexico or Australia will be more expensive, however, with conversion and transport losses adding materially to final delivered costs. Under a more targeted strategy, imported

derivatives such as ammonia or methanol could prove more economical at a system level by using existing port infrastructure and reducing the need for costly new hydrogen pipelines.

Figure 2: Germany cost of domestic and imported hydrogen

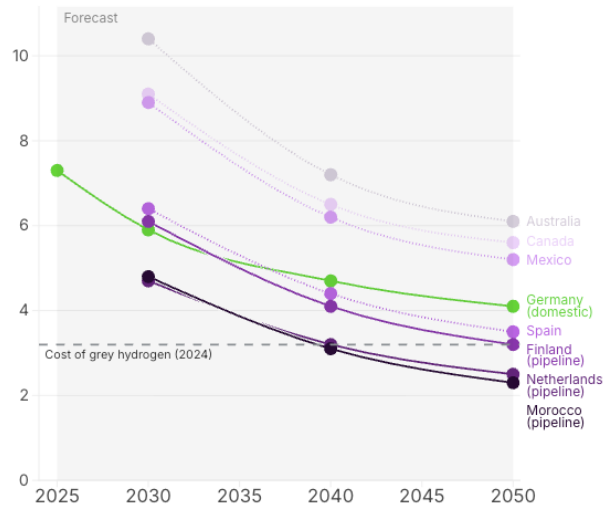
Cost of hydrogen produced in Germany

Although the outlook for renewables-based green hydrogen improves by 2050, it is unlikely to reach parity with the current cost of fossil-based grey hydrogen



Cost of imported vs domestic green hydrogen

Imports could offer partial relief. By 2030, EWI estimates that green hydrogen imports via pipeline could be cheaper than domestic production



Sources: European Hydrogen Observatory, Institute of Energy Economics at the University of Cologne, H2Global.
Notes: EWI = Institute of Energy Economics at the University of Cologne, 2025.

The cost picture that emerges is consistent and uncomfortable. Green hydrogen has not followed the cost reduction curves that might justify the scale of Germany's infrastructure commitment. Blue hydrogen looks more affordable on paper but remains structurally dependent on gas markets, carbon capture and carbon pricing assumptions that are far from settled. Neither is on a trajectory that closes the competitiveness gap with direct electrification in the sectors where electrification is feasible.

The fiscal wager behind Germany's hydrogen-led transition

Key findings

- The regulated cost base of Germany's planned hydrogen network exceeds €50 billion, far higher than the often-cited €19.8 billion construction cost.
- The financing model for the core network assumes near-full utilisation by 2040. Under a plausible limited-demand scenario, at least €34.7 billion in unrecovered costs would fall to the state by 2055.
- Raising pipeline tariff caps in response to low utilisation is not a viable solution. The increases required to recover costs would suppress demand faster than they raise revenue.
- As hydrogen demand lags, policy is expanding to protect pipeline utilisation. A shift to blue hydrogen would deepen Germany's gas dependency, expand infrastructure exposure and risk open-ended demand subsidies tied to uncertain hydrogen prices.

Energy transitions are not just technological projects. They are financial bets on how quickly new markets will develop, with clear consequences for who pays when expectations fall short. Those consequences are rarely visible in headline investment figures or policy announcements. Instead, they emerge from the financial engineering that enables infrastructure to be built ahead of demand.

How is Germany financing its hydrogen network?

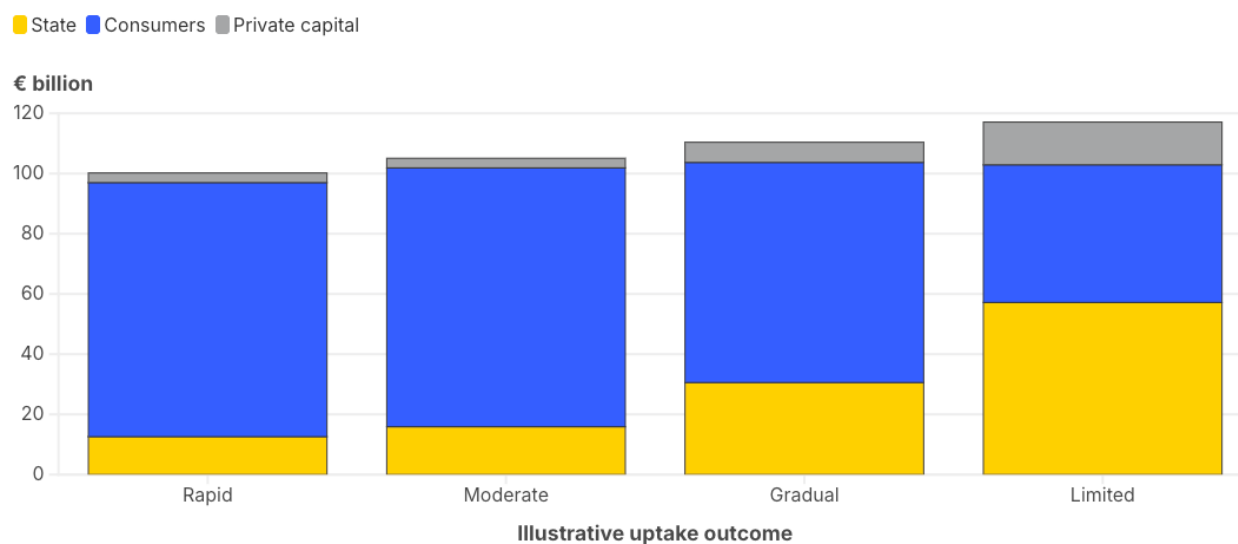
Germany is financing its hydrogen network using a regulated cost-recovery model. This means network operators build the infrastructure and recover their costs over time through fees charged to users. But hydrogen is not yet an established market, and early demand is expected to be low. The fees required to cover costs would be too high to support uptake.

To address this, fees are capped and shortfalls are deferred into a state-backed credit facility known as the amortisation account. This allows infrastructure to be built ahead of demand, with repayment pushed into the future when the market is more mature.

If hydrogen demand grows quickly, this model works as intended: The pipeline fills, revenues grow and public backstops remain theoretical. If it does not, deferred costs remain unpaid and shift onto the public balance sheet. If the amortisation account is not settled by 2055, at least 76% of any outstanding balance falls to the state, meaning taxpayers rather than users carry the burden.

This wager is unusually large in Germany, where national transition planning puts low-carbon hydrogen at the centre of industry, power and infrastructure. Under a rapid hydrogen ramp-up, costs can be recovered from users over time. Under weaker uptake, the same financing mechanisms shift risk onto the public balance sheet. Total system costs might not grow significantly, but who foots the bill can change markedly.

Figure 3: Sensitivity of funding liabilities to Germany's hydrogen uptake



Source: IEEFA.

Notes: Indicative illustration of how funding liabilities could shift as hydrogen uptake weakens. Based on aggregation of scenario modelling presented later. Reflects incidence rather than programme-level commitments. Figures rounded and shown for comparative purposes only.

This type of financial engineering is common to the energy transition, where it helps mobilise private capital before markets are fully formed. It has worked well for wind and solar, where end demand is effectively guaranteed and long-term cost trajectories are not only predictable but largely favourable. Hydrogen inherits the same financial design but without these stabilising features. Higher upfront costs, uncertain demand and unresolved competitiveness issues significantly increase downside risk borne by the state.

A cautionary fiscal tale: LNG and Deutsche Energy Terminal

Germany's recent liquefied natural gas (LNG) expansion provides a concrete illustration of how this architecture behaves when infrastructure is built ahead of demand that never arrives. Germany commissioned LNG terminals rapidly under emergency conditions, backed by fixed payment obligations, state guarantees and expectations of private capacity bookings.

From a policy perspective, these investments were intended to function as an insurance mechanism, ensuring Germany retained physical access to global gas markets in the event of further supply

disruptions. Even so, Germany's LNG terminal utilisation has remained structurally weak, averaging just 36.3% in 2025. Two floating storage regasification units have already been redeployed, including one at Mukran where not a molecule of LNG was commercially regasified before its relocation. State-owned LNG terminal operator Deutsche Energy Terminal (DET) was established to absorb operator losses from Germany's emergency LNG terminals and is backed by up to €4.1 billion in state guarantees for this purpose.⁴³ Independent analysis compiling official data suggests that total public exposure could reach €17 billion or more once extended contracts, fixed works and compensation mechanisms are fully accounted for.⁴⁴

The episode illustrates a broader dynamic. When infrastructure is built ahead of demand, contingent liabilities can migrate onto the public balance sheet. Over time, fixed costs, guarantees and loss-compensation mechanisms can eclipse one-off construction costs, if utilisation disappoints. This same risk-shifting logic now underpins Germany's planned hydrogen core network but without the justification of an acute energy crisis and at far larger fiscal scale.

The amortisation account: Socialising utilisation risk

Large-scale hydrogen deployment faces a sequencing problem. Producers will not invest without transport infrastructure, industrial users delay conversion without supply certainty, and transmission system operators (TSOs) cannot finance a multi-billion-euro network without credible demand.

Germany's policy response to this impasse is the amortisation account, Europe's largest regulated credit facility for hydrogen infrastructure. It allows the hydrogen network to be pre-financed through a substantial credit facility from state-owned bank KfW while constraining transport tariffs to a politically and commercially acceptable level. Because early utilisation of the hydrogen network is expected to be low and the fees collected from users are capped, revenues collected will initially fall short of repaying TSOs' allowed costs. The amortisation account absorbs these shortfalls, accumulating a credit balance that attracts financing charges.

Cost recovery depends on optimistic demand

It is a legal requirement that the amortisation account be fully cleared by 2055. In setting the tariff framework, Germany's Federal Network Agency (BNetzA) therefore works backwards from this constraint, balancing eventual cost recovery against marketability during the ramp-up phase. Setting fees too high risks suppressing uptake and undermining revenues, while setting them too low could

⁴³ European Commission. [Commission approves €4.06 billion German State aid measure to support the operation of four Floating LNG Terminals](#). 20 December 2024.

⁴⁴ Environmental Action Germany and the Center for American Progress. [LNG Projects Are a Bad Deal for Germans and Americans](#). 4 June 2025. Note: This report assumes operator loss guarantees remain within the initial €4.1 billion state aid guarantee budget.

ultimately be insufficient to recover accumulated balances if throughput disappoints. The resulting transport fee cap of €25 per kilowatt of booked capacity per year (kWh/h/a) reflects this tradeoff.⁴⁵

Modelling from research institute Fraunhofer underpins this calibration,⁴⁶ deriving the tariff caps required to clear the amortisation account by 2055 under different booking trajectories, as shown in Table 3. The most ambitious scenario considered, O45-Strom, reflects a normative climate-aligned pathway to 2045 in which hydrogen plays a substantial cross-sector role, including in heating and firm power generation. By 2040, this pathway embeds roughly 30 gigawatts (GW) of hydrogen turbines and a further 11GW of hydrogen-fired combined heat and power capacity. For context, that eclipses Germany's entire gas-fired power fleet today.

The central Reference case follows nearer-term policy realities but assumes that from the mid-2030s onward, hydrogen uptake converges toward the O45-Strom trajectory. Fraunhofer acknowledges that “long-term optimism is required for the functioning of the core network financing”.⁴⁷ In other words, its tariff calibrations require hydrogen to achieve sustained structural relevance within Germany's energy system.

Table 3: Fraunhofer-modelled tariff caps required to clear the amortisation account by 2055

Uptake scenario	Assumed full utilisation ⁴⁸	Required tariff cap (€/kWh/h/a)	Amortisation account balance in 2055 (€ billion)
Rapid (O45-Strom)	2034	13.4	0.0
Moderate (Reference)	2041	25.9	0.0
Delayed (Reference +2 years)	2043	29.6	0.0

Source: Fraunhofer IEG.

Note: Figures provided in 2025 (real) terms where applicable.

Against this backdrop, BNetzA's decision to apply a uniform €25/kWh/h/a cap is therefore consistent with strong throughput assumptions, implying a pipeline network that is fully utilised before 2041.

In effect, this structure allows private capital to be mobilised on the expectation that costs will ultimately be recovered either from network users over time or, if utilisation falls short, through public

⁴⁵ German Federal Network Agency. [Decision relating to the determination proceedings for the setting of a ramp-up tariff for the hydrogen core network](#). 14 July 2025.

⁴⁶ Fraunhofer-Einrichtung für Energieinfrastrukturen und Geotechnologien IEG. [Hintergrundscenarien zur Festlegung des Hochlaufentgelts im Wasserstoff-Kernnetz](#). 15 March 2025. See page 63.

⁴⁷ Ibid. See page 13: “Es ist wichtig zu betonen, dass dieser langfristige Optimismus für das Funktionieren der Kernnetzfinanzierung erforderlich ist.”

⁴⁸ Fraunhofer's Moderate and Delayed scenarios apply a 70–90% contribution-factor scenario, reflecting real-world operating conditions — pipelines that deliver lower theoretical capacity due to factors like flow constraints, pressure losses, routing inefficiencies and compressor limitations.

backstops. By design, this concentrates early utilisation risk within the amortisation account, deferring the clearance of accumulated balances until after the ramp-up period. The scale of this risk depends on the total cost of the network.

How a “€19.8 billion” hydrogen network costs over €50 billion

As Germany socialises the utilisation risk of its hydrogen network, the scale of the exposure matters. Here, public debate around the hydrogen core network typically understates its true cost by focussing on two headline figures: the estimated €19.8 billion capex cost and the €24 billion amortisation account credit line. Both materially understate the true exposure.

Fraunhofer modelling for BNetzA shows that even under the most optimistic assumptions, the regulated cost base approaches €50 billion.⁴⁹ Recent reporting also suggests costs are already rising, with network operators projecting that procurement and project revisions will add a further €5 billion to the final bill.⁵⁰ The sizeable gap between the headline construction cost and the full regulated cost base reflects standard features of regulated network economics:

- **Financing and timing overheads.** Building ahead of confirmed demand while repaying by 2055 means decades of interest and administrative costs.
- **Unrecovered book values on repurposed lines.** Existing regulated assets carry legacy value that must also be recovered through hydrogen tariffs.
- **Operating expenditure.** Maintenance costs that persist, largely irrespective of utilisation (including compressor energy, maintenance and inspection).

Alongside capital expenditure, these define the full cost base that the amortisation account must ultimately recover.

How much will Germany's hydrogen network cost?

Germany's hydrogen network is often described as a €19.8 billion project, but that figure reflects construction costs only. Once financing, repurposed assets and operational costs are included, the total exceeds €50 billion under current plans.

The regulator expects user fees to recover these costs over time. But if hydrogen demand and pipeline usage fall short, tens of billions of euros could remain outstanding over the long term, with most of the burden falling on the state.

⁴⁹ Fraunhofer-Einrichtung für Energieinfrastrukturen und Geotechnologien IEG. [Hintergrundscenarien zur Festlegung des Hochlaufentgelts im Wasserstoff-Kernnetz](#). 15 March 2025. See page 63.

⁵⁰ Clean Energy Wire. [German utilities call for hydrogen law as grid cost estimates rise](#). 4 March 2026.

Amortisation account balances under alternative uptake paths

The framework described above will clear the amortisation account by 2055 under optimistic long-term assumptions about hydrogen uptake. These assumptions sit uneasily with recent assessments by the German Federal Court of Auditors, which has warned that the national hydrogen strategy has fallen behind plan, posing material risks to public finances.⁵¹

To test the sensitivity of public exposure to utilisation, IEEFA models two illustrative booking trajectories while holding the transport tariff fixed at the adopted €25/kWh/h/a cap.⁵² In a gradual uptake case, utilisation rises steadily and reaches 75% by 2050, broadly consistent with sustained cross-sector hydrogen adoption but taking longer to materialise. In a limited hydrogen demand scenario, bookings peak at around 20% of network capacity by 2037 before stagnating thereafter. This second scenario broadly reflects IEEFA's [sectorally adjusted](#) demand analysis. Excluding liquid derivatives imports (which bypass pipeline infrastructure) and assuming demand is limited in sectors amenable to electrification, pipeline-relevant hydrogen demand would be substantially smaller than headline forecasts suggest.⁵³ Both cases compare allowed revenues with the regulated cost base. Any shortfall accumulates in the amortisation account and accrues financing charges (see Table 4).

Table 4: IEEFA-modelled amortisation account balances in 2055 under lower network utilisation

Uptake scenario	Assumed utilisation path	Assumed tariff cap (€/kWh/h/a)	Amortisation account balance in 2055 (€ billion)
Gradual	75% peak by 2050	25.0	14.6
Limited	20% peak by 2037	25.0	45.7

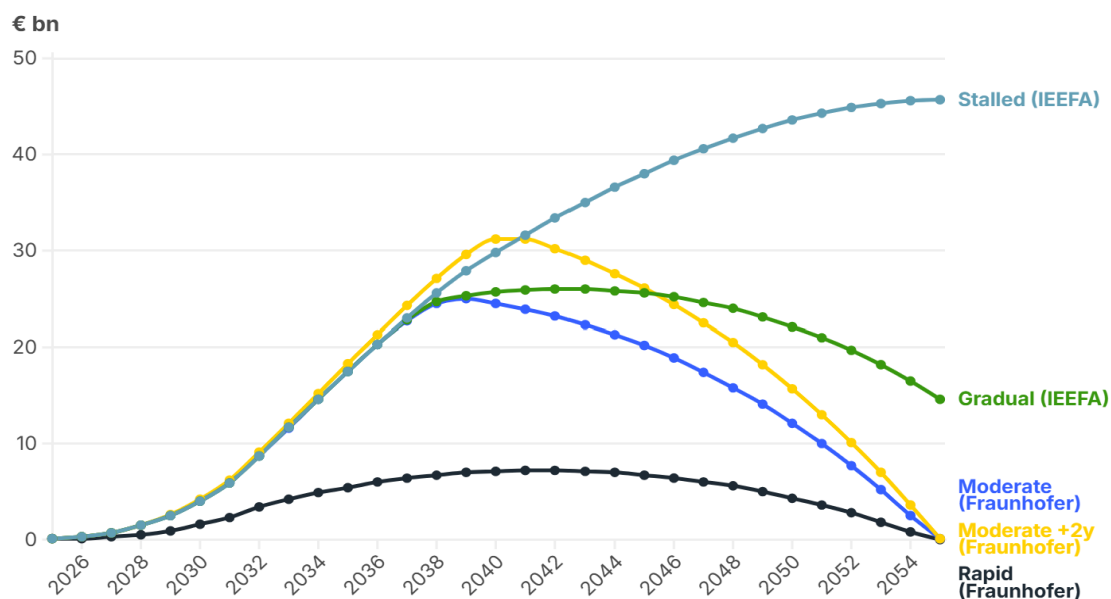
Source: IEEFA.

Note: Figures provided in 2025 (real) terms where applicable.

⁵¹ German Federal Court of Auditors. [Wasserstoffstrategie des Bundes auf dem Prüfstand](#). 28 October 2025.

⁵² We hold the regulator-implied cost-recovery path from the Fraunhofer Reference scenario and mirror its early-year booking trajectory, while imposing weaker long-run utilisation. Incremental amortisation account financing costs are reintegrated. Applying lower-than-actual cost recovery biases residual balances downward.

⁵³ Germany has sized the pipeline network on the expectation of system-wide hydrogen relevance. IEEFA's [sectoral analysis](#) suggests the applications most likely to use the network (hard-to-abate industrial processes) represent a modest share of projected total demand once liquid derivatives imports (which bypass pipelines entirely) and electrifiable processes are stripped out. When that residual pipeline-relevant demand is measured against a network calibrated for central official forecasts, 20% peak utilisation represents an entirely plausible outcome, rather than a worst-case or extreme assumption.

Figure 4: Amortisation account balance trajectories by scenario

Sources: Fraunhofer IEG, IEEFA.

Notes: Fraunhofer scenarios are calibrated for a zero balance in 2025 with fee caps fixed to achieve that goal (Rapid = €13.4/kWh/h/a; Moderate = €25.9, Moderate +2y = €29.6). IEEFA scenarios instead set the cap at €25 and test the resulting balance under less optimistic hydrogen uptake scenarios.

Figure 4 shows how delayed utilisation is not self-correcting. Once revenue shortfalls are deferred into the amortisation account, subsequent improvements in throughput are insufficient to unwind accumulated balances. Under limited uptake, the balance continues to grow with little prospect of reversal.

Limited scope for tariff hikes under weak uptake

The IEEFA modelled balance trajectories above naturally raise the question of whether higher transport fees could recover costs under weaker hydrogen uptake. In theory, adjusting tariffs is the primary lever available to the regulator if utilisation disappoints. In practice, however, the scope for hikes is tightly constrained.

Fraunhofer identifies ramp-up fees in the region of €35/kWh/h/a as “no longer marketable”.⁵⁴ This threshold reflects more than political discomfort. It marks the point at which higher network charges undermine hydrogen demand itself. At this level, fee increases are expected to rapidly erode rather

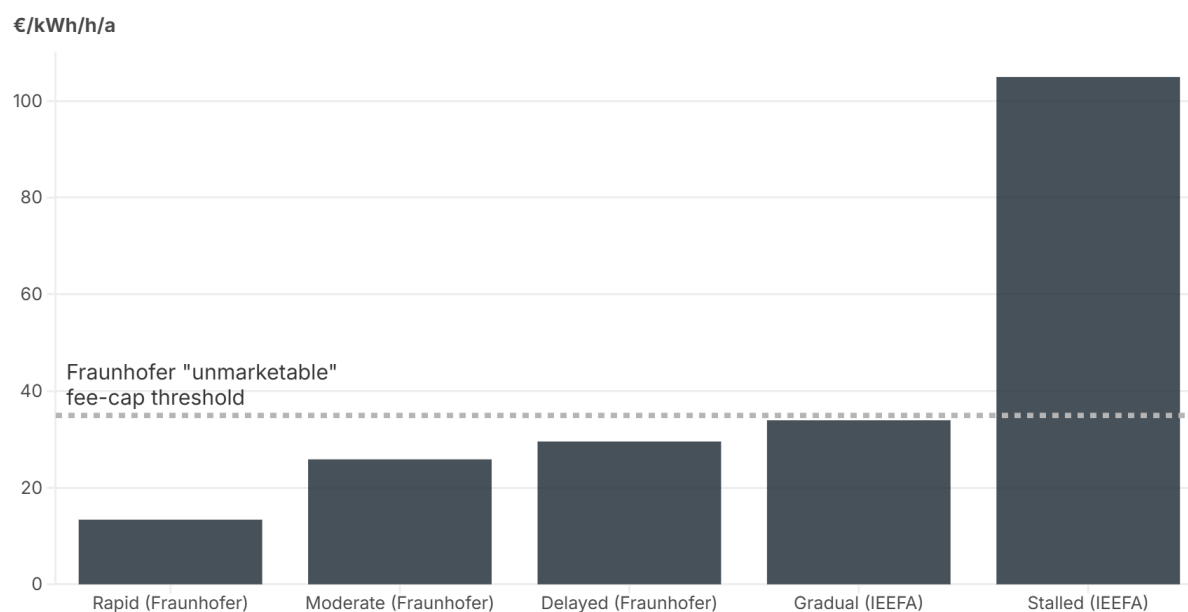
⁵⁴ [The Federal Network Agency](#) notes that, in the “most adverse scenario”, clearing the amortisation account by 2055 would require a €35/kWh/h/a ramp-up fee, which the commissioned expert consultants (Fraunhofer) classify as no longer marketable (“nicht mehr marktgängig ein”). See page 37.

than expand the revenue base, as users defer conversion decisions, reduce bookings or exit the market altogether.

Applying this constraint to our alternative uptake paths highlights the limits to tariff adjustment as a corrective tool. Clearing the amortisation account by 2055 under the gradual pathway requires a transport fee of around €34/kWh/h/a, fractionally short of Fraunhofer's unmarketable threshold. If regulators were to maintain a €25/kWh/h/a cap in the early years while utilisation ultimately disappointed, balances would accumulate rapidly. Correcting course later would then require substantially higher fees to unwind those balances, exceeding the levels implied by the eventual uptake path. Fraunhofer's modelling illustrates how even a modest two-year delay to the network's utilisation trajectory raises the cap required to clear the amortisation account by 2055 from €25.9 to €29.6/kWh/h/a. In our gradual case, this would certainly mean breaching marketability thresholds.

Under a limited hydrogen uptake scenario, the constraint becomes binding immediately. The fee required to clear the accumulated balance would exceed €100/kWh/h/a, far beyond any level compatible with sustained market participation (see Figure 5).

Figure 5: Fee cap required per scenario to balance the amortisation account in 2055



Sources: Fraunhofer IEG, IEEFA.

Under less optimistic hydrogen uptake scenarios, tariff adjustment therefore ceases to function as a viable recovery mechanism. Rather than restoring balance, higher fees would further suppress demand, reinforcing the utilisation shortfalls they are intended to correct for. The implication is not that tariffs cannot be raised, but that their effectiveness is sharply bounded once uptake falls below a critical threshold.

From financing bridge to fiscal liability

Taken together, the preceding analysis implies a structural shift in the role of the amortisation account under weaker hydrogen uptake. Where utilisation follows modelled trajectories that now appear overly optimistic, the amortisation account functions as intended — a temporary financing bridge that smooths early losses and is repaid gradually by users as demand matures. Where uptake is materially slower or falls short, that logic breaks down. Fraunhofer acknowledges this dynamic, noting that “without a substantial long-term role for hydrogen in the German energy system, the core network would be oversized and robust financing would be hardly possible”.⁵⁵

If balances accumulate under weaker-than-planned uptake and tariff adjustment is constrained (as political and economic realities suggest), the amortisation account automatically hardens into a long-dated fiscal exposure. Under existing backstop arrangements, *at least* 76% of any residual balance would be borne by the state,⁵⁶ a share that could rise further as additional losses are absorbed to preserve network solvency. Under a limited demand scenario, the German state would become liable for at least €34.7 billion of unrecovered funds by 2055 (equivalent to 76% of a €45.7 billion total amortisation account balance).

This outcome would not reflect a failure to deploy policy levers but the exhaustion of viable options within the framework’s design constraints. With utilisation weak and pricing flexibility limited, deferred recovery locks utilisation risk onto the public balance sheet by default.

The integrated and compounding fiscal exposure

The hydrogen core network and the amortisation account represent the largest and most concentrated source of public exposure under weaker hydrogen uptake in Germany. They are not, however, the only channel through which utilisation risk is transferred onto the public balance sheet.

Germany has in effect created two parallel insurance systems to manage energy security during its hydrogen transition — a planned capacity mechanism in the power sector and a sustained public commitment to LNG. This creates overlapping public exposures that have not been sized against a common hydrogen demand assumption. The slower that the hydrogen economy develops, the longer both systems remain in place and the more they cost. Figures 6 and 7 illustrate how exposure is redistributed across bearers and mechanisms under alternative hydrogen uptake scenarios.

⁵⁵ Fraunhofer-Einrichtung für Energieinfrastrukturen und Geotechnologien IEG. [Hintergrundscenarien zur Festlegung des Hochlaufentgelts im Wasserstoff-Kernnetz](#). 15 March 2025. See page 13: “Ohne eine langfristig substantielle Bedeutung von Wasserstoff im deutschen Energiesystem ist das Kernnetz in dieser Größe überdimensioniert und eine robuste Finanzierung somit kaum möglich.”

⁵⁶ KfW. [Wasserstoff-Kernnetz](#). 24 March 2025.

Hydrogen-ready power capacity

Germany currently plans around 10GW of hydrogen-ready generation capacity to ensure security of supply during the transition. Like other dispatchable assets, such plants may require capacity payments where market revenues are insufficient to cover fixed costs.

Under a rapid uptake scenario, in which hydrogen is deployed at scale across sectors, hydrogen-fired plants are assumed to operate at higher utilisation rates, contributing to firm system supply rather than acting primarily as peaking capacity. In this case, dedicated capacity support phases out quickly, with costs shifting towards operating support mechanisms, ultimately borne by consumers. This assumption is effectively necessary for a rapid rollout to be realised.

Under weaker uptake, low utilisation persists, limiting revenue recovery and extending both the duration and scale of explicit public support required to maintain system readiness. For an assumed 10GW fleet and a central capacity payment assumption of €100,000 per megawatt per year, the difference between rapid and limited hydrogen uptake scenarios corresponds to €4.8 billion in additional public exposure in our modelling. This figure reflects the longer duration of support required under weaker hydrogen uptake, as payments are phased out more slowly over time.

Persistence of LNG as an option

If hydrogen does not scale as anticipated, the political conditions required to retire LNG capacity will be delayed. In the absence of firm low-carbon substitutes, terminals are likely to be retained as strategic security assets.

However, slower hydrogen uptake does not automatically increase LNG terminal utilisation. Additional system demand could instead be met or reduced by electrification, energy efficiency or even pipeline gas, depending on market conditions. Germany's gas demand shows no sign of structural growth. The risk is therefore one of persistence rather than throughput.

In such a case, LNG operator-loss support, charter costs and other fixed obligations would persist, extending the duration of public exposure. The difference between rapid and limited uptake scenarios corresponds to around €5.1 billion in additional public exposure to crisis-era assets.⁵⁷

⁵⁷ LNG scenario endpoints are anchored to official Federal Ministry for Economic Affairs and Climate Action (BMWK) budget figures submitted to the Bundestag budget committee (as compiled by Deutsche Umwelthilfe). The €5.1 billion scenario differential largely reflects persistence risk: Infrastructure liabilities are assumed to run off even under the limited scenario, while DET exposure is capped at the EU-approved state-aid ceiling of €5 billion. Sources: BMWK/Bundestag budget committee, Deutsche Umwelthilfe, European Commission state-aid decision SA.110126.

Hydrogen support programmes

Programme-based industrial support instruments such as H2Global, Important Projects of Common European Interest (IPCEI) and early import contracts operate within defined funding envelopes and are treated as fixed exposures in this analysis. Under weaker uptake, their fiscal impact is modelled as extended programme duration rather than automatic escalation of headline commitments. This is a conservative approach to the full fiscal exposure. Total planned public exposure across the three main support programmes amounts to approximately €20 billion.⁵⁸ As a result, these programmes do not drive the compounding fiscal effects shown in Figures 6 and 7, but equally, they do not offset them.

Exposure to LNG and hydrogen support programmes are often framed as individual, contingent liabilities. Taken together with network financing, however, they form a system in which public obligations grow as hydrogen uptake weakens.

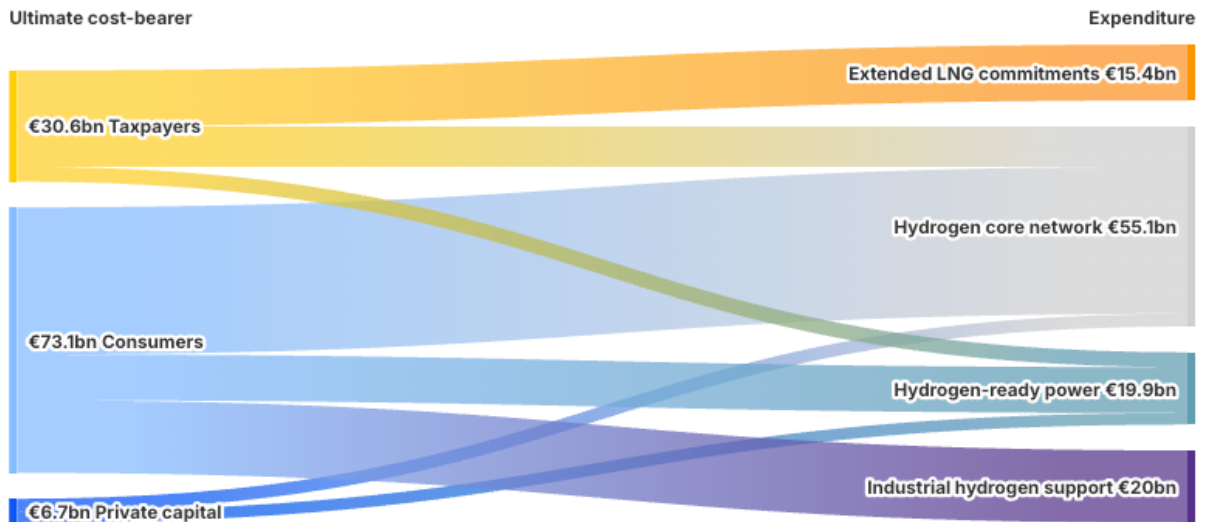
Figures 6 and 7 illustrate this dynamic. As uptake assumptions are progressively relaxed across scenarios, public exposure rises, while contributions from consumers fall away. Private capital is largely insulated with loss retention capped by state backstops. The result is a relatively modest increase in total system costs but a significant shift in who ultimately bears them.

Across the scenarios, the total difference between a rapid hydrogen uptake pathway and a limited one amounts to around €45 billion in additional public funding requirements. This increase is driven primarily by residual network financing balances but is reinforced by power market support and prolonged exposure to LNG. For perspective, an additional €45 billion exposure under a limited outcome equates to around €1,000 per German taxpayer.

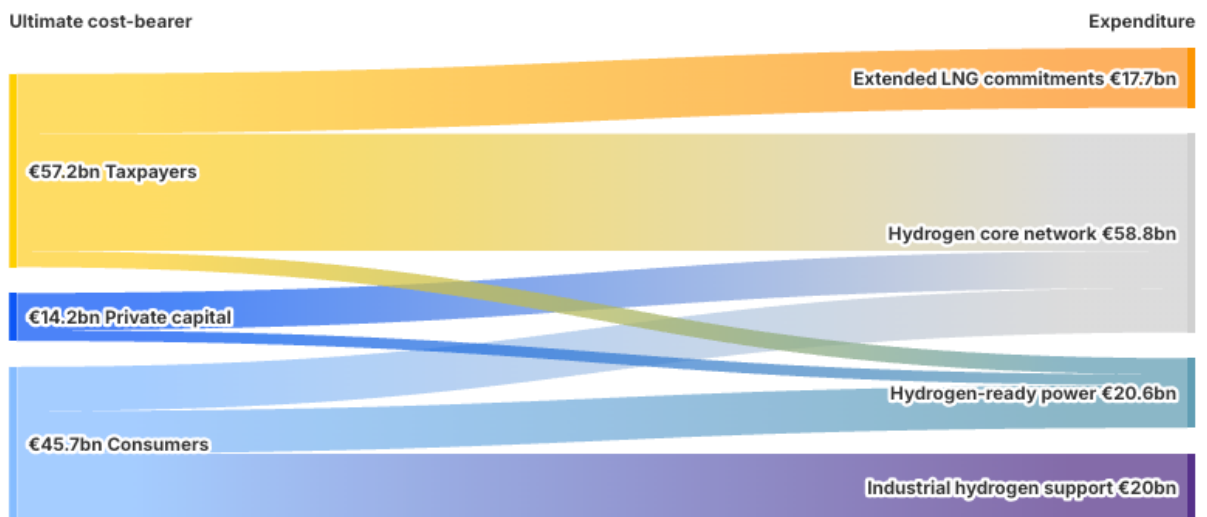
⁵⁸ This reflects the Climate and Transformation Fund hydrogen allocation, additionally updated for confirmed H2Global commitments. The total envelope remains subject to revision under the new coalition budget, indicating significant expansion is unlikely at present.

Figure 6: Simplified breakdown of Germany's hydrogen-related funding under alternative hydrogen uptake scenarios

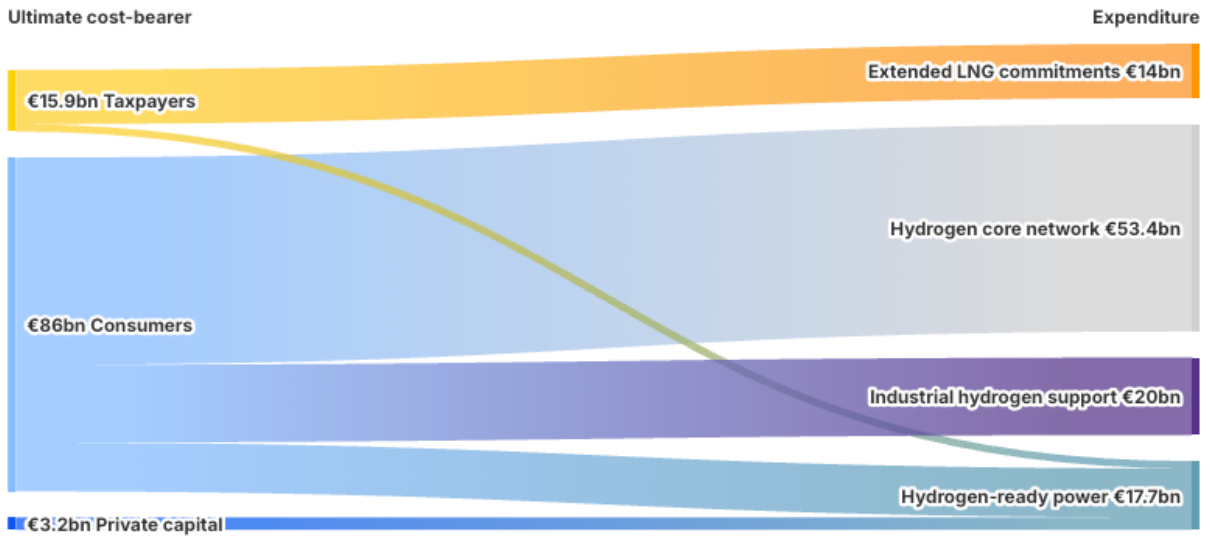
Gradual uptake (IEEFA)



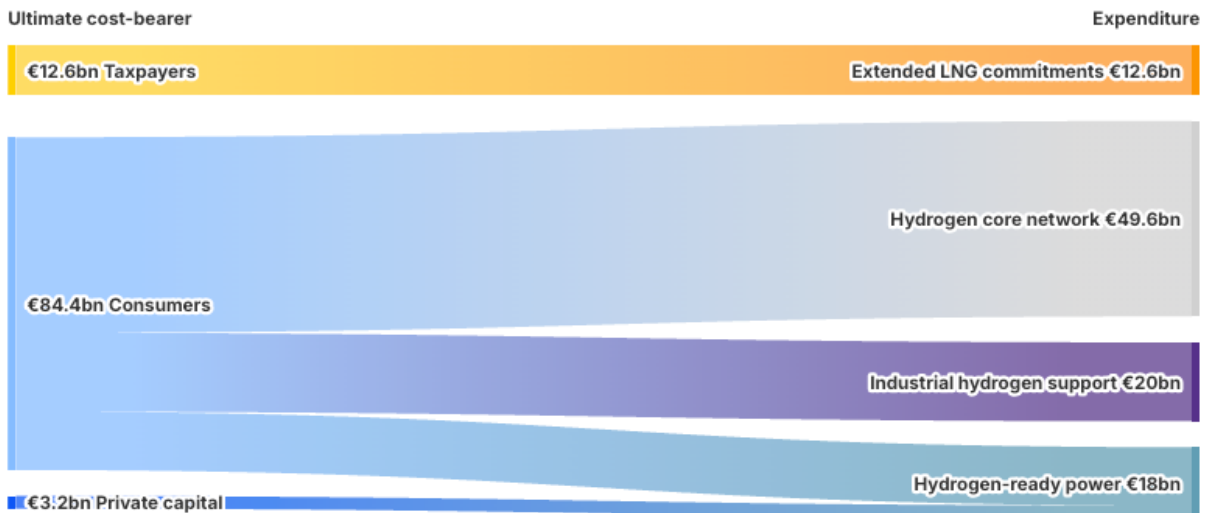
Limited uptake (IEEFA)



Moderate uptake (Fraunhofer)



Rapid uptake (Fraunhofer)

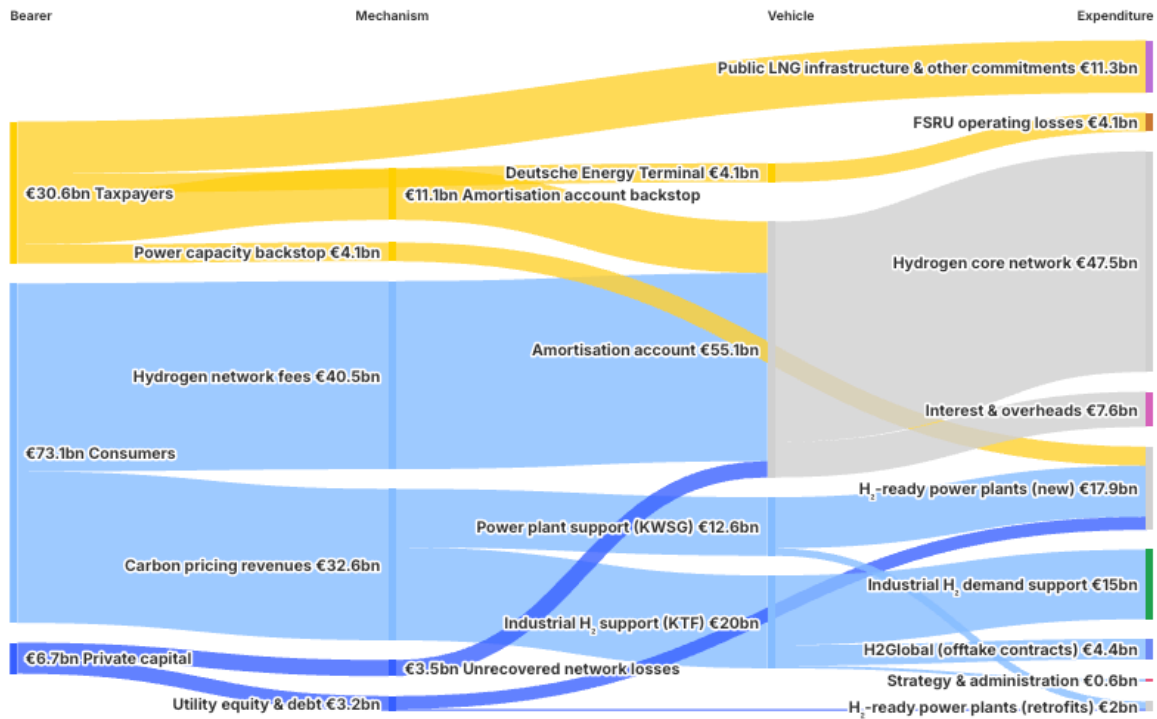


Sources: German Federal Ministry for Economic Affairs and Climate Action, BNetzA, freedom of information responses, European Commission, Fraunhofer scenarios, Environmental Action Germany, IEEFA.

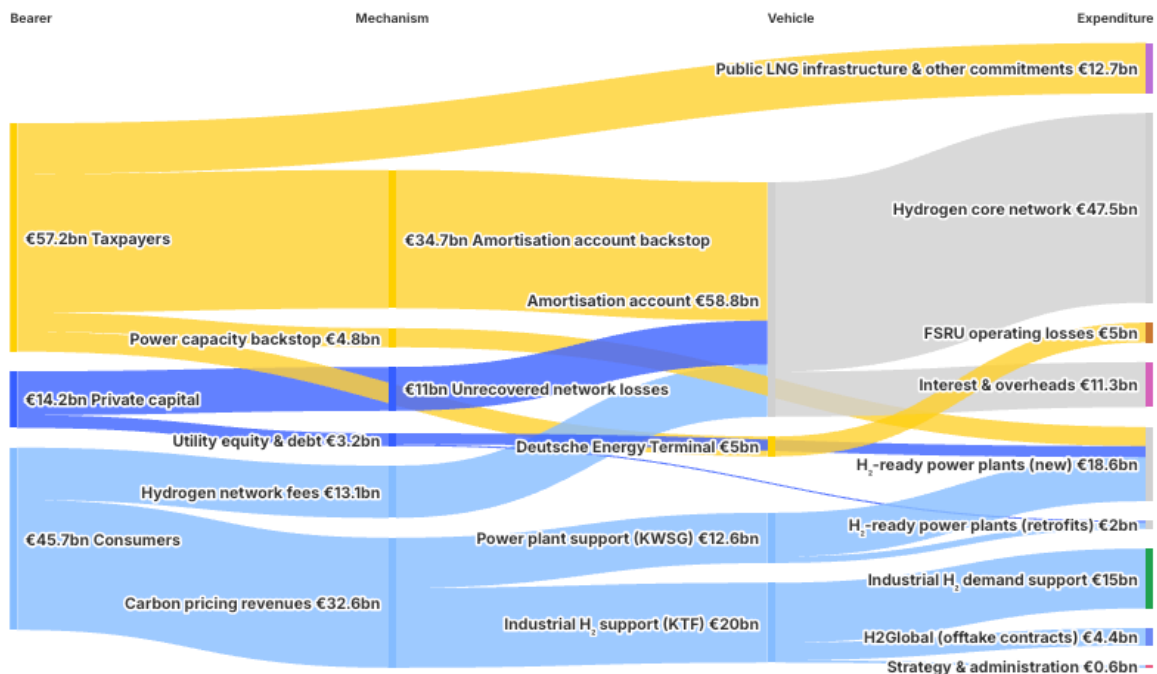
Note: Where official numbers are unavailable, conservative estimates are applied.

Figure 7: Detailed breakdown of Germany's hydrogen-related funding under alternative hydrogen uptake scenarios

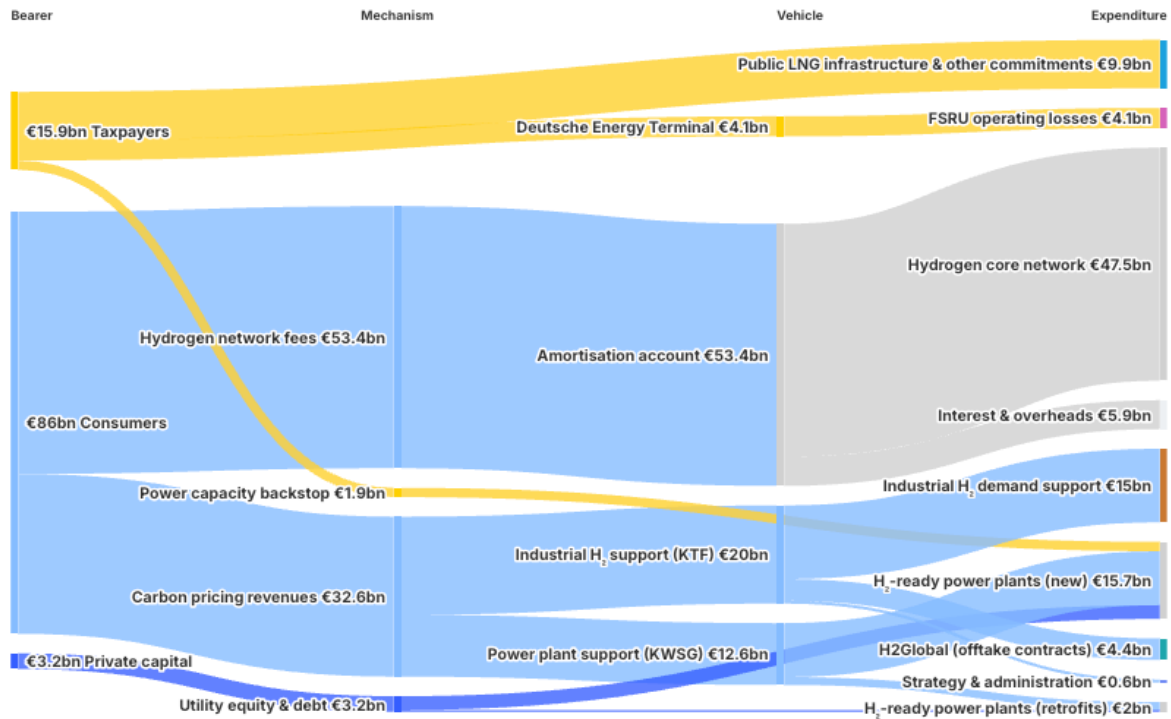
Gradual uptake (IEEFA)



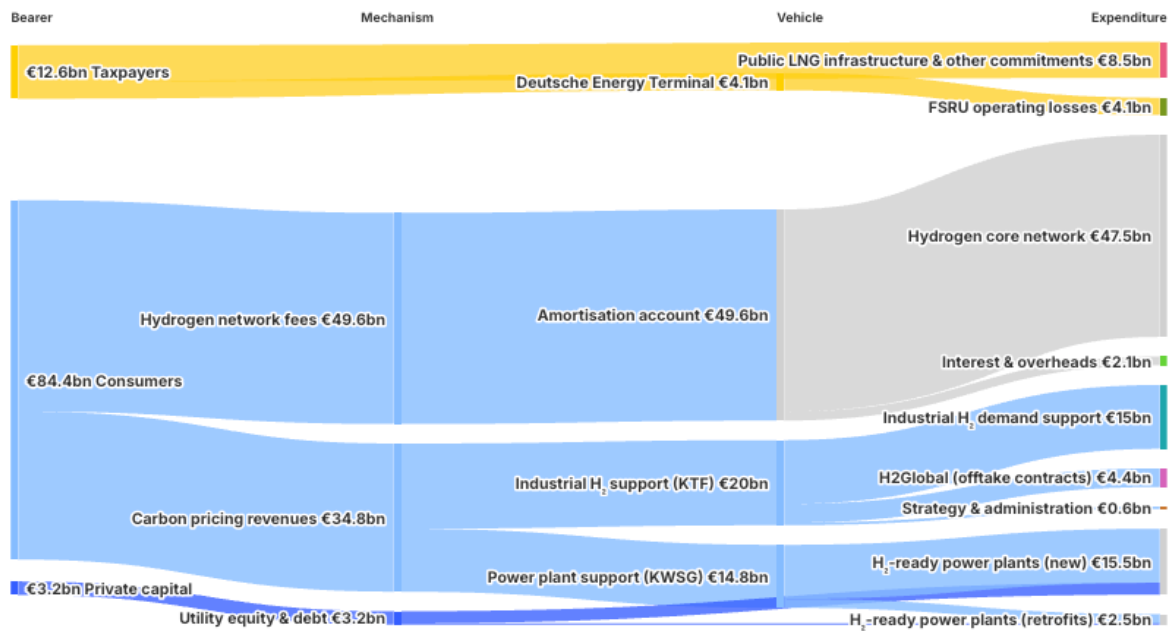
Limited uptake (IEEFA)



Moderate uptake (Fraunhofer)



Rapid uptake (Fraunhofer)



Sources: German Federal Ministry for Economic Affairs and Climate Action, BNetzA, freedom of information responses, European Commission, Fraunhofer scenarios, Environmental Action Germany, IEEFA.

Note: Where official numbers are unavailable, conservative estimates are applied.

Policy creep: Defending the hydrogen bet

Earlier sections detail how Germany's hydrogen strategy ties fiscal risk to uncertain hydrogen demand. Scenario modelling shows that when network usage falls short of expectations, the public share of costs rises materially and that fiscal exposure is accumulated through multiple channels.

Policy architecture drives this ratcheting effect. The amortisation account spreads early losses over time, but in doing so embeds utilisation risk at the very centre of strategy. To encourage utilisation, Germany plans to introduce additional policy layers. Hydrogen-ready power plant support aims to anchor demand in the power sector. Targeted industrial carbon contracts for difference (CCfDs) intend to stimulate real-economy hydrogen use, while programmes such as H2Global attempt to secure supply by bridging price gaps between producers and consumers. Each instrument addresses a specific bottleneck that could hamper utilisation.

Individually these measures address genuine barriers. Taken together, however, they reveal a policy framework that assumes demand will eventually arrive at scale and that progressively expands public exposure to ensure that outcome. Rather than treating demand shortfalls as a signal to resize ambition, policy adapts to preserve utilisation itself. This dynamic can be described as policy creep — the gradual expansion of policy to protect infrastructure commitments that were made under optimistic demand assumptions. Recent developments suggest policy creep is now entering a new phase.

Enter blue hydrogen

As cost realities become clearer, the green hydrogen bubble is deflating in plain sight.⁵⁹ Roughly 400km of Germany's hydrogen backbone has been completed and pressurised (around 4% of the planned network) but with no suppliers connected and no customers contracted. This is not a commissioning delay but evidence of a structural lack of demand. Policymakers committed to the hydrogen backbone now face a narrowing window before the gap between infrastructure ambition and commercial reality becomes politically untenable.

Blue hydrogen's quiet emergence at this moment is no coincidence. After years of political resistance to carbon capture and storage (CCS), the German policy environment has shifted. The effective moratorium on CCS has been removed, and the Hydrogen Acceleration Act passed by the Bundestag in February 2026 explicitly designates blue hydrogen infrastructure as being of “overriding public interest”, a designation absent from previous iterations.

Favourable near-term production costs relative to green hydrogen make blue hydrogen a tempting fallback, one that might encourage pipeline utilisation in the near term.

⁵⁹ Green hydrogen is produced from water using renewable energy. Blue hydrogen is produced from natural gas with carbon capture.

The cost of rescue

Blue hydrogen does not resolve the infrastructure exposure embedded in the hydrogen strategy, so much as it substantially expands it. Producing hydrogen from natural gas at scale requires reforming capacity, carbon capture systems, and carbon dioxide transport and storage infrastructure. These assets would sit alongside the hydrogen backbone, layering a second infrastructure system on top of the first. Although outside the scope of this chapter, the capital requirements associated with blue hydrogen production and carbon management could plausibly rival those of the hydrogen core network itself.

There is also a strategic contradiction. Hydrogen was framed, in part, as a response to the energy crisis triggered by Russia's invasion of Ukraine and as a relief from structural dependence on gas supply chains. Blue hydrogen would re-anchor hydrogen production in those same gas markets, meaning supply shocks and price volatility would continue to shape costs. This undermines any relief from gas dependence and increases the likelihood of future public intervention to shield consumers from volatile gas markets.



The trap for policymakers is not stranded infrastructure, but infrastructure that works well enough to justify open-ended and economy-wide demand subsidies. Blue hydrogen does not reduce the likelihood of that outcome — it increases it.

Even setting aside carbon capture rate and technological uncertainties, blue hydrogen remains structurally expensive compared to incumbent fuels without subsidy and cannot compete with direct electrification where that is feasible. This creates a clear policy dilemma and is where policy creep risks becoming a trap. If CCS fails to close the competitiveness gap, policymakers are left with two options: either accept large-scale stranded assets across *both* hydrogen and carbon capture infrastructure, or intervene to sustain demand.

On recent evidence, and with dual infrastructures to protect, the latter appears more likely. Hydrogen usage quotas and broad-based demand subsidies become the final levers, extending support across large parts of the economy until such a time as hydrogen becomes competitive.

The nightmare scenario for Germany's public finances is not a hydrogen network that fails. It is one that partially succeeds by locking in gas dependency, expanding the infrastructure footprint and driving widespread economic conversion to an energy source that remains structurally uncompetitive. The trap for policymakers is not stranded infrastructure, but infrastructure that works well enough to justify open-ended and economy-wide demand subsidies. Blue hydrogen does not reduce the likelihood of that outcome — it increases it.

Formalising the trap

Recent industry proposals illustrate how such support frameworks could become institutionalised. German energy association BDEW has proposed consolidating the current patchwork of hydrogen support mechanisms into a single legislative framework governing production, infrastructure and demand.⁶⁰ Framed as a way to provide regulatory certainty and coordinate value-chain development, such legislation would embed the assumption that hydrogen requires sustained policy support across the entire system for the foreseeable future.

If embedded in law, the policy question would shift. Rather than asking whether hydrogen deployment is economically justified, policymakers would instead focus on how to coordinate the incentives required to sustain it. In practice, this opens the door to intervention across the energy system — including price support mechanisms, sectoral demand incentives, blending mandates and procurement requirements — all aimed at ensuring hydrogen infrastructure operates at scale, regardless of whether hydrogen can ever become economically competitive.

⁶⁰ Bundesverband der Energie- und Wasserwirtschaft. [BDEW schlägt Wasserstoffgesetz „H2G“ vor](#). 3 March 2026.

Recommendations

Germany's hydrogen strategy is built around infrastructure deployed ahead of demand. That infrastructure only makes sense if hydrogen achieves system-wide relevance. Where demand falls short, the financing architecture automatically transfers a growing share of costs onto the public balance sheet. The central policy challenge is therefore how to respond to weak utilisation, before that transfer occurs. It is better to recognise infrastructure risk early than to continually expand public subsidies to protect it. The recommendations below therefore focus on two priorities: avoiding policy that expands hydrogen demand primarily to defend infrastructure commitments, and ensuring the scale of infrastructure exposure is calibrated for a rollout led by genuine demand.

Table 5: Recommendations to limit excess public spending on hydrogen

Policy discipline	Infrastructure guardrails
<p>Ensure the amortisation account does not dictate demand policy Any new demand-side support should require independent assessment demonstrating that decarbonisation value and cost-competitiveness are the primary justification. Where support is proposed for sectors in which electrification or derivative imports offer a cheaper abatement pathway, the burden of proof should sit with proponents of the hydrogen option.</p>	<p>Gate pipeline expansion to verified demand The hydrogen core network buildout should proceed in phases tied to confirmed industrial offtake and supply commitments, aligned with awarded CCfDs and confirmed industrial conversion projects rather than speculative volumes.</p> <p>Transparency and guardrails for the amortisation account The regulator should publish a transparent 2055 repayment path and regularly disclose balances, interest and utilisation. Where utilisation falls below defined thresholds, automatic policy reviews should be triggered before further network expansion is authorised.</p>
<p>Apply strict economic tests to blue hydrogen Blue hydrogen requires reforming capacity, carbon capture systems, and transport and storage infrastructure. This layers a second capital-intensive system on top of the core network. Support should be contingent on clear system-wide advantages over alternatives like electrification or derivatives.</p>	<p>Integrate LNG and hydrogen planning Hydrogen deployment should be coordinated with the gradual run-off of LNG guarantees. This would reduce the risk of simultaneously underwriting two infrastructure systems against the same demand uncertainty.</p>
<p>Technology-neutral capacity mechanisms Capacity mechanisms should allow hydrogen-ready gas plants to compete directly with storage, demand response, imports and grid reinforcement. If cheaper options can reliably deliver system adequacy, they should take precedence.</p>	<p>Prioritise derivatives for early import markets For hard-to-abate sectors, fuels such as ammonia or methanol arrive as liquids through existing port infrastructure, bypassing the pipeline network entirely. Import policy should reflect this, developing derivatives corridors in parallel with (rather than subordinate to) pipeline infrastructure planning.</p>

About IEEFA

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