

Article

A Scenario Framework for Investment Appraisal and Shared Risk in Smart Microgrids in Industrial Zones

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Abstract

This study develops a scenario-based analytical framework for assessing smart microgrids in industrial zones as infrastructure investments and for analyzing multi-actor risk allocation and governance. No empirically validated return is reported for a specific Bulgarian industrial zone. Public institutional, market, financial, technology and environmental sources are instead used to benchmark the scenario assumptions. Three scenarios are evaluated for a reference zone with annual consumption of 12,000 MWh. The model incorporates photovoltaic (PV) degradation, battery round-trip efficiency of 85–90%, annual usable-capacity degradation, one modeled battery replacement within a 12–15-year service interval, component-based capital and operating expenditures, and an author-defined semi-quantitative likelihood–impact risk matrix. Net present value (NPV) is EUR –1,114,726 in the conservative scenario, EUR 697,836 in the baseline scenario and EUR 3,424,835 in the favorable scenario. Discounted payback is not achieved within 20 years in the conservative scenario and is approximately 14.1 and 7.0 years in the baseline and favorable scenarios, respectively. Deterministic one-at-a-time sensitivity analysis identifies electricity price, capital expenditures, and the direct PV self-consumption ratio as the dominant financial drivers. The indicative reduction in location-based emissions associated with grid electricity purchases is 802.9–1385.5 tonnes of carbon dioxide equivalent (tCO₂e) per year under the selected grid-average electricity emission factor. The contribution lies in integrating public-data availability assessment, external parameter benchmarking, battery service life, degradation and replacement economics, investment appraisal, threshold analysis, semi-quantitative risk prioritization and contractual risk allocation within one reproducible framework. The outputs remain illustrative and require project-level validation using measured hourly loads, binding prices, financing terms and enforceable contracts.

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1. Introduction

Industrial zones are becoming a key meso-level of industrial transition because manufacturing, warehousing, logistics and service activities are concentrated within them and require reliable, predictable and economically manageable electricity infrastructure (Kang

& Ma, 2021). The traditional model is no longer sufficient. Under that model, an industrial zone is treated mainly as a territory with roads, communications, grid connection and administrative services. This approach is limited for enterprises integrated into international value chains because they face requirements related to sustainability, carbon reporting and energy efficiency (Xu et al., 2024). The European Union (EU) context strengthens this pressure. The Carbon Border Adjustment Mechanism (CBAM) entered its definitive regime on 1 January 2026 (European Commission, n.d.-b). Corporate sustainability reporting rules are also relevant because large and listed undertakings are required to disclose social and environmental risks and impacts (European Commission, n.d.-c). In such an environment, the electricity system of an industrial zone cannot be treated merely as a utility component, since it affects production cost, operational continuity, sustainability reporting and investment attractiveness. This is why it becomes necessary to examine whether a smart microgrid can be assessed as strategic infrastructure, rather than only as a technological add-on to individual production sites. In the present study, such an assessment is considered possible only when data, formulas, scenarios and limitations are presented transparently and when the calculations do not allow unjustifiably optimistic conclusions.

The problem is particularly significant for Bulgaria because public investment has been directed toward industrial-park infrastructure. The AttractInvestBG program has a total budget of BGN 212.5 million (approximately EUR 108.65 million at the fixed conversion rate), while 11 selected projects jointly receive BGN 206.5 million (approximately EUR 105.58 million) (Organisation for Economic Co-operation and Development, 2026). These amounts establish an institutional opportunity for infrastructure modernization but do not, by themselves, demonstrate smart metering, local generation, battery storage, energy-management systems or enforceable internal energy-allocation mechanisms. Public funding and demonstrable microgrid capability are therefore treated as separate analytical categories. The absence of public technical data is interpreted as a limitation of public-data availability, not as proof that the technologies are absent. The broader recovery-plan context is also documented by the European Commission (European Commission, n.d.-a).

The research question is formulated as follows: under what externally benchmarked, conservatively measurable and methodologically traceable conditions can an industrial microgrid be assessed as an instrument for investment appraisal, energy cost management and multi-actor financial risk allocation? The aim is to construct an integrated analytical framework in which documentary regional evidence is evaluated through a public-data availability assessment, scenario inputs are benchmarked against observable data, and energy-flow calculations, battery service life and replacement assumptions, and financial calculations are translated into semi-quantitative likelihood–impact risk priorities and mitigation instruments. The study does not claim to measure the actual infrastructure or returns of a specific industrial zone. Such a claim would require hourly user-level loads, technical surveys, bid prices, financing terms and enforceable contracts. The results are therefore presented as illustrative outputs of a reproducible template. Methodological novelty is located not in the use of net present value or payback indicators separately, but in the explicit integration of source-status classification, external parameter benchmarking, battery replacement economics, comparative documentary evidence criteria, threshold analysis and allocation of financial risk among the zone operator, users, investors, lenders and technology providers.

The analytical sequence is organized as follows. Section 2 develops the theoretical and financial-risk background. Section 3 presents the source corpus, workflow, external parameter benchmarking, scenario assumptions, battery service life, degradation and replacement treatment and equations. Section 4 reports regional documentary evidence, information gaps, investment, environmental, sensitivity and semi-quantitative risk results. Section 5 in-

interprets the findings and develops regulatory and financial risk-management mechanisms. Section 6 presents managerial and policy implications, Section 7 states the limitations and validation requirements, and Section 8 summarizes the conditional conclusions.

2. Theoretical Framework

2.1. *The Industrial Zone as an Eco-Industrial Energy System*

The concept of the eco-industrial park changes the way in which the industrial zone is viewed. It is not treated as a mere aggregation of separate enterprises. It is treated as a managed territorial system. Within that system, economic, environmental and social outcomes are formed through the coordinated use of infrastructure, resources, data and institutional mechanisms. The international framework of the United Nations Industrial Development Organization (UNIDO), the World Bank Group and Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) defines eco-industrial parks through requirements and indicators related to park management, environmental performance, economic viability and social aspects (Tas et al., 2021). This framework is relevant for the present study because it does not reduce sustainability to a separate photovoltaic system, but emphasizes the overall governance of the industrial territory. The literature on industrial symbiosis highlights that geographical proximity, institutional interaction and shared flows of materials, energy, water and services may create collective competitive advantage (Neves et al., 2020). From this perspective, the energy infrastructure of an industrial zone should be analyzed as a component of industrial symbiosis (Fraccascia et al., 2021). Within the industrial zone, not only material flows (Lybæk et al., 2021) but also electricity generation, consumption, storage, and digital control are coordinated (Uusikartano et al., 2021). The theoretical focus is thus shifted from the individual energy asset to a zonal infrastructure architecture capable of supporting low-carbon competitiveness (Nuhu et al., 2022).

The industrial zone is an appropriate level for such analysis because it combines high loads, spatial concentration, large roof areas, shared infrastructure and opportunities for coordinating user load profiles (Sun et al., 2024). In a single enterprise, a photovoltaic system is sized according to one production regime, whereas in an industrial zone a set of different daily and seasonal profiles may be used (Wei et al., 2022). This creates the possibility of a higher direct PV self-consumption ratio, but only if loads are measured, analyzed in aggregate and governed contractually in order to distribute economic benefits (Ahmad Fadzil et al., 2022). Without such coordination, local generation may remain a fragmented investment that reduces part of the costs of one user but does not alter the strategic infrastructure value of the industrial zone. For this reason, the study adopts a distinction between a photovoltaic installation and an industrial microgrid. A photovoltaic installation generates electricity, whereas an industrial microgrid governs a set of assets, loads, data, contracts and risks.

2.2. *Industrial Microgrid and Energy Flow Management*

A microgrid is commonly defined as a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the external grid (United States Department of Energy, n.d.; Al-Ismail, 2021; Ahmethodžić et al., 2023). In this study, the term “smart” denotes advanced metering, coordinated energy management, controllable battery operation and verifiable digital data exchange; it does not imply autonomous or artificial-intelligence-based control. The financial model evaluates only a grid-connected industrial microgrid configuration; islanding capability, protection coordination, black-start capability and resilience performance are outside the modeled scope. In an industrial setting, manufacturing and warehousing users have high loads and greater sensitivity to interruptions, supply

contracts are more complex, and peak-demand costs may be material. An industrial microgrid should therefore be evaluated not only by installed capacity but also by its ability to increase the direct PV self-consumption ratio, reduce peak demand, limit external-grid purchases and generate auditable energy data. International analyses of electricity grids indicate that digitalization, storage and demand flexibility will have increasing importance for a secure energy transition ([International Energy Agency, 2023](#)). Industrial zones may be both sources of high load and resources for local flexibility; the microgrid is therefore treated as a controllable energy and governance architecture rather than as an isolated generation asset.

The energy management system (EMS) is the central digital component of this architecture ([Nasir et al., 2022](#)). It enables data collection, load forecasting, alignment of local generation with consumption, battery management and reduction in economically disadvantageous excess PV electricity ([Ahmad et al., 2023](#)). Where a battery energy storage system (BESS) is present, management may be directed towards short-term energy shifting, peak-demand reduction and an increase in the value of local generation ([Chaudhary et al., 2021](#)). In an industrial zone, this is particularly important because production schedules, warehouse logistics, cooling, compressor systems, pumping regimes and charging infrastructure for corporate electric vehicles may form different peaks. If these loads are managed without coordination, local generation may be underutilized and part of the investment value may be lost ([Liu et al., 2023](#)). If, however, the energy management system operates on reliable hourly data, the direct PV self-consumption ratio may be increased and investment robustness may be improved ([Miah et al., 2022](#)). Recent reviews further indicate that commercial and industrial microgrid performance depends on coordinated forecasting, storage dispatch and control across heterogeneous loads ([Atef et al., 2026](#); [Castañeda-Arias et al., 2025](#); [Khan et al., 2024](#)).

2.3. Investment Models and Multi-Actor Risk Allocation and Governance

Investment in an industrial microgrid may be structured through different models ([D'Adamo et al., 2022](#)). One option is direct capital expenditure (CAPEX) by the zone operator. Another option is a power purchase agreement. An energy service company (ESCO) model may also be used. A microgrid-as-a-service model is also possible, in which operating expenditures (OPEX) become especially important ([Ceglia et al., 2022](#)). Each of these models allocates risk differently and therefore cannot be treated as a neutral financial choice ([Gržanić et al., 2022](#)). Under direct capital investment, control over the assets is greater, but financial risk is concentrated with the zone operator or the zone investor. Under a power purchase agreement, the initial capital burden may be reduced, but dependencies arise from the agreed price, contract duration, minimum consumption and creditworthiness of industrial users ([Lage et al., 2024](#)). Under an energy service model, operational responsibility may be transferred to a specialized provider, but contractual complexity increases. The investment model should therefore be selected after loads have been measured and legal admissibility has been clarified, not before those steps have been completed. Policy-sensitive photovoltaic and storage appraisals also show that financing and incentive design can materially alter the preferred system configuration ([D'Adamo et al., 2024](#)).

In this study, shared risk is operationalized as multi-actor risk allocation and governance: financial, operational, technological, regulatory and cybersecurity exposures are assigned to the actors best able to manage them. This is an essential characteristic of an industrial microgrid because economic benefits and risks arise among multiple participants ([D'Adamo et al., 2023](#)). The zone operator may manage the infrastructure but may not fully control the production schedules of industrial users. Industrial users may receive lower

energy costs, yet they may be unwilling to accept long-term contractual obligations or disclose detailed load profiles. An external investor may finance the assets but will require cash-flow predictability and legal certainty. Public institutions may reduce regulatory risk through rules and funding criteria, but they cannot replace operational management. Each risk should therefore be allocated to the participant with the greatest capacity to manage it (Köteles & Torma, 2024). Technological risk is allocated primarily to the provider; operational risk, to the operator and users; financial risk, to the investor and lender; and regulatory risk, jointly to the operator and the relevant institutions through the project's legal structure and applicable regulatory framework.

The literature remains fragmented across several analytical domains. Techno-economic studies commonly quantify generation, storage costs and investment indicators, but they do not always connect those outputs to the contractual allocation of risk among multiple industrial users. Electricity demand forecasting has been strengthened through ensemble methods, which confirms that load uncertainty should be treated as a measurable input rather than as a fixed assumption (Iftikhar et al., 2024). Financial-stress research has likewise shown that interest-rate, market and asset-price disturbances may propagate through emerging-market investment conditions, although such evidence does not provide a project-level allocation mechanism (Yousfani et al., 2025). The unresolved gap concerns the integration of load measurability, asset service life assumptions, financial sensitivity, regulatory admissibility and multi-actor risk allocation and governance within one industrial-zone framework.

3. Materials and Methods

3.1. Research Design and Source Corpus

A sequential and reproducible design is applied. Documentary regional benchmarking is first performed through a standardized documentary evidence rubric. A public-data availability assessment then separates observable information from unavailable project data. Scenario inputs are benchmarked against public market, financial, technology and environmental sources. Energy balance, battery service life, degradation and replacement effects, capital expenditures, operating expenditures and discounted cash flows are subsequently calculated. Uncertainty is examined through one-at-a-time sensitivity analysis, graphical comparison of the resulting NPV ranges, and break-even thresholds. Finally, an author-defined semi-quantitative likelihood–impact risk matrix and a financial risk-management framework translate numerical exposure into contractual and governance decisions. The complete sequence is presented in Figure 1.

The source corpus consists of official institutional documents, public market and technology datasets, regulatory instruments and peer-reviewed literature. External parameters are benchmarked using data from the Independent Bulgarian Energy Exchange (IBEX), the Bulgarian National Bank (BNB), the European Commission Joint Research Centre (JRC), Eurostat, the European Environment Agency (EEA), the International Renewable Energy Agency (IRENA), and the National Renewable Energy Laboratory (NREL). Values drawn from these sources are not transferred mechanically into a Bulgarian project forecast. They are used to bound scenario values and to identify parameters that must be replaced by project-specific measurements. Official sources for Bulgaria, Romania, Serbia, Turkey and Greece are used for the regional comparison. A strict distinction is retained among documentary values, externally benchmarked scenario assumptions and calculated outputs.

Established abbreviations are introduced once and are used consistently thereafter. The term ‘industrial microgrid’ retains the definition given in Section 2.2 and is not redefined in the methodology.

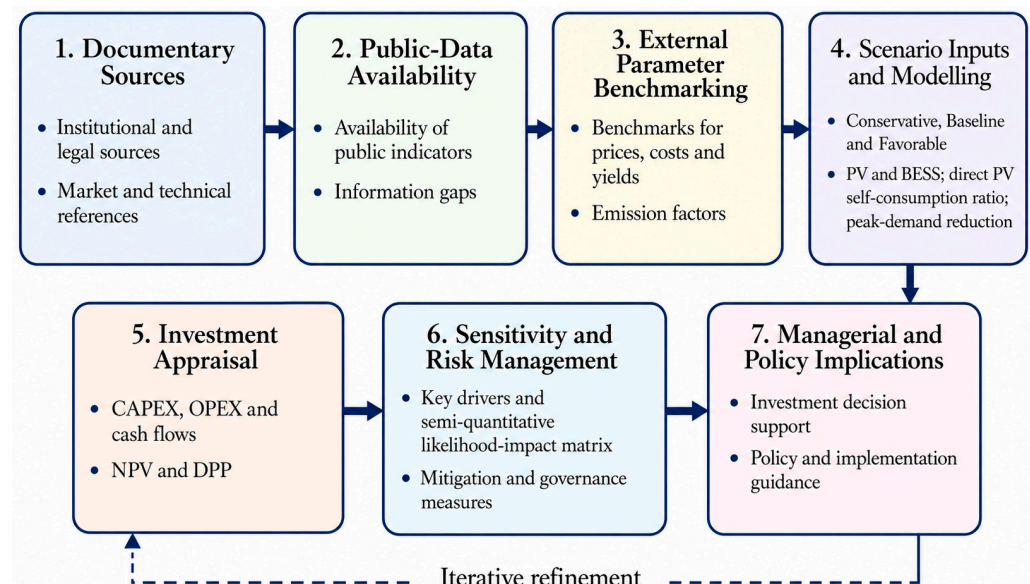


Figure 1. Research workflow and analytical decision sequence. Source: Authors' elaboration.

3.2. Scenario Framework for an Industrial Zone

The scenario model is developed for a reference industrial zone with annual electricity consumption of 12,000 MWh. This is an analytical reference value and not a statement about a specific real zone. Several manufacturing, warehousing and logistics users with predominantly daytime demand are assumed, while perfect coincidence between photovoltaic generation and load is explicitly rejected. The alternative system includes photovoltaic generation, battery energy storage, an energy management system, metering and a residual grid connection. Because no user-level hourly load series is available, the model is not presented as an engineering design or investment offer. It is used to identify the conditions under which a project may remain vulnerable, become acceptable or achieve a stronger investment margin.

Three scenarios are constructed to prevent dependence on a single favorable forecast. The conservative scenario combines lower yield and a lower direct PV self-consumption ratio with higher capital cost, financing risk and faster battery degradation. The baseline scenario represents a central externally benchmarked case. The favorable scenario assumes stronger load coordination and lower unit cost, but it does not assume autonomy, complete direct use of PV generation or equal values for purchased and excess PV electricity. Battery benefits are calculated net of round-trip losses, decline with usable-capacity degradation, and are restored after the modeled battery replacement; the corresponding replacement expenditure is charged in the same year. The complete parameter set is summarized in Table 1.

Table 1 separates the scale of the reference zone from the technical and financial variables that determine the results. Battery performance is represented through round-trip efficiency, usable-capacity degradation, service life and replacement cost so that long-term cash flows do not assume unchanged storage performance. The common grid-average electricity emission factor is used only for an indicative location-based operational-emissions estimate and does not constitute a life cycle assessment.

The ranges were selected through external parameter benchmarking and conservative localization rather than through optimization toward a positive net present value. Table 2 reports the relationship between each material assumption, the external source and its precise treatment in the model. Values are retained as scenarios where no Bulgarian industrial-zone measurement is publicly available.

Table 1. Input parameters of the scenario model for an industrial microgrid.

Indicator	Conservative Scenario	Baseline Scenario	Favorable Scenario
Annual industrial consumption	12,000 MWh	12,000 MWh	12,000 MWh
Photovoltaic capacity	3.0 MWp	3.5 MWp	4.0 MWp
BESS energy capacity	1.5 MWh	2.0 MWh	2.5 MWh
Specific annual yield	1230 kWh/kWp	1280 kWh/kWp	1320 kWh/kWp
Direct PV self-consumption ratio	68%	75%	82%
Purchase price of electricity	125 EUR/MWh	150 EUR/MWh	175 EUR/MWh
Assumed unit value of excess PV electricity	30 EUR/MWh	45 EUR/MWh	60 EUR/MWh
Gross annual economic benefit from peak-demand reduction before storage losses	20,000 EUR	40,000 EUR	65,000 EUR
Discount rate	8.0%	7.5%	7.0%
Annual PV generation degradation	0.6%	0.5%	0.5%
Battery round-trip efficiency	85%	88%	90%
Annual usable-capacity degradation of BESS	2.0%	1.5%	1.0%
Modeled BESS replacement year	12	13	15
Replacement cost share of initial BESS CAPEX	45%	40%	35%
Grid-average electricity emission factor (location-based proxy)	0.32 tCO ₂ e/MWh	0.32 tCO ₂ e/MWh	0.32 tCO ₂ e/MWh

Source: Authors' simulation based on the external benchmarks reported in Table 2.

Table 2. External benchmarking and treatment of material scenario assumptions.

Parameter	Scenario Value or Range	External Benchmark	Treatment in the Model
Annual consumption	12,000 MWh	Author-defined reference-zone assumption	Not externally observed; replace with measured annual demand and user-level hourly loads
Specific PV yield	1230–1320 kWh/kWp	European Commission JRC PVGIS (European Commission Joint Research Centre, n.d.)	Replace with location-specific output
Direct PV self-consumption ratio	68–82%	Industrial-load studies (Amini Toosi et al., 2023 ; Keskiniis et al., 2025)	Plausibility range only; replace with hourly coincidence analysis
Purchase price	125–175 EUR/MWh	IBEX 2025 market evidence (Independent Bulgarian Energy Exchange, 2026) and Eurostat 2025 non-household electricity-price statistics (European Commission & Eurostat, 2026)	All-in avoided-procurement scenario, not a forecast of exchange or retail price
Assumed unit value of excess PV electricity	30–60 EUR/MWh	Author-defined conservative discount to purchase-price range	Replace with actual offtake, curtailment and settlement terms
PV unit CAPEX	660,000–720,000 EUR/MWp	IRENA 2024 global utility-scale reference: USD 691/kW (International Renewable Energy Agency, 2025)	Scenario includes localization, roof works, metering and integration
BESS unit CAPEX	570,000–650,000 EUR/MWh	IRENA utility-scale battery reference: USD 192/kWh; NREL integration evidence	Higher turnkey industrial scenario includes power conversion system (PCS), controls, safety and integration
Gross economic benefit from peak-demand reduction	20,000–65,000 EUR/year	Author-defined scenario assumption	Validate from hourly peaks, tariffs and connection terms

Table 2. Cont.

Parameter	Scenario Value or Range	External Benchmark	Treatment in the Model
BESS energy capacity, efficiency and service life	1.5–2.5 MWh; 85–90% efficiency; 1–2%/year degradation; replacement in years 12–15 at 35–45% of initial BESS CAPEX	Capacity and replacement share: author assumptions; performance and service life evidence: National Renewable Energy Laboratory (2021a, 2021b)	Replace through hourly power–energy optimization, warranty terms and binding bid data
Fixed OPEX	1.8–2.2% of CAPEX plus BESS reserve	Component-based author assumption	Replace with maintenance, EMS, insurance and warranty contracts
Discount rate	7.0–8.0%	BNB: 3.93% long-term rate; 4.28% new corporate lending rate (2026)	Author-defined project hurdle rate; not project-specific WACC
Grid-average electricity emission factor	0.32 tCO ₂ e/MWh	EEA country-level generation-intensity indicator	Rounded source-informed proxy; not marginal or life cycle factor

Source: Authors' elaboration based on the sources specified in the table.

Each parameter in Table 2 remains a separately replaceable input. The external benchmark establishes a defensible interval, while the treatment column prevents a market statistic, technical benchmark or financing indicator from being misrepresented as a measured project value. This distinction is essential because public exchange prices do not equal a specific industrial supply contract, global technology costs do not equal a Bulgarian engineering, procurement and construction (EPC) offer, and a sovereign financing benchmark does not equal a project-specific weighted average cost of capital (WACC).

Table 3 formalizes the audit trail from source status to computational role. Documentary values are extracted from official sources, scenario values are externally bounded but remain assumptions, and calculated values are generated only through the reported equations. Battery service life, financial and environmental variables are classified under the same protocol.

Table 3. Status, units, source basis and computational role of input variables.

Variable	Status in the Model	Unit	Source or Justification	Role in the Calculations
Annual industrial consumption	Scenario assumption	MWh	Reference zone; replace with measured loads	Baseline cost and grid purchases
Photovoltaic capacity	Scenario assumption	MWp	Replace with site design	First-year generation
Specific yield	Externally bounded assumption	MWh/MWp	PVGIS (European Commission Joint Research Centre, n.d.); replace with site output	First-year generation
Direct PV self-consumption ratio	Externally bounded assumption	%	Literature plausibility; replace with hourly loads	Avoided grid purchase
Electricity purchase price	Market-bounded assumption	EUR/MWh	IBEX and Eurostat evidence (Independent Bulgarian Energy Exchange, 2026; European Commission & Eurostat, 2026); replace with contract	Baseline cost and net benefit
Assumed unit value of excess PV electricity	Author assumption	EUR/MWh	Conservative discount; replace with offtake terms	Excess PV electricity revenue

Table 3. Cont.

Variable	Status in the Model	Unit	Source or Justification	Role in the Calculations
Gross economic benefit from peak-demand reduction	Author assumption	EUR/year	Validate from hourly peaks and tariffs	Economic benefit from peak-demand reduction
PV and BESS capital expenditures	Scenario-calculated value	EUR	Component model; replace with binding bids	Incremental CAPEX
Fixed OPEX	Scenario-calculated value	EUR/year	Maintenance coefficient plus reserve	Annual net operating benefit
Discount rate	Author-defined hurdle rate	%	BNB benchmarks plus project-risk allowance	Discounting
BESS energy capacity, efficiency and degradation	Mixed: author-defined capacity; externally bounded performance	MWh, % and %/year	Reference-zone sizing and National Renewable Energy Laboratory (2021a, 2021b) evidence; replace with hourly optimization and warranty data	BESS CAPEX and net storage benefit
BESS replacement year and cost share	Author-defined service life assumption	Year and % of initial BESS CAPEX	Replace with warranty, augmentation and binding bid evidence	Replacement-adjusted cash flow
Grid-average electricity emission factor	Source-informed proxy	tCO ₂ e/MWh	EEA country indicator	Indicative operational emissions

Source: Authors' own simulation.

In project-level application, the reference consumption, photovoltaic yield, direct PV self-consumption ratio, capital cost, operating cost, financing rate and replacement terms must all be replaced by measured, bid or contract values. Reproducibility is therefore achieved through traceable substitution rather than through a claim that the current scenario values are final.

3.3. External Parameter Benchmarking and Validation Protocol

A public-data availability and external parameter-benchmarking layer is used because no reproducible user-level hourly dataset for a named Bulgarian industrial zone was identified. The Photovoltaic Geographical Information System (PVGIS) provides location-specific photovoltaic output, IBEX provides observed Bulgarian market information, the Bulgarian National Bank provides observable financing benchmarks, and IRENA and NREL provide technology-cost and service life evidence. These sources bound selected inputs but do not constitute empirical validation of the reference zone. Annual demand and the direct PV self-consumption ratio remain scenario assumptions until hourly user data are obtained.

The external literature provides an additional validity check. Published industrial-load microgrid studies confirm that the coincidence between demand and photovoltaic production, storage dispatch and control strategy can materially change the economic outcome. Forecasting research further indicates that electricity demand estimation should be based on validated time-series methods when sufficient observations are available. Accordingly, project-level use of the framework requires at least twelve months of hourly data, out-of-sample load validation and a documented rule for abnormal shutdowns, seasonal production and user entry or exit.

The 7–8% discount interval is treated as an indicative project hurdle rate rather than as a calculated WACC. The Bulgarian National Bank reported a 3.93% long-term convergence rate and a 4.28% weighted average rate on newly granted loans to non-financial

corporations in early 2026 (Bulgarian National Bank, 2026). The scenario interval therefore incorporates an author-defined allowance for project, technology, contractual and regulatory risk. A project-specific WACC cannot be derived without debt-equity weights, loan margins, taxation, security structure and counterparty credit quality. The same evidentiary principle is applied to uncertainty: deterministic sensitivity is used because reliable probability distributions and correlations cannot be estimated without project-level observations.

3.4. Formulas and Computational Sequence

The equations link externally benchmarked inputs to energy, battery, financial and environmental outputs. The notation is unified so that each annual cash flow is traceable from physical energy quantities through battery service adjustment, operating cost, replacement expenditure, discounting and payback. All variables, indices and units are defined immediately after the corresponding equations.

$$E_0 = P_{PV}Y_{PV} \quad (1)$$

$$E_t = E_0(1 - d_{PV})^{t-1} \quad (2)$$

$$E_{SC,t} = \alpha_{SC}E_t \quad (3)$$

$$E_{EX,t} = E_t - E_{SC,t} \quad (4)$$

$$E_{GRID,t} = E_D - E_{SC,t} \quad (5)$$

In Equations (1)–(5), E_0 is first-year photovoltaic generation (MWh), P_{PV} is installed photovoltaic capacity (MWp), Y_{PV} is specific annual yield (MWh/MWp), E_t is photovoltaic generation in year t , d_{PV} is the annual photovoltaic degradation rate, $E_{SC,t}$ is directly self-consumed PV electricity (MWh), α_{SC} is the direct PV self-consumption ratio, $E_{EX,t}$ is excess PV electricity (MWh), $E_{GRID,t}$ is electricity purchased from the external grid (MWh), and E_D is annual electricity demand (MWh). The scenario calculations hold E_D and α_{SC} constant over the horizon; a project application should replace both assumptions with measured hourly data.

$$\tau_t = \begin{cases} t - 1, & t < t_r, \\ t - t_r, & t \geq t_r. \end{cases} \quad (6)$$

$$B_t^{net} = B_0\eta_{BESS}(1 - d_B)^{\tau_t} \quad (7)$$

Here, τ_t is the number of elapsed degradation years since commissioning or the modeled replacement, t_r is the replacement year, B_t^{net} is the net economic benefit from peak-demand reduction in year t (EUR), B_0 is the gross first-year economic benefit from peak-demand reduction before storage losses (EUR), η_{BESS} is battery round-trip efficiency, and d_B is the annual degradation rate of usable battery capacity. Equation (7) is a simplified financial representation of the storage service. It does not constitute an hourly power-system dispatch model and does not specify battery power, discharge duration, chemistry or cycle count.

$$C_{BASE,t} = E_D p_{EL,t} \quad (8)$$

$$C_{MG,t} = E_{GRID,t} p_{EL,t} + OPEX_{FIX} - E_{EX,t} p_{EX,t} - B_t^{net} \quad (9)$$

$$NB_t = C_{BASE,t} - C_{MG,t} \quad (10)$$

In Equations (8)–(10), $C_{BASE,t}$ is annual electricity cost under the grid-only reference case (EUR), $C_{MG,t}$ is annual cost under the grid-connected microgrid scenario (EUR), $p_{EL,t}$ is the effective purchase price of electricity (EUR/MWh), $p_{EX,t}$ is the assumed unit value of excess PV electricity (EUR/MWh), $OPEX_{FIX}$ is annual fixed operating expenditure

(EUR/year), and NB_t is the annual net operating benefit before battery-replacement expenditure (EUR). Prices are held constant in real terms within each scenario, whereas a project model may introduce annual price paths.

$$CAPEX_{MG} = (P_{PV}c_{PV} + B_E c_{BESS} + C_{EMS} + C_{GRID})(1 + \rho) \quad (11)$$

$$\Delta CAPEX = CAPEX_{MG} - CAPEX_{BASE} \quad (12)$$

$$OPEX_{FIX} = CAPEX_{MG}\omega + M_{BESS} \quad (13)$$

In Equations (11)–(13), $CAPEX_{MG}$ is total microgrid capital expenditure (EUR), c_{PV} is photovoltaic unit cost (EUR/MWp), B_E is battery energy capacity (MWh), c_{BESS} is battery unit cost (EUR/MWh), C_{EMS} is energy-management-system cost (EUR), C_{GRID} is residual grid-integration and metering cost (EUR), ρ is the design and contingency allowance, $CAPEX_{BASE}$ is capital expenditure under the grid-only reference case (EUR), $\Delta CAPEX$ is the incremental initial CAPEX (EUR), ω is the annual maintenance and management coefficient, and M_{BESS} is the annual battery-maintenance and technical-risk reserve (EUR/year). The initial battery system capital expenditure is $C_{BESS} = B_E c_{BESS}$.

$$R_t = \begin{cases} \gamma C_{BESS}, & t = t_r, \\ 0, & t \neq t_r. \end{cases} \quad (14)$$

$$CF_t = NB_t - R_t \quad (15)$$

In Equations (14) and (15), R_t is battery-replacement expenditure in year t (EUR), γ is the replacement-cost share of initial battery system capital expenditure, and CF_t is the annual net cash flow after replacement expenditure (EUR). The replacement resets τ_t in Equation (6), while photovoltaic degradation continues without reset. The modeled replacement is assumed to become operational within the replacement year, and the associated expenditure is charged in that same year.

$$NPV = -\Delta CAPEX + \sum_{t=1}^n \frac{CF_t}{(1+r)^t} \quad (16)$$

$$A_T = -\Delta CAPEX + \sum_{t=1}^T \frac{CF_t}{(1+r)^t} \quad (17)$$

$$DPP = (T^* - 1) + \frac{|A_{T^*-1}|}{CF_{T^*}/(1+r)^{T^*}}, \quad T^* = \min\{T : A_T \geq 0\} \quad (18)$$

In Equations (16)–(18), NPV is net present value (EUR), r is the annual discount rate, n is the evaluation horizon of 20 years, A_T is accumulated discounted cash flow through year T , T^* is the first year in which A_T becomes non-negative, and DPP is the interpolated discounted payback period (years). If no $T^* \leq n$ exists, payback is reported as not achieved within the horizon.

$$GHG_t^{op} = E_{SC,t} EF_{grid} \quad (19)$$

In Equation (19), GHG_t^{op} is the indicative reduction in location-based greenhouse-gas (GHG) emissions associated with grid electricity purchases (tCO₂e/year), and EF_{grid} is the grid-average electricity emission factor used as a location-based proxy (tCO₂e/MWh). The indicator is not a marginal-dispatch estimate, a life cycle assessment or a verified carbon-credit quantity.

The computational protocol is therefore auditable from source classification to externally benchmarked assumptions, energy flows, battery service adjustment, component

costs, replacement-adjusted cash flows, investment indicators, sensitivity thresholds and the semi-quantitative risk matrix. All reported tables use unrounded intermediate values; displayed values are rounded only for presentation.

4. Results

4.1. Regional Documentary Benchmarking

The regional evidence is interpreted through two complementary layers. Table 4 presents documentary context for industrial territories and public investment. Table 5 applies an author-defined documentary evidence scoring rubric to five dimensions: metering and data, EMS/BESS evidence, contractual or operator architecture, regulatory or market pathways, and explicit public energy integration. Scores of 0, 1 and 2 denote no explicit evidence, partial or indirect evidence, and explicit documentary evidence. The rubric does not measure actual deployment and is not based on an expert survey.

Table 4. Regional documentary context for industrial territorial models.

Country	Industrial Territorial Form	Documentary Evidence	Scale/Value	Interpretation
Bulgaria	Industrial parks and zones	AttractInvestBG: 11 selected projects (Organisation for Economic Co-operation and Development, 2026)	BGN 206.5 m selected; BGN 212.5 m program (EUR 105.58 m; EUR 108.65 m)	Material investment window; park-level microgrid evidence not established
Romania	Industrial parks	119 industrial parks (Invest Romania, n.d.)	Count only	Large traceable network; register does not verify microgrid operation
Serbia	Free zones	15 free zones (Government of the Republic of Serbia, n.d.)	Count only	Investment regime; not equivalent to energy-system readiness
Turkey	Organized industrial zones	Shared green-infrastructure program (World Bank, 2021)	Values not used in model	Strong operator architecture for coordinated infrastructure
Greece	Industrial parks and substations	20 parks and 9 substations (European Commission, n.d.-e)	EUR 66.03 m	Energy infrastructure is explicit in public modernization

Source: Authors' synthesis of official and institutional sources, including [Organisation for Economic Co-operation and Development \(2026\)](#), [Invest Romania \(n.d.\)](#), the [Government of the Republic of Serbia \(n.d.\)](#), the [World Bank \(2021\)](#) and the [European Commission \(n.d.-e\)](#).

The score for Bulgaria is supported by a documented funding and park-governance framework, but the available program evidence contains no park-level metering or EMS/BESS indicators. Bulgaria is therefore assigned a score of 0 for metering/data and EMS/BESS evidence, 1 for contract/operator architecture, 2 for the regulatory/market pathway established through the Energy Act and electricity-trading rules, and 1 for public energy integration, which is institutionally possible but not demonstrated at project level ([Organisation for Economic Co-operation and Development, 2026](#); [Republic of Bulgaria, 2003](#); [Energy and Water Regulatory Commission, 2026](#)). Romania is assigned scores of 1, 0, 1, 1, and 1 because the national register provides park and operator visibility but no explicit storage or energy-management evidence ([Invest Romania, n.d.](#)).

Serbia is assigned scores of 0, 0, 1, 1, and 0 because the free-zone framework documents investment governance without explicit microgrid-relevant energy integration ([Government of the Republic of Serbia, n.d.](#)). Turkey is assigned scores of 1, 1, 2, 1, and 2 because organized industrial-zone governance and the World Bank green-infrastructure program explicitly support coordinated infrastructure, although park-level metering and

BESS evidence remain partial (World Bank, 2021). Greece is assigned scores of 1, 1, 1, 1, and 2 because public modernization explicitly includes substations, renewable energy, storage and smart-energy-management elements, but does not provide a complete public operator, settlement or metering dataset (European Commission, n.d.-e). The resulting documentary evidence scores are summarized in Table 5.

Table 5. Documentary evidence scores for industrial microgrid-relevant information.

Country	Metering/Data	EMS/BESS Evidence	Contract/Operator Architecture	Regulatory/Market Pathway	Public Energy Integration	Total Score (0–10)
Bulgaria	0	0	1	2	1	4
Romania	1	0	1	1	1	4
Serbia	0	0	1	1	0	2
Turkey	1	1	2	1	2	7
Greece	1	1	1	1	2	6

Source: Authors' documentary evidence scoring based on the sources reported in Table 4. Scale: 0 = no explicit evidence; 1 = partial or indirect evidence; 2 = explicit documentary evidence. Scores indicate public visibility, not verified deployment or empirical probability.

The scoring audit trail therefore links every country score to the documentary evidence summarized in Table 4. A score of 0 records the absence of explicit evidence in the reviewed source, 1 records partial or indirect evidence, and 2 records explicit evidence. The totals are used only to compare documentary evidence availability; they do not rank actual deployment, technical performance or legal admissibility. The resulting policy implication is a common disclosure requirement for metering, EMS/BESS, operator and settlement architecture, regulatory status and energy-integration outcomes.

4.2. Information Gaps and Gap Analysis

The gap analysis establishes that public sources can document program scale and regional institutional forms but cannot support a project-level estimate of actual microgrid performance. No systematic public database was identified for hourly user loads, park-level photovoltaic generation, battery dispatch, EMS functions, internal settlement, financing terms or user credit concentration. These absences prevent empirical calibration of the direct PV self-consumption ratio, peak-demand reduction, counterparty loss and debt-service capacity. Scenario modeling is therefore retained until primary technical, contractual and financial data are collected. The resulting public-data availability and project-data gaps are summarized in Table 6.

Table 6 defines the evidentiary boundary of the model. Hourly load data are required for the direct PV self-consumption ratio and battery sizing; binding bids are required for CAPEX and OPEX; financing terms and counterparty data are required for WACC, debt-service coverage and credit-loss analysis; and contractual and legal evidence is required for settlement and revenue recognition. The external benchmarks improve plausibility but do not replace these project observations.

Table 6. Public-data availability and project-data gaps.

Indicator	Required Project Information	Public-Data Availability	Consequence for the Model
Hourly load profiles	Consumption by hour and user	No systematic public database identified	The direct PV self-consumption ratio and BESS sizing remain assumptions

Table 6. *Cont.*

Indicator	Required Project Information	Public-Data Availability	Consequence for the Model
Local generation	Installed capacity and measured output	No comparable park-level database identified	Current generation cannot be estimated from the available public data
EMS and battery operation	Functions, power, capacity, dispatch and operator	No systematic database identified	Peak-demand reduction and control remain scenario-based
Internal contractual model	Allocation, settlement, entry, exit and default rules	No common public project standard identified	Revenue recognition and allocation remain uncertain
Cybersecurity	Architecture, access control, redundancy and incidents	No project-level public evidence identified	Risk cannot be empirically calibrated
Financing and counterparties	Debt terms, security, payment history and load concentration	No project-level public data identified	WACC, DSCR and counterparty-loss metrics cannot be calculated

Source: Authors' own research.

4.3. Component-Based Calculation of Capital Expenditures

Capital expenditures are disaggregated into photovoltaic capacity, battery storage, the energy management system, residual grid integration and a design-and-contingency allowance (Table 7). The structure preserves auditability and allows bid values to replace scenario costs without changing the calculation. The grid-only reference case is retained so that NPV is based on additional rather than total microgrid investment.

Table 7. Component-based capital expenditures by scenario (Equations (11) and (12)).

Component	Conservative Scenario	Baseline Scenario	Favorable Scenario
Photovoltaic capacity	3.0 MWp	3.5 MWp	4.0 MWp
Unit cost of photovoltaic capacity	720,000 EUR/MWp	690,000 EUR/MWp	660,000 EUR/MWp
Photovoltaic system	2,160,000 EUR	2,415,000 EUR	2,640,000 EUR
BESS energy capacity	1.5 MWh	2.0 MWh	2.5 MWh
Unit cost of battery storage	650,000 EUR/MWh	610,000 EUR/MWh	570,000 EUR/MWh
BESS capital cost	975,000 EUR	1,220,000 EUR	1,425,000 EUR
Energy management system	250,000 EUR	270,000 EUR	290,000 EUR
Residual grid integration and metering	380,000 EUR	360,000 EUR	340,000 EUR
Subtotal before reserve	3,765,000 EUR	4,265,000 EUR	4,695,000 EUR
Reserve percentage for design and contingencies	10%	9%	8%
Reserve for design and contingencies	376,500 EUR	383,850 EUR	375,600 EUR
Total capital expenditures of the microgrid	4,141,500 EUR	4,648,850 EUR	5,070,600 EUR
CAPEX of the grid-only reference case	900,000 EUR	1,000,000 EUR	1,100,000 EUR
Incremental CAPEX	3,241,500 EUR	3,648,850 EUR	3,970,600 EUR

Source: Authors' own calculations.

The favorable scenario requires the highest absolute investment because it includes the largest photovoltaic and battery capacities. Its stronger financial result therefore does not arise from a lower total project cost, but from lower unit costs, a higher direct PV self-consumption ratio, a higher avoided-purchase value and a stronger economic benefit from peak-demand reduction. The comparison therefore uses incremental CAPEX rather than total microgrid CAPEX.

4.4. Component-Based Calculation of Operating Expenditures

Annual fixed operating expenditure is calculated by applying a maintenance and management coefficient to total microgrid CAPEX and adding a separate battery-maintenance and technical-risk reserve (Table 8). The approach avoids treating the microgrid as a passive

photovoltaic asset, but it remains a scenario representation; warranty-specific maintenance, augmentation and insurance terms must replace it in a real project.

Table 8. Component-based fixed operating expenditures (Equation (13)).

Indicator	Conservative Scenario	Baseline Scenario	Favorable Scenario
Maintenance and management coefficient	2.2%	2.0%	1.8%
Maintenance and management cost	91,113 EUR	92,977 EUR	91,271 EUR
Reserve for battery system and technical risk	25,000 EUR	30,000 EUR	35,000 EUR
Fixed operating expenditures	116,113 EUR	122,977 EUR	126,271 EUR

Source: Authors' own calculations.

Fixed OPEX is material in every scenario and is propagated into annual cash flow and sensitivity analysis. The coefficients decline moderately with scale, whereas absolute expenditure increases with system size. The favorable-scenario value is calculated from unrounded intermediate amounts and is displayed to the nearest euro.

4.5. Energy Balance of the Industrial Microgrid

Under an annual demand of 12,000 MWh, first-year photovoltaic generation ranges from 3690 to 5280 MWh and directly self-consumed PV electricity ranges from 2509.2 to 4329.6 MWh. External-grid purchases remain between 7670.4 and 9490.8 MWh. The microgrid is therefore modeled as hybrid infrastructure that reduces, but does not eliminate, dependence on the external grid. The energy balance derived from Equations (1)–(5) is reported in Table 9.

Table 9. First-year energy balance of the industrial microgrid (Equations (1)–(5)).

Scenario	First-Year Generation	Directly Self-Consumed PV Electricity	Excess PV Electricity	Purchase from the External Grid
Conservative	3690 MWh	2509 MWh	1181 MWh	9491 MWh
Baseline	4480 MWh	3360 MWh	1120 MWh	8640 MWh
Favorable	5280 MWh	4330 MWh	950 MWh	7670 MWh

Source: Authors' own calculations.

The persistent external-grid requirement is relevant to connection, metering, balancing and contractual design. No autonomy or islanding claim is made because such a claim would require power-rated storage, duration, redundancy, protection studies and hourly dispatch analysis that are outside the present financial scenario model.

4.6. Operating Balance and Economic Value of Directly Self-Consumed PV Electricity

The operating balance links the physical energy result to the annual financial result. Directly self-consumed PV electricity reduces external purchases; excess PV electricity is valued below the avoided purchase price, and fixed OPEX is added. The economic benefit from peak-demand reduction is adjusted for battery round-trip losses and is not treated as unrestricted revenue. The first-year operating balance obtained from Equations (7)–(10) is presented in Table 10.

First-year net benefit is EUR 249,961, EUR 466,623 and EUR 746,933 in the conservative, baseline and favorable scenarios. In the baseline case, the gross economic benefit from peak-demand reduction of EUR 40,000 is reduced to EUR 35,200 by the 88% round-trip-efficiency assumption. These benefits are then reduced over time by photovoltaic and battery degradation, while the modeled battery replacement is deducted in year 13.

For the baseline scenario, grid-dependent electricity cost is EUR 1,800,000. Microgrid purchases cost EUR 1,296,000, fixed OPEX is EUR 122,977, excess PV electricity is valued

at EUR 50,400 and net economic benefit from peak-demand reduction is EUR 35,200. The resulting first-year microgrid cost is EUR 1,333,377 and the first-year net benefit is EUR 466,623.

Table 10. First-year operating balance and net operating benefit by scenario (Equations (7)–(10)).

Indicator	Conservative Scenario	Baseline Scenario	Favorable Scenario
Cost under the grid-only reference case	1,500,000 EUR	1,800,000 EUR	2,100,000 EUR
Cost of electricity purchased from the external grid under the grid-connected microgrid scenario	1,186,350 EUR	1,296,000 EUR	1,342,320 EUR
Fixed operating expenditures	116,113 EUR	122,977 EUR	126,271 EUR
Assumed value of excess PV electricity	35,424 EUR	50,400 EUR	57,024 EUR
Net economic benefit from peak-demand reduction after round-trip losses	17,000 EUR	35,200 EUR	58,500 EUR
Cost under the grid-connected microgrid scenario	1,250,039 EUR	1,333,377 EUR	1,353,067 EUR
Annual net operating benefit in the first year	249,961 EUR	466,623 EUR	746,933 EUR

Source: Authors' own calculations.

4.7. Discounted Cash Flows and Intermediate Verification

Annual benefits are calculated year by year rather than multiplied by the twenty-year horizon. Photovoltaic output and battery service value decline according to their scenario rates, replacement expenditure is deducted in the specified year, and each resulting cash flow is discounted. Table 11 reconciles discounted benefits with the incremental initial CAPEX; Table 12 provides the full baseline path.

Table 11. Intermediate verification of discounted investment results (Equations (6)–(16)).

Indicator	Conservative Scenario	Baseline Scenario	Favorable Scenario
Annual net operating benefit in the first year	249,961 EUR	466,623 EUR	746,933 EUR
Scenario discount rate	8.0%	7.5%	7.0%
PV generation degradation	0.6%	0.5%	0.5%
BESS capacity degradation	2.0%	1.5%	1.0%
Battery replacement	Year 12; 438,750 EUR	Year 13; 488,000 EUR	Year 15; 498,750 EUR
Sum of discounted replacement-adjusted cash flows	2,126,774 EUR	4,346,686 EUR	7,395,435 EUR
Incremental CAPEX	3,241,500 EUR	3,648,850 EUR	3,970,600 EUR
Net present value	−1,114,726 EUR	697,836 EUR	3,424,835 EUR

Source: Authors' own calculations.

Table 12 reports the baseline cash-flow path using unrounded intermediate values. Year zero contains the additional investment. The modeled EUR 488,000 battery replacement is deducted in year 13 and resets the storage-service degradation clock, while photovoltaic degradation continues. The replacement creates a temporary negative annual cash flow and delays discounted recovery.

Accumulated discounted cash flow becomes positive during year 15, producing an interpolated discounted payback period (DPP) of approximately 14.1 years. At year 20, accumulated discounted cash flow equals the baseline NPV of EUR 697,836. The conservative scenario remains unrecovered, whereas the favorable scenario retains a materially larger margin.

The annual reconciliation demonstrates that first-year savings alone are insufficient for investment approval. Replacement timing, contracted energy value, capital cost and a sustained direct PV self-consumption ratio must be evaluated over the complete horizon.

Table 12. Annual discounted cash flows under the baseline scenario (Equations (1)–(18)).

Year	Generation	Directly Self-Consumed PV Electricity	Net Cash Flow	Discounted Cash Flow	Accumulated Discounted Flow
0	-	-	-	-	−3,648,850 EUR
1	4480 MWh	3360 MWh	466,623 EUR	434,068 EUR	−3,214,782 EUR
2	4458 MWh	3343 MWh	463,323 EUR	400,929 EUR	−2,813,854 EUR
3	4435 MWh	3326 MWh	460,045 EUR	370,318 EUR	−2,443,536 EUR
4	4413 MWh	3310 MWh	456,788 EUR	342,043 EUR	−2,101,492 EUR
5	4391 MWh	3293 MWh	453,553 EUR	315,926 EUR	−1,785,566 EUR
6	4369 MWh	3277 MWh	450,339 EUR	291,802 EUR	−1,493,764 EUR
7	4347 MWh	3260 MWh	447,146 EUR	269,519 EUR	−1,224,245 EUR
8	4326 MWh	3244 MWh	443,974 EUR	248,937 EUR	−975,307 EUR
9	4304 MWh	3228 MWh	440,822 EUR	229,926 EUR	−745,382 EUR
10	4282 MWh	3212 MWh	437,692 EUR	212,365 EUR	−533,016 EUR
11	4261 MWh	3196 MWh	434,581 EUR	196,145 EUR	−336,871 EUR
12	4240 MWh	3180 MWh	431,491 EUR	181,163 EUR	−155,708 EUR
13	4218 MWh	3164 MWh	−53,741 EUR	−20,989 EUR	−176,697 EUR
14	4197 MWh	3148 MWh	431,121 EUR	156,632 EUR	−20,066 EUR
15	4176 MWh	3132 MWh	428,003 EUR	144,651 EUR	124,585 EUR
16	4156 MWh	3117 MWh	424,907 EUR	133,585 EUR	258,170 EUR
17	4135 MWh	3101 MWh	421,831 EUR	123,366 EUR	381,536 EUR
18	4114 MWh	3086 MWh	418,776 EUR	113,928 EUR	495,464 EUR
19	4093 MWh	3070 MWh	415,741 EUR	105,211 EUR	600,675 EUR
20	4073 MWh	3055 MWh	412,725 EUR	97,161 EUR	697,836 EUR

Source: Authors' own calculations.

4.8. Investment Results

The financial results confirm conditional rather than automatic viability. Conservative NPV is EUR −1,114,726 and the DPP is not achieved within twenty years. Baseline NPV is EUR 697,836 with a DPP of approximately 14.1 years. Favorable NPV is EUR 3,424,835 with a DPP of approximately 7.0 years. These values are illustrative outputs of the stated assumptions and are not expected returns for a named industrial zone. The scenario-level investment indicators are consolidated in Table 13.

Table 13. Summary investment results by scenario.

Scenario	Capital Expenditures of the Microgrid	Incremental CAPEX	Annual Net Operating Benefit in the First Year	Net Present Value	Discounted Payback Period (DPP)
Conservative	4,141,500 EUR	3,241,500 EUR	249,961 EUR	−1,114,726 EUR	Not achieved within 20 years
Baseline	4,648,850 EUR	3,648,850 EUR	466,623 EUR	697,836 EUR	14.1 years
Favorable	5,070,600 EUR	3,970,600 EUR	746,933 EUR	3,424,835 EUR	7.0 years

Source: Authors' own calculations.

The negative conservative result limits optimism bias. The baseline result indicates value creation but remains exposed to price, cost, replacement, liquidity and counterparty risk. The favorable result represents an upper scenario and cannot substitute for project due diligence.

Environmental and Carbon-Reporting Results

Environmental output is limited to an indicative reduction in location-based emissions associated with grid electricity purchases. Directly self-consumed PV electricity is multiplied by a rounded, source-informed grid-average electricity emission factor for Bulgaria of 0.32 tCO₂e/MWh. Under the GHG Protocol, the location-based method reflects the average emissions intensity of the grid on which electricity consumption occurs and generally uses

grid-average emission-factor data (World Resources Institute & World Business Council for Sustainable Development, 2015). Excess PV electricity is excluded because its displacement effect depends on dispatch and settlement. Embodied PV and BESS emissions, marginal generation and life cycle effects are not modeled. The scenario results obtained from Equation (19) are reported in Table 14.

Table 14. Indicative reduction in location-based emissions associated with grid electricity purchases (Equation (19)).

Indicator	Conservative	Baseline	Favorable
Directly self-consumed PV electricity	2509.2 MWh	3360.0 MWh	4329.6 MWh
Grid-average electricity emission factor (location-based proxy)	0.32 tCO ₂ e/MWh	0.32 tCO ₂ e/MWh	0.32 tCO ₂ e/MWh
Indicative reduction in location-based emissions associated with grid electricity purchases	802.9 tCO ₂ e/year	1075.2 tCO ₂ e/year	1385.5 tCO ₂ e/year
Share of reference-zone electricity demand covered by directly self-consumed PV generation	20.9%	28.0%	36.1%

Source: Authors' calculations using directly self-consumed PV electricity and a rounded scenario proxy informed by the European Environment Agency country-level electricity-generation-intensity indicator (European Environment Agency, 2026).

The indicator supports preliminary location-based emissions screening but is not a verified carbon saving, carbon-credit quantity, or automatic Carbon Border Adjustment Mechanism (CBAM) compliance or environmental, social and governance (ESG) reporting result. Project reporting requires an explicit accounting boundary, updated annual factors, treatment of guarantees of origin, and consistency with each user's location-based and market-based reporting methods.

4.9. Sensitivity of Investment Results

A deterministic one-at-a-time sensitivity analysis is used because probability distributions and correlations cannot be estimated credibly without hourly loads, binding bids, financing observations and operating history. Seven variables are stressed around the baseline scenario, and break-even thresholds are calculated. Monte Carlo simulation is reserved for an empirical case in which distributions can be estimated rather than assumed. The adverse and favorable one-at-a-time results are reported in Table 15. Under the CAPEX stress test, total microgrid CAPEX, fixed OPEX and BESS replacement expenditure are scaled proportionally, while the CAPEX of the grid-only reference case remains unchanged.

Electricity price, CAPEX and the direct PV self-consumption ratio produce the widest NPV ranges. At 127.5 EUR/MWh, baseline NPV becomes EUR −45,920. A 10% CAPEX increase, with derived OPEX and replacement expenditure recalculated, leaves NPV of EUR 88,522. The break-even purchase price is approximately 128.9 EUR/MWh, the break-even direct PV self-consumption ratio is approximately 59.9%, and the maximum tolerable CAPEX increase is approximately 11.5% under the other baseline assumptions. These values are monitoring thresholds, not forecasts. The relative NPV ranges are visualized in Figure 2.

Table 15. Sensitivity of investment results to key parameters.

Tested Parameter	Adverse Test	Result	Favorable Test	Result
Direct PV self-consumption ratio	65% instead of 75%	NPV 235,055 EUR; DPP 17.5 years	85% instead of 75%	NPV 1,160,617 EUR; DPP 11.0 years

Table 15. Cont.

Tested Parameter	Adverse Test	Result	Favorable Test	Result
Electricity price	127.5 instead of 150 EUR/MWh	NPV −45,920 EUR; no DPP within 20 years	172.5 instead of 150 EUR/MWh	NPV 1,441,591 EUR; DPP 10.1 years
Capital expenditures	CAPEX +10%; OPEX and replacement recalculated	NPV 88,522 EUR; DPP 19.1 years	CAPEX −10%; OPEX and replacement recalculated	NPV 1,307,149 EUR; DPP 9.9 years
Operating expenditures	OPEX +15%	NPV 509,782 EUR; DPP 15.3 years	OPEX −15%	NPV 885,889 EUR; DPP 13.2 years
Gross economic benefit from peak-demand reduction	20,000 instead of 40,000 EUR	NPV 529,455 EUR; DPP 15.2 years	50,000 instead of 40,000 EUR	NPV 782,026 EUR; DPP 13.7 years
Discount rate	8.5% instead of 7.5%	NPV 401,266 EUR; DPP 15.7 years	6.5% instead of 7.5%	NPV 1,031,271 EUR; DPP 11.8 years
Battery replacement cost	50% instead of 40% of initial BESS CAPEX	NPV 650,187 EUR; DPP 14.5 years	30% instead of 40% of initial BESS CAPEX	NPV 745,484 EUR; DPP 13.8 years

Source: Authors' own calculations.

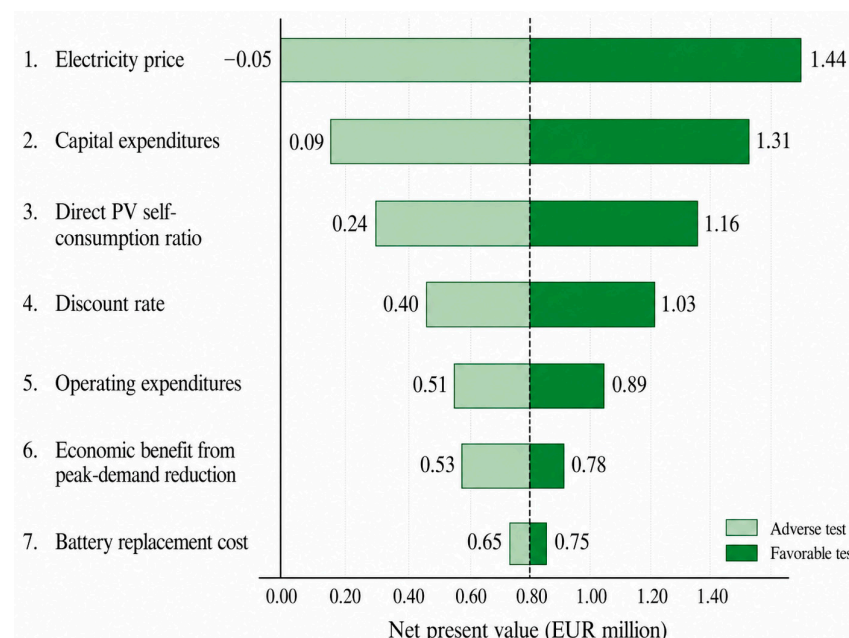


Figure 2. One-at-a-time sensitivity analysis of baseline-scenario NPV across key parameters. Source: Authors' calculations. Values are expressed in EUR million; the dashed line represents the baseline NPV.

4.10. Risk Matrix Derived from the Results

The sensitivity results and documented information gaps are translated into an author-defined semi-quantitative likelihood–impact risk matrix. Likelihood and impact are scored from 1 to 5 and multiplied to obtain a risk-priority score. Scores of 1–4 are classified as low, 5–9 as moderate, 10–16 as high and 17–25 as critical. The ratings are not empirical probabilities and were not produced by a Delphi or expert-survey procedure; they provide a transparent prioritization device that must be recalibrated when project evidence becomes available. The cyber-risk category is informed by literature identifying vulnerabilities across metering, communication, control and data layers (Jamil et al., 2021; Pinto et al., 2023; Bouslimani et al., 2025), while the assigned score remains author-defined because no project incident history is available. The resulting risk prioritization is presented in Table 16.

Table 16. Semi-quantitative likelihood–impact risk matrix for an industrial microgrid.

Risk	Primary Source	Likelihood	Impact	Risk-Priority Score/Class	Risk Owner	Principal Mitigation
Information	Absence of hourly user loads	4	5	20/Critical	Zone operator	12 months of validated measurement
Technological	PV–BESS–EMS integration failure	3	4	12/High	Provider/operator	Performance guarantees and testing
Market	Electricity-price volatility	4	4	16/High	Operator/users	Price bands and periodic reforecasting
Financial	CAPEX overrun and financing-cost increase	4	5	20/Critical	Investor/lender	Fixed-price procurement and rate protection
Operational	Production-schedule instability	3	4	12/High	Industrial users	Load-management obligations
Counterparty	Exit or default of a major user	3	5	15/High	Operator/investor	Credit support and replacement-user clauses
Regulatory	Unclear allocation or network status	3	5	15/High	Operator/institutions	Preliminary legal qualification
Cybersecurity	Compromise of metering or control	3	5	15/High	Operator/provider	Segmentation, redundancy and incident response
Reporting	Unsupported emissions or ESG claim	2	3	6/Moderate	Users/operator	Documented accounting boundary

Source: Author-defined semi-quantitative risk prioritization based on the sensitivity results and documented information gaps. Scores are prioritization judgments, not observed event frequencies.

Information and financial risks receive critical scores because they directly affect sizing, cash-flow reliability and financing capacity. Market, counterparty, regulatory and cybersecurity risks are classified as high. The cybersecurity score reflects potential interruption of control, corruption of settlement data and contractual liability, but it remains a semi-quantitative assessment until a system architecture, threat model and incident history are available.

5. Discussion

The results support treatment of an industrial microgrid as an interdependent system of generation, storage, digital control, contracts and finance. Battery losses, degradation and replacement reduce investment margins, while the negative conservative result confirms that technical feasibility does not imply financial viability.

The methodological contribution extends beyond standard NPV and payback calculations. A public-data availability assessment precedes scenario construction; each input is classified by source status; regional evidence is assessed using a common documentary evidence scoring rubric; battery service life, degradation and replacement are incorporated into discounted cash flows; and sensitivity thresholds are translated into risk owners and mitigation instruments. This integration distinguishes the framework from stand-alone asset appraisals that do not include a multi-actor risk-allocation and governance layer.

The direct PV self-consumption ratio remains the principal operational determinant because it determines the share of local generation that displaces grid purchases. However, the break-even results show that electricity price and CAPEX may dominate the financial margin. Comparable techno-economic evidence confirms that dispatch strategy can materially change industrial PV–BESS performance (Keskinis et al., 2025), while the profitability of self-consumption and storage varies with incentive and settlement design (Lage et al., 2024). Reviews of photovoltaic and storage valuation identify capital cost, energy-price assumptions and uncertainty treatment as recurrent determinants of

project value (Gómez-Restrepo et al., 2024), and structured renewable energy risk analyses similarly demonstrate the need to connect economic outputs with explicit risk treatment (Gołębiewski & Galant-Gołębiewska, 2021). The present framework extends these asset- and policy-level approaches by adding public-data availability, replacement-adjusted cash flows, threshold-based re-approval, risk ownership and contractual mitigation for a multi-user industrial zone. Load forecasting and meter validation should therefore precede final sizing, while price, minimum-use, cost-overflow and replacement obligations should be agreed before financial close. Demand-forecasting evidence is relevant to this measurement problem, whereas financial-stress evidence supports periodic re-estimation of financing and market conditions (Iftikhar et al., 2024; Yousfani et al., 2025).

The environmental and regional results require similarly cautious interpretation. The emissions indicator is location-based and operational, not marginal or life cycle. The regional score measures documentary evidence availability, not actual technological deployment. Both outputs are therefore screening aids rather than verified performance claims.

Deterministic sensitivity was preferred to Monte Carlo simulation because project-level distributions are unavailable. This limits probabilistic inference but avoids unsupported precision. Hourly loads, market-price histories, component bids, debt terms and operating observations would permit subsequent stochastic dispatch, cash-flow-at-risk and debt-service analysis.

An industrial zone becomes an energy-management unit only when the operator can collect data, coordinate loads, enforce commitments and allocate savings. Positive NPV is insufficient without long-term user stability, legal admissibility, replacement funding, cybersecurity obligations and a transparent settlement mechanism.

5.1. Regulatory Risk in the Bulgarian Energy Regime

The European framework provides several possible participation routes but does not create an automatic legal category for every industrial microgrid. Directive (EU) 2019/944 addresses active customers, citizen energy communities and closed distribution systems, while Directive (EU) 2018/2001 addresses renewables self-consumers and renewable energy communities. Directive (EU) 2024/1711 further develops energy sharing and long-term contracting. Article 38 of Directive (EU) 2019/944 is particularly relevant because a geographically confined industrial or commercial site may qualify as a closed distribution system only under specified conditions (European Parliament and Council, 2018, 2019, 2024). The Commission's electricity-market-design materials provide the related institutional context (European Commission, n.d.-d).

In Bulgaria, the legal route depends on asset ownership, network operation, supply, aggregation, metering, balancing and settlement. The Energy Act, the Energy from Renewable Sources Act and the 2026 electricity-trading rules provide pathways relevant to active customers, jointly acting active customers, citizen energy communities, renewables self-consumers and renewable energy communities, including registration and settlement-period metering requirements (Republic of Bulgaria, 2003, 2011; Energy and Water Regulatory Commission, 2026). A residual grid connection, common meters and an EMS do not by themselves determine whether electricity is being self-consumed, shared, supplied or distributed. Project-specific legal qualification is therefore required before the revenue model is approved.

The contractual architecture should define asset ownership, meter hierarchy, balancing responsibility, data access, allocation of directly self-consumed PV electricity and its financial benefits, treatment of excess PV electricity, peak-demand-related savings, OPEX, battery replacement, user entry and exit, default, curtailment, cybersecurity, confidentiality and dispute resolution. Minimum-use, security and replacement-user clauses are

needed where loss of a major user could transfer an unpriced cash-flow shock to the remaining participants.

Regulatory conditions directly affect financial results. If internal allocation is inadmissible or cannot be measured, the financial benefit from directly self-consumed PV electricity may not become a billable saving. If excess PV electricity cannot be realized under the assumed unit value, revenue declines. If the economic benefit from peak-demand reduction is not recognized in the applicable connection or tariff structure, part of the storage benefit disappears. The defensible sequence is legal qualification and metering design, hourly measurement, conditional contracting, technical sizing and final investment approval.

5.2. Financial Risk Management of Industrial Microgrid Investments

Financial risk management is distinguished from financial appraisal. NPV and DPP report an outcome under specified assumptions; risk management determines how deviations are monitored, allocated and mitigated. The framework covers electricity-price risk, CAPEX overrun, OPEX escalation, financing-rate and refinancing risk, liquidity pressure, counterparty default, battery replacement, cybersecurity and regulatory interruption. Periodic re-estimation is required because external financial stress may transmit into borrowing conditions, asset prices and user credit quality.

The 7–8% interval is an indicative hurdle rate, not a project-specific WACC. Before financial close, the lender and investor model should specify debt-equity weights, interest margins, repayment profile, taxes, covenants, security, reserve accounts and minimum debt-service coverage ratio (DSCR). Value at Risk, cash-flow-at-risk and DSCR are not calculated here because the required financing and probability data are absent. Instead, sensitivity and break-even thresholds are used as transparent monitoring triggers. The complete financial risk-management framework is summarized in Table 17.

Table 17. Financial risk-management framework linked to scenario evidence.

Financial Exposure	Cash-Flow Channel	Quantitative Evidence	Monitoring Indicator	Mitigation Instrument	Primary Owner
Electricity-price risk	Value of avoided purchases	127.5 EUR/MWh: NPV −45,920 EUR	Effective contracted price	Price band, indexation and reforecasting	Operator/users
CAPEX overrun	Initial investment and derived costs	CAPEX +10%: NPV 88,522 EUR	Committed cost vs. budget	Fixed-price EPC, contingency, change control	Investor/contractor
OPEX escalation	Lower annual net operating benefit	OPEX +15%: NPV 509,782 EUR	Actual OPEX vs. budget	Long-term service terms and escalation cap	Operator/provider
Direct PV self-consumption risk	Lower avoided purchases	Direct PV self-consumption ratio of 65%: NPV 235,055 EUR	Hourly coincidence and contracted load	Minimum-use commitments and EMS rules	Operator/users
Financing-rate risk	Discount and debt-service burden	8.5%: NPV 401,266 EUR	Loan margin and refinancing date	Fixed-rate tranche or repricing limit	Investor/lender
Liquidity/replacement risk	Large mid-life outflow	Year 13: EUR 488,000 replacement	Funded replacement reserve	Sinking fund, warranty, staged augmentation	Operator/investor
Counterparty risk	Loss of demand or payment	Risk-priority score 15/High	Credit quality and load concentration	Security, step-in and replacement-user clauses	Investor/operator
Cyber/regulatory interruption	Suspended control, settlement or revenue	Risk-priority scores 15/High	Control availability and legal milestones	Insurance, redundancy, conditions precedent	Operator/provider

Source: Authors' synthesis of the sensitivity and semi-quantitative risk-prioritization results.

The risk register should be maintained through procurement and operation. A contracted purchase price approaching EUR 128.9/MWh, a direct PV self-consumption ratio approaching 59.9%, or committed CAPEX exceeding the baseline by approximately 11.5%

should trigger re-approval, resizing or contractual remediation. These trigger values are conditional on the remaining baseline assumptions and must be re-estimated when project data change.

6. Managerial and Policy Implications

Industrial-zone operators. Implementation should begin with at least twelve months of validated hourly loads, peak-demand analysis, controllable-load identification and roof/site assessment. Metering and analytical infrastructure should precede final equipment procurement. EMS control rules should then be specified, while battery power, storage duration, and photovoltaic capacity should be sized against observed coincidence and grid-connection constraints.

Industrial users. Participation requires confidentiality safeguards, controlled access to load data and an enforceable allocation of costs, savings and exit obligations. Minimum-use, credit-support and settlement clauses should protect the shared cash flow, while verified energy quantities may support user-level sustainability reporting.

Public authorities. Support programs should require an energy audit, interoperable metering plan, roof and grid assessment, preliminary storage and cybersecurity design, legal-structure analysis and a plan for publishing non-confidential performance indicators. These requirements need not mandate immediate construction of a full microgrid; they should preserve technical and contractual readiness for later integration.

Investors and lenders. Due diligence should combine technical sizing with contractually supported cash flow, user concentration, pricing rules, cost-overflow allocation, replacement reserves, performance guarantees, insurance, cybersecurity obligations and default remedies. The conservative scenario should be retained as a mandatory downside case. DSCR and leverage ratios should be calculated only after actual financing terms are available.

7. Limitations and Future Research

No hourly dataset, binding bid package, financing term sheet or executed internal-energy contract for a named industrial zone is used. External benchmarks improve the plausibility of the ranges but do not constitute empirical project validation. PVGIS output, effective procurement prices, bid CAPEX/OPEX, financing terms and the emissions factor must be replaced or updated for the selected site and reporting year.

The BESS representation is deliberately simplified. Energy capacity is modeled, but power rating, discharge duration, chemistry, cycle count, state-of-charge constraints, dispatch optimization, outages and warranty-specific degradation are not simulated. Round-trip efficiency, usable-capacity degradation and replacement therefore represent financial service assumptions rather than a complete physical storage model. Deterministic sensitivity is used to avoid unsupported probability distributions. This separation between a simplified annual degradation assumption and project-specific state-of-health metrics is consistent with the BESS health-management literature (Nazaralizadeh et al., 2024).

Project-level validation should include at least twelve months of user-level hourly loads, out-of-sample demand forecasting, location-specific photovoltaic simulation, roof and connection studies, power-and-energy battery optimization, binding EPC and maintenance offers, legal opinion, counterparty credit assessment, financing terms and documented carbon-accounting boundaries. A real case should then compare forecast and observed direct PV self-consumption ratios, peak-demand reduction, degradation, operating cost and settlement.

8. Conclusions

An integrated scenario framework was developed for the investment appraisal of industrial-zone microgrids and for the analysis of their energy-management, risk-allocation, and governance requirements. Public documentary evidence was separated from project assumptions through a public-data availability assessment, and scenario ranges were benchmarked against observable market, financial, technology and environmental sources. Battery efficiency, degradation, service life and replacement were incorporated into cash flows. Regional evidence was assessed using a documentary evidence scoring rubric, sensitivity was evaluated through one-at-a-time parameter variation, graphical comparison of NPV ranges, and break-even thresholds, and risks were assigned semi-quantitative likelihood–impact risk-priority scores and responsible parties.

The main thesis is supported conditionally. Conservative NPV is EUR −1,114,726 and the DPP is not achieved within twenty years. Baseline NPV is EUR 697,836 with a DPP of approximately 14.1 years, while favorable NPV is EUR 3,424,835 with a DPP of approximately 7.0 years. The indicative reduction in location-based emissions associated with grid electricity purchases is 802.9–1385.5 tCO₂e per year under the selected grid-average electricity emission factor. Electricity price, CAPEX and the direct PV self-consumption ratio are the dominant financial drivers. An industrial microgrid may become financially viable strategic infrastructure only when hourly data, legal admissibility, user commitments, procurement controls, replacement funding, cybersecurity and financial risk allocation are established. The outputs remain illustrative until validated against a real industrial-zone dataset.

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Abbreviations

The following abbreviations are used in this manuscript:

BESS	Battery Energy Storage System
CAPEX	Capital Expenditures
CBAM	Carbon Border Adjustment Mechanism
EMS	Energy Management System
ESCO	Energy Service Company
ESG	Environmental, Social and Governance
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit
NPV	Net Present Value
OPEX	Operating Expenditures
DPP	Discounted Payback Period
PVGIS	Photovoltaic Geographical Information System
UNIDO	United Nations Industrial Development Organization
DSCR	Debt Service Coverage Ratio
WACC	Weighted Average Cost of Capital
EPC	Engineering, Procurement and Construction
PCS	Power Conversion System
IBEX	Independent Bulgarian Energy Exchange
JRC	Joint Research Centre
NREL	National Renewable Energy Laboratory
BGN	Bulgarian lev
BNB	Bulgarian National Bank
tCO ₂ e	Tonnes of Carbon Dioxide Equivalent
EEA	European Environment Agency
EU	European Union
EUR	Euro
GHG	Greenhouse Gas
IRENA	International Renewable Energy Agency
OECD	Organisation for Economic Co-operation and Development
PV	Photovoltaic
USD	United States dollar

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