eBESS: Full Documentation

Concept, 15-Minute Electricity Arbitrage, BESS Physics,
Financial Model (Expanded) & Forecasts, Tokenization, Risks, Compliance, ESG, SOP & Appendices

eBESS

October 05, 2025

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Abstract

eBESS connects real battery energy storage systems (BESS) with on-chain infrastructure tracking and ecosystem participation. We charge during low-price intervals and discharge during high-price intervals in *15-minute* wholesale markets (96 blocks/day). This document explains why electricity arbitrage is a durable trend, how our system earns money, baseline and scaling economics, operations, risks, tokenization and reinvestment and growth framework, and how we report results transparently to ecosystem participants. Throughout we use the configuration: **1 MW / 2.15 MWh**, built from **10 modules** of **100 kW / 215 kWh** each; module cost **€31,500**, grid connection & commissioning **€90,000**. Monthly OPEX baseline **€2,800** (rent €1,500 + maintenance €1,300). Target cadence ~**2.5 cycles/day**.

1 Executive Summary

Mission. Turn structural electricity-market volatility into predictable, transparent, on-chain cash flows while improving grid resilience and renewable integration.

What eBESS does.

- Deploys modular BESS nodes at grid-connected sites; per node: **1 MW / 2.15 MWh** (10×100 kW / 215 kWh).
- Schedules charge/discharge across 15-minute price intervals; targets ~2.5 full cycles/day (partial blocks allowed).
- Allocates realized gross arbitrage revenues, after OPEX and reserve provisions, toward infrastructure expansion, system optimization, and long-term development of the eBESS ecosystem.

Why now. Quarter-hour markets amplify tradable dispersion; rising renewables deepen intraday spreads; storage is mature and safe; tokenization brings auditability and access.

Economics (per 1 MW).

- **CAPEX:** 10 modules × €31,500 = €315,000 + grid/commissioning €90,000 = **€405,000**.
- **OPEX: €2,800/month**.
- **Baseline gross/day:** ≈ **€1,995** (anchored by 2 cycles ≈ €1,596; scaled to 2.5).
- **Baseline net/year:** ≈ **€694,575** (365×gross/day − annual OPEX).
- **Simple payback:** €405,000 / €694,575 ≈ **0.58 years**.

2 Investment Thesis

2.1 Thesis in brief

1. **Structural spreads:** Renewables introduce durable intraday volatility (troughs vs peaks).
2. **Granularity tailwind:** 15-minute markets increase targetable windows and enable partial cycles.
3. **Mature tech:** $LiFePO_4$ BESS is safe, modular, serviceable; inverters are efficient.

4. **Tokenized rails:** On-chain transparency and public reporting align ecosystem participants and strengthen trust.

2.2 What success looks like

Consistent per-MW gross/day, low downtime, transparent on-chain reinvestment allocations, and a portfolio that scales with demonstrable synergies.

3 Market Context and Trend

3.1 Structural volatility

Renewables are variable (midday solar; weather-driven wind) while demand peaks are social and seasonal. Without storage, grids see daytime price troughs (near zero/negative) and evening scarcity (spikes). As renewables rise, spreads become a *structural* feature rather than noise.

3.2 15-minute market mechanics

Quarter-hour clearing (96 intervals/day) increases actionable windows and reduces the opportunity cost of waiting. Partial cycles become natural: at 1 MW, each 15-min block is 0.25 MWh.

3.3 From speculation to infrastructure

Arbitrage with BESS is a physical service that reduces curtailment, displaces peaker marginal hours, and supports reliability — while earning cash flows tied to real market prices.

4 System Overview (BESS Node)

4.1 Physical configuration

- **Power/Energy:** 1 MW / 2.15 MWh total.
- **Modules:** 10 units, each 100 kW / 215 kWh.
- **Round-trip efficiency:** $\eta_{\text{rt}} \approx 0.90$.
- **Chemistry:** $LiFePO_4$ (safety, longevity).

4.2 Timing and blocks

At 1 MW, a 15-minute block carries $e_{\text{block}} = 0.25$ MWh. A full charge needs $2.15/0.25 = 8.6$ blocks (8 full + 1 partial). A full cycle (charge+discharge) is ≈ 4.3 h of active power.

4.3 Controls and safety

Bidirectional PCS, BMS (SoC/SoH), EMS (forecasting & scheduling), SCADA telemetry; site: ventilation, fire suppression, access control.

4.4 CAPEX and OPEX

Item	Amount	Notes
Modules (10 × €31,500)	€315,000	10 × (100 kW / 215 kWh)
Grid connection & commissioning	€90,000	One-off per 1 MW site
Total CAPEX (1 MW)	**€405,000**	
Rent (monthly)	€1,500	
Maintenance (monthly)	€1,300	
Total OPEX (monthly)	**€2,800**	

5 How It Works: 15-Minute Electricity Arbitrage

5.1 Daily operating loop

1. **Ingest:** day-ahead and intraday 15-minute prices; load/renewables forecasts; equipment constraints.
2. **Plan:** pick charging windows (low prices) and discharging windows (high prices) under power/energy limits; target ~2.5 cycles/day; allow partial blocks.
3. **Execute:** EMS dispatches setpoints; logs telemetry and realized prices; enforces safety and availability.
4. **Report:** compute gross arbitrage; subtract OPEX and approved reserves; publish dashboards and monthly packs.

5.2 Per-block and per-cycle accounting

Let $P = 1$ MW, $\Delta = 0.25$ h, $E = 2.15$ MWh, $\eta_{\mathrm{rt}} \approx 0.90$. Per charge block: energy bought = 0.25 MWh at price p_t. Per discharge block: energy sold = 0.25 MWh at price p_t. A full cycle uses ≈ 8.6 charge + ≈ 8.6 discharge blocks (partials included), subject to efficiency.

5.3 Illustrative timelines (two cycles)

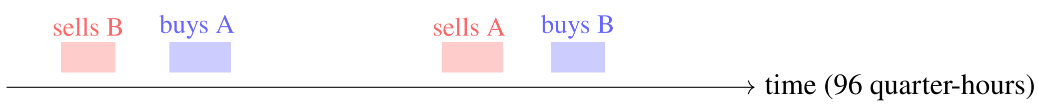

Figure 1: Two-cycle day: buy in troughs, sell in peaks. EMS selects specific QH intervals.

6 Optimization Model (Plain Formulation)

6.1 Decision variables (per 15-min block t)

$u_t^c \in [0, 1]$ (charging), $u_t^d \in [0, 1]$ (discharging), E_t (MWh), with mutual exclusion $u_t^c \cdot u_t^d = 0$.

6.2 Dynamics and constraints

$$E_{t+1} = E_t + \eta_c P u_t^c \Delta - \frac{1}{\eta_d} P u_t^d \Delta, \tag{1}$$

$$0 \le E_t \le E_{\max} = 2.15, \quad 0 \le u_t^c, u_t^d \le 1, \quad u_t^c \cdot u_t^d = 0. \tag{2}$$

For $\eta_{\text{rt}} = \eta_c \eta_d \approx 0.90$, a common choice is $\eta_c = \eta_d = \sqrt{0.90}$.

6.3 Objective (gross arbitrage)

$$\max \sum_t \left(p_t P u_t^d \Delta - p_t P u_t^c \Delta \right) - C_{\text{var}}(u^c, u^d), \tag{3}$$

where C_{var} aggregates variable fees or degradation proxies if applied.

7 Financial Model (Expanded): Assumptions, Math, Scenarios

7.1 Assumptions (per 1 MW node)

- Power/Energy: 1 MW / 2.15 MWh (10×100 kW / 215 kWh).
- Efficiency: $\eta_{\text{rt}} \approx 0.90$ accounted in planning.
- Cadence: ~2.5 cycles/day (partial cycles allowed).
- OPEX: €2,800/month (€1,500 rent + €1,300 maintenance).
- Anchor (empirical): 1.075 MWh system showed €798 for 2 cycles (≈ €399/cycle). Doubling capacity ⇒ **€798 per cycle**.

7.2 Energy throughput & timing

Per 15-min block at 1 MW: 0.25 MWh. A full charge uses 8.6 blocks; a full cycle ≈4.3 h of active power. Daily throughput at 2.5 cycles: $2.5 \times 2.15 = 5.375$ MWh in/out (pre-efficiency).

7.3 Per-cycle & per-day formulas

Per-cycle gross (full):

$$\pi_{\text{cycle}} = \left(p_{\text{sell}} \cdot \eta_{\text{rt}} - p_{\text{buy}} \right) \cdot E.$$

Daily gross: $\Pi_{\text{day}} = \sum_{k=1}^{N_{\text{cycles}}} \pi_{\text{cycle},k}$, typically $\approx N_{\text{cycles}} \times €798 at base.$

7.4 Variable fees and break-even spread

If variable fees apply (market + grid) at c_{var} €/MWh per leg, effective buy price $p'_{\text{buy}} = p_{\text{buy}} + c_{\text{var}}$, effective sell price $p'_{\text{sell}} = p_{\text{sell}} - c_{\text{var}}$. **Break-even spread** per cycle:

$$p_{\text{sell}} - p_{\text{buy}} > \frac{2c_{\text{var}}}{\eta_{\text{rt}}} + \frac{\epsilon}{E}, \quad \epsilon = \text{desired margin €}.$$

7.5 Reserve policy and degradation

We typically reserve 0–10% of gross for degradation/insurance. Alternatively, a per-throughput cost c_{deg} €/MWh can be applied; both approaches are functionally similar if consistently reported.

7.6 Scenario matrix by cadence and gross/day

Cycles/day	Gross/day	Net/month	Net/year	Payback
2.0	€1,596	€45,080	€548,940	~0.74y
2.5	€1,995	€57,050	€694,575	~0.58y
3.0	€2,394	€69,020	€840,210	~0.48y

7.7 Spread-driven per-cycle examples (illustrative)

Assume $E = 2.15$ MWh, $\eta_{\text{rt}} = 0.90$:

Buy/Sell (€ / MWh)	Spread	Per-cycle Gross	Daily Gross (2.5x)
€40 / €120	€80	€(120·0.940)·2.15 = €154.8	€387
€20 / €200	€180	€(200·0.920)·2.15 = €309.1	€773
€10 / €250	€240	€(250·0.910)·2.15 = €408.3	€1,021

These are purely formulaic illustrations; realized results reflect actual quarter-hour prices and selected intervals.

7.8 Waterfall: gross to net (monthly)

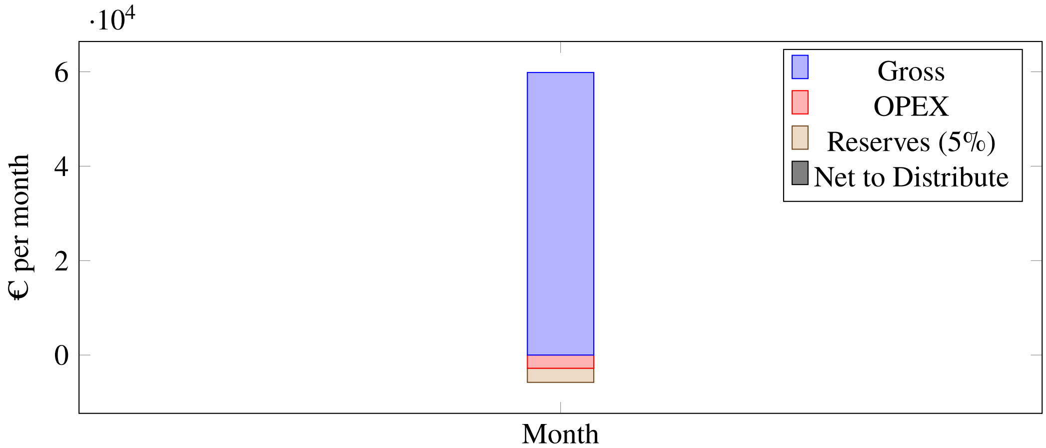

Figure 2: Illustrative monthly waterfall (Base): Gross €59,850; OPEX €2,800; Reserves 5% (€2,992); Net €54,058.

7.9 NPV/IRR under multiple horizons and rates (illustrative)

Let discount $r \in \{8\%, 12\%, 16\%\}$, degradation proxy $g = 8\%$/y on net. **Yearly net path (Base)**: Y1 €694,575; Y2 €638,009; Y3 €586,968; Y4 €540,011; Y5 €496,810.

Horizon	NPV @ 8%	NPV @ 12%	NPV @ 16%
5 years	€2.05M	€1.64M	€1.34M
7 years	€2.55M	€2.00M	€1.61M
10 years	€3.19M	€2.47M	€1.95M

IRR (indicative): very high due to short payback; we report realized trailing 12M IRR from actuals in monthly packs.[1]

7.10 Cumulative cash flow (illustrative)

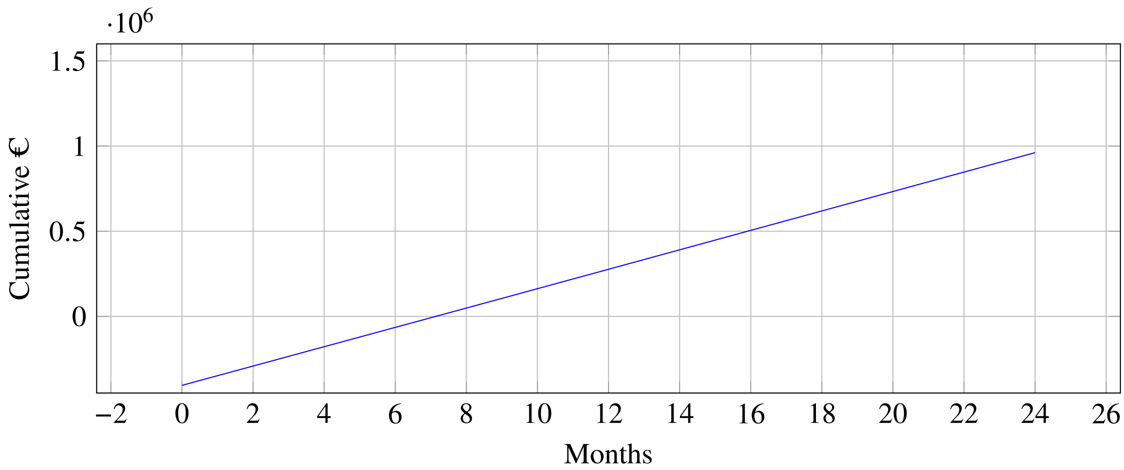

Figure 3: Illustrative cumulative cash flow (Base, with €57,050/mo net). Breakeven between months 8–9.

8 Sensitivity and Risk

8.1 Key drivers

Spread depth ($p_{\text{sell}} - p_{\text{buy}}$), cycles/day, availability, variable fees, OPEX, reserves policy.

8.2 Tornado (schematic)

8.3 Risk register

Risk	Cause/Trigger	Mitigation	Owner
Spread compression	Weather, demand shifts, interconnection	Selective scheduling; multi-zone nodes; ancillary services (where accretive)	Trading/EMS
Operational downtime	Hardware faults, outages	Spares, SLAs, preventive maintenance; NOC 24/7	Ops

[1] *Exact IRR depends on realized net path and any reserve/tax policies; the above is directional and conservative on degradation.*

Regulatory change	Rule updates, fees	Licensed partners; legal review; adaptive procedures	Compliance
Smart-contract issues	Bugs, misconfig	Audits; multisig; rate limits; bug bounty	Protocol
Data quality errors	API outages, bad telemetry	Redundant feeds; plausibility checks; failover	EMS/Ops

9 Scaling the Portfolio

9.1 Linear baseline (Base scenario)

Per-node CAPEX €405k; OPEX €33.6k/year.

Portfolio	MW	CAPEX	OPEX/yr	Baseline Net/yr
5 nodes	5	€2.025M	€168,000	€3.4729M
10 nodes	10	€4.050M	€336,000	€6.9458M
20 nodes	20	€8.100M	€672,000	€13.8915M

9.2 Full portfolio table (1–20 MW)

MW	Nodes	CAPEX (€)	OPEX/yr (€)	Baseline Net/yr (€)
1	1	405,000	33,600	694,575
2	2	810,000	67,200	1,389,150
3	3	1,215,000	100,800	2,083,725
4	4	1,620,000	134,400	2,778,300
5	5	2,025,000	168,000	3,472,875
6	6	2,430,000	201,600	4,167,450
7	7	2,835,000	235,200	4,862,025
8	8	3,240,000	268,800	5,556,600
9	9	3,645,000	302,400	6,251,175
10	10	4,050,000	336,000	6,945,750
11	11	4,455,000	369,600	7,640,325
12	12	4,860,000	403,200	8,334,900
13	13	5,265,000	436,800	9,029,475
14	14	5,670,000	470,400	9,724,050
15	15	6,075,000	504,000	10,418,625
16	16	6,480,000	537,600	11,113,200
17	17	6,885,000	571,200	11,807,775
18	18	7,290,000	604,800	12,502,350
19	19	7,695,000	638,400	13,196,925
20	20	8,100,000	672,000	13,891,500

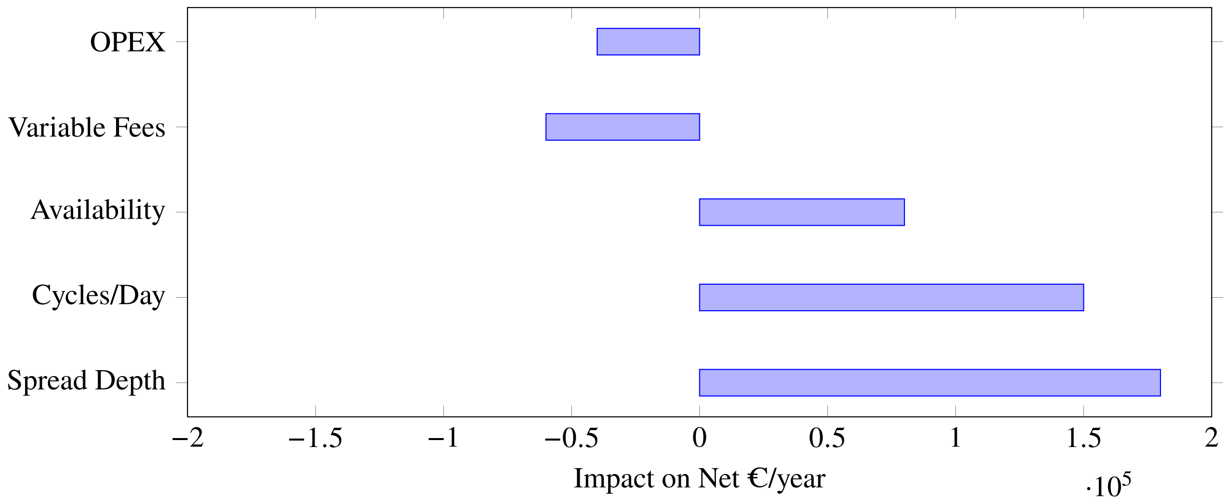

Figure 4: Illustrative sensitivity: positive bars improve net; negative reduce it.

Note: Baseline net scales linearly at €694,575 per MW before synergies. Real portfolios can realize 5–15% upside.

9.3 Scaling chart

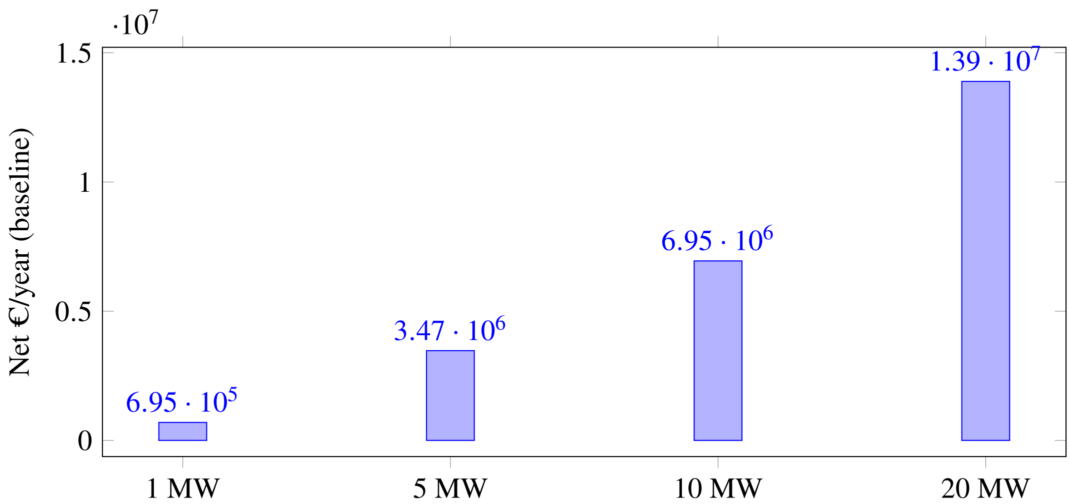

Figure 5: Baseline net profit scales nearly linearly; portfolio synergies can add upside.

10 Tokenization and USDT Distributions

10.1 Why tokenization

Fractional access to infrastructure cash flows, on-chain auditability, automated reinvestment allocations, global reach, faster feedback loop between operations and capital.

10.2 Economic flow

- **Off-chain:** EMS executes arbitrage; monthly gross and OPEX compiled; optional reserves deducted.
- **Treasury:** converts distributable net to USDT.
- **Distributor:** funds period, snapshots balances (or Merkle proofs), enables pro-rata claims.

10.3 Distribution math

Let G_m = gross in month m, O_m = OPEX, R_m = reserves (policy), α = share to holders:

$$D_m = \alpha \cdot \max\{0,\, G_m - O_m - R_m\}, \quad D_{m,i} = w_i D_m.$$

10.4 Governance & security

Multisig over treasury and distributor parameters; audits; bug bounty; rate limits and circuit breakers; clear operator accountability.

11 Operations & SOP (Standard Operating Procedures)

11.1 NOC & monitoring

24/7 dashboards: SoC, temperatures, PCS state, alarms. KPIs: cycles/day, availability, gross/net, alarm MTTR. Alert levels and escalation matrix.

11.2 Preventive maintenance

Vendor schedules, CBM (condition-based maintenance), spares inventory, firmware change control, periodic performance tests.

11.3 Incident response (summary)

1. Detect & classify severity.
2. Stabilize asset (safe SoC, isolate fault).
3. Diagnose & remediate; log actions.
4. Return-to-service test; post-mortem & lessons learned.

11.4 Data pipeline & QA

Redundant price feeds, telemetry checks, plausibility rules, failover logic, immutable audit logs, monthly reconciliation between EMS and settlements.

12 Compliance, Legal, and Insurance

12.1 Market access

Operate via licensed partners/aggregators; adhere to participation and settlement rules; KYC/AML where applicable for off-chain flows.

12.2 Legal & contracts

Site lease, interconnection, equipment warranties, service SLAs, insurance (equipment & liability), disclosures, token T&Cs.

12.3 Insurance

All-risks for equipment; liability; business interruption (where available). Review exclusions and deductibles; maintain reserves for gaps.

13 ESG and System Impact

13.1 Renewable integration

Absorb midday surpluses; serve evening peaks; reduce curtailment; displace marginal peakers. Report avoided emissions with transparent methodology.

13.2 Transparency

On-chain reinvestment allocations + public monthly packs create a verifiable link between physical operations and investor outcomes.

14 Reporting and Transparency

14.1 Monthly pack

KPIs (availability, cycles/day, gross/day distribution), OPEX breakdown, reserves, USDT funding transactions, holder claim stats, links to artifacts (IPFS/Arweave) and on-chain events.

14.2 Dashboards

Public graphs for high-level KPIs; CSV exports for analysts; rolling 12M metrics; cohort analysis by site/vintage.

15 Roadmap and Go-To-Market

15.1 Roadmap

- **Q1 2026:** token launch; prepare first 1 MW site.
- **Q3 2026:** commission 1 MW node

- **Q4 2026:** scale to 2 MW; portfolio reporting; formalize reserves policy.
- **2027:** 3 MW+ with optional balancing services; vendor consolidation.
- **2028+:** expand to 10 MW across EU; deeper EMS automation and cross-zone optimization.

15.2 GTM

Audience: crypto natives, ESG-focused investors, infra funds. Channels: website/GitBook, X/Telegram, monthly reports, live dashboards. Listings: DEX + CEX (phased liquidity). Partners: aggregators, BESS vendors, insurers, auditors.

16 Investor FAQ (Extended)

How do you make money?

Buy low / sell high in 15-min markets, ~2.5 cycles/day, per-cycle gross scales with capacity and spread depth. Net after OPEX and reserves is distributed in USDT monthly.

What are the main risks?

Spread compression, downtime, rule changes, data errors, smart-contract risks. We mitigate via selective scheduling, portfolio diversification, SLAs/spares, audits, multisig, and transparent reporting.

How fast is payback?

At Base scenario: ~0.58 years per 1 MW node (illustrative; actuals vary).

What's the token for?

Pro-rata reinvestment allocations of realized net in USDT for the relevant period (per policy), with on-chain transparency.

Appendix A: Seasonal Archetypes (96-Block Lanes)

Summer (solar-heavy): deep midday troughs, sharp evening peaks — two cycles/day naturally fit (midday→evening, night→morning). **Winter (demand-heavy):** higher baseload prices, dual peaks (morning/evening) — partial cycles around both peaks. **Windy days:** stochastic lows — EMS preserves availability to clip sudden spikes across the day.

Appendix B: Variables and Symbols

Symbol	Meaning
P	Rated power (MW), here $P = 1$.
E	Energy capacity (MWh), here $E = 2.15$.

Δ	Block duration (h), $\Delta = 0.25$ for 15 minutes.
u_t^c, u_t^d	Charge/discharge fractions in block t.
E_t	State of energy in block t.
p_t	Market price in block t (€/MWh).
η_c, η_d	Charge/discharge efficiencies; $\eta_{\mathrm{rt}} = \eta_c \eta_d$.
G_m	Gross profit in month m.
O_m	OPEX in month m.
R_m	Reserves (policy) in month m.
D_m	Distributable amount in month m (USDT).

Appendix C: Example Calculations (Base Scenario)

Assume $\eta_{\mathrm{rt}} = 0.90$, $E = 2.15$ MWh. Anchor ⇒ per-cycle gross ≈ €798. Daily gross at 2.5 cycles ⇒ €1,995. Monthly net ⇒ 30×1995−2800 =€57,050.$Yearlynet$⇒ 365×1995−33,600 =€694,575.$Simplepayback$⇒ €405,000 / €694,575 ≈ 0.58 y.

Appendix D: Sensitivity Tables

Cycles/day	Gross/day	Net/month	Net/year	Payback
2.0	€1,596	€45,080	€548,940	~0.74y
2.5	€1,995	€57,050	€694,575	~0.58y
3.0	€2,394	€69,020	€840,210	~0.48y

Appendix E: Reserve Policy Scenarios

At Base gross/day €1,995: monthly gross €59,850; yearly gross €728,175.

Reserve % (of gross)	Net/month	Net/year	Notes
0%	€57,050	€694,575	No reserve
5%	€54,058	€658,166	Degradation/insurance
10%	€51,065	€621,758	Conservative buffer

Appendix F: NPV/IRR Panels (8%, 12%, 16%)

5-year horizon (Base net path; $g = 8\%$/y):

Rate	NPV (€)	Comment
8%	2,050,000	Strong surplus over CAPEX
12%	1,640,000	Conservative base rate
16%	1,340,000	Stress discount

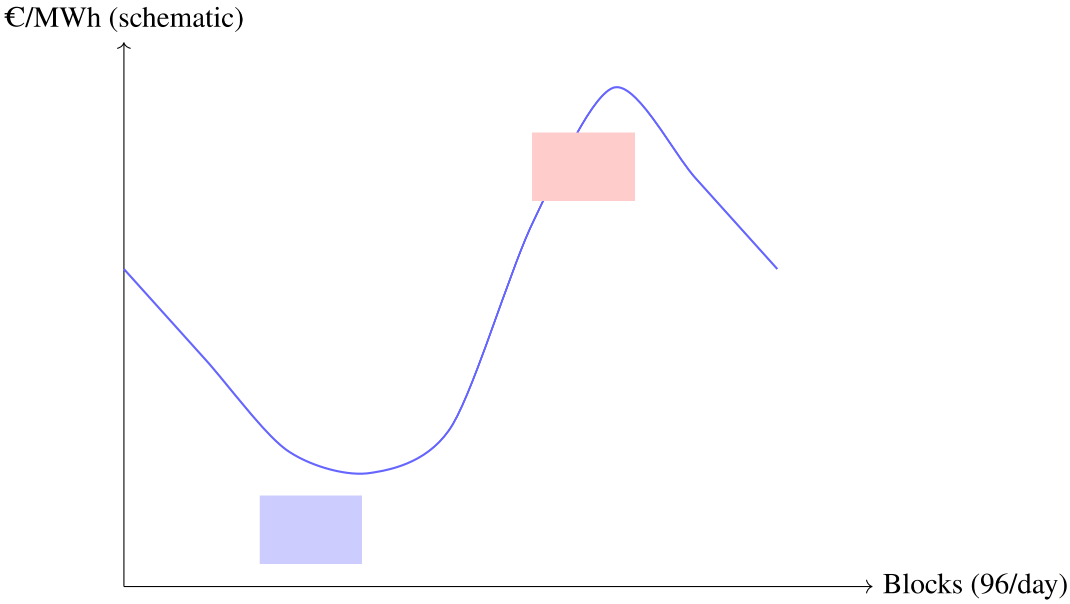

Figure 6: Schematic daily price lane (summer-like): midday lows, evening highs; ideal for two cycles.

10-year horizon shows additional upside from operational longevity; we report realized trajectories annually.

Appendix G: Multi-Zone Strategy (Narrative)

Diversify nodes across bidding zones to reduce correlation, exploit differing renewable mixes and congestion patterns, and smooth portfolio gross/day variance. Coordinate dispatch windows across zones to avoid synchronized troughs.

Appendix H: Site & Vendor Selection Criteria

Dimension	**Criteria**
Grid interconnection	Capacity availability; lead time; fees; curtailment rules.
Zoning/permits	Permitting complexity; environmental constraints.
Vendor diligence	Track record; warranty; service network; parts availability.
SLA	Response times; penalties; spares commitments.
Site OPEX	Rent; security; connectivity; utilities.

Appendix I: SOP Checklists

Daily: alarms review, availability checks, schedule validation, SoC window, thermal scan. **Weekly:** performance review, firmware notices, spares counts. **Monthly:** KPI pack, OPEX reconciliation, reserve accounting, distribution prep.

Appendix J: Degradation & LCOS (Illustrative)

We treat degradation via reserves (e.g., 5–10% gross) rather than explicit €/MWh throughput in base model. If needed, an explicit LCOS can be modeled as:

$$\mathrm{LCOS} = \frac{\mathrm{CAPEX} \cdot \mathrm{CRF}(r, n) + \mathrm{OPEX}_{\mathrm{fix}} + c_{\mathrm{deg}} \cdot \mathrm{MWh}_{\mathrm{thru}}}{\mathrm{MWh}_{\mathrm{delivered}}}.$$

This can be integrated into C_{var} or reserve policy. We publish realized reserve usage annually.[2]

Appendix K: Full Economics 1–20 MW (Formulas)

For MW = M: CAPEX = €405k·M, OPEX/yr = €33.6k·M, Baseline Net/yr = €694.575k·M; Payback (years) ≈ CAPEX / Net.

Disclaimer. This document is informational. Results depend on market conditions, availability, fees, and policy choices regarding reserves and taxes. We commit to transparent monthly reporting and conservative operations.

Reinvestment Policy

All operational revenues generated by the eBESS system are primarily allocated toward infrastructure expansion, system optimization, reserve formation, and long-term project development. The eBESS token is designed to align ecosystem participants with platform growth. Token holders may benefit from ecosystem bonuses, platform incentives, and participation mechanisms linked to project development and expansion.

[2] *CRF — capital recovery factor, r — discount, n — years.*