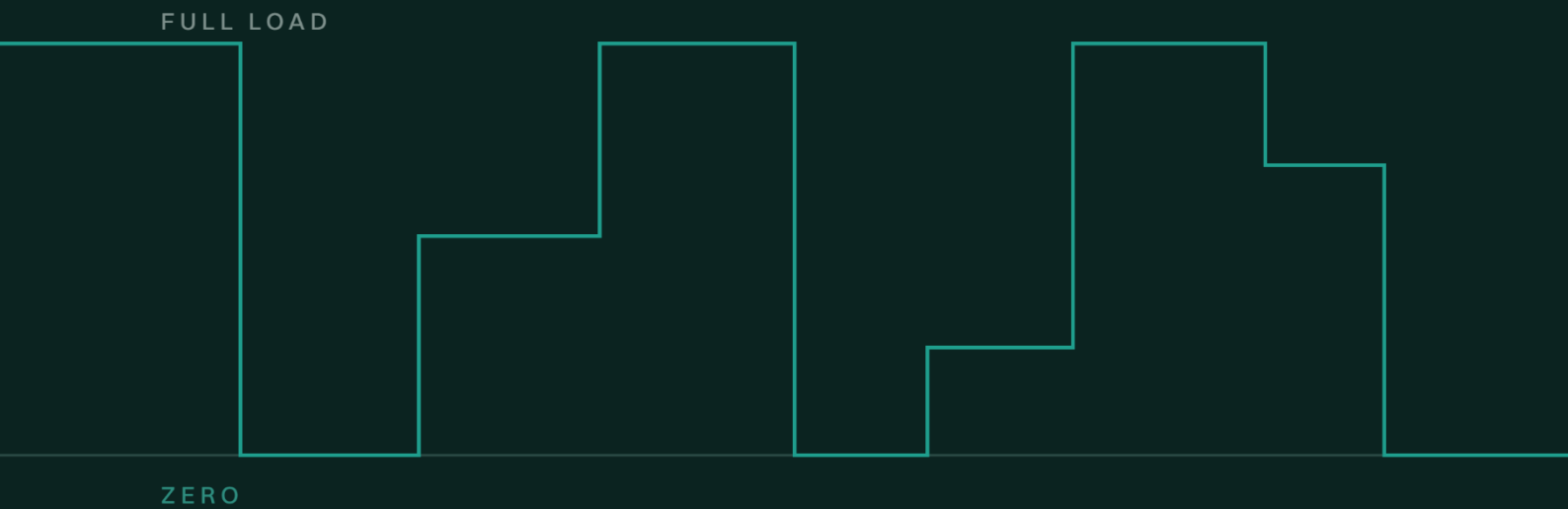




WHITEPAPER

Why electrolyzers must be fully flexible

Carbon footprint, RFNBO compliance and business case viability

Arvin Tavanaei and Rene de Milliano, Alquion

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Executive summary

For a grid-connected electrolyser, the share of output that can be declared RFNBO compliant is what decides the business case. RFNBO hydrogen counts toward the RED III reduction targets, which gives it a market and a premium price. In order to be RFNBO compliant, the produced hydrogen must meet the requirements set out in the delegated regulations, including a 70 percent carbon reduction and hourly matching of renewables generation versus consumption from 2030. Hydrogen that misses the threshold loses access to the certification and associated price premium. In 2025 certified RFNBO volumes traded between 7 and 10 EUR/kg against just over 2 EUR/kg for grey hydrogen.

An electrolyser plant will encounter hours in which its own renewable supply via power purchase agreement (PPA) falls short, these hours are both the most expensive and have the highest CO₂ emission. Conventional alkaline stacks cannot run below a minimum load, typically 20 to 30 percent of nameplate capacity. To meet this minimum load requirement, it will either draw from the grid or shut down the stack. Two options with significant downsides. A small grid share disqualifies everything produced in that hour, as RVO's certification guidance sets out [4]. Those hours averaged around 100 EUR/MWh in the Netherlands and Germany in 2025, so the power bill goes up in the same hours the hydrogen loses its price, which makes that output loss-making most of the time. The carbon result is no better. Implied carbon intensity in those hours averaged 14.1 kg CO₂ per kg H₂ in the Netherlands and 19.9 kg in Germany, against 9 to 11 kg for unabated SMR, so the hydrogen is dirtier than the route it is meant to replace.

The alternative is shutting the stacks down when renewable supply is not available, resulting in irreversible damage to the electrodes due to reverse current and reducing the lifetime and efficiency of the stack with each start/stop sequence. An operator would be choosing between an hour that produces non-RFNBO hydrogen and a stack that reaches the end of its life sooner. Avoiding both requires a technology that can shut down completely without degrading.

Techno-economic modelling shows full shutdown capability is worth close to eight percentage points of project IRR, an uplift of 82.2 percent. For a 100 MW grid-connected reference project with offshore wind PPA, an alkaline plant with a 30 percent minimum load returns a project IRR of 9.5 percent, one with a 20 percent minimum load returns 12.4 percent, and a plant that can shut down to zero returns 17.3 percent. Capital and fixed costs are similar in all three cases.

Flexibility has further value that this paper describes but does not quantify, such as easing grid congestion where offshore wind comes ashore and using hours that a wind farm would otherwise curtail.

Headline results

1. Project IRR rises from 9.5 percent at a 30 percent electrolyser minimum load, and 12.4 percent at a 20 percent minimum load, to 17.3 percent with no minimum load, on a 100 MW grid-connected reference project with comparable capital and fixed costs.
2. Non-compliant hours in the Netherlands and Germany averaged 101 to 104 EUR per MWh in 2025, so the output that cannot be declared is also the output that costs the most to make.
3. Implied electrolysis carbon intensity in those hours averaged 14.1 kg CO₂ per kg H₂ in the Netherlands and 19.9 kg in Germany, against 9 to 11 kg for unabated SMR and a 3.39 kg RFNBO ceiling.

Introduction

Renewable hydrogen producers in Europe increasingly face a choice between maintaining the technical minimum load by drawing expensive and high-carbon electricity from the grid or shutting off the stacks in the absence of qualifying renewable electricity. Under Directive (EU) 2018/2001 as recast by Directive (EU) 2023/2413 (RED III) and its implementing regulations [1], only hydrogen produced from electricity that meets strict temporal and geographical correlation criteria can be counted as a Renewable Fuel of Non-Biological Origin (RFNBO) and issued a Proof of Sustainability. The hydrogen must also save at least 70 percent of the greenhouse gas emissions of the fossil comparator.

This paper argues that a project's RFNBO share is what decides its business case, and that reaching a full share depends on how the plant behaves in the hours when compliant renewable electricity is unavailable. Those hours are expensive on the day-ahead market, and hydrogen made in them cannot be declared, so the output that costs the most to produce is also the output that earns the least. It is also dirtier than the unabated steam methane reforming (SMR) that RFNBOs are meant to displace [5, 6, 7].

What RFNBO compliance requires

RFNBO status attaches to the electricity used rather than to the plant. The relevant instruments are RED III Article 27(6) [1], Delegated Regulation (EU) 2023/1184 on temporal and geographical correlation and additionality [2], and Delegated Regulation (EU) 2023/1185 on the greenhouse gas saving methodology [3]. As the Netherlands Enterprise Agency (RVO) sets out in its January 2025 guidance [4], a grid-connected electrolyser on a Power Purchase Agreement (PPA) must show, for every unit of hydrogen it wants to count as RFNBO, that the electricity was contracted under a qualifying PPA, additional, and temporally and geographically correlated with renewable generation. Until 1 January 2030 that correlation is assessed monthly. From that date it must be shown hour by hour [2].

A wind or solar backed PPA only supplies electricity while the underlying asset generates, and any grid electricity drawn outside those hours is only partially RFNBO-eligible, if at all [4]. Grid electricity qualifies automatically under DR 2023/1184 Article 6 [2] whenever the day-ahead price is below 20 EUR per MWh, or below 0.36 times the price of an EU ETS allowance (EUA) for one tonne of CO₂, which at the 2025 average allowance price gives

an effective threshold of 26 EUR per MWh. A very low price stands in for surplus renewable generation, on the reasoning that consumption in such hours does not call additional fossil plant onto the system.

In addition to hourly matching against renewable generation or low-price grid hours, the plant must show a 70 percent carbon reduction for the hydrogen it declares. The carbon intensity is averaged across everything produced in the hour, so a partly qualifying hour can still land above the threshold, and then none of its output can be declared. RVO's guidance shows an electrolyser held at a 15 percent minimum load overnight covering roughly a quarter of one hour's consumption from the grid, failing the test, and losing the whole hour [4, Table 6; see also Sec. 4.1.1, Example 3].

Table 1: Hydrogen tiers, RFNBO requirements and market access [1, 2, 3, 14].

Requirement	RFNBO	Low-carbon	Grey
More than 70 percent carbon reduction	✓	✓	X
Renewable electricity source	✓	X	X
Grid electricity only below Art. 6 price threshold	✓	X	X
Temporal correlation	✓	X	X
Same bidding zone as RES	✓	X	X
Counts toward RED III mandate	✓	X	X
Price tier (EUR per kg)	Above 6 (premium)	Above 2.5 (willingness to pay)	2.5 (commodity)

Only RFNBO counts toward the binding RED III Article 25 mandates (Table 1), which require 42.5 percent of hydrogen used in industry to be renewable by 2030, rising indicatively to 60 percent by 2035 [1]. Buyers subject to the mandate must source RFNBO volumes to meet it, although transposition into national law is still incomplete across the member states. Low-carbon hydrogen clears the greenhouse gas threshold but none of the other tests, so it carries no purchase mandate and its market rests on voluntary willingness to pay.

In 2025 SMR hydrogen traded at just over 2 EUR per kg on average, while RFNBO-compliant hydrogen ranged between 7 and 10 EUR per kg depending on origin, with the EEX HYDRIX renewable hydrogen index averaging approximately 8.2 EUR per kg [14]. The tier a plant's output falls into determines both its addressable market and the price it can realise.

Compliant operation has two routes in any given hour. Either load is matched to the PPA generation profile, or electricity is bought in an hour that passes the price test. The hours in which neither applies are the ones that decide a project's RFNBO share, because the plant must then either stop or produce hydrogen it cannot declare. Whether it can stop depends on the electrolyser, since most plants with a technical minimum load cannot shut down without a degradation cost. A plant that can shut down to zero output without that

penalty is what we call fully flexible. Such a plant can decline every hour it cannot declare, which is what allows it to approach a full RFNBO share.

What this paper does

The three goals are:

1. Establish why clean shutdown capability, rather than a wide operating window, is the mechanism that allows a grid-connected project to approach a full RFNBO share under the hourly regime that applies from 2030.
2. Quantify the carbon footprint of hydrogen produced from grid electricity in non-compliant hours, using hourly ENTSO-E data for the Netherlands and Germany over calendar year 2025, and compare it against the SMR benchmark and the RED III fossil comparator.
3. Quantify what full flexibility is worth to the business case, using a techno-economic model of a 100 MW grid-connected project, and set out the system-level consequences beyond the project itself.

For the second goal we computed hourly grid carbon intensity for both bidding zones as the generation-weighted average of per-fuel combustion emission factors applied to ENTSO-E actual generation and flagged each hour against the Article 6 price test [12]. Carbon intensity per kilogram of hydrogen is evaluated at 53 to 58 kWh per kg H₂, a middle-of-life range for current commercial alkaline and PEM systems [10]. Project returns come from a techno-economic model of a 100 MW on-grid project paired with offshore wind [15]. Full parameters (Table A1), model assumptions (Table A2) and method notes are in the appendix.

Results and discussion

How a flexible electrolyser operates

Figure 1 shows how an electrolyser runs over a typical sunny day on an offshore wind PPA. The profile is the output of an hourly dispatch optimisation, which chooses in each hour whether to produce, to buy from the grid, or to sell contracted power. Wind output is low through much of the day. Day-ahead prices fall around midday, driven by solar, and rise in the morning and evening. What the plant can do in the low-wind hours depends on its minimum load. A fully flexible plant shuts down when its PPA is not delivering, and the grid price is too high to qualify. A plant with a minimum load cannot shut down, so it buys from the spot market to hold that floor and makes hydrogen that doesn't qualify as RFNBO. The flexible plant also has contracted power it is not using and can sell that power when the price makes selling worth more than producing.

The next two sections cover those hours in which the PPA does not cover the minimum load. First the price of grid electricity and why grey production loses money, then the carbon intensity of the same hours, both using Dutch and German data for 2025. The final section carries both into a 15-year business case and gives the project internal rate of return at each minimum load.

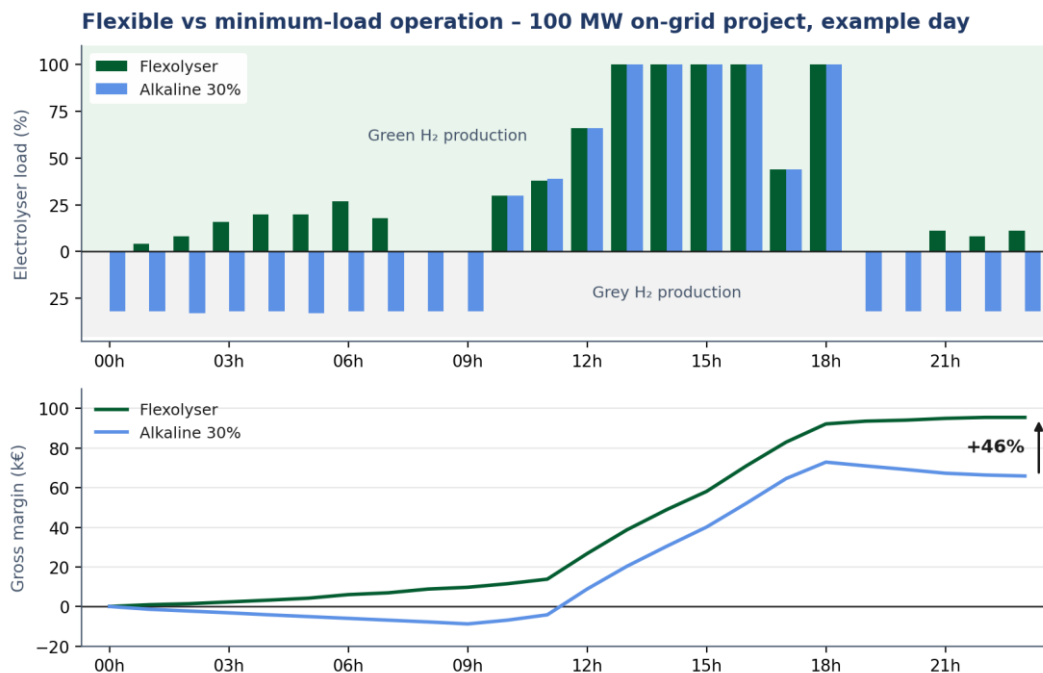


Figure 1: Optimised operation of a fully flexible electrolyser versus an alkaline system with 30 percent minimum load, representative sunny low-wind day, 100 MW on-grid project with offshore wind PPA [15].

The cost of running through non-compliant hours

Under DR 2023/1184 Article 6 [2], grid electricity qualifies as RFNBO input when the day-ahead price is below the threshold, so non-compliant hours are the grid's high-price hours. Hydrogen made in them is produced from expensive power and sold at the commodity price. Non-compliant hours in 2025 averaged 101 to 104 EUR per MWh, which at a typical electrolyser consumption of 53 to 58 kWh per kg puts the electricity cost alone at 5.35 to 6.03 EUR per kg against a sale price of 2.50 EUR per kg.

Most electrolysers on the market today can only turn down to a minimum load, which for conventional alkaline systems is typically around 20 to 30 percent of nameplate capacity, below which the stack cannot operate safely. In an hour when renewables fall short, the operator holds that residual minimum load on grid electricity or stops and accepts the degradation that repeated shutdowns inflict through reverse-current effects.

Battery storage is the other way to cover such an hour. A battery charged only in qualifying hours can bridge short gaps, but it adds capital cost and what it can cover is bounded by installed capacity and duration, so extended or repeated shortfalls would require oversizing it to a degree that is rarely economical.

What closes the gap in full is the ability to reach zero output whenever qualifying renewable electricity is unavailable, and to do so without a degradation penalty each time. Under the hourly regime that becomes mandatory from 2030 [2], that capability is close to a precondition for approaching a 100 percent RFNBO share.

Carbon intensity in non-compliant hours

The hours in which a plant without shutdown capability draws its minimum load from the grid are not a random cross-section of the year. They are the hours with the least wind and solar output, when the generation mix contains more gas and coal. The intensity that should be attributed to those hours is therefore well above an annual grid average.

The next figures describe the price and carbon intensity of Dutch and German grid electricity rather than the output of any particular plant. How much of a plant's production is affected depends on how often its PPA falls short.

In the Netherlands, 86.2 percent of hours (7,551 of 8,760) cleared above the 26 EUR per MWh threshold, and in Germany 86.0 percent (7,530) did so. Implied electrolysis carbon intensity in those hours averaged 14.1 kg CO₂ per kg H₂ in the Netherlands and 19.9 kg in Germany, against 9 to 11 kg for unabated SMR and an 11.3 kg RED III fossil comparator (Figure 2). The RFNBO ceiling is 3.39 kg.

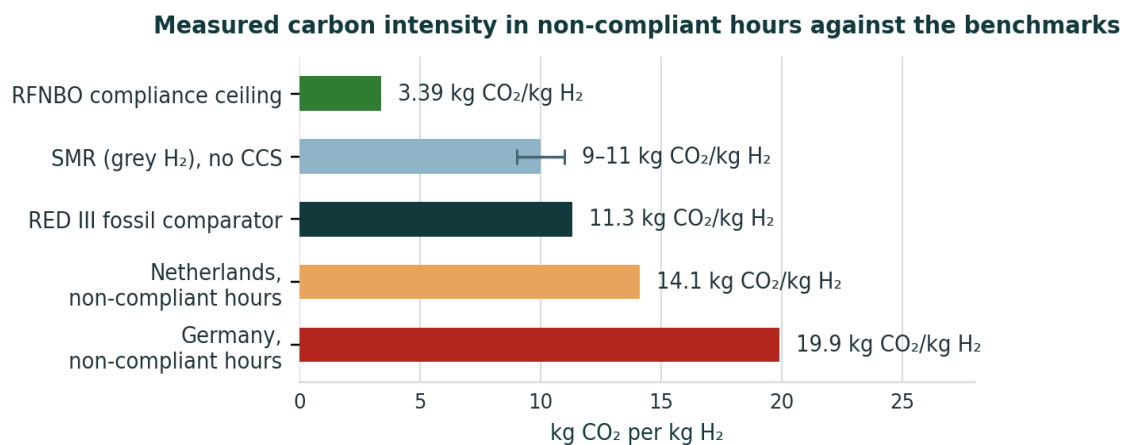


Figure 2 Measured electrolysis carbon intensity in non-compliant hours, Netherlands and Germany, 2025, against the RFNBO ceiling, the SMR range and the RED III fossil comparator.

In the compliant hours the position reverses. Their average day-ahead price was negative, at minus 1.7 EUR per MWh in the Netherlands and minus 0.9 EUR per MWh in Germany, against roughly 101 to 104 EUR per MWh in non-compliant hours, and their average implied footprint fell to 2.8 to 3.1 kg CO₂ per kg H₂ in the Netherlands, below the ceiling itself, and 6.6 to 7.2 kg in Germany.

Germany's monthly mean stayed above the SMR range in every month of 2025 (Figure 3). The Netherlands fell below the 10 kg SMR midpoint only in May and June, at 8.5 and 9.1 kg, its two cleanest months, and even then, remained far above the RFNBO ceiling.

Counted hour by hour rather than averaged, 66 percent of Dutch and 92 percent of German non-compliant hours were individually above the SMR range, and only 5 percent of Dutch non-compliant hours, with effectively none in Germany, were clean enough to declare (Figure 4).

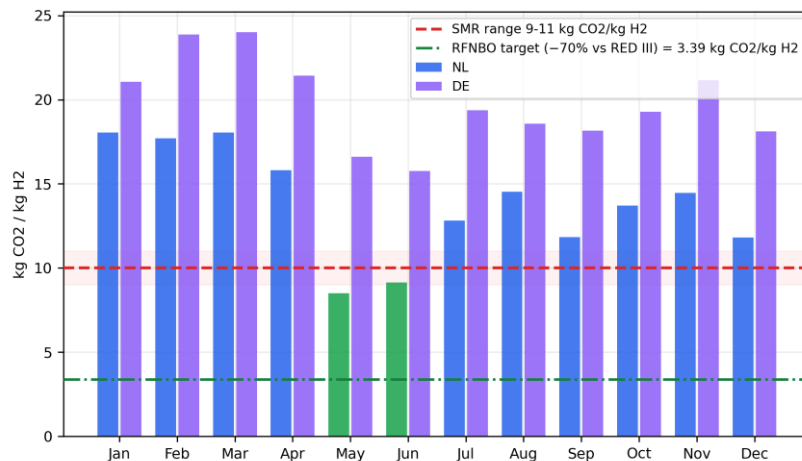


Figure 3: Monthly mean electrolysis carbon footprint in non-compliant hours (at or above 26 EUR per MWh), Netherlands and Germany, 2025. Germany never falls below the SMR benchmark in any month. The Netherlands falls below the 10 kg SMR midpoint only in May and June, shown in green.

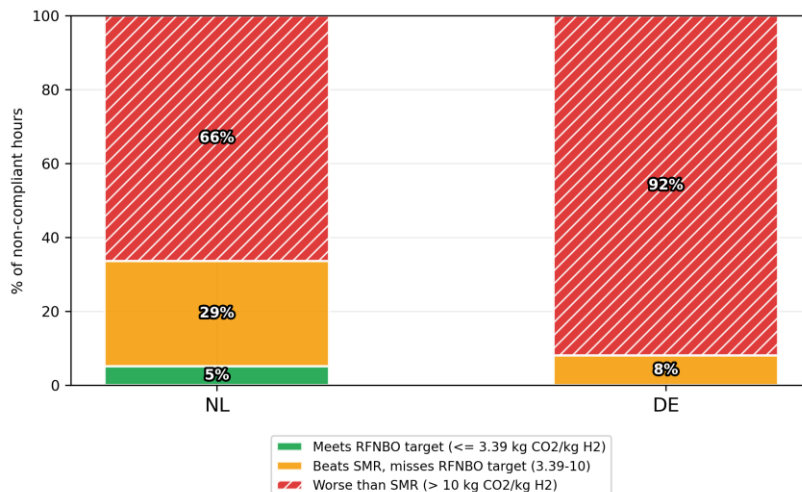


Figure 4: Carbon-intensity distribution of non-compliant hours, 2025. Share meeting the RFNBO threshold (at or below 3.39 kg CO2 per kg H2), beating SMR but missing RFNBO (3.39 to 10), or worse than SMR (above 10). In both countries the majority of non-compliant hours are worse than unabated SMR.

Day-ahead price and grid carbon intensity are strongly and positively correlated in both countries (Figure 5), and the relationship is carried by price-responsive fossil generation rather than by any compositional artefact. The price test in Article 6 is therefore also a carbon-intensity screen in practice, since hours that fail it are disproportionately hours of fossil-dominated marginal generation.

Adding wind and solar lifts the annual renewable share but does little for the low-wind, low-sun hours that force a plant onto the grid, where gas will set both the price and the emissions for years to come. A plant holding its minimum load through those hours loses the hour's batch and produces hydrogen dirtier than the fossil pathway it was built to replace, at the power prices set out above.

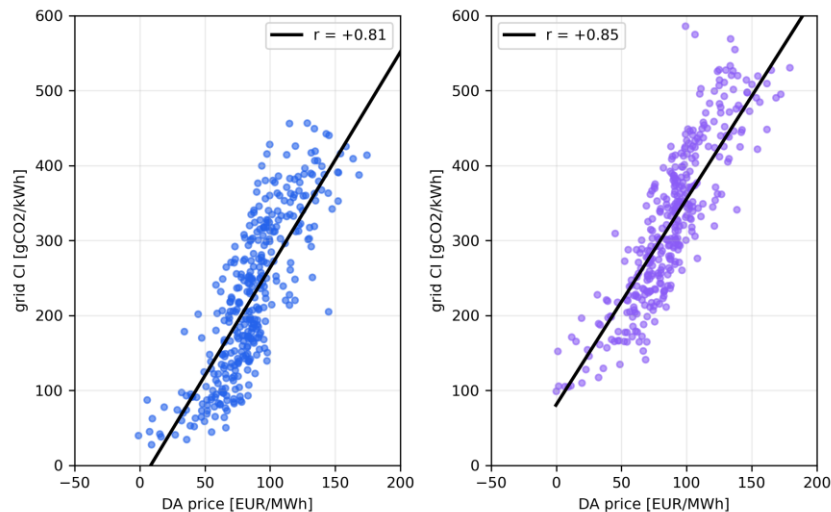


Figure 5: Daily-average day-ahead price versus daily-average grid carbon intensity, 2025. Netherlands on the left, $r = +0.81$, and Germany on the right, $r = +0.85$. Higher-price days are consistently higher-carbon days in both markets.

Project economics

Power and grid costs make up about 55 percent of the levelised cost of hydrogen from a grid-connected electrolyser, against 30 percent for capital and 15 percent for operating costs (Figure 6). Techno-economic modelling shows, arbitrage on contracted power, avoided production in the highest-priced grid hours and a lower grid tariff decrease power and grid costs by up to 40 percent against a conventional alkaline plant with a minimum load. The production cost of hydrogen falls by around 25 percent. The three mechanisms are quantified and explained in this section.

Hydrogen cost drivers as share of LCOH (%)

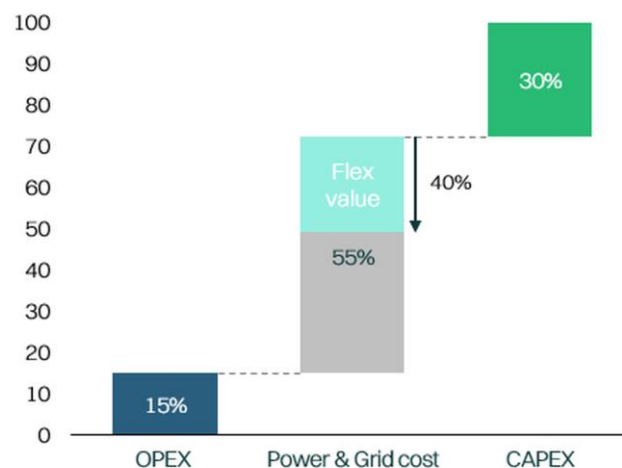


Figure 6: Cost drivers of hydrogen production as a share of the levelised cost of hydrogen, and the share of that cost addressed by flexibility, for a representative grid-connected project

Levelised cost is the usual metric for comparing projects, but it often divides total cost by total volume and so treats green and grey hydrogen as the same product. In 2025 hydrogen that could be declared RFNBO sold at 7 to 10 EUR per kg and hydrogen that could not sold at just over 2 EUR per kg. A plant can therefore lower its levelised cost by running

more hours and yet has a less positive business case. Project internal rate of return is used in this section because it prices the two separately and captures the true added value.

The operating difference shown in Figure 1 determines the project return over a 15-year life. For a 100 MW grid-connected project with a 105 MW offshore wind PPA, a conventional alkaline plant with a 30 percent minimum load returns a project internal rate of return of 9.5 percent. Widening the operating window to a 20 percent minimum load lifts that to 12.4 percent. Shutting down completely is the most effective solution and takes the IRR to 17.3 percent (Figure 6). The main assumptions are listed in Table A2 of the appendix.

Figure 7 splits the step from a 20 percent minimum load to zero into three mechanisms. Arbitrage on contracted power accounts for 1.9 points. The PPA delivers whether or not the plant uses it, and a plant that can go to zero can sell the full contracted volume in any hour where the market price exceeds the value of the hydrogen that power would make, while a 20 percent floor keeps that share committed to production. Avoided grey production accounts for 2.1 points. A plant with a floor buys power at 101 to 104 EUR per MWh in a shortfall hour and sells the hydrogen at 2.50 EUR per kg, and since the hour fails as a whole, any PPA share in it is sold grey as well.

The grid tariff discount accounts for 0.9 points and depends on the contracts the system operator offers, so it differs by country. TenneT (NL) prices the fully variable transport right (VVTR) below a firm contract, and a plant that can drop to zero on instruction can place its whole 100 MW connection under it. A 20 percent floor means 80 MW under the VVTR and 20 MW firm at the undiscounted tariff (Table A2).

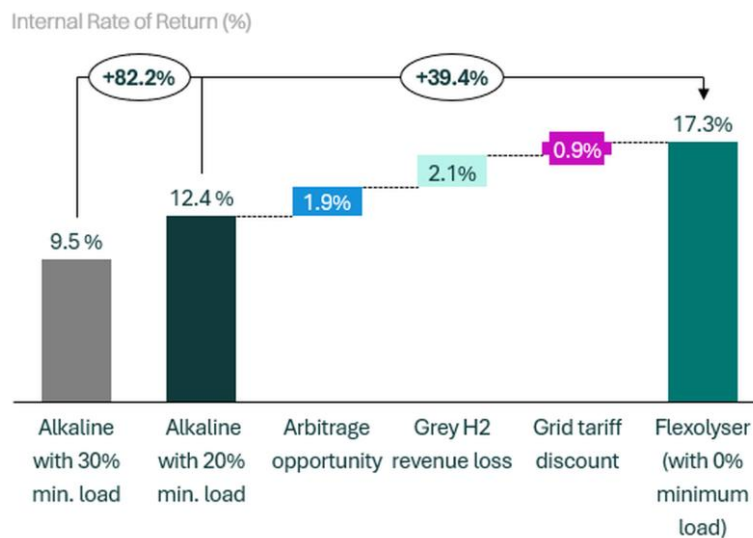


Figure 7: Project internal rate of return for a representative grid-connected project, comparing conventional alkaline configurations at 30 percent and 20 percent minimum load against a fully flexible electrolyser with no minimum load [15].

Main findings

1. Power and grid costs are about 55 percent of the levelised cost of hydrogen, against 30 percent for capital and 15 percent for operating costs. Flexibility decreases them by up to 40 percent and the production cost of hydrogen by around 25 percent.
2. Non-compliant hours are the high-price hours, so a minimum-load plant buys expensive power to make hydrogen it can only sell at the commodity price.
3. The flexible plant stops instead, and where it holds contracted power, it can resell that rather than produce, when the day-ahead price makes resale the better option.
4. Project IRR rises from 9.5 percent at a 30 percent minimum load to 17.3 percent with no minimum load, an uplift of 82.2 percent.
5. Comparable capital and fixed costs across the three configurations mean the difference flows undiluted into the return.

System value of flexibility

The RFNBO premium is the most immediate reason to build flexibility into electrolyser operation, and the preceding sections cover it. The same capability also has value to the grid and to the offshore wind developer (Figure 8), and that value grows as the renewable share of the grid rises. Both are described qualitatively here, without quantification.

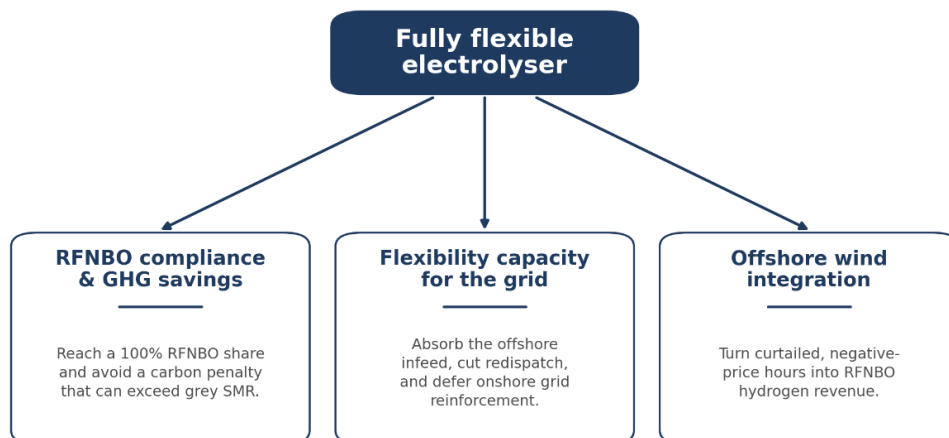


Figure 8: The three domains in which full flexibility creates value.

Both rest on the scale of North Sea offshore wind. The Netherlands operates roughly 4.7 GW today and plans to reach approximately 21 GW around 2032, with stated ambitions of some 50 GW by 2040 and 70 GW by 2050 [16]. Nine North Sea states committed under the 2023 Ostend Declaration to at least 120 GW by 2030 and 300 GW by 2050 [17]. That power comes ashore at a limited number of landing points, in the Dutch case increasingly through TenneT's standardised 2 GW HVDC connections [18], into an onshore grid already congested across large parts of the country.

Congestion relief at the landing point

A flexible electrolyser sited at or near a landing point acts as a controllable sink for the incoming infeed. It ramps up as the wind farms load the connection and down as they ebb,

so the flow carried inland is firmer and partially smoothed rather than the full variability of the wind profile.

The TSO consequently needs less downward redispatch of the wind farms, which cuts congestion-management costs that are otherwise socialised into network tariffs, and onshore reinforcement can be dimensioned closer to the smoothed flow than to the wind peak, which defers or reduces grid-expansion investment. DR 2023/1184 Article 4(3) [2] recognises the redispatch-avoidance service, in that electricity consumed to avoid downward redispatch of a renewable generator counts as fully renewable, although in the Netherlands the route awaits the TSO providing the required evidence [4]. Shell's 200 MW Holland Hydrogen 1 is under construction on the Tweede Maasvlakte, one of the main Dutch landing points for offshore wind and will be supplied under contract from the Hollandse Kust Noord wind farm [19].

Curtailment-hour capture benefiting the wind developer

As offshore capacity outgrows inflexible demand, more hours clear at low or negative day-ahead prices and wind farms curtail. Support schemes are designed not to shield generators from those hours. Contracts-for-difference and premium schemes pay little or no compensation during negative prices, to encourage curtailment rather than production into an oversupplied grid, and under the Dutch SDE++ no subsidy is paid for electricity produced at negative prices [20]. The wind farm then earns nothing on energy it could physically produce.

Negative-price hours in the Dutch bidding zone rose from 316 in 2023 to around 470 in 2024 [21], and 13.8 percent of all Dutch hours in 2025 cleared below the 26 EUR per MWh compliance threshold. A flexible electrolyser can use those hours. Article 6 of DR 2023/1184 [2] deems the temporal-correlation test satisfied at low prices, so with additionality and geographical correlation still demonstrated, electricity the wind farm could not otherwise sell becomes RFNBO hydrogen. Where the developer owns the electrolyser, that adds a revenue stream on top of normal operation. It is an addition to the business case rather than a business case on its own, since those hours are too few to support a plant by themselves.

Where the value accrues

The value does not stay with the party paying for the flexibility. Because the electrolyser raises the revenue a wind project earns, the developer can bid a lower strike price in future CfD auctions, and under a two-sided contract the government tops up less, so the saving reaches taxpayers. More flexible demand at the landing point also reduces network reinforcement, and those avoided costs are a saving for the public. Current ownership and remuneration structures do not clearly assign that benefit to any one party, even though it is the developer who invests in it.

Conclusion

On why clean shutdown capability, rather than a wide operating window, is the compliance mechanism:

The RFNBO framework certifies electricity for hydrogen production, and from 2030 it does so hour by hour. An electrolyser plant with a technical minimum load must cover any shortfall from the grid, and a modest grid share is enough to fail the 70 percent test for that hour's entire batch, with RVO's worked example losing a full hour on roughly a quarter of its consumption. The carbon intensity from the grid is averaged across everything produced in the hour, so a partly qualifying hour still fails as a whole. Battery storage helps at the margin but cannot cover extended or repeated non-generating periods at economical scale. Clean shutdown capability, meaning the ability to reach zero output without a degradation penalty, is what closes the gap in full.

On the carbon footprint of hydrogen produced in non-compliant hours:

In 2025, 86.2 percent of Dutch hours and 86.0 percent of German hours cleared above the 26 EUR per MWh effective compliance threshold. Implied electrolysis carbon intensity in those hours averaged 14.1 and 19.9 kg CO₂ per kg H₂, which is 1.4 and 2.0 times the SMR benchmark midpoint and 1.24 and 1.76 times the RED III fossil comparator. Counted hour by hour, 66 percent of Dutch and 92 percent of German non-compliant hours were individually worse than unabated SMR, and only 5 percent of Dutch non-compliant hours met the RFNBO threshold. Day-ahead price and carbon intensity are strongly correlated in both markets, so the Article 6 price test is in practice also a carbon-intensity screen.

On the commercial and system-level consequences:

Only RFNBO hydrogen counts toward the binding RED III Article 25 mandates and observed 2025 prices ranged from just over 2 EUR per kg for SMR hydrogen to between 7 and 10 EUR per kg for RFNBO-compliant hydrogen. Techno-economic modelling of a representative grid-connected project gives a project IRR of 9.5 percent for a conventional alkaline plant with a 30 percent minimum load, 12.4 percent at a 20 percent minimum load, and 17.3 percent for a fully flexible plant with no minimum load. Capital and fixed costs are broadly comparable across the three, so the difference comes from operating behaviour. The step from a 20 percent floor to zero is the part a wider operating window cannot deliver without taking a penalty on the electrolyser performance caused by reverse currents.

Flexibility is not only a compliance cost. It lets a project reach a full RFNBO share and sell all its output at the premium, rather than degrading batches to commodity grey and, in non-compliant hours, to a carbon intensity that can exceed SMR.

On system level, absorbing the offshore infeed at the landing point eases congestion, reduces redispatch and defers network reinforcement. Converting otherwise-curtailed, low-price hours into RFNBO hydrogen adds revenue for the wind developer. The last two spill beyond the project onto the grid and the taxpayer. A project designed around full flexibility is aligned with the direction of EU policy, with the North Sea expansion and with its own investment case.

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Appendix

Calculation parameters

Table A1: Input parameters used in the carbon-intensity and compliance analysis.

Parameter	Unit	Value	Source
Emission factor, natural gas	g CO ₂ per kWh	400	Direct combustion [9]
Emission factor, hard coal	g CO ₂ per kWh	900	Direct combustion [9]
Emission factor, lignite	g CO ₂ per kWh	1,060	Direct combustion [9]
Emission factor, biomass	g CO ₂ per kWh	Direct combustion factor, not zero-rated	Methodological choice
Electrolyser specific energy consumption	kWh per kg H ₂	53 to 58 (midpoint 56)	Middle of life [10]
EUA price, 2025 average	EUR per tonne CO ₂	73	[13]
Effective Art. 6 compliance threshold	EUR per MWh	$\max(20, 0.36 \times 73) = 26$	DR 2023/1184 Art. 6 [2]
NL regulatory average grid emission factor	g CO ₂ eq per MJ	99.9 (359.6 g per kWh)	DR 2023/1185 Annex C [3]
RFNBO carbon intensity ceiling	kg CO ₂ per kg H ₂	3.39	70 percent saving on Art. 29a comparator [1, 3]
Analysis period	-	Calendar year 2025, 8,760 hours	ENTSO-E [12]

Techno-economic model assumptions

Both configurations are modelled on identical cost and performance assumptions, so the difference in outcome is driven by operating behaviour rather than by a technology cost advantage. Electricity is dispatched against forward market price curves, and the plant is free to buy from the grid, consume PPA output, or resell PPA output, subject to the minimum load of the configuration being modelled.

Table A2: Main assumptions of the 100 MW on-grid techno-economic model [15].

Parameter	Value
Plant size	100 MW
Project duration	15 years
Project year	2030
Degradation	10 percent efficiency loss over 10 years

Parameter	Value
Minimum load	0 percent fully flexible, 20 and 30 percent for the comparators
System efficiency, middle of life	53 kWh per kg H ₂
Plant CAPEX	1,500 EUR per kW, identical for all three configurations – Interpolated from Worley estimate of 2035 [22]
Stack replacement CAPEX	10 percent of CAPEX
OPEX	2.2 percent of CAPEX per year
PPA	105 MW offshore wind
PPA price	73.46 EUR per MWh
Market price curves	Forward curves to 2050, quarter-hourly day-ahead and imbalance, hourly intraday purchased from Montel Analytics
Grid tariff	TenneT fully variable (NL market)
Hydrogen sale price	7.00 EUR per kg RFNBO, 2.50 EUR per kg grey

Method notes

Hourly carbon intensity was computed as the generation-weighted average of per-fuel direct-combustion emission factors applied to ENTSO-E actual generation per production type, for the NL and DE_LU bidding zones. Biomass was counted at its direct-combustion factor rather than zero-rated, which is a conservative choice relative to regulatory accounting and raises measured intensity in both zones.

Each hour was flagged compliant or non-compliant using the DR 2023/1184 Article 6 rule, being a day-ahead price below 20 EUR per MWh or below 0.36 times the EU ETS allowance price. Evaluated at the 2025 average EUA price, the binding threshold is 26 EUR per MWh. The threshold is ETS-indexed, so it moves with the allowance price and should be re-derived from live values before being relied on commercially.

Correlation between day-ahead price and grid carbon intensity was tested at both hourly and daily resolution. Pearson r was +0.68 in the Netherlands and +0.72 in Germany hourly, rising to +0.81 and +0.85 on daily-mean data. Spearman rank correlations were higher still, at +0.75 and +0.78 hourly and +0.84 and +0.88 daily, indicating a strong relationship that is not fully linear. A robustness variant holding must-run generation at annual-mean output leaves the coefficients essentially unchanged, confirming that the relationship is carried by price-responsive fossil generation rather than by compositional artefacts.



Alquion builds fully flexible industrial electrolyzers that shut down cleanly to zero output, so hydrogen projects can run on qualifying renewable electricity alone.

a.tavanaei@alquion.com

r.de.milliano@alquion.com

alquion.com