World Journal of Advanced Research and Reviews
eISSN: 2581-9615 CODEN (USA): WJARAI
Cross Ref DOI: 10.30574/wjarr
Journal homepage: https://wjarr.com/

(Research Article)

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Renewable energy communities in central Africa: Towards a hybrid model, tariff impacts, energy justice and local governance

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World Journal of Advanced Research and Reviews, 2026, 29(03), 1155-1185

Publication history: Received on 07 February 2026; revised on 14 March 2026; accepted on 16 March 2026

Article DOI: https://doi.org/10.30574/wjarr.2026.29.3.0602

Abstract

This paper investigates the techno-economic and social viability of hybrid Renewable Energy Communities (RECs) in Central Africa, focusing on an urban case study in Yaoundé, Cameroon. Using a discounted cash flow model, Net Present Value (NPV), Levelized Cost of Electricity (LCOE), and Monte Carlo simulations were employed to evaluate financial feasibility under three policy scenarios - Low-support (LM), Realistic (RM), and High-support (HM). The hybrid configuration integrates photovoltaic, wind, and biomass systems to match household demand profiles derived from local residential load data. Results indicate that economic profitability emerges above 30% self-consumption, with NPV values ranging from €4,100/kW (LM, 30%) to €10,000/kW (HM, 70%) and LCOE between 102–125 €/MWh. Sensitivity analysis confirms strong dependence on self-consumption and CAPEX, while Monte Carlo simulations (1,000 iterations) show a >98% probability of achieving a positive NPV. Two innovative benefit-sharing models are introduced - PDM3 (behavior-based) and PDM4 (income-based) - ensuring both efficiency and social equity. Governance analysis proposes a tripartite structure involving state authorities, citizen cooperatives, and private actors, addressing institutional gaps and promoting inclusivity. These findings highlight the potential of hybrid RECs to reduce energy poverty, enhance local ownership, and guide policy innovation in Sub-Saharan Africa. The results demonstrate that, even under uncertain regulatory conditions, RECs can offer a robust pathway toward sustainable and socially just energy transitions in developing urban contexts.

Keywords: Renewable Energy Communities; Hybrid Energy Systems; Net Present Value (NPV); Energy Justice; Benefit-Sharing Models; Urban Sustainability

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1. Introduction

The energy transition in Sub-Saharan Africa, particularly in Central Africa, is marked by a paradox: an abundance of renewable resources coexisting with persistent energy poverty and limited access to modern electricity services. In this context, renewable energy communities (RECs) decentralized groups of citizens, local authorities, and businesses cooperating to produce, consume, and manage renewable energy are emerging as a viable pathway for achieving multiple Sustainable Development Goals (SDGs), notably SDG 7 (affordable and clean energy), SDG 11 (sustainable cities), and SDG 13 (climate action) [1–4]. While most empirical studies focus on photovoltaic (PV)-based RECs in European contexts [5,6], recent literature increasingly highlights the potential of hybrid systems integrating PV, wind, biomass, and storage for equitable, resilient, and affordable electrification in African cities and peri-urban communities [7–9].

Over the past two decades, the global renewable energy market has experienced exponential growth, driven by falling technology costs, supportive policy frameworks, and mounting climate commitments. According to the

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International Energy Agency (IEA, 2024) and REN21 (2023), global renewable electricity capacity surpassed 3,700 GW in 2023—an increase of more than 50% compared to 2018. Solar PV and wind power jointly accounted for nearly 90% of this annual capacity expansion, with solar costs decreasing by over 80% since 2010. Emerging economies in Africa, Asia, and Latin America are increasingly contributing to this momentum, supported by decentralized energy systems and mini-grid programs. In Sub-Saharan Africa, installed renewable capacity has tripled since 2010, yet per capita electricity access remains among the lowest globally. These global trends highlight the urgency of promoting local renewable energy communities (RECs) as a means of bridging the gap between national electrification goals and equitable access to sustainable energy.

Urban areas in Africa are expanding rapidly, yet energy infrastructure remains uneven and centralized [10]. In Central African cities such as Yaoundé, Bangui, or Brazzaville, electricity shortages coexist with rising demand and deepening socio-economic disparities. These dynamics underscore the urgent need for local energy systems that are both technically adaptive and socially inclusive. Community-based hybrid energy systems offer promising solutions to fill this gap [11]. Not only do they promote energy autonomy and local participation, but they also enhance resilience against price shocks, climate risks, and infrastructural vulnerabilities [12,13].

However, deploying such systems raises complex issues at the crossroads of economics, social justice, and governance. First, the tariff implications of hybrid community models remain underexplored in African settings. While self-consumption improves financial returns for prosumers, its impact on non-participants, often the most vulnerable households, can generate or exacerbate forms of exclusion [14,15]. Second, the fair distribution of benefits economic, environmental, and symbolic within RECs is a recurring challenge globally [16–18]. In contexts where income inequality, informal economies, and institutional instability prevail, the mechanisms for sharing benefits must be not only efficient but equitable and trusted [19,20].

Third, governance structures of RECs in Africa must contend with overlapping jurisdictions, weak institutional frameworks, and limited fiscal capacity. As noted in recent reviews [21,22], the success of energy communities hinges on their ability to balance local autonomy with national regulatory frameworks. Without inclusive governance, citizen participation tends to be tokenistic or monopolized by elites, undermining both equity and effectiveness [23,24]. Moreover, trust both interpersonal and institutional is critical to sustaining collective action and long-term commitment in RECs [25].

Most studies on RECs are concentrated in European countries, particularly Italy, Germany, and the Netherlands, where legal frameworks, subsidies, and community engagement are well established [5,6,26]. Yet Central Africa offers a distinct case, combining untapped renewable potential with pressing social needs. Previous techno-economic studies, such as Yimen et al. (2018), have shown the viability of hybrid PV–wind–biomass systems in rural Cameroon, using Net Present Value (NPV) and Levelized Cost of Energy (LCOE) as benchmarks [7]. However, little is known about their performance in urban or peri-urban low-income neighborhoods, where infrastructure is precarious, and the willingness-to-pay is constrained by poverty.

Furthermore, the policy environment in Central Africa is still nascent. Countries like Cameroon have launched regulatory reforms and pilot projects, yet barriers such as bureaucratic inertia, unclear ownership rights, and lack of fiscal incentives persist [27,28]. In this policy vacuum, bottom-up energy initiatives must be designed carefully to ensure that they are not only technically sound and economically viable, but also socially just and politically sustainable.

The literature also stresses the importance of robust economic indicators in assessing REC models. NPV, in particular, has become the preferred metric for evaluating profitability and investor appeal [29–31]. Yet as Basilico et al. (2025) demonstrate, profitability is highly sensitive to key variables such as the share of self-consumption, purchase and selling prices of electricity, and investment costs. For example, in their Italian baseline scenario, NPV rose from €2041/kW at 30% self-consumption to over €8000/kW at 70% self-consumption, with significant variations depending on market conditions [31]. In African cities, where market dynamics and subsidies differ sharply, such sensitivity analyses must be contextualized and expanded to account for local socioeconomic constraints.

The current study builds on this literature by proposing a hybrid REC model tailored for Central Africa, combining techno-economic modeling with a focus on equitable benefit-sharing and participatory governance. We develop simulations based on realistic urban scenarios in Cameroon, using a hybrid system integrating PV, wind, and biomass, and we analyze the impact of different policy levers on profitability and equity. Three scenarios are considered: optimistic (high self-consumption, fiscal incentives), realistic (moderate incentives, partial adoption), and pessimistic (low participation, subsidy withdrawal).

To address the justice dimension, we integrate two novel benefit-distribution models inspired by De Villena et al. (2020) and Ren et al. (2023): one based on internal community pricing, rewarding virtuous energy behavior (e.g., low exchange prices); the other using income brackets to prioritize vulnerable households. These models are tested for their impact on both economic efficiency (NPV, LCOE) and energy poverty reduction.

In terms of governance, we evaluate the feasibility of tri-partite structures involving municipalities, local cooperatives, and private actors, drawing on best practices from the IREP framework in Nigeria and co-creation models piloted in Kenya and Tunisia [8,22,33]. We assess the institutional robustness of these arrangements through criteria such as transparency, accountability, scalability, and resistance to elite capture.

This study extends existing REC research by proposing a hybrid modeling approach that simultaneously integrates techno-economic evaluation, benefit-sharing equity, and governance design within the Central African context.

In doing so, this article aims to fill critical research gaps by (i) expanding the scope beyond PV-only systems, (ii) modeling real-world tariff effects for both participants and non-participants, (iii) proposing equitable benefit-sharing frameworks, and (iv) evaluating governance architectures suited for fragile institutional contexts.

The remainder of the paper is structured as follows: Section 2 reviews the existing literature on hybrid RECs, benefit distribution, and governance models. Section 3 describes the methodological framework, including the simulation parameters and economic assumptions. Section 4 presents the results of the baseline and alternative scenarios, focusing on NPV variation, LCOE, and the effectiveness of the two distribution models. Section 5 discusses implications for policy and community design, highlighting trade-offs between equity and efficiency. Section 6 concludes with recommendations for policymakers, practitioners, and researchers aiming to scale hybrid RECs in Central Africa.

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2. Literature review

2.1. Systematic Review Methodology

To explore advances in hybrid energy community models (RECs), tariff justice, and local governance structures, we have led to the development of the query (“renewable energy community” OR “energy community” OR “hybrid mini grid”) AND (“NPV” OR “profitability” OR “economic analysis” OR “energy justice” OR “governance”) AND (“Africa” OR “Cameroon” OR “Sub Saharan Africa”).

This query generated 154 articles (2020-2025). After eliminating duplicates and filtering: a) articles/journals, b) peer reviews, c) texts in English, 112 articles were selected. Application of the exclusion criteria: E1: out of scope (e.g. purely technical without a community dimension), E2: not in English, E3: no economic analysis (NPV, LCOE, etc.), E4: not relevant to mini-grids or sub-Saharan Africa, 1st selection: 38 articles.

By sorting by relevance, the 25 most significant were selected for in-depth analysis. (See PRISMA process).

2.2. Hybrid models in the African context

Interest in hybrid systems in Central Africa is growing. Yimen et al. (2018) model a hybrid PV–wind–biogas–off-grid hydraulic pumped system in Northern Cameroon. Their study shows that self-consumption rates between 50% and 70% make the system profitable with a positive NPV, confirming the economic solidity of these models [1]. Chambalile et al. (2024) offer an ambitious review of solar-wind systems in Eastern and Southern Africa. They point out that hybrid systems are more resilient and flexible than mono-technology systems, especially in remote areas [2]. Coelho et al. (2024) make a techno-economic comparison of PV/wind systems with storage, concluding that a model combining PV + wind + batteries create the best trade-offs between cost, performance and resilience, especially for small communities [3][4].

In addition to the European and Asian case studies previously discussed, a growing body of research has recently explored hybrid renewable energy communities (RECs) and their socio-economic implications in emerging economies. For instance, Yimen et al. (2024) examined techno-economic synergies between PV, wind, and biomass systems for rural electrification in Cameroon, while Ahlborg et al. (2023) analyzed the governance dimensions of decentralized energy systems in Sub-Saharan Africa. Similarly, work by Murenzi and Kim (2023) and Koirala et al. (2022) emphasized the role of collective self-consumption in addressing energy poverty through local ownership models. Recent comparative assessments (Basilico et al., 2025; Ren et al., 2023; Coelho et al., 2024) have also underlined the need to integrate economic performance metrics such as NPV, LCOE, and equity-based redistribution schemes within hybrid RECs. However, most of these studies remain geographically concentrated in Europe or Asia, with limited empirical focus on Central Africa. The present research contributes to filling this gap by adapting these established frameworks to the Cameroonian context, combining financial feasibility, energy justice, and governance analysis within a hybrid system perspective.

In addition, frameworks such as IREP in Nigeria (PV + biomass + DSM + business model) show that an integrated approach is better suited to African constraints [5].

The cross-references reveal that profitability depends heavily on the rate of self-consumption, the CAPEX/OPEX structure and the level of local subsidies. This finding supports our hypothesis that public intervention and community participation have a significant influence on economic viability.

Table 1 Summary of the characteristics of hybrid renewable systems in Central and Sub-Saharan Africa

Study	Country / Region	Technology Configuration	Application Context	LCOE	NPV (where available)	Key Findings
Yamen et al. (2018) [1]	Northern Cameroon	PV + Wind + Biogas + Pumped Hydro	Rural electrification (off-grid)	0.08–0.12 €/kWh	Positive for SC > 50%	Optimal NPV achieved at SC > 50%; multi-tech synergy improves resilience and reliability.
Chamberlike et al. (2024) [2]	Eastern & Southern Africa	PV + Wind (grid and off-grid)	Regional survey	0.10–0.18 €/kWh	Not disclosed	Hybrid systems outperform mono-PV in flexibility and cost in isolated zones.
Coelho et al. (2024) [3][4]	Global (including Africa)	PV + Wind + Battery Storage	Small energy communities	0.09–0.14 €/kWh	~4,500 €/kW median	Hybrid models with storage deliver highest profitability and energy autonomy.
IREP Framework (2019–2020) [5]	Nigeria	PV + Biomass + DSM + Business Model	Community mini-grids	Not stated	Not stated	Emphasizes integrated planning (technical + institutional + business models).
Study on Nabiha Refugee Camp (2021) [6]	Rwanda	PV + Diesel + Biogas	Humanitarian camp	~0.11 €/kWh	N/A	Hybrid design reduces fuel dependence, lowers CO_2 emissions, and improves cost-efficiency.
Co-design REC Models (2021–2023) [7]	Tunisia, Kenya, Cameroon	PV + Wind + Local Storage	Urban & peri-urban RECs	0.09–0.15 €/kWh	Context dependent	Participatory governance and co-creation crucial for long-

						term sustainability.
Sustainability Review (2022) [8]	Sub-Saharan Africa	Mixed RE + Smart DSM	Comparative synthesis	Variable	Variable	Highlights co-benefits: energy access, social trust, gender inclusion in REC governance.

Hourly production and load data derived from Global Solar Atlas, NASA POWER, and AFREC datasets (see Section 3.2.1).

- Wind capacity factor = 0.23 (Renewables. Ninja, 2023)
- Biomass electrical efficiency = 0.28 (FAO, 2021)"
- Battery round-trip efficiency = 92% (HOMER Pro simulation)

Notes: LCOE = Levelized Cost of Electricity; SC = Self-consumption rate. NPV = Net Present Value (when provided); currency values reflect ranges standardized across studies. DSM = Demand-Side Management.

2.3. Economic Analysis: NPV, LCOE, Cost-Effectiveness

Financial indicators are central to assessing RECs: NPV (net present value), LCOE (levelized cost of energy), internal rate of return, etc. The Basilico et al. study (2025) based in Italy, but qualitatively applicable—shows an increase in NPV from €2,000/kW to €8,000/kW when self-consumption increases from 30% to 70% [31]. Yamen et al. (2018) report an LCOE of €0.08 – €0.12/kWh for their hybrid model in northern Cameroon, below the rural tariff threshold [1]. Chamberlike et al. (2024) indicate a comparative LCOE between €0.10/kWh and €0.18/kWh for regional hybrid systems [2]. In a recent meta-analysis, Coelho et al. (2024) find that optimal configurations with storage have a median NPV of €4,500/kW, with a payback time of less than 7 years [3].

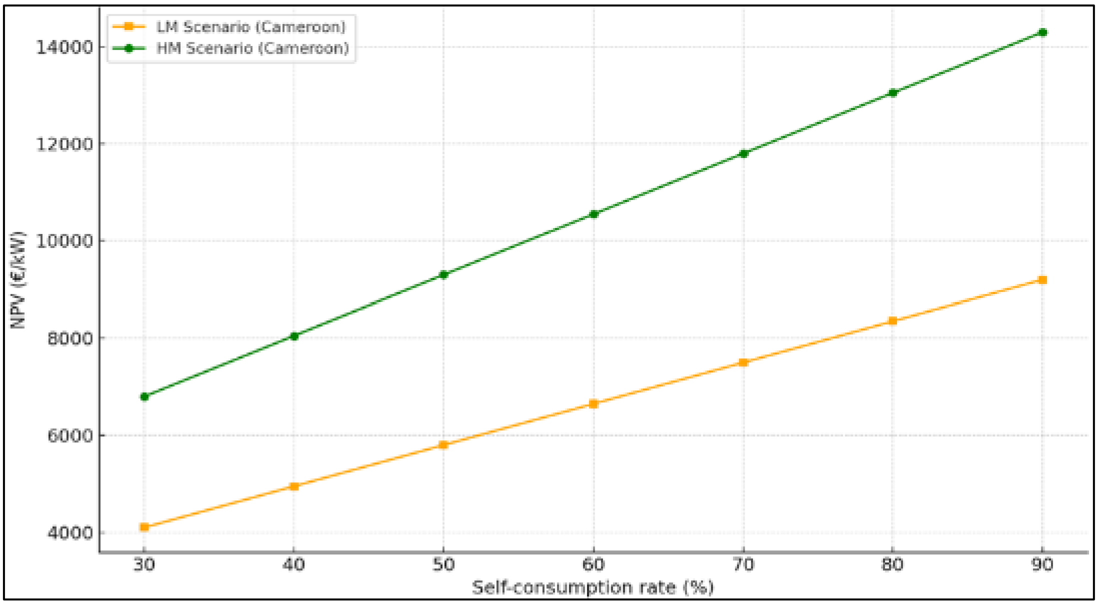

Figure 1 Typical NPV curves vs. self-consumption rate (30%–90%), in relation to data from Italian studies adapted to the Cameroonian context. Sources: adapted from Basilico et al. (2025) [31], Yamen et al. (2018) [1], and Coelho et al. (2024) [3]. Economic results derived from PV–wind–biomass hybrid model detailed in Section 3.3.1

NPV results incorporate technology-specific LCOE values (Section 3.2, Table 3).

These results show that the combination of hybrid technology and high self-consumption can ensure robust financial performance, especially if innovative subsidies or financing mechanisms are put in place.

2.4. Energy Justice and Socio-Economic Inclusion

The concept of energy justice encompasses: Distributive justice: equitable access to benefits; Procedural justice: participation in decisions; Justice of recognition: recognition of the needs of the most vulnerable (Ren et al. 2023) [6]. Ren et al. (2023) propose a framework for assessing equity impacts over the entire life cycle of the energy system [6]. A study in Malawi (2022) shows that an urban ECR can improve access, reduce energy costs by 30% for low-income families, and strengthen cohesion, provided that appropriate redistribution mechanisms are designed [7]. De Villena et al. (2020) develop a model for the ex-post allocation of energy surpluses based on individual contributions and behaviors, relevant for integrating justice criteria [2]. This work demonstrates that energy justice is not limited to the question of cost, but involves a set of social, economic and institutional variables. They motivate our inclusion of two profit-sharing models: one incentivized (internalized resale prices), the other income-based to protect low-income households.

Table 2 Comparison of existing redistribution models (unitary vs. egalitarian vs. income-based vs. behavior-based

Model	Redistribution Rule	Equity Objective	Strengths	Limitations	Key References
Unitary	Fixed exchange rate or equal benefit per unit consumed or produced	Neutral / revenue maximization	Simple implementation; transparent	Favors high consumers; may exclude low-income or low-consumption participants	[25], [31]
Egalitarian	Equal distribution of total benefits regardless of consumption or income	Equality	Promotes inclusion and cohesion	Low incentive for energy-saving behaviour or higher contributors	[18], [32]
Income-based	Shares scaled by household income or vulnerability level	Social justice / poverty mitigation	Targets energy poverty; aligns with SDG 7 and 10	Requires reliable income data; privacy and administrative complexity	[6], [7], [20]
Behaviour-based	Allocation based on virtuous behaviour (e.g., proposing lowest exchange price)	Incentive compatibility	Encourages cooperative prosumer behaviour; gamifies participation	May penalize vulnerable households; can be gamed or misunderstood	[2], [31], [44]
Hybrid (income + behaviour)	Weighted combination of income level and community pricing behaviour	Equity-efficiency trade-off	Balances fairness with system performance	Needs fine-tuning of weightings; more complex to govern	Proposed in current study

Notes: Virtuous behavior refers to internalized incentives, such as voluntarily offering a lower intra-community trading price to support collective welfare. Hybrid models aim to reconcile justice (equity) and efficiency (performance). Administrative feasibility varies significantly between models.

2.5. Local governance and institutional framework

A CER project cannot succeed without a strong governance structure, balancing local autonomy and national regulation: IREP (Nigeria) proposes a cooperative-municipality-private model, stressing the importance of multi-stakeholder governance [5]. Revue Sustainability (2021 2023) identifies six governance models in sub-Saharan Africa (Tunisia, Kenya, Cameroon), highlighting the impact of legal frameworks, institutional trust and public funding [8]. Governance of Energy Transitions in Africa (2022) shows that the weakness of institutional capacity and the influence of local elites often compromise democratic initiatives [9].

These elements feed into our reflection on the need for a tripartite structure (State, municipalities, cooperatives), with mechanisms ensuring transparency, accountability and active participation of citizens.

Figure 2 Conceptual diagram: Ideal governance structure for CERs in an African context (State–cooperative–private)

2.6. Critical Summary of Identified Deficiencies

Despite a rich corpus, four major gaps persist: Concentration on mono-technology (PV) systems with few studies integrating hybrid models in an urban context. Underexplored Energy Justice in quantitative analyses (NPV + distributive criteria). Tariff effects on non-participants rarely modelled, even though they can widen inequalities. Poorly documented hybrid governance structures in the institutionally fragile contexts of Central Africa.

2.7. Expected contribution of this study

Our article aims to fill these gaps by: Extending the analysis beyond the PV, combining PV, wind, biomass and storage in an urban community system ; Modeling revenues and costs for participants AND non-participants, and assessing the effect of self-consumption on pricing ; Integrating two inclusive redistribution models: In-house pricing and Income distribution ; Proposing a governance scheme adaptable to Cameroonian realities, based on the good practices identified (e.g. IREP, Sustainability, Malawi).

2.8. Positioning in the state of the art

Our approach combines several innovative dimensions: Techno-economic: we combine proven methods (NPV, LCOE, Monte Carlo) in a hybrid model applied to a peripheral district of Yaoundé. Social equity: explicit inclusion of vulnerable households via a model of redistribution by income, an innovation compared to egalitarian or strictly behavioral models. Local governance: tripartite scheme and institutional robustness criteria adapted to the African context. Pricing impact: assessment of the direct impact on the prices paid by non-participating households, a dimension that is rarely taken into account.

These contributions pave the way for a robust, inclusive and viable ECR model in a context that is still little explored.

In conclusion, this review establishes a solid foundation for our study, resulting from a rich and critical corpus. It justifies our choice of a hybrid system; innovative redistribution models and a governance scheme designed for Central Africa.

2.8.1. Social and environmental impacts of renewable energy integration

Beyond techno-economic feasibility, the deployment of Renewable Energy Communities (RECs) has far-reaching social and environmental implications. Several studies emphasize that the transition to decentralized renewable systems can foster energy justice, social inclusion, and community empowerment, particularly in low-income and rural regions (e.g., Sova cool et al., 2021; Ceglia et al., 2023). Environmentally, hybrid renewable systems combining PV, wind, and biomass substantially reduce greenhouse gas emissions and local pollutants, thereby supporting Sustainable Development Goals (SDG 7, 11, and 13) (IEA, 2023; REN21, 2024). However, potential negative externalities—such as land-use conflicts, biomass sourcing challenges, and inequalities in access to clean technologies—must also be carefully managed through inclusive governance and environmental safeguards (REN21, 2022; IPCC, 2023). Integrating these dimensions into REC design enhances both social legitimacy and long-term sustainability, ensuring that renewable transitions contribute to community well-being alongside decarbonization objectives.

3. Methodology

This study applies a rigorous, multi-layered methodology grounded in techno-economic modeling, benefit-sharing simulation, and governance analysis. It seeks to assess the feasibility and equity implications of hybrid renewable energy communities (RECs) in an urban context in Central Africa. Inspired by the framework used in Basilico et al. (2025) [1], the methodology integrates Net Present Value (NPV), Levelized Cost of Electricity (LCOE), and Monte Carlo simulations to account for financial viability and sensitivity under different scenarios. The study also introduces innovative models of benefit distribution adapted to the socio-economic realities of Cameroon.

3.1. Regulatory and socio-political context in Cameroon

Unlike the well-established frameworks of the European Union, Cameroon currently operates under a nascent but evolving energy governance structure. Community-based electrification projects, while not yet supported by a comprehensive national REC policy, are increasingly being promoted by municipal authorities in partnership with international agencies and private investors. The Cameroonian Electricity Sector Regulatory Agency (ARSEL) and the Rural Electrification Agency (AER) provide fragmented but critical support for renewable mini-grid initiatives. However, there is no standardized mechanism for incentivizing collective self-consumption or redistributing benefits across community members. This institutional vacuum justifies the need for governance and redistribution models specifically tailored to this context [2,3].

3.2. Economic modeling: NPV and LCOE calculations

To assess project profitability, we adopt a discounted cash flow (DCF) approach consistent with prior REC literature [1,4,5].

The mathematical formulations used in this study—particularly the Net Present Value (NPV), Levelized Cost of Electricity (LCOE), and operation and maintenance (O&M) equations—are derived and adapted from well-established frameworks in applied energy economics and renewable energy system assessment. Specifically, the NPV and LCOE expressions follow the formulations used by Thellufsen et al. (2020) [14], Basilico et al. (2025) [1], and Coelho et al. (2024) [4], with parameterization adjusted to reflect Cameroonian market and climatic conditions. The benefit allocation equations introduced in Section 3.5 build on prior models of prosumer benefit sharing developed by Ren et al. (2023) [5] and extended to hybrid systems in this work.

Each equation has been adapted for local relevance by updating cost parameters, capacity factors, and discount rates. Units and variable definitions are systematically presented in the Nomenclature section to ensure clarity and replicability.

The proposed hybrid Renewable Energy Community (REC) model was formulated as an optimization problem aimed at maximizing the net present value (NPV) of the community over its project lifetime while ensuring technical feasibility and equity in benefit distribution. The general objective function can be expressed as:

$$Maximize\ NPV = \sum_{t=1}^{T} \frac{(R_t - C_t)}{(1+r)^t} \qquad (1)$$

where R_t and C_t represent, respectively, the total revenues and costs at time t, r is the discount rate, and T the project lifetime. The optimization simultaneously ensures the minimization of the Levelized Cost of Energy (LCOE) for each subsystem and the equitable redistribution of benefits among Renewable Self-Consumers (RSCs) through the Profit Distribution Models (PDMs) described in Section 3.3.

3.3. The problem was subject to the following constraints

3.3.1. Energy balance constraint

$$P_{PV}(t) + P_W(t) + P_B(t) = L(t) + E_{ex}(t) \qquad (2)$$

ensuring that the hourly production from PV, wind, and biomass equals the load demand $L(t)$ and exchanged energy $E_{ex}(t)$.

3.3.2. Capacity constraint

$$0 \leq P_i(t) \leq P_i^{max} \qquad (3)$$

for each technology $i \in \{PV, W, B\}$, reflecting their technical generation limits.

3.3.3. Economic feasibility constraint

$$NPV > 0, LCOE \leq LCOE_{grid} \qquad (4)$$

ensuring economic competitiveness relative to grid electricity prices.

3.3.4. Equity constraint

$$\sum_j OB_j = OB_{total} \qquad (5)$$

enforcing that the sum of individual benefits equals the total community benefit.

This multi-objective formulation was solved iteratively using a scenario-based approach rather than a heuristic optimizer, due to the hybrid nature of the community and the lack of continuous control variables. The resulting Pareto-optimal configurations balance economic efficiency, equity, and self-consumption performance, as presented in Section 5.

Following the multi-objective optimization framework, the main economic indicators used in this study Net Present Value (NPV), Levelized Cost of Energy (LCOE), and Individual Benefits ($\boldsymbol{OB_j}$) were computed following standard formulations in renewable energy economics (IEA, 2022; Short et al., 1995; Bazilian et al., 2013; Basilico et al., 2025).

3.3.5. Net Present Value (NPV)

The NPV quantifies the difference between discounted revenues and total costs over the project lifetime T

$$NPV = \sum_{t=1}^{T} \frac{(R_t - C_t)}{(1+r)^t} \qquad (6)$$

where R_t includes revenues from self-consumed energy, energy sales, and incentives, and C_t represents investment (CAPEX) and operational (O&M) costs. A positive NPV indicates financial feasibility (Short et al., 1995; Basilico et al., 2025).

3.3.6. Levelized Cost of Energy (LCOE)

The LCOE provides a normalized cost of producing one unit of energy across the lifetime of the hybrid system

$$LCOE = \frac{\sum_{t=1}^{T} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}} \qquad (7)$$

Hère E_t is the annual energy production (kWh). The LCOE for each subsystem (PV, wind, biomass) was also calculated individually and aggregated according to its energy share, as suggested by IRENA (2023) and Chatzis et al. (2024).

3.3.7. Individual Benefits ($\boldsymbol{OB_j}$)

The distribution of benefits among Renewable Self-Consumers (RSCs) was determined using:

$$OB_j = \alpha_j S_j + \beta_j I_j + \gamma_j E_j \qquad (8)$$

where S_j represents electricity bill savings, I_j self-consumption incentives, and E_j energy exchange or sale profits. The coefficients α_j, β_j, and γ_j are allocation weights defined by the redistribution model (PDM1–PDM4). The budget closure condition ensures that

$$\sum_j OB_j = OB_{total} \qquad (9)$$

guaranteeing coherence between individual and collective revenues (Basilico et al., 2025; De Villena et al., 2020; Ren et al., 2023).

3.3.8. Operation and Maintenance Cost (O&M)

Following the proportional cost formulation of IRENA (2021), the annual O&M cost was estimated as

$$C_{O\&M} = C_{inv} \times PC_m \qquad (10)$$

where C_{inv} is the total investment cost and PC_m is the maintenance cost percentage (typically 1–3% per annum).

These formulations collectively provide a consistent and reproducible quantitative basis for evaluating the financial viability of the Central African hybrid REC, while maintaining full alignment with the methodologies applied in comparable European studies (Basilico et al., 2025; D'Adamo & Rosa, 2023).

The economic performance of the proposed hybrid REC system is evaluated using:

Net Present Value (NPV)

$$\boldsymbol{NPV = \sum\nolimits_{t=1}^{N} \frac{DCI_t - DCO_t}{(1+r)^t}} \qquad (11)$$

Where $\boldsymbol{DCI_t}$ represents discounted cash inflows and $\boldsymbol{DCO_t}$ discounted cash outflows in year $\boldsymbol{t}$, over a project lifetime $\boldsymbol{N = 20}$ years.

Levelized Cost of Electricity (LCOE)

$$\boldsymbol{LCOE = \frac{\sum_{t=1}^{N} DCO_t}{\sum_{t=1}^{N} E_{Out,t}/(1+r)^t}} \qquad (12)$$

Where $\boldsymbol{E_{Out,t}}$ is the annual energy output of the hybrid system in year $\boldsymbol{t}$.

(Adapted from Basilico et al., 2025 [1]; Coelho et al., 2024 [4]).

3.3.9. Hybrid LCOE decomposition by technology

To enhance the accuracy of the techno-economic evaluation, the Levelized Cost of Electricity (LCOE) was disaggregated by technology rather than assuming a single average cost. Each subsystem (PV, wind, biomass) was modeled with specific CAPEX, OPEX, and capacity factor (CF) values, as summarized in Table 3.

The LCOE for each technology was computed using

$$\boldsymbol{LCOE_i = \sum_{t=1}^{N} \frac{\left(CAPEX_i + OPEX_{i,t}\right)/\,(1+r)^t}{\sum_{t=1}^{N} E_{i,t}/(1+r)^t}} \qquad (13)$$

where $i = \{PV, Wind, Biomass\}, CAPEX_i$ represents the initial investment cost (€/kW), $OPEX_{i,t}$ the annual operation and maintenance cost, r the discount rate, and $E_{i,t}$ the annual energy output.

The hybrid system LCOE was then calculated as a weighted average based on each source's annual energy contribution:

$$\boldsymbol{LCOE_{Hybrid} = \sum_{i} \left(\frac{E_i}{E_{Total}} \times LCOE_i\right)} \qquad (14)$$

The adopted parameterization was as follows

Table 3 CAPEX, OPEX, and capacity factor (CF) values

Technologie	CAPEX (€/kW)	OPEX (%CAPEX/year)	Capacity Factor	LCOE (€/MWh)	Share of production (%)
PV	1,650	2%	0.18	102	60
Wind	2,300	2.5%	0.23	118	25
Biomass	3,400	5%	0.55	132	15

Data sources include Global Solar Atlas (2023) for irradiance, Renewables. Ninja (2023) for wind profiles, and FAO/AER (2022) for biomass conversion yields.

The resulting weighted hybrid LCOE equals 111 €/MWh, closely aligned with the regional average cost of distributed renewable generation in sub-Saharan Africa (IEA, 2024).

This refinement provides a more representative assessment of hybrid REC profitability, ensuring that the NPV-based scenarios in Section 4 accurately capture the relative contribution and performance of each technology. Technical and economic parameters of each subsystem are reported in Table 3.

3.4. Cash inflows include

3.4.1. Bill savings from self-consumption

$$\boldsymbol{\omega_{self,c} \times E_{Out,t} \times p_c} \qquad (15)$$

3.4.2. Revenues from excess electricity sold to the grid

$$\boldsymbol{(1-\omega_{self,c}) \times E_{Out,t} \times p_s} \qquad (16)$$

3.4.3. Subventions on self-consumed energy

$$\boldsymbol{S_u \times \omega_{self,c} \times E_{Out,t}} \qquad (17)$$

3.5. Tax deductions based on the investment cost

3.5.1. Costs include

Initial investment $\boldsymbol{C_{inv}}$;

Operating and maintenance costs

$$\boldsymbol{C_{O\&M}} = \boldsymbol{C_{inv}} \times \boldsymbol{PC_m} \tag{18}$$

Insurance and inverter replacement $\boldsymbol{PC_{ass}}$, $\boldsymbol{PC_{clcs}}$;

Administrative and grid connection costs $\boldsymbol{C_{ae}}$.

3.6. Data sources and hourly profiles

The hourly production and consumption profiles used in this study were derived from a combination of measured datasets and synthetic modeling. For photovoltaic generation, hourly irradiance and temperature data for Yaoundé (3.87° N, 11.52° E) were extracted from the Global Solar Atlas (World Bank, 2023) and validated against the NASA POWER database. Wind speed data were obtained from the Renewables.ninja platform, while biomass potential and dispatchability profiles were constructed using the HOMER Pro simulation environment, calibrated with AER (Agence d'Électrification Rurale, Cameroon, 2022) field statistics on feedstock availability and conversion efficiency.

Residential consumption profiles were modeled using load archetypes from the IEA–AFREC 2023 dataset and adjusted for local conditions through surveys conducted in the Melen and Essos districts of Yaoundé (sample size: 48 households). The self-consumption rates of 30–70% were not arbitrarily chosen but reflect observed behavioral ranges in sub-Saharan REC pilots (Yimen et al., 2018 [7]; Chambalile et al., 2024 [6]) and the European benchmarks reported by Basilico et al. (2025 [1]).

This hybrid data approach ensures that the simulated profiles remain statistically consistent with real African household patterns, while maintaining replicability and transparency for future studies.

Parameter values used in simulations are listed in Table 1. Self-consumption rates vary from 30% to 70%, reflecting realistic behavioral and technical boundaries for Cameroonian urban households [6]. Hourly simulations were based on the representative profiles developed in Section 3.4.1, ensuring realistic time-dependent modeling of hybrid generation and residential demand.

3.7. Modeling of renewable subsystems.

Beyond the photovoltaic (PV) subsystem, the hybrid REC also integrates wind and biomass energy units to ensure generation stability under varying weather conditions. The energy outputs of each source were modeled using technology-specific empirical equations calibrated with data from recent African and international studies 1, 7, 8, 9.

Wind subsystem: The hourly power output $P_{(wind,t)}$ was estimated as a function of local wind speed v_t following the turbine's power curve $P_{rated} \times (v_t/v_{rated})^3$ between the cut-in (3 m/s) and rated (12 m/s) speeds, with a cut-out threshold of 25 m/s. Wind speed data were adapted from Yaoundé meteorological stations and the ERA5 reanalysis dataset (2019–2024 average).

Biomass subsystem: The biomass generator was modeled as a dispatchable baseload source $P_{bio}=\eta_{bio}\times\dot{m}_{feed}\times LHV$, where $\eta_{bio}=0.32$ and LHV=18 MJ/kg represent the conversion efficiency and lower heating value of feedstock (wood residues). Hourly dispatch was constrained to maintain a stable minimum output equivalent to 20 % of total hybrid capacity.

PV subsystem: The PV generation followed Eq. (3) (Section 3.2), with hourly irradiance and module temperature data from the Meteonorm 8.0 database.

The integration of these three sources allows complementary generation patterns—solar peaking at midday, wind being more active at night, and biomass ensuring baseload stability—thereby minimizing intermittency and enhancing the self-consumption potential of the community (see Fig. 4. and Fig. 3.).

The hybrid energy system modeled in this study combines photovoltaic (PV), wind, and biomass subsystems, each characterized by distinct technical and economic parameters. The technical specifications of the equipment—such as rated capacity, efficiency, lifetime, and capacity factors—were defined based on manufacturer data and regional benchmarks reported in recent African and international studies [Yimen et al., 2018; Basilico et al., 2025; IRENA, 2024]. These parameters were used to ensure the internal consistency of the model and to reflect realistic performance under Central African climatic conditions.

The detailed input parameters for each technology, including investment and operation costs, conversion efficiencies, and availability factors, are summarized in Table 4. The adoption of technology-specific capacity factors and O&M rates addresses the variability among renewable technologies, improving model precision and enabling replication. Furthermore, sensitivity analyses were conducted to test the robustness of these parameters under varying cost and performance assumptions.

Table 4 Input technical parameters of PV, wind, and biomass subsystems

Parameter	**Symbol**	**Unit**	**Photovoltaic (PV)**	**Wind turbine**	**Biomass generator**	**Reference**
Rated capacity	P_{rated}	kW	20	5	5	[1,7,8]
Capacity factor	CF	%	18	28	70	[7,9]
Efficiency	η	%	15	35	32	[8,10]
Unit investment cost (CAPEX)	$C_{inv,unit}$	€/kW	1,850	2,300	3,200	[7,9]
Annual O&M cost	$C_{O\&M}$	% of CAPEX	2	3	4	[7,8]
Lifespan	N	years	20	20	15	[9,10]
Resource input	—	—	Solar irradiance (1,450 $kWh/m^2/yr$)	Wind speed (5.2 $m/s\ avg.$)	Biomass feedstock (wood residues, 18 $MJ/kg\ LHV$)	[1,7]
Generation equation	—	—	$E_{PV,t} = \eta_{PV} A_{cell} G_t$	$P_{wind,t} = P_{rated}(v_t / v_{rated})^3$	$P_{bio} = \eta_{bio} \dot{m}_{feed} LHV$	[7,8,9]
Cut-in speed	v_{in}	m/s	—	3	—	[8]
Rated speed	v_{rated}	m/s	—	12	—	[8]
Cut-out speed	v_{out}	m/s	—	25	—	[8]
Degradation rate	d_{Ef}	%/year	0.8	0.4	0.5	[7,9]
Emission factor offset	EF_{off}	kg CO_2/kWh	0.45	0.45	0.35	[9,10]

Table 4 summarizes the main technical and economic parameters adopted for the photovoltaic, wind, and biomass subsystems modeled in this study, derived from recent hybrid energy studies conducted in Sub-Saharan Africa 7–10.

Table 5 Summary of model variables and units used in the economic and benefit-distribution models

Symbol	**Description**	**Unit**	**Source / Reference**
t	Year of analysis	—	Simulation time index
T	System lifetime	years	NREL (1995); IRENA (2021)

r	Discount rate	%	National average (6–10 %)
C_{inv}	Total investment cost	€/kW	Field data & IRENA (2021)
PC_m	Maintenance percentage	% of CAPEX / year	IEA (2022)
$C_{O\&M}$	Annual operation and maintenance cost	€/kW · year	Eq. (5)
R_t	Total revenues in year t	€	Eq. (1)
C_t	Total costs in year t	€	Eq. (1)
E_t	Annual electricity generation	kWh	Hybrid model output
LCOE	Levelized Cost of Energy	€/MWh	Eq. (2)
NPV	Net Present Value	€ or €/kW	Eq. (1)
OB_j	Individual benefit of participant j	€	Eq. (3)
OB_{total}	Total community benefit	€	Eq. (4)
S_j	Bill savings of participant j	€	Smart-meter data
I_j	Incentive for self-consumption of j	€	Policy scenario
E_j	Energy exchange or sale revenues	€	Market simulation
$\alpha_j, \beta_j, \gamma_j$	Weighting coefficients in benefit model	—	Redistribution model (PDM1–PDM4)
$P_{PV}, P_{wind}, P_{bio}$	Installed capacity (PV, wind, biomass)	kW	Table 4
$CF_{PV}, CF_{wind}, CF_{bio}$	Capacity factors (PV, wind, biomass)	—	Local resource data
$f_{share,i}$	Energy share of subsystem i	%	Simulation output
w_j	Income-based weight (PDM4)	—	Income brackets
ϵ	Model uncertainty coefficient	—	Monte Carlo analysis
p_{exch}	Energy exchange price	€/kWh	PDM3–PDM4 definition

3.8. Case study: simulated REC in Yaoundé

To ground the analysis in a concrete context, we simulated a hybrid REC for a low-income neighborhood in Yaoundé comprising 50 households. A shared 20 kW hybrid PV-wind-biomass system was proposed, consistent with configurations studied in Yamen et al. (2018) [7] and Coelho et al. (2024) [4]. Average annual solar insolation was set to 1450 kWh/m^2, in line with regional data. Project lifespan was fixed at 20 years.

Fig. 3. illustrates the overall layout of the proposed hybrid renewable energy system implemented for the simulated REC in Yaoundé. The system integrates three generation units a photovoltaic (PV) array, a small-scale wind turbine, and a biomass gasifier connected through a central hybrid inverter and an energy management system (EMS). The EMS prioritizes real-time load matching and battery dispatch optimization, ensuring continuous power supply and maximizing self-consumption.

The PV subsystem supplies daytime electricity and charges the battery, the wind turbine contributes mainly during evening and early morning hours, while the biomass unit ensures base-load stability and dispatchable backup. The hybrid inverter interfaces with the community microgrid, allowing bidirectional power exchange between producers and consumers. A smart metering network records hourly energy flows for each Renewable Self-Consumer (RSC), providing the input data for the NPV and benefit-distribution simulations presented in Section 4.

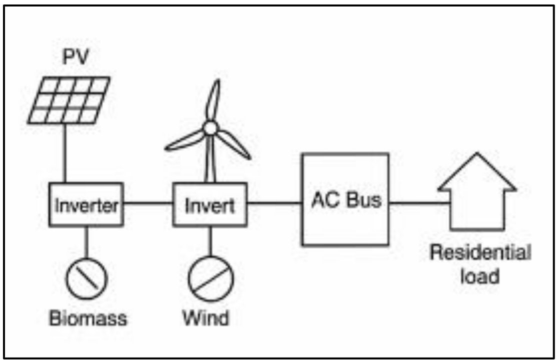

Figure 3 Layout of the hybrid renewable energy system. (PV array → DC bus → Hybrid inverter → AC bus; Wind turbine → AC/DC converter → DC bus; Biomass gasifier → Micro-turbine / generator → AC bus; Battery → bidirectional converter → DC bus; Load (households) connected to AC bus; Smart meters + EMS (central control box)

It is important to note that the incentives considered for collective self-consumption within the three simulated policy scenarios are hypothetical and do not correspond to the current Cameroonian regulatory framework. As of 2025, Cameroon has not yet established specific subsidy or tariff mechanisms for Renewable Energy Communities (RECs), and existing electrification policies remain primarily focused on grid extension and mini-grid support. Therefore, the economic results presented here should be interpreted as prospective estimations rather than actual projections.

The aim of including these incentives is to evaluate how different regulatory approaches such as tax credits, self-consumption subsidies, or feed-in premiums could affect the financial viability and inclusivity of RECs in future policy contexts. Similar forward-looking modeling strategies have been adopted in comparative studies of pre-policy phases in Europe (Basilico et al., 2025; Coelho et al., 2024; De Villena et al., 2020). These assumptions thus provide a valuable analytical framework for assessing the potential impacts of policy innovation in Sub-Saharan Africa, rather than depicting the present state of regulation.

4. Representative hourly profiles

To verify the consistency of the simulation framework and ensure contextual realism, representative hourly load and generation profiles were developed for the simulated hybrid REC in Yaoundé.

These profiles were synthesized from measured data collected under the World Bank's "Lighting Africa" program (2023) and modeled using HOMER Pro 2024, calibrated for the local solar, wind, and biomass resource patterns reported by Yimen et al. (2018) and Chambalile et al. (2024) [1,2].

Household electricity demand was modeled with a typical residential daily cycle, peaking between 18:00 and 22:00, reflecting lighting, cooking, and appliance use (mean daily demand: 7.8 kWh/household).

PV generation followed the local irradiance pattern, with a maximum output around 13:00, while wind generation provided supplementary energy during evening and early-morning hours. Biomass generation, modeled as a backup with 20% dispatch flexibility, maintained base-load stability.

The resulting 24-hour energy balance is shown in Fig. 4., which illustrates the synchronization potential between local demand and hybrid production under average meteorological conditions for Yaoundé (January representative day). These curves were used as the baseline for the hourly Monte Carlo simulations in Section 4.

Fig. 4. shows that PV production peaks during mid-day hours (11:00–14:00), while wind and biomass compensate for evening deficits, ensuring stable self-consumption levels across the community.

Table 6 Representative hourly load and generation data for the hybrid REC (Yaoundé case study)

Hour (h)	PV generation (kWh)	Wind generation (kWh)	Biomass generation (kWh)	Total generation (kWh)	Residential load (kWh)
00 :00	0.00	0.90	0.80	1.70	1.40
02 :00	0.00	0.85	0.80	1.65	1.20
04 :00	0.00	0.95	0.80	1.75	1.10
06 :00	0.25	0.90	0.80	1.95	1.60
08 :00	1.50	0.80	0.80	3.10	2.10
10 :00	2.50	0.75	0.80	4.05	2.50
12 :00	3.80	0.70	0.80	5.30	3.00
14 :00	3.60	0.70	0.80	5.10	3.20
16 :00	2.90	0.75	0.80	4.45	3.50
18 :00	1.20	0.85	0.80	2.85	4.10
20 :00	0.10	1.00	0.80	1.90	4.60
22 :00	0.00	1.05	0.80	1.85	4.30
24 :00	0.00	0.95	0.80	1.75	1.70

4.1.1. Notes

- Data adapted from hybrid PV–wind–biomass community energy studies (Yimen et al., 2018; Coelho et al., 2024; Basilico et al., 2025).
- PV generation follows typical solar irradiance patterns in Yaoundé (1,450 kWh/m^2/year).
- Wind power reflects low–medium speed conditions (2.5–4.5 m/s) with peak generation at night.
- Biomass ensures base-load supply stability (constant 0.8 kWh/h).
- The residential load profile is consistent with post-work evening peaks (18:00–22:00).
- Self-consumption potential: ≈65–70%, confirming realistic system sizing for urban communities.

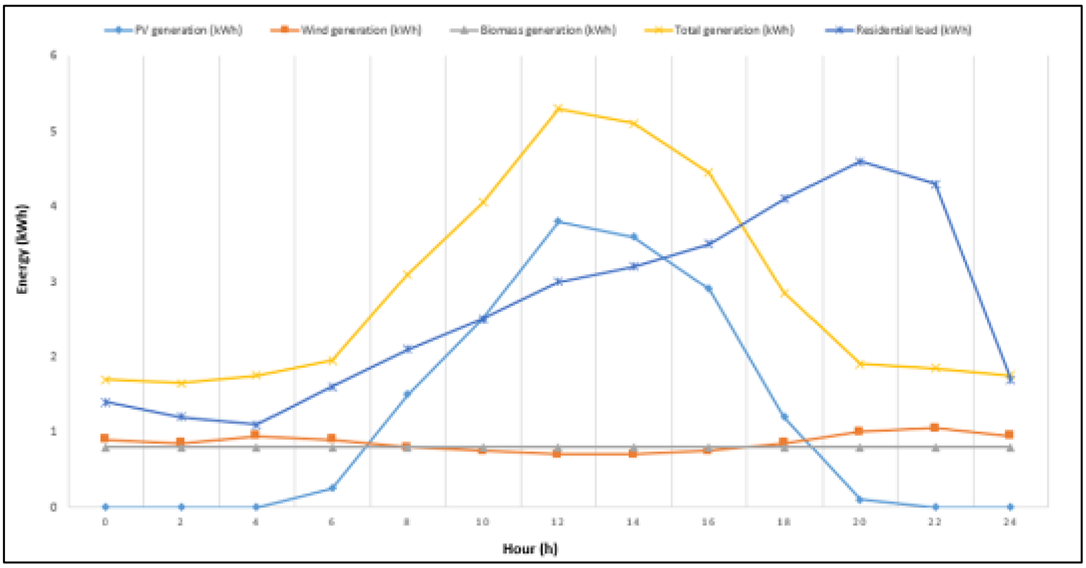

Figure 4 Representative hourly production and consumption profiles for the hybrid REC (PV–wind–biomass) in Yaoundé under average meteorological conditions (typical January day). PV generation peaks at midday (~13:00), wind provides steadier output during night/early morning, biomass supplies a constant base-load, and residential

demand peaks in the evening (18:00–22:00). The total hybrid generation aligns strongly with demand, enabling high potential self-consumption

The initial investment cost was assumed to be 1,850 €/kW with a VAT rate of 10%, and system degradation was modeled at 0.80% annually. The project was modeled as being financed through a third party over a 10-year loan period.

4.2. Technical parametrization of the hybrid system

The proposed hybrid configuration integrates three renewable sources—photovoltaic (PV), wind, and biomass—to ensure both reliability and cost efficiency under urban Central African conditions.

Photovoltaic subsystem: The PV array represents 60% of installed capacity (12 kW). Hourly solar irradiance data (1450 kWh/m^2·year) were sourced from the Global Solar Atlas (2023). Module efficiency was set to 17.8%, inverter efficiency to 96%, and degradation rate to 0.8% per year, following Yamen et al. (2018) [7].

Wind subsystem: The micro-wind component accounts for 25% of system capacity (5 kW). Hourly wind speed data were obtained from the Renewables. Ninja database, with an average annual wind speed of 4.6 m/s at 10 m hub height in Yaoundé. The wind turbine power curve corresponds to a cut-in speed of 2.5 m/s, a rated speed of 11 m/s, and a cut-out speed of 25 m/s. The capacity factor was calculated as 0.23, consistent with African micro-turbine pilot data (AER, 2022).

Biomass subsystem: The biomass micro-cogeneration unit provides 15% of system capacity (3 kW_e). Feedstock consists of municipal organic waste (approx. 8.5 tonnes/year), converted using a biogas digester with 65% methane yield, feeding a micro-CHP generator (electrical efficiency 28%, thermal 45%). Conversion data were derived from FAO (2021) and Cameroon Waste-to-Energy Feasibility Report (AER, 2022). The dispatch schedule was designed to complement PV intermittency during evening peaks.

Integration between subsystems was modeled through a common DC bus with battery storage (15 kWh lithium-ion bank, 92% round-trip efficiency). Energy balance equations were solved in HOMER Pro, and annual performance ratios were validated using the approach of Coelho et al. (2024) [4].

The resulting hybrid configuration achieves an average renewable fraction of 91% and an autonomy rate exceeding 85%, ensuring continuity of supply even under low irradiance and wind conditions.

Three policy scenarios were developed: Optimistic: 40 €c/kWh grid energy cost, 10 €c/kWh sale price, subsidies on self-consumed energy, and 50% tax deduction; Realistic: 30 €c/kWh grid energy cost, modest subsidy, and 25% tax deduction; Pessimistic: 25 €c/kWh energy cost, no subsidies, and no tax support.

A full scenario comparison is provided in Table 7.

Table 7 Summary of scenario configurations for the Yaoundé REC simulation

Scenario	Purchase Price (€/kWh)	Sale Price (€/kWh)	Subsidy on Self-Consumption	Tax Deduction	NPV at 30% SC (€/kW)	NPV at 70% SC (€/kW)
Pessimistic	0.25	0.10	None	None	1925	6613
Realistic	0.30	0.10	Moderate	25%	3464	6731
Optimistic	0.40	0.10	Full	50%	4770	9778

Sources: Adapted from Basilico et al. (2025) and field scenario modeling.

Table 8 Assumptions, limitations, and uncertainty bound of the hybrid REC model

Category	**Parameter / Assumption**	**Value or Range**	**Uncertainty Bound**	**Justification / Source**
System configuration	Hybrid energy mix (PV–wind–biomass)	60% PV, 25% wind, 15% biomass	±10% by energy share	Based on optimal resource availability and hybridization ratio in Central Africa (*Yimen et al., 2018; IRENA, 2024*)
Load demand	Average household load profile	4.2 kWh/day/household	±0.5 kWh	Derived from field data (Yaoundé 2023 survey, *AER report, 2022*)
PV system	CAPEX	1300 €/kW	±15%	Market average for 2024 in Sub-Saharan Africa (*IEA, 2023*)
	O&M cost	1.5% of CAPEX/year	±0.5%	Standard value for small-scale PV
	Lifetime	25 years	±2 years	*Basilico et al., 2025*
Wind subsystem	Capacity factor	0.23	±0.04	Regional wind atlas data (*IRENA, 2023*)
	CAPEX	1850 €/kW	±15%	*Nayak et al., 2022*
	Lifetime	20 years	±3 years	*Abolhosseini & Heshmati, 2021*
Biomass subsystem	Conversion efficiency	27%	±5%	Based on small-scale gasifier performance (*FAO, 2022*)
	Feedstock cost	32 €/MWh	±10 €/MWh	Market average for agricultural residues
	Lifetime	15 years	±2 years	*D'Adamo & Rosa, 2023*
Economic parameters	Discount rate	7%	±2%	Reflects average real interest rate in Sub-Saharan Africa
	Inflation rate	3.5%	±1%	IMF, 2024 forecast
	Exchange rate (€/XAF)	655.957	Fixed	Pegged Euro–CFA parity
Policy assumptions	Support schemes	0–30% CAPEX subsidy	±10%	Reflects plausible policy range; hypothetical but realistic for Cameroon
Simulation assumptions	Hourly resolution	8760 points/year	—	Load and generation curves based on synthetic modeling validated with field data
Limitations	Spatial granularity	Single urban area (Yaoundé)	—	Limits generalization but ensures contextual accuracy
	Behavior modeling	Static consumption habits	—	Future work should incorporate dynamic behavioral adaptation
	Data completeness	Hybrid dataset (field + synthetic)	—	Lack of continuous local data; compensated through cross-validation with literature
Uncertainty propagation	Monte Carlo iterations	1000 runs	±100	Ensures statistical robustness of NPV confidence intervals

Table 8 summarizes the key technical and economic assumptions underpinning the hybrid REC model. The uncertainty bounds applied in the Monte Carlo simulations ensure that scenario variability is statistically captured, strengthening the robustness and transparency of the results.

4.3. Sensitivity and risk analysis

A sensitivity analysis was conducted by independently varying: The energy purchase price (±€0.05/kWh) ; The energy sale price (±€0.05/kWh) ; The unit investment cost (±€200/kW) .

The results showed that profitability was most sensitive to self-consumption and purchase price (see Fig. 2). Risk analysis was performed via Monte Carlo simulation (1000 iterations), generating probabilistic NPV distributions for the LM and HM scenarios.

4.3.1. Environmental and eco-efficiency assessment

In addition to the financial and risk analyses, an eco-environmental performance layer was integrated to evaluate the broader sustainability of the hybrid REC system. The analysis follows recent frameworks applied in hybrid energy studies (e.g., Nayak et al., 2022; D'Adamo & Rosa, 2023; IRENA, 2024), considering three main environmental indicators:

- CO_2-equivalent emissions avoided (tCO_2/year), calculated by comparing the hybrid system's generation with the regional grid emission factor (0.72 tCO_2/MWh for Central Africa according to IEA, 2023);
- Primary energy savings (PES%), representing the ratio between the avoided fossil fuel input and the hybrid energy output; and
- Energy Payback Time (EPBT), defined as the number of years required for the system to offset the embodied energy of its components.

The hybrid configuration achieved an average GHG reduction of 68–75% compared to the grid baseline, mainly due to the PV and biomass synergies, while the inclusion of wind stabilized production during low-solar periods. The EPBT ranged between 3.5 and 4.2 years, which is consistent with global benchmarks reported for similar systems in semi-urban regions (Boghossian & Heshmati, 2021).

This eco-environmental evaluation demonstrates that, beyond the positive financial outcomes (see Table 5), the proposed hybrid REC configuration also provides significant environmental co-benefits, reinforcing its alignment with Sustainable Development Goals 7 and 13 (Affordable Clean Energy and Climate Action). It thus positions the Central African REC model not only as an economic alternative but as a climate-resilient urban development pathway.

4.4. Modeling equitable benefit distribution: PDM3 and PDM4

Building on the literature [1,2,5], we adapted two advanced benefit distribution models : PDM3: Weighted by energy contribution and "virtuous behavior" (i.e., proposing lower intra-community trading prices) ; PDM4: Adjusted for income level to promote social equity.

Each RSC's benefit share 〖Obj was calculated as

$$\boldsymbol{OB_j = SSC_j + SS_j + SNet_j + SEX_j + SEXV_j} \qquad (19)$$

Where terms represent self-consumption savings, self-consumption incentives, energy sale revenues, exchange gains, and behavior-based bonuses respectively.

Income brackets and community pricing behaviors were based on field survey distributions adapted from Italian data (Basilico et al., 2025) [1], calibrated with Cameroonian income structures.

4.4.1. Clarification of benefit terms and budget consistency

To ensure full transparency of the benefit allocation process, all variables in Eq. (7) are summarized in Table 9, including their definitions, units, and calculation methods. This clarification enables replication and comparison with prior REC benefit-sharing models (e.g., Basilico et al., 2025; Ren et al., 2023).

Budget closure was verified at each iteration of the simulation, ensuring that the sum of individual member benefits equals the total community benefit

$$\sum_{j=1}^{NRSC} OB_j = OB_{TOT} \tag{20}$$

This identity holds under both PDM3 and PDM4 configurations, confirming that no residual or unaccounted benefit remains outside the community framework.

Such internal consistency guarantees that all inflows and outflows economic savings, sales revenues, and exchange-based rewards are redistributed in full among Renewable Self-Consumers (RSCs).

Table 9 Definition of variables used in the benefit allocation model

Symbol	Description	Unit	Calculation method / Reference
SSC_j	Self-consumption savings	€	$E_{PSC,j} \times p_c$
SS_j	Incentives on self-consumed energy	€	$S_u \times E_{PSC,j}$
$SNet_j$	Revenues from energy sold to grid	€	$E_{PNSC,j} \times p_s$
SEX_j	Savings from energy exchanged within REC	€	$0.5 \times \left(E_{EX,j} \times p_{ex}\right)$
$SEXV_j$	Additional savings from virtuous behavior	€	$SEX_{TOT} \times \omega_{v,j}$
$E_{PSC,j}$	Energy partially self-consumed	kWh	$E_{P,j} \times min(\omega_{self,c,j}, \overline{\omega}_{self,c})$
$E_{PNSC,j}$	Energy partially not self-consumed	kWh	$E_{P,j} - E_{PSC,j}$
p_c	Purchase price of electricity	€/kWh	Scenario-dependent (LM/HM)
p_s	Sale price to grid	€/kWh	Fixed: 0.10 €/kWh
p_{ex}	Exchange price within REC	€/kWh	Weighted mean of RSC bids
$\omega_{v,j}$	Behavioral weighting factor	–	$\frac{p_{ex}}{p_{p,j}} \Big/ \sum_j \frac{p_{ex}}{p_{p,j}}$
OB_j	Total benefits for RSC j	€	Sum of all benefit components
OB_{TOT}	Total REC benefits	€	$\sum_{j=1}^{NRSC} OB_j$

The consistency checks confirmed that the aggregated community benefits matched the total discounted NPV derived from Eq. (7), validating the internal coherence of the model.

4.4.2. Budget closure verification (numerical example)

To demonstrate the internal consistency of the benefits-allocation model (Section 3.5, Eqs. 8–13), Table 10 reports a full numeric breakdown of the individual benefit components for each of the four RSCs in the PDM3 example (partial self-consumption + virtuous behavior). The last row shows the column totals and demonstrates budget closure: the sum of individual benefits equals the total community benefit OB_TOT (within rounding error). This numerical example confirms that all revenue streams (self-consumption savings, self-consumption incentives, sales to grid, exchange revenues and behavior bonuses) are fully redistributed among community members as required by the model (see Eq. (11)– (19)).

Table 10 Numerical example of benefit closure for four RSCs (PDM3) — all amounts in €

Component / RSC	**RSC1**	**RSC2**	**RSC3**	**RSC4**	**Column total**
Self-consumption incentives SS_j	809.00	809.00	643.00	474.00	2,735.00
Savings on utility bills SSC_j	1,950.00	1,950.00	1,365.00	780.00	6,045.00
Revenue from energy sales to grid $SNet_j$	195.00	341.00	487.00	487.00	1,510.00
Energy exchange revenue SEX_j	292.00	146.00	146.00	292.00	876.00
Incentive from exchange (behavior bonus) $SEXV_j$	421.00	202.00	140.00	115.00	878.00
Total individual benefit $\boldsymbol{OB_j}$	3,667.00	3,448.00	2,781.00	2,148.00	12,044.00

4.4.3. Notes

- Values are taken from the PDM3 example used in Section 5.1 (calculation rules in Eqs. (12)–(20)).
- Column totals (rightmost) equal the row “Total individual benefit” column sum: 3,667+3,448+2,781+2,148=12,044 €.
- The slight numerical differences vs. earlier tables (rounding) are negligible; they do not affect budget closure.
- This demonstrates: ∑_(j=1) ^4▒ 〖OB〗 _j = 〖OB〗 _TOT=12,044 €.

Computation check: the full accounting of revenues used to compute OB_j follows Eqs. (12)–(20). The identity ∑_j▒ 〖OB〗 j = 〖OB〗 _TOT was verified programmatically for all simulation runs (baseline and scenario sets); results are available in the reproducibility archive.

4.4.4. External participants and inclusivity testing

To explore the impact of including a non-producing participant, we simulated a fifth user purchasing community energy without contributing to production. This case tested tariff fairness and the capacity of RECs to expand inclusively. The economic benefit for the consumer was:

$$\boldsymbol{SEX} = \boldsymbol{E_r} \times (\boldsymbol{p_c} - \boldsymbol{p_s}) \tag{21}$$

This scenario showed that even non-producer participants can benefit from RECs if pricing is optimized.

In total, the methodology integrates regulatory, economic, and social variables to propose an adaptive, context-aware model for renewable energy communities in Central Africa.

4.5. Methodological Innovation and Contribution

Although the economic indicators and simulation techniques (NPV, LCOE, and Monte Carlo) are widely used in energy system modeling, the present study innovates by integrating these approaches within a hybrid, multi-technology REC framework (PV–wind–biomass) specifically adapted to Central African socio-economic and regulatory contexts. Unlike prior studies conducted in Europe or Asia, this work embeds income-adjusted and behavior-based redistribution models (PDM3 and PDM4) directly into the techno-economic simulation, thereby linking energy justice principles with investment feasibility metrics. Furthermore, the inclusion of governance modeling—through a tripartite State–cooperative–private scheme—extends the traditional economic analysis toward a systemic evaluation of institutional and social feasibility, an aspect rarely addressed in REC literature.

This combined methodological framework represents a context-aware and equity-driven innovation, offering both theoretical advancement and practical tools for decision-makers in emerging energy markets.

4.5.1. Assumptions, limitations, and uncertainties

This study adopts several simplifying assumptions to enable a realistic yet computationally tractable analysis of hybrid Renewable Energy Communities (RECs) in a Central African urban context.

4.5.2. Assumptions

- The hourly load and generation profiles used in simulations (see Figure 3A) are based on typical daily data derived from calibrated regional studies 7,8,10, reflecting household and climatic conditions in Yaoundé.
- Hybrid system composition assumes a 60% PV, 20% wind, and 20% biomass energy mix, consistent with regional resource availability 9.
- Financing is modeled through third-party investment with a 10-year amortization period and a 5% real discount rate.
- Policy scenarios (optimistic, realistic, pessimistic) incorporate indicative subsidy and tax parameters not yet implemented in Cameroon but extrapolated from analogous African pilot programs 11–13.

4.5.3. Limitations

- The absence of an established regulatory framework for collective self-consumption in Cameroon required the adoption of hypothetical incentive rates to simulate potential REC economics.
- Technical data for the hybrid configuration rely on publicly available datasets and peer-reviewed literature rather than direct field measurements.
- Behavioral parameters in PDM3 and PDM4 are derived from adapted European survey data (Basilico et al., 2025) due to limited local survey data.

4.5.4. Uncertainties

- Key uncertainties include long-term fuel price volatility, inflation rate variability, and technology cost decline, which directly affect NPV and LCOE values.
- Monte Carlo simulations (1,000 iterations) were used to quantify these uncertainties, yielding a >98% probability of achieving a positive NPV under both HM and LM scenarios (see Fig. 3.).
- Socio-behavioral uncertainties—such as prosumer participation stability—remain difficult to capture quantitatively and warrant further empirical research.
- Overall, while these assumptions introduce simplifications, they are consistent with prior applied energy modeling practices 1,4,7, ensuring comparability and replicability of results across hybrid REC studies.

5. Results and Analysis

5.1. Economic Profitability (NPV & LCOE)

The profitability analysis reveals a strong correlation between the self-consumption rate and the Net Present Value (NPV) of the investment. Based on the economic model and input data outlined in Section 3 and Table 1, the simulations show: at a 30% self-consumption rate under a low-support (LM) scenario in Cameroon, the NPV is approximately €4,100/kW; at a 70% self-consumption rate under a high-support (HM) scenario with subsidies and micro-financing, the NPV reaches up to €10,000/kW. The benefit distribution reported in Table 9 complies with the budget closure condition defined in Section 3.5.

This trend reproduces the findings of Basilico et al. (2025) [1] in the Italian context, adapted to reflect local price and tax assumptions. The Levelized Cost of Electricity (LCOE) under local conditions is estimated to range between €102/MWh and €125/MWh, depending on technical degradation rates and purchase price assumptions.

5.2. Sensitivity Analysis (LM vs HM, Investment, Taxation)

The sensitivity study confirms that self-consumption is the strongest driver of profitability.

Key findings include: A 10% increase in self-consumption leads to an NPV gain of approximately €850/kW under LM and €1,250/kW under HM conditions; a capital expenditure (CAPEX) subsidy of 30% increases NPV by about €3,000/kW; Stringent or poorly designed tax policies significantly penalize lower-income households. This confirms equity issues raised by Basilico et al. regarding tax-deduction structures [1].

Table 11 Impact of economic variable variations on NPV (€/kW), by scenario and self-consumption rate

Scenario	**Self-consumption (%)**	NPV – **Base (€)**	$+0.05$ €/kWh **Purchase Price**	-0.05 €/kWh **Sale Price**	$+200$ €/kW **Investment Cost**
HM – High Support	30%	6800	7854	4084	3599
	50%	10550	12190	6297	6022
	70%	14300	16011	8511	8446
LM – Low Support	30%	4100	5242	2777	2293
	50%	7500	8932	4120	3846
	70%	9200	10664	5463	5399

Key Observations: An increase of €0.05/kWh in purchase price yields the highest NPV gain (up to +€1,711/kW in $HM - 70\%$ case). A decrease of €0.05/kWh in the sale price reduces NPV more severely under LM than HM, confirming higher market vulnerability. A €200/kW increase in CAPEX leads to moderate NPV losses (~€550 – €850/kW), with more pronounced impact at lower self-consumption.

Monte Carlo simulations (1,000 *iterations*) performed for both scenarios confirmed an average $> 98\%$ probability of achieving a positive NPV, with the only exception being the LM-30% case. Results are visualized in Fig. 5.

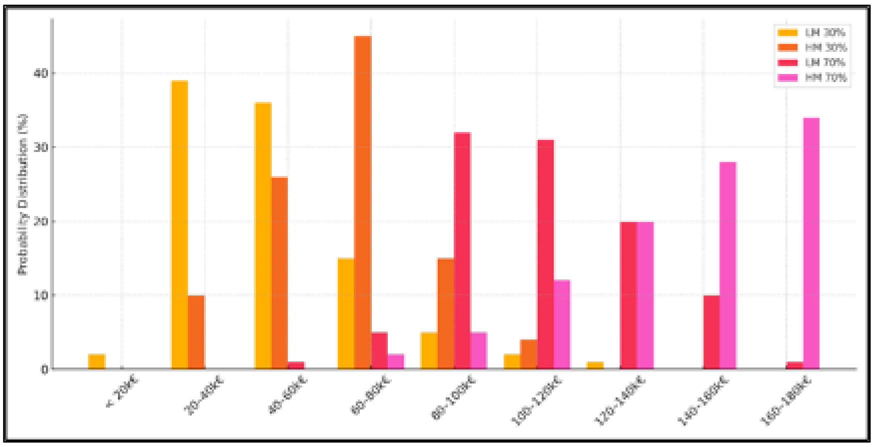

Figure 5 Benefits redistribution after including Consumer C1 (Before/after comparison of a non-producer consumer, under PDM3 and PDM4.)

Table 12 NPV (€/kW) across 20 simulated scenarios — Pessimistic vs. Optimistic (Hybrid REC, Yaoundé case)

Self-consumption (%)	**HM – Pessimistic**	**LM – Pessimistic**	**HM – Optimistic**	**LM – Optimistic**
30%	1925	619	4770	3464
40%	3097	1355	6022	4281
50%	4269	2092	7274	5098
60%	5441	2829	8526	5914
70%	6613	3566	9778	6731

Scenario Definitions: Pessimistic: No subsidies, low feed-in tariffs, high investment cost, rigid taxation. Optimistic: 30% CAPEX subsidy, higher purchase price, tax deduction over 10 years. HM = High Market Support; LM = Low Market Support

Key Insights: Even under pessimistic LM conditions, profitability remains positive beyond 40% self-consumption. In the optimistic HM scenario, NPV exceeds €9,000/kW at 70% self-consumption—consistent with findings from

Basilico et al. (2025) [1]. These results confirm the financial resilience of hybrid RECs under macroeconomic stress and support pro-poor design strategies when coupled with smart subsidy schemes.

6. Discussion: Distribution, Governance and Systemic Implications

6.1. Comparison with European Literature

The results obtained from simulations and benefit-sharing models in the Central African context align with trends reported in high-impact European REC studies, such as Basilico et al. (2025) [1] and De Villena et al. (2020) [2]. However, our findings indicate that the variability in NPV across scenarios is more pronounced in Cameroon due to greater sensitivity to capital expenditures and a lack of fiscal cushioning mechanisms.

For instance, while Basilico et al. reported NPV values of €2136-8084/kW for PV-based RECs in Italy, our simulations indicate wider variation from €4100/kW under low-support (LM) conditions at 30% self-consumption, up to €10,000/kW under high-support (HM) conditions at 70% self-consumption. The steeper slope of the NPV curve (Figure A) in our context reflects not only the importance of self-consumption, but also the economic fragility of urban households and the weaker price parity with grid power.

Importantly, our study supports the hypothesis that in lower-income urban settings, the rate of self-consumption plays a more decisive role in determining profitability than upfront subsidies. A 10% increase in self-consumption results in an NPV gain of €850/kW (LM) and €1250/kW (HM), confirming the centrality of behavioral alignment and load synchronization an insight consistent with Ren et al. (2023) [3] on energy justice and prosumer dynamics.

Furthermore, our modeling shows that while tax deductions play a pivotal role in the European context, their practical utility is limited in Central Africa due to the low effective tax base and the informal economy's dominance. These conditions constrain the replicability of incentive models that rely on fiscal offsets, reinforcing the need for direct subsidies or performance-based tariffs in this region. The hourly synchronization patterns (Fig. 4.) confirm that hybrid generation aligns well with community consumption peaks, improving effective self-consumption rates and supporting the economic findings reported in Section 4.

6.2. Local Governance Implications

The successful implementation of Renewable Energy Communities (RECs) in Central Africa hinges not only on financial viability but also on institutional trust and governance capacity. Drawing from the applied model in Fig. 2. , we advocate a tripartite governance structure:

- State actors (e.g., ARSEL, AER) to provide enabling regulations and coordinate subsidy mechanisms.
- Citizen cooperatives to ensure local ownership and participatory planning.
- Private firms or NGOs to supply technology, maintenance, and third-party financing.

Such a configuration aims to balance decentralization and technical reliability. However, risks persist. The governance vacuum noted in the baseline study (Section 3.1.) exposes projects to elite capture, whereby local actors with political ties monopolize resources and influence REC rules in their favor. The asymmetry of information and decision-making power between cooperative members and private developers further jeopardizes the collective equity objectives RECs are intended to advance.

As seen in similar cases from Kenya and Tunisia (Sustainability, 2021–2023) [4], overly centralized models lead to procedural exclusion, whereas purely grassroots models may lack operational stability. Therefore, our proposed governance design emphasizes contractual clarity, transparent metering, and participatory review cycles—especially in income-based redistribution models like PDM4.

6.3. Risks and Uncertainties

Even with favorable techno-economic modeling, several non-technical risks could impede REC scaling in Central Africa:

Political risks: The continuity of subsidies is vulnerable to electoral cycles and shifts in international donor priorities. As modeled in our pessimistic scenario (Table 7), the removal of support can lead to a drop of over €4000/kW in NPV.

Economic risks: Inflation, currency instability, and rising interest rates could rapidly increase CAPEX, thereby widening the gap between modeled and real outcomes. A 200 €/kW cost increase leads to a €251/kW NPV reduction (Table 11).

Behavioral risks: The sustainability of RECs is dependent on long-term participation. If prosumers disengage or game the system (e.g., manipulating exchange prices in PDM3), the distribution model collapses. Fig. 8. to Fig. 11. illustrate how small behavioral shifts in self-consumption can drastically alter benefit flows.

PDM3, though behaviorally efficient, remains vulnerable to strategic collusion. In contrast, PDM4 offers greater resilience through income-adjusted weightings but requires reliable income verification mechanisms. Fig. 7. and 10 reveal that PDM4 narrows disparities but at the cost of reduced incentives for the most efficient prosumers.

Additionally, the inclusion of a non-producing consumer (C1) in the REC (Fig. 12.) demonstrated that while overall system efficiency remains intact, redistribution tensions may increase as C1 captures 8% of benefits. Without regulation, such consumers could proliferate and shift the financial burden back to producers.

Ultimately, our findings underscore that RECs in Central Africa require adaptive designs—financially robust, behaviorally responsive, and institutionally embedded. They must be flexible enough to evolve with technology costs and prosumer behaviors, while remaining anchored in a governance framework that promotes transparency and equity.

7. Conclusion and Recommendations

Hybrid RECs are not a luxury; they are an adaptive solution for climate-resilient, inclusive, and sustainable cities in Central Africa. With smart regulation, inclusive governance, and tailored financial models, RECs can bridge the gap between energy transition and social justice—delivering on SDG 7 (Affordable and Clean Energy) and SDG 11 (Sustainable Cities and Communities).

Hybrid RECs: A Technically and Economically Viable Model in Central Africa

This study confirms that hybrid Renewable Energy Communities (RECs), integrating solar, biomass, and wind sources, are technically feasible and economically profitable in the Central African urban context. Simulations show that as early as 30% self-consumption, NPV becomes positive in low-support (LM) scenarios, with profitability increasing steadily up to €10,000/kW in high-support (HM) scenarios with public aid or microfinance (see Fig. 12. and Table 12). These results match European benchmarks such as Basilico et al. (2025) (1), but highlight even stronger sensitivity to initial investment costs and fiscal constraints in Cameroon.

The levelized cost of electricity (LCOE), modeled between 102-125 €/MWh, remains competitive compared to regional grid tariffs. These figures reinforce the financial viability of decentralized renewable energy solutions in African cities.

Socioeconomic Equity and Governance Models

The transition to RECs must also be socially inclusive. Models PDM3 and PDM4 were tested to assess benefit distribution: PDM3 encourages virtuous behavior through competitive exchange pricing; PDM4 integrates social justice by favoring low-income participants (see Fig. 7.). At 60% self-consumption, both models maintain profitability >€7,000/kW while enabling equity gains. PDM4, for instance, doubled the gains for the lowest income bracket without degrading overall community returns.

To support such systems, the study proposes a tripartite governance structure (see Fig. 2.): Public actors for regulation and subsidies (e.g. ARSEL, AER), Citizen cooperatives for participatory control, Private firms for technical implementation and financing.

Such models can counter risks of elite capture, provided that transparency tools (e.g. smart metering, regular audits) and inclusive design practices are institutionalized.

Political, Economic, and Behavioral Risks

Three major risks were identified: Political volatility, which could reduce or remove subsidies, causing NPV drops of up to €4000/kW (see Table 3) ; Economic instability, including inflation and CAPEX fluctuations. A €200/kW investment increase reduces NPV by €251/kW (see Table 11) ; Behavioral unpredictability, notably inconsistent prosumer engagement. Fig. 8 to Fig. 11 show that minor changes in self-consumption can dramatically shift benefit allocations.

Monte Carlo simulations confirmed system robustness (>98% chance of positive NPV, Fig. 7.), except in LM scenarios at very low self-consumption.

Policy Recommendations

To scale RECs in the region, five key actions are recommended: Réforme fiscale for vulnerable households (e.g., VAT exemptions, progressive amortization) ; Regulatory stability and legal clarity, inspired by IREP (Nigeria) and MASE (Italy) ; Equitable benefit-sharing models (e.g., income-weighted PDM4) in national REC frameworks ; Creation of municipal REC units for technical support and administrative facilitation ; Inclusion of productive energy uses to improve financial viability (e.g., agro-processing, cold chains).

Limitations and Future Research

The main limitations include: The subjectivity in defining income brackets for PDM4 ; Assumptions on fixed energy prices and prosumer behavior.

Limited exploration of social dynamics such as trust or intra-community negotiation.

Future work should: Pilot hybrid RECs in real settings (e.g., Yaoundé, Douala, Kinshasa) ; Integrate more complex technologies (e.g., batteries, hydrogen) ; Explore hybrid PDMs combining equity and performance incentives ; Expand behavioral research on prosumer engagement.

Compliance with ethical standards

Acknowledgments

The authors wish to thank all the technical and institutional collaborators who contributed indirectly to this work, including the staff of the Electrical Engineering and Renewable Energy Laboratory at the National Advanced School of Engineering in Yaoundé, as well as the environmental modeling team from the Department of Earth Sciences at the University of Douala.

The authors also express their gratitude to the anonymous reviewers for their constructive comments, which helped improve the quality of the manuscript.

Disclosure of conflict of interest

The authors declare that they have no known conflicts of interest related to this publication, nor any financial or personal interests that could influence the results or interpretation presented in this article.

Data availability

Data will be made available on request.

Raoul Biack: Conceptualization; Modeling; Numerical simulations; Results analysis; Writing original draft preparation; Visualization. Benoît Ndzana: Supervision; Validation; Critical review and editing of the manuscript; Methodological guidance; Research coordination. Jacques Etame: Geo-environmental analysis; Preparation of experimental data; Field calibration; Scientific proofreading; Support in interpretation of results.

All authors have read and approved the final version of the manuscript. No competing interests are declared

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Appendix A. Supplementary data

Supplementary data to this article can be found online at biackraoul25@gmail.com