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Research Article

Regional Coordination of Electricity Pricing, Cross-Border Interconnection and Shared Storage for the West African Power Pool

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Abstract

National electricity-planning frameworks are increasingly constrained by their inability to internalise cross-border complementarities in renewable resources, demand profiles and flexibility needs. This paper evaluates whether a regionally coordinated dynamic-pricing mechanism, combined with cross-border interconnection and shared energy storage, can improve the economic and environmental performance of an interconnected power system in West Africa. A multi-period, multi-country optimisation framework is formulated for five ECOWAS member states (Senegal, Mali, Mauritania, The Gambia and Guinea) and applied to three configurations: an isolated national system, a statically priced regional interconnection, and a fully coordinated regional system combining dynamic pricing with shared storage. Because each configuration relaxes the decision space of the previous one, a monotonic cost improvement is expected by construction, so results are read as evidence on the magnitude of that improvement rather than as an independent test of each mechanism. Within this scope, the coordinated configuration reaches, by 2050, an average cost of 45.86 FCFA/kWh and a renewable share of 68.46% without modelled subsidies. A central finding, less directly implied by the scenario structure, is that these gains are not accompanied by larger cross-border flows: exchange volumes fall from roughly 5,000 MWh/day under static interconnection to about 850 MWh/day once shared storage is activated, indicating that temporal flexibility can substitute, in part, for spatial flexibility. Thermal emissions are also lower than under static interconnection, though not comparable to the isolated case owing to differing system boundaries. As the storage and pricing mechanisms have not yet been decomposed and no sensitivity analysis has been run, these results are exploratory rather than confirmatory. With that caveat, they support treating regional electricity pricing as a coordination instrument for interconnection and storage policy, discussed alongside the institutional conditions - harmonised rules, transparent burden-sharing, and consumer protection - required within the WAPP/EEEOA framework.

Keywords

Regional Electricity Market, Dynamic Pricing, Shared Storage, Cross-Border Interconnection, Renewable Integration, West African Power Pool, Senegal

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1. Introduction

The increasing penetration of variable renewable energy is changing how electricity systems must be operated and coordinated. National planning approaches become restrictive when renewable resources, demand profiles and flexibility needs differ across neighbouring countries: a country with a temporary surplus may coexist with a deficit-facing neighbour, while both maintain costly national reserves. Interconnection provides spatial flexibility by moving surplus generation to where it is needed, while storage provides temporal flexibility by shifting energy across periods. The premise of this study is that regional integration is not only an infrastructure problem: the economic value of interconnection depends on how generation, demand, storage and transmission are coordinated over time, with regional dynamic pricing acting as the coordination signal linking the two.

The contribution of this work is the joint assessment of three mechanisms usually studied separately - regional interconnection, shared storage and dynamic pricing - within a common multi-country optimisation problem, with particular attention to whether shared storage changes the volume and pattern of cross-border flows, and whether dynamic pricing improves the temporal allocation of renewable electricity regionally.

The formulation builds on the authors' earlier national-scale work on dynamic electricity pricing in Senegal [1-3], but differs in system boundary and decision structure: the unit of analysis becomes a set of interconnected systems in which cross-border flows, shared storage and coordinated pricing are determined jointly, rather than a single national system.

The West African Power Pool (WAPP/EEEOA) is the institutional vehicle for this coordination, planning regional infrastructure, facilitating interconnections and developing the market rules needed to move from bilateral exchange toward an organised regional market [4, 5, 7-9]. As renewable penetration grows, this role becomes more important, since absorbing surpluses and transferring them regionally requires finer coordination of flows, reserves and storage than bilateral trade alone provides.

The central research question is: to what extent can a regionally coordinated dynamic-pricing mechanism, combined with interconnection and shared storage, improve renewable integration, reduce costs and strengthen resilience in West Africa? Four objectives follow: extending a national pricing formulation to a multi-country framework; comparing an isolated national system with a regional one; evaluating the effect of shared storage on renewable integration; and analysing the economic, social and environmental effects of regional dynamic pricing.

The paper proceeds with a literature review (Section 2), methodology (Section 3), results and discussion (Section 4), policy recommendations (Section 5), conclusion (Section 6) and research perspectives (Section 7).

2. Literature Review

Despite the growing literature on regional electricity markets, renewable-energy integration, storage deployment and demand-side flexibility, these research streams remain only partially connected. Regional market studies generally emphasise transmission capacity and cross-border exchanges; storage studies focus primarily on temporal balancing and renewable-energy absorption; and dynamic-pricing studies typically examine demand response within individual electricity systems. This separation makes it difficult to determine how price signals interact with regional electricity flows and shared storage resources. The review below is organised around four axes that mirror this separation, before identifying the resulting research gap.

2.1. Regional Electricity-market Integration and the Role of the WAPP/EEEOA

Regional electricity-market integration rests on the premise that an interconnected system can be more efficient, more resilient and less costly than a set of isolated national systems. Cross-border exchanges allow the pooling of production capacity, better utilisation of existing plant, reduced reserve requirements and improved management of supply-demand imbalances, particularly where energy resources are unevenly distributed [4, 5]. World Bank assessments of regional power projects in West Africa report similar gains from expanded interconnection and access [6]. Economically, regional trade can lower total system cost by allowing importing countries to draw on cheaper generation abroad rather than dispatching more expensive domestic plant, a mechanism that is especially relevant for countries with high peak-hour marginal costs [17, 18]. Technically, interconnection strengthens supply security by allowing reserves that would otherwise be held nationally to be partly pooled, a benefit that grows in importance as variable renewable shares increase [14, 15]. Regional integration is not, however, reducible to the construction of transmission lines: it also requires market rules, settlement mechanisms, operator coordination, regulatory harmonisation and transparent transmission-tariff methodologies, without which physical interconnections may remain under-used [8, 9].

The West African Power Pool (WAPP/EEEOA) is the institution mandated to carry out this coordination across ECOWAS member states, with the objective of improving the access, reliability and competitiveness of electricity supply through an integrated regional market [4, 7]. Its functions span the planning of regional generation and transmission infrastructure, the facilitation of interconnections, the development of market rules, and coordination with national regulators [8, 9]. The regional market has evolved from bilateral exchanges toward a more structured architecture that includes short-term trading mechanisms, settlement procedures, financial guarantees and common transport rules, formalised through a regional electricity market code and a regional transmission-tariff methodology adopted by the ECOWAS Regional Electricity Regulatory Authority [8, 9]. As solar and wind penetration increases, the WAPP's coordination role becomes more strategic still, since absorbing renewable surpluses in one member state and transferring them to areas of higher demand requires closer coordination of flows, reserves and storage than the current bilateral-trade stage typically provides.

2.2. Renewable-resource Complementarity and the Role of Shared Storage

West Africa exhibits substantial diversity in energy resources: strong solar potential in Sahelian and semi-arid zones, significant hydropower along major river basins, more localised but locally important wind potential, and natural gas serving in several countries as a transition resource alongside variable renewables [12, 13, 15]. This diversity creates temporal and spatial complementarities - solar output typically peaks at midday while system peaks often occur in the evening, and hydropower, where available, can offset solar and wind variability. In a purely national model, each country must size its capacity for its own peaks, its own contingencies and its own renewable targets, which can lead to over-investment in storage, thermal capacity or reserves; at regional scale, complementary resource and demand profiles reduce these requirements through pooling. Regional complementarity also affects costs directly: where marginal costs differ across countries, trade allows the least-cost resources to be dispatched first, so that a high-marginal-cost country can import cheaper electricity while a country with a renewable surplus can monetise its production, tending to reduce the regional average cost per kWh.

Storage plays a central role in systems with high renewable penetration, shifting energy across time, providing reserve services, reducing congestion and limiting reliance on peaking plant. Shared storage is represented in this study as a regional flexibility resource rather than as an exclusively national asset, a distinction that matters because the value of storage depends not only on the amount of energy that can be shifted but also on the spatial distribution of renewable generation and demand. Rather than developing redundant storage capacity in every country, a coordinated approach can site storage where it adds the most system value and mobilise it across borders according to interconnection constraints and hourly needs [10, 11]. A shared facility can absorb renewable surpluses occurring in one part of the interconnected system and subsequently release energy when regional demand or generation conditions justify it, allowing storage operation to interact with both cross-border flows and dynamic pricing. This interaction makes it possible to assess whether temporal flexibility can reduce the need for large cross-border transfers or additional peaking capacity - a question taken up directly in Section 4. At the same time, shared storage raises governance questions of ownership, operation, cost allocation and compensation between beneficiary countries that require dedicated market rules [10, 11], and recent WAPP-region programmes on storage deployment underscore the growing institutional attention to these questions [10, 11].

2.3. Dynamic Pricing in Interconnected Systems

Dynamic pricing rests on the idea that electricity prices should reflect real or anticipated system conditions rather than a fixed national average [16-18]. Previous studies have further shown that time-varying electricity prices and demand-response mechanisms can influence consumption patterns and encourage load shifting, although the magnitude of the response depends on tariff design and consumer flexibility [19, 20]. In an interconnected system, this pricing logic must extend beyond national demand-side adjustment to incorporate cross-border flows, interconnection constraints and the regional availability of renewable resources. A regional dynamic tariff can improve the efficiency of exchanges: where a country faces high demand and a high marginal cost, the price can rise to curb consumption or attract imports, while a country with a renewable surplus can offer a lower price to encourage local consumption or exports. Within the regional framework developed here, dynamic pricing is interpreted as a coordination signal rather than solely as a mechanism for recovering electricity costs: the price is linked to temporal variations in system conditions so as to influence the timing of consumption relative to the availability and marginal cost of electricity, encouraging demand or storage charging when renewable generation is abundant and marginal costs are low, and creating incentives to shift consumption or discharge stored energy when supply conditions tighten. A tariff of this kind can be formulated from a base tariff to which an hourly marginal-cost component, a congestion or interconnection-use component, and a social component protecting vulnerable consumers are added, so as to reconcile economic efficiency, system stability and social equity. Implementing such a mechanism at regional scale nonetheless requires reliable hourly data, appropriate metering, transparent marginal costs, coordination among regulators, settlement rules for exchanges, and continued protection instruments - social tariffs, subsidised first blocks or targeted transfers - in the countries where tariffs also perform a social function.

2.4. Limits of Isolated National Models and the Research Gap

National models remain useful for analysing domestic policy, national generation-mix trajectories, national storage needs and the tariff effects specific to a given country. Because they treat each system as independent, however, they implicitly assume that every country must secure its own supply-demand balance, reserves and flexibility, which tends to overstate national capacity requirements - particularly for storage and back-up thermal generation - and to understate the value of renewable surpluses, which are assessed only against domestic demand rather than against the possibility of export, storage or use elsewhere in a regional system. National models can also misrepresent resilience: a local shock, such as a rise in the price of gas, a drop in solar output or a plant outage, can have large consequences in an isolated system, whereas in an interconnected system regional exchanges and shared storage can absorb part of the shock by mobilising alternative resources. Assessing resilience therefore requires a multi-country framework.

In the case of Senegal and West Africa specifically, work on how a coordinated dynamic tariff might interact with regional electricity exchanges and shared storage remains limited: existing models typically analyse either the national transition, or interconnection, or storage, but rarely their combination within a single decision architecture. The resulting research gap is therefore not simply the absence of another regional electricity model, but a limited understanding of how spatial flexibility (interconnection), temporal flexibility (storage) and price-based coordination (dynamic pricing) interact when considered jointly. This article addresses that gap by formulating a regional multi-country dynamic-pricing framework and comparing an isolated Senegalese system, a statically priced regional interconnection, and a fully coordinated regional configuration combining dynamic pricing with shared storage, so as to evaluate the combined effects of regional coordination on system cost, renewable share, cross-border exchanges, storage utilisation, subsidy needs, avoided emissions and resilience to shocks.

3. Methodology

The regional framework is formulated as a multi-period optimisation problem in which electricity demand, generation, renewable production, storage operation and cross-border exchanges are jointly determined. Each country is represented as an interconnected energy subsystem characterised by its own demand profile, generation portfolio, renewable-resource availability, storage capacity and transmission connections; the regional system is then linked through cross-border flow variables and shared flexibility resources. This formulation allows the optimisation to determine not only how much electricity should be generated, but also where and when electricity should be produced, stored, transferred and consumed. The national dynamic-pricing formulation developed in the authors' earlier work [1-3] is retained as the point of departure for the marginal-cost-based tariff logic, but the decision structure itself - the system boundary, the coupling variables and the coordination mechanism between countries - is specific to the present regional framework and constitutes its main methodological contribution.

Three questions guide the formulation:

1) Is an interconnected regional system less costly than an isolated national system?
2) Does shared storage improve the integration of variable renewable generation?
3) Does regionally coordinated dynamic pricing improve the economic efficiency and resilience of the West African power system?

3.1. Geographic Scope

To keep the simulation tractable, the study considers a subset of West African countries representative of the region's interconnection challenges: Senegal, Mali, Mauritania, The Gambia and Guinea. This subset was retained primarily because open demand, generation-mix and cost data of sufficient quality could be assembled for these five systems within the study's timeframe; extending the framework to the full WAPP membership is a matter of data availability rather than of the model's structure, and is discussed as a priority extension in Section 7. Senegal is treated as the reference system, continuing the national line of the authors' earlier work. Mali and Mauritania introduce Sahelian configurations with strong solar potential and significant interconnection needs; The Gambia represents a small system heavily dependent on regional exchange; and Guinea introduces a substantial hydropower component, useful for examining complementarity between solar, hydro, thermal generation and storage.

$$C = \{SEN, MLI, MRT, GMB, GIN\} \quad (1)$$

3.2. Temporal Horizon and Resolution

The model spans 2025 to 2050, consistent with the transition trajectories examined in the authors' earlier national work. To limit computational complexity, two resolutions are combined: an annual resolution for demand, capacity and cost trajectories, and a representative hourly resolution for dynamic pricing, exchanges and storage. A calculation period is defined by the triplet (c, t, h), where c denotes the country, t the year and h the representative hour.

3.3. Generation Technologies and Scenarios

The set of generation technologies I comprises solar photovoltaics, wind, hydropower, transitional natural gas, regional imports and storage. The renewable subset is defined as I_{ren} = {solar, wind, hydro}. Natural gas is treated as a transitional thermal technology, dispatched when renewable generation, storage and imports are insufficient to meet demand.

Three configurations are compared in order to isolate the effects of regional interconnection, shared storage and dynamic pricing.

Table 1. *Summary of the scenarios studied.*

Scenario	Description	Analytical purpose
S1 - Isolated Senegal	National optimisation with no regional exchange	Assess the limits of a strictly national transition
S2 - Static interconnection	Regional exchange under static/weakly differentiated tariffs	Measure the effect of interconnection alone
S3 - Coordinated regional system	Regional interconnection, dynamic pricing and shared storage combined	Evaluate the combined gains from full regional coordination

Two methodological caveats follow directly from this design and should be kept in mind when reading Section 4. First, S3 introduces dynamic pricing and shared storage simultaneously relative to S2, so the comparison identifies their combined effect rather than their separate contributions; intermediate configurations isolating storage-only and pricing-only effects would be required to decompose this result, and are proposed as a priority extension in Section 7 rather than treated as already resolved here. Second, and more fundamentally, S2 and S3 are constructed by successively relaxing the feasible decision space available to S1 (adding cross-border flow variables in S2; adding shared storage and dynamic-pricing variables in S3) without removing any option available in the more restricted scenario. Because the model minimises total system cost, this nesting means that S3's cost cannot exceed S2's, which in turn cannot exceed S1's, essentially by construction, independently of whether the added mechanisms are economically meaningful at the scale simulated. The results reported below should therefore be read as evidence on the magnitude and pattern of the gains from relaxing these constraints - which is informative - rather than as an independent confirmation that interconnection, storage and dynamic pricing are individually welfare-improving in a more general sense; this distinction is revisited in Section 4.8.

3.4. Decision Variables and Parameters

The principal decision variables are summarised in Table 2.

Table 2. *Principal decision variables of the regional model.*

Variable	Definition	Unit
$E_{c,i,t,h}$	Electricity generated by technology i in country c	MWh
$D_{c,t,h}$	Electricity demand of country c	MWh
S^{ch} / $S^{out}_{c,t,h}$	Energy charged / discharged to storage	MWh
$S_{c,t,h}$	State of charge of storage	MWh
Imp / $Xpt_{c,t,h}$	Imports / exports of country c	MWh
$Flow_{c,k,t,h}$	Electricity flow from country c to country k	MWh
$P_{c,t,h}$	Dynamic tariff applied in country c	FCFA/kWh
$C^{marg}_{c,t,h}$	Hourly marginal cost of country c	FCFA/kWh

The main parameters are summarised in Table 3.

Table 3. Principal parameters of the regional model.

Parameter	Definition	Unit
$Cap_{c,i,t}$	Installed capacity of technology i in country c	MW
$CF_{c,i,t,h}$	Hourly capacity factor of technology i	-
$IC_{c,k}$	Interconnection capacity between c and k	MW
η^{ch} / η^{out}	Storage charge / discharge efficiency	-
$\alpha_{c,t}$	Minimum renewable share target	%
$P_{c,t}^{base}$	Base tariff of country c	FCFA/kWh
P_c^{social}, Q_c^{life}	Social tariff and protected consumption threshold	FCFA/kWh, kWh/month
δ_h, λ	Hourly differentiation and regional-flow coefficients	-

3.5. Objective Function

The objective is to minimise the discounted total regional system cost, comprising investment, operating, storage, subsidy and cross-border trade costs. Writing DF_t for the period discount factor and $Cost_{c,t,h}$ for the total period cost of country c, the objective is:

$$min\ Z = \Sigma_t\ DF_t\ \Sigma_c\ \Sigma_h\ Cost_{c,t,h} \tag{2}$$

$$DF_t = \frac{1}{(1+r)^{t-t_0}} \tag{3}$$

$$Cost_{c,t,h} = C^{inv} + C^{op} + C^{stor} + C^{subs} + C^{trade} \tag{4}$$

where r is the discount rate, t0 the reference year, and the five terms on the right-hand side of equation (4) are respectively the investment, operating, storage, subsidy and cross-border trade costs of country c in year t and hour h (each implicitly indexed by c,t,h).

3.6. System Constraints

$$\Sigma_i\ E_{c,i,t,h} + Imp_{c,t,h} + S_{c,t,h}^{out} = D_{c,t,h} + Xpt_{c,t,h} + S_{c,t,h}^{ch}, \forall\ c,t,h \tag{5}$$

$$E_{c,i,t,h} \leq Cap_{c,i,t} \times CF_{c,i,t,h}, \forall\ c,i,t,h \tag{6}$$

$$0 \leq Flow_{c,k,t,h} \leq IC_{c,k}, \forall\ c,k,t,h \tag{7}$$

Imports and exports are linked to bilateral flows through $Imp_{c,t,h} = \Sigma_{k\neq c}\ Flow_{k,c,t,h}$ and $Xpt_{c,t,h} = \Sigma_{k\neq c}\ Flow_{c,k,t,h}$.

3.7. Storage Dynamics and Renewable Integration

$$S_{c,t,h} = S_{c,t,h-1} + \eta^{ch}\ S_{c,t,h}^{ch} - \frac{S_{c,t,h}^{out}}{\eta^{out}}, 0 \leq S_{c,t,h} \leq Cap_{c,t}^{stor} \tag{8}$$

In S3, part of the storage fleet is pooled at regional scale. The regional storage level and its capacity are given by:

$$S_{t,h}^{reg} = \Sigma_c\ S_{c,t,h} \leq Cap_t^{stor,reg} \tag{9}$$

$$\frac{\Sigma_{i\in Iren}\ E_{c,i,t,h}}{\Sigma_i\ E_{c,i,t,h}} \geq \alpha_{c,t} \tag{10}$$

A regional counterpart of this constraint, aggregating renewable generation and total generation across all countries against a regional target $\alpha_{t,}^{reg}$ allows the effect of a coordinated regional renewable objective to be evaluated separately from country-level targets. Installed renewable capacity $Cap_{c,i,t}$ is set exogenously and held equal across S2 and S3 for each country and year, so that the differences in renewable share reported in Section 4.2 reflect differences in the usable fraction of that capacity - through curtailment avoidance and demand reallocation - rather than differences in the underlying capacity build-out; this equality of installed capacity across S2 and S3 is a modelling choice rather than an emergent result, and is stated here explicitly rather than left implicit in the results.

3.8. Marginal Cost, Dynamic Pricing and System Indicators

The hourly marginal cost $C_{c,t,h}^{marg}$ corresponds to the cost of the last unit of production dispatched to meet demand in country c, approximated in a merit-order logic by the renewable/storage cost when renewables and storage cover demand, and by the gas cost when gas is the marginal technology. The regional dynamic tariff is then built from a base tariff plus a component proportional to the deviation of the hourly marginal cost from its period average, $C_{c,t}^{marg,avg}$, and a regional-flow component:

$$P_{c,t,h} = P_{c,t}^{base} + \delta_h \left(C_{c,t,h}^{marg} - C_{c,t}^{marg,avg}\right) + \lambda \ \Sigma_{k\neq c} \ Flow_{c,k,t,h} \quad (11)$$

subject to tariff bounds $P_c^{min} \leq P_{c,t,h} \leq P_c^{max}$ that limit excessive price variation, and to a protected social tariff $P_{c,t}^{life} \leq P_c^{social}$ for consumption below the monthly threshold $Q_{c,}^{life}$ so that dynamic efficiency and consumer protection are reconciled rather than treated as competing objectives.

The subsidy need is the positive gap between the total cost of service and tariff revenue, $Subs_{c,t}$ = max [0, $Cost_{c,t}$ - $Rev_{c,t}$], with the subsidy rate $\tau_{c,t}^{subs} = Subs_{c,t}/Cost_{c,t} \times 100$ used to assess the financial sustainability of each scenario. To avoid circularity with the subsidy cost term $C_{c,t,h}^{subs}$ that appears in the objective function (Section 3.6), $Cost_{c,t}$ used for this indicator is defined net of investment and subsidy costs - it aggregates only operating, storage and trade costs - so that $Subs_{c,t}$ is an ex-post accounting indicator computed on the optimised dispatch, not an input that the objective function could trivially satisfy by construction. Thermal emissions are computed from gas-fired generation, $Em_{c,t} = \Sigma_h \ E_{c,gas,t,h} \times EF_{gas,}$ and avoided emissions relative to a reference scenario as $Em_{s,t}^{avoided} = Em_t^{ref} - Em_t^s$. System-level indicators used to compare scenarios include the average regional cost per kWh, the regional renewable share, the total volume of cross-border exchanges, storage utilisation, the subsidy rate, avoided emissions, peak-demand reduction and a reserve margin computed as $RM_{c,t} = (Cap_{c,t}^{available} - PeakDemand_{c,t}) / PeakDemand_{c,t} \times 100$. Resilience is assessed through four stress tests applied to each scenario: a gas-price increase, a solar-output shortfall, a sharp demand surge, and a temporary interconnection outage, with the effect on cost, subsidies, exchanges, renewable share and reserve margin recorded for each.

3.9. Data and Numerical Implementation

Required inputs include country-level demand and its growth trajectory, the generation mix, technology costs, installed and interconnection capacities, network losses, national renewable targets, and tariff and social parameters. Where hourly data are not available, representative hourly profiles are constructed from available annual and monthly series; this semi-empirical approach preserves consistency with institutional order-of-magnitude estimates while enabling dynamic analysis of costs, storage and exchanges, and its limits are discussed explicitly in Section 4.8. The model is implemented in Python, with data preparation in pandas and numpy and the optimisation formulated and solved in Pyomo [21]. The pipeline proceeds from data import and preparation, through hourly profile generation, scenario definition (S1-S3), model solution, indicator computation, scenario comparison and robustness testing, to automated production of tables and figures - a modular architecture designed to accommodate additional countries, technologies or market mechanisms (carbon pricing, real-time regional trading, green hydrogen) in future extensions. The solver, optimality gap and solution times used to obtain the results in Section 4 are not yet reported in this draft and should be added, together with a formal convergence check for each scenario, before the model formulation can be considered fully reproducible.

4. Results and Discussion

The simulations compare S1 (isolated Senegal), S2 (static regional interconnection) and S3 (regional interconnection with dynamic pricing and shared storage), allowing the effect of interconnection to be separated from the additional effect of tariff coordination and regional storage. The pattern of results is broadly consistent with the authors' earlier national-scale finding that marginal-cost-based tariff signals can lower cost, improve renewable integration and reduce subsidy needs [1-3]; the contribution of the present analysis is to show how that logic extends, and in some respects changes in character, once a regional system boundary and shared flexibility resources are introduced.

4.1. System Cost

Table 4 summarises the principal indicators obtained in 2050, and Figure 1 presents the year-by-year evolution of the average electricity cost across the three scenarios between 2025 and 2050.

Table 4. Comparison of principal indicators across scenarios, 2050.

Indicator	S1	S2	S3
Average cost (FCFA/kWh)	≈ 49	≈ 51	45.86
Renewable share (%)	≈ 65.0	≈ 64.0	68.46
Exchange volume (MWh/day)	0	≈ 5,000	≈ 850
Storage discharge (MWh/day)	≈ 7,000	≈ 16,000	≈ 29,000
Subsidy rate (%)	0.00	0.00	0.00
Thermal emissions (tCO_2/day)	≈ 10,800	≈ 30,600	24,995.40

S1 = Isolated Senegal; S2 = Static interconnection; S3 = Coordinated regional system. Values preceded by ≈ are read directly from the simulation figures rather than exported at full numerical precision; only S3 was exported with exact output values in the underlying simulation report.

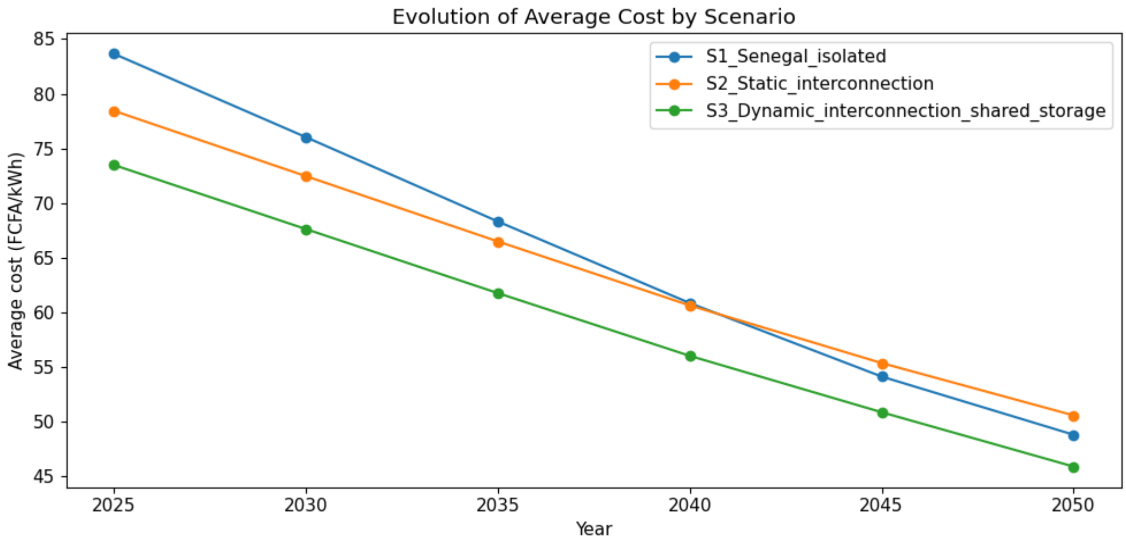

Figure 1. Average cost of electricity by scenario, 2025-2050.

By 2050, the coordinated regional configuration (S3) reaches an average cost of 45.86 FCFA/kWh, against roughly 49-51 FCFA/kWh for the isolated and statically interconnected scenarios. This outcome should not be attributed to a single mechanism: it reflects the combined effect of the wider balancing opportunities created by interconnection, the temporal energy shifting enabled by shared storage, and the demand reallocation induced by dynamic pricing. As noted in Section 3.4, part of this ordering (S3 ≤ S2 ≤ S1) is expected simply because each scenario nests the decision space of the previous one; the informative quantity is therefore the magnitude of the gap, not merely its sign. S3 is consequently better read as providing the most favourable cost trade-off among the configurations considered under the assumptions used here, rather than as unambiguously superior on every indicator irrespective of how success is defined.

4.2. Renewable Integration

Figure 2 presents the evolution of the renewable-energy share across the three scenarios between 2025 and 2050.

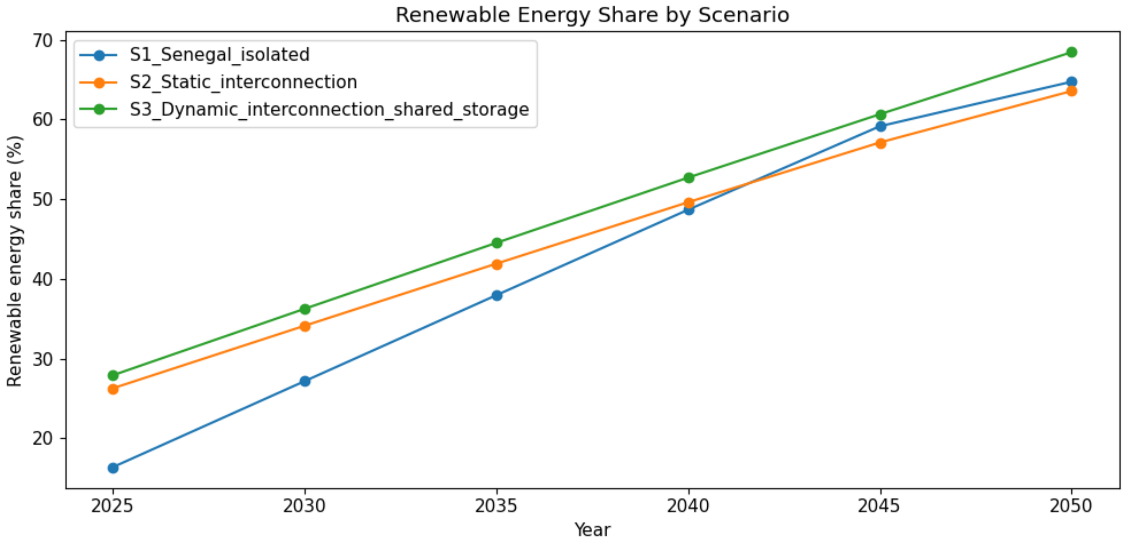

Figure 2. *Renewable-energy share by scenario, 2025-2050.*

The renewable share rises steadily in all three scenarios, from roughly 16% (S1), 26% (S2) and 28% (S3) in 2025 to about 65%, 64% and 68.46% respectively by 2050. S3 achieves the highest penetration. This is best understood not as an increase in installed renewable capacity, which is broadly comparable across the regional scenarios, but as an increase in the usable fraction of renewable generation: shared storage absorbs solar and wind surpluses that would otherwise be curtailed or under-utilised, while dynamic pricing encourages the shift of consumption toward periods of renewable availability. The distinction between installed capacity and usable generation is, in this sense, one of the more informative results of the comparison across S2 and S3.

4.3. Cross-border Exchanges: a Trade-off, Not a Shortfall

Figure 3 presents the evolution of the volume of cross-border electricity exchanges across the three scenarios between 2025 and 2050.

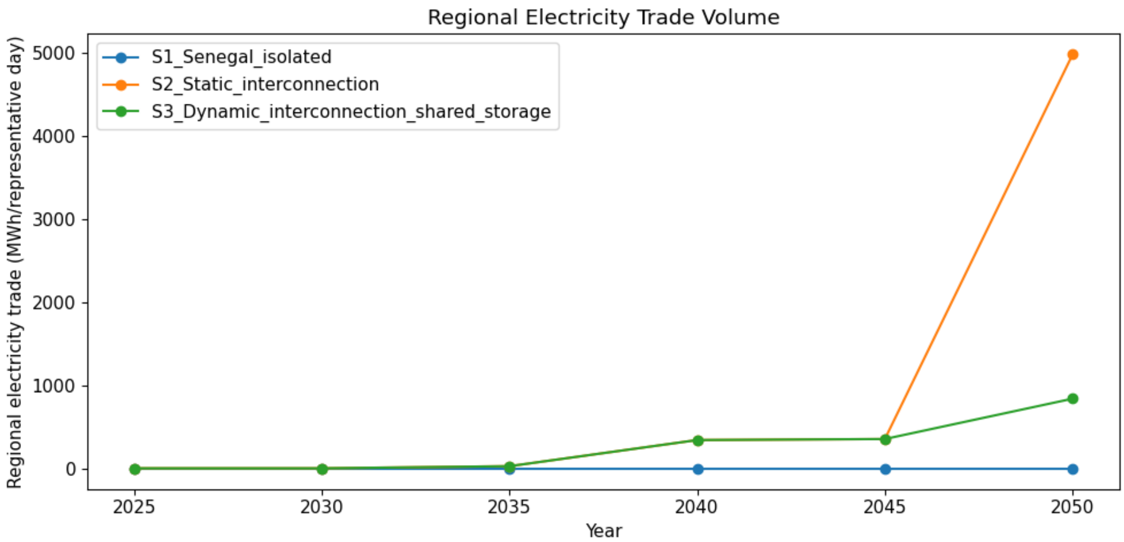

Figure 3. *Cross-border electricity exchange volume by scenario, 2025-2050.*

An important and, at first glance, counter-intuitive result is that the improvement obtained under S3 is not reflected in a larger volume of cross-border exchanges. In 2050, S2 requires a substantially higher regional transfer volume (about 5,000 MWh/day) than S3 (about 850 MWh/day). This difference does not indicate weaker regional integration in S3; it indicates that regional integration operates, in this configuration, primarily through temporal rather than spatial coordination.

Surplus renewable electricity is increasingly absorbed by shared storage and released when system conditions become less favourable, rather than transferred across borders in real time. S3 therefore combines spatial flexibility through interconnection with temporal flexibility through storage, and the latter appears, in these simulations, to substitute in part for the former as a balancing mechanism - a finding with direct implications for how transmission-capacity planning and storage investment might be sequenced regionally, discussed further in Section 5.1 and 5.3.

4.4. The Role of Shared Storage

Figure 4 presents the evolution of storage discharge across the three scenarios between 2025 and 2050.

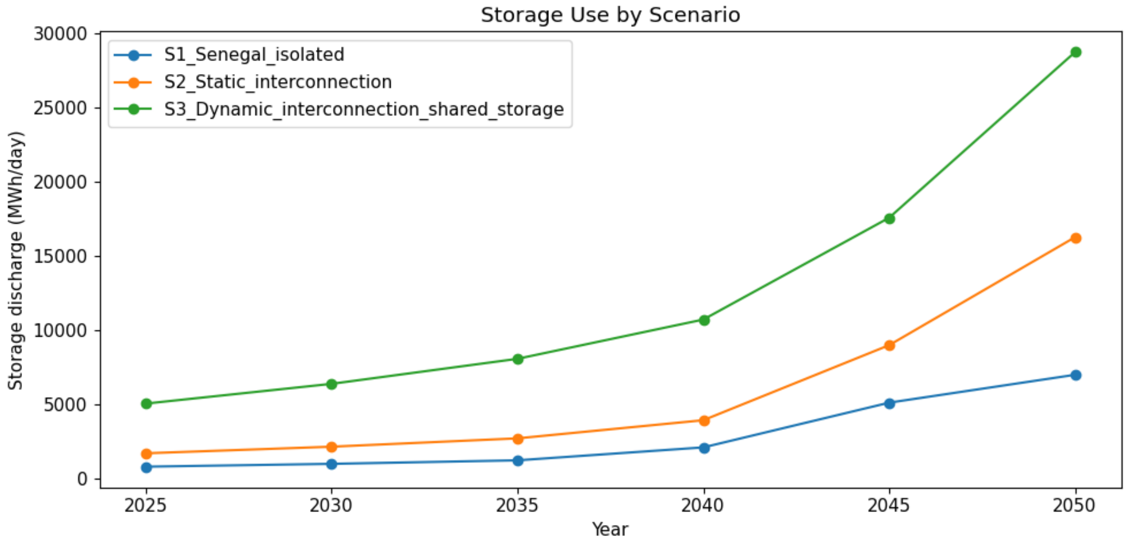

Figure 4*. Storage discharge by scenario, 2025-2050.*

Storage discharge increases sharply across the horizon in all scenarios, reaching roughly 7,000 MWh/day (S1), 16,000 MWh/day (S2) and 29,000 MWh/day (S3) by 2050. These results highlight the increasingly important role of storage as renewable penetration rises within the coordinated regional configuration.

Figure 5 presents the representative regional hourly profile simulated for 2050 under the coordinated configuration (S3).

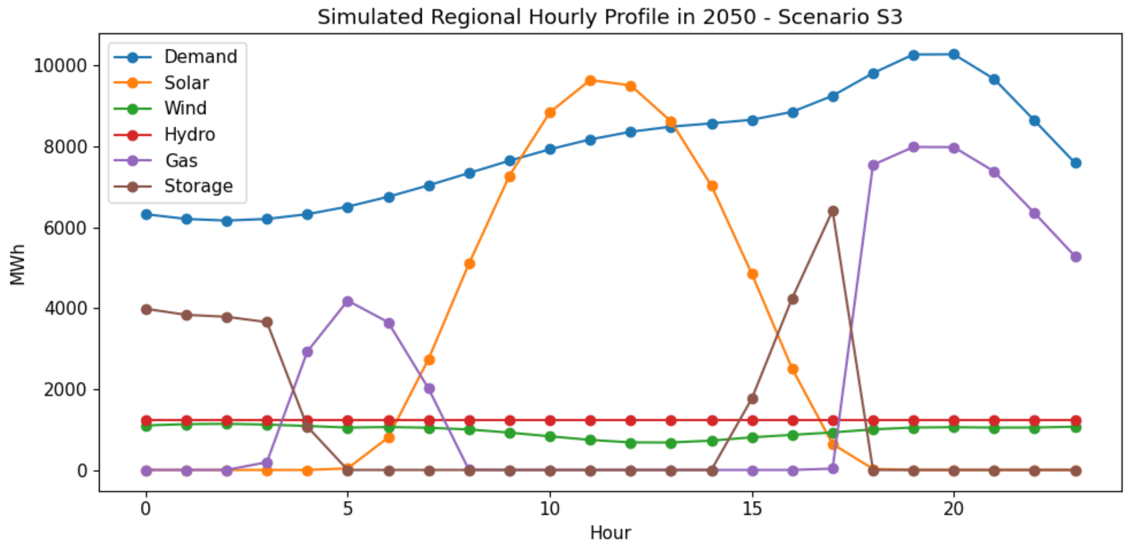

Figure 5*. Representative regional hourly profile in 2050, Scenario S3. This single day illustrates the S3 dispatch pattern and is not an average or a worst case.*

The representative 2050 hourly profile for S3 illustrates the storage mechanism directly: demand rises through the day to an evening peak around 19:00-20:00, while solar output peaks around midday and falls rapidly in the late afternoon; storage discharges mainly in the early morning and, more markedly, in the late afternoon and early evening as solar output declines while demand continues to rise, with hydropower providing a comparatively stable baseload and gas retained for adjustment during periods of peak tension.

4.5. Subsidies and Financial Sustainability

Figure 6 presents the evolution of the modelled subsidy rate across the three scenarios between 2025 and 2050.

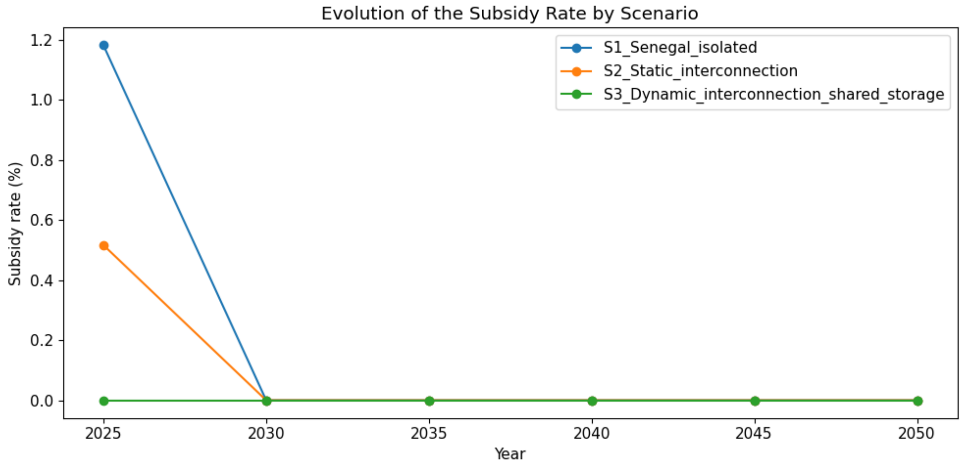

Figure 6. *Modelled subsidy rate by scenario, 2025-2050.*

The modelled subsidy rate falls to zero in all three scenarios from 2030 onward, with S3 reaching this level earliest. This result requires a careful reading. In the model, the subsidy is defined as the positive gap between modelled system costs and simulated tariff revenue; a zero rate therefore indicates that, under the model's assumptions, simulated revenue covers modelled cost. It does not imply that every social or budgetary constraint associated with electricity pricing disappears in practice, particularly given that temporal price differentiation under dynamic pricing may generate heterogeneous impacts across consumer groups. The relevant observation is that S3 reaches this financial equilibrium while simultaneously sustaining a higher renewable share and greater storage utilisation than S2, suggesting that a well-designed regional dynamic tariff could contribute to reduced budgetary support needs alongside faster renewable integration, subject to the institutional safeguards discussed in Section 5.5.

4.6. Thermal Emissions

Figure 7 presents the evolution of thermal-generation emissions across the three scenarios between 2025 and 2050.

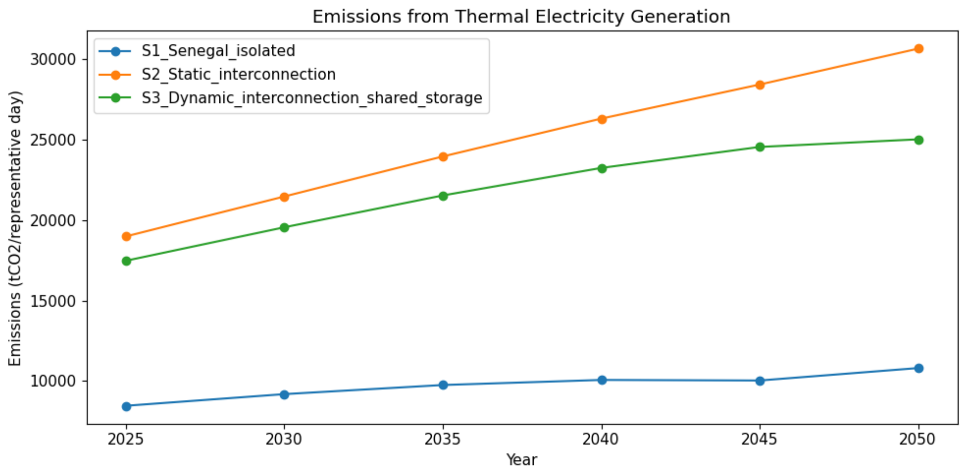

Figure 7. *Thermal-generation emissions by scenario, 2025-2050.*

Thermal emissions increase across all three scenarios between 2025 and 2050, driven mainly by demand growth. S1 shows the lowest absolute emissions, but this reflects a narrower system boundary - a single national system - rather than superior environmental performance, and it is not directly comparable to the regional scenarios in aggregate terms. The informative comparison is between S2 and S3: in 2050, S2 reaches approximately 30,600 tCO2/day against 24,995.40 tCO2/day for S3, indicating that pairing dynamic pricing with shared storage reduces thermal emissions relative to static regional interconnection. This reduction follows from better use of renewable output: storage limits curtailment when solar generation is abundant and substitutes for gas when evening demand rises, consistent with the broader literature on storage as a flexibility and decarbonisation lever in interconnected systems [10, 15].

4.7. Economic, Technical and Institutional Discussion

Taken together, the results support the case for a regional approach to West Africa's energy transition. A strictly national transition requires each country to size its own generation, storage and reserve capacity independently, whereas a regional approach allows resources to be pooled, redundancy to be reduced, and complementarities between countries to be exploited. S3 shows that combining dynamic pricing, shared storage and interconnection can improve renewable share, reduce emissions relative to static interconnection, ease peak management and sustain financial equilibrium under the model's assumptions. Realising this outcome in practice, however, presupposes several institutional conditions: harmonised market rules and settlement mechanisms between countries; transparent allocation of the costs and benefits of shared storage; coordination among national regulators on tariff methodology to avoid distortions between national markets; and continued protection for vulnerable consumers within the regional tariff design. Regional dynamic pricing is, on this reading, best understood as a coordination instrument for the West African power system - aligning demand, renewable production, storage and cross-border exchange around a coherent economic signal - rather than as a device whose sole purpose is to vary prices.

4.8. Limitations

Several aspects of the present analysis bound how the results should be read. The three-scenario design (S1, S2, S3) adds dynamic pricing and shared storage to S2 simultaneously in constructing S3, so the reported gains capture their combined rather than separable effect; disentangling the two would require intermediate configurations (interconnection with storage but static pricing; interconnection with dynamic pricing but no shared storage) that were not run in the present study and are proposed as a priority extension in Section 7. Relatedly, because each scenario's feasible decision space nests the previous one (Section 3.4), the ordering S3 ≤ S2 ≤ S1 on system cost is partly an expected consequence of the model's structure rather than an independent finding; what the simulation adds is the magnitude of the gap and its distribution across cost, renewables, exchanges and emissions, not confirmation that the ordering itself would hold. The interconnection matrix used here is illustrative and should, in a subsequent iteration, be replaced by the WAPP/EEEOA's detailed official transfer capacities; similarly, the hourly marginal costs are a constructed approximation based on available technologies, demand profiles and cost assumptions rather than observed regional dispatch data. Where hourly observations were unavailable, representative profiles were constructed from annual and monthly series. This semi-empirical approach enables regional-scale dynamic analysis but introduces uncertainty regarding the representation of short-term variability and extreme operating conditions. The present analysis does not include a systematic sensitivity assessment of discount rates, technology-cost trajectories and demand elasticity. Future work should therefore examine the robustness of the reported economic outcomes under alternative parameter assumptions. The institutional and regulatory arrangements required to operationalise a coordinated regional tariff, although discussed qualitatively in Sections 4.7 and 5, are not explicitly represented in the optimisation framework. The results should therefore be interpreted as a prospective, system-level assessment of the potential benefits of coordinated regional flexibility rather than as a forecast of actual WAPP market performance or a direct implementation roadmap.

5. Policy Recommendations

The simulation results point toward S3 - interconnection, dynamic pricing and shared storage combined - as the most favourable trajectory identified for strengthening renewable integration, improving system flexibility and reducing emissions relative to static interconnection. Within the scope and assumptions of the present modelling framework, the results suggest several policy directions for strengthening regional renewable integration and system flexibility.

5.1. Strengthen Regional Interconnections

Interconnection widens the balancing area over which resources can be pooled and complementarities exploited; within the WAPP/EEEOA, strengthening interconnections should be treated as a strategic priority covering not only new lines but also their availability, maintenance, real transfer capacity and integration into a coherent regional market framework [4, 5, 9].

5.2. Build a Regional Dynamic-pricing Framework Progressively

The comparison between S2 and S3 indicates that physical interconnection alone does not capture the full flexibility potential of regional coordination. Within the modelled framework, coupling regional exchanges with dynamic pricing and shared storage provides additional opportunities to align demand with renewable availability and system conditions [16-18]. A practical sequencing would begin with simple peak/off-peak differentiation before evolving toward marginal-cost-based dynamic tariffs.

5.3. Develop Shared Storage as Regional Infrastructure

Storage utilisation under S3 (≈ 29,000 MWh/day by 2050) substantially exceeds S2 (≈ 16,000) and S1 (≈ 7,000), confirming its strategic role in absorbing renewable surpluses and releasing them where and when regional demand requires. Developing shared storage will require clear rules on ownership, operation, remuneration and cost-sharing among beneficiary countries [10, 15].

5.4. Establish a Regional Energy-data Platform

Because the present results rely on a semi-empirical base combining open data and representative profiles, an operational regional dynamic-pricing mechanism will need more detailed data on hourly demand, marginal costs, cross-border flows, plant availability, network losses, storage capacity and interconnection constraints. A regional energy-data platform coordinated by the WAPP/EEEOA, in conjunction with national operators and regulators, would strengthen market transparency and the quality of investment decisions.

5.5. Protect Vulnerable Consumers

Dynamic pricing can improve economic efficiency but may expose consumers with limited ability to shift consumption - low-income households, small consumers, rural users - to greater price variability. A social tariff for essential consumption should be maintained and progressively harmonised at regional level, with dynamic pricing applied principally beyond this protected threshold, so as to reconcile economic efficiency, renewable integration and energy equity.

5.6. Establish a Regional Compensation Mechanism

Because regional coordination generates collective benefits that are not necessarily distributed evenly, a compensation mechanism is recommended to remunerate countries providing regional flexibility services, share the savings generated by cross-border trade, and support vulnerable consumers in the countries most exposed to tariff changes - thereby strengthening confidence among member states and the political acceptability of the regional market.

5.7. Position Senegal as a Regional Solar-wind Hub

Senegal's geographic position, its accumulated experience with solar integration, its coastal wind potential and its interconnections with neighbouring systems suggest a strategic role as a regional solar-wind hub, contingent on continued investment in renewable capacity, storage infrastructure, interconnection and digital system-operation tools, and on close coordination with The Gambia, Mali, Mauritania and Guinea.

5.8. Harmonise Regulation and Market Rules

Regional dynamic pricing can only function if market rules are sufficiently harmonised across national regulators - covering interconnection access, transmission-tariff methodologies, settlement procedures, congestion management, storage remuneration and dispute resolution - a harmonisation role in which the ECOWAS Regional Electricity Regulatory Authority and the WAPP/EEEOA will be central.

5.9. Summary of Recommendations

Table 5. *Synthesis of the policy recommendations.*

Recommendation	Objective	Horizon
Strengthen regional interconnections	Increase exchange capacity and supply security	Short-medium term
Progressive regional dynamic pricing	Align prices with marginal cost and renewable availability	Medium term
Develop shared storage	Pool reserves and reduce curtailment	Medium-long term
Regional energy-data platform	Improve transparency and planning	Short term
Protect vulnerable consumers	Preserve affordable access	Ongoing
Regional compensation mechanism	Share costs and benefits equitably	Medium term
Position Senegal as solar-wind hub	Leverage comparative renewable advantage	Medium-long term

6. Conclusions

This study shows that the value of regional electricity integration extends beyond the physical exchange of electricity between interconnected countries. Interconnection, shared storage and dynamic pricing operate as complementary flexibility mechanisms, providing spatial balancing, temporal energy shifting and demand-side coordination respectively. Because the three scenarios are constructed by successively relaxing the feasible decision space (Section 3.4), the direction of the ordering observed across S1, S2 and S3 was expected; what the simulation adds is evidence on its magnitude and pattern. Under the assumptions considered, and read with that qualification in mind, coordinated operation across five West African systems - Senegal, Mali, Mauritania, The Gambia and Guinea - leads by 2050 to a lower modelled electricity cost (45.86 FCFA/kWh), a higher renewable share (68.46%), a zero modelled subsidy rate and lower thermal emissions than a statically interconnected regional system.

A finding of particular interest is that stronger regional coordination does not necessarily require larger cross-border transfers: shared storage substitutes, in part, for spatial balancing through temporal flexibility, so that the coordinated configuration moves less electricity across borders than the statically interconnected one while achieving better outcomes on cost, renewables and emissions. This pattern is less directly a consequence of the nested-scenario structure than the overall cost ordering, since a coordinated system could in principle have relied on higher, not lower, exchange volumes to reach the same cost outcome; it is accordingly the result in this study that carries the most independent informational weight, and the one for which the underlying mechanism (temporal substituting for spatial flexibility) is discussed in most detail in Section 4.3.

These results should be interpreted as exploratory, system-level evidence rather than as a forecast of actual West African regional market performance. Their interpretation remains subject to the modelling assumptions and limitations discussed in Section 4.8, particularly those related to scenario design, data resolution and parameter uncertainty. Within these bounds, the study provides evidence that coordinated regional planning can strengthen the effectiveness of West Africa's energy transition by combining spatial, temporal and price-based flexibility. Senegal, given its solar and wind potential, geographic position and existing interconnections with neighbouring systems, is well placed to contribute to this regional trajectory.

7. Research Perspectives

The present results open several directions for further work, summarised below rather than restated in full:

1) Decomposing the S3 configuration into intermediate scenarios that isolate the separate contributions of shared storage and dynamic pricing (Section 4.8);
2) Replacing the illustrative interconnection matrix with WAPP/EEEOA official transfer capacities, losses and technical outage data;
3) Extending the hourly formulation toward a real-time regional market representation, including nodal prices, congestion and ancillary services;
4) Introducing a carbon price on thermal generation to test its interaction with regional trade and renewable investment;
5) Representing green-hydrogen production from renewable surpluses as a seasonal storage and export vector;
6) Developing a digital-twin representation of the West African grid combining real data, optimisation and interactive scenario testing for operators and regulators;
7) Incorporating electric-vehicle charging demand and vehicle-to-grid flexibility into the regional formulation;
8) Complementing the technical results with an institutional analysis of the regulatory frameworks, exchange contracts, compensation mechanisms and political-economy conditions needed to implement a regional dynamic tariff among Senegal, Mauritania, Mali, The Gambia and Guinea.

Taken together, these directions indicate that the present framework is not a geographic extension of the national tariff model but an opening onto a broader regional architecture linking electricity-system optimisation, dynamic pricing, shared storage, market governance and the climate and digital dimensions of the transition.

Abbreviations

WAPP/EEEOA	West African Power Pool
ECOWAS	Economic Community of West African States
ERERA	ECOWAS Regional Electricity Regulatory Authority
ECREEE	ECOWAS Centre for Renewable Energy and Energy Efficiency
FCFA	CFA Franc (West African CFA Franc)
MW/MWh	Megawatt / Megawatt-hour
tCO_2	Tonnes of Carbon Dioxide

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Mamadou Lamine Samb: Conceptualization, Supervision, Validation, Writing – review & editing

Data Availability Statement

The demand, generation-mix and cost assumptions used in this study are drawn from open sources cited in the reference list. The Python/Pyomo implementation, the representative hourly profiles and the simulation outputs underlying Tables 4-5 and Figures 1-7 are available from the corresponding author upon reasonable request.

Conflicts of Interest

The authors declare no conflicts of interest.

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