Clean Hydrogen & Derivatives Pricing: Bridging the Gap to Bankability

Looking Back at the 2025 IPFA-Facilitated Clean Hydrogen Pricing Survey as the Market Resets

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EXECUTIVE SUMMARY

Until not long ago, the debate over clean hydrogen pricing centred on whether it would evolve beyond fixed-price structures. The more pressing question now is how pricing models can determine a project's viability — locking in willing offtakers and securing bankability.

Drawing on a 2025 Survey of 19 senior practitioners and on subsequent market developments, this article examines the forces shaping clean hydrogen pricing models – and what they now need to achieve.

- **Securing a willing buyer comes before perfecting how price risk is shared.** Until a buyer commits to paying the green premium, there is no sale — and so no price risk to share.
- **The 2026 Strait of Hormuz shock pushed up fossil-fuel benchmarks and reinforced the energy security case** for some hydrogen pathways and import-dependent markets. But neither has yet translated into firm offtake at scale or a durable narrowing of the cost gap.
- **Public support is still indispensable but becoming more differentiated.** Subsidies are increasingly calibrated by use case and by the size of the cost gap they are expected to close, reflecting a drive to crowd in demand.
- **Pricing is moving toward flexible architectures, not a single market standard.** The key question is no longer which benchmark prevails, but which models attract offtakers without sacrificing bankability.

Key words: clean hydrogen, hydrogen derivatives pricing, project finance, market price risk, offtake, bankability, pricing models, energy transition

WHAT'S IN THIS ARTICLE

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** The views expressed in this article are those of the author and do not necessarily reflect the views of IPFA or the author's employer.*

Setting the Stage: A Question Worth Asking Again

A pricing model for each clean hydrogen and derivatives project is forged in commercial negotiation between offtakers and sponsors, then tempered against the requirements of lenders. But what becomes of that negotiation when a far-reaching disruption — industry-wide, nation-wide, at times region-wide, as the 2026 Strait of Hormuz shock proved — strikes before the pricing model is settled?

At its core, a pricing model sets how a project's revenue forms and how market price risk is allocated over the offtake term — and few decisions weigh more heavily on a clean hydrogen project. In a sector this young, that task of developing the bankable pricing model is easily overshadowed by the more visible problems of weak demand and the cost gap. Yet market weakness does not mean that market price risk is absent, only harder to see and to price, and so easier to underestimate.

The 2025 Survey examined how pricing models were evolving in this nascent industry. A summary of the Survey design, respondent profile and project sample is shown below and in the *Exhibit*.

Why revisit the Survey now? Because demand signals have weakened: expectations have been revised down. Yet projected 2030 clean-hydrogen output still implies a market needing billions in capital.[1] And that capital has consistently been sought on a project-finance basis — limited or non-recourse — a route more than 80% of Survey respondents confirmed they were pursuing. The conditions that shape pricing models have shifted since the Survey was run — most sharply with the 2026 Strait of Hormuz shock, which moved markets and the policy calculus alike. That makes this a fitting moment to look back at the Survey's findings and ask what still holds, and what it means for financing clean hydrogen and derivatives production projects.

2025 SURVEY SNAPSHOT

Coverage. 43 questions across four areas: respondent and project profiles; pricing models in use; pricing models preferred by project stakeholders; expectations on market price risk allocation.

Who responded. 19 senior practitioners (53% senior management, 37% mid-level). 90% are active across multiple projects (26% working on 10 or more clean hydrogen and derivative projects).

Respondents' project exposure.

Scale	Most worked across projects of several sizes: 63% large (>$1B), 53% medium ($100M–$1B), 32% small (<$100M)
Geography	All major clean hydrogen geographies: Europe 42%, MENA 37%, North America 32%, Australia 26% (respondents could indicate multiple regions)
Pathways	All respondents were involved in green hydrogen, and 37% were involved in blue hydrogen projects on top of that.
Use cases	Ammonia (53%); e-SAF and methanol (47% each); shipping, power, oil refining, iron & steel (32-42% each) (respondents could indicate multiple use cases)
Offtaker type	Industrial buyers 84%; traders & aggregators 53%
Offtake tenor	10+ years is the most popular target (over 50% of respondents)
Offtake status	Mostly non-binding EOIs and MOUs (58%); binding term sheets 26%

The Market Constraint: Demand and the Cost Gap

Like any project-financed asset, a clean hydrogen and derivative project lives or dies on bankable offtake. But the sector has no open, liquid spot market to fall back on (see sidebar), so the offtake arrangement — and the pricing model at its heart — has to carry the whole load. That load splits into two tasks: closing the cost gap and allocating market price risk. The cost gap comes first.

2025 Survey look-back — *offtake is relationship-led, not market-led*

Over **90%** of respondents reported that the projects they were involved in secured offtake through direct negotiations with strategic partners; **50%** through long-term contracts with captive affiliates; and **33%** through government partnerships and hydrogen-hub participation. Developers did not have the luxury of leaving demand formation to market forces; they had to manufacture demand themselves through existing relationships, captive consumers and public-sector support.

The promise of demand growth has been clean hydrogen's strongest magnet — and, so far, its hardest barrier. The existing 100 MTPA grey-hydrogen market was a natural benchmark: a proven volume base clean hydrogen could take share from, replace and hopefully outgrow. That logic attracted capital, shaped national strategies and launched the first wave of projects. But what looked like a plausible demand story has not translated into committed buyers at scale, leaving the already hard task of designing workable pricing models for a nascent sector harder still.

Since the Survey, the demand outlook has visibly weakened across the sector. Market expectations have been revised down: lower offtake volumes, conversion into firm agreements remains weak, and project cancellations have spread across geographies.[2,3] Regulatory uncertainty around US tax incentives and EU implementation has added further drag. At the same time, supported markets have continued to generate pockets of progress, particularly in green-hydrogen and green-ammonia tenders and auctions in the EU and India, and often in the substitution of clean molecules into existing value chains[4] (with direct implications for pricing), and a handful of projects have reached financial close.[5] Yet these remain isolated successes, not a trend.

The Cost Gap behind the Demand Problem

The weakness of demand is effectively a pricing problem, and at its centre lies the cost gap. In most applications, clean hydrogen and its derivatives still cost more than their fossil-based alternatives. Early hopes that scale and learning-curve effects would steadily narrow that gap have been set back by persistent inflation and elevated electricity prices through the first half of the 2020s[6], and when cost parity might be reached remains unclear. As a result, willingness to pay remains narrow, and demand has yet to spread beyond early movers.

The 2025 Survey confirmed the cost gap as the central pricing problem. Respondents ranked the high green premium (the other side of the cost gap coin – see sidebar) as the top challenge in pricing negotiations, followed by underdeveloped price benchmarks, regulatory uncertainty and unpredictable demand. 44% reported green premiums measured in multiples of the fossil-fuel price, with a further 28% facing premiums above 30%. Only about one in five described the premium as moderate or small.

Note on terminology: cost gap vs. green premium

Cost gap and green premium are the two terms the sector reaches for most when it talks about why clean hydrogen is hard to sell. They are two names for the same shortfall, seen from opposite sides of the deal:

Cost gap: the shortfall between the delivered cost of clean hydrogen (or its derivative) and the reference price of a fossil equivalent.

Green premium: the same shortfall seen from the buyer's side — the incremental price paid for the low-carbon product over the fossil-based alternative.

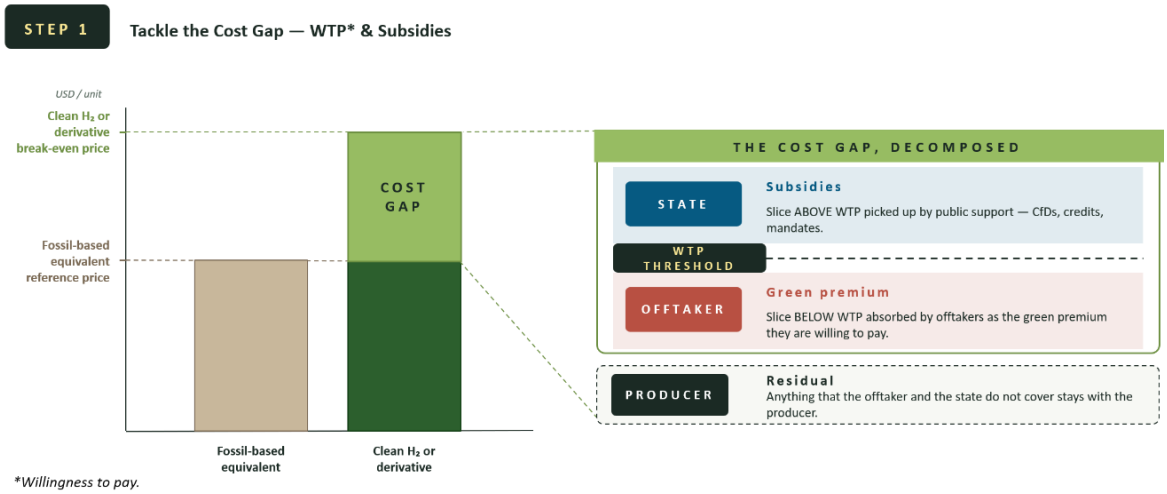
Voluntary decarbonisation has supported some willingness to pay the green premium, but not on a market-wide basis. In green shipping, cargo owners' willingness to pay the premium fell from 4.5% in 2024 to 3% in 2025 — the lowest level since 2022.[7] If buyers are less willing to pay even in a sector with relatively strong decarbonisation commitments, it is hard to see demand holding up better in sectors with weaker commitments.

The Two-Task Pricing Problem: Start with the Cost Gap

In a mature commodity market, an established benchmark provides an observable reference price, so both sides anchor to it and the pricing exercise is largely about managing volatility around that anchor. Clean hydrogen cannot start there: it has no liquid market and no established benchmark to anchor to. The only figure both sides can still pin down is the cost gap defined earlier, so it becomes the starting point. The gap is therefore structural: it is present before any question of volatility arises, and it surfaces even where the pricing formula tracks no commodity at all. Pricing therefore cannot begin with volatility; it has to start by closing the cost gap — making the exercise a two-task problem.[3]

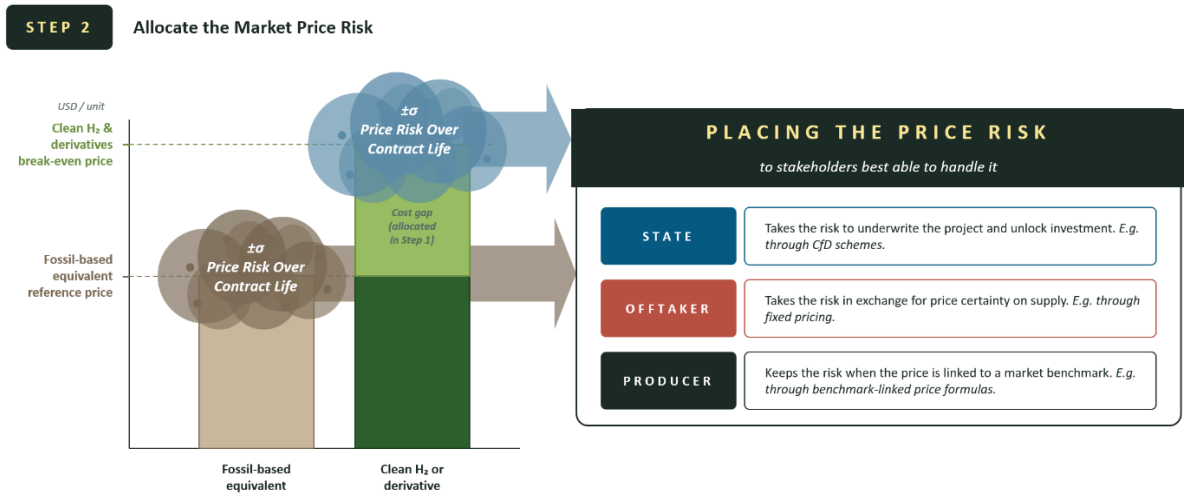
The cost gap is not a conventional risk. Closing it is a commercial issue of allocating a known commercial burden among three parties: the public sector through subsidies, the offtaker through a green premium, and the producer through any residual squeeze on returns, as shown in Figure 1. Which mix prevails depends on the regulatory regime, the offtaker's willingness to pay, and the project's economics—and varies markedly by project.

Figure 1. Clean Hydrogen Pricing — Step 1: Tackle the Cost Gap



Only once the cost gap is decomposed and allocated to the satisfaction of the stakeholders does the second task arise: **allocating market price risk** over the life of the offtake arrangement — a genuine risk, unknown in direction and magnitude as presented in Figure 2.

Figure 2. Clean Hydrogen Pricing — Step 2: Allocate Market Price Risk over the Life of the Contract



The two steps decompose a complex problem; they are not two separate negotiations. The order matters: it reveals which task carries the most weight. Today that is the cost gap — the wider it is, the more it crowds out the structuring effort that would otherwise go to allocating market price risk. As the cost gap narrows, more of that risk leaks down the chain, and within the same negotiation the balance tips toward allocating it (Step 2).

But for now, with the cost gap stubbornly wide, the question is who can cover it — and what (if anything) has recently changed the answer. Two forces stand out: increasingly selective public support and the energy-security shock triggered by the closure of the Strait of Hormuz in 2026.

Public Support Remains Indispensable — but More Selective

With the gap still too wide for even willing offtakers to absorb fully, it effectively leaves only one place for the balance to come from. Governments carry much of it through production subsidies, and recent European auctions confirm their willingness to continue funding part of the green premium. Support is turning into a catalyst for offtake and market formation rather than an open-ended subsidy. Three patterns in how that support is allocated – visible most clearly in the recent European Hydrogen Bank (EHB) auctions – shape which projects prove bankable and the commercial models future projects are likely to be built on.

First, winning an auction and reaching financial close are two different thresholds. An awarded subsidy improves project economics, but it does not solve the rest of the bankability stack: firm offtake, acceptable power costs, EPC bankability and, ultimately, a positive credit committee decision. That is why some first-round winners in the EHB auctions have still struggled to reach financial close. Subsidy support is increasingly a necessary condition for progress, but no longer a sufficient one on its own.[3]

Second, support is gravitating toward the projects with the smallest cost gap - and this is exactly what a competitive auction is designed to do. The third EHB auction was oversubscribed more than six times (€8.4 billion in bids for a €1.3 billion budget), and the marginal clearing premium sat below €1/kg — a level that effectively selects for projects with low-cost renewable power and credible offtake.[8] Where public funds are scarce, the auction compresses rather than absorbs the green premium, and the hardest-to-abate uses risk being squeezed out altogether.

Third, support is becoming explicitly differentiated — the system's answer to that selection pressure. The third EHB auction (results announced May 2026) awarded fixed per-kilogram subsidies in a very wide band: €0.44–3.49/kg across nine projects in seven EEA countries. For the first time, it introduced separate baskets for the general RFNBO category and for maritime and aviation offtakers — use cases that face higher abatement costs and weaker willingness to pay, and would otherwise be crowded out by cheaper industrial projects.[8] State support is moving from "one subsidy fits all" to a differentiated grid that mirrors the sector's own fragmentation.

Read together, these three patterns reinforce a single point for pricing-model design: production-side subsidies can lay the foundation, but they cannot substitute for a pricing structure that works commercially between offtaker, sponsor and lender. Nor can they fully de-risk projects that are otherwise marginal on power costs, counterparty quality or contract tenor.

The 2026 Strait of Hormuz Shock: From Climate Choice to Energy Security

The closure of the Strait of Hormuz in early 2026 — described by some as one of the most significant energy supply disruptions in recent decades, with crude flows through the Strait collapsing from around 20 mb/d to roughly 2 mb/d in March 2026[9] — turned importing economies' dependence on fossil fuels from an abstraction into a tangible exposure.

The disruption is best understood as two distinct shocks, each with different consequences for pricing.

- **The price shock.** Brent above $130/bbl, TTF gas up ~35%, JKM up ~50%. Fossil-fuel reference prices and grey-hydrogen costs rose sharply, narrowing the green premium in percentage terms, with the effect likely to reverse as fossil prices normalise.[9,12,13]
- **The supply shock.** A material share of global oil and LNG supply was taken offline, and importers' exposure to fossil-fuel concentration was demonstrated rather than argued. *It strengthens the political case for state-supported offtake and may widen the pool of buyers willing to value non-fossil supply for reasons other than price.*

The two differ in reach: a supply shock strikes only those directly exposed, while the price shock it sets off reaches everyone. For consumers and governments, these shocks were a wake-up call — not the first of their kind, unlikely to be the last, and, in a tighter market, potentially far worse — and precisely the kind of warning a prudent decision-maker can no longer leave out of long-term planning. Yet neither shock has produced new offtake commitments at scale, because the two run on different clocks — the price shock will fade as supply normalises; the supply-shock narrative may persist long enough to shift policy and procurement behaviour.[10] Long-term financial models behind capital allocation decisions

cannot safely lean on the first — they unwind when prices revert — and the second still awaits policy follow-through that has not arrived.

By mid-June 2026 the immediate price shock has begun to ease, but the disruption left the lasting effect on the policy context: it recasts clean hydrogen from a decarbonisation choice into a question of energy security. The climate argument alone, on the willingness-to-pay evidence, has struggled to move buyers market-wide; energy crises, by contrast, have repeatedly prompted state-led responses, from targeted subsidies to wholesale reconfiguration of the energy system.[11] An integrated rationale — energy security and independence now sitting alongside emissions reduction — is a more durable basis for sustained public support than climate goals on their own.

What Might the 2026 Shock Mean for the Cost Gap?

While the strategic case for clean hydrogen has clearly strengthened since the 2026 shock, whether the cost gap narrowed durably is a separate question. To assess that, it helps to separate the shock's effect on the fossil benchmark from its effect on clean hydrogen's input costs.

On the fossil-fuel side, the effect was immediate: the price shock summarised above. For projects benchmarked against grey hydrogen, ammonia or methanol made from natural gas, that lifted the fossil reference price and temporarily compressed the green premium as a percentage of the incumbent alternative.

On the input-cost side, the effect is mixed and depends on the production route — and it can offset part of the advantage the higher fossil price just created.

- **Blue hydrogen.** Natural gas is both the benchmark it is priced against and its principal feedstock, so a higher gas price raises production cost even as it lifts the reference price; with carbon-capture capex and CO_2 transport and storage on top, the crisis is widely read as leaving blue worse off: its cost gap fails to narrow, and probably widens.[11]
- **Green hydrogen.** Its main input is electricity, and bankable projects typically lock in dedicated renewable power, so the gas spike barely reaches them; only electrolysers drawing grid power in gas-linked markets see costs rise. If anything, green reads as a modest beneficiary of the narrowing cost gap, which is nevertheless helped by fresh drive for energy resilience.[14]

Either way, part of any benchmark gain is handed back on the cost side, so the crisis brings no clean, structural narrowing of the gap; the net effect turns on technology, input sourcing and location.

Even so, temporary compression still has value — it can warm up offtake discussions that had stalled on price, even if none of this yet justifies financing assumptions over a 15–20 year project life. The more durable signal lies elsewhere: green-hydrogen projects secured by low-cost renewable power should benefit over time from the broader fall in renewable electricity costs, especially in hard-to-electrify uses such as ammonia, methanol, shipping fuels and e-SAF.

Demand remains the binding constraint, and the cost gap must close before market price risk can be allocated — a balance the 2026 shock tilted strategically more than financially. With those constraints established, the weight falls on pricing models: to translate selective policy support and hesitant buyer

interest into revenue structures that offtakers will sign and lenders can underwrite. The next section turns to how the market is trying to do exactly that.

Pricing Models and Market Price Risk Allocation

Once the cost gap is allocated, the pricing model has a narrower but still decisive task: allocating market price risk in a way that survives both the offtakers' negotiating table and the credit committee. In practice, the market still leans on fixed-price structures while edging toward a fragmented mix of benchmarks and indexed models — a shift the 2025 Survey mapped in detail. The 2026 Strait of Hormuz shock was a sharp reminder of the potential impact of a sudden price spike — and why structures that contain market risk without undermining bankability are likely to matter more.

Diverging Stakeholder Preferences

At the centre of the pricing-model dilemma, developers, offtakers and lenders want the same outcome — a bankable project with predictable revenue, underpinned by public support. But that is where agreement ends: each would rather someone else bear the market price risk that remains once the cost gap is covered.

This divergence was clearly visible in the 2025 Survey. When asked about their key priorities in clean hydrogen and derivatives offtake negotiations, developers and equity investors wanted offtake contracts to support cost recovery, debt service and acceptable returns. Offtakers prioritised price competitiveness and flexibility in a market whose long-term shape remains uncertain. Lenders prioritised predictability and the ability to assess risk: in the Survey, cash-flow visibility, counterparty quality and alignment with government support ranked among their most important requirements.

In more mature commodity markets, benchmarks are a natural way to ease that tension by making price risk easier to allocate, transfer and manage, and are worth exploring as part of discussions of future clean-hydrogen pricing models.

Why benchmarks matter — and why no single one has emerged

A liquid benchmark (e.g. in mature commodity markets) is what makes price risk measurable and manageable: indexation lets each link pass it to the next — producer to offtaker, offtaker to its own customers — until it lands with whoever is best placed to bear it. That is the real appeal, reinforced by industry practices and precedents: most offtakers are energy and commodity companies fluent in indexation, for whom a credible benchmark can make a 15-20-year commitment far easier to sign.

Yet the 2025 Survey shows the market has not converged on one. Firms already using benchmark-linked models pointed to several proxies at once — ammonia (57%), natural gas (43%) and clean-hydrogen cost indices (43%) — rather than a shared standard.

The reason the proxies cluster this way is mainly that clean hydrogen demand is likely to anchor primarily to existing applications such as ammonia, methanol and refining in the coming years, based on

BNEF's base case scenario[4]. A clean-hydrogen deal is therefore likely to reference the incumbent it displaces. Because the molecule serves several pre-existing chains, there is no single benchmark for it to converge on; pricing inherits the fragmented reference landscape of the chains it enters.

There is also a reason not to want a global benchmark. When the Strait of Hormuz closed, US gas-pump prices moved within days, though the United States was never directly exposed to the supply shock. Index your local-demand-focused project to global ammonia or gas prices and you import precisely that volatility into a contract meant to hedge against it — the opposite of what an energy-security buyer is paying for. A regional reference, closer to the project's actual operating environment, for some offtakers may fit better.

Pricing models in use — fixed price is the anchor but not the dominant player

The Survey data showed that pure fixed price (a flat $/kg with no adjustment) is rare in practice: only 1 out of 19 respondents reported it as a model adopted (or expected to be adopted) in their projects. Instead, fixed price is typically paired with an escalation logic: 39% cited fixed price linked to market benchmarks and 33% cited fixed price indexed to inflation. In parallel, a meaningful share reported variable and risk-sharing structures — including benchmark-based variable pricing (28%) and variable pricing with floors and ceilings (17%).

This pattern reflects a deliberate logic: developers and offtakers use linkages to benchmarks and benchmarks to avoid locking either side into terms that become untenable as power prices, gas prices, or policy regimes shift.

Why fragmentation runs deep

This fragmentation in pricing practices is no accident — four features of the clean hydrogen sector pull pricing in different directions:

- **Use cases.** Clean hydrogen and its derivatives serve very different end-markets — ammonia for fertiliser, synthetic fuel for aviation, feedstock for refining and steel, and hydrogen for power — each with its own buyers, value-in-use and willingness to pay.
- **Technologies.** Green hydrogen (electrolysis) and blue hydrogen (gas reforming with carbon capture) have very different price drivers — renewable power for one, natural gas and carbon for the other.
- **Project scale and demand concentration.** Concentrated industrial demand tends to favour bespoke, e.g. cost-based pricing, while more diversified demand may make a benchmark more useful; smaller projects are often likely to be price-takers.
- **Geography and regulation.** Each market often has its own certification rules and support schemes, and prices off the reference that fits its own resource base and energy costs, which may differ significantly (by country and region).

REGIONAL SNAPSHOT — DIFFERENT DYNAMICS, DIFFERENT PRICING SIGNALS

United States	Progress stumbles on weakened regulatory certainty; focus on "blue" hydrogen produced captively for industrial users.
European Union	Regulatory and competitiveness headwinds, but a fresh push for energy independence post-Hormuz; differentiated subsidies through the Hydrogen Bank.
China	First green ammonia projects becoming operational; scale arriving through specific hubs (e.g. Chifeng) and offtake chains.
India	Renewable ammonia tenders used to discover long-term fixed prices through reverse auctions; residual cost gap still largely unresolved.[15]

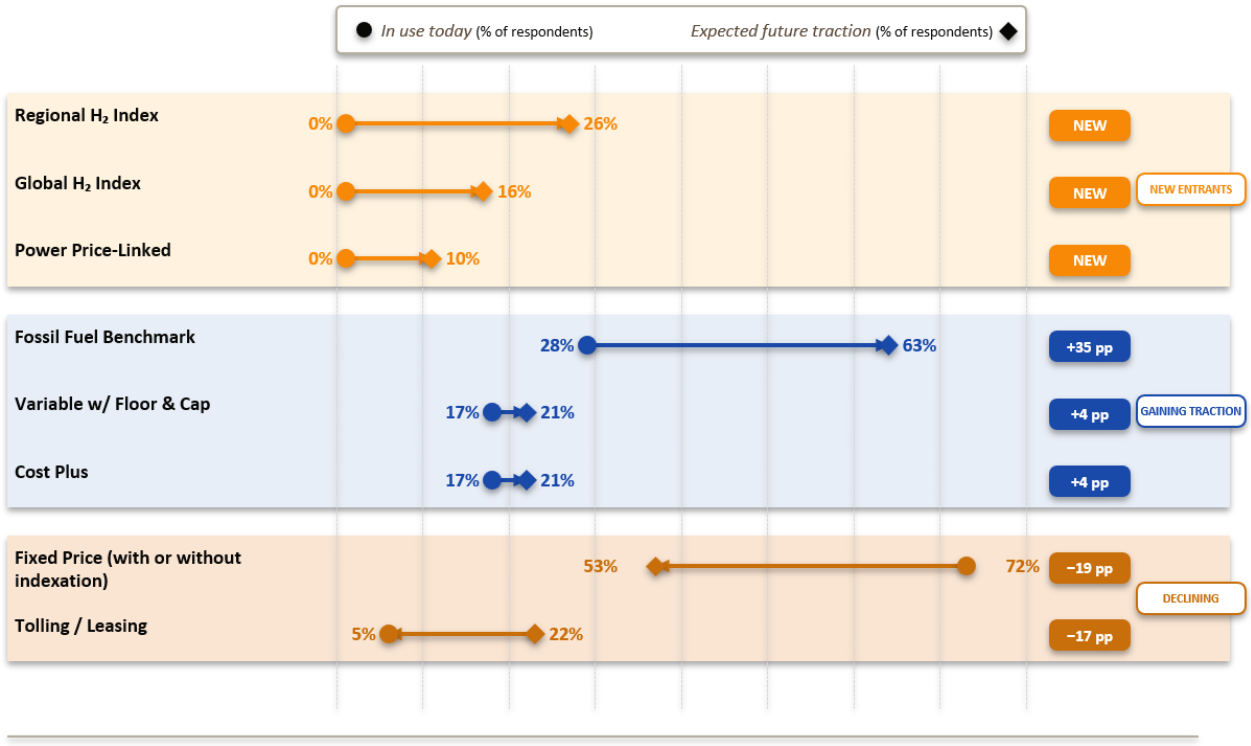
Direction of travel

Asked how clean hydrogen and derivatives pricing would evolve — toward one global standard or a diversified mix — respondents overwhelmingly expected diversification. A clear majority (61%) saw pricing evolving into a mix of global and regional benchmarks, while 17% expected a shift toward region-specific benchmarks and a further 17% toward highly tailored, project-specific models. That expectation carried through to the pricing mechanisms themselves: respondents did not foresee a single global benchmark emerging, but rather today's mix of structures shifting in relative weight over time, as Figure 3 demonstrates.

A number of observations follow from the opinions of the senior industry professionals:

- **Fixed-price dominance was expected to fade.** The most cited model today (72%), fixed-price structures were the only ones respondents expected to lose share, slipping to 53% as benchmark-linked alternatives gain.
- **Fossil-based benchmark pricing was expected to gain the most ground.** Cited by 28% today, expectations for it more than doubled to 63% — the steepest rise of any model in the set.
- **Floor-and-cap structures were gaining traction.** Variable pricing with a floor and cap had a relatively stable niche (17% today, 21% expected).
- **Regional indices were new entrants — and the 2026 shock is a tailwind for them.** Regional H_2 indices showed limited current use in our sample but ~26% expected adoption, and the supporting infrastructure is beginning to form: S&P Global has begun extending its hydrogen assessments to market-based regional benchmarks, such as those for India and Northwest Europe.[16] The post-Hormuz reverberations of global benchmarks may strengthen the case for regional indices that reflect actual market conditions rather than imported volatility.

Figure 3. Clean Hydrogen Pricing Models — Direction of Travel



Note: Each bar shows the share of respondents reporting current use or expected future adoption of the respective pricing model. Categories are non-mutually exclusive — respondents could indicate multiple models simultaneously. Δpp reflects the shift from current use to expected future traction.

Looking further out, market price-hedging instruments remain very little used today, owing to a lack of suitable instruments, and a wide majority of respondents expected only a "moderate increase" even over the long term (5+ years).

Taken together, the Survey points to a market that will keep diversifying — no single pricing model, no common benchmark, and little ability to hedge price risk; the Hormuz shock only sharpens the pull toward local, flexible references. With nothing market-wide to lean on, price risk has to be managed deal by deal, inside the pricing structure itself — so whether a project gets financed comes down to whether its structure yields a revenue profile a lender can underwrite.

Implications for Project Finance

Three findings from the 2025 Survey, read alongside recent market developments, stand out. Together they suggest what a pricing model is likely to need to deliver to support a bankable project.

- **Two tasks, not one.** With a cost gap persisting, pricing models must first help bridge the cost gap with fossil-based alternatives — often with public support — before allocating market price risk in a form offtakers will accept. What matters, then, is how well a pricing model does both jobs — closing the gap and then allocating price risk — rather than the headline price alone.
- **Fixed price is not likely to remain the only model in use.** Fixed price remains an anchor, but it is unlikely to suit all offtakers in a market still shaped by a wide cost gap and higher fossil-price

volatility. Many buyers will prefer structures that preserve cost visibility without full exposure to future market price exposure over the long-term. Fixed price is therefore losing its status as the default, with indexed and hybrid structures increasingly likely to take its place.

- **Pricing benchmarks are likely to diversify.** Rather than converge on a single benchmark, the market is more likely to move toward a mix of fossil-linked references, regional benchmarks and local indices, reflecting both stakeholder risk preferences and the need to avoid importing unnecessary global volatility. For lenders, this points to market due diligence moving from a supporting workstream toward the core of the credit assessment, and being run project by project rather than off a template. Some of these reference series are new and may not yet feature in lenders' internal credit models.

CLEARING THE BANKABILITY TEST — What the Pricing Model Must Deliver

- **Cost competitiveness remains the first credit question.** With no liquid market in sight, lenders favour projects with a smaller cost gap and a more attractive position on the cost curve — such a project leans less on public support or a single counterparty to stay covered over the life of the loan, and lets demand hold more credibly at the agreed price.
- **Minimum-price protection will remain central.** Whatever pricing structure is used, lenders are likely to place particular weight on minimum-price protection, whether delivered through contract floors, support mechanisms or other downside protections that preserve debt service under stress. A collar shows the appeal: its floor guarantees the producer a minimum while its cap limits the offtaker's exposure, sharing price risk rather than loading it onto one side — which can also ease the buyer hesitation now limiting offtake.
- **What ultimately gets financed is a revenue profile lenders can model and diligence.** Cost competitiveness and a minimum-price floor matter because they feed the same end: cash flows a lender can size debt against and stress over the life of the offtake. And that diligence is no routine exercise. Each deal is likely to be underwritten on its own merits, calling for specialised due diligence across the markets each project depends on – clean hydrogen and its derivatives, the commodities they are priced against, power markets and the applicable subsidy regimes.

POSTSCRIPT — A Note to Readers

A sincere thank you to everyone who took the time to complete the 2025 Survey. In a quickly changing environment, senior practitioner input is especially valuable.

The industry's evolution is far from over, and neither is the need to observe it carefully. For readers interested in the underlying survey, or in adding their own perspective, the survey remains available here:

Clean Hydrogen Pricing Survey

Exhibit. About the 2025 Survey

Why the Survey Matters

Pricing models are central to revenue predictability, market price risk allocation, and ultimately the ability to bring offtakers and lenders into clean hydrogen production projects.

In established commodity markets, pricing models have extensive history. They give investors, offtakers and lenders standard tools to isolate and quantify market price risk separately from other project risks, relying on recognised benchmarks and pricing formulas. In emerging sectors such as clean hydrogen and derivatives, the market may be barely present, with a long-term price view very difficult to quantify. That does not mean market price risk is absent — it means it must be allocated before the market has fully formed.

A fixed-price approach may seem like the most straightforward fix — and indeed it has featured in several pioneering projects that reached financial close. It gives lenders a clearer revenue case and removes the borrower's exposure to market price movements. But it can be difficult for some offtakers to accept. Even when they are prepared to commit to long-term offtake volumes, they may be unwilling or unable, for risk-management or institutional reasons, to take open-ended exposure to market price risk.

What the Survey was designed to test

The Survey covered three substantive areas: (i) pricing models currently in use; (ii) preferred market price risk allocation approaches and pricing models; and (iii) expected direction of travel of pricing models. Different branches were directed at different respondent profiles (offtakers, equity investors, lenders). Given the early stage of the market and the commercial sensitivity of the subject, the Survey was conducted anonymously — only basic information on project archetypes and respondent profiles was collected.

Defining the scope

"Clean hydrogen and derivatives" refers in this Survey to hydrogen produced through either renewable-electricity electrolysis (green) or natural gas with carbon capture and storage (blue), and to derivatives produced from such hydrogen — principally ammonia, methanol, and synthetic aviation/marine fuels.

Unless stated otherwise in the article, references to clean hydrogen cover both green and blue pathways; where a point applies only to one pathway, this is indicated explicitly.

Respondents were drawn from across the project value chain: project developers, equity investors, offtakers, lenders and advisers. The Survey was open to senior practitioners with direct involvement in clean hydrogen and derivatives projects; respondents were not pre-screened on geography, use case, or stakeholder type. With 19 senior practitioners responding across all major regions and use cases, the Survey is a focused expert panel representing various stakeholders shaping the industry, rather than a wide opinion poll.

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