Green Hydrogen for Indian Industry 2026: Economics, Open Access and Bankability

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A 2026 practitioner guide to green hydrogen economics, open access power, banking, storage and bankable project structures in India.

India's green-hydrogen conversation has moved beyond policy headlines. In 2026, the real questions from industrial buyers, developers, lenders and utilities are practical: what delivered hydrogen cost is actually achievable, how should renewable power be structured, when does storage make sense, what grid and open-access constraints matter, and which project configurations are bankable under Indian conditions?

For Indian industry, green hydrogen is not a universal substitute for natural gas, LPG or grey hydrogen. It is a location-specific, process-specific and power-structure-specific decarbonisation pathway. The economics can look credible for refineries, fertilisers, specialty chemicals, export-oriented manufacturing and selected mobility or e-fuel use cases. They remain difficult for many smaller industrial loads unless policy support, low-cost renewable power, and high utilisation of electrolysers come together.

This article focuses on what matters in 2026: delivered cost build-up, renewable sourcing choices, storage and flexibility requirements, water and balance-of-plant considerations, open-access and ISTS implications, and the project-finance lenses that lenders and offtakers are using in India.

Why green hydrogen economics in India are now a serious boardroom topic

The policy base is stronger than it was even two years ago. The National Green Hydrogen Mission created visibility, while implementing frameworks from MNRE, SIGHT incentives for domestic manufacturing and production pathways, and state-level land and power facilitation have started translating into project movement. Large Indian groups have announced integrated renewable-to-hydrogen platforms, but the next wave is increasingly about industrial offtake contracts rather than only captive flagship projects.

Three factors explain why 2026 is different:

- Solar-plus-wind hybrid tariffs for good sites and scaled procurements have stayed competitive, broadly in the Rs 3.0-4.2/kWh range depending on location, CUF profile, evacuation and contracting structure.
- Electrolyser capex expectations have improved, although not uniformly. Alkaline systems for larger projects are being quoted at materially lower levels than PEM, with domestic manufacturing support slowly helping localisation.
- Industrial decarbonisation pressure is no longer just reputational. Export supply chains, CBAM-linked competitiveness concerns for some sectors, and customer procurement requirements are making low-carbon molecules commercially relevant.

Even so, many early financial models remain overly optimistic. Common mistakes include assuming very high electrolyser utilisation without adequate round-the-clock renewable sourcing, underestimating auxiliary load and water-treatment cost, ignoring compression and storage capex, or using merchant power assumptions that are not financeable.

The delivered cost of green hydrogen in 2026: what numbers are realistic?

For Indian conditions in 2026, a realistic delivered green hydrogen cost for a reasonably scaled industrial project often falls in a broad band of about Rs 260-420/kg, depending on power cost, plant load factor, electrolyser capex, financing and delivery configuration. Lower numbers are possible for very advantaged sites with integrated renewable supply and policy support. Higher numbers remain common where renewable firmness is weak, open-access charges are high, or hydrogen needs compression, trucking and intermittent operation.

A practical cost stack for green hydrogen usually includes:

- Renewable electricity cost, usually the dominant component
- Electrolyser capex and stack replacement reserve
- Water treatment and demineralised water system
- Compression, storage and dispensing or process integration
- Balance of plant, civil works and evacuation
- O&M, insurance and manpower
- Financing cost and contingency

As a rule of thumb, electricity can account for roughly 55-75% of delivered hydrogen cost in Indian models, depending on utilisation and financing assumptions. If an electrolyser consumes around 50-55 kWh/kg including auxiliaries for many practical systems, each Re 1/kWh change in effective power cost changes hydrogen cost by roughly Rs 50-55/kg. That is why power-structure design matters more than presentation slides about long-run electrolyser learning curves.

Illustratively:

- At an effective delivered renewable power cost of Rs 3.2/kWh, electricity alone may contribute around Rs 160-176/kg.
- At Rs 4.2/kWh, that rises to roughly Rs 210-231/kg.
- Add capex recovery, O&M, water, compression and financing, and the total can move quickly above Rs 300/kg unless utilisation is strong.

This is the main commercial challenge when competing against grey hydrogen linked to natural gas or captive fossil routes. If natural gas prices soften, green hydrogen parity can drift further away. If gas tightens, carbon costs rise in export markets, or buyers value emissions reduction, parity improves. In other words, green hydrogen economics in India are still highly sensitive to commodity cycles and contracting structure.

Renewable-power sourcing: captive, open access, co-located or grid-backed hybrid?

For most projects, hydrogen economics are won or lost in the power architecture. There is no single best model. The right structure depends on project scale, land availability, process continuity, state charges, banking rules, and whether the buyer values lowest average cost or highest production certainty.

The main structures used in India in 2026 are:

- Co-located captive renewable plus electrolyser near generation source
- Third-party open-access renewable supply to an industrial electrolyser site
- Group captive or captive hybrid procurement for industrial users
- Grid-backed hybrid structures where renewable generation is supplemented by scheduled grid power
- Integrated solar-wind-BESS supply for higher electrolyser utilisation

Co-located projects can avoid some open-access complexity and may reduce delivered energy cost if land, water and evacuation are workable. But they may require hydrogen transport to the industrial consumer, which adds compression, storage and logistics cost. If hydrogen must be trucked as compressed gas, economics can deteriorate rapidly for smaller daily volumes.

Industrial-site electrolysis supplied through open access can simplify molecule delivery and support direct process integration. However, this approach faces state-specific wheeling, transmission, cross-subsidy surcharge, additional surcharge and banking-rule risks. Many developers still under-model these charges or assume annual banking where only restrictive monthly or no banking is available.

For larger loads, solar-wind hybrid is increasingly the starting point because pure solar results in low electrolyser utilisation unless oversized curtailment is accepted or grid power is added. Wind improves evening and monsoon generation, but site quality matters enormously. In well-matched hybrid geographies, annual renewable utilisation for the electrolyser can improve meaningfully, but not enough by itself to deliver flat 24x7 operation.

That leads to the critical strategic choice: is the project optimising for lowest levelised hydrogen cost or for steady hydrogen output?

- Lowest-cost models often accept variable hydrogen production with smaller or no battery systems and some hydrogen buffer storage.
- Steady-output models require either more renewable oversizing, BESS, grid top-up, or a combination of all three.

For many industrial processes, full flat hydrogen output is not actually necessary. If the offtaker can tolerate production swings and has buffer storage or process flexibility, project economics improve. This is often overlooked in board discussions that assume hydrogen must be supplied like baseload natural gas.

Storage, flexibility and the BESS question in hydrogen projects

A frequent modelling error in green hydrogen is treating BESS as mandatory. In reality, battery storage is only one of several flexibility tools, and often not the cheapest one for hydrogen systems.

Developers should compare at least four options:

- Renewable oversizing with controlled curtailment
- Limited BESS for intra-day smoothing and ramp management
- Hydrogen buffer storage to decouple production from consumption
- Grid top-up power under defined operational windows

BESS can be useful when the electrolyser benefits from smoother loading, when time-of-day power economics matter, or when grid interconnection imposes ramp or scheduling constraints. A 1-3 hour BESS may also help improve renewable capture and reduce electrolyser start-stop cycling. But if the objective is multi-day or seasonal balancing, batteries are usually too expensive relative to hydrogen storage or operational flexibility.

Hydrogen storage itself is not free, but for many industrial systems it is more logical to store the molecule than to force full electrical firmness. Compressed gaseous storage for short-duration balancing can support process continuity. For larger projects, storage design must consider pressure levels, safety systems, land footprint and demand profile.

In advisory practice, the least-cost design often emerges from integrated optimisation across these variables rather than from a default assumption that more battery means a better project. For example:

- A project targeting 85-90% electrolyser utilisation may need expensive renewable oversizing plus storage, hurting hydrogen cost.
- A project designed around 55-70% utilisation with flexible offtake may deliver a much more financeable Rs/kg outcome.
- A refinery or ammonia user with existing storage and process integration may absorb variability better than a small merchant buyer.

This is exactly why bankable modelling for hydrogen must include hourly or sub-hourly production simulation, renewable correlation analysis, curtailment assumptions, outage treatment, and sensitivity runs for state charges and seasonal wind variation.

Open-access, transmission and regulatory issues that materially change viability

In 2026, regulatory details remain one of the biggest differentiators between a good hydrogen concept and a weak one. The most important issues for Indian projects include ISTS benefit eligibility where relevant, state open-access charges, banking permissibility, connectivity timelines, forecasting and scheduling obligations, and treatment of standby or supplemental grid power.

Industrial buyers should evaluate at least the following before committing to site selection:

- State-wise cross-subsidy surcharge and additional surcharge trajectory
- Banking availability, settlement period and banking charges
- Wheeling and transmission losses and their seasonal variation
- Grid outage history and substation constraints at the offtake point
- Whether the electrolyser can economically use unscheduled or top-up grid supply
- Water abstraction permissions and discharge compliance
- Local safety, zoning and PESO-related requirements for hydrogen handling

One practical lesson from recent Indian projects is that a nominally cheap renewable tariff can become uncompetitive after delivered-cost build-up. Once losses, wheeling, transmission and surcharges are included, the effective cost at the electrolyser busbar can be materially higher than the headline PPA tariff.

Likewise, many hydrogen developers seek very high annual operating hours but underestimate curtailment risk or scheduling complexity. If the project depends on merchant top-up power during low-renewable periods, lenders will heavily discount such assumptions unless backed by a robust contracted framework.

Utilities and policymakers also need to recognise that green hydrogen projects are unusual loads. They can provide flexible demand response if designed correctly. Electrolysers can ramp, absorb renewable surplus and support grid balancing, but only if tariff design, scheduling rules and market access enable that flexibility. Rigid industrial tariff structures may prevent the system from capturing these benefits.

What lenders and offtakers look for in a bankable green-hydrogen project

By 2026, lenders are no longer looking at green hydrogen as a purely thematic story. They are applying disciplined infrastructure and industrial-project tests. The projects that move forward are those with clarity on offtake, power sourcing, technology selection and operational risk allocation.

A bankable Indian hydrogen project usually needs:

- Credible offtake from a process user with clear hydrogen demand profile
- Contracted or highly defensible renewable power structure
- Realistic electrolyser performance assumptions at Indian ambient conditions
- Defined stack degradation and replacement provision
- Conservative compression, storage and delivery modelling
- Water source certainty and environmental compliance path
- EPC and integration accountability across multiple packages
- Sensible contingency and DSCR assumptions under downside cases

Offtake quality is critical. Merchant hydrogen remains difficult to finance at scale unless there is a strong anchor buyer. Lenders prefer industrial offtakers with investment-grade or near-investment-grade profiles, long-term demand visibility, and pass-through logic where hydrogen is embedded into core production economics.

Technology choice also matters. Alkaline electrolysers remain attractive for many large Indian applications because of lower capex and established operating history, especially where ultra-fast ramping is not essential. PEM can be relevant where dynamic response and footprint are more important, though capex is usually higher. Project sponsors should avoid assuming best-case OEM metrics without accounting for local operating conditions, water quality, spares availability and service support.

Another issue is EPC fragmentation. Hydrogen projects often involve renewable generation, evacuation, water systems, electrolysers, compression, storage and industrial tie-ins under separate scopes. If interface risk is not tightly managed, delays and performance disputes become likely. This is where owner's engineering, PMC discipline and lender's engineer review are not optional overheads but core risk controls.

A robust lender model should at minimum test:

- Renewable underperformance by 10-15%
- Effective power-cost increase due to charge revisions
- Electrolyser efficiency degradation over time
- Delayed stack replacement or higher replacement cost
- Lower plant availability in initial years
- Reduced offtake or process shutdown periods
- Capex overruns and commissioning delay

If the project only works under perfect assumptions, it is not bankable.

Where the strongest use cases are emerging in India

The best near-term Indian use cases are those where hydrogen is already a feedstock or reducing agent, not where it is being forced into an uneconomic substitution case.

The strongest segments in 2026 include:

- Refineries seeking partial replacement of grey hydrogen and emissions reduction
- Ammonia and fertiliser value chains where hydrogen is already central to the process
- Chemicals and specialty materials with export-facing decarbonisation pressure

- Integrated industrial clusters where renewable supply, water and offtake are geographically aligned
- Ports and heavy transport pilots where offtake can be aggregated and supported by policy

Weaker use cases remain:

- Small standalone industrial consumers without scale benefits
- Projects dependent on expensive delivered open-access power in restrictive states
- Merchant hydrogen production without anchored offtake
- Cases requiring high transport distance for compressed hydrogen with low daily utilisation

For policymakers, the implication is straightforward: support should prioritise bankable industrial corridors, transmission-enabled renewable access, and demand-linked procurement structures rather than only symbolic capacity announcements. For utilities, the opportunity is to design tariff and market structures that allow electrolysers to behave as flexible loads instead of treating them as conventional industrial demand.

For C&I consumers and developers, the message is even simpler. Green hydrogen is viable in India only when the molecule, power and process are designed together. A cheap electrolyser quote alone does not create a good project. Nor does a low solar tariff without attention to utilisation, storage, delivery and open-access charges.

The winning projects in 2026 are those built on hourly energy modelling, state-specific regulatory diligence, realistic capex and degradation assumptions, and bankable offtake structures. That is exactly where specialist advisory matters most.

If you are evaluating a green hydrogen opportunity, open-access power structure, storage strategy or lender-ready feasibility model, contact Growthifye's advisory desk for project-specific support on sizing, economics, grid integration, PMC and financing strategy.

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