International Journal of Sustainable Energy Planning and Management Vol. 47 2025 7–20

International Journal of Sustainable Energy Planning and Management

Scenario-based framework for national energy storage integration in decarbonization pathways

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ABSTRACT

The integration of large-scale energy storage is pivotal for enabling reliable, affordable, and decarbonized national power systems. This study introduces a scenario-based strategic planning framework to guide the deployment of storage under varying policy and technological futures. The framework is applied to generalized national-scale scenarios rather than a single-country case, ensuring that the insights are transferable across diverse contexts. It explicitly considers a portfolio of storage technologies, including batteries, pumped hydro, and hydrogen-based systems. Four national-scale scenarios are examined to explore how different planning approaches affect emissions, cost, and grid stability. The results show that strategic early investment in storage—as modeled in Scenario A—can lead to a 50 % storage penetration rate by 2050, avoid 220 Mt of carbon dioxide emissions, and reduce the levelized cost of energy from 112 to 76 USD per MWh. Scenario A also demonstrates the most cost-effective reliability enhancement, achieving a cost per avoided blackout hour of 105 263 USD. In contrast, Scenario D, which assumes policy inaction, results in only 20 GW of installed storage capacity by 2050, an 18 % reduction in renewable-energy curtailment, and a persistently high levelized cost of energy of 118 USD per MWh. These findings underscore the critical role of storage in supporting national decarbonization and highlight the need for coordinated planning. The proposed framework serves as a practical decision-support tool for aligning storage investments with long-term energy and climate goals.

Keywords

Energy storage systems;
Scenario analysis;
Carbon mitigation;
Strategic planning

http://doi.org/10.54337/ijsepm.10125

1. Introduction

The global shift toward decarbonized energy systems has created unprecedented challenges in balancing electricity supply and demand due to the variability of wind and solar. While these resources are vital for reducing emissions, their intermittency can destabilize power systems if not properly managed. Largescale energy storage systems (ESS) are a promising solution, providing flexibility, grid stability, reduced curtailment, and improved resilience. Yet, deploying ESS at national or regional scales faces multi-dimensional barriers, including high capital costs, evolving regulation, siting issues, lack of unified planning models, and inconsistent valuation frameworks. Despite technological advances, there is still a critical need for strategic frameworks that balance technical feasibility, policy alignment, and economic viability. Several studies have explored storage integration, offering fragmented insights. The National Grid Energy Storage Strategy outlines general frameworks but lacks detailed national methodologies [1], while state-level policy analyses show uneven progress across 17 U.S. states [2].

Economic appraisals in the IJSEPM literature emphasize financial feasibility but often neglect technical and environmental integration factors [3]. Other studies stress the need for modernization and coordination, yet without concrete operational strategies [4]. Comparative analyses highlight whole-system approaches but omit

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Received 29.04.2025 | Accepted 13.11.2025 | Published 10.12.2025

List of Abbreviations

ESS	Energy storage systems
VRE	Variable renewable energy
LCOS	Levelized cost of storage
LCOE	Levelized cost of energy
PDMI	Peak demand matching index
CME	Carbon mitigation efficiency
PHS	Pumped hydro storage V2G Vehicle-to-grid

execution pathways [5]. Work on integrated energy systems underscores cross-sector planning but simplifies storage and flexibility modelling [6]. Recent 100% renewable scenarios demonstrate feasibility but lack actionable frameworks linking design to implementation [7]. Several studies quantify the link between storage and emissions reduction, but most remain limited. Market-based analyses evaluate short-run marginal emissions from arbitrage, while national scenarios examine renewable integration without fully addressing siting, long-duration storage, or resilience [8]. These contributions are valuable yet stop short of detailed and transferable planning frameworks. At the same time, research highlights storage's critical role in decarbonization scenarios, including cost-projection analyses [42], policy-driven and market reform frameworks [44, 45, 48], and thermal storage for demand-side flexibility [50]. These strengthen the evidence base, while this work adds a scenario-driven, multi-metric framework generalizable across national contexts.

Comprehensive reviews on power markets [9] provide insights into pricing and flexibility but emphasize conceptual approaches over quantitative modeling of national-scale storage deployment. Their findings are informative but not directly applicable to planning frameworks requiring spatial, temporal, and infrastructure co-optimization.

The Massachusetts Future Grid Plan is context-specific [10], while NREL's Storage Futures Study projects long-term U.S. storage with limited transferability [11]. GAO reports flag regulatory challenges without actionable pathways [12], and discussions of storage as a solution lack operational strategies [13]. The IEA's Net Zero by 2050 report offers broad roadmaps without execution detail [14]. Studies on renewable integration outline constraints but not concrete planning frameworks [15]. Recent analyses note storage's resilience value but lack long-term field data [16]; integration reviews address technical advances but miss policy dimensions [17]; curtailment studies model ideal performance without real-world limits [18]. Integrated storage–risk frameworks [19] and optimization-based storage selection [20] provide insights mainly for microgrids. Advances in machine learning for motor operation [21] indirectly support system planning. Flexibility planning [22] and renewable–storage economics [23] highlight cost-conscious strategies but remain broad. Despite these contributions, a unified, scenario-based, and multi-metric planning framework for national storage integration is still absent.

This paper addresses the gap with a comprehensive framework for integrating ESS into future national power systems. The framework is demonstrated through generalized national-scale scenarios rather than a single-country case study, ensuring results are illustrative and transferable. It combines decision metrics with infrastructure readiness assessments, enabling policymakers to evaluate storage under diverse pathways. By treating storage as a central pillar rather than a secondary element, the framework promotes reliable, low-carbon, and resilient infrastructures. Core elements such as siting and sizing strategies, differentiated transition scenarios, and multi-dimensional performance indicators (economic, environmental, resilience) support holistic, data-informed planning. The analysis focuses on the electricity sector, providing insights for reliability and decarbonization but not capturing synergies across heating, cooling, transport, and industry. Research shows electricity-only analyses may yield suboptimal outcomes compared to holistic smart energy systems, where sector coupling enables cost-effective climate neutrality [37, 38]. This framework should thus be read as complementing, not replacing, broader smart energy perspectives. Sector-integrated smart energy systems—linking electricity with heating, cooling, transport, and industry—deliver more affordable and effective balancing than electricity-only approaches by shifting flexibility to thermal and fuel-based storage [37, 38, 39]. This contextualizes the present results as electricity-system insights complementary to, not substitutes for, holistic designs.

The paper is structured as follows: Section 1 defines the research problem and motivation. Section 2 reviews literature and limitations. Section 3 presents the framework and metrics. Section 4 outlines scenarios, simulation, and results.

Section 5 discusses policy implications. Section 6 concludes with contributions and future directions.

2. Energy Transition Planning Models

This section reviews widely used energy transition planning tools and highlights their limitations for large-scale storage integration.

2.1. Energy Transition Planning Tools

The models discussed here were selected because they (i) are widely applied in national or regional planning, (ii) are open-source or broadly licensed, (iii) provide sufficient temporal or operational resolution for flexibility analysis, and (iv) explicitly represent storage, though often in stylized forms. They are representative rather than exhaustive.

Commonly used tools include MARKAL/TIMES, OSeMOSYS, LEAP, and EnergyPLAN. The MARKAL and TIMES models, developed by IEA-ETSAP, employ bottom-up optimization for technology-rich, long-horizon planning but treat storage generically, using energy balances without dynamic operation or siting detail. OSeMOSYS, widely adopted in developing countries, supports scenario analysis but assumes ideal efficiencies and neglects degradation and infrastructure constraints [43]. LEAP provides a user-friendly platform for policy-oriented planning, yet storage is often modeled with minimal technical detail, as a black-box component. EnergyPLAN simulates complex systems at hourly resolution with stronger detail on batteries and pumped hydro but emphasizes operational feasibility over long-term investment strategies [36,37].

Collectively, these tools advance transition research but simplify storage in terms of siting, infrastructure, and investment co-optimization. The MARKAL and TIMES models support technology-rich optimization, OSeMOSYS provides an accessible open framework [43], LEAP is policy-oriented, and EnergyPLAN captures detailed hourly interactions [36,37].

Aggregation is a common simplification across technologies, not only storage. Thermal plants, renewable clusters, and transmission are often modeled in aggregated forms to retain tractability. When storage is modeled with more technical detail than other technologies, its value streams may be misrepresented; uniform aggregation risks understating siting, congestion, and resilience benefits. The proposed framework addresses this by coupling storage siting and sizing with infrastructure readiness and testing sensitivity to spatial and temporal granularity.

2.1.1 Limitations of Existing Planning Tools for Storage Integration

Despite advances, existing models often treat storage as a supplementary feature. Most use idealized or aggregated forms, overlooking degradation, stateof-charge dynamics, and locational dependencies. A key gap lies in spatial resolution: few co-optimize siting with renewable zones, demand centers, or grid bottlenecks. Investment logic is also underdeveloped—storage value depends on price volatility, ancillary services, and system interactions that are difficult to model with coarse temporal granularity or simplified market designs.

Still, models such as MARKAL, TIMES, OSeMOSYS, and especially EnergyPLAN have made important progress. EnergyPLAN supports hourly renewable and storage assessments [36]; MARKAL/TIMES provide technologyrich optimization; OSeMOSYS and LEAP deliver transparent, accessible frameworks. These underscore significant progress in representing storage.

Nevertheless, most approaches emphasize cost, feasibility, or emissions while giving less attention to siting,

Table 1: Representative literature on storage economics, flexibility, and system scenarios.

Model / Study	**Type**	**Strengths**	**Limitations**
Lo´pez Prol & Schill	Economic review	Storage economics and market design [18]	Limited siting/grid detail; planning transferability
Heuberger & Mac Dowell	Flexibility study	CCS–flexibility interactions [24]	Not focused on storage deployment/siting
Connolly et al.	Scenario analysis	100% renewable energy system pathways [3]	Simplified storage representation; lacks economic coupling
Lund et al. (Energy-PLAN)	System modelling	Smart energy systems and national-scale analysis [36, 37]	Limited short-term operation and market detail
Schill et al.	Market review	Impacts of storage on electricity market performance [9]	Theoretical focus; limited spatial and temporal granularity
Heuberger et al.	Integrated flexibility planning	Multi-sector coordination in low-carbon grids [24]	Model complexity; limited empirical validation

co-optimization, and resilience. Few integrate resilience metrics such as the *cost per avoided blackout hour* or evaluate storage strategies under divergent socio-technical futures. This motivates the scenariobased framework proposed here, which couples storage siting and sizing with multi-dimensional indicators covering economic, environmental, and resilience outcomes.

Moreover, achieving carbon neutrality requires integration beyond electricity. Heating, cooling, transport, and industry must be included. The Smart Energy Denmark strategy illustrates how sector coupling provides consistent decarbonization pathways [3,6,40,45,46].

In the next section reviews planning models to position the proposed framework and ensure continuity between the research gaps identified in the Introduction and the detailed assessment of modeling tools.

2.2 Literature on Storage Planning

Recent studies recognize storage's role in mitigating intermittency, frequency regulation, and energy security. L´opez Prol and Schill [24] analyze renewable–storage economics but emphasize market dynamics over grid planning.

Tveten et al. show how demand-side flexibility enhances VRE integration and market value, treating storage and flexibility as coupled levers [25]. Tariq demonstrates that storage-enabled energy management supports higher VRE penetration though without national siting detail [26]. Lund highlights crossvector value stacking from combining electricity and thermal storage in district heating, while abstracting from granular deployment [27]. R¨oder et al. optimize district heating networks with distributed thermal storage, offering spatial insights but focused on heat rather than transmission-level storage [28].

While valuable, these contributions treat storage largely in isolation from infrastructure and policy frameworks. Co-optimization of storage with generation and transmission expansion remains underexplored.

Key research gaps include:

- Insufficient spatial and sizing resolution for grid-scale storage.
- Limited integration with infrastructure readiness and transmission.
- Lack of frameworks combining storage, generation, and transmission planning.

This motivates a scenario-driven approach linking high-level planning with technical and economic modeling. The proposed framework evaluates large-scale storage deployment across multiple national transition pathways.

3. Proposed Strategic Planning Framework

The complexity of national energy transitions demands planning approaches that move beyond isolated technical evaluations of storage. Traditional studies often treat storage as either a dispatchable asset or an economic add-on, rarely addressing when, where, and under what conditions storage should be deployed as part of coordinated, long-term transition strategies.

This paper proposes a flexible, transferable framework for integrating largescale energy storage systems into national strategies. Unlike conventional methods, which treat storage statically, this framework positions it as a core planning component essential for achieving grid reliability, emissions reduction, and investment efficiency.

Central to the framework is a scenario-based structure that stress-tests storage strategies under divergent national pathways. These scenarios include:

- High Electrification: Rapid adoption of electric vehicles and heating drives electricity demand and peak loads, requiring responsive, short-duration storage technologies. - Decentralized Future: Widespread deployment of distributed energy resources necessitates modular, flexible storage across decentralized networks. - Delayed Transition: Slower renewable deployment increases reliance on storage to maintain grid reliability and reduce fossil fuel dependency. - StorageDriven Hybridization: Proactive deployment of mid- and large-scale storage enables higher renewable penetration while alleviating transmission congestion.

These scenarios are not forecasts but analytical tools to evaluate technology trade-offs, deployment priorities, and investment strategies under uncertainty.

Because storage needs are tightly coupled to demand growth, peak profiles, and demand reduction measures, each scenario embeds an explicit demand pathway. Scenario A assumes accelerated end-use electrification (EVs and heat pumps) with net annual demand growth of 2.5% and peak-enhancing effects (+20% by 2050) that are partially mitigated by smart charging and dynamic tariffs. Scenario B applies moderate electrification (1.5% annual demand growth) with targeted efficiency improvements, yielding a smaller peak increase (+10%). Scenario C emphasizes prosumer adoption and efficiency-first measures: rooftop PV, building retrofits,

Table 2: Scenario demand and peak assumptions (illustrative).

Scenario	Net demand growth (avg/yr)	Peak change (2050 vs 2025)	Demand reduction levers	Peak mitigation levers
A (High Electr.)	2.5%	+20%	Moderate efficiency	Smart charging, TOU, V2G
B (Cost-focused)	1.5%	+10%	Targeted retrofits	Selective DR, TOU
C (Decentralized)	1.8%	+8%	Strong efficiency, BTM PV	DR, community storage, VPPs
D (Stagnation)	0.8%	+12%	Limited	Minimal

and demand response flatten peaks despite higher behind-the-meter activity (net demand growth 1.8%, peak effect +8%). Scenario D maintains limited electrification (0.8% annual growth) but exhibits unfavorable peak dynamics (+12%) due to lack of coordination. These demand trajectories directly shape storage sizing: stronger electrification without coordination raises short-duration capacity needs for peak shaving, while efficiency and flexible demand reduce both energy and power requirements of the storage fleet.

Table 2 summarizes the assumed annual demand growth, peak change by 2050, and the main levers used to reduce demand and mitigate peaks in each scenario, which directly shape storage power/energy needs.

An essential part of strategic planning involves siting and sizing storage systems. Spatial criteria include proximity to renewable hubs, grid congestion relief, transmission capacity, and land availability. Economic sizing weighs capital costs against value streams such as arbitrage, peak shaving, and reliability contributions. The framework also compares centralized (grid-tied) versus distributed (behind-the-meter) storage configurations to recommend contextspecific solutions.

To evaluate storage strategies across scenarios, the framework employs a suite of quantitative decision metrics:

Levelized Cost of Storage (LCOS) evaluates the average cost per MWh of energy delivered:

$$\mathrm{LCOS} = \frac{\sum_{t=1}^{N}\left(\frac{C_{\mathrm{cap},t}+C_{\mathrm{op},t}}{(1+r)t}\right)\sum_{t=1}^{N}\left(\frac{E_{\mathrm{delivered},t}}{(1+r)^{t}}\right)}{} \quad (1)$$

Carbon Mitigation Efficiency (CME) measures emissions avoided per unit of investment:

$$\mathrm{CME} = \frac{\Delta \mathrm{CO}_2}{C_{\mathrm{total}}} \quad (2)$$

Peak Demand Matching Index (PDMI) quantifies storage contribution to peak demand management:

$$\mathrm{PDMI} = \frac{P_{t\in\mathrm{peak}}\min\left(E_{\mathrm{storage},t}, D_{\mathrm{peak},t}\right)}{P_{t\in\mathrm{peak}} D_{\mathrm{peak},t}} \quad (3)$$

Additional metrics enhance multi-dimensional assessment:

– Levelized Cost of Energy (LCOE) compares system-wide costs:

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{N}\left(\frac{C_{\mathrm{inv},t}+C_{\mathrm{op},t}}{(1+r)^{t}}\right)}{\sum_{t=1}^{N}\left(\frac{E_t}{(1+r)^{t}}\right)} \quad (4)$$

– Cost per Avoided Blackout Hour assesses resilience benefits:

$$\mathrm{Cost}_{\mathrm{blackout}} = \frac{C_{\mathrm{storage}}}{H_{\mathrm{avoided}}} \quad (5)$$

– Investment per MWh of Flexibility measures flexibility provision:

$$\mathrm{Investment}_{\mathrm{flex}} = \frac{C_{\mathrm{storage}}}{E_{\mathrm{flex}}} \quad (6)$$

– Storage Utilization Ratio captures operational efficiency:

$$\text{Utilization Ratio} = \frac{E_{\mathrm{cycled}}}{E_{\mathrm{max}}} \quad (7)$$

These metrics provide a comprehensive view across economic, environmental, resilience, and flexibility dimensions, enabling balanced trade-offs in storage deployment decisions.

Beyond metrics, the framework emphasizes system-level integration. Storage deployment is evaluated not in isolation, but in connection with transmission infrastructure, renewable generation clustering, and market mechanisms such as carbon pricing and capacity remuneration. Factors like interconnection timelines, land constraints, and regulatory readiness are incorporated into decision-making, supporting co-optimization across generation, transmission, and storage.

The originality of this framework lies in merging scenario design, performance evaluation, and infrastructure awareness into a unified, scalable planning tool. It complements existing energy models by bridging long-term vision and operational feasibility, especially critical for countries with evolving infrastructure and regulatory landscapes.

Figure 1 illustrates the sequential process of the proposed framework—from scenario development to deployment evaluation—culminating in optimized, resilient storage integration strategies.

In summary, this framework redefines energy storage from a technical afterthought into a strategic enabler of flexible, low-carbon, and resilient energy systems by embedding uncertainty, spatial logic, and multi-dimensional evaluation into national transition planning.

4. Simulation and Results

To operationalize the proposed framework, a set of forward-looking simulation scenarios was developed using a stylized, representative regional power system model. Rather than focusing on a single country, this generalized setup ensures broader applicability and comparison of storage integration strategies across different policy and infrastructure conditions. The design reflects a mid-sized national grid with three zones: high-renewable areas (wind and solar), dense urban load centers, and rural regions with limited transmission.

The simulation spans 2025–2050 in five-year steps, balancing foresight with computational tractability. This timeframe captures evolving technology costs, policy interventions, and demand growth trends.

All scenarios are implemented in the Python for Power System Analysis (PyPSA), an open-source platform suited for integrated power system planning.

Rationale for model choice and link to Section 2. PyPSA was chosen to address gaps identified in Section

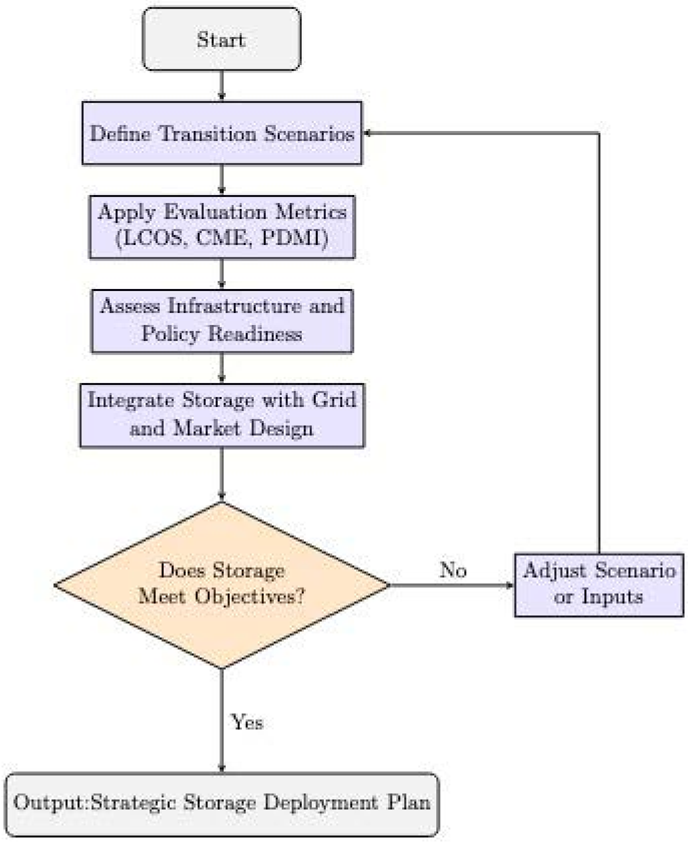

Figure 1: Strategic storage planning framework.

2.1.1. Unlike MARKAL/TIMES or OSeMOSYS, which often represent storage in aggregated terms, PyPSA co-optimizes generation, storage, and transmission with hourly resolution and explicit state-ofcharge dynamics. Compared to LEAP's policy focus and EnergyPLAN's operational simulations, PyPSA enables investment planning with spatial granularity (buses, lines, siting), congestion-aware dispatch, and custom performance metrics (e.g., LCOS, PDMI, blackout-cost) used in this study. While PLEXOS offers detailed short-term operations, it is less suited for the scenario-spanning investment analysis here. The PyPSA ecosystem (e.g., PyPSA-Eur/Sec) also provides a pathway to extend this electricity-sector work toward sector-coupled smart energy systems, directly aligning with holistic perspectives highlighted in our review.

PyPSA supports custom evaluation metrics such as Levelized Cost of Storage (LCOS), Carbon Mitigation Efficiency (CME), and Peak Demand Matching Index (PDMI). Input parameters—including costs, efficiencies, and lifetimes—are sourced from IRENA, NREL, and IEA. The generation mix includes solar PV, onshore wind, natural gas, and hydro, while storage is modeled as lithium-ion batteries (short-duration), vanadium redox flow batteries (mid-duration), and pumped hydro (long-duration). The model simulates storage operation dynamically, accounting for both daily and seasonal balancing under grid capacity and spatial load constraints.

Although stylized, the parameter envelope (2025 peak load ≈18 GW, annual demand ≈85 TWh, and transmission constraints of 500–1200 MW on key corridors) is broadly representative of mid-sized OECD power systems with heterogeneous resources and urban centers. The intent is not to reproduce a single country but to remain empirically plausible, ensuring transferability to multiple contexts with similar scale and network characteristics.

Table 3 summarizes the baseline assumptions used in the simulation setup.

4.1 Scenario Design and Results including demand and peak assumptions

While the scenario framework was introduced earlier as part of the strategic planning architecture, this section details the assumptions and structure of each modeled pathway. The goal is to show how different policy, technology, and behavioral choices affect storage deployment and system outcomes.

To capture diverse transition trajectories, the model applies a scenario-based approach. Instead of predicting one future, this method tests how varying policy

Table 3: Key Input Parameters for Simulation Scenarios (2025 Baseline Year).

Category	Parameter	Value	Unit
	Timeframe	2025–2050	Years
	Discount rate *r*	5	%
Planning Horizon	Carbon price (start)	50	USD/ton CO_2
	Load growth rate	2.5	%/yr
	Solar PV capex	650	USD/kW
	Onshore wind capex	900	USD/kW
Generation Tech	Natural gas efficiency	52	%
	Hydro availability factor	45	%
	Li-ion capex (2025)	350	USD/kWh %
	Li-ion efficiency	90	USD/kWh %
	Flow battery capex (2025)	500	
Storage Tech	Flow efficiency	70	
	PHS energy capex	200	USD/kWh
	Li-ion lifetime	12	Years
	PHS lifetime	40	Years
	Transmission constraints	500–1200	MW
	Peak load (2025)	18	GW
Grid Assumptions	Annual demand (2025)	85	TWh
	Reserve margin	15	%

Table 4: Performance Metrics Across Scenarios.

Node	Scen.	Tech.	Util. Ratio	PDMI	CME (tCO_2/USD)	LCOS (USD/MWh)
N1	A	Li-ion	0.87	0.66	0.42	135
N2	A	PHS	0.75	0.61	0.38	92
N1	B	Li-ion	0.58	0.44	0.25	142
N2	B	Flow Bat.	0.52	0.39	0.21	160
N1	C	Flow Bat.	0.69	0.55	0.31	145
N2	C	Li-ion	0.82	0.78	0.40	130
N1	D	Li-ion	0.33	0.21	0.11	170
N2	D	PHS	0.29	0.18	0.08	150

ambition, technology adoption, and consumer behavior shape storage's role. Each scenario represents a possible national pathway, illustrating shifting priorities for storage under different conditions.

Scenario A: Aggressive Decarbonization with Strong Policy Support Rapid movement toward net-zero, supported by carbon pricing and subsidies. Transport and heating electrification drive high peaks. Storage becomes critical for stability and capacity.

Scenario B: Gradual Transition with Cost-Focused Planning Decarbonization proceeds cautiously, led by markets. Renewables grow moderately; storage deployment prioritizes cost-effectiveness, with lithium-ion dominant.

Scenario C: Decentralized Future with Prosumer-Led Adoption

Communities and consumers drive transition. Rooftop PV, home batteries, and community storage are widespread, raising local flexibility but complicating coordination and equity. Planning emphasizes distributed management and digital control.

Scenario D: Policy Stagnation and Minimal Storage Uptake

Limited policy action and weak incentives keep fossil reliance high and storage minimal. This stress-test highlights vulnerabilities such as blackout risks and curtailment penalties.

These scenarios are not forecasts but structured "what-if" explorations. They allow planners to evaluate how storage performs under divergent sociotechnical conditions and when, where, and how much should be deployed for resilience and decarbonization.

In order to test the framework, a set of performance metrics was applied across nodes and scenarios. Table 4 summarizes outcomes. Under Scenario A, Node 1—near renewable hubs—achieves the highest utilization ratio (0.87) and carbon mitigation efficiency (0.42 tCO_2/USD). In Scenario C, Node 2—close to demand centers—reaches a peak PDMI of 0.78, reflecting distributed, prosumerled value. By contrast, Scenario D shows underutilization and poor economics, with LCOS reaching 170 USD/MWh and CME falling below 0.12.

Figures 2–3 illustrate the long-term role of storage. Figure 2 shows penetration levels (share of demand served by storage) between 2025 and 2050. Scenario A achieves 50% penetration by 2050 through large-scale investment, while Scenario C reaches 42% with distributed adoption. Scenario B lags at 35%, and Scenario D stagnates at 6%.

Figure 3 presents cumulative avoided CO_2 emissions by 2050. Scenario A leads with 220 $MtCO_2$, followed by Scenario C (180 $MtCO_2$), Scenario B (140 $MtCO_2$), and Scenario D (40 $MtCO_2$).

Finally, Figure 4 highlights cross-metric trade-offs across scenarios, linking storage penetration, system cost, and blackout-cost benefits. It reinforces that proactive strategies (Scenarios A and C) deliver higher resilience and lower lifecycle costs, while reactive pathways (Scenario D) impose systemic risks.

Moreover, the economic and operational performance of large-scale storage deployment was assessed under different transition narratives. Two core dimensions were emphasized: investment efficiency and system reliability. These are captured in Figure 4, which compares total investment and investment per MWh of delivered flexibility, and Figure 5, which presents the Peak Demand Matching Index (PDMI) and the Storage Utilization Ratio across all scenarios.

Figure 4 highlights the cost dynamics of strategic deployment. Scenario A, guided by strong policy, shows the highest capital commitment (100 billion USD) but also the most favorable outcome (450 USD/MWh),

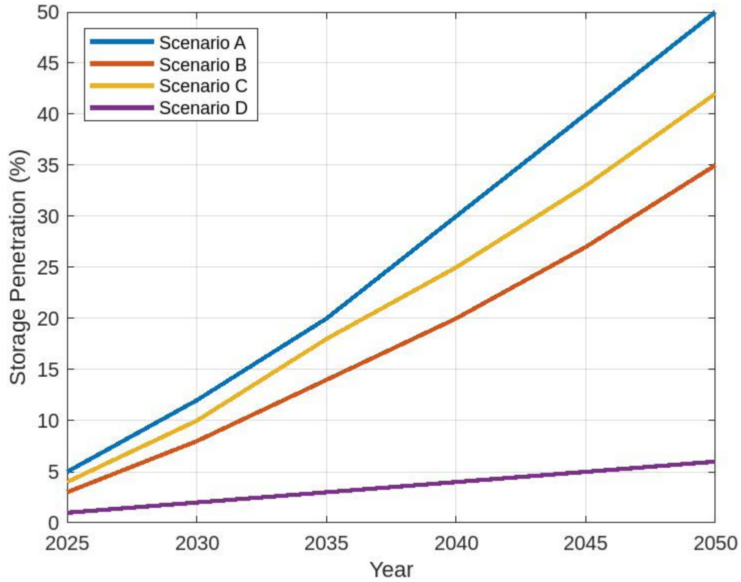

Figure 2: Storage penetration levels from 2025 to 2050 across four transition scenarios. Scenario A demonstrates the highest integration trajectory (50% by 2050), followed by Scenario C (42%), Scenario B (35%), and Scenario D (6%).

reflecting efficient integration with renewables and system planning. Scenario B invests 85 billion USD at 400 USD/MWh, demonstrating disciplined prioritization of high-value sites. Scenario C spends 90 billion USD with a unit cost of 420 USD/MWh, slightly less efficient but showing the potential of decentralized models when well coordinated. In contrast, Scenario D invests only 30 billion USD yet delivers the least cost-effective result (800 USD/MWh), with underutilized capacity and fragmented planning.

Figure 5 complements this by assessing peak support and utilization. Scenario A again leads, achieving a PDMI of 0.85 and utilization ratio of 0.78, reflecting effective alignment with critical periods. Scenario C performs strongly (PDMI 0.76; utilization 0.69), proving distributed assets can enhance reliability. Scenario B yields PDMI 0.72 and utilization 0.81, showing active storage use but less peak alignment. Scenario D lags with PDMI 0.30 and utilization 0.25, signaling poor operational returns.

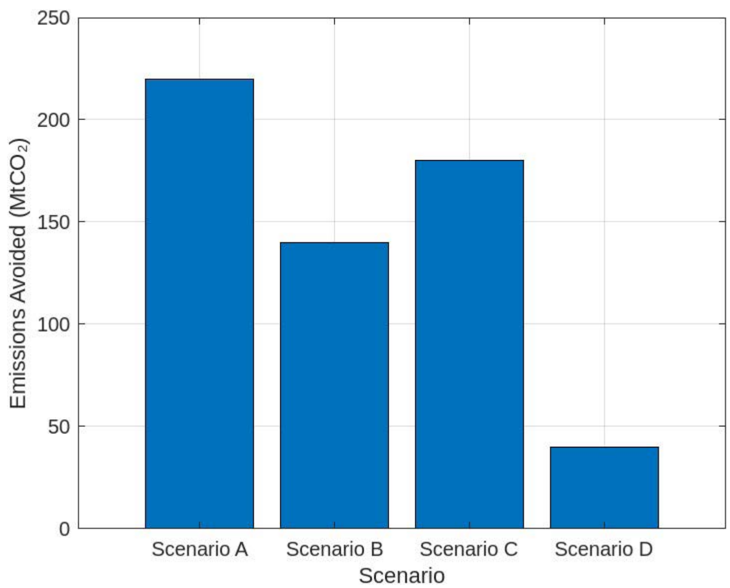

Figure 3: Cumulative CO_2 emissions avoided between 2025 and 2050 in each scenario.

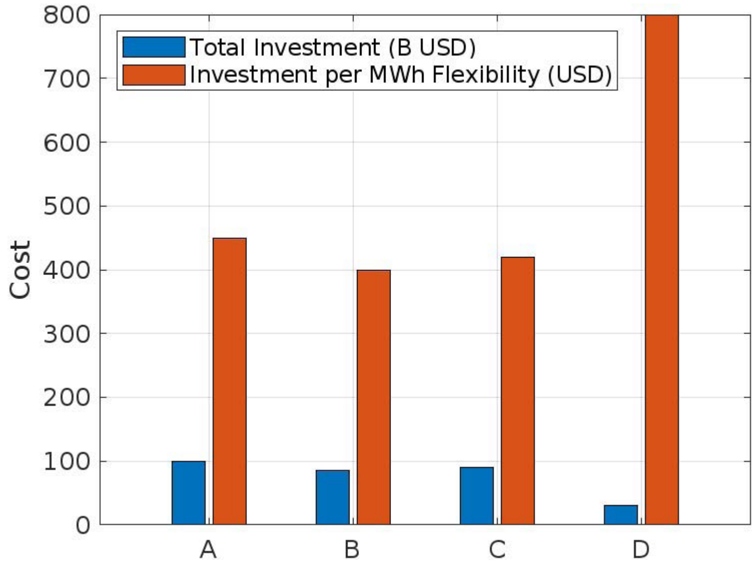

Figure 4: : Investment Cost Comparison.

To evaluate long-term effects, two further indicators were assessed: storage capacity growth and renewable curtailment reduction. Table 3 presents total installed capacity by 2050, growth rate, and dominant technology. Scenario A leads with 120 GW, driven by centralized planning and grid-scale lithium-ion. Scenario C follows with 95 GW of mostly decentralized batteries. Scenario B reaches 85 GW under cost-efficiency priorities. Scenario D, with minimal action, achieves only 20 GW over 25 years.

Table 5 shows curtailment reductions. Scenario A cuts curtailment by 68%, mainly via congestion relief. Scenario C reduces 54%, while Scenario B achieves 42%. Scenario D limits curtailment by only 18%, highlighting the risks of weak planning.

Two additional decision metrics broaden the assessment. Table 6 reports the Levelized Cost of Energy (LCOE) across milestones. Scenario A falls from 112 to 76 USD/MWh, Scenario C reaches 82 USD/MWh, Scenario B remains moderate, while Scenario D stays above 118 USD/MWh—penalizing delayed investment. Table 7 presents cost per avoided blackout hour as a resilience metric. Scenario A prevents over 950 outages at about 105,000 USD/hour, Scenario C performs

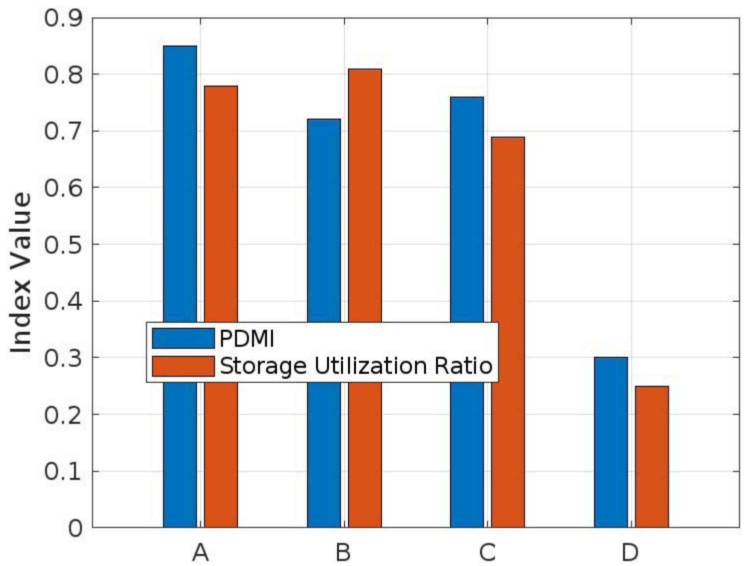

Figure 5: PDMI and Storage Utilization Ratio by Scenario and Storage Type.

Table 5: Curtailment Reduction by Scenario (2025–2050).

Scenario	Curtailment (TWh)	Reduction (%)	Main Cause
A	5.2	68	Grid Congestion
B	8.4	42	Peak Mismatch
C	6.0	54	Local Limitations
D	12.5	18	No Flexibility

Table 6: Levelized Cost of Energy (LCOE) by Scenario (USD/MWh).

Scenario	LCOE (2025)	LCOE (2035)	LCOE (2050)
Scenario A	112	94	76
Scenario B	115	102	85
Scenario C	118	100	82
Scenario D	123	121	118

Table 7: Investment levels, blackout hours avoided, and associated cost efficiency across scenarios).

Scenario	Investment (Billion USD)	Blackout Hours Avoided	Cost per Hour (USD)
Scenario A	100	950	105,263
Scenario B	85	720	118,056
Scenario C	90	770	116,883
Scenario D	30	180	166,667

comparably, while Scenario D shows the highest cost per avoided outage, underscoring inefficiency.

Together, these results highlight the value of early and coordinated storage strategies. Strongly planned pathways (Scenario A) deliver superior cost, emissions, and resilience outcomes, maximizing storage's role in renewable integration and grid stability. In contrast, weakly planned cases (Scenario D) show how benefits erode when storage is marginalized. The framework introduced here thus enables decision-makers to test realistic futures, identify optimal siting and sizing, and design supportive policies. Future extensions could incorporate social, economic, and cross-sectoral dynamics to reflect real-world conditions and evolving energy goals.

5. Planning and System Implications

The simulation results show that storage is no longer an add-on but a central pillar of national decarbonization strategies. A key insight is the advantage of early investment: scenarios prioritizing early storage—particularly Scenario A—achieve deeper emission reductions, higher efficiency, and greater flexibility [30]. This aligns with findings in the broader literature, such as Victoria et al. (2020), who showed that early and coordinated storage deployment reduces long-term system costs and renewable curtailment in European transition pathways [41]. Early action aligns infrastructure, policy, and consumer behavior, enabling dynamic pricing, smart charging, and vehicle-to-grid (V2G) systems [31]-[32].

Real-world transport electrification provides stress tests. In Japan, electrifying seventy-eight million vehicles would add 156 TWh annually, raising consumption by over 15% [33]. Without smart management, evening peaks could nearly double, and meeting the demand with lithium-ion alone would cost more than 50 trillion [34]. In the U.K., full electrification would add about 83 TWh (a 31% rise), with unmanaged charging risking an 18 GW peak increase [35]. Smart charging programs reduce this to 6 GW [36].

These cases show that aggressive decarbonization cannot rely only on centralized storage. Scenario A demonstrates scalable pathways through distributed systems, smart charging, and renewable–hydrogen hybrids. Scenario B emphasizes low-cost demand-side programs, as seen in Japan's off-peak schemes and the U.K.'s dynamic tariffs. Scenario C highlights decentralized flexibility via microgrids and prosumer models, while Scenario D warns of higher costs and system vulnerability from delayed action.

Technology readiness alone is insufficient—policy design is critical. Japan illustrates the importance of matching technologies to roles: lithium-ion for short-term flexibility, pumped hydro for long-duration, and flow batteries for intermediate use [35]. The U.K. shows how regulation—time-of-use tariffs, smart metering, and V2G pilots—can unlock demand-side flexibility and limit costly grid reinforcements [36].

Across all scenarios, clear lessons emerge. Scenario A requires coordinated investment across storage, transmission, and sector coupling. This is consistent with findings that cross-sector integration (e.g., power-to-heat with thermal storage, power-to-gas, and flexible e-mobility) can reduce the scale and cost of electricity storage needed for system balancing [39]. The scenario results also reveal important interactions between storage penetration and overall system costs. In Scenario A, high storage penetration initially increases capital expenditures but lowers total costs through avoided curtailment and reduced backup generation. Scenarios B and C illustrate potential cannibalization: as storage expands, marginal savings fall due to competition between distributed batteries, pumped hydro, and hydrogen storage. These dynamics highlight the need to balance electricity storage with complementary options such as thermal and hydrogen-based pathways, as suggested in recent energy system studies.

Scenario B confirms that even with limited budgets, strategic flexibility can deliver strong results. Scenario C shows decentralized systems can succeed with digital infrastructure and community engagement. Scenario D illustrates risks from regulatory inertia, where unmanaged demand shocks undermine stability.

Overall, effective storage deployment requires co-optimized investment in generation, transmission, and flexibility.

Policy mechanisms—feed-in tariffs, capacity remuneration, tax incentives, and dynamic markets—must evolve with real-world performance. Japan and the U.K. demonstrate that empowering consumers through active grid participation is reshaping systems. Storage is no longer only technical infrastructure; it is civic infrastructure, vital for resilient, equitable, and carbon-free futures.

6. Conclusion

This paper introduces a comprehensive and adaptable planning framework for integrating large-scale energy storage systems into national energy transitions. Unlike conventional approaches that treat storage as a static support asset, the proposed framework incorporates dynamic scenario modeling, spatial deployment logic, and quantitative metrics to assess storage's systemic role under diverse transition conditions. Four national scenarios capture variations in policy ambition, technological uptake, and consumer behavior: Scenario A models aggressive decarbonization with strong policy support; Scenario B reflects a gradual, cost-optimized transition; Scenario C envisions a decentralized, prosumer-led future; and Scenario D represents policy stagnation with minimal storage integration. Simulation results show that strategic planning and regulatory alignment—as in Scenario A—deliver superior outcomes, including 50% storage penetration, 220 $MtCO_2$ avoided, an LCOE of 76 USD/MWh, and the lowest cost per avoided blackout hour (105,000 USD/hour). Scenario C also performs strongly, while Scenario D highlights the risks of fragmented planning.

The central contribution of this work lies in offering a scenario-driven methodology that bridges energy policy with techno-economic evaluation, empowering decision-makers to align storage deployment with climate, reliability, and infrastructure goals. Future research could extend this framework to incorporate regulatory dynamics, distributional equity, and sectoral integration. Insights from Japan's EV transition highlight the value of early investment and decentralized strategies, while the United Kingdom's experience underscores the importance of smart charging policies, flexibility markets, and early standardization in enabling scalable storage integration.

Finally, we note a key limitation and avenue for future work: by restricting the assessment to the electricity sector, our cost and capacity results likely represent conservative (upper-bound) estimates relative to *smart energy system* pathways in which sector coupling provides cheaper balancing through thermal and fuel storage chains. Evidence indicates that climate-neutral smart energy systems can meet balancing needs with lower total system costs by leveraging cross-sector flexibility [39]. Extending the proposed framework to co-optimize electricity with heating, cooling, transport, and industry—e.g., by adding power-to-heat with district heating storage, power-to-gas/PtX options, and vehicle-to-grid—will be a priority for future research.

Our framework provides valuable insights for electricity-sector storage planning, but achieving fully carbon-neutral societies will also require integration across power, heat, transport, and industry. Strategies such as Smart Energy Denmark illustrate how sector coupling enables comprehensive and cost-effective decarbonization pathways [40]. Extending the present framework toward such cross-sectoral smart energy system analyses is an important direction for future research.

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