

The Hydrogen Offtake Test: Project Value in Offshore Wind Electrolysis

An investment framework for electricity opportunity cost, hydrogen demand and cash collection

Authored by Chennakeshav Adya

Independent Researcher

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Abstract

Offshore wind electrolysis requires a customer that can accept the specified hydrogen and pay for it through a completed delivery chain. The investment decision also depends on the electricity sales surrendered when wind output is diverted. This paper develops a decision framework joining the electricity alternative, conversion performance, product qualification, customer obligations and funding requirements.

The analysis draws on current official hydrogen-market evidence, the identified EU renewable-fuel rules and the UK Low Carbon Hydrogen Standard and support documents. It distinguishes published programmes from executed project commitments and physical delivery from qualification, invoicing and collection. Contract, engineering and financing evidence are linked to the cash flows they support.

A reproducible hypothetical exercise compares a 20 MW conversion system with the electricity-sale alternative for an existing 100 MW wind asset. Under the specified Normal case, flexible hydrogen production produces an incremental ten-year net present value of \$20.802 million. The Adverse case produces a negative \$28.175 million. The Normal fixed-dispatch zero-value price is \$4.326 per accepted kilogram. A separate dated liquidity exercise identifies a \$2.706 million month-end funding requirement during the assumed buyer interruption.

Every numerical input is specified for illustration. Monthly aggregation, simplified performance, excluded equipment replacement and the absence of transaction-specific contracts limit the results. The paper provides an investment test and an evidence roadmap; it establishes no actual project valuation, prevailing hydrogen price or lender commitment.

JEL Classification: G31, G32, L94, Q42, Q48

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1. The investment boundary begins with a saleable product

Electrolysis changes the revenue route of an offshore wind investment. A decision to add it commits capital to conversion equipment and to a delivery chain with its own operating requirements. The commercial test starts at the customer's acceptance point: which product can be delivered, in what quantity, at what time, under which environmental specification, and against which payment obligation? The analysis proposed here follows that chain backwards

through transport, storage, hydrogen processing and electricity supply. Each boundary needs a responsible party and an observable acceptance test.

The wind asset also retains an alternative use for its output. A comparison needs a credible electricity-only case with its actual export constraints, connection schedule and electricity contracts. The integrated case then identifies incremental expenditure, revenue and obligations. An internal power transfer price changes the distribution of earnings between the wind and hydrogen companies. The consolidated investment comparison separately measures the value surrendered when electricity is diverted from another available sale. This distinction allows investors to examine whether apparent hydrogen profitability depends on a transfer from the wind business.

Public evidence establishes the importance of completing this commercial chain. The IEA's 2026 review reports that industry and refining accounted for almost all hydrogen demand in 2025, while only around one-fifth of newly signed low-emissions offtake volumes carried firm contractual commitments. These are market-level observations within the IEA's assessed dataset. They do not demonstrate demand for a particular offshore project or establish a price that its buyer can afford. [1]

The proposed investment discipline is to maintain three linked records: a physical balance, a contractual receipts schedule and an incremental cash-flow comparison. The physical balance tracks energy, kilograms, inventory and losses. The receipts schedule distinguishes accepted product, invoiced sales and cash collected. The comparison measures the complete system against the electricity alternative. Unresolved project inputs remain explicit assumptions awaiting verification. The hypothetical calculations introduced later in the paper are analytical examples; no commercial quote, forecast or executed customer agreement is supplied.

2. Establish demand at the customer's process boundary

A named potential customer becomes useful investment evidence when its consumption specification and conversion programme can be examined. An existing hydrogen user may already have process equipment, but its procurement decision still depends on delivery pressure, purity, continuity, price and environmental attributes. A new user may need a different furnace, reduction process, fuel system or product certification. The proposed diligence record therefore joins the hydrogen producer's delivery plan to the customer's operating plan and identifies which expenditure and permissions remain outstanding on each side.

The IEA's 2025 demand chapter reported that new applications represented less than 1% of global hydrogen demand in 2024 and that offtake activity was concentrated in established sectors. Its historical figures provide context for testing customer readiness. The succeeding edition supplies more recent observations, while the two reports retain different reporting periods. Neither edition converts a customer's stated interest into a payment commitment. [2]

Demand assessment should examine the customer's decision under several stated conditions. These include a delayed conversion programme, lower industrial output, a change in its competing feedstock cost and the expiry of a downstream product premium. The proposed analysis calculates the buyer's total delivered switching cost, including its own capital expenditure and operating changes. Any assumed carbon value or product premium needs an

identified payer, qualifying rule, measurement boundary and duration. An aggregate policy target supplies no evidence about the allocation of that value in the proposed sale.

A useful commercial milestone is agreement on the physical specification and acceptance protocol before negotiating the final price formula. This can reveal that two parties are discussing different products: hydrogen at the producer's outlet and hydrogen at the customer's required pressure after transport. Each additional service then has a stated supplier and tariff. A proposed anchor customer should also provide a dated readiness schedule, financial information and the authority of the entity signing the contract. Those records allow the investment committee to classify remaining demand uncertainty without assigning an unsupported probability.

Table 1. Demand evidence and the corresponding investment use

Evidence	Quantity information	Payment evidence	Investment use
Customer interview	Indicative consumption	None established	Develop product specification
Non-binding memorandum	Proposed annual demand	Subject to future agreement	Track negotiations
Conditional executed sale	Defined schedule and conditions	Depends on conditions being met	Model conditional receipts
Effective supported sale	Agreed nominations and remedies	Defined obligor and support	Test a contracted case

Proposed diligence classification. A document's legal effect depends on its executed terms and governing law.

3. Charge the hydrogen case for the electricity it consumes

The electricity alternative should describe the choices genuinely available to the wind project. A merchant export route, an existing power purchase agreement and compensated curtailment produce different foregone receipts. The proposed comparison uses interval-specific net value at a consistent electrical boundary. Export losses, imbalance costs, network charges and contractual penalties belong in that calculation when relevant. The model also identifies whether the plant can physically redirect power during an export constraint. A transmission restriction elsewhere in the network does not itself demonstrate that the electrolyser can receive the affected output.

Consider a hypothetical interval in which the wind project can sell electricity at a net value of 60 currency units per MWh. Suppose the hydrogen system consumes 0.055 MWh for each accepted kilogram at the stated delivery boundary. The foregone electricity value is 3.30 currency units per kilogram. If the interval's net electricity value is 20, that component becomes 1.10. These are arithmetic illustrations using authored assumptions. They exclude conversion capital, other operating costs and hydrogen transport, and they establish no prevailing market price.

The dispatch rule should compare the incremental hydrogen receipt after variable processing and delivery costs with the electricity value surrendered. Existing hydrogen delivery obligations can add replacement purchases or shortfall damages to the choice. An operator may therefore run during an interval with a low standalone conversion margin to meet a binding delivery schedule. The financing model needs that obligation represented explicitly. Using a freely optimised dispatch schedule alongside an inflexible sales commitment would describe incompatible operating strategies.

An annual average electricity price conceals the relationship between wind output and dispatch. The proposed analysis retains the generation, price and eligibility timestamps through conversion and customer delivery. It reports which hours produce positive operating contribution and which hours are used to satisfy contractual obligations. Fixed capital recovery is then tested over the

whole project. A positive marginal operating contribution in selected hours supplies only one part of that assessment; the remaining question is whether enough eligible sales occur to fund the installed system.

Table 2. Electricity counterfactuals at a common boundary

Alternative	Foregone value input	Additional check
Merchant export	Interval net sale receipt	Export capacity and settlement costs
Existing power contract	Contract cash-flow effect	Diversion and shortfall provisions
Compensated curtailment	Compensation actually lost	Eligibility and payment conditions
Uncompensated restriction	Available alternative receipt	Physical power access and duration
Deferred grid connection	Dated future electricity case	Connection expenditure and timing

Proposed modeling choices; actual contract rights and network conditions require verification.

4. Compare complete onshore and offshore systems

The laboratory's July 2024 research summary describes two configurations: electrical export to onshore electrolysis and offshore electrolysis using desalinated seawater with hydrogen piped ashore. It identifies four representative US coastal locations and states that the technical feasibility of the offshore configuration is less established. The summary also explains that the modeled results depend on location, technology and preliminary policy assumptions. The underlying full paper was unavailable for direct review here, so its detailed cost results are not adopted. [3]

For an investment comparison, both configurations should terminate at the same customer delivery point. Onshore electrolysis requires the relevant electrical export route and coastal processing site. Offshore conversion adds marine equipment and hydrogen-export interfaces. The proposed cost schedule assigns each component once: turbine electrical equipment, cable or pipeline, conversion plant, water treatment, compression, storage, landfall and customer connection. Shared assets need a capacity allocation rule and a statement of which expenditure remains necessary if one business is postponed.

The operating case should examine access and repair as part of the system boundary. A replacement component at an offshore platform needs a feasible lifting, isolation and transport procedure. The service contract should define which conditions suspend access and whether the performance commitment accommodates those conditions. An onshore plant needs its own utility connections, water supply, land rights and local operating permissions. These are diligence requirements for the proposed project; the paper supplies no observed availability ranking between the configurations.

Phasing can preserve a development choice while limiting the capital committed before demand is secured. For example, a sponsor could assess an initial coastal module sized to an executed sale and reserve space for expansion. The comparison must include the cost of modularity, any duplicated equipment and restrictions imposed by the original wind financing. A later offshore module would still require a separate design and completion case. The resulting option has value only under the assumed future choices and costs; it has no independently verified market valuation here.

Table 3. Configuration comparison at the customer gate

Attribute	Onshore electrolysis	Offshore electrolysis
Energy export interface	Electrical cable	Hydrogen pipeline in the stated case

Attribute	Onshore electrolysis	Offshore electrolysis
Water supply boundary	Coastal treatment and utility system	Offshore treatment and marine equipment
Maintenance plan	Land-based access plan	Marine access and isolation plan
Shared-cost allocation	Electrical export and coastal facilities	Marine platform, landfall and pipe
Completion evidence	Cable, plant and customer connection	Plant, pipeline and customer connection

Proposed scope comparison informed by the two configurations described in [3].

5. Reconcile performance guarantees with the operating schedule

A vendor performance schedule needs an explicit boundary. Electricity consumption at a stack, at an electrolyser system and at a delivered-hydrogen meter can describe different services. The proposed technical schedule states feedwater conditions, outlet pressure, purity, auxiliary demand, minimum stable load, ramp limits, start-up consumption and ambient assumptions. It also identifies the equipment excluded from a quoted efficiency. Investors can then reconcile the guarantee with the electrical and hydrogen meters used in the operating model.

DOE's PEM targets distinguish stack performance from system energy consumption and identify installation costs excluded from the system capital figures. Their notes require performance, durability and cost targets to be met together and call for dynamic operation and cycling to be considered when relevant. These are research and development guideposts. A target dated 2026 supplies no evidence that a vendor has delivered the corresponding commercial performance at the proposed offshore site. [4]

Sizing should follow a chronological supply-and-demand case. The proposed test compares several electrolyser capacities using the same wind series, electricity opportunities and customer delivery schedule. It records operating hours, part-load consumption, curtailed generation, hydrogen inventory and unmet nominations for each size. A larger unit may process additional windy-hour output while carrying higher fixed expenditure. A smaller unit may operate more frequently while foregoing some production opportunities. The investment question is the resulting change in discounted receipts and expenditure under stated assumptions.

Degradation and replacement require a dated plan alongside the initial performance curve. A contractual efficiency remedy may compensate for excess energy consumption while leaving an extended outage outside the remedy. The financing assessment should therefore examine the remedy's cap, payment timing, exclusions and provider credit. It should also fund replacements when scheduled and assess whether replacement work coincides with buyer shutdowns. A provision for replacement expenditure in a lifetime cost metric does not establish that cash is available in the year the equipment needs replacement.

Table 4. Performance boundaries and contract evidence

Metric	Boundary to specify	Evidence to request
Stack efficiency	Stack electricity and hydrogen output	Test conditions and degradation curve
System consumption	Included auxiliaries and outlet state	Metered acceptance procedure
Delivered consumption	Compression, treatment and losses	Complete process-energy balance
Installed cost	Equipment, civil works and integration	Priced scope and exclusions
Replacement life	Hours, cycles and end-of-life criterion	Warranty, reserve and work programme

Proposed guarantee reconciliation; [4] supplies the distinction between stack, system and excluded installation costs.

6. Carry water, heat and safety through the design

Water availability needs its own balance. DOE's May 2026 Program Record 25003 separates direct from indirect water use and distinguishes withdrawal from consumption. Its modeled electrolysis cases also separate reaction water, treatment and cooling-related requirements. This supports a boundary-based assessment of water use, with local constraints assessed separately from aggregate consumption. The record's freshwater-based US scenarios provide no permit or seawater-processing guarantee for an offshore installation. [5]

The proposed design record begins with source-water quality and the electrolyser manufacturer's inlet requirement. It then identifies intake, filtration, desalination where required, final purification, cooling, cleaning and discharge. Each process has a capacity, energy requirement, consumables schedule and outage case. Marine discharge consent and site-specific environmental effects need independent assessment. A comparatively small forecast share of total operating expenditure would leave those completion and continuity requirements unchanged. The financial model should represent the effect of losing treatment capacity even when its normal operating cost is modest.

Hydrogen safety also requires project-specific engineering. DOE identifies ventilation, leak detection, flame detection and materials selection as relevant controls, reflecting hydrogen's ignition properties, nearly invisible flame and potential effects on some metals. That guidance establishes general hazards and controls. It does not replace an offshore hazard study, local regulatory requirements or a complete emergency-response plan. [6]

The proposed investment record links each material safety recommendation to a design owner, capital allowance, operating procedure and commissioning evidence. It should examine simultaneous marine and process emergencies, safe isolation of shared electrical equipment and the consequences of a hydrogen-system trip for wind operations. Heat or oxygen revenue belongs in a separate supported case until a customer specification, delivery system and payment agreement are verified. A by-product's physical production establishes a possible supply; commercial value depends on the additional cost and the customer's willingness to purchase that supply.

7. Match storage and transport to the delivery promise

DOE's delivery guidance identifies pipelines, compression, storage, transport and point-of-use equipment as parts of the hydrogen chain. It also highlights purity, leakage and the trade-off between production location and delivery requirements. These mechanisms justify assessing logistics within the same system boundary as production. They supply no evidence that a proposed coastal pipeline has available capacity or that a listed industrial customer can receive its output. [7]

The proposed storage case uses chronological inventory, with stated injection and withdrawal capacities, minimum inventory and losses. Storage must bridge the particular interruption being tested. A volume sufficient for a short operating fluctuation may be inadequate for a prolonged wind lull or buyer outage. The model should distinguish physically usable inventory from hydrogen that cannot be withdrawn at the required rate or pressure. Storage availability and transport availability should be represented separately, including planned maintenance and common infrastructure dependencies.

Liquid delivery adds a different process chain. DOE describes energy consumption in liquefaction and losses through evaporation during storage or transport. The qualitative mechanisms are relevant to the boundary; its undated numeric technology statements are not adopted as guarantees for a current plant. [8] A proposed comparison should request the actual liquefaction performance schedule, loading arrangements, vessel or tanker capacity, receiving equipment and loss allocation. A delivered liquid-hydrogen price also needs a consistent custody and energy basis.

A transport contract should connect its capacity rights to the hydrogen sale. Reservation charges, interruption priority, quality limits and liability caps can affect cash flow even when the delivery asset is owned by another party. Proposed lender diligence should identify what happens if production is complete before the route is commissioned. Temporary storage or trucking can be assessed as a separately priced contingency, subject to confirmed permits and capacity. The paper assumes no available alternative route and assigns no recovery revenue to an unverified replacement buyer.

Table 5. Delivery and storage choices requiring a common product boundary

Choice	Operating interface	Cash-flow item	Evidence dependency
Compressed-gas pipeline	Pressure, quality and flow	Capacity tariff and interruption	Access rights and completion
Tube-trailer delivery	Loading and receiving windows	Fleet and handling expenditure	Roads, permits and buyer equipment
Liquid-hydrogen delivery	Liquefaction and receiving plant	Process energy and product losses	Performance and transfer protocol
Buffer storage	Injection and withdrawal limits	Inventory funding and reservation	Usable capacity and reliability
Derivative route	Conversion and customer product	Conversion, transport and reconversion	Executable full-chain specification

Proposed comparison using the general mechanisms in [7] and [8]; no route economics or capacity is verified.

8. Convert offtake into a timed and supported receipt

Institutional financing analysis identifies buyer non-payment and the absence of a substitute buyer as offtake risks. The World Bank/OECD-hosted report also discusses the difficulty created by limited pricing benchmarks. These are relevant risk categories for a proposed hydrogen sale, with project-specific enforceability and lender requirements left for transaction review. A long contract duration alone supplies no conclusion about the credit quality of the cash flows. [15]

The proposed contract schedule separates nomination, delivery, acceptance, invoicing and payment dates. Annual minimum quantities need monthly or other periodic payment mechanics if the project incurs costs throughout the year. Make-up rights also need an accounting and cash treatment: a payment received today may create a future delivery obligation. A proposed model should show the resulting inventory and cash consequences in the periods when they arise. It should identify which interruptions suspend payment and how long a dispute can delay receipt.

Credit support requires a defined amount, issuer, term and replenishment rule. The investment record should examine the identity of the buyer, the beneficiary of any guarantee, the circumstances permitting a draw and the relationship between support expiry and termination settlement. A guarantee from another entity in the same economically exposed group should be assessed alongside that group's obligations. A bank instrument needs its own issuance, renewal and draw conditions. These proposed checks establish the information needed for assessment; the paper confirms no instrument or rating.

Replacement sales require physical and regulatory compatibility as well as a prospective customer. The proposed downside case identifies the time needed to reach another buyer, any new connection expenditure, a possible specification change and the treatment of environmental evidence. Assumptions about replacement price and recovery are stated openly. Until supported, the financing case can retain zero substitute-sale revenue during the modeled interruption and show the equity or liquidity required to fund it. The committee can then decide how much uncontracted exposure it is willing to accept.

9. Treat EU renewable-electricity qualification as a dispatch constraint

Commission guidance places renewable hydrogen within the RFNBO framework and states that the rules cover domestic production and imports. [16] The identified consolidated Regulation 2023/1184 distinguishes direct-connection evidence from grid-electricity routes. Its general grid route links additionality, temporal matching and geographic conditions. Article 6 provides monthly matching through 2029 and hourly matching from 2030, with specified earlier national application and exceptions. Article 11's transition concerns Article 5(a) and (b) for qualifying pre-2028 installations; it excludes capacity added after 1 January 2028. [9]

For the general grid route, Article 5 includes a 36-month commissioning condition and restrictions on generation aid, with stated exclusions. Article 7 permits the same bidding zone, a qualifying interconnected zone with the specified price relationship, or an offshore bidding zone connected to the electrolyser's zone. These conditions require route-specific evidence. [9]

The proposed operating model records the legal route relied upon for each electricity input. It then tracks generation, consumption and any relevant storage evidence at the necessary time resolution. Qualification should be evaluated before a sale is assigned a renewable premium or support payment. A broad description such as dedicated offshore wind leaves open the installation date, connection topology, grid imports and the evidence required by the chosen route. Each of those matters needs a documented conclusion from the project's advisers and certifier.

The PPA and electricity data rights should support that evidence. The producer needs access to the generation information on which its claim depends, together with treatment of corrected readings, unavailable records and changes in the contracted installation. The proposed contract should also allocate the cash effect of non-qualifying output. A customer might accept the physical molecule under one product specification while rejecting the claimed premium under another. The model therefore tracks qualified and unqualified sales separately, with the price and remedy specified for each.

Changes in compliance assumptions should be visible in the development schedule. The proposed assessment examines whether an expansion, replacement supply arrangement or commissioning delay changes the applicable evidence or transition treatment. The paper does not determine the legal status of a specific installation. Its purpose is to expose the relationship between electricity sourcing, dispatch freedom and saleable product classification so that the investment case can be updated when a verified compliance conclusion becomes available.

Table 6. EU electricity-qualification checks and proposed evidence ownership

Check	Rule location	Proposed evidence owner
Direct-connection case	Article 3	Electrical design and metering leads

Check	Rule location	Proposed evidence owner
Grid electricity route	Article 4	Compliance and power-procurement leads
Additionality	Articles 5 and 11	Development and legal leads
Temporal matching	Article 6	Metering and dispatch leads
Geographic conditions	Article 7	Market-access and legal leads

[9] identifies the legal routes and requirements; evidence ownership is a proposed project control.

10. Separate product qualification from lifecycle-emissions accounting

Renewable-electricity qualification and the fuel's emissions calculation require distinct evidence. Regulation 2023/1185 sets a methodology containing input, processing, transport, distribution and end-use terms, with the stated fossil comparator in its Annex. Commission guidance separately describes the RFNBO requirement for at least 70% greenhouse-gas savings. [10] [16] The proposed compliance record should retain the calculation boundary and source for each input, including energy consumed after the electrolyser. A renewable electricity label supplies only part of that record.

The UK uses its own identified standard. Version 4 sets a threshold of 20.0 grams CO₂ equivalent per MJ of hydrogen on a lower-heating-value basis, and a common 30-minute reporting unit. Its consignment and evidence provisions govern how relevant production is recorded. The parent publication guidance states that supported projects should use the version specified in their agreement. Those facts require a project to identify both its applicable version and its contract boundary before calculating qualifying revenue. [11]

For a proposed export arrangement, the diligence record should identify the destination scheme, the product being certified and the party responsible for maintaining the chain of evidence. A UK production record may be useful information for an EU buyer while leaving separate RFNBO requirements unresolved. The proposed model assigns no equivalence value to the two labels. A legal and certification review needs to establish which evidence transfers, which further measurements are required and who bears any shortfall in the customer's claimed product attributes.

Emissions-related promises also belong in the sale agreement's remedy structure. The proposed contract should state the relevant metric, the treatment of measurement corrections, any qualification cure period and the consequences of a customer using an invalid claim. A price adjustment, replacement delivery and termination right can have different cash effects. The investment record should calculate the consequences of the actual proposed remedy and its cap. Environmental performance reporting, physical product quality and credit support each address a separate contractual exposure.

11. Model support using its actual conditions and payment dates

Public support can change a project's receipts, provided the project qualifies and receives an effective award. The UK HAR2 shortlist notice explicitly distinguishes shortlisting from the availability of funding and describes further due diligence. That April 2025 notice establishes the status conveyed by that document; it supplies no current award conclusion for any listed project. [12] A proposed investment case should maintain separate scenarios for prospective support, executed support and receipts that have satisfied the contract's payment conditions.

The December 2025 HAR1 explanatory summary describes variable-premium price support and sliding-scale volume support. It states that zero monthly sales produce no subsidy for that month. It also warns that later rounds may have different terms and that the definitive LCHA prevails. [13] These boundaries matter when a producer models a complete buyer shutdown. The proposed cash-flow test represents both the interrupted commodity receipt and the applicable support response, using the actual agreement's definitions and qualifying volumes.

The Commission's May 2026 IF25 auction explanation likewise distinguishes invitation, completion guarantee, signed grant and implementation. It gives deadlines for financial close and operation, and links support to qualifying production. These are terms of the identified auction explanation, with the executed grant controlling an individual project. [14] A support amount should therefore enter the financing case with its conditions, timing and duration. Prospective support is carried separately until the relevant award and obligations are verified.

The proposed support ledger records the beneficiary entity, qualifying output, payment calculation, reporting evidence, audit rights and suspension or recovery provisions. It also identifies restrictions on combining support with other income. A financing model should examine delayed reimbursement and amounts subject to correction, as well as the period after support expires. The paper supplies no forecast award, subsidy rate or entitlement for an offshore project. Its investment test asks whether the remaining customer contract and cost base are credible under the specific support case being considered.

Table 7. Support milestones and permitted modeling treatment

Milestone	Evidence available	Proposed treatment
Application or shortlist	Eligibility-stage notice	Separate contingent scenario
Invitation to grant preparation	Further obligations and deadline	Model costs and remaining conditions
Signed support agreement	Project-specific obligations	Use actual calculation and term
Qualifying accepted production	Output and required records	Calculate contract entitlement
Cash received	Bank and settlement evidence	Reconcile receipt and adjustments

Proposed modeling classification grounded in the distinct stages described in [12]-[14].

12. Frame the investment decision around unresolved exposure

The proposed investment committee paper should identify the evidence that supports each revenue stream and the expenditure required to earn it. The electricity alternative, conversion system, delivery route and buyer readiness programme need one consistent schedule. The committee can then see which risks remain with the sponsor, which have contractual remedies and which depend on third-party infrastructure. Each material assumption has an owner, an evidence deadline and a defined effect on the financing case if it remains unresolved.

Approval conditions should be expressed in terms that can be checked. Examples include an effective landfall right, a completed customer interface design, a priced replacement schedule, an executed credit instrument and a documented product-qualification conclusion. A condition should identify the responsible reviewer and the evidence needed for satisfaction. The committee's approval can also cap the expenditure committed before those conditions are met. Those controls are proposed governance arrangements; the paper reports no observed improvement in project outcomes from applying them.

An operating evidence package should reconcile electricity input, hydrogen output, accepted deliveries, inventory, qualified consignments, invoices and cash. Exceptions should show whether the problem concerns physical performance, missing evidence, customer acceptance or

collection. Corrected meter readings should remain traceable to the original record and the affected claim or invoice. This proposed reconciliation allows management and financing parties to inspect the same quantities through successive stages without assuming that production, revenue recognition and payment occur together.

The resulting decision is conditional and project-specific. Electrolysis can add value in a hypothetical case when the incremental contracted receipts, verified support and avoided expenditure exceed the additional capital, operating cost and foregone electricity value. A different set of prices, interruptions or qualification constraints can reverse that result. The remaining sections examine those relationships through stated numerical assumptions. Any proposed investment still needs independent engineering, legal, environmental, tax and financing diligence, together with actual customer and infrastructure commitments.

13. Define the physical hydrogen boundary

The following exercise uses entirely authored hypothetical assumptions. Every wind profile, price, capital cost, operating cost, acceptance condition and financing input is specified solely for this numerical illustration. Normal and Adverse identify deterministic cases; they carry no probability, generation-percentile or market-calibration interpretation. The comparison starts with the same existing 100 MW wind asset. Its electricity-sale counterfactual is held constant while an incremental hydrogen conversion system, water handling, storage and delivery interface are considered. The conversion-system electrical-input ceiling is 20 MW, including the modelled compression duty. The \$32m aggregate hydrogen investment includes those facilities. Existing wind capital expenditure is outside this incremental decision.

Table 8 uses the twelve actual calendar months of 2027, totalling 8,760 hours. Monthly wind MW multiplied by calendar hours gives MWh. The 20 MW conversion-system electrical-input ceiling multiplied by hours and assumed system availability gives the monthly equipment-energy ceiling. This 20 MW covers the combined modelled electrolysis and compression electrical input. Normal availability is 95% except July at 80%; Adverse availability is 85% except July at 70%. Adverse grid prices are 1.4 times the Normal column and otherwise-curtailed wind is 2% in every month. Normal buyer acceptance support is 100%; Adverse support is 85%. These fractions constrain accepted monthly deliveries and represent no estimated default probability.

Table 8. Authored 2027 calendar and availability inputs

Month; hours	Normal wind MW	Adverse wind MW	Normal grid \$/MWh	Normal curtailed %	Normal plant %	Adverse credit %
Jan; 744	48	36	45	12	95	85
Feb; 672	46	34.5	43	10	95	85
Mar; 744	44	33	40	8	95	85
Apr; 720	40	30	38	6	95	85
May; 744	36	27	35	5	95	85
Jun; 720	32	24	32	4	95	85
Jul; 744	30	22.5	30	4	80	85
Aug; 744	32	24	34	5	95	85
Sep; 720	37	27.75	39	6	95	85
Oct; 744	42	31.5	43	8	95	85
Nov; 720	46	34.5	48	10	95	85
Dec; 744	49	36.75	50	12	95	85

Every value hypothetical. Conversion-system electrical-input ceiling 20 MW, including modelled compression; electrolysis plus compression 52 kWh/kg; 220,000 kg/month scheduled demand; Normal price \$5.50/kg; Adverse \$4.00/kg. Purchased externally supplied treated water \$2/m³; desalination, cooling and other auxiliary electrical duty excluded.

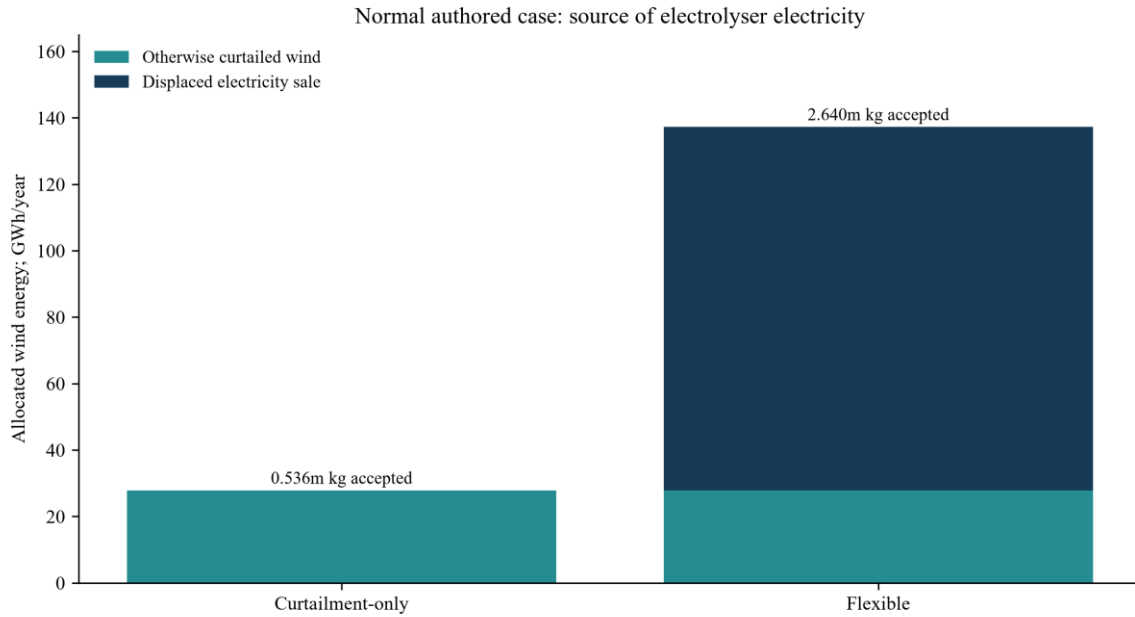
$$p_m = \frac{1000E_m}{e}; d_m = \min(D_m, x_{m-1} + p_m); x_m = x_{m-1} + p_m - d_m \quad (1)$$

Here p is production, d delivered and accepted hydrogen, x physical closing inventory, D the credit-supported acceptance ceiling and E allocated electricity. The modelled electrolysis-plus-compression intensity e is 52 kWh/kg: 50 for electrolysis plus 2 for compression. Dividing MWh by this intensity requires the 1,000 kWh/MWh conversion. Compression receives no additional electricity-cost line. The numerical case purchases externally supplied treated water at an assumed \$2/m³. Nonpower variable expenditure is \$0.40 per produced kg: \$0.02 purchased water, from 0.010 cubic metres, plus \$0.08 nonpower treatment and \$0.30 nonpower delivery. These assumed fees contain no additional electricity. Desalination, cooling and other process auxiliary electrical duties beyond the stated 50+2 kWh/kg are excluded. Detailed technical performance and auxiliary-duty requirements require later engineering; 52 kWh/kg represents only the specified model boundary. Fixed incremental expenditure is \$1.2m annually.

The Curtailment-only route allocates otherwise-curtailed monthly wind. Flexible dispatch uses that allocation first, followed by wind that could have earned grid receipts. Production is bounded by plant capacity, route-specific energy and storage headroom. Scheduled acceptance is 220,000 kg per month before the credit constraint. Storage holds at most 100,000 kg. A stated look-ahead rule limits target inventory to remaining accepted demand, draining stock by December; it uses the known authored schedule. No speculative terminal stock value is credited. Production, acceptance and invoicing remain separate quantities.

This monthly allocation is an aggregation assumption. It supplies no evidence that curtailed electricity and available electrolysis capacity coincide within each hour, that a storage or grid connection can perform the implied transfers, or that any regulatory matching test is satisfied. Dispatch follows the specified physical rule without hourly optimisation, start-up costs, degradation, hydrogen losses or an economic stop rule. Those omissions delimit the interpretation of Figure 1 and the subsequent financial comparisons.

Figure 1. Electricity allocation to hydrogen under Normal authored assumptions.



Hypothetical annual wind energy; 20 MW conversion-system electrical-input ceiling includes modelled compression; 52 kWh/kg covers modelled electrolysis plus compression only. Externally supplied treated water assumed; desalination, cooling and other auxiliary electrical duties excluded. Accepted volume labels follow constrained monthly dispatch.

14. Charge the electricity opportunity cost once

The electricity-sale counterfactual exports all wind except the specified otherwise-curtailed fraction. It earns the positive part of the stated grid price. The negative-price sensitivity assumes the asset can avoid selling at a negative price; no compulsory dispatch or penalty is modelled. Allocating otherwise-curtailed electricity to hydrogen therefore carries zero foregone-grid receipt in this exercise. Allocating exportable electricity reduces counterfactual receipts by allocated MWh multiplied by the corresponding monthly price. The remaining wind-sale receipt plus foregone receipt reconciles to the unchanged counterfactual in every month.

$$\Delta C_m = H d_m - \pi_m^+ [E_m - \min(E_m, C_m)] - v p_m - \frac{F}{12}; \Delta V = -(I + W_0) + CA(r, N) + \frac{W_T}{(1+r)^N} \quad (2)$$

In this definition H is the accepted hydrogen price, C_m otherwise-curtailed wind, π_m^+ the nonnegative grid price, v nonpower variable cost, and F annual fixed incremental cost. Annual C sums the twelve incremental operating-cash terms. $A(r, N)$ sums discounted annual payments. Initial uses are $I = \$32m$ hydrogen capital expenditure and $W_0 = \$2m$ working cash. Ten identical operating years are assumed at an 8% unlevered discount rate. $W_T = \$2m$ is an explicit terminal working-cash recovery, discounted to \$0.926387m; it carries no plant resale or hydrogen-inventory value. Removing that recovery reduces NPV by exactly its discounted amount. Adding \$1m capital expenditure reduces NPV by \$1m and leaves operating cash unchanged.

Table 9. Hydrogen routes versus wind-electricity sale; annual hypothetical results

Scenario / route	Accepted H2 mkg	System-input utilisation %	Foregone power \$m	Incremental OCF \$m	Unlevered NPV \$m
Normal / Curtailment-only	0.535625	15.898	0.000000	1.531686	-22.795878
Normal / Flexible	2.640000	78.356	4.234995	8.029005	20.801665
Adverse / Curtailment-only	0.101416	3.010	0.000000	-0.834902	-38.675872

Scenario / route	Accepted H2 mkg	System-input utilisation %	Foregone power \$m	Incremental OCF \$m	Unlevered NPV \$m
Adverse / Flexible	2.244000	66.603	6.148425	0.729975	-28.175419

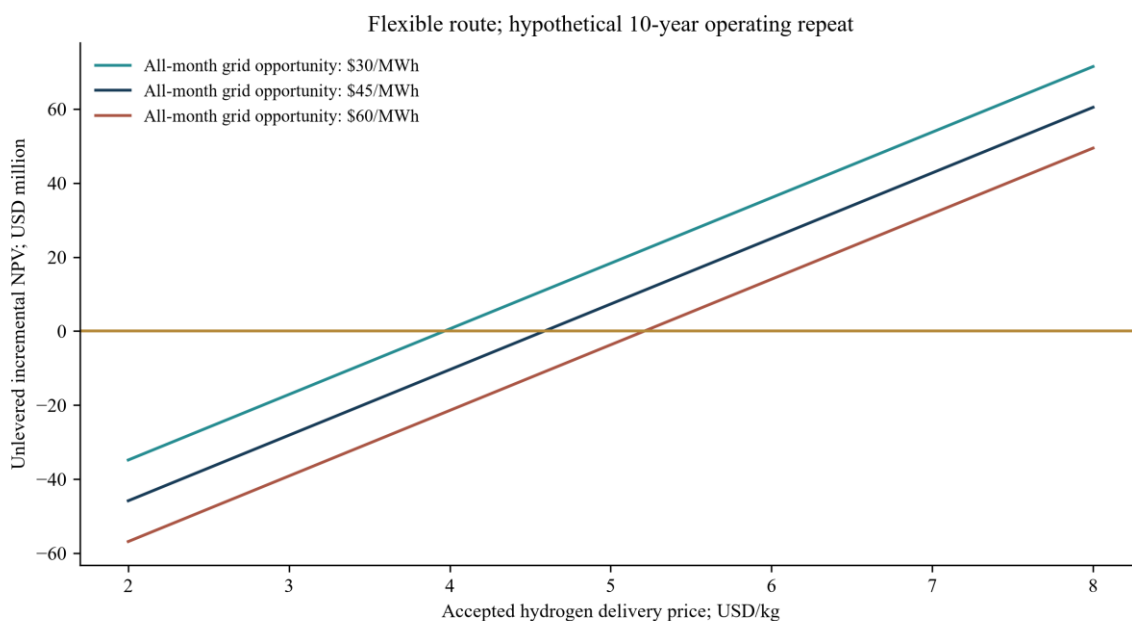
Incremental to unchanged wind-only plant. H2 capex \$32m plus \$2m initial working cash; ten identical operating years at 8%; \$2m terminal working-cash recovery.

Normal wind-only receipts are \$13.101723m. Flexible hydrogen retains \$8.866728m of these receipts and forgoes \$4.234995m. Accepted hydrogen invoices are \$14.520000m. Subtracting foregone electricity receipts, \$1.056000m nonpower expenditure and \$1.200000m fixed expenditure gives \$8.029005m incremental annual operating cash. The resulting \$20.801665m incremental NPV is conditional on the supplied physical and collection assumptions. It identifies value added to the unchanged wind counterfactual under this case.

Normal Curtailment-only production accepts 535,624.615 kg and earns \$1.531686m incremental operating cash; its \$22.795878m negative NPV shows that avoiding electricity opportunity cost alone does not recover the assumed incremental investment. Flexible utilisation is 78.356% of all calendar nameplate hours, while Curtailment-only utilisation is 15.898%. Availability and utilisation are separately calculated; installed capacity receives no assumed full-utilisation revenue.

Adverse Flexible foregone electricity rises to \$6.148425m while accepted hydrogen falls to 2.244m kg at \$4.00/kg. Incremental operating cash remains positive at \$0.729975m, with NPV negative \$28.175419m. The ten-year annual valuation assumes steady-state equivalence between invoices and operating collections, supported by the stated working-cash provision. The separate dated cash ledger in section 17 tests collection timing explicitly. Tax, subsidy, asset ageing, stack replacement and residual equipment value are excluded from the valuation; no project forecast is supplied. Figure 2 varies hydrogen and grid prices within this same bounded calculation.

Figure 2. Flexible-route incremental value versus accepted hydrogen price.



Hypothetical ten-year repeat at 8%; each curve replaces all monthly grid prices with the stated value; all other Normal assumptions retained.

15. Test the minimum offtake price and volume

An offtake test requires a specified accepted volume, price and ability to support deliveries. For a fixed dispatch path, the zero-NPV price divides required annual capital recovery plus foregone electricity and operating expenditure by accepted kg. The formula is undefined when accepted volume is zero. Zero accepted demand produces zero hydrogen invoices and retains fixed expenditure; no deemed invoice, cancellation compensation or take-or-pay cash is introduced.

$$H^* = \frac{\frac{I+W_0 - \frac{W_T}{(1+r)^N}}{A(r,N)} + O + vP + F}{Q} \quad (3)$$

Q sums delivered and accepted kg, P produced kg and O foregone-grid receipts. The Normal Flexible fixed-dispatch threshold is \$4.325734/kg at 2.640m accepted kg. Curtailment-only requires \$11.842610/kg at its much smaller accepted quantity. These values use precisely the same capital, terminal recovery and discounting assumptions as Table 9. A price threshold is conditional on retaining that physical dispatch; it cannot establish feasibility at another volume without recalculation.

Table 10. Zero-NPV offtake tests under Normal physical assumptions

Route	Zero-NPV price \$/kg	Minimum scheduled mkg/year	Accepted mkg at threshold	Minimum credit %
Curtailment-only	11.842610	No feasible volume	Not applicable	No feasible fraction
Flexible	4.325734	1.659964	1.659964	62.877434

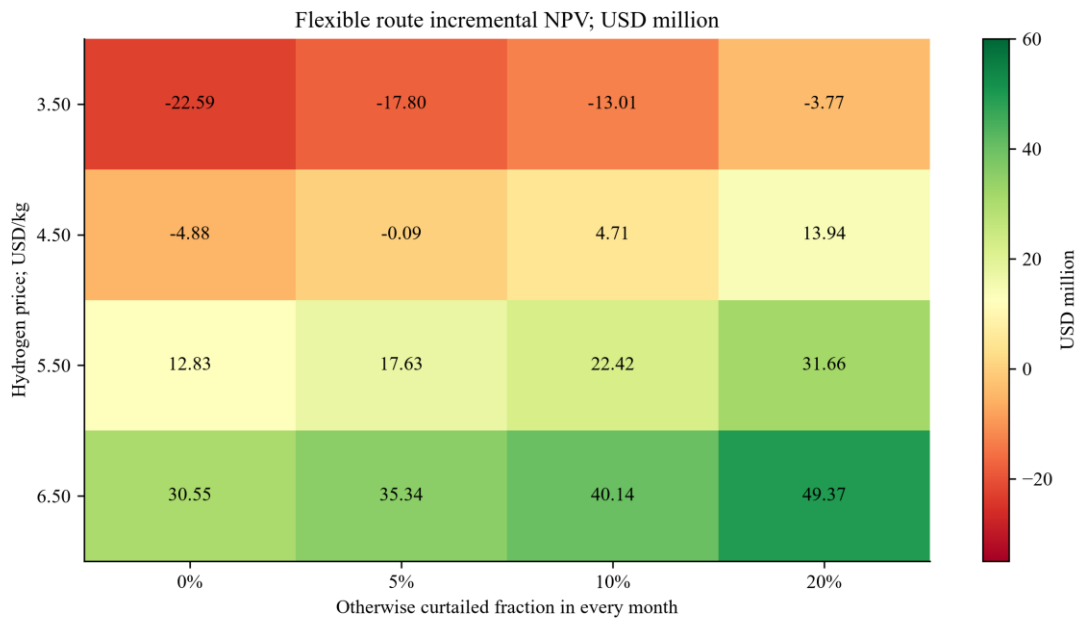
Price threshold holds dispatch fixed. Volume and credit thresholds re-run physical dispatch at \$5.50/kg; credit test retains 2.64m kg scheduled demand. Fractions describe hypothetical acceptance support, not default probabilities.

The volume and credit tests therefore repeat the monthly physical calculation at each candidate quantity. A numerical bisection locates zero NPV at the hypothetical \$5.50/kg price. Flexible requires 1.659964m kg scheduled and accepted annually under full support and a uniform monthly schedule. Holding the 2.640m kg annual schedule fixed instead requires a uniform credit-supported acceptance fraction of 62.877434%. Both computations reach the same accepted quantity in this supplied case. Their correspondence reflects this model's capacity and schedule assumptions and supplies no universal conversion between credit quality and volume.

Curtailment-only has no feasible annual scheduled-volume threshold at \$5.50/kg under the Normal wind assumptions. Increasing scheduled demand leaves production bounded by 27,852.480 MWh of otherwise-curtailed wind, or 535,624.615 kg. Its high-demand NPV remains negative. A larger nominal offtake contract cannot create electrical supply or production capacity. Flexible high-demand accepted output is also finite at 3.157846m kg; plant availability and calendar hours eventually bind.

Figure 3 recalculates NPV across hydrogen prices and otherwise-curtailed fractions. Each curtailment sensitivity replaces every month's fraction while preserving monthly wind and grid-price assumptions. The resulting grid-revenue opportunity is charged once. The matrix measures conditional model responses and contains no estimate of future curtailment. Figure 4 separately shows the price required when credit-supported accepted-delivery capacity changes. A contract review would need verified product quality, metering, acceptance, nomination, logistics and credit provisions before relating an actual contract to these assumed quantities. No legal enforceability or buyer creditworthiness conclusion is drawn here.

Figure 3. Hydrogen price and otherwise-curtailed wind sensitivity.



*Hypothetical USD million NPV; curtailment percentage replaces every month; Normal monthly grid prices retained.
Monthly aggregation cannot prove hourly matching.*

16. Separate project value from debt capacity

The financing illustration uses the smaller of the Normal and Adverse annual incremental operating-cash results for each route. It divides the positive part by an authored 1.30 coverage factor to obtain a hypothetical level annual debt-service ceiling. Discounting ten annual payments at an illustrative 6% produces a debt-capacity calculation. These are chosen arithmetic parameters; they are neither lender requirements nor quoted financing terms. The two cases have no empirical confidence level, and the minimum is a stated-case constraint.

$$a^* = \frac{\max(0, \min_j C_j)}{k}; B = a^* A(i, n); S = \alpha a^*; Z = I + W_0 + S - B \quad (4)$$

In the equation a^* is annual service, B debt, S initial restricted service reserve and Z equity. The reserve is half the sized annual service. Equity funds the \$32m hydrogen capital expenditure, \$2m initial working cash and service-linked reserve after the debt source. Sources and uses reconcile together, including this reserve feedback. The reserve does not enter the earlier unlevered operating cash or project NPV. Changing debt rates, coverage or reserve fractions leaves those earlier results unchanged in the implemented checks.

Table 11. Separate conditional debt and reserve funding; USD million

Route	Limiting OCF	Annual service	Debt source	DSRA use	Equity source	Sources / uses
Curtailment-only	-0.834902	0.000000	0.000000	0.000000	34.000000	34.000000
Flexible	0.729975	0.561519	4.132832	0.280760	30.147928	34.280760

Authored 1.30x minimum stated-case OCF coverage; 6%; ten annual payments. DSRA half sized annual service. No gearing cap or lender commitment.

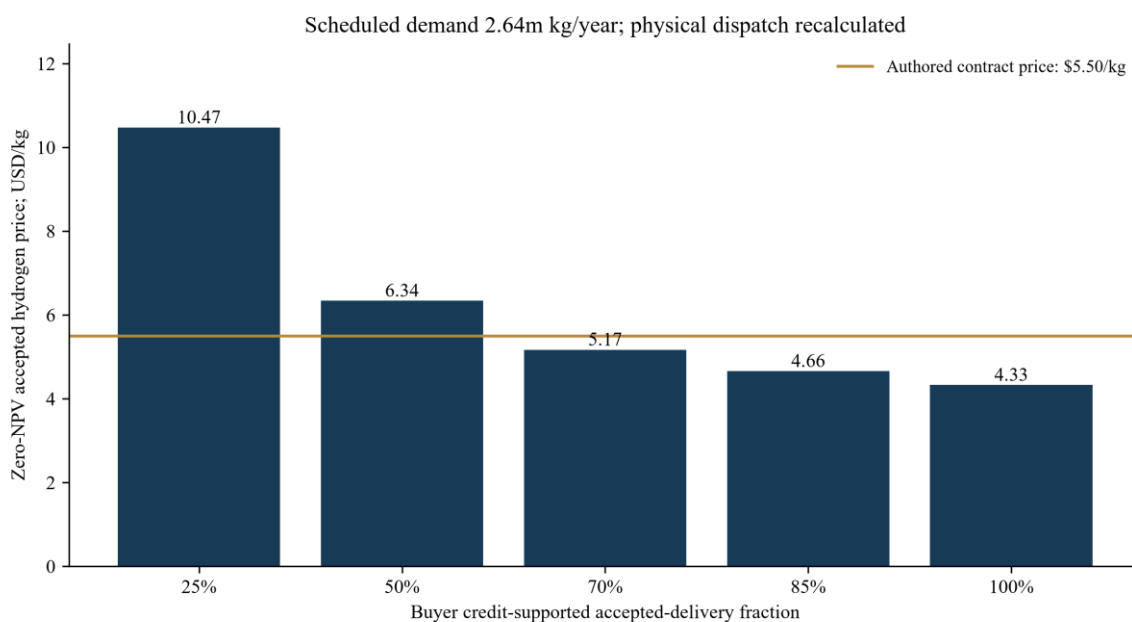
Flexible limiting cash is \$0.729975m, supporting \$0.561519m annual service and \$4.132832m debt under the assumed annuity. Its \$0.280760m reserve raises total financing uses to \$34.280760m. Equity is \$30.147928m. Curtailment-only limiting operating cash is negative \$0.834902m. Applying the nonnegative-service boundary produces zero supported debt and zero

service-linked reserve; equity funds \$34.000000m of uses. A zero-cash case also produces zero supported debt. No negative debt source is permitted.

Positive Normal Flexible incremental NPV and comparatively small stated-case debt capacity answer different questions within these calculations. The valuation uses Normal operating cash discounted at the selected project rate. The financing illustration limits service against both supplied cases. Adverse Flexible operating cash is positive while its incremental NPV remains negative because that cash is insufficient to recover the investment at the selected discount rate. Financing proceeds receive no treatment as incremental economic revenue or as an addition to NPV.

Actual financing analysis would require project-specific taxes, maintenance and replacement expenditure, reserve rights, debt maturity, repayment shape, security, working-capital arrangements and contracted revenues. None is verified by this illustration. The simple operating-cash measure is a pre-tax proxy and carries no representation that a lender would accept it as CFADS. Figure 4 relates credit-supported delivery capacity to the accepted price needed for project value; it grants no borrowing availability. The monthly debt-service test that follows is a separately specified cash stress and uses its own disclosed payments.

Figure 4. Accepted-delivery credit availability and zero-NPV price.



Hypothetical acceptance-capacity fractions; physical dispatch recalculated; no probability interpretation or lender commitment.

17. Follow accepted deliveries into dated cash

The separate 2027 liquidity example is a standalone electrolyser-SPV ledger with \$0.5m opening unrestricted cash and \$1m restricted DSRA. Buyer support is zero in May and June, 50% in July and full in other months. Previously issued invoices remain collectible under the assumed two-month lag. Every new invoice equals actual delivered and accepted kg times \$5.50; unsupported volume creates no invoice. Opening receivables and inventory are zero. The plant stores up to 100,000 kg before the interruption and stops producing when storage headroom and current acceptance are exhausted.

$$J_m = H_{d_m}; R_m = J_{m-2}; AR_m = AR_{m-1} + J_m - R_m; L_m = L_{m-1} + R_m - P_m - M_m + T_m \quad (5)$$

J is invoiced revenue, R actual receipts, AR receivables and L unrestricted cash before new financing. P includes actual wind-transfer payments, nonpower and fixed operating payments, replacement fees and debt service. The wind transfer invoice is priced at the specified foregone-grid receipt; it is the SPV's cash payment for that electricity. The consolidated incremental valuation charges that same opportunity once. A second consolidated electricity invoice is excluded. Capital expenditure is assumed pre-funded before this operating-year ledger and is absent from its monthly cash payments.

Table 12. Separate dated electrolyser-SPV cash and inventory path

Date	Made / accepted tkg	Closing stock tkg	Invoice / receipt \$m	Receivables \$m	Unfunded cash \$m	With bridge \$m
2027-01-31	271.846 / 220.000	51.846	1.210000 / 0.000000	1.210000	-0.152014	2.553607
2027-02-28	245.538 / 220.000	77.385	1.210000 / 0.000000	2.420000	-0.766331	1.939289
2027-03-31	242.615 / 220.000	100.000	1.210000 / 1.210000	2.420000	-0.153262	2.552358
2027-04-30	220.000 / 220.000	100.000	1.210000 / 1.210000	2.420000	0.499682	3.205302
2027-05-31	0.000 / 0.000	100.000	0.000000 / 1.210000	1.210000	-1.390318	1.315302
2027-06-30	0.000 / 0.000	100.000	0.000000 / 1.210000	0.000000	-1.280318	1.425302
2027-07-31	110.000 / 110.000	100.000	0.605000 / 0.000000	0.605000	-2.169134	0.536486
2027-08-31	220.000 / 220.000	100.000	1.210000 / 0.000000	1.815000	-2.705621	0.000000
2027-09-30	220.000 / 220.000	100.000	1.210000 / 0.605000	2.420000	-1.172443	1.533178
2027-10-31	220.000 / 220.000	100.000	1.210000 / 1.210000	2.420000	-0.534870	2.170751
2027-11-30	220.000 / 220.000	100.000	1.210000 / 1.210000	2.420000	0.096986	2.802607
2027-12-31	120.000 / 220.000	0.000	1.210000 / 1.210000	2.420000	0.065722	2.771343

Hypothetical 2027 month-end netting; two-month collections; May/June no accepted deliveries; \$0.5m opening cash; \$1m opening DSRA excluded. USD million and thousand kg.

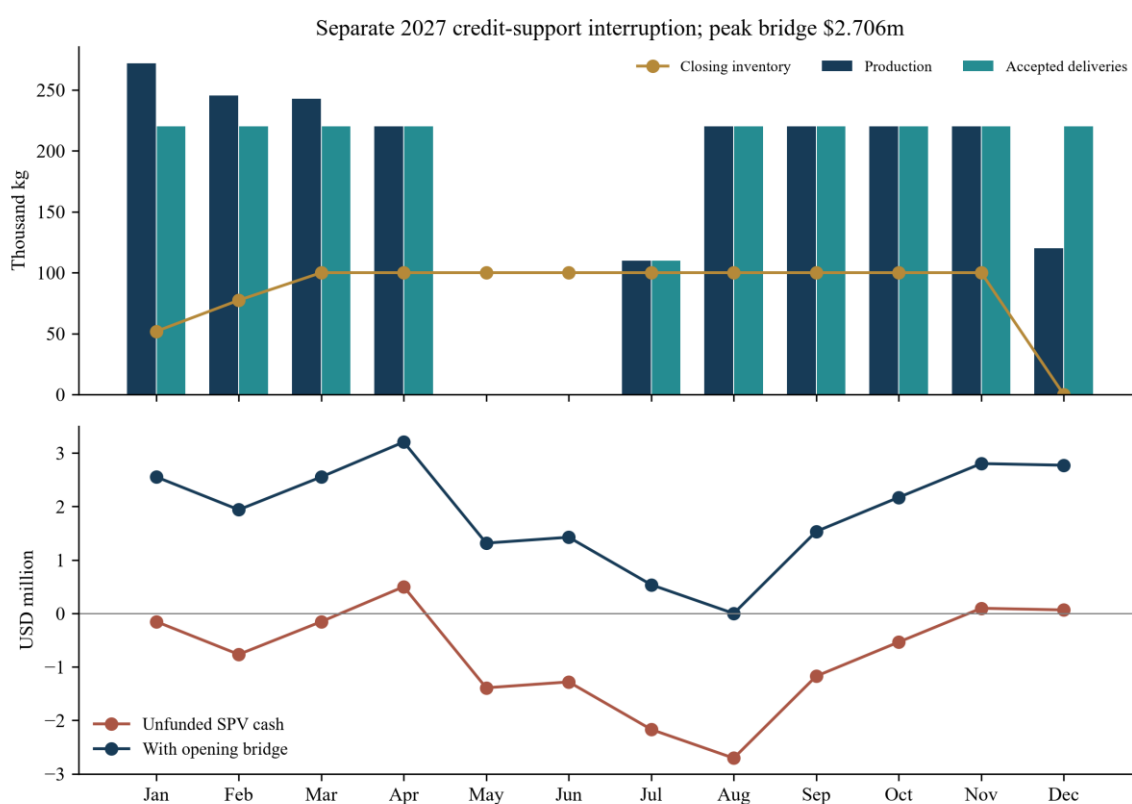
The SPV posts \$3m collateral in May and recovers \$1.5m in September. It pays an assumed \$0.6m counterparty/contract replacement administration cost in July and \$1m debt service in each of June and December. This administration cost is specified solely for the numerical liquidity illustration, with no actual fee quotation. Equipment stack replacement remains excluded from the project valuation. The annual \$2m service stress is deliberately separate from Table 11's sized service. Restricted opening DSRA is excluded from unrestricted cash and receives no assumed draw. Same-date month-end receipts and payments are netted; the example cannot establish an intramonth or intraday funding maximum.

Production and acceptance are both zero in May and June, with inventory remaining 100,000 kg. Cash receipts nevertheless remain \$1.21m in each month because March and April accepted deliveries are being collected. July accepts 110,000 kg and issues a \$0.605m invoice; its receipt arrives in September. August cash reaches negative \$2.705621m before new funding. An opening bridge of that amount leaves minimum month-end unrestricted cash at zero. The bridge remains

unrepaid in the displayed path; its interest and fees are excluded, so the funded closing balance is not distributable surplus.

December drains physical stock to zero, leaving \$2.420000m receivables and \$1.500000m posted collateral outstanding. Neither asset is converted into year-end cash. Unfunded closing cash is \$0.065722m; with the unrepaid opening bridge it is \$2.771343m. The valuation's separate year-ten working-cash recovery assumes actual release at that endpoint and does not accelerate these December receivables. The implemented selfchecks reconcile stock, accepted invoices, lagged receipts, receivables, collateral, unrestricted cash, bridge funding and financing sources/uses. These arithmetic checks establish consistency within the supplied assumptions; hourly operations, credit enforceability and real project viability remain outside the evidence provided by this model.

Figure 5. Separate 2027 SPV inventory and dated cash example.



Hypothetical month-end netting; credit interruption constrains deliveries and production; receipts follow actual invoices by two months; bridge remains unrepaid.

18. Contract terms that carry the hydrogen revenue

The offtake contract should make the model's accepted deliveries and collection dates enforceable. The investment committee should ask counsel to trace one consignment through measurement, acceptance, invoicing, dispute and collection. An annual tonnage and headline price leave those transitions unresolved.

Start with the delivery point and product specification. Pressure, purity and permitted contaminants affect processing cost and the buyer's ability to use hydrogen. The contract needs an agreed meter, calibration procedure, measurement interval and response to conflicting records. Acceptance should have a defined response period and a method for resolving an off-specification event. Storage capacity and an alternative disposal route should be assessed against

the period during which the buyer can reject product. The base financial case should exclude rejected kilograms unless another identified buyer can accept them under executable terms.

Minimum purchase obligations require careful treatment of exceptions. A buyer may agree to a nominal floor while retaining broad rights to suspend nominations during its own plant outage, commissioning delay or force majeure. The cash-flow case should reflect the surviving payment obligation in each event. Take-or-pay receipts, where legally enforceable and credit-supported, need their own contractual payment line and conditions. They should remain separate from the physical delivery revenue used in the worked model. The institutional financing literature identifies the difficulty of replacing a specialised hydrogen buyer; a substitute-buyer assumption requires evidence of compatible infrastructure and demand. [15]

Test the proposed price formula against the retained power opportunity cost, transport charges and replacement expenditure. Indexation can introduce basis risk when its reference differs from actual costs. Recalculate the adverse case with the agreed caps, floors, reset dates and index-discontinuation provisions.

Table 13. Offtake terms and the evidence required for underwriting

Contract term	Evidence to obtain	Model treatment	Closing consequence
Product and delivery point	Agreed purity, pressure, meter and interface drawings	Include processing and delivery cost at the same boundary	Resolve specification gaps before equipment commitment
Minimum purchase	Executed floor and each exception or relief event	Model the surviving cash obligation by event	Exclude unsupported minimum revenue
Acceptance and rejection	Testing protocol, dispute timetable and off-specification route	Separate produced, accepted and rejected kilograms	Size storage against rejection exposure
Payment and security	Invoice dates, grace periods and usable credit support	Use collection dates and stressed recovery assumptions	Match liquidity to the payment exposure
Price indexation	Complete formula, reset dates, caps and fallback index	Recalculate actual net margin under each scenario	Resolve unhedged cost and index basis
Buyer readiness	Conversion works, permits and commissioning dependencies	Delay deliveries when the receiving facility is unavailable	Align long-stop dates and funding obligations
Termination and assignment	Compensation, lender rights and transfer consent requirements	Separate enforceable recoveries from residual value assumptions	Obtain approvals needed for financing and sale

Proposed diligence framework. Contract enforceability, available security and actual buyer obligations require transaction-specific legal and credit review.

19. Capital commitments and cash controls

Capital should be committed against identifiable construction and operating evidence. An electrolyser purchase, a hydrogen pipeline and the buyer's conversion works can reach completion on different dates. Drawdown conditions should identify which party funds the cost of this mismatch and whether the financing remains available after a material delay. A reserve described as a contingency should have a specified owner, funding date, permitted use and replenishment obligation. Its treatment in sources and uses should correspond to the cash ledger.

Separate the wind project's existing debt restrictions from the proposed hydrogen financing. Diverting electricity can affect the wind project's contracted delivery, security package and distribution capacity. A transfer price between two project companies needs an executed intercompany agreement and consent under the relevant finance documents. Consolidated

investment valuation should recognise the actual external receipts lost by diverting power. Standalone solvency should recognise the cash invoices due between entities. Both views are needed, with the intercompany amounts eliminated only in the consolidated analysis.

The cash waterfall should identify unrestricted operating cash, restricted debt reserves, collateral and distribution accounts. A deposit in a restricted reserve cannot fund an ordinary supplier invoice unless the relevant release condition permits it. A letter of credit should be assessed by its beneficiary, expiry, drawing conditions and issuer exposure. The model's minimum cash requirement should remain visible after adding debt service and any collateral posting. Funding that requirement through shareholder support requires an enforceable commitment and a credible funding source.

The worked cases omit support receipts. A later supported case should retain the unsupported comparison and identify its executed award, qualifying production and collection assumptions.

20. Valuation in an acquisition or joint venture

An acquisition should distinguish the value of an operating wind asset from the proposed hydrogen investment and any development rights. Combining them into one enterprise-value multiple obscures the incremental capital required to make the hydrogen route usable. A buyer can reconcile the valuation through separate cash flows for existing electricity sales, committed hydrogen operations and contingent expansion. The sum should include the shared costs and the electricity revenue sacrificed by the hydrogen route exactly once.

Development rights require evidence of transferability, duration and conditions. Relevant documents can include the seabed or site arrangements, generation and export permissions, pipeline access, water arrangements, support award and customer agreement. An exclusivity arrangement with a prospective buyer can restrict alternative sales without providing a minimum revenue obligation. The acquisition review should identify which rights continue following a change of control and which depend on consent, financial close or construction milestones. No development premium is assumed in this paper.

In a joint venture, the contribution of power should be valued consistently with the external electricity alternative. The contribution of customer access should be linked to an executable contract and the associated credit exposure. Shareholder reserved matters should address dispatch priority, additional capital, related-party pricing and the response to a buyer outage. A majority interest in one entity does not establish control of the entire production and delivery chain. Valuation should follow the actual rights and cash flows conveyed.

Subject to legal and tax advice, proposed contingent consideration could reference an executed offtake, effective support agreement or completion test. Each event needs a definition, outside date and treatment of partial satisfaction. No seller or lender acceptance is established here.

21. Procurement and integrated completion tests

Procurement should translate the financial model's system boundary into a performance schedule. Electricity consumption stated for the electrolyser stack needs reconciliation to the full electrical input required at the agreed hydrogen delivery point. Compression, drying, cooling, water treatment and other auxiliaries require explicit inclusion or separate allowances. The model uses

an authored 52 kWh per kilogram boundary comprising 50 kWh for electrolysis and 2 kWh for compression. It does not represent a vendor guarantee or a measured offshore operating result.

Equipment guarantees should identify the load range, inlet conditions, delivery pressure, purity and test duration. An annual average efficiency figure can conceal poor performance at the loads most frequently produced by the wind farm. The detailed design needs a jointly usable wind profile, electrolyser operating map and storage dispatch model. Availability calculations should distinguish scheduled maintenance, equipment failure, power unavailability and delivery restrictions. Each cause should have a responsible party and a consequence under the relevant contract.

Completion should include an integrated demonstration of the route to the buyer. A test at the electrolyser outlet provides limited evidence about a downstream compressor, pipeline or receiving facility. The agreed test plan should cover meter reconciliation, product acceptance, restart behaviour, relevant safety functions and the handling of an interrupted delivery. The parties need a documented response when one component passes its individual test while the combined chain cannot supply accepted hydrogen.

The ten-year valuation excludes a separately specified stack replacement programme. A project appraisal needs a dated plan for renewal, marine access, spare parts and compressor overhauls. Asset life, offtake duration, support duration and warranty coverage require separate verification.

22. Data required to operate and verify the investment

The operating dataset should connect time-stamped generation, electrical input, hydrogen output, storage movements, accepted deliveries, invoices and receipts. Each record needs its own unit and boundary. Electrical input in MWh should reconcile to hydrogen production using the relevant performance assumptions; inventory should reconcile opening stock, production, deliveries and measured losses. The buyer's accepted quantity should reconcile to the invoice, followed by the actual cash receipt and any deductions. Exception reports should identify the originating record and the person responsible for its resolution.

Separate commercial dispatch from regulatory qualification. An economic model can recommend using an available MWh while the applicable certification or support rules impose additional conditions. The worked monthly aggregates illustrate economic relationships and do not demonstrate hourly or half-hourly matching. A project implementation needs the time resolution, source evidence and verification procedures required by its actual regime. Keep excluded or disputed consignments outside the premium revenue case until their treatment is established.

Forecasting tools can support operating decisions when their outputs are tested against measured data. A proposed wind forecast or price signal should be evaluated for the decision it affects, including storage congestion, nomination deadlines and contractual dispatch limits. Automated recommendations should not change the offtake terms, claim eligibility or book a receipt. The project should retain the input version, proposed action, approval and resulting measured outcome so that operating improvements can be distinguished from changes in assumptions.

23. An implementation sequence for the investment decision

The proposed sequence begins with the electricity alternative and the receiving customer. Establish the existing route to market, the volumes that would genuinely be curtailed and the

buyer's feasible demand at the delivery boundary. Then compare complete hydrogen configurations using consistent output specifications and cost boundaries. The sequence below is a decision roadmap, not an observed construction schedule or a commitment to complete a project within a stated period.

Table 14. Proposed implementation roadmap and decision evidence

Stage	Decision evidence	Proposed accountable function	Investment consequence
Define alternatives	Electricity sales baseline, constrained output and receiving customer requirements	Sponsor and commercial team	Select options for comparable engineering study
Resolve configuration	Common delivery point, performance boundary, logistics and permits	Technical adviser and project team	Freeze the scope used for cost and output modelling
Contract revenue	Accepted volumes, payment dates, relief events and usable credit support	Commercial team with legal and credit advisers	Replace expressions of interest with executable inputs
Confirm qualification	Applicable rules, meter design, certificates and support agreement conditions	Compliance team and appointed verifier	Establish which volumes and receipts can enter the supported case
Commit funding	Integrated completion tests, reserves, sources and uses and downside cash	Sponsor and financing parties	Set funding conditions and limits on early commitments
Operate and reassess	Reconciled production, acceptance, receipts and model variance records	Operations and finance teams	Update dispatch and capital decisions using measured performance

Authored sequence for investment preparation. Actual owners, timing, approvals and conditions must be agreed for the transaction.

Each stage should update the affected cash flows and record the evidence behind material changes before further expenditure is committed.

24. Conclusions and limits of the hydrogen offtake test

The investment case depends on accepted hydrogen revenue exceeding incremental costs and the electricity value sacrificed, within a delivery chain that can operate and collect cash. The worked scenarios demonstrate how a change in curtailment, buyer acceptance, price and payment timing can alter that result. Their numerical outputs are conditional on authored assumptions. They provide a reproducible investment test and do not establish a market price, a financeable debt amount or an actual project's return.

The principal limitations are monthly time resolution, simplified performance and authored wind and price vectors. Transaction-specific engineering quotes, replacement schedules and contracts remain necessary. Recalculate the electricity alternative, accepted-volume case and dated cash ledger using those verified inputs.

An investment committee can use the framework to identify the next evidence required. If value depends on unsold hydrogen, unsupported curtailment or cash that remains tied up in receivables, the unresolved dependency should change the proposed commitment. Where the complete chain has documented performance, demand, qualification and funding, the project can proceed to a transaction-specific approval on that evidence.

Frequently Asked Questions

What is the first test before adding electrolysis to offshore wind?

Define the customer's product, delivery point, quantity schedule and payment obligation. Then compare the complete hydrogen chain with the credible electricity alternative using consistent boundaries. The proposal needs evidence for the buyer's readiness and credit as well as for production.

Can constrained wind electricity be assigned zero value?

A hypothetical case can assume zero alternative receipt for specifically identified intervals. Actual analysis needs the export constraint, any compensation or contractual receipt, physical access to that power and the duration of availability. Wind capital and the added hydrogen system still need funding.

Does a 2026 electrolyser target establish a current equipment quote?

DOE's published table identifies technology-development targets and excluded installation costs. A project needs its supplier's actual priced scope, system boundary, performance guarantee and operating conditions. A target year supplies no verification of commercial delivery. [4]

Does EU monthly matching continue throughout a project's life?

Article 6 moves from monthly matching through 2029 to hourly matching from 2030, with specified exceptions. Transaction review must establish the applicable route and national rules. [9]

Does UK hydrogen support cover a month with no sales?

The identified HAR1 explanatory summary states that zero monthly sales receive no subsidy for that month. The executed LCHA and its qualifying-volume conditions determine the project's entitlement. Later-round terms need their own review. [13]

Does a physically deliverable kilogram automatically earn a renewable premium?

The proposed contract needs both physical acceptance and the environmental evidence required for its specified product. Qualification and pricing can fail independently. The model should distinguish accepted physical volumes, qualifying sales, amounts invoiced and cash collected.

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About the Author

Chennakeshav (CK) is a corporate finance and investment banking executive with 25+ years of global experience in deal origination, structuring and execution across M&A, growth capital and corporate strategy. He has led value-creation mandates for founders, corporates and funds — bridging the boardroom view to hands-on execution and close.

His career spans Morgan Stanley, HSBC, Lloyds Banking Group, EWEC, ADQ portfolio companies and Emirates Growth Fund, across TMT, real estate, fintech, deeptech, cleantech, infrastructure and energy. He has partnered with C-suite leaders, private equity and venture funds, sovereign wealth funds and family offices to finance complex fund raises and scale-up ventures, and has led M&A due diligence, post-merger integration and business-transformation initiatives to create value.

At Matchpoint Partners he is Managing Partner, leading the firm's corporate finance, M&A and capital-raising practice. He holds an MBA from London Business School, an engineering degree from VTU and a Master of Laws (LLM, in progress) from UCL London.

An active start-up mentor, CK mentors at Techstars, DIFC FinTech Hive, Startup Grind, Founder Institute and IN5, serves as Entrepreneur Mentor in Residence (EMiR) at London Business School, and judges the Entrepreneurship World Cup.

<https://www.linkedin.com/in/ckadya/>

<https://www.matchpoint-partners.com/team/ck-adya.html>

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