

Solar without Subsidy: Revenue Floors, Hedging and Storage in Merchant Projects

An Hourly Cash Flow Framework for Merchant Solar and Storage

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October 2026

Abstract

This paper examines how merchant solar projects convert electricity production into contractual receipts and funded cash. It develops a proposed diligence framework for capture price, settlement location, protected quantity, negative-price terms, battery dispatch and payment liquidity. Primary sources from Europe, Great Britain, the United States and Australia are used within their stated market and time boundaries.

A fictional 100 MW solar project and an optional 25 MW/50 MWh battery are compared across five revenue arrangements. Four seasonal daily profiles are expanded into 8,760 chronological hourly intervals. The calculation separates physical sales, PPA difference payments, a fixed-volume hub swap, a capped local floor, storage energy transfers, operating costs, scheduled debt and a daily cash ledger. Twenty-year incremental storage value and deterministic sensitivities are calculated from explicit author assumptions.

In the illustration, an annual-average revenue shortcut gives USD 9.404 million while hourly local sales give USD 2.431 million. All five first-year cases have debt-service coverage below 1.00 under the assumed debt. Storage has positive incremental NPV of USD 1.823 million under the baseline inputs and retains a combined-project debt-service shortfall. These calculated outcomes describe the fictional case only. The proposed approval framework joins reviewed revenue rights, feasible operations and dated funding; project-specific valuation requires the omitted costs, actual contracts and attributable data.

JEL Classification: Q42, Q41, G32, C63

Keywords: merchant solar, capture price, power purchase agreements, revenue floors, hedge basis, battery storage, project finance, collateral liquidity

1. Research question and cash-flow boundary

This paper examines the contractual and operating choices that should be tested when solar-project revenue depends on market sales and commercial risk transfers. Its working definition of a merchant project excludes a public production-price support contract from the revenue case being evaluated. Any tax benefit, certificate income, capacity payment or public credit support should be identified separately before a transaction is described as subsidy-free. This definition is an analytical boundary for the paper; a specific project's classification requires its actual funding and contractual records.

The European Commission's April 2026 PPA recommendation distinguishes physical delivery from financial settlement and separately distinguishes pay-as-produced from shaped or baseload profiles. It identifies credit, basis and regulatory exposures as relevant to contract choice and bankability. [3] These distinctions provide the starting vocabulary for examining how a project converts generation into cash.

The proposed investment test follows that conversion through four records: the production forecast, the physical market settlement, the commercial hedge settlement and the cash account. For each record, the diligence team should identify the responsible entity, measurement period, quantity definition and contractual dispute mechanism. A forward-price curve belongs in the valuation inputs; a signed floor belongs in the contract record; an available cash reserve belongs in the liquidity record. Each should retain its own evidence.

The principal question is the cash available for operating costs, debt service, replacement expenditure and equity distributions under the agreed contracts. A quoted price per megawatt-hour addresses only one component of that question. The research therefore proposes examination of the interaction between delivered volume, sale location, settlement reference, hedge quantity and storage operating rights. No project-level return, lender commitment, executable hedge quotation or observed project settlement is available in this paper. All transaction recommendations below are author-proposed diligence actions. The later analytical cases should be read within their stated assumptions.

2. Capture price and the joint behavior of production and prices

For this paper, solar capture price means total energy-sale value divided by the corresponding exported energy over the measurement period. The calculation should pair each generation interval with the applicable market price at the relevant settlement location. A capture ratio should state its denominator, such as the time-weighted average price for the same location and period. Keeping those definitions visible makes seasonal, regional and contractual comparisons interpretable.

Berkeley Lab's 2025 data guide offers an appropriate methodological reference. It distinguishes annual energy value, capacity value, curtailment and value-factor records. Its hourly generation series through 2024 includes modeled and debiased estimates, with some directly reported ERCOT data; its clean generation series reflects curtailment where curtailment is recorded. [1] A project team using this resource should preserve those estimation and coverage limits when constructing a comparator.

ACER's 2026 monitoring page, covering EU developments through the end of 2025, reports that increased solar generation lowers daytime prices and contributes to larger daily price swings. It also highlights regional differences and the role of interconnection. [2] The appropriate underwriting question is therefore how a particular export profile coincides with prices in its own market.

The proposed analysis should retain the joint sequence of prices and generation. Under the paper's capture-price definition, changing the distribution of output across intervals changes the weighting of prices. Two annual datasets with identical total production can consequently produce different calculated sale values. The reviewer should ask whether a forecast applies a

historical capture adjustment, a modeled hourly profile or a technology-specific forward value, and record that choice.

Further tests should examine daylight-saving treatment, missing intervals, commissioning periods and the treatment of zero-export observations. A price series and a generation series should use compatible timestamps and units. The valuation should report energy value and any separately contracted capacity value in separate lines. Capture-price evidence should then be carried into the revenue case with the same location, period and output definition.

3. Revenue floors and the architecture of the PPA

A contract review should identify the precise object receiving price protection. Possible objects include eligible exported energy, a specified delivery schedule or a financial settlement quantity. The reviewer should also identify the term, escalation rule, caps, suspension conditions, settlement reference and payment counterparty. This proposed record allows the claimed floor to be reconstructed from the agreement.

EPA's green-power purchasing guide describes a financial PPA example in which the generator sells electricity into the wholesale market and the purchaser exchanges the difference against an agreed price. Physical electricity supply to the purchaser remains separately arranged. [4] The guide is used here for this settlement mechanism; its 2018 market statistics and tax or accounting descriptions are outside the current evidence base.

The Commission's 2026 recommendation describes pay-as-produced arrangements as transferring production/profile exposure to the offtaker, while shaped or baseload delivery transfers profile and balancing exposure toward the generator or an intermediary. [3] For project assessment, the contract's quantity definition should be read alongside its settlement method.

In the simplified analytical case of a fixed price for every eligible exported unit, protected revenue is that fixed price multiplied by eligible output. The resulting annual cash amount still depends on the volume qualifying under the agreement. Diligence should therefore ask how outages, curtailment, metering corrections and negative-price periods affect eligibility. Where the contract uses deemed generation, the calculation method and dispute process should be documented.

A private floor can also be considered with a cap or sharing arrangement. The author-proposed comparison is the resulting net cash under a common production and price sequence, including premiums, fees and excluded intervals. Each submitted proposal should be accompanied by a term sheet identifying its scope. The project team should ask who pays each settlement, when payment occurs and what remedies follow a failure to pay.

The floor's contribution to financing should be assessed against the proposed debt-service calendar. Its contract term, termination exposure and counterparty support should be visible alongside the protected price. A financing conclusion requires the relevant lender's actual assessment of those terms.

4. Fixed-volume hedging, basis and liquidity

A fixed-volume financial hedge should be evaluated using both its contracted quantity and the project's physical export. In the paper's simplified settlement definitions, the physical sale earns

exported quantity multiplied by the sale price; the hedge adds contracted quantity multiplied by the difference between the fixed hedge price and its reference price. This identity provides an auditable starting point for scenario analysis.

When contracted quantity equals exported quantity and both price references coincide, the defined cash flows combine to the fixed price multiplied by exported output. Where either equality fails, the scenario retains a residual quantity or price difference. This is a mathematical statement within the defined case. The actual agreement should be checked for its own calculation conventions, netting and exceptions.

EPA identifies settlement-location basis as the difference between the generator's sale location and the location used to set the financial PPA contract price. [4] A review should name both locations and examine the source of their historical price differences. Proposed hedges at a hub, regional reference or bidding zone should retain that identification throughout the valuation.

Quantity selection should receive the same attention as fixed-price selection. A proposed low-generation/high-price stress should calculate the cash on actual exports alongside the full contractual financial settlement. Additional cases should vary commissioning date, degradation, prolonged outage and hedge renewal. The review should record who approves hedge quantities and how forecasts can change during the contract term.

ICE's clearing description states that cleared positions require initial margin and at-least-daily variation or mark-to-market payments, with potential special intraday calls. [5] These mechanics establish a separate liquidity question for a cleared hedge. Bilateral PPA collateral provisions should be examined in their own executed documents.

The proposed liquidity schedule should follow payment timing, collateral calls, eligible collateral and release conditions. It should also identify committed facilities, draw conditions and cash restrictions. A project with an acceptable long-term modeled value should still be subjected to a period-by-period funding test for its chosen hedge structure.

5. Negative-price clauses, curtailment and settlement exceptions

Negative-price treatment should be translated into an interval-level contract rule before valuation. The proposed review should identify the triggering market, threshold, duration requirement, time convention and effect on eligible output. It should ask whether the rule suspends a payment, changes the settlement reference, permits curtailment or reallocates compensation. Those are questions for the signed agreement.

Great Britain's public CfD rules provide a documented comparator. DESNZ's 21 April 2026 delivery plan states that contracts awarded from Allocation Round 4 onward receive no difference payments for settlement periods with a negative day-ahead price. The same discussion addresses different incentives where intraday prices become negative after a positive day-ahead price. [6] This specific public-support rule should remain identified as a GB CfD provision in any comparison.

For a merchant agreement, the author proposes a clause-by-clause examination of production, dispatch, metering and compensation. Economic curtailment requested by a commercial counterparty, network-related curtailment and an equipment outage should each have a defined

treatment in the review. Where compensation is proposed, the reviewer should identify the payer, formula, timing, caps and evidence needed to establish entitlement.

The negative-price record should preserve magnitude, duration and the share of project output affected. A simple event count provides only a partial description. AEMO's Q2 2026 report documents different negative-price patterns across NEM regions and a shift toward less-negative price magnitudes during that quarter. [9] The project analysis should retain the market and period of that observation.

The same attention applies to losses. AEMO's 2026-27 MLF publication identifies annual NEM transmission-loss factors and expressly cautions that they apply to that financial year and should not be used as future-year indicators. [10] A longer-term valuation should disclose how subsequent loss factors are treated. The proposed review should also distinguish a contract's energy measurement point from the point at which market losses and charges are applied.

6. Storage as a constrained operating asset

Storage appraisal should begin with the intended service and the physically available equipment. The proposed specification should record power capacity, usable energy, charging sources, connection limits, operating range, warranty conditions and augmentation plan. These inputs should have named evidence owners, such as the equipment supplier, independent engineer or connection provider.

The 2025 Annual Technology Baseline distinguishes storage power and energy capacities, incorporates augmentation in its cost assumptions and recognizes usage-related degradation. Its approximately daily cycling and 85% round-trip efficiency are model assumptions. [7] A project model should use its own supported technical values and separately identify any benchmark assumptions retained from this source.

The proposed dispatch calculation should carry state of charge between intervals. It should account for charge and discharge limits, conversion losses and any energy reserved for contracted services. An intended evening delivery should be tested against the preceding charging opportunity and the actual energy available. The model should identify the source of charging energy and its purchase or opportunity cost.

Connection architecture also requires explicit treatment. CAISO's 2025 annual report describes hybrids as a single modeled resource receiving one dispatch instruction. It describes co-located resources as separately metered and dispatched resources sharing an interconnection, subject to aggregate capability limits. [8] These are CAISO-specific participation descriptions that illustrate why a site layout alone is insufficient for revenue modeling.

For a proposed solar-storage combination, the incremental appraisal should compare the combined asset with the same solar project operating alone. Both cases should use an identical solar-generation and price dataset. The comparison should itemize storage capital expenditure, charging cost, foregone direct exports, operating cost, degradation and incremental market receipts.

Any proposed storage dispatch intended to support a shaped PPA should be tested together with that PPA. The contract review should ask whether dispatch control, renewable-attribute ownership and charging permissions support the planned delivery. It should also identify which

entity carries responsibility when the battery is unavailable. Storage investment should proceed to financing review with those technical and contractual questions documented.

7. Revenue stacks within distinct market boundaries

A storage revenue case should identify the jurisdiction, service definition, eligibility requirements and measurement period for every revenue line. EIA's September 2025 article reports that, for 2024, 66% of U.S. utility-scale battery capacity had arbitrage among its reported uses and 41% identified it as its primary use. [12] These survey classifications provide evidence of operating applications; a project's receipts require its own settlements or supported forecast.

AEMO's Q2 2026 report describes narrower NEM battery price spreads and lower aggregate arbitrage receipts than in the comparable 2025 quarter. Its revenue measure excludes FCAS costs and Frequency Performance Payment outcomes. [9] The report offers a time-bounded reminder to define the netting convention before using a market revenue comparison.

CAISO's hypothetical battery model co-optimizes energy and regulation in one scenario and observes state-of-charge constraints. The report discloses excluded cycling-related variable operating costs and limits comparability of certain WEIM simulated revenues with actual settlements. [8] A sponsor's simulation should similarly disclose which costs, constraints and settlement rules are represented.

The U.S. legal example used here is FERC's October 2019 PJM compliance order, which distinguishes accounting for state-of-charge limits from operator management of that state and discusses dispatch-deviation penalties. [11] Current participation terms should be checked against the relevant market's current tariff and project registration.

For Great Britain, the review should retain the project's own power-sale, balancing and connection arrangements. For the EU, the relevant bidding zones and any cross-zone PPA exposures should be identified. For the United States, the relevant ISO, utility or balancing authority and settlement node should be named. For Australia, NEM regional settlement and loss-factor assumptions should be kept separately from Western Australia's WEM arrangements.

The proposed revenue stack should then test simultaneous feasibility. Each interval should show how power, stored energy and reserved capability are allocated among delivery obligations and services. Commercial rights and operational capacity should be reconciled before service revenues are combined in a financing case.

8. Proposed bankability and valuation decision gates

The author proposes three decision gates for a merchant solar investment. The first is revenue-definition completeness. Every material receipt should have an identified quantity, price reference, counterparty, term and payment rule. Where a receipt depends on a forecast, its data vintage and methodology should be recorded. Where it depends on a contract, the relevant clause should be available for review.

The second gate is downside funding. A proposed lender case should test cash available on the debt-service dates together with liquidity demands arising from the chosen hedge. Review scenarios should include low production, adverse settlement-location differences, changed negative-price exposure, constrained exports and counterparty payment delay. The scenarios

should state which variables are changed together and why the combination is being examined. Their outputs should retain the label assigned to the scenario.

The third gate is the incremental value of flexibility. Storage and shaped delivery should each be assessed against a documented baseline. The review should identify the additional capital and operating commitments, the transferred contractual exposures and the dispatch rights needed to earn the modeled value. Any overlap between those activities should be resolved within a single operating schedule.

Valuation should also disclose the boundary between the contracted period and the merchant tail. The proposed review should record assumptions for remaining equipment life, degradation, major maintenance, recontracting, future capture price and disposal costs. A merchant-tail scenario should have its own sensitivity results. No current long-term executable price or project-specific residual value has been verified for this paper.

Investment documentation should carry these gates into a concise approval record: accepted contractual terms, approved model inputs, unresolved diligence items and conditions required before commitment. The same record should identify who can authorize future hedge changes and storage dispatch mandates.

The resulting decision is transaction-specific. A supported floor, a compatible hedge quantity and a technically feasible storage plan should each have a distinct evidentiary record. Financing and valuation conclusions should follow the reviewed combination of those records, with remaining assumptions visible to the decision-maker.

9. A fictional project and a chronological test

The illustration follows a 100 MW solar plant through 8,760 hourly intervals. Four explicitly specified daily profiles represent winter, spring, summer and autumn, weighted by 90, 92, 92 and 91 consecutive days respectively. Solar output follows a daylight sinusoid evaluated at each hour's midpoint. Seasonal peaks range from 55 MW to 95 MW. The profiles are deliberately transparent so that generation, price exposure and storage transfers can be reproduced from the stated inputs.

An 80 MW interconnection limit constrains net exports. The baseline permits solar production and export during negative local prices; clipping occurs when the export limit binds. This operating rule applies to all five comparisons. The storage case follows its charging windows before exporting residual solar energy. A separate voluntary-curtailement scenario switches off residual solar exports when the local node price is negative. Neither rule is presented as economically optimal or as a permission available to an actual project.

The five cases share the same underlying solar resource and interconnection. They comprise merchant solar, an as-generated fixed-price arrangement with a negative-hub-price suspension, a constant-volume hub swap, a capped local revenue floor, and merchant solar with a 25 MW/50 MWh battery. The baseline gives the battery permission to charge solely from solar. It receives no capacity payment, ancillary-service payment or subsidy. Each revenue stream appears once in the cash reconciliation.

The solar asset costs USD 70 million at time zero. Storage adds USD 12 million. Solar operating cost begins at USD 2 million annually, with an additional USD 0.25 million for storage; both rise

by 2% each year. Year one uses undegraded output and battery capacity. From year two, solar output falls by 0.5% annually and usable battery energy capacity by 2%. Battery power remains 25 MW. All twenty operating years reuse the fictional nominal price profiles and contract parameters.

Initial debt is USD 45 million in every case. Storage capital expenditure is entirely additional equity in this comparison. Opening unrestricted cash and a separately funded debt-service reserve are also equity-funded uses at time zero. These assumptions permit a comparison of operating mechanisms and incremental battery value; they do not establish a financing proposal for a real asset.

All plant characteristics, prices, contract terms, financing assumptions, fees and operating permissions in the following illustration are fictional author assumptions. Calculated outcomes describe this example only. They are not observed market results, an executable offer, a project valuation, a price forecast or a probability assessment. The source-based market discussion does not calibrate these fictional inputs.

Table 1. Fictional plant and operating assumptions

Item	Value	Unit	Rule
PV nameplate	100.000	MW	Year-one profile is undegraded
Export limit	80.000	MW	Net PV and battery export
Battery power / capacity	25 / 50	MW / MWh	Year one; no grid charging
Round-trip efficiency	90.000	%	Equal square-root charge and discharge efficiencies
PV / battery annual degradation	0.5 / 2.0	%	Applied from year two
Charge / discharge hours	11-15 / 18-21	hour beginning	Charge from PV; dispatch window order
PV / battery initial capex	70 / 12	USD million	Paid at time zero
PV / battery first-year opex	2.00 / 0.25	USD million	2% annual escalation

All values are author assumptions. No observed project is represented.

Table 2. Representative days and annual weights

Season	Days	PV peak MW	Daylight hours	Hub adjustments
Winter	90	55.000	7.0-17.0	+8 all hours; +15 extra 11-15
Spring	92	85.000	6.0-18.0	+0 all hours; +0 extra 11-15
Summer	92	95.000	5.0-19.0	-7 all hours; -10 extra 11-15
Autumn	91	70.000	6.5-17.5	+4 all hours; +0 extra 11-15

Hourly base hub prices and node basis are retained in the reproducible model. Days are consecutive, totaling 365.

10. The annual-average revenue trap

The fictional annual time-average hub price is USD 45.08/MWh. Applying that price to 208,623 MWh of metered solar exports produces a revenue shortcut of USD 9.404 million. The hourly calculation gives physical revenue of USD 2.431 million at the local node. The USD 6.973 million difference can be traced to two separate calculations: the solar generation shape and the difference between hub and local-node prices.

First, weighting the hub price by the plant's actual exported energy gives a hub capture price of USD 18.82/MWh. The solar-shape revenue gap is USD 5.477 million. The denominator is

exported energy after interconnection clipping, so the capture price describes the price received on metered output. Available energy that is curtailed receives no revenue and is reported separately. Using gross available generation in this denominator would change the economic question.

Second, the PV-weighted local-node capture price is USD 11.65/MWh. The local basis reduces physical revenue by another USD 1.496 million. In this example, the node trades USD 8/MWh below the hub during hours 9 to 16, USD 5/MWh below during hours 17 to 21, and USD 3/MWh below otherwise. Those spreads are fixed author assumptions. They show how an explicitly defined location difference survives a contract whose financial settlement references the hub.

The hourly profiles contain 918 negative-hub-price hours and 1,101 negative-local-price hours. The baseline exports 80,683 MWh during negative local prices. Its positive annual hub average therefore sits alongside substantial negative-priced solar output. Winter solar peaks are lower and the winter midday prices are higher; summer produces more energy into the deepest midday price depression. The seasonal and hourly weights both contribute to the calculated result.

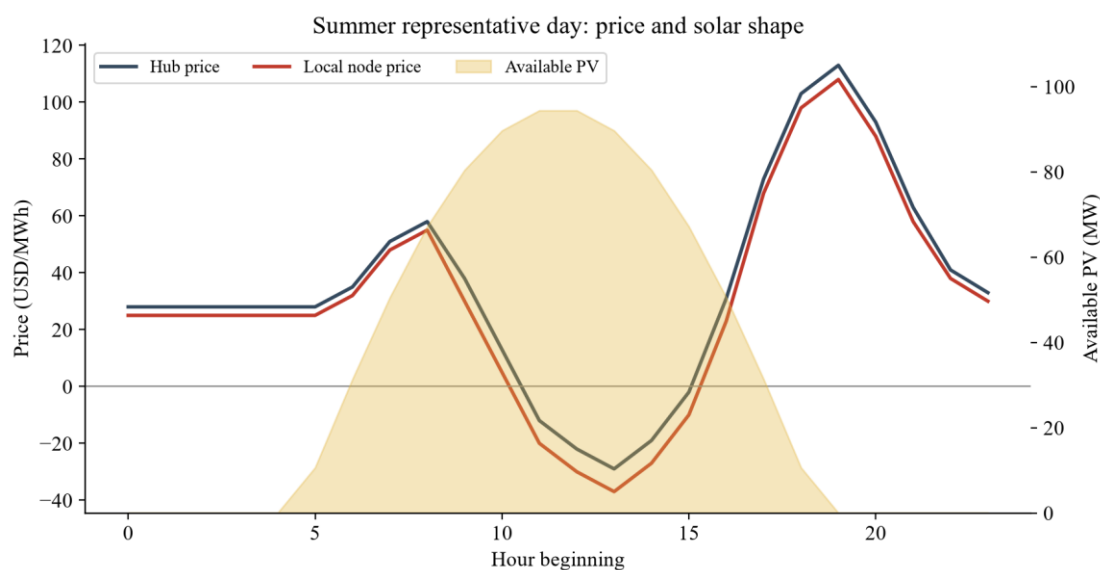
The two gaps reconcile exactly: annual-average shortcut less hourly local revenue equals the shape gap plus the basis gap. This accounting identity makes the shortcut's limitation visible without attaching a probability to it. A project-specific application would require independently established production, curtailment and settlement-price series. The fictional result supplies a reproducible diagnostic for checking which price, volume and location an annual revenue figure actually represents.

Table 3. Capture-price and revenue decomposition

Metric	Calculated value	Unit
Time-average hub price	45.076	USD/MWh
PV-weighted hub capture price	18.823	USD/MWh
PV-weighted node capture price	11.654	USD/MWh
Annual-average revenue shortcut	9,403,857.837	USD
Hourly local-node revenue	2,431,188.655	USD
Solar-shape revenue gap	5,476,991.599	USD
Local-basis revenue gap	1,495,677.584	USD

Prices use actual PV-only metered export as weights, excluding curtailed MWh.

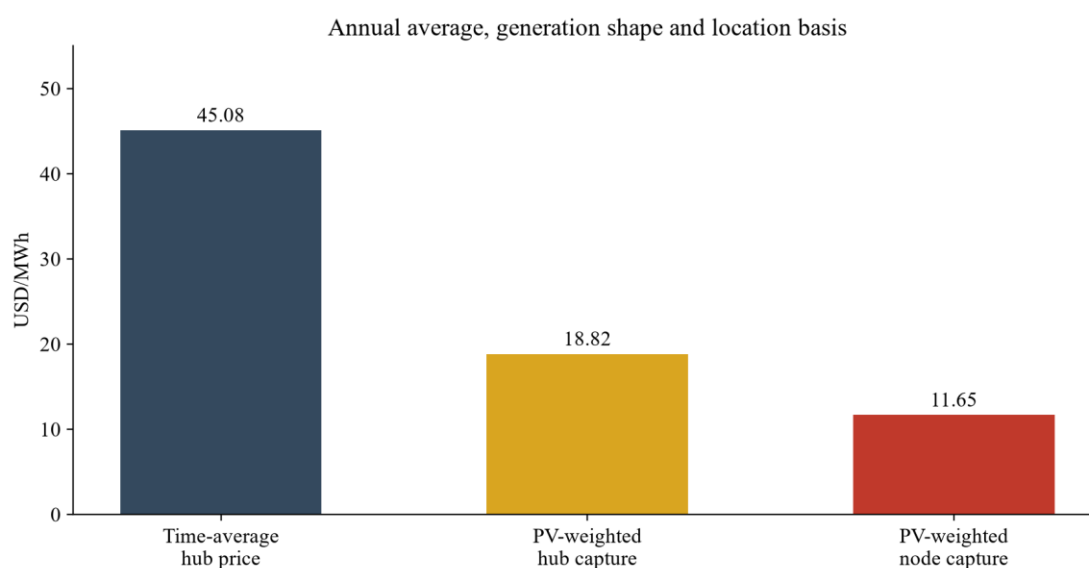
Figure 1. Representative summer price and solar profiles



Fictional author assumptions; deterministic calculations; no market observations.

Fictional hourly profiles expanded chronologically; prices and generation are separate axes.

Figure 2. Time-average hub price, solar capture and local basis



Fictional author assumptions; deterministic calculations; no market observations.

Calculated from actual metered PV-only export weights; author assumptions.

11. What each revenue contract actually pays

The as-generated arrangement targets USD 55/MWh on actual exports in hours when the hub price is non-negative. The calculation records local physical receipts and a difference-settlement of exported MWh multiplied by USD 55 less the node price. Together, those amounts equal USD 55 per eligible MWh. During negative hub prices, the difference-settlement is suspended and the plant receives the node price on its exports. All 68,508 MWh exported in suspended hours remain exposed under the baseline operating rule.

This contract generates USD 3.923 million of additional settlement cash, producing USD 4.354 million of first-year CFADS after solar operating costs. Paying USD 55 on every exported MWh would produce USD 9.474 million of CFADS under the same output and cost assumptions. The

suspension clause therefore has a large calculated effect in this constructed price profile. That alternative is an arithmetic reference; it is outside the five contracted cases and is not an available offer.

The hub swap settles 15 MWh in every hour, including hours with no solar production. Its annual settlement quantity is 131,400 MWh. Financial cash equals 15 multiplied by the difference between the USD 55 strike and that hour's hub price. Physical revenue remains exported solar MWh multiplied by the node price. The swap produces USD 1.304 million of net annual cash and USD 1.735 million of CFADS. Across the 4,558 hours with no solar generation, its aggregate settlement is a USD 0.323 million payment by the project. Production-hour receipts exceed that payment, but the night-time obligation remains explicit.

The local floor pays the smaller of USD 25/MWh and the positive difference between USD 40/MWh and the node price. Every exported MWh is eligible, including negative-priced exports. Its USD 6/MWh fee applies to all exported MWh, including volumes receiving no top-up. Curtailed and unavailable energy receive neither a payment nor a fee. Annual top-ups are USD 3.664 million and fees USD 1.252 million, yielding USD 2.844 million CFADS.

The capped floor provides limited downside support. At the example's lowest node price of negative USD 37/MWh, gross physical revenue plus the maximum top-up equals negative USD 12/MWh; after the fee, the result is negative USD 18/MWh. Contract labels alone leave this residual exposure unspecified. The actual settlement formula, eligible volume, cap, fee basis and suspension test determine the cash outcome in the illustration.

Table 4. Contract settlement rules

Case	Settlement quantity	Contract cash	Negative-price rule	Fee
Merchant PV	Actual exported MWh	Node price x export	Export continues	0.000
As-generated PPA	Actual export when hub ≥ 0	$(55 - \text{node}) \times \text{eligible export}$	Suspension when hub < 0 ; exposed exports receive node price	0.000
Fixed-volume hub swap	15 MWh each hour	$15 \times (55 - \text{hub})$	Swap continues at all hours	0.000
Capped local floor	All actual exported MWh	$\text{export} \times \min(25, \max(40 - \text{node}, 0))$	All exported MWh eligible, including negative prices	6 USD per all exported MWh
Merchant PV plus storage	Actual net exported MWh	Node price x net export	Window dispatch; residual exports continue	0.000

Financial difference-settlements are added once to physical receipts. PPA form is an illustrative nodal difference settlement.

Table 5. Year-one contract economics

Case	Physical revenue USD m	Contract settlement USD m	Fee USD m	CFADS USD m
Merchant PV	2.431	0.000	0.000	0.431
As-generated PPA	2.431	3.923	0.000	4.354
Fixed-volume hub swap	2.431	1.304	0.000	1.735
Capped local floor	2.431	3.664	1.252	2.844
Merchant PV plus storage	4.390	0.000	0.000	2.140

CFADS equals physical revenue plus contract cash less fee and annual operating cost. PV opex 2.00m; storage case opex 2.25m.

12. Storage energy, export limits and dispatch

The battery charges from available solar during hours 11 to 15 and discharges during hours 18 to 21, proceeding in chronological order within each window. Charging stops when power, available solar or usable energy capacity binds. Discharging stops when power, stored energy or spare interconnection capacity binds. The rule uses no optimization, price forecast or simulated perfect foresight. It remains unchanged in the scenario calculations, making its limitations visible when prices or physical constraints change.

Round-trip efficiency is 90%. Charge and discharge efficiencies each equal the square root of 90%, approximately 94.87%. Each charged MWh therefore adds about 0.9487 MWh to stored energy; each exported discharge MWh requires about 1.0541 MWh from storage. Opening stored energy is zero. State of charge carries through every interval and season transition. Discharge windows empty the battery in the modeled profiles, and closing stored energy at year end is zero. The program checks this terminal condition explicitly.

Available solar energy totals 213,919 MWh. PV-only operation exports 208,623 MWh and curtails 5,296 MWh. With storage, annual solar-to-battery charging is 19,237 MWh, battery discharge is 17,313 MWh, conversion losses are 1,924 MWh, and curtailment falls to 1,611 MWh. Total net export rises to 210,384 MWh. The annual physical identity is available solar equals exported energy plus curtailed energy plus conversion losses plus the change in stored energy.

Storage captures 3,685 MWh that the PV-only case would curtail. Most charged energy consequently comes from solar that the plant could otherwise export. That diversion carries an opportunity cost or benefit at the prevailing local price. Net export increases by only 1,761 MWh because conversion losses absorb part of the recovered curtailment. The much larger change in revenue comes from moving metered energy between differently priced hours. The calculation includes both effects automatically through changed hourly net exports.

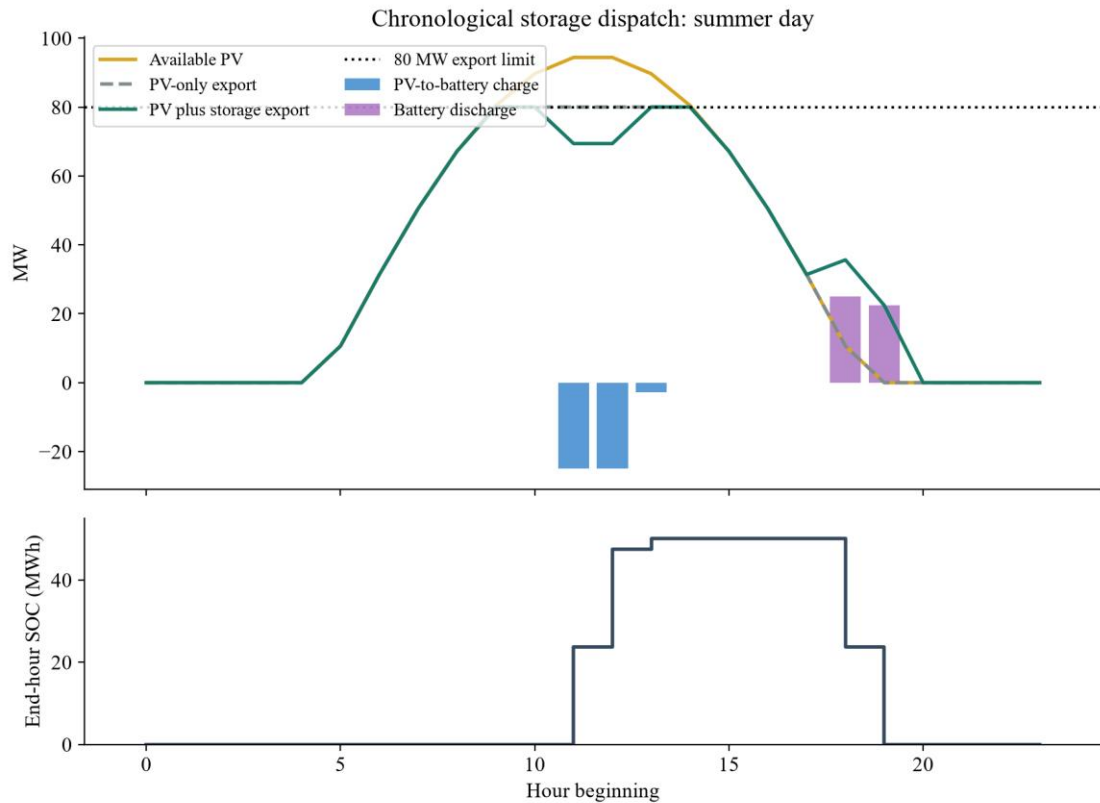
First-year physical revenue rises from USD 2.431 million to USD 4.390 million. Deducting incremental storage operating cost leaves USD 1.709 million of incremental CFADS. No separate arbitrage credit is added to those receipts, and discharged solar is counted once at the export meter. Grid purchases are zero. This boundary avoids adding the same shifted energy to solar revenue, discharge revenue and a second hypothetical trading-profit line.

Table 6. Annual physical energy reconciliation

Energy item	PV only MWh	PV plus storage MWh
Available PV	213,918.787	213,918.787
Export	208,622.680	210,384.074
Curtailment	5,296.107	1,610.994
Battery conversion losses	0.000	1,923.719
Final stored energy	0.000	0.000
Gross PV-to-battery charge	0.000	19,237.189
Gross battery discharge	0.000	17,313.470

Available PV equals export plus curtailment plus conversion losses plus closing less opening SOC. Charge/discharge are internal transfers and are not additional generation.

Figure 3. PV-only and PV-plus-storage dispatch on a summer day



Fictional author assumptions; deterministic calculations; no market observations.

Charge and discharge are internal transfers; ending hourly SOC and the net export limit are shown.

13. Debt coverage and payment liquidity

The fictional debt uses fifteen equal annual payments with interest calculated at 6% on each year's opening principal. Annual principal and interest total USD 4.633 million. For the timing ledger, that annual amount is allocated equally to quarter ends; interest is not recomputed quarterly. Debt service is zero in years 16 to 20. DSCR is annual CFADS divided by scheduled principal and interest. The model defines CFADS as physical revenue plus contract settlements less contract fees and operating costs. Tax and maintenance capital expenditure are set to zero explicitly; a real financing model would require those missing project-specific inputs.

All five baseline cases have first-year DSCR below 1.00: merchant solar 0.093, as-generated PPA 0.940, hub swap 0.375, capped floor 0.614, and merchant solar with storage 0.462. Annual CFADS deficits relative to debt service are approximately USD 4.202 million, USD 0.280 million, USD 2.898 million, USD 1.790 million and USD 2.493 million respectively. These deficits follow directly from the chosen debt amount and operating assumptions. They do not establish lender thresholds or actual project solvency.

A separate daily ledger starts with USD 1 million unrestricted cash. Monthly receipts comprise physical sales plus contract settlements less contract fees, and arrive fifteen days after month end. Operating costs are paid separately each day and debt is paid at quarter ends. December's net receipts remain unsettled at the year-end measurement date. For example, the PPA has USD 0.552 million outstanding in that closing balance. It ends the modeled year with USD 0.168 million cash despite its annual CFADS deficit, using part of the opening cash buffer.

The swap alone posts collateral. Its fictional contractual requirement uses the previous day's maximum hub price: thirty days multiplied by twenty-four hours multiplied by 15 MWh multiplied by the positive excess above the strike. First-day collateral is zero and all outstanding collateral is released at the final day end. This spot-peak proxy is stated solely as a hypothetical cash-security rule; it does not calculate a forward mark-to-market, a forecast exposure or an exchange margin requirement.

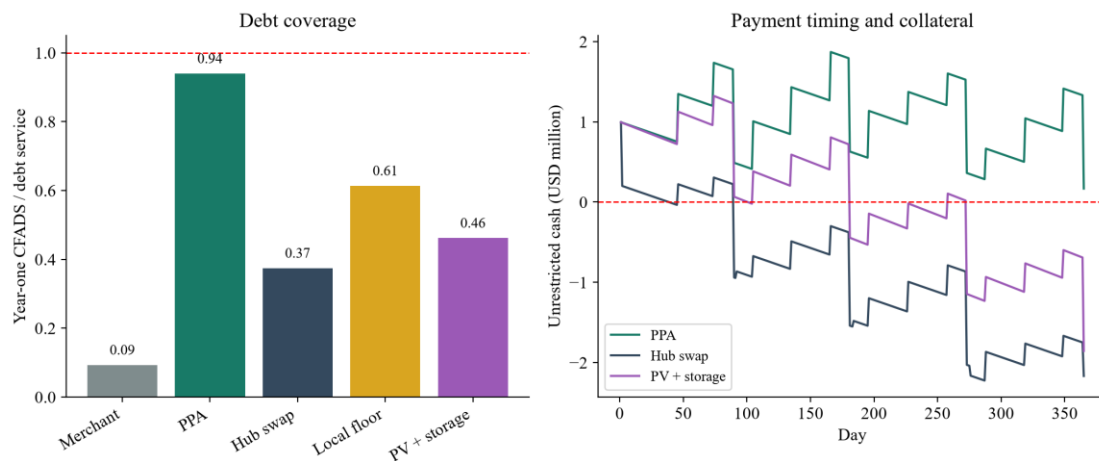
Peak collateral is USD 0.788 million. The swap case requires USD 2.913 million additional liquidity beyond opening cash at its deepest modeled deficit. Collateral posting and return are cash transfers, with zero net annual expense. The separately restricted six-month debt-service reserve is USD 2.317 million. It is excluded from CFADS and unrestricted cash, with no automatic draw assumed. The ledger thus distinguishes operating debt coverage, receivable timing, collateral funding and restricted reserves.

Table 7. Debt coverage and payment liquidity

Case	DSCR	Debt shortfall USD m	Extra liquidity USD m	Peak collateral USD m
Merchant PV	0.093	4.202	3.390	0.000
As-generated PPA	0.940	0.280	0.000	0.000
Fixed-volume hub swap	0.375	2.898	2.913	0.788
Capped local floor	0.614	1.790	1.165	0.000
Merchant PV plus storage	0.462	2.493	1.856	0.000

45m debt, 6%, 15 years; annual debt service calculated as a level annuity. Initial unrestricted cash 1m; six-month DSRA is separately restricted. Extra liquidity is peak funding need, not an annual expense.

Figure 4. Annual debt coverage and daily unrestricted cash



Fictional author assumptions; deterministic calculations; no market observations.

Hypothetical annuity debt and cash-collateral rule; negative cash identifies required external funding.

14. One-factor stresses and operating permissions

Each scenario changes one stated input while holding the other model rules constant. No probabilities, expected values or confidence ranges are assigned. A 15% reduction in available solar lowers merchant CFADS to approximately negative USD 0.018 million and PPA CFADS to USD 3.374 million. The swap's annual financial settlement remains USD 1.304 million because its contracted quantity and hub prices are unchanged. Its CFADS falls to USD 1.286 million

through lower physical revenue. This arithmetic exposes the distinction between fixed contractual quantity and realized generation.

Reducing every node price by USD 10/MWh leaves hub prices unchanged. Merchant CFADS falls to negative USD 1.655 million and the hub-swap case to negative USD 0.351 million. PPA CFADS falls to USD 3.669 million because its suspended exports remain node-exposed. The floor reaches USD 1.180 million CFADS; the top-up cap limits compensation in the lowest-price hours. These results arise from the stated settlement locations and exclusions, independently of any change in plant output.

Adding USD 40/MWh to all hub and node prices produces USD 8.776 million merchant CFADS. The fixed-volume swap pays USD 3.952 million to its counterparty and leaves USD 4.824 million CFADS. In this scenario, the hub never falls below zero, so every PPA export qualifies for USD 55/MWh and its CFADS reaches USD 9.474 million. The contractual suspension boundary creates a discrete change in eligible volumes as well as changes in the physical prices.

Reducing evening prices by USD 60/MWh has a smaller effect on PV-only receipts because the model contains little solar generation in hours 18 to 21. Storage CFADS falls from USD 2.140 million to USD 1.042 million. The fixed-volume swap gains settlement cash in those hours and reaches USD 2.990 million CFADS. Its night-time exposure therefore changes the scenario response even when physical solar production is small or zero.

Voluntary curtailment at negative local prices increases merchant CFADS to USD 1.835 million. Floor CFADS falls from USD 2.844 million to USD 2.714 million because curtailed negative-price exports lose capped top-ups as well as fees and physical losses. The same operating rule can therefore have different cash consequences across contracts. Reducing the export limit to 60 MW also raises merchant CFADS slightly in this constructed profile by clipping additional low-priced output. Both counterfactuals describe mechanically specified permissions and policies; project-specific dispatch authority, contract obligations and compensation remain outside the illustration.

Table 8. One-factor scenarios: year-one CFADS

Scenario	Merchant USD m	PPA USD m	Hub swap USD m	Storage USD m
Base	0.431	4.354	1.735	2.140
Solar output down 15%	-0.018	3.374	1.286	1.771
Node basis worse by 10	-1.655	3.669	-0.351	0.036
All hub and node prices up 40	8.776	9.474	4.824	10.555
Evening prices down 60	0.372	4.354	2.990	1.042
Negative-price voluntary curtailment	1.835	5.037	3.139	3.435
Export limit reduced to 60 MW	0.578	4.112	1.882	2.193

Each scenario changes only the stated input. No probabilities or forecast interpretations are assigned. The capped-floor case is calculated separately.

15. Storage capital expenditure and degradation

The storage investment is assessed incrementally against the identical merchant PV asset. At time zero, its cash outflow is USD 12 million. In each subsequent year, incremental operating cash equals merchant PV-plus-storage CFADS less merchant PV-only CFADS. Both assets experience

the same solar degradation and operating-cost escalation; the storage case also experiences declining usable battery capacity and additional battery operating cost. Debt service is identical and cancels from this unlevered comparison.

The discount rate is an assumed nominal 8%, with annual operating cash received at year end. The present value of twenty incremental cash flows is USD 13.823 million. This is the break-even initial battery capital expenditure under the specified model: paying that amount at time zero gives zero incremental NPV. Against assumed expenditure of USD 12 million, incremental NPV is positive USD 1.823 million. The calculation excludes replacement, augmentation, residual value, taxes and maintenance capital expenditure. Each excluded item requires an explicit assumption before any project valuation can use this framework.

Usable battery capacity falls from 50 MWh in year one to 46.12 MWh in year five, 41.69 MWh in year ten, 37.68 MWh in year fifteen and 34.06 MWh in year twenty. Incremental CFADS declines from USD 1.709 million to USD 0.936 million over the twenty years. The repeated nominal prices hold the trading environment fixed, while degradation reduces transferable energy and escalating operating cost absorbs an increasing amount of the remaining revenue benefit.

Evening-price sensitivities show how closely capital value depends on the assumed spread. Lowering hours 18 to 21 by USD 40/MWh reduces break-even capital expenditure to USD 7.889 million and incremental NPV to negative USD 4.111 million at the assumed USD 12 million cost. Increasing those hours by USD 40/MWh raises break-even expenditure to USD 19.756 million. These are separate deterministic cases using the same window dispatch; they are neither probability-weighted investment outcomes nor claims about future storage returns.

The positive baseline incremental NPV coexists with a USD 2.493 million first-year debt-service shortfall for the combined asset. Battery value and financing adequacy answer different model questions. The calculation attributes the battery's incremental operating value, while the DSCR calculation tests the combined project's chosen debt payments. An investment conclusion would additionally require a complete project cash flow, verified capital and operating costs, financing terms and a documented treatment of the excluded items.

Table 9. Storage operating-value path

Operating year	Battery capacity MWh	Incremental CFADS USD m	PV plus storage CFADS USD m	Debt service USD m
1	50.000	1.709	2.140	4.633
5	46.118	1.530	1.733	4.633
10	41.687	1.319	1.221	4.633
15	37.682	1.121	0.702	4.633
20	34.062	0.936	0.172	0.000

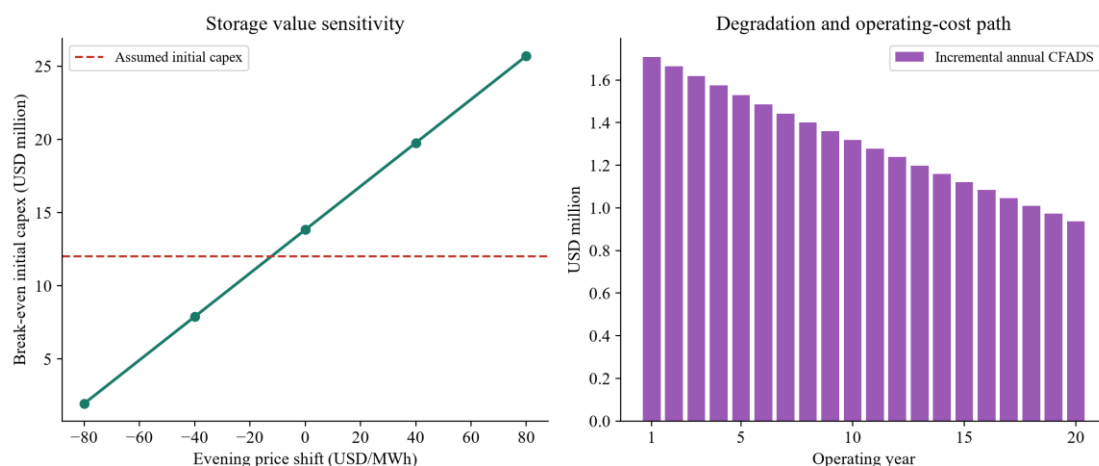
Year one is undegraded; degradation begins in year two. No battery replacement, augmentation, terminal value, tax or maintenance capex. Incremental CFADS uses identical PV assets in both cases.

Table 10. Storage initial-capex sensitivity

Evening price shift USD/MWh	Break-even capex USD m	Assumed capex USD m	Incremental NPV USD m
-80.000	1.956	12.000	-10.044
-40.000	7.889	12.000	-4.111
0.000	13.823	12.000	1.823
40.000	19.756	12.000	7.756
80.000	25.690	12.000	13.690

Twenty operating years, 8% nominal discount rate; no financing effects. Price shift applies at hours 18-21 to both hub and node.

Figure 5. Storage break-even initial capex and incremental operating cash



Fictional author assumptions; deterministic calculations; no market observations.

Twenty operating years, 8% nominal discount rate; no terminal value, augmentation, tax or financing effects.

16. Interpreting and reproducing the illustration

Reproduction begins with the four seasonal profiles, their consecutive day counts, the twenty-four base hub prices and the explicit node-basis schedule. The hourly arrays then pass through the PV-only and storage energy balances. Contract formulas are applied to metered export and their specified settlement quantities. Operating cost, debt service and daily cash timing are calculated afterwards. This sequence keeps generation, export, contract volume and available cash as separately traceable quantities.

The supporting calculation retains raw numeric outputs, all twenty annual operating rows for every case, time-zero funding uses, a complete debt schedule and ninety-six representative hourly trace rows. The traces contain available solar, prices, PV-only exports, storage exports, charge, discharge, curtailment, losses and closing state of charge. The year-one daily ledgers retain receipts, costs, debt, collateral movements and unrestricted cash. Reader tables round amounts for presentation; the model calculations use unrounded values.

Internal assertions check hourly energy conservation, the interconnection and battery limits, no simultaneous charge and discharge, solar-only charging and zero year-end stored energy. Separately written scalar summations recompute merchant revenue, PPA receipts, hub-swap settlements, floor receipts and discounted incremental storage value. Annual cash reconciliation accounts for December's unsettled balance and verifies that collateral posting and return net to zero. These checks document implementation consistency; an independent recalculation remains a separate review task.

The illustration has deliberate resolution limits. Repeating four daily shapes omits intra-season weather variation, consecutive cloudy periods, outages, changing intraday dispatch, imbalance charges and multi-day storage scarcity. Nominal prices are held constant through the operating life. Contracts and financing contain solely the stated features; counterparty default, termination compensation and any actual collateral documentation are unmodeled. Tax, replacement, augmentation and maintenance capital expenditure are zero or excluded, as identified in the assumptions.

A project-specific application would replace those fictional inputs with attributable evidence, retain the same explicit energy and settlement boundaries, and reconcile every cash assumption with the executed documents. The calculated lesson is confined to the mechanisms demonstrated here: annual averaging obscures generation-weighted prices, the illustrated hub swap retains local and quantity exposures, the limited floor leaves residual downside, and storage value depends on physical limits, losses, dispatch and capital cost. Each conclusion follows from a stated formula, retained inputs and a reproducible case.

17. Contract terms and settlement responsibilities

Commission Recommendation (EU) 2026/917 describes physical and financial PPA settlement separately from pay-as-produced and shaped delivery profiles. [3]

The proposed contract review should turn each revenue arrangement into an executable settlement schedule. Record the contracting entity, delivery point, reference price, contracted quantity, measurement interval, payment currency and payment date. Identify the meter and price series that determine the amount payable. Reconcile those definitions with the production and price inputs used in underwriting. Any difference should remain an explicit retained exposure with an accountable owner.

For a proposed financial hedge, trace the physical sale and financial settlement separately through the bank accounts. Ask whether the contracted quantity follows actual eligible output, a forecast profile or a predetermined volume. Establish how amendments, outages, disputed meters and corrected prices enter the calculation. Where prices are published at a different location from the asset's physical settlement, identify that difference in the exposure register. The proposed acceptance test is a worked invoice assembled from the actual draft terms, supported by the referenced data and reviewed by someone who did not prepare it.

The review should also address the conditions attached to a floor. Identify its commencement, expiry, premium, caps, exclusions, quantity limits and treatment of negative prices or interrupted generation. Request advice on termination, assignment, change provisions and credit support from the actual documents. A proposed budget should retain any uncovered operating periods and expenditure required to maintain eligibility. The underwriting memorandum should state which costs and obligations accompany the quoted protection, and which counterparties must perform before a payment becomes collectible.

Prepare a calendar that joins metering, invoices, payment due dates and correction windows. Name the person who can approve a settlement, dispute an amount and authorise a contract change. Preserve every accepted calculation and supporting dataset. If a correction arrives after an investor distribution, the proposed treasury process should identify its funding route. Legal advisers should confirm that the intended allocation appears in the final documents.

Table 11. Proposed contract and settlement review

Arrangement	Quantity basis	Payment evidence	Approval question
Physical sale	Metered eligible export	Meter and price records	Which delivery point?
Financial hedge	Defined hedge profile	Separate settlement	Collateral funding if required?
Revenue floor	Defined protected quantity	Floor terms and invoice	Which exclusions apply?
Battery service	Reserved capability	Availability and instruction	Which dispatch has priority?
Corrected settlement	Revised accepted data	Adjustment and bank entry	Who funds the correction?

Author-proposed diligence matrix. Actual agreements determine quantity definitions, payment obligations, rights and remedies. No term is presented as universal.

18. Hedge collateral and operational liquidity

ICE's clearing risk framework describes initial collateral for cleared positions, at-least-daily variation or mark-to-market settlement, and discretionary special intraday calls. This description concerns cleared portfolios. [5] A proposed hedge should pass a separate liquidity approval before execution. Ask the counterparty to identify collateral triggers, valuation methods, thresholds, eligible instruments, notice requirements and release conditions in the offered terms. Reconcile each term with treasury's ability to obtain cash or security. Identify committed funding, amounts subject to another approval and support whose availability remains unverified.

The proposed collateral operating procedure should specify who receives a call, checks its calculation, escalates a dispute and authorises payment. Confirm account instructions through the agreed verification process and retain the valuation and payment evidence. Identify weekends, holidays, currency conversion and banking cutoffs where they affect the response. A treasury exercise can present a stipulated call during an outage and require the team to demonstrate the complete response using the actual contract timetable.

Distinguish a collateral deposit from a realised hedge loss and from an available cash reserve. The proposed management report should show restricted balances, accrued settlements, paid settlements and remaining drawable facilities separately. Record the conditions for releasing posted collateral and the timing assumed for that release. Ask counsel and lenders how permitted security, account restrictions and additional financial commitments interact with the hedge. Any proposed netting or reuse of funds needs confirmation from the relevant agreements before the funding schedule treats the cash as available.

In a fictional treasury exercise, a solar project has a positive expected annual hedge receipt while a valuation change creates an earlier collateral demand. The proposed committee question is whether an identified funding source can meet that dated demand alongside operating payments. An approval could require a funded liquidity allocation, a reduced contracted volume or revised collateral terms, subject to actual quotations and lender consent. Document the selected condition and the person responsible for keeping it current after execution.

19. Lender reserves and default controls

The proposed debt review should map every payment and reserve to the financing documents. Record the definition of cash available for debt service, testing dates, reserve requirements, distribution conditions and reporting obligations. Ask the lender and advisers to confirm how hedge settlements, collateral movements, battery receipts and disputed amounts are treated. The underwriting case should retain any difference between project accounting and the contractual

covenant calculation. A debt service reserve account, or DSRA, should enter the approval package with its permitted uses, replenishment obligations and actual funding source identified.

Prepare a dated priority schedule for the proposed accounts. Show operating payments, taxes where applicable, debt service, reserve funding and any permitted distributions in the sequence specified by the documents. Identify which account can fund a hedge collateral call and whether using it affects another covenant or reserve condition. Counsel should reconcile the rights of lenders and hedge counterparties, including any security and termination payment provisions. The proposed downside review should use that agreed schedule so that a single cash balance is assigned consistently across competing obligations.

Test an operational shortfall through the actual notice and decision process. A stipulated scenario might combine reduced generation, delayed settlement and a reserve replenishment requirement. Ask the asset manager to identify the reporting deadline, the decision maker and the permitted response. Distinguish a distribution restriction, a covenant breach, a payment default and any potential acceleration using the agreement's own definitions. The paper makes no universal statement about their sequence or legal consequences. The approval file should retain the adviser's interpretation and the relevant provisions.

Agree a proposed response plan for exhausted contingencies. Identify permitted sponsor support, proposed waivers, expenditure deferrals and restrictions on new trading commitments. Each action should retain its consent requirement and deadline. A sponsor's willingness to help should remain separate from an executed funding obligation. Where a proposed cure depends on asset sales or refinancing, record the evidence for timing and availability without assuming completion. The committee should receive the residual funding gap and unresolved permissions before approving leverage or distributions.

Table 12. Proposed financing and liquidity control register

Control	Document evidence	Responsible review	Unresolved condition
Debt service reserve	Permitted uses and funding	Lender and treasury	Available restricted cash
Collateral payment	Call and draw conditions	Treasury and legal	Dated funding source
Distribution test	Covenant calculation	Finance and lender	Permitted release
Default response	Notice and cure provisions	Legal and asset manager	Consent and deadline
Sponsor support	Executed commitment	Credit and legal	Amount and availability

Proposed review fields. Reserve use, security priority, breach consequences and support availability require confirmation from the actual financing documents and advisers.

20. Battery dispatch and competing commitments

The 2025 Annual Technology Baseline distinguishes battery power capacity from energy capacity and treats degradation as dependent on model usage. [7]

The proposed battery review should begin with a rights schedule for each party that can influence charging, discharge, reserved capacity or maintenance. Identify obligations to the solar offtaker, hedge counterparty, market operator, optimiser, battery service provider and lenders where they apply. Ask the engineering adviser to define project-specific accepted operating limits and available energy at each relevant interval. Commercial reviewers should establish whether the contemplated commitments can be performed together and retain unresolved conflicts.

Assign a dispatch priority for incompatible requests. A proposed agreement should identify who may reserve state of charge, which instruction takes precedence and how associated costs are

allocated. Specify how the operator treats a solar delivery obligation when charging the battery would reduce export. Record whether grid charging is permitted, how its energy and network charges are allocated and what metering supports that allocation. Ask counsel to verify any restriction affecting energy attributes or the source of stored electricity. The dispatch plan should reflect the actual market registration and connection permissions.

Evaluate availability commitments against the same physical battery schedule used for energy trading. Ask whether a proposed service requires power capacity, stored energy, a response duration or another capability during specified periods. Deduct the capacity or energy reserved under that obligation before assessing another use. The engineering reviewer should address losses, degradation, temperature limits and maintenance assumptions where they affect the offered duty. A proposed optimiser fee should have a defined calculation base and treatment of charging costs, penalties and unavailable periods. Every additional income line needs its associated operating obligation and expenditure.

A fictional scheduling exercise can place a delivery commitment, an attractive energy trade and a reserved service in the same interval. The project team should produce one feasible instruction, its settlement treatment and the contractual consequence of the unserved request. The exercise should also show what happens when telemetry is interrupted or the battery reaches an operating limit. Conditional approval could restrict participating services, reserve a specified operating capability or require revised instructions, supported by the agreed test.

Table 13. Proposed battery commitment compatibility review

Commitment	Capability to reserve	Evidence to test	Conflict decision
Solar delivery	Required export profile	Delivery and charging plan	Allocate reduced export
Energy trading	Power and stored energy	Feasible interval schedule	Respect prior obligations
Reserved service	Required availability	Accepted service definition	Deduct reserved capability
Maintenance	Unavailable equipment	Approved work schedule	Reconcile commitments
Telemetry failure	Permitted fallback	Stipulated response test	Suspend or restrict action

Author-proposed compatibility test. Offered services remain conditional on engineering limits, market participation permissions and executed contracts. No revenue uplift is assumed.

21. Diligence records and closing conditions

The proposed data room should support a repeatable reconciliation from equipment and meters to contracts, settlements and cash. Request the executed or proposed revenue agreements with their schedules, amendments and credit instruments. Retain the connection documentation, market registration records, meter hierarchy and permissions needed for the contemplated operating strategy. Ask the seller or developer to identify documents that remain unsigned, unavailable or subject to consent. Each missing item should have a named decision consequence; the approval package should avoid treating the existence of a folder as evidence that its contents establish the required right.

For an operating asset, request the available interval production, export, charging, discharge, outage and settlement records with their measurement definitions. Record timestamps, time zones, units, revision history and gaps before using the series. Reconcile selected invoices to the meter and price records and then to bank receipts. Investigate unexplained differences. The technical and commercial advisers should recommend an evidence period appropriate to the asset and explain the limitations that remain.

For a development project, identify the evidence supporting proposed production, connection timing and battery performance assumptions. Separate a quotation, a conditional offer, a study and an executed commitment. Request documentation for construction milestones, performance testing, defects, warranty eligibility and operating responsibilities. Review the proposed settlement and collateral workflows before financial close, including access to data held by an optimiser or trader. Where independent testing remains future work, retain it as a closing or post-closing condition with an agreed consequence if the evidence differs from the approved case.

The proposed diligence register should connect each conclusion to a document version and reviewer. Include rights of access after a change of owner, replacement of a service provider or contractual dispute. Request the practical export format and test a handover using a selected dataset. Commercial approval can require the missing record, a narrower operating assumption or an explicitly accepted residual exposure. The closing checklist should state the evidence that discharges each condition. Subsequent monitoring should retain open obligations, expiry dates and agreed remedial actions so that the investment case remains connected to the asset's actual administration.

22. Underwriting exceptions and implementation approval

The proposed investment memorandum should name the contract structure selected and record why it satisfies the committee's stated objectives. Present retained price, volume, location, counterparty and liquidity exposures with the evidence used to assess them. Identify assumptions approved for modelling and assumptions awaiting confirmation. A commercial term sheet, engineering assessment and financing document should retain their individual status throughout the decision. Approval of the financial case should refer to the specific document versions and conditions reviewed so that later negotiations can be checked against the accepted exposure.

Create a bounded exception process for changes in volume, tenor, collateral or dispatch rights. Each request should identify the proposed change, its contractual basis, the affected cash dates and the supporting analysis. Name the authority that may accept the exception and any lender or counterparty consent required. A request with an unresolved legal or technical question should retain that condition in its approval status. The investment team should record the scope and duration of an accepted exception and the evidence required for renewal or closure.

Before execution, conduct a proposed operating rehearsal using one settlement period and one stipulated stress event. Treasury should calculate payments and collateral; operations should issue a feasible dispatch instruction; the asset manager should prepare the lender report. Ask a separate reviewer to trace the results to the proposed contracts and approved assumptions. Record discrepancies and their disposition before the relevant commitment is signed. This exercise should have a defined acceptance standard and responsible signatories. Its findings support only the tested workflow and stated conditions.

Following execution, hand over a calendar, authority schedule and unresolved-action register to the operating team. Establish a proposed reporting cadence for exposure, settlement corrections, collateral, reserve balances and battery commitments. A material contract amendment or equipment change should trigger review of affected assumptions through the exception process. Record actual receipts and expenditures separately from forecasts. Each subsequent committee decision should state the current evidence, permitted action and next review date.

23. Dispatch data and model validation

The proposed dispatch model should have an explicit decision boundary. Identify the asset configuration, permitted markets, contractual commitments and engineering limits it represents. Record which data were available when a decision would have been made. Separate forecasts from realised prices and measurements, retaining their timestamps and revisions. A historical replay should use the information available at the relevant decision time. The validation report should disclose missing data, substituted series and changes to the asset configuration that limit comparison with the proposed operating strategy.

Test the model against an independently specified feasible baseline and account for the same costs and obligations in each comparison. Include energy purchased for charging, losses, service fees, applicable network charges, contractual penalties and battery use under stated assumptions. Ask the engineering adviser to confirm that generated instructions remain within accepted limits. A proposed optimisation result should preserve periods when a constraint binds and explain the associated dispatch choice. Any claimed improvement requires the defined test, comparison basis and evidence; no empirical performance benefit is assumed in this framework.

For a proposed AI-assisted forecasting or dispatch component, request its input definitions, training and evaluation boundaries, change history and failure procedure. Test missing telemetry, stale prices, implausible forecasts and communication failure using stipulated cases. A qualified operator should define the permitted fallback instruction and authority to suspend automated action. Version control should connect the model, configuration and approved limits to each operating decision. The project should retain access to the records needed to review a disputed instruction, including where a service provider hosts the software.

Acceptance should address the commercial effect of a faulty instruction. Ask the relevant agreements to allocate responsibility for unauthorised trading, unavailable services and incorrect settlement data. Review the provider's obligations, limitations and insurance with advisers. A proposed monitoring plan should compare actual instructions and settlements with approved operating limits, investigate exceptions and require review before material changes enter service. The decision file should distinguish test results, contractual remedies and future expectations.

24. Investment decisions and the limits of the evidence

The proposed investment decision begins with a reconciliation of electricity, contractual settlement and dated cash. The fictional project demonstrates why each record matters. Its annual time-average hub price, solar-weighted hub price and solar-weighted node price describe different quantities. A committee can request all three calculations together with curtailed output before accepting an annual energy-sales assumption. A disagreement between them requires a traceable explanation of generation shape, location and the measurement boundary.

The complete base hub-price vector, in USD/MWh for hours beginning 0 through 23, is 35, 35, 35, 35, 35, 35, 42, 58, 65, 45, 20, 5, -5, -12, -2, 15, 38, 80, 110, 120, 100, 70, 48 and 40. Add the all-hour and midday seasonal adjustments in Table 2; midday means hours 11 through 15. Local prices then equal the resulting hub price less USD 8/MWh in hours 9 through 16, less USD 5/MWh in hours 17 through 21, and less USD 3/MWh otherwise. These are fictional inputs for reproduction, with no calibration to an observed electricity market.

For each season, available hourly solar equals its stated peak multiplied by the sine of π times the hour midpoint less sunrise, divided by sunset less sunrise. Output is zero when the midpoint lies outside the stated daylight interval. Apply the year-specific solar degradation factor afterwards. Expand the four profiles in the stated order using their consecutive day counts. The non-leap-year month lengths used solely for the payment calendar are 31, 28, 31, 30, 31, 30, 31, 31, 30, 31, 30 and 31 days. The synthetic season sequence is deliberately separate from an observed calendar or weather series.

Revenue protection then needs an explicit quantity definition. In the illustrated PPA, negative hub prices suspend the difference payment while exported output continues to receive the local price. In the capped floor, a limited top-up and an all-export fee leave defined residual exposure. A proposed acceptance record should therefore state the eligible output, settlement reference, suspension test, top-up limit and fee basis together. Replacing the example's rules with an actual agreement requires counsel and commercial reviewers to verify its own calculation and dispatch terms.

For the hub swap, the prescribed financial quantity continues through hours without solar generation. The model makes both positive and negative settlement cash visible alongside physical sales. A proposed hedge approval should identify the intended quantity profile, the process for changing it and the party responsible for providing cash when settlement or collateral demands precede physical receipts. The fictional collateral proxy supplies a timing example only. A transaction-specific test requires the offered valuation method, call frequency, dispute process and drawable funding commitments.

Storage investment needs a separate incremental decision. The illustration compares the same solar asset with and without the battery under identical production and price inputs. Additional receipts arise from the changed export schedule; charging, losses, displaced solar sales and additional operating costs enter that same comparison. The resulting positive incremental value is conditional on assumed capital expenditure, repeated nominal prices and the fixed dispatch windows. The evening-price sensitivities show that this value changes materially when the specified trading opportunity changes. They contain no assigned probabilities or claim about a future market spread.

The battery case also retains a first-year debt-service shortfall under the chosen project debt. This finding gives the investment committee two explicit questions: what incremental cash the battery produces under the specified case, and whether the combined asset can meet its scheduled financing obligations. An actual approval would require a complete project valuation, financing terms, operating permissions and the missing expenditure assumptions. The example's unrestricted cash buffer and restricted debt-service reserve should each remain separately identified when examining those questions.

The proposed commercial implementation follows three approvals. Revenue approval accepts the specific price, quantity, counterparty and payment rules. Funding approval accepts a dated schedule of operating payments, settlements, debt, collateral and reserves. Operating approval accepts a feasible dispatch schedule within the connection, equipment and contractual limits. Each approval should name its evidence, unresolved conditions and the authority responsible for amendments. The diligence matrices in this paper provide proposed review fields; their completion requires the actual transaction records.

The evidence has geographic and temporal boundaries. The European, Great British, U.S. and Australian sources describe their own institutions, periods and market arrangements. The paper uses them for identified mechanisms and comparisons. It supplies no evidence that one jurisdiction's participation rights, public-support terms or settlement rules apply in another. The fictional project belongs to no specified jurisdiction and receives none of those sources' numerical market outcomes as a model input. A real application needs its own applicable rules and attributable operating or forecast data.

Further research could replace the four repeated daily profiles with a documented chronological dataset, compare feasible dispatch policies, and add outages, replacement expenditure, taxes, imbalance charges, financing changes and counterparty default. Such work should disclose data access, estimation methods and out-of-sample limitations. AI-assisted forecasting or optimisation should receive a reproducible comparison against a defined feasible baseline before any performance improvement is reported. This paper supplies no observed AI result or causal estimate.

The proposed commitment condition is a reviewed connection from physical capability to contract rights and funded payment dates. A committee applying this framework should retain the signed terms, accepted technical assumptions, model version, settlement evidence and open conditions together. Subsequent changes in hedging, storage use or financing should return to the affected approval with revised calculations. The conclusion remains bounded by that evidence and by the assumptions disclosed throughout the illustration.

Frequently Asked Questions

Does a revenue floor cover every project cash shortfall?

Review the actual price reference, eligible volume, exclusions, premium and payment dates. The proposed funding assessment should also cover operating expenditure, collateral and debt obligations outside that settlement. The floor's scope and collectability require document and credit review.

What evidence should accompany a hedge collateral facility?

Request the executed commitment, draw conditions, eligible uses, expiry and banking timetable. Compare them with the proposed hedge's call and payment process. Any funding that remains subject to consent or renewal should retain that condition in the liquidity report.

Can a debt service reserve fund a hedge payment?

Ask lenders and legal advisers to confirm the permitted use from the actual account and financing documents. Record any replenishment or consent condition. The proposed cash schedule should assign the balance once across the obligations that can validly draw on it.

How should a project approve multiple battery revenues?

Require one feasible operating schedule that meets the contemplated commitments within the accepted engineering and market permissions. Identify reserved capability, charging expenditure, service obligations and dispatch priority. Commercial approval should retain any unresolved conflict and the action required to close it.

What should remain open when diligence evidence is incomplete?

Record the missing document or dataset, the affected assumption, accountable reviewer and decision deadline. The committee can request further evidence, use a narrower supported assumption or explicitly accept the defined residual exposure. Completion of the action requires the agreed evidence.

What would support a claimed AI dispatch benefit?

Require a reproducible test against a defined feasible baseline using the same information boundary, operating limits and full cost treatment. Preserve model versions and test data. Any reported result should retain its measurement period and limitations; this paper supplies no empirical AI performance claim.

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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.

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