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Energy System Policies, Economics and Markets

Group Report

The Value of Storage and Renewable Penetration in a European Power System under Nuclear and Carbon Constraints

Group 5

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Abstract

This study evaluates the value of electricity storage and its interaction with renewable penetration in a simplified European power-system model implemented in PyPSA. A 13-scenario framework is developed to compare no-storage, battery, hydrogen, and combined battery–hydrogen cases under a common 24% nuclear-generation cap, together with carbon-limit reductions of 20%, 40%, and 55%. The analysis considers annual system cost, generation mix, renewable penetration, mean electricity price, curtailment, load shedding, net CO_2 emissions, and optimized storage size. The no-storage reference case reveals a clear flexibility deficit, characterized by high renewable curtailment, non-zero load shedding, and elevated electricity prices. Introducing storage improves system performance in all tested cases, with hydrogen providing the largest overall benefit through stronger reductions in system cost, curtailment, and adequacy problems than battery storage. Stricter carbon limits increase renewable penetration and reduce emissions, but also raise total system cost and electricity prices. Additional storage-economics indicators, including discharge revenue, profitability proxy, and LCOS, show that optimized storage capacity approximately recovers its annualised cost through model-based market revenues, while the broader value of storage appears through lower total system cost and improved adequacy. Overall, the results indicate that long-duration storage delivers the strongest flexibility value within the tested assumptions, while carbon constraints remain necessary to ensure structural emissions reductions.

1 Introduction

The European electricity system is undergoing a transition toward higher shares of variable renewable generation while simultaneously facing increasing pressure to reduce carbon emissions. Wind and solar power are central to this transition because of their low operational emissions and growing installed capacity. However, the variability of these technologies introduces temporal and spatial mismatches between electricity supply and demand. As renewable penetration increases, the power system requires more flexibility to absorb surplus generation during high-output periods and to supply demand reliably during low-renewable periods.

Electricity storage is one of the most important flexibility options available in such systems because it can absorb surplus renewable generation, shift energy across time, and reduce curtailment and scarcity [3]. In economic terms, storage shifts energy from relatively low-value periods to higher-value periods. In system terms, it can reduce renewable curtailment, decrease scarcity, limit load shedding, and moderate electricity prices. The value of storage is therefore not limited to the amount of energy discharged; it lies in the total system benefit created by better coordination of generation, demand, and network constraints across time.

At the same time, carbon constraints change the economic conditions under which the system operates. Without a policy constraint, storage may improve cost and flexibility without necessarily reducing emissions. Carbon caps therefore play a different role from storage: they force the generation mix toward lower-emission technologies, while storage helps the system accommodate that transition more efficiently.

This study investigates these interactions using a simplified European PyPSA model. Rather than attempting to predict the real future European power system, the report applies a controlled scenario framework to compare how storage technologies and carbon limits affect system cost, prices, generation mix, renewable penetration, curtailment, adequacy, and emissions under a common set of assumptions. The analysis is structured around three connected steps: first, establishing a no-storage reference case to identify the baseline system behaviour; second, introducing battery, hydrogen, and combined battery–hydrogen storage under the same carbon setting to isolate the flexibility value of storage; and third, testing progressively stricter carbon-limit cases to examine how storage performs as the system moves toward higher renewable penetration and lower emissions. The scope is intentionally focused on comparative scenario analysis within a simplified but consistent modelling framework. In addition to the system-level indicators, the study also evaluates indicative storage economics through model-based discharge revenue, charging cost, profitability proxy, and LCOS.

2 Methodology

2.1 Modelling framework

The model follows a least-cost optimisation logic in which generation, transmission usage, storage operation, and load shedding are chosen to satisfy electricity demand at minimum annual system cost, subject to technical and policy constraints. In simplified form, the optimisation can be interpreted as

$$\min C = \sum_t w_t \sum_g c_g p_{g,t} + \sum_i C_i^{\text{cap}} x_i + \sum_t w_t c^{\text{shed}} p_t^{\text{shed}}, \tag{1}$$

where w_t is the snapshot weighting, c_g is the generator marginal cost, $p_{g,t}$ is generator dispatch, C_i^{cap} is annualised investment cost, x_i is optimised capacity, and p_t^{shed} is load shedding. The expression is included here only to clarify the economic interpretation; the full optimisation is implemented directly in PyPSA [1].

In this framework, electricity prices are interpreted as model marginal prices from the nodal electricity-balance equations. For scenario comparison, mean load-weighted prices are more informative than individual hourly time-series traces, since the aim of the project is to compare annual system performance across multiple storage and carbon-cap cases.

2.2 European network representation

The European electricity system is represented as a simplified zonal network in which each bus corresponds to a regional electricity node connected by transmission lines and links. Each zone may include electricity demand, renewable generation, conventional generation, and storage. This structure is sufficiently detailed for comparative scenario analysis and for interpreting regional storage placement, while remaining computationally manageable for a 13-scenario study [2].

As shown in Figure 1, the network representation provides the spatial backbone for comparing storage location, transmission connectivity, and generation distribution across scenarios. It should not be interpreted as a full nodal planning model for Europe, but rather as a simplified regional system suitable for controlled scenario comparison.

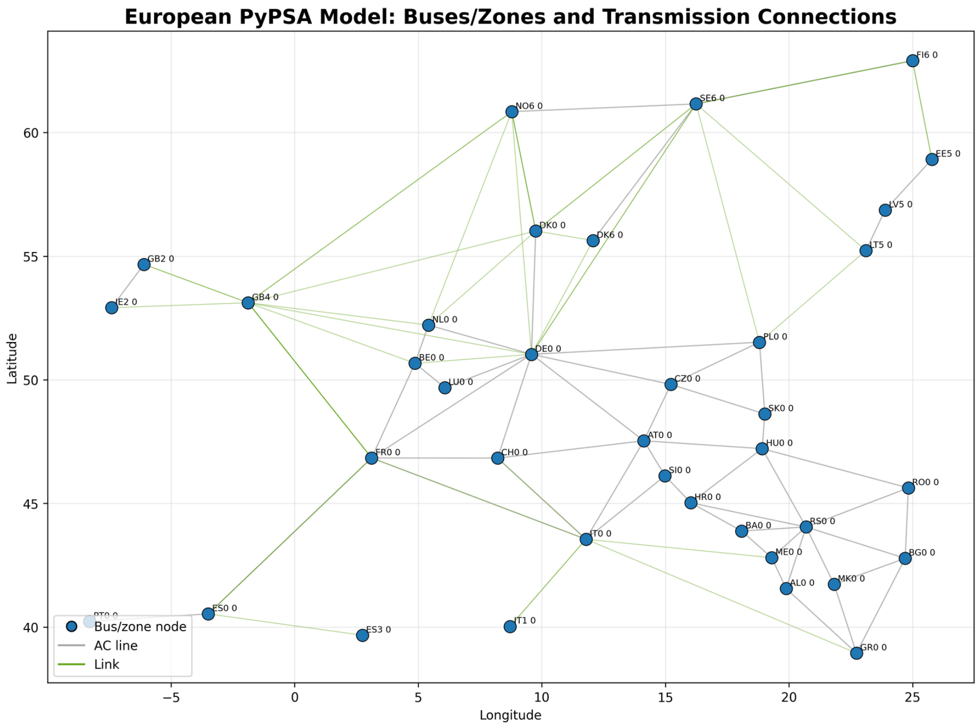


Figure 1: European PyPSA model buses/zones and transmission connections used in the scenario analysis.

To keep the model computationally feasible, the final scenario set is solved at a four-hour temporal resolution. Snapshot weights are scaled during downsampling so that annual quantities such as electricity demand, generation, emissions, and system cost remain comparable across all scenarios.

2.3 Storage modelling assumptions

Storage is introduced as an extendable option at all buses in the storage scenarios. The model is therefore free to place storage in those zones where it provides the greatest system benefit. Two storage technologies are considered: battery storage and hydrogen storage. These were selected to represent two contrasting forms of flexibility: short-duration, high-efficiency storage and long-duration, lower-efficiency storage.

Battery storage is modelled as an 8-hour technology with charging and discharging efficiencies of 0.92. Hydrogen storage is modelled as a 48-hour technology with charging efficiency of 0.70 and discharging efficiency of 0.50. This creates a clear contrast between the two technologies: batteries provide relatively efficient short-term balancing, while hydrogen provides lower-efficiency but much larger intertemporal shifting potential. The values in Table 1 are modelling assumptions selected to represent a short-duration, high-efficiency battery option and a long-duration, lower-efficiency hydrogen option within the scenario analysis.

Table 1: Main storage assumptions used in the scenario analysis.

Technology	Duration [h]	Charge efficiency	Discharge efficiency
Battery	8	0.92	0.92
Hydrogen	48	0.70	0.50

Using a 5% discount rate, the implemented annualised storage capital costs are approximately 181,836 EUR/MW/year for battery storage and 115,646 EUR/MW/year for hydrogen storage. These values are calculated from the power and energy cost assumptions used in the notebook, combined with the fixed storage durations shown in Table 1.

For each optimised storage unit, energy capacity is calculated from the installed power capacity and storage duration:

$$E_{\text{storage}} = P_{\text{nom,opt}} \times h_{\text{max}}. \tag{2}$$

The results are therefore reported in both GW and GWh, since these describe different physical roles of storage: power capacity determines the maximum charge/discharge rate, while energy capacity determines how long storage can sustain delivery.

2.4 Nuclear cap and carbon constraints

All final scenarios apply a 24% annual nuclear-generation cap. This should be understood as a scenario-design choice rather than as a literal policy copy. The cap was chosen because recent official EU statistics show that nuclear power accounted for 23.3% of total EU electricity production in 2024, so a 24% cap provides a rounded, policy-relevant reference point while preventing the model from becoming unrealistically nuclear-dominated [4, 5]. In the implementation, this cap is applied by scaling the available nuclear capacity so that the maximum possible annual nuclear generation is limited to approximately 24% of annual electricity demand. It should therefore be interpreted as a scenario-design constraint on available nuclear potential, not as a detailed policy model for nuclear dispatch. In simplified notation, the intended cap can be represented as

$$G_{\text{nuclear}} \leq 0.24\, D_{\text{annual}}, \tag{3}$$

where G_{nuclear} is annual nuclear generation and D_{annual} is annual electricity demand.

The carbon-constrained scenarios are then introduced by imposing emissions reductions relative to the no-storage reference emissions. If E_{ref} is the reference emissions level, then a reduction level r gives the carbon cap

$$E_{\text{cap}} = E_{\text{ref}}(1 - r). \tag{4}$$

The tested reduction levels are 20%, 40%, and 55%, corresponding to carbon caps of 938.23, 703.67, and 527.76 $MtCO_2$/year. The choice of progressive carbon-cap tightening is motivated by the broader EU climate-policy direction: the European Climate Law sets legally binding targets of at least 55% net greenhouse-gas reduction by 2030, 90% by 2040, and climate neutrality by 2050 [6, 7]. For that reason, the present study uses 20% and 40% as intermediate sensitivity levels and 55% as the main ambitious benchmark within the tested scenario set.

2.5 Performance indicators

For each scenario, the following indicators are extracted:

- annual system cost,
- mean load-weighted electricity price,
- net CO_2 emissions,
- renewable curtailment,
- load shedding,
- generation by carrier,
- renewable penetration,
- storage power and storage energy capacity,
- storage market revenue, profitability proxy, and levelized cost of storage (LCOS).

Renewable penetration is defined as

$$\text{Renewable penetration} = \frac{G_{\text{renewable}}}{D_{\text{annual}}}, \tag{5}$$

where annual renewable generation includes wind, solar, run-of-river hydro, biomass, and geothermal generation.

The value of storage is defined as the reduction in annual system cost:

$$\text{Storage value} = C_{\text{without storage}} - C_{\text{with storage}}. \tag{6}$$

For the reference storage cases, storage value is calculated relative to the reference no-storage case. For the carbon-limit cases, each storage case is compared with the no-storage case at the same carbon limit, so that the storage effect is isolated from the separate policy effect of the carbon cap.

2.6 Additional storage-economics indicators

To complement the system-level assessment, four indicative storage-economics indicators are calculated for the storage scenarios. Discharge revenue is computed as storage discharge multiplied by the nodal model electricity price, while charging cost is computed as storage charging multiplied by the same nodal price signal. The gross arbitrage margin is therefore the difference between discharge revenue and charging cost. A profitability proxy is then defined as the gross arbitrage margin minus the annualised storage-capacity cost. Finally, the levelized cost of storage (LCOS) is calculated as the sum of annualised storage cost and charging cost divided by discharged electricity. These indicators should be interpreted as model-based economics within the least-cost optimization framework, rather than as a full real-world business-case analysis.

2.7 Scenario workflow

The full scenario workflow is implemented in a Jupyter/PyPSA environment. In simplified form, the procedure is:

1. Load the European PyPSA network.
2. Downsample snapshots to four-hour resolution and scale snapshot weights.
3. Apply the nuclear-cap implementation by scaling the available nuclear capacity.
4. Add high-cost load shedding as a feasibility slack option.
5. For storage scenarios, add battery and/or hydrogen storage.
6. For carbon-limit cases, add the relevant CO_2 global constraint.
7. Solve each optimisation problem.
8. Export cost, prices, dispatch, generation mix, emissions, curtailment, load shedding, storage capacities, and storage economics indicators.
9. Generate comparison figures, zonal generation maps, and summary tables.

3 Scenario Design

The final scenario set consists of 13 cases. All cases use the same base network and the same 24% nuclear cap. The differences between scenarios are the storage technology and, where relevant, the carbon-limit reduction. The scenario structure is designed to maintain a clear analytical progression: first a no-storage reference case, then storage cases under the same carbon setting, and finally carbon-constrained storage comparisons.

This scenario set allows three connected comparisons. First, the value of storage can be measured against the no-storage reference under the same carbon setting. Second, the effect of carbon caps can be studied across no-storage and storage cases. Third, the interaction between storage and carbon constraints can be examined by comparing storage value at the same carbon limit. This

Table 2: Final 13-scenario set used in the study.

Case ID	Case name	Storage configuration	Carbon-limit setting
C1	Reference no storage	No storage	None
C2	Reference battery	Battery	None
C3	Reference hydrogen	Hydrogen	None
C4	Reference battery + H_2	Battery + hydrogen	None
C5	CL20 no storage	No storage	20% reduction
C6	CL20 battery	Battery	20% reduction
C7	CL20 hydrogen	Hydrogen	20% reduction
C8	CL40 no storage	No storage	40% reduction
C9	CL40 battery	Battery	40% reduction
C10	CL40 hydrogen	Hydrogen	40% reduction
C11	CL55 no storage	No storage	55% reduction
C12	CL55 battery	Battery	55% reduction
C13	CL55 hydrogen	Hydrogen	55% reduction

preserves a coherent storyline across the report rather than treating the 13 cases as unrelated experiments.

4 Results

4.1 Reference case: no storage, no carbon cap

The reference case establishes the benchmark system behaviour under the imposed 24% nuclear cap, without additional storage and without a tightened carbon cap. This case is used as the starting point for evaluating the value of storage and the effect of stricter carbon constraints. The results indicate a system cost of 101.92 billion EUR/year and a mean load-weighted electricity price of 63.54 EUR/MWh. The reference system also exhibits substantial renewable curtailment of 109.15 TWh/year and non-zero load shedding of 0.907 TWh/year, indicating that the system lacks sufficient flexibility under the assumed generation and transmission configuration. Net CO_2 emissions in the reference case are 1172.79 $MtCO_2$/year.

Table 3: Key metrics for the reference no-storage case.

Metric	Value
System cost	101.92 billion EUR/year
Mean load-weighted price	63.54 EUR/MWh
Price standard deviation	158.19 EUR/MWh
Renewable curtailment	109.15 TWh/year
Load shedding	0.907 TWh/year
Net CO_2 emissions	1172.79 $MtCO_2$/year
Renewable penetration	20.87% of annual demand
Nuclear generation	713.94 TWh/year

As shown in Table 3, the benchmark system already exhibits both excess renewable generation and scarcity. Figure 2 complements this interpretation by showing the regional generation mix of the no-storage reference case. The map indicates that the benchmark system is primarily supported by nuclear generation together with significant contributions from coal and lignite in several continental zones, while wind-based generation is more concentrated in the northern regions. The coexistence of high curtailment and positive load shedding shows that the system has both periods of excess renewable availability and periods of insufficient supply, which is a clear sign of inadequate temporal flexibility.

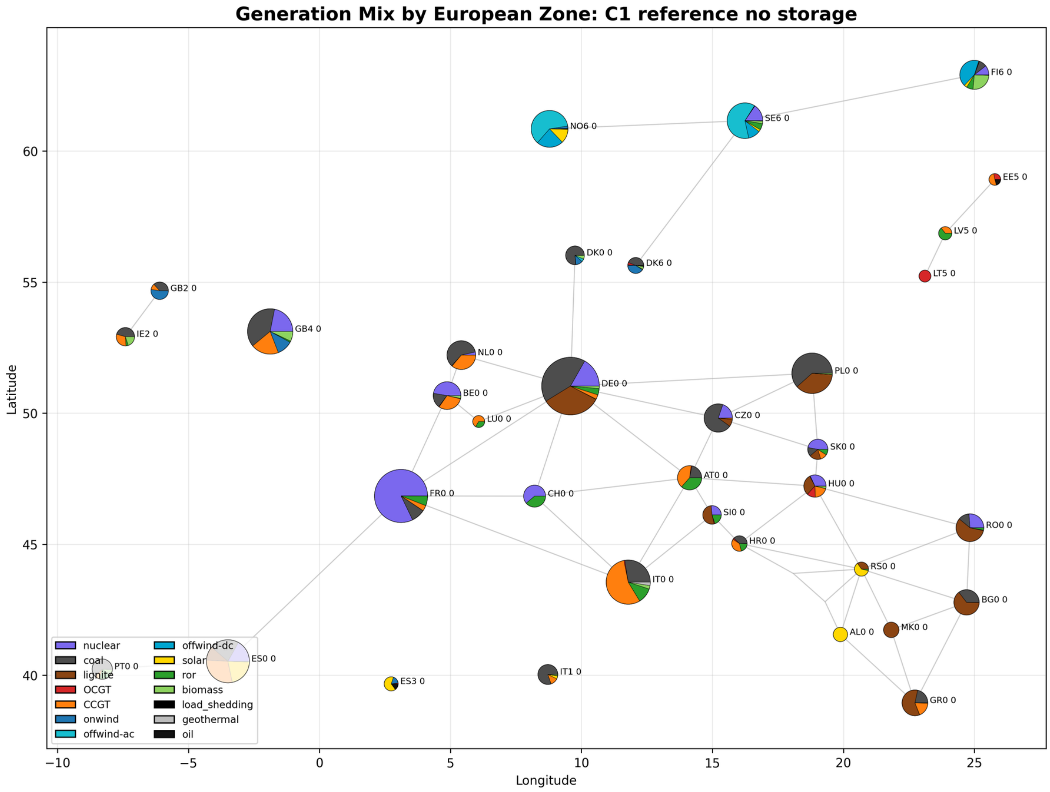


Figure 2: Generation mix by European zone for the no-storage reference case. The map illustrates the regional distribution of generation technologies before new storage is introduced.

4.2 Value of storage under the reference carbon setting

The next step is to isolate the value of storage under the same nuclear-cap setting and without additional carbon-cap tightening. Four cases are compared: no storage, battery, hydrogen, and battery + H_2. Table 4 summarises the corresponding performance metrics.

Table 4: Storage comparison at the reference carbon setting.

Case	Cost bn EUR/yr	Mean price EUR/MWh	Curtailment TWh/yr	Load shedding TWh/yr	Storage power GW	Storage energy GWh
No storage	101.92	63.54	109.15	0.907	0.00	0.00
Battery	93.70	55.98	47.12	0.065	31.39	251.10
Hydrogen	87.48	49.16	0.03	0.000	33.18	1592.64
Battery + H_2	87.48	49.16	0.03	0.000	33.20	1592.83

As shown in Table 4, the storage comparison reveals a clear improvement in system performance once storage is introduced. Relative to the no-storage reference, battery storage reduces system cost by about 8.22 billion EUR/year and lowers the mean price by 7.56 EUR/MWh. It also cuts renewable curtailment from 109.15 to 47.12 TWh/year and reduces load shedding from 0.907 to 0.065 TWh/year. Hydrogen storage performs even better: the system cost falls by about 14.44 billion EUR/year, the mean electricity price decreases to 49.16 EUR/MWh, curtailment is almost eliminated, and load shedding disappears entirely.

An important result is that the combined battery + H_2 case performs almost identically to the hydrogen-only case. This suggests that, within the present model setup, the long-duration balancing capability of hydrogen already captures nearly all of the storage value, leaving little additional benefit for battery storage once hydrogen is available. In other words, storage clearly improves the system, but hydrogen provides the dominant contribution to that improvement under the reference carbon setting.

4.3 Generation mix and carbon-constrained renewable penetration

To examine the impact of decarbonization pressure, carbon-cap reductions of 20%, 40%, and 55% are imposed while maintaining the 24% nuclear cap. Figure 3 presents the annual generation mix across all 13 scenarios, while Figure 4 shows the corresponding net CO_2 emissions.

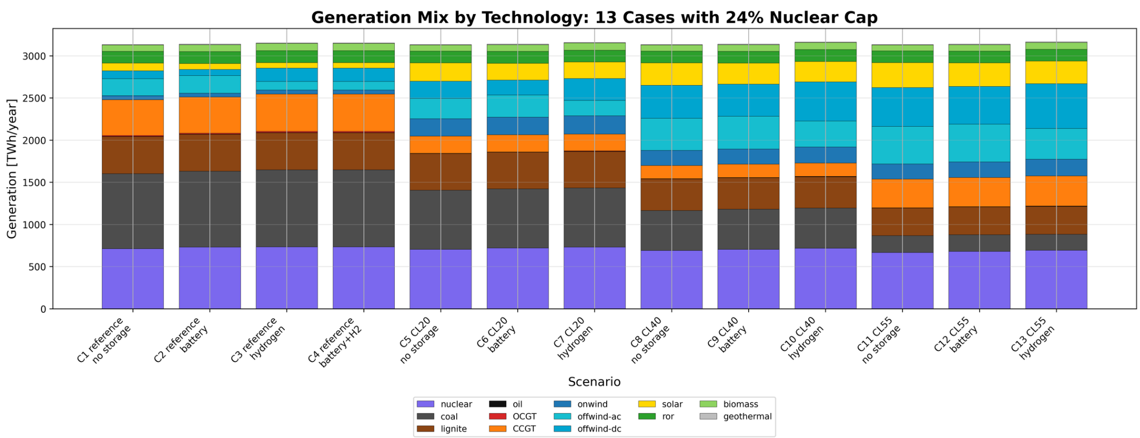


Figure 3: Annual generation mix by technology for all 13 scenarios. Values are shown in TWh/year.

The generation-mix comparison in Figure 3 shows that tighter carbon caps progressively reduce the contribution of high-emission technologies, particularly coal and lignite, while increasing the relative importance of lower-carbon and renewable generation. This shift is strongest in the hydrogen scenarios, where storage enables a much larger share of variable renewable generation to be retained within the system rather than curtailed. Although the nuclear cap remains fixed, the tighter carbon limit still pushes the system toward greater renewable penetration by restricting the use of fossil generators.

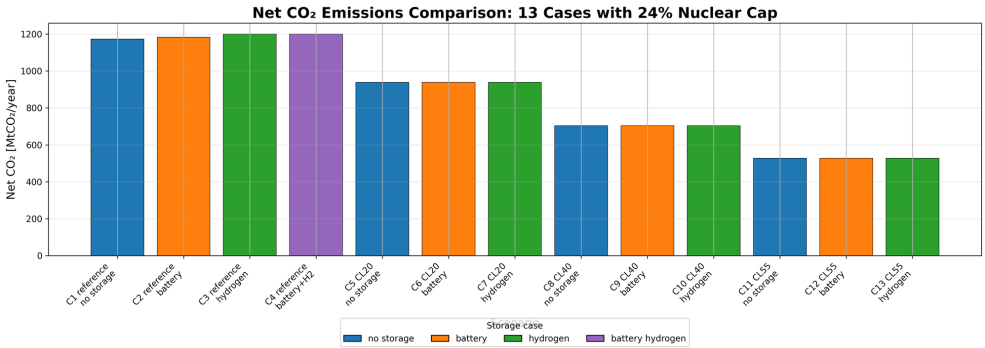


Figure 4: Net CO_2 emissions across the 13 scenarios.

Figure 4 confirms the effect of the carbon policy. Net CO_2 emissions decline from 1172.79 $MtCO_2$/year in the reference case to approximately 938.23, 703.67, and 527.76 $MtCO_2$/year under the 20%, 40%, and 55% carbon-cap reductions, respectively. Therefore, the carbon cap is effective in forcing a cleaner generation mix. At the same time, the generation-mix results indicate that this transition is supported most effectively in the hydrogen cases, which can integrate renewable generation with very limited curtailment.

4.4 *Effect of carbon caps on cost, price, curtailment, and adequacy*

The next question is how the tighter carbon caps affect overall system performance and whether storage remains valuable in a more decarbonized setting. Figures 5 and 6 compare system cost and mean electricity price across all scenarios.

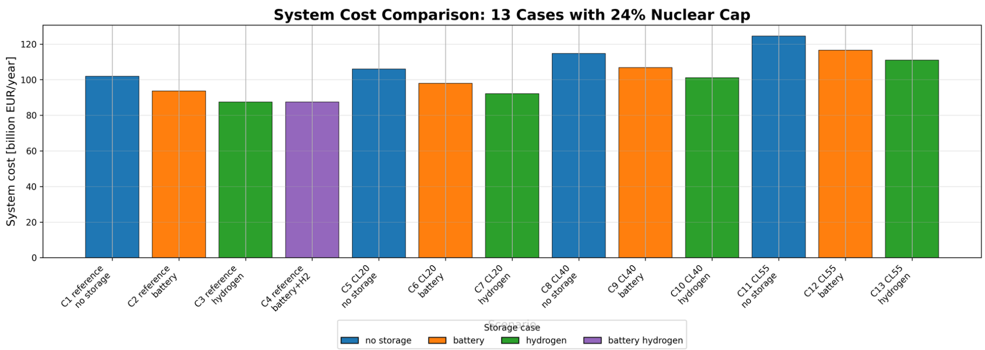


Figure 5: Total system cost across the 13 scenarios.

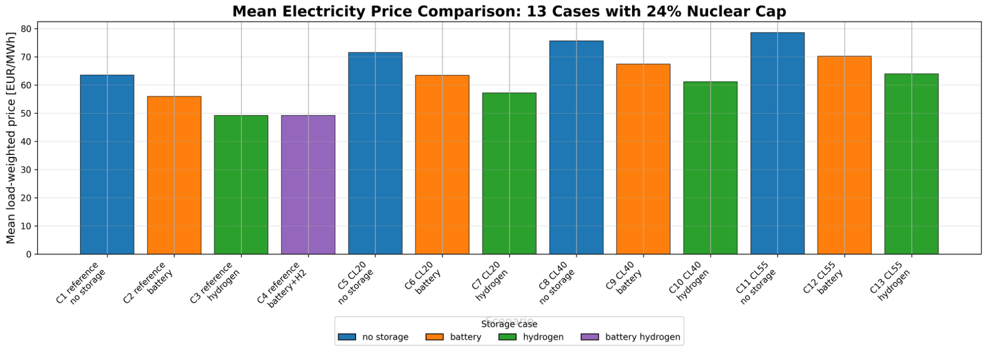
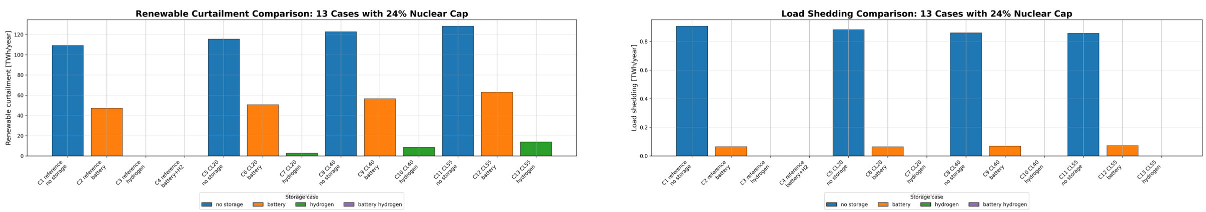


Figure 6: Mean load-weighted electricity price across the 13 scenarios.

As shown in Figures 5 and 6, a clear pattern emerges: as the carbon cap becomes stricter, both total system cost and electricity prices increase in all storage configurations. For the no-storage cases, system cost rises from 101.92 billion EUR/year in the reference case to 105.95, 114.71, and 124.47 billion EUR/year under the 20%, 40%, and 55% carbon-cap reductions. The corresponding mean prices increase from 63.54 to 71.56, 75.67, and 78.57 EUR/MWh. Thus, decarbonization imposes a clear cost and price penalty on the system.

However, storage substantially mitigates this penalty. Under the same carbon caps, battery storage reduces the system cost to 97.98, 106.81, and 116.60 billion EUR/year, while hydrogen reduces it even further to 92.17, 101.15, and 111.00 billion EUR/year. A similar pattern is observed for mean electricity prices, where hydrogen consistently delivers the lowest values among the storage options. This shows that storage remains economically beneficial even in a stricter low-carbon system.

The same conclusion is visible in the curtailment and adequacy results. Figure 7 compares renewable curtailment and load shedding across all 13 cases.



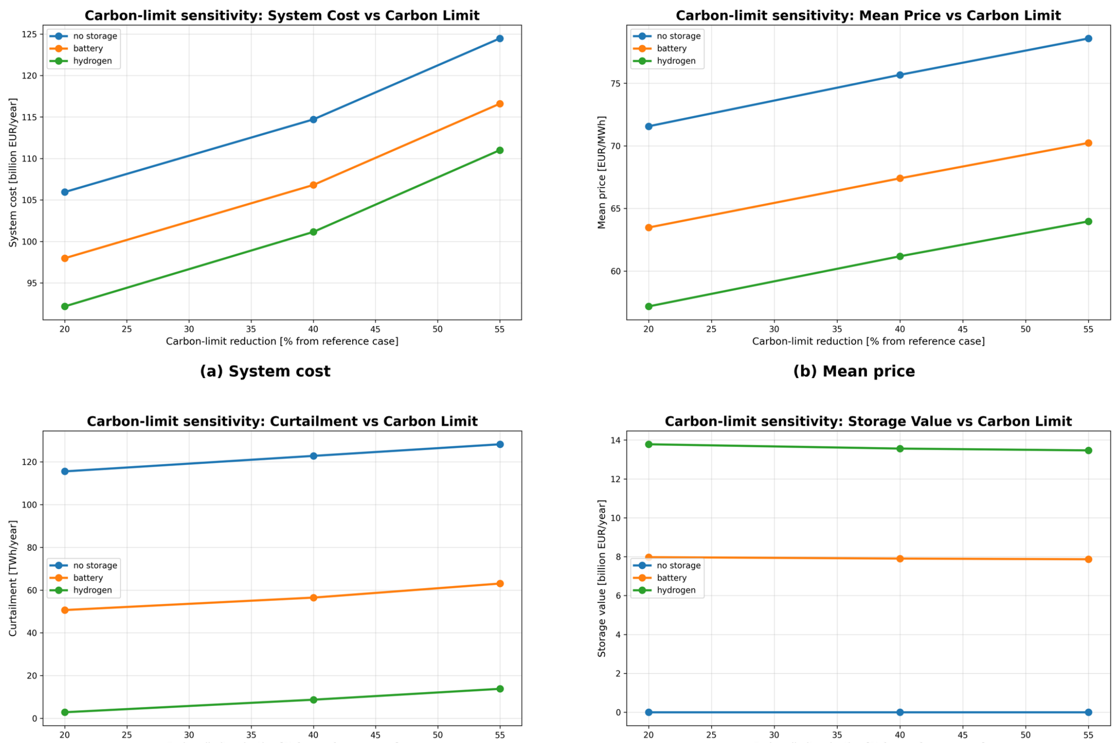
(a) Renewable curtailment. *(b) Load shedding.*

Figure 7: Curtailment and adequacy comparison across the 13 scenarios.

As seen in Figure 7, without storage, curtailment increases from 109.15 TWh/year in the reference case to 115.53, 122.78, and 128.21 TWh/year as the carbon cap is tightened. Battery storage lowers these values substantially, but curtailment remains relatively high at 50.66, 56.48, and 63.06 TWh/year for the three carbon-cap cases. In contrast, hydrogen storage almost eliminates curtailment at the 20% cap and keeps it much lower than the alternatives even at the strictest carbon cap, with values of 2.84, 8.72, and 13.81 TWh/year.

The adequacy results show a similar pattern. No-storage cases continue to exhibit load shedding of around 0.86–0.91 TWh/year, while battery reduces the shortage to about 0.06–0.07 TWh/year. Hydrogen eliminates load shedding in all tested carbon-cap cases. Therefore, storage is not only valuable in economic terms, but also plays a critical role in maintaining adequacy under decarbonization pressure.

To make the carbon-cap sensitivity more explicit, Figure 8 shows the trends for cost, mean price, curtailment, and storage value as a function of the carbon limit.



(a) System cost

(b) Mean price

(c) Curtailment

(d) Storage value

Figure 8: Carbon-limit sensitivity. Storage reduces the cost and curtailment penalty of stricter carbon limits, with hydrogen giving the largest value.

Figure 8 confirms that tightening the carbon cap monotonically increases system cost and mean electricity price, while also raising renewable curtailment. Yet the figure also shows that storage continues to reduce these penalties, and that hydrogen consistently outperforms battery. This result is reinforced by Figure 9, which compares storage value at the same carbon limit.

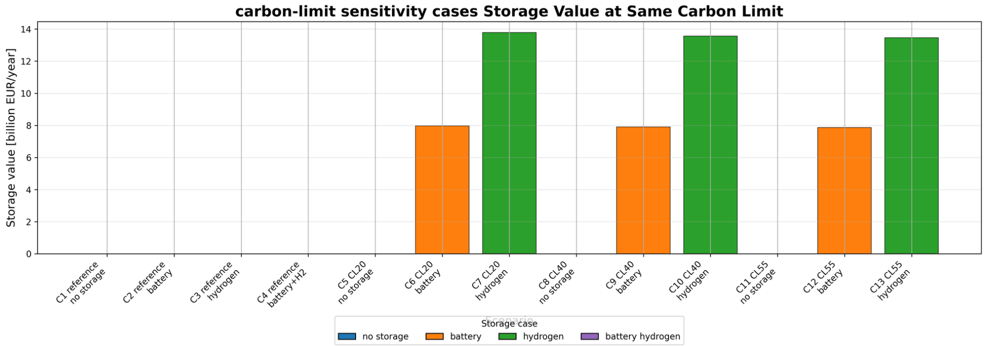
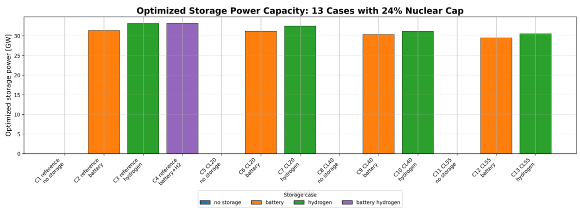


Figure 9: Storage value at the same carbon limit.

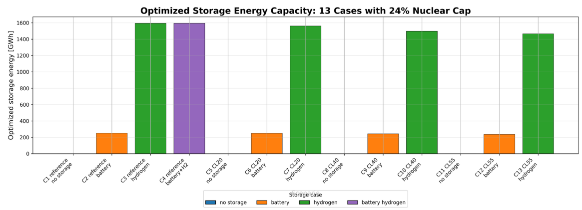
At the same carbon cap, as shown in Figure 9, hydrogen provides a storage value of approximately 13.78, 13.56, and 13.47 billion EUR/year for the 20%, 40%, and 55% carbon-cap cases, respectively. The corresponding values for battery are about 7.98, 7.90, and 7.87 billion EUR/year. Thus, even as decarbonization pressure becomes stronger, hydrogen remains the most valuable storage option within the tested assumptions.

4.5 Storage sizing requirements

The final result concerns the scale of storage required by the model. Figures 10a and 10b show the optimized storage power and storage energy capacities across the 13 cases.



(a) Storage power capacity.



(b) Storage energy capacity.

Figure 10: Optimized storage sizing across the 13 scenarios.

As shown in Figure 10, the power-capacity results indicate that both battery and hydrogen storage require broadly similar installed power levels, typically in the range of about 30–33 GW. However, the energy-capacity requirements differ dramatically. Battery storage requires around 236–251 GWh across the tested cases, whereas hydrogen storage requires approximately 1466–1593 GWh. The combined battery + H_2 case also remains dominated by the hydrogen energy requirement.

This difference in required energy capacity highlights the distinct functional roles of the two storage technologies. Battery acts as a shorter-duration balancing option, while hydrogen provides much larger intertemporal shifting capability. This is consistent with the earlier finding that hydrogen is more effective at reducing curtailment and eliminating load shedding, especially under stricter carbon caps.

4.6 *Storage economics: revenue, profitability, and LCOS*

To strengthen the economic interpretation, storage-economics indicators are included without changing the main scenario structure. The storage market revenue is calculated from storage discharge multiplied by the nodal model electricity price. The charging cost is calculated from storage charging multiplied by the same nodal price signal. The gross arbitrage margin is therefore the difference between discharge revenue and charging cost. A profitability proxy is then calculated by subtracting the annualised storage capacity cost from this gross arbitrage margin. Finally, the levelized cost of storage (LCOS) is calculated as the sum of annualised storage cost and charging cost divided by the discharged electricity.

Table 5: Indicative storage revenue, discharged energy, profitability proxy, and LCOS across storage scenarios.

Case	Discharge revenue bn EUR/yr	Charging cost bn EUR/yr	Annualised storage cost bn EUR/yr	Discharged energy TWh/yr	Profitability proxy bn EUR/yr	LCOS EUR/MWh
C2 battery	7.27	1.57	5.71	15.64	0.00	465.09
C3 hydrogen	4.96	1.12	3.84	9.55	0.00	519.09
C4 battery + H_2	4.97	1.12	3.84	9.61	0.00	516.83
C6 CL20 battery	7.17	1.50	5.67	15.46	0.00	463.87
C7 CL20 hydrogen	4.91	1.15	3.76	12.11	0.00	405.35
C9 CL40 battery	7.00	1.48	5.52	15.41	0.00	454.50
C10 CL40 hydrogen	4.83	1.22	3.60	14.92	0.00	323.41
C12 CL55 battery	6.88	1.52	5.36	15.59	0.00	441.51
C13 CL55 hydrogen	4.80	1.27	3.53	15.83	0.00	303.25

Figure 11 and Table 5 show that storage earns positive market revenue by discharging during higher-value periods and charging during lower-value periods. In the model, the gross arbitrage margin is approximately equal to the annualised storage cost, so the resulting profitability proxy is approximately zero across the tested cases. This is consistent with a least-cost optimisation with extendable storage capacity: storage is built until the marginal additional unit no longer earns excess profit under the model price signal. Therefore, the near-zero profitability proxy should not be interpreted as storage having no system value. Instead, it means that the system-wide value of storage is reflected in lower total system cost, lower curtailment, reduced load shedding, and lower prices, while competitive energy-market revenues mainly recover the optimised annualised storage cost.

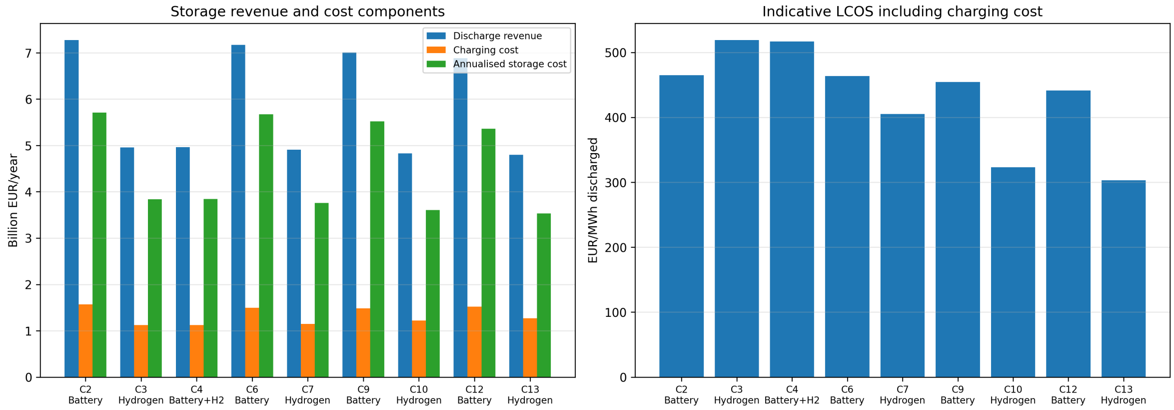


Figure 11: Storage revenue components and indicative LCOS across the storage scenarios.

The LCOS results add an important interpretation to the storage comparison. Battery LCOS remains relatively stable across the tested cases, decreasing slightly from 465.09 EUR/MWh in the reference battery case to 441.51 EUR/MWh in the CL55 battery case. Hydrogen has a higher LCOS in the reference case, but its LCOS falls strongly as the carbon limit becomes stricter, from 519.09 EUR/MWh in the reference hydrogen case to 303.25 EUR/MWh in the CL55 hydrogen case. This happens because hydrogen is used more intensively under stricter carbon constraints, spreading its annualised cost over a larger amount of discharged energy. This supports the earlier conclusion that hydrogen is most valuable in the model when long-duration shifting becomes more important under low-carbon system conditions.

4.7 Best-performing scenario within the tested setup

The results show the best-performing case depends on the metric of interest. If the objective is purely the lowest system cost within the tested assumptions, the hydrogen case under the reference carbon setting performs best. If the objective is stronger decarbonization, the stricter carbon-cap cases are preferable, but they come at the expense of higher system cost and higher electricity prices.

A more balanced interpretation is therefore that hydrogen storage is the strongest-performing storage option across the tested cases, because it consistently delivers the lowest or near-lowest cost, the lowest mean electricity prices among the storage cases, the smallest renewable curtailment, and zero load shedding. Battery storage also provides clear benefits compared with the no-storage benchmark, but it is less effective than hydrogen. Finally, the battery + H_2 case provides almost no additional benefit compared with hydrogen alone, implying that hydrogen already captures the dominant share of the storage value in the present model setup.

Table 6: Best-performing cases by criterion within the tested scenario set.

Criterion	Best case	Interpretation
Lowest system cost	Reference hydrogen / battery + H_2	Lowest-cost storage result under the reference carbon setting.
Lowest mean price	Reference hydrogen / battery + H_2	Lowest mean electricity price among all tested cases.
Lowest curtailment	Reference hydrogen / battery + H_2	Curtailment is almost zero.
Lowest load shedding	Hydrogen cases	Hydrogen removes load shedding in all hydrogen scenarios.
Lowest net CO_2	CL55 cases	The strictest carbon cap determines the emissions outcome.
Best same-limit storage value	CL20 hydrogen	Highest cost reduction relative to no storage at the same carbon limit.
Best balanced low-carbon case	CL55 hydrogen	Low emissions, zero load shedding, and much lower cost than CL55 no storage.

Overall, the results show that tighter carbon caps increase renewable penetration and reduce emissions, but also make the system more expensive and less stable without additional flexibility. Storage reduces these penalties, and hydrogen provides the largest overall value among the tested technologies. The added storage-economics results refine this interpretation rather than overturning it: they show that system value and private profitability are related, but not identical, and that optimized storage approximately recovers annualised cost through model-based market revenues. The best-performing scenario should therefore be described not as the optimal solution for Europe in general, but as the best-performing configuration within the assumptions, model structure, and case design of this study.

5 Discussion

The results show that the system behaviour is shaped by two different forces: flexibility and decarbonization. Storage affects the first force by shifting energy across time and reducing the operational penalties associated with renewable variability. Carbon caps affect the second force by directly restricting emissions and changing the economic viability of the generation mix. The most important interpretation of the results is therefore that storage and carbon policy solve different but complementary problems.

5.1 *Why hydrogen performs better than battery storage*

Hydrogen performs better than battery storage in the tested scenarios because the dominant flexibility requirement in the model is long-duration energy shifting rather than only short-duration balancing, which is consistent with the broader role of long-duration storage in high-renewable systems discussed in the literature [8]. Batteries are more efficient, but their shorter duration limits their ability to absorb large renewable surpluses and cover longer scarcity periods. Hydrogen has lower round-trip efficiency, but its much larger energy duration allows the model to transfer energy across longer temporal gaps.

This difference is visible throughout the results. Compared with battery storage, hydrogen achieves lower system cost, lower mean electricity price, far lower renewable curtailment, and zero load shedding in the carbon-constrained cases. The energy-capacity results in Figure 10 support the same interpretation: hydrogen requires a much larger storage-energy volume than battery storage even when the power capacities are broadly similar. This shows that the system benefits more from long-duration storage than from high-efficiency short-duration storage within the present assumptions.

The result should not be interpreted too generally. It does not imply that hydrogen is always superior to batteries in real power systems. Rather, it means that in this simplified annual PyPSA framework, with the chosen technology costs, durations, and efficiencies, the model places a higher value on multi-hour or multi-day shifting than on shorter-term balancing.

5.2 *Storage improves flexibility, but carbon caps drive decarbonization*

Another important finding is that storage is not automatically a decarbonization policy. In the reference carbon setting, storage reduces cost and curtailment and improves adequacy, but it does not force emissions downward in the way a binding carbon cap does. This is because storage acts within the existing economic structure of the system. If fossil generation remains economically attractive in some hours, storage can reduce cost without necessarily reducing total emissions.

The carbon-limit cases clarify this distinction. When the carbon cap becomes stricter, fossil generation is displaced, renewable penetration increases, and net emissions fall. However, these improvements come with higher system cost and higher electricity prices. Storage then becomes valuable in a different way: not as the direct cause of emissions reduction, but as the technology that reduces the cost, curtailment, and adequacy penalty of complying with the carbon limit.

This interpretation is especially clear in the CL55 hydrogen case. The carbon cap forces the system to 527.76 $MtCO_2$/year, while hydrogen storage reduces the system cost by 13.47 billion EUR/year relative to the corresponding CL55 no-storage case. In other words, the carbon cap delivers decarbonization, while storage makes decarbonization easier to operate. The added storage-economics results also show that system value is not the same as private profitability. In the optimized least-cost model, storage is built until model-based market revenue approximately recovers its annualised cost, which is why the profitability proxy remains close to zero. This should not be interpreted as storage having little economic importance. Rather, it indicates that much of the value of storage appears at the system level through lower total cost, lower curtailment, lower load shedding, and improved adequacy, rather than through large excess profit for the storage asset itself.

5.3 Interpreting the best-performing scenario

There is no single universally best scenario, because the answer depends on the performance criterion. The lowest system cost occurs in the reference storage cases without additional carbon tightening, whereas the lowest emissions occur in the strict carbon-cap cases. The scenario with the highest renewable penetration is not necessarily the most economically attractive, since strong decarbonization can increase cost and price levels if flexibility is insufficient.

A more balanced conclusion is therefore needed. Within the tested assumptions, hydrogen is the strongest-performing storage technology because it consistently delivers the largest system-cost reduction, the lowest electricity prices among the storage cases, the lowest curtailment, and zero load shedding in the carbon-constrained scenarios. Among the low-carbon cases, the CL55 hydrogen configuration provides the best overall trade-off between emissions reduction, cost, renewable integration, and adequacy. It should therefore be described as the best-performing low-carbon case within this scenario set, rather than as an optimal blueprint for the real European system.

5.4 Limitations

The results should be interpreted within the scope of a simplified comparative scenario study. First, the model uses a zonal European representation rather than a fully nodal grid model, so the results are better suited for system-level comparison than for detailed infrastructure planning. Second, the final scenarios are solved at four-hour temporal resolution, which captures annual trends consistently but cannot fully represent short-term balancing behaviour or fast price variations. Third, detailed operational constraints such as unit commitment, ramping limits, reserve requirements, and ancillary services are not modelled explicitly. Finally, the storage comparison depends on fixed assumptions for storage cost, duration, and efficiency, which means that the relative ranking of battery and hydrogen should be interpreted as conditional on the selected input assumptions.

6 Conclusion

This project examined the value of electricity storage and its interaction with renewable penetration in a simplified European PyPSA model under nuclear and carbon constraints. The no-storage reference case revealed a clear flexibility challenge, with high renewable curtailment, non-zero load shedding, and relatively high electricity prices. Introducing storage improved system performance significantly, and hydrogen storage delivered the largest overall benefit.

Under the reference carbon setting, hydrogen reduced annual system cost more than battery storage, lowered the mean electricity price to 49.16 EUR/MWh, almost eliminated renewable curtailment, and removed load shedding. The combined battery–hydrogen case provided almost no additional benefit beyond hydrogen alone. This indicates that long-duration shifting is the dominant missing flexibility service in the present model setup.

Tighter carbon caps changed the system more fundamentally by increasing renewable penetration and reducing emissions. Under the 55% carbon-limit case, emissions were constrained to 527.76 $MtCO_2$/year, but this came with higher system cost and higher electricity prices in the no-storage case. Storage remained valuable in these low-carbon cases by reducing the cost, curtailment, and adequacy penalty of decarbonization. Among the tested configurations, the CL55 hydrogen case provides the best balance between low emissions, lower cost than the corresponding no-storage system, and strong adequacy performance.

The additional storage-economics indicators show that the optimized storage capacity approximately recovers its annualised cost through model-based market revenues, while the broader system value appears through lower total system cost and improved adequacy. The overall conclusion is that storage and carbon policy play different but complementary roles. Carbon caps are required to ensure structural emissions reductions, while storage provides the flexibility needed to integrate higher renewable shares at lower cost and with better adequacy. Within the tested assumptions, hydrogen is the best-performing storage technology, and the CL55 hydrogen case represents the best-balanced low-carbon configuration in the analysed scenario set.

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