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A ten-year analysis of cross-border vs in-country and hourly matched PPA procurement, and how technology blend and settlement location shape cost and hedge effectiveness.

European PPA strategies and the hidden cost of cross – border basis risk

Market data by Renewabl and PEXAPARK

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Author
Paul Hill, Head of Energy Markets, Renewabl

Reviewed by
JP Cerda, CEO and co-founder, Renewabl
Ruby Tebbutt, Trade Specialist, Renewabl

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Drawing on Pexapark's 10-year PPA price benchmarks (June 2026) across the four in-scope European markets.

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Executive summary

This analysis set out to test one question: does a single-transaction cross-border virtual Power Purchase Agreement (vPPA), which looks cost effective on the cover, actually protect a buyer's power bill?

We modelled four procurement strategies across 1,000 ten-year price simulations: a single cross-border vPPA, multiple in-country PPAs, technology-optimised in-country PPAs, and a completely unhedged approach. The buyer's demand sits in four markets – France, Italy, Germany and Spain – while supply is drawn from Spain and Finland for the cross-border vPPA, and from the buyer's own four markets for the in-country strategies.

The analysis finds:

- On expected cost, the three hedged strategies finish in a near-tie – all within about €1/MWh, at around €50/MWh
- What separates them is risk: in-country procurement reduces 10-year cost uncertainty by 85–91%, compared with only about 40% for the cross-border vPPA, whose bad-year cost runs roughly 29% higher than the optimised in-country mix.
- A key cost driver is the country where the contract settles. A cross-border vPPA pays out in the generator's market, not the buyer's, leaving basis risk that settling in-country eliminates.
- The best-hedged strategies also score highest on hourly matching – about 82% against load, versus 14% for the cross-border vPPA. That gap is less significant under today's annual Scope 2 accounting but becomes material under the proposed hourly rules.
- The advantage holds across every buyer load profile tested.

European policies and global accounting standards are considering transitioning from annual averages to requiring hour-by-hour tracking and reporting of clean electricity consumption. Our analysis shows that such a change can bring significant benefits in the form of lower electricity costs and sharply reduced exposure to price volatility. The same hourly view that supports a stronger Scope 2 claim also helps the energy buyer to build a more resilient portfolio.

Cost and risk both fall as more of the buyer's load is hedged hour by hour

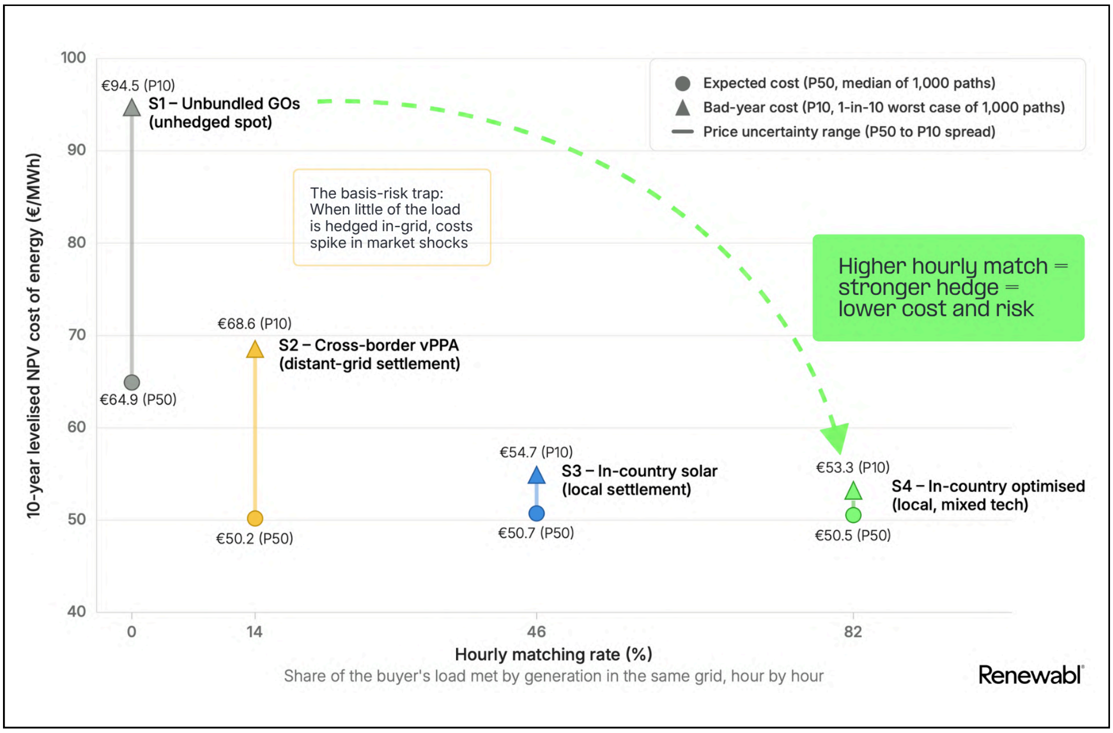


Figure 1: How optimising your hourly matching score can improve NPV cost whilst also minimising uncertainty and risk.

1. Introduction

Most European corporations buying renewable energy are trying to satisfy two stakeholders simultaneously: a sustainability manager with a renewable energy target to hit, and an energy buyer with a budget to defend and a portfolio to keep stable.

To satisfy these dual mandates, companies in Europe have often turned to the cross-border virtual Power Purchase Agreements (vPPAs) – for example, Spanish solar or Finnish wind – markets that have abundant natural resources and offer comparatively low strike prices – sold to a buyer whose operations are based elsewhere in Europe. This works because the EU's Guarantee of Origin (GO) system, run via the Association of Issuing Bodies (AIB), treats most of Europe as a single market. A GO issued in Spain can be retired against annual consumption in any other AIB member country. They are well-priced, the legal templates are mature, and they enable corporate sustainability targets to be met. Often this results in buyers securing vPPAs in markets that offer low strike prices.

The question we set out to test: a cross-border vPPA looks cheap on paper, but does its basis risk – the gap that opens when the generator and buyer sit in different price zones – mean the true cost is greater than the headline strike price suggests?

Basis risk is the gap between the power price in the market where the project is located and the price in the market where the buyer is consuming, which can swing widely when those markets move out of step.

If the market turns volatile – as it did through 2022 when the loss of Russian gas pushed European power prices to record highs in gas-setting hours – the cheap structure may not actually hedge the buyer's electricity bill. The volatility of this model is live: Spain logged 397 negative-price hours in Q1 2026, up from 48 a year earlier [1], and falling solar capture factors mean the cannibalisation that weakens a Spanish-solar vPPA is still worsening [2].

To test that, we modelled a representative pan-European corporate with 100 GWh of annual load split equally across France, Italy, Germany and Spain (25 GWh per country – broadly the footprint of a small enterprise data-centre cluster, a regional retail estate, or a manufacturing site).

We ran four procurement strategies over a 10-year horizon (2027–2036) and looked at both the expected cost and the bad-year cost of each, across these three load-shape archetypes. The 100 GWh load is illustrative – €M figures scale linearly with annual volume (e.g. a 200 GWh buyer doubles them; a 500 GWh buyer multiplies by five), while €/MWh figures don't change.

The four procurement strategies

S1 – Unbundled GOs only. Buy all power from the spot market in each country and bolt on unbundled Guarantees of Origin (GOs) to reduce the supply's Scope 2 emissions footprint. We assume €2.5/MWh as the average GOs price across the 10-year horizon. The vPPA strategies (S2, S3 and S4 below) receive GOs bundled with the vPPA, the value of which is embedded in the strike price.

S2 – Single cross-border vPPA. Buy the full volume virtually from outside the buyer's zones. We tested three variants: 100% Spanish solar (taken as the headline case in the results below), 100% Finnish wind, and a 50/50 blend of the two. The vPPA settles at the generator's spot hub (OMIE for ES, Nord Pool for FI); the buyer continues consuming from its local FR/IT/DE/ES hubs at their spot prices. As the buyer is purchasing power that it is not consuming, there is no direct hedge of its electricity costs. This is the structural exposure the analysis tests. We use 100% Spanish solar as the 'headline' case in this analysis, as it is the lowest cost (see section 2.1) and the most frequently transacted of the 3 variants.

S3 – Single in-country solar PPA. A 25 GWh solar PPA, physical or virtual, in each country. A deliberately single-technology test: S3 isolates the value of in-country settlement on its own.

S4 – Optimised in-country PPAs. Same in-country approach as S3, but **the wind/solar split optimised in each country to maximise hourly matching against the load profile,** i.e. setting the precise ratio of wind and solar capacity based on localised generation and load data. The best level of hourly matching analysed is 82% across the portfolio.

The rationale behind the choice of solar as the single technology in S3 is that solar has been the predominant technology in European corporate vPPA volumes in recent years, supported by lower average strike prices, faster project delivery in southern markets, and deeper secondary-market liquidity than onshore wind. It also reflects the realistic case which many corporates are in today, whereby they have already signed "their first solar vPPA", and are looking to move away from this; S4 then tests what a buyer gains by moving from single-technology to a wind/solar mix that is optimised to best match their demand profile.

By comparing these four strategies, the model isolates whether the lower headline price of cross-border contracts holds up against the structural advantage of in-country settlement over a 10-year horizon – including in years where prices spike hard.

Costs in this paper are calculated as 10-year NPV cashflows for each strategy, discounted at 5% to 2027, expressed as €/MWh figures (i.e. divided by undiscounted total consumed MWh – 1 million MWh over the 10 years).

Section 2 shows the key results of the analysis.

Note: Full methodology and data sources are in section 4. The short version: 1,000 Monte Carlo paths, hourly settlement across five European markets (FR, IT, DE, ES, FI), anchored to EEX baseload forwards with an hourly solar & wind cannibalisation overlay, and using recently observed vPPA strikes from Pexapark (June 2026).

2. Results

The analysis shows that **the strategies with the greatest effective hedge for the corporate buyer are also among the least expensive.**

- On one side, not hedging any demand is the most expensive strategy and the one that leads to the greatest volatility.
- On the other end of the spectrum, optimised in-country and hourly matching is among the most cost effective, and the most risk effective.

The cross-border vPPA is competitive with the in-country cases on expected cost – marginally the cheapest of the hedged strategies – but it leaves significant portions of electricity demand exposed to wholesale power price volatility, and its bad-year cost is far higher than either in-country option.

On probability and tail risk

Throughout the analysis, we focus on three values: P50, P10 and P90. These represent the median, bad-year, and good-year scenarios, respectively from the buyer's perspective. We use the exceedance-probability convention standard in renewables financing: a "Pxx" cost is the level the actual outcome has an xx% probability of exceeding. P10 is the bad-year mark (only 1 in 10 paths come in worse), P90 is the good-year mark (with only 1 in 10 paths coming in better), P50 is the median (half of the 1,000 paths cost more, half less).

For a buyer concerned about price shocks, P10 is the number that matters. Costs are quoted as levelised €/MWh across the full 10-year horizon, so a "bad year" here means a bad 10-year path - one whose total cost lands in the worst 10% of outcomes. The bad-year cost includes paths that look like 2022, when the European gas crisis pushed power prices to record highs. We've kept those hours in the model because that's the kind of shock a 10-year hedge is meant to protect against - without them, the downside numbers would be smaller.

Reading tail risk: how an effective in–counrty hedge collapses the cost range

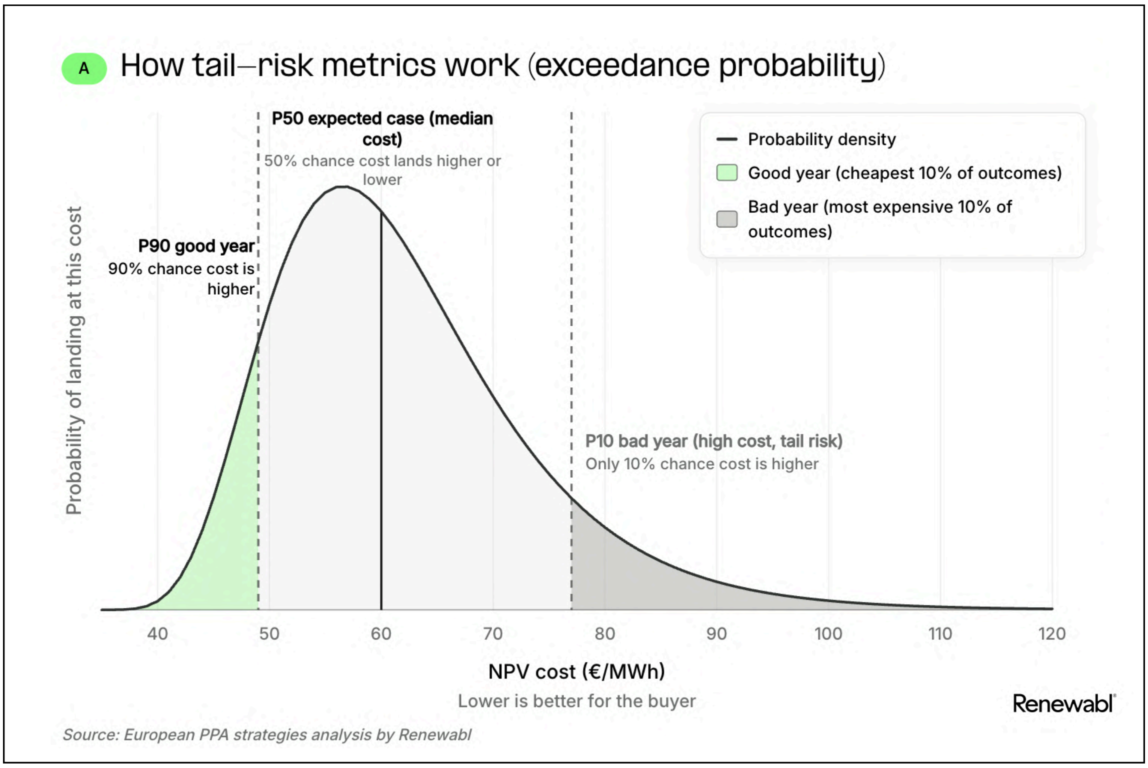


Figure 2: How increasing the level of hedge effectiveness significantly reduces the variance of possible energy cost outcomes (right), while other strategies remain significantly exposed to price shocks.

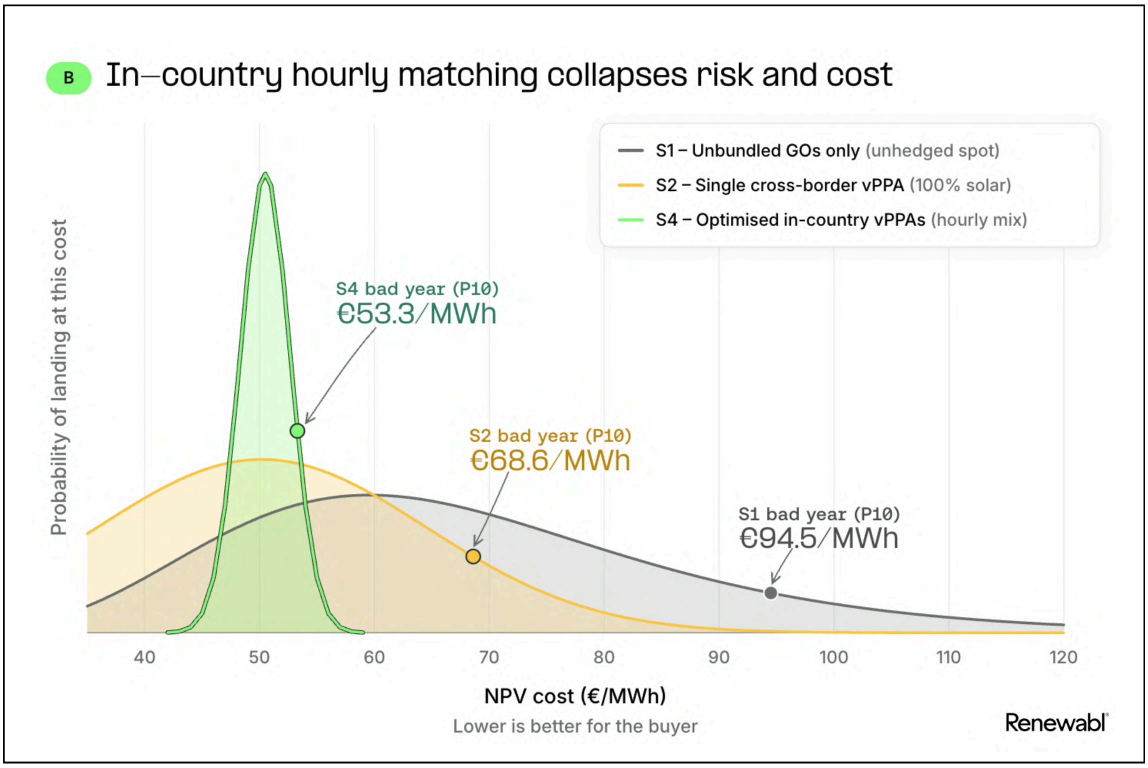


Figure 2: How increasing the level of hedge effectiveness significantly reduces the variance of possible energy cost outcomes (right), while other strategies remain significantly exposed to price shocks.

2.1 Expected cost: Not hedging is most expensive, while in–country and optimised hourly matching is cheapest

The results of the central P50 cases – the median outcome across 1,000 simulated paths – are represented in the table below. The unhedged S1 portfolio costs €64.9/MWh, while the three hedged strategies land within roughly €1/MWh of each other, around €50–€51.

The cross-border vPPA strategy reduces costs somewhat, and is marginally the cheapest of the hedged strategies on expected cost (€50.2/MWh, versus €50.5 for S4 and €50.7 for S3). All three hedged strategies now sit within about €0.6/MWh of each other on expected cost; the difference shows up in the bad year, not the median. In absolute terms, the three strategies equate to savings of €14.7/MWh (S2), €14.2/MWh (S3) and €14.4/MWh (S4), respectively, compared to S1.

These figures are realised 10-year portfolio costs, not contract strike prices. A Spanish solar PPA might be signed at €35/MWh, but once cannibalisation, generation shape and the cost of serving unmatched hours are accounted for, the buyer's delivered cost lands materially higher. Separating headline strike from delivered cost is the point of the analysis: a low strike does not mean a low bill.

Table 1: Expected costs & portfolio savings across the procurement strategies

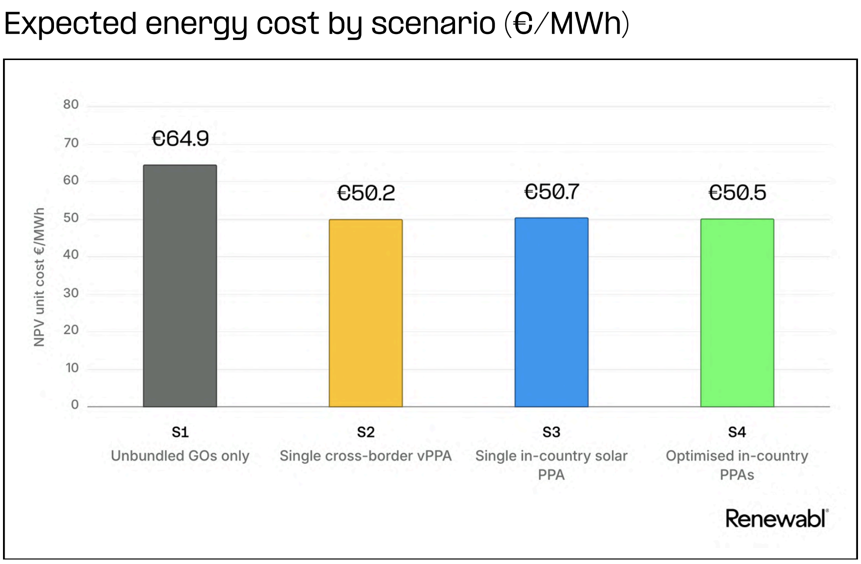
Strategy	Settlement & grid alignment	Expected cost (P50)	Expected unit savings vs. S1*	% Cost savings vs. S1	Hourly physical match
S1: Unbundled GOs	Unhedged spot market	€64.9/ MWh	*Baseline*	*Baseline*	0%
S2: Single cross-border vPPA	Distant grid (100% ES solar)	€50.2/ MWh	-€14.7/ MWh	22.7%	~14%
S3: Single in-country solar PPA	Domestic grid (FR, IT, DE, ES)	€50.7/ MWh	-€14.2/ MWh	21.9%	~46%
S4: Optimised in-country PPAs	Domestic grid (Optimised wind/solar)	€50.5/ MWh	-€14.4/ MWh	22.2%	~82%

The cross-border vPPA is only cost effective in the hours the generator is producing – Iberian solar noon, in the headline 100% solar case – and at the local spot price in those hours, which is depressed by solar cannibalisation in Spain.

In-country PPAs generate and settle in the buyer's own market – so even when solar produces at noon rather than at the buyer's evening peak, the payout better reflects the same market dynamics the buyer's bill is exposed to. S4 then narrows the timing gap further by optimising the technology blend for the load profile.

**Note: Portfolio savings are calculated for a representative corporate buyer with a 100 GWh/year load over a 10-year horizon (1,000,000 MWh total cumulative consumption).*

Figure 3: Expected NPV unit cost by strategy over a 10-year horizon (P50).



2.2 Volatility and the value of a clean power hedge

While cross border vPPAs have marginally lower expected costs than in-country PPAs, the tail risk shows that the latter are critical for reducing volatility and protecting against the worst market outcomes.

Table 2 and Figure 4 below show the same four strategies but now include the difference between the P50 (expected) cost and the P10 (bad-year) cost. Unbundled GOs only (S1) has a 10-year P10 cost of around €94.5/MWh - roughly €30/MWh higher than its P50 expected case. The cross-border vPPA (100% solar) P10 case has a total cost of €68.6/MWh, about 37% above its expected case. The in-country strategies almost eliminate the variance between P50 and P10. S3 costs about €4/MWh more than its median in a bad year, and S4 only €2.8/MWh more.

The results demonstrate the significant benefits of optimised in-country PPAs (S4); the costs of the cross-border vPPA strategy (S2) in the bad year are 29% higher than the costs of the in-country hourly matching (S4) strategy. The bad year is not hypothetical: the model draws each path freely from 2019–2025, so any single path can land repeatedly in 2022-style shock years.

Table 2: Cost outcomes & volatility protection outcomes across the four strategies

Strategy	Expected cost (P50)	Bad-year cost (P10)	"Volatility premium" (P10 - P50 Gap)	10-year price risk removed (€M)*
S1: Unbundled GOs	€64.9/MWh	€94.5/MWh	+€29.6/MWh	Baseline (wears €52M volatility)
S2: Single cross-border vPPA	€50.2/MWh	€68.6/MWh	+€18.4/MWh	€21.1M (37% of risk removed)
S3: Single in-country solar PPA	€50.7/MWh	€54.7/MWh	+€4.0/MWh	€44.1M (85% of risk removed)
S4: Optimised in-country PPAs	€50.5/MWh	€53.3/MWh	+€2.8/MWh	€47.1M (91% of risk removed)

**Price risk removed refers to the reduction in the cost variance between P10 (bad year) and P90 (good year).*

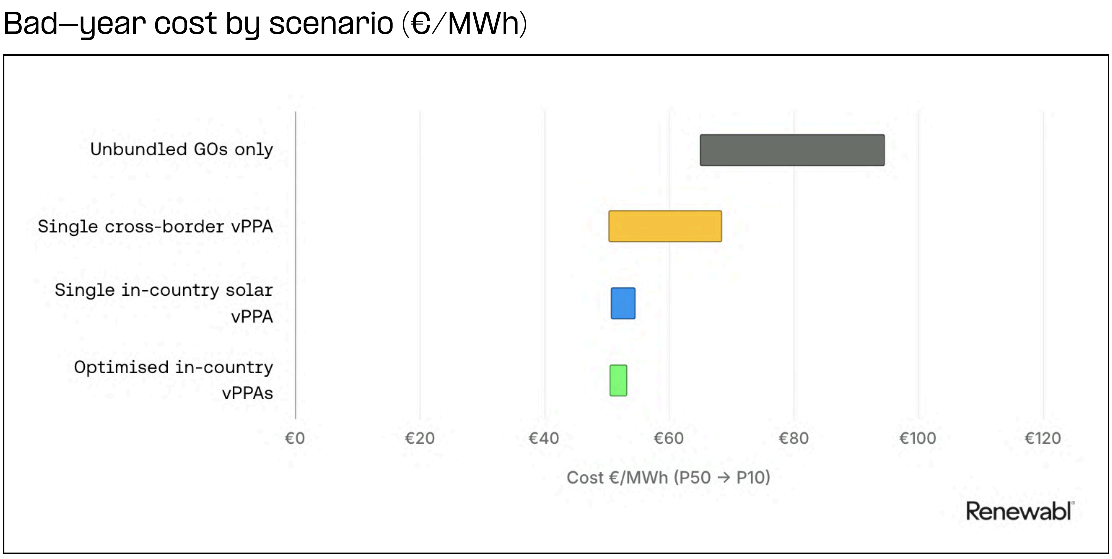


Figure 4: Bad-year cost (P50 → P10) by strategy. Bar extends from expected case to 10th-percentile outcome.

The pattern from Section 2.1 holds in stressed conditions, but with greater force. In a 2022-style shock, all four buyer markets spike together – yet the cross-border vPPA settles only at the generator's hub, where Iberian and Nordic prices do not always move in step with continental ones. When those correlations break down – Nordic wind output dropping during a continental cold snap, or Iberian solar producing at midday while continental peaks hit in the evening – the vPPA's payout fails to offset the buyer's worst hours. In-country PPAs settle against the same market that sets the buyer's bill, so the price the PPA receives moves in a more correlated fashion with the price the buyer pays – even when the hours of generation and consumption don't perfectly line up. Cross-border vPPAs lose that alignment.

2.3 Technology mix moves cost, not basis risk

Looking more in depth at S2, which assesses **three different technology mixes (100% wind, 100% solar, 50/50 split)** in a cross border vPPA, it demonstrates that the technology impacts €/MWh at both the expected (P50) and bad-year cases (P10). The delta between technology types/blends is greater for expected costs (P50) compared to a bad-year cost (P10).

The two single-technology variants (100% wind and 100% solar) of the cross-border vPPA are ~€16/MWh apart on expected cost (P50); and roughly €12/MWh apart on a bad-year tail (P10). The 50/50 blend lands between them on both (€58.2 expected, €74.6 bad-year).

Overall, this demonstrates that picking solar over wind makes the deal cheaper in expectation and somewhat softer in the tail but fundamentally it does not change the basis-risk structure. This is because S2's risk reduction is mechanical.

The vPPA already reduces ~40% of the buyer's price uncertainty simply by reducing the reliance on the spot market – not by covering the specific hours when local prices spike. A cross-border vPPA is comparable to a directional bet on pan-European spot correlations rather than a hedge of the buyer's bill.

The technology selected (solar vs wind vs blend) shifts both cost and tail risk, but does not change the structure. Whether to do one at all is a decision about how much basis risk you are willing to wear. Based on the numbers in this analysis, that basis risk is significant: €16–18/MWh between expected and bad-year cost across the three technology mixes.

Cross–border vPPA cost & bad–year cost by supply mix (€/MWh)

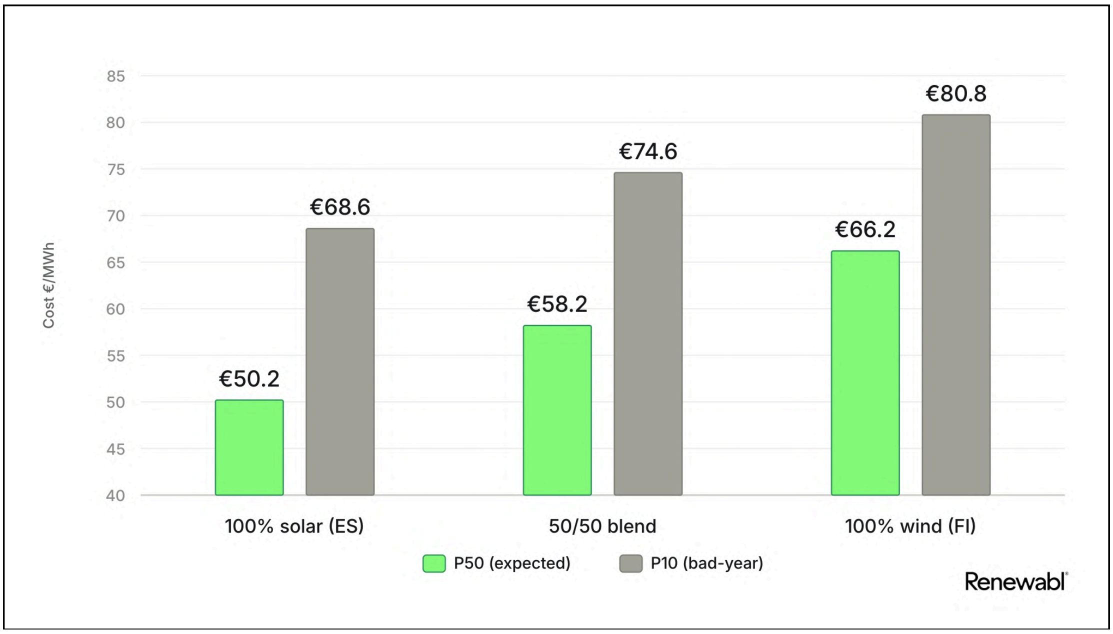


Figure 5: S2 expected and bad-year cost across the three technology-mix variants: 100% solar (ES), 50/50 blend, 100% wind (FI). Based on the average from each load archetype.

2.4 Variance reduction is what a buyer is paying for

Viewed as variance reduction: how much of the 10-year price uncertainty does each strategy actually remove?

On the unhedged S1 portfolio, the worst-10% outcomes land about €52M above the best-10% over the 10 years, which is the price risk a 100 GWh buyer is wearing when buying entirely from the spot market with no PPA hedge in place. The cross-border vPPA (100% solar) reduces ~40% of this uncertainty. The in-country strategies reduce uncertainty by 85% (S3) and 91% (S4), respectively. Ultimately, this is achieving the objective of an effective hedge, materially narrowing the range of plausible outcomes a buyer must plan for.

Price uncertainty removed vs no hedge
(€M, 10–yr NPV P10–P90 spread)

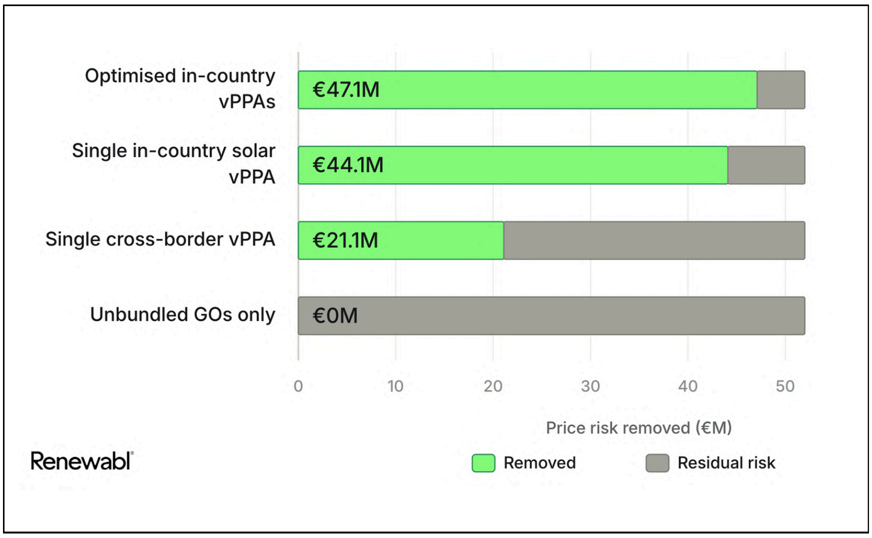


Figure 6: Price uncertainty removed vs. S1: reduction in 10-year NPV P10–P90 spread, €M. Mixed archetype, 100 GWh annual load.

2.5 Does the load profile change the picture?

A buyer's load profile, whether it's a data centre, a retailer or a factory, barely changes the result. The four strategies keep the same cost ranking no matter who the buyer is – the unhedged S1 is always dearest and the three hedged strategies cluster.

That ranking does depend on the year: in normal and high-price years, in-country procurement matched to the load profile (S4) is among the cheapest options and the most resilient; in unusually low-price years a hedge costs slightly more, because the higher hedge price is locked in. The conclusion holds throughout: matching in-country supply to the load shape is the strongest protection against the years that carry the greatest cost.

Buyer archetype barely changes NPV (P50, S1–S4, €M, 10–yr)

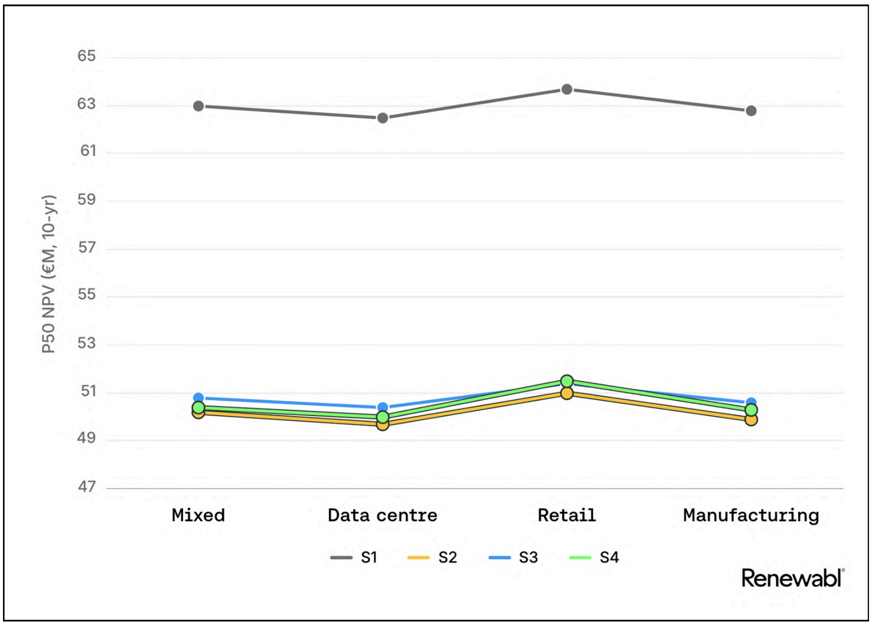


Figure 7: Buyer archetype comparison – P50 (median) 10-year NPV by strategy (S1–S4), €M

3. Implications

The first decision is whether to hedge at all – buying unbundled GOs is the most expensive option and the most exposed in a bad year. Once the buyer is hedging, the choice between the three is determined by (1) where the contract settles (cross-border carries basis risk; in-country does not), (2) how many counterparties the organisation can manage, and (3) how to optimise a technology blend which best matches your demand. The summaries below pull out the case pros and cons each.

Table 3: A summary of the pros and cons of the different procurement strategies; and which buyer types it is best suited to

Strategy	Advantages	Disadvantages	Who it suits
S1: Unbundled GOs	Lowest friction; full flexibility; no long term commitment.	No shock protection: bad-year cost rises to ~€94.5/MWh, around 46% above the expected case. Range of possible 10-year outcomes is ~€52M wide.	Buyers with no balance-sheet capacity for a long position, or have a highly variable load.
S2: Single cross-border vPPA	Mature template, deep counterparty market, robust renewable claim (bundled GOs from a real asset). Cuts the range of 10-year outcomes by about 40% (~€52M to ~€31M).	Basis risk: although the cross-border vPPA is marginally the cheapest hedged strategy in expectation (€50.2/MWh), its bad-year cost still rises to ~€68.6/MWh (~37% above the expected case) – materially worse than either in-country option in the tail. The technology mix shifts both expected cost (P50) and tail (P10) but doesn't alter the basis-risk structure.	Buyers needing a simple renewable claim which can be agreed at pace, therefore, accepting partial hedge for transaction speed and simplicity.
S3: Single in-country solar PPA	Settling at the buyer's own hub removes basis risk, collapsing the range of outcomes by ~85% (~€52M to ~€8M). Expected cost €50.7/MWh.	Solar-only matches ~46% of the buyer's hours. Exposed to solar cannibalisation as European penetration rises. Increased legal and resource costs to sign four separate contracts rather than one cross-border deal.	Buyers wanting material risk reduction without mixed-tech complexity; solar-aligned loads.

Strategy	Advantages	Disadvantages	Who it suits
S4: Optimised in-country PPAs	Best on hedge effectiveness and hourly match. Essentially tied for cheapest on expected cost (€50.5/MWh – within €0.6/MWh of S2 and S3); bad-year cost only ~6% above this. Range of outcomes narrowest at ~€5M. Removes 91% of price risk relative to the unhedged baseline (S1), compared to 85% for S3 and 40% for S2 - the most effective risk reduction of the four strategies by a significant margin. ~82% hourly match - closest of the four to 24/7 CFE.	As with S3, more contracts can add resource burden and extend timelines, in both procurement and ongoing management. Potentially reduced project availability in some countries, e.g. wind is scarce in Poland and Spain. Cost benefit over S3 is negligible (~€0.2/MWh at P50, ~€1.6/MWh at P10), so the case rests on hourly match and price predictability for buyers.	Companies seeking to credibly claim clean energy use; achieve higher emissions reduction under possible granular Scope 2 accounting rules; support local businesses and minimise their exposure to volatile energy markets.

3.1 Interpreting the results

Two things sit underneath every conclusion.

1. The expected-cost spread between the three vPPA strategies is very close (about €50–€51/MWh), but the bad-year spread is dramatic.

On headline price a buyer could land anywhere – the cross-border vPPA (S2) is marginally the cheapest in expectation. But a buyer who weighs portfolio volatility lands firmly on the in-country options (S3/S4): the cross-border vPPA is by far the most exposed of the three in the bad year, even though it is the cheapest at the median.

Moving from a single cross-border vPPA to multiple in-country agreements (S3/S4) results in material risk reduction, but may add to upfront legal, advisory and management costs as the portfolio splits across several national contracts.

One way buyers could manage this is to build the portfolio in stages. Pexapark notes growing interest in shorter, 5-to-10-year PPAs from operational assets [3], which can secure savings sooner, alongside longer new-build contracts where additionality is the priority.

2. The technology blend inside a cross-border vPPA (ES solar vs FI wind in our example) is a decision about expected price level, not risk reduction; whether to do one at all is the risk-appetite question.

To represent the cross-border vPPA we take 100% Spanish solar as the headline configuration – solar dominates European corporate vPPA volumes today and is the cheapest of the three technology mixes on expected cost. We also test a 50-50 Spanish-solar / Finnish-wind split as a diversification variant. That blend reflects how a mature corporate buyer might want to structurally diversify market exposure across two independent power grids and generation technologies.

3.2 The overlap with Scope 2 reporting standards

Whilst the analysis so far has focused on cost and procurement risk, the strategies that hedge cost most effectively are also those which match generation to consumption hour by hour. S4 reaches about 82% hourly matching against load, S3 around 46%, and the S2 by only about 14% (The 25 GWh of ES demand matched with the ES vPPA supply volumes). Hourly accounting is only applicable when procuring in-country. Today's annual Scope 2 accounting treats all four as equivalent on the renewable claim, but hourly accounting would not.

The proposed transition from annual to hourly Scope 2 reporting will encourage procurement strategies which hedge effectively. A buyer's hourly-matching score is, in effect, an indicator of where they sit on the cost-and-risk curve shown in Figure 2. The hourly matching score shows which hours are already covered and which are still exposed to the volatility shown earlier.

In–country optimised portfolios surge hourly matching from 14% to 82%

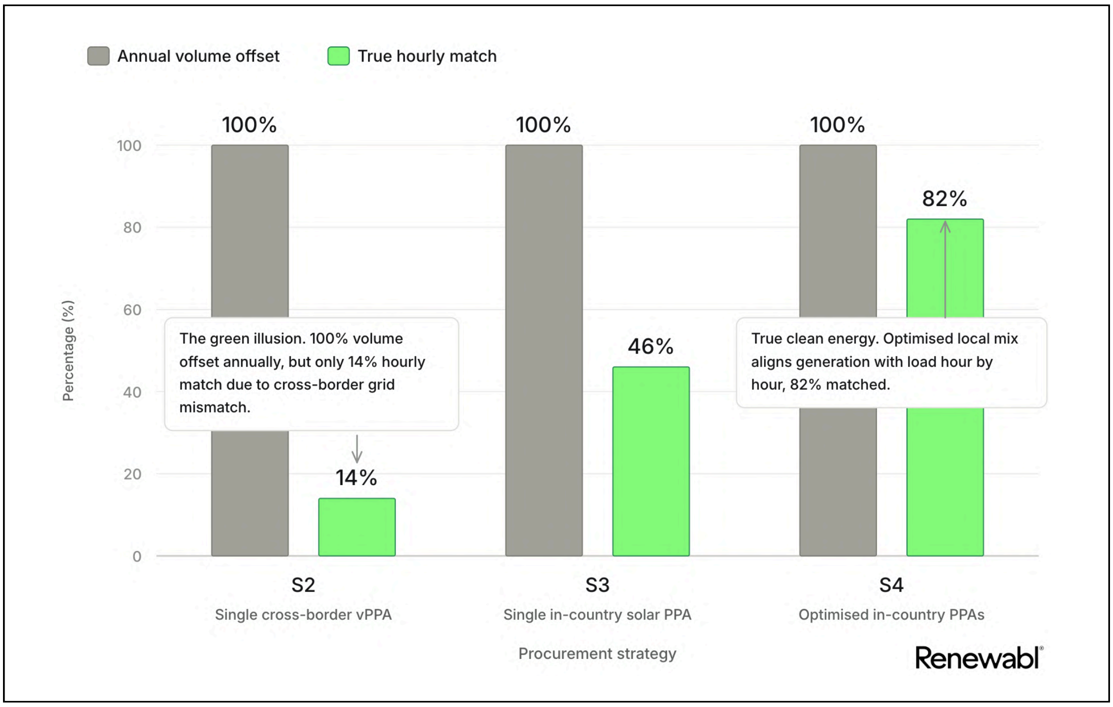


Figure 8: In country optimised portfolios significantly improves hourly matching scores

Other evidence aligns with this market direction: Pexapark and Finergreen both report a shift in 2025 toward more structured, domestic and hybrid PPA portfolios [3, 4], in part because the basis risk on cross-border vPPAs has become harder to ignore. At the same time, the cost of delivering firm, round-the-clock renewable power – combining solar, wind and storage – is falling as technology costs decline, as per IRENA report. [5]

Google's expanded partnership with Engie in Germany [6] is an example of this pattern: wind and solar PPAs paired with battery and pumped-storage to push German operations toward ~85% hourly carbon-free by 2026; the parallel UK arrangement with Shell does the same on the GB grid, targeting ~95%. The natural next step for in-country buyers who have already secured one PPA is to optimise around the hours not yet covered.

More broadly, hourly-matching analysis is a positive tool for any buyer building or refining their procurement portfolio: it surfaces which hours are exposed, which technologies and locations actually cover them, and where storage or additional contracts deliver the most hedge effectiveness per euro spent.

4. Methodology

For this analysis, we conducted a stochastic Monte Carlo analysis of hedging cost and effectiveness for a multi-zone European corporate buyer, calibrated to current market strikes, tradable forward benchmarks, and relevant historical spot data.

The model is a Monte Carlo settlement engine: it simulates 1,000 plausible 10-year paths for hourly spot prices across the five in-scope markets (FR, IT, DE, ES, FI), then runs each of the four procurement strategies through every path and reports the distribution of outcomes.

A handful of choices are worth flagging because they materially shape how the numbers should be interpreted:

- **Hourly settlement.** Every cashflow runs on 8,760-hour shapes for both generation and load, so basis risk in the stressed hours isn't smoothed away by monthly averaging.
- **PPAs settle pay-as-produced.**
- Hourly matching is only applicable when procuring **in-country.**
- **vPPA strikes are anchored to live market benchmarks.** Current third-party (Pexapark) 10-year strike observations per market × technology.
- Markets – demand: FR, IT, DE, ES. Cross-border supply (S2): ES, FI. In-country supply (S3, S4): FR, IT, DE, ES.
- **Three buyer archetypes.** Data-centre (flat 24/7), retail (morning + evening peaks, low overnight), manufacturing (midday-centred daytime load, no evening peak). Every strategy is run against each.
- **Cost framing.** €/MWh figures are 10-year NPV discounted at 5% to 2027, divided by undiscounted consumed MWh.
- **Solar and wind cannibalisation.** Both applied hour-by-hour, calibrated to recent capture ratios and held flat across the horizon.

Data sources

- Historical spot prices – hourly day-ahead across the five in-scope markets, multi-year window covering both pre-crisis and crisis conditions.
- Forward curves – traded baseload calendar forwards (EEX).
- PPA strike prices – Pexapark price assessment benchmarks per market, per technology, start date 1 Jan 2027.
- Generation profiles – hourly capacity factors by country × technology, each series calibrated to its median historical year.
- Buyer demand profiles – representative hourly load shapes per archetype in each country.

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For product and analysis enquiries

hello@renewabl.com

For media enquiries

Luma Manina
Head of Marketing
luma@renewabl.com

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